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A PROJECT REPORT ENTITLED

SCREENING AND SELECTION OF ARTIFICIAL LIFT SYSTEMS USING ARTIFICIAL INTELLIGENCE TECHNIQUE FOR A GIVEN WELL

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

BY
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SUBMITTED IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF THE DEGREE OF MASTER OF SCIENCE IN PETROLEUM ENGINEERING

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……………………………………

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NOVEMBER 2023

DECLARATION

I declare that this project work is my own work. It is being submitted for the degree of Master of Science in Petroleum Engineering at the University of Mines and Technology (UMaT), Tarkwa. It has not been submitted for any degree or examination in any other University.

…………………………………………
(Signature of student)

14th...day of……November……2023

ABSTRACT

In spite of numerous studies over the past few decades to comprehend tight formations and create cutting-edge technologies to optimise the application of artificial lifts, there are still varying opinions on the best strategy, Artificial Lift (A.L.) type, and ideal circumstances for installing artificial lifts throughout the life of a well. This research thoroughly analyses the use of artificial lift systems with a particular focus on multi-fractured formations. The review focuses on two recent unconventional horizontal wells called Osprey and Hawk. The goal is to screen and design an optimal and cost-effective Artificial Lift Technology that best fits the Wells in this study. An Artificial Intelligence Screening model was built using Python programming language and supported by Random Forest Algorithm. Productivity analysis and the design specification of the selected lift system after the screening was done using PROSPER Simulation Software. Gas Lift was selected for Osprey well with a productivity Increment of 67%. With regards to the Hawk field, Gas lift was also selected with a productivity increment of 47%. The implementation of any of the optimization strategies for the gas lift will enhance profitability, reduce operational costs, and extend the life of the wells. However, it is recommended to run additional simulations for additional lift methods and use them with the decision matrix, and also keep adding more criteria to the decision matrix that have an impact on screening and selection.

I dedicate this work to my mother, Mrs. Rose Esi Nyarko for her love and support.

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CHAPTER 1

INTRODUCTION

1.1 Statement of the Problem

Reservoir pressure, after long periods of production, drops significantly to levels where oil rates are not economically viable and in cases where the production tubing is too large, it can actually reduce the rate at which a well will flow (Höök, 2009). This can cause the well to load up with liquids and die. The need to maintain oil production requires the implementation of an Artificial Lift system to increase production. Gas lift is widely utilized around the world, and it dominates production in the Gulf Coast of the United States (Guo *et al*., 2007). Plunger lift has recently become more common on gas wells for de-watering purposes (Beauregard and Ferguson, 1981). There are more than 750 000 raised wells that use sucker-rod pumps. In the US, sucker-rod pumps raise around 350,000 wells (Kramer *et al*. 1982). To handle greater GOR applications, multiphase pumps are increasingly being used (Saadawi, 2017) and Saudi Aramco, for example, uses electric submersible pumps (ESPs) to produce around 37% of its reserves (Lastra, 2017).

Horizontally multi-fractured wells, generally result in high production rates as compared to vertical wells. It is associated with some technical difficulties that can reduce its production (Wu, 2022). With less work done on horizontal multi-fractured wells from various oil fields, this has set the project for using Nodal Analysis and Artificial Intelligence (AI) techniques to optimise production by proper selection of artificial lift systems. These techniques will optimise production by proper selection, installation, and operation of gas lift technology.
The gas lift method involves the injection of compressed gas at extremely high pressure in the annulus, and this causes a reduction in viscosity by minimising fluid density (Teteros, 2015). Due to rising frictional losses and rising frictional pressure decreases at high injection flow rates, the gas lift has a negative impact.

Other possible issues with gas lift include aging surface equipment, subsurface well completion conditions in an established field, imprecise production metering, and fluctuating gas compressor availability and efficiency. (Sylvester, 2015). Many operators follow the standard procedure of allocating the lift gas to a well in accordance with a gas-lift performance curve to find the ideal gas lift rate. (Sylvester, 2015). This project seeks to optimise artificial lift system performance on a horizontal multi-fractured well and its inflow and outflow performance.

1.2 Objectives of Research

The objectives of this project were to:

i. Screen Artificial Lift Systems for production of wells using AI techniques;
ii. Select and design an optimal Artificial Lift system to increase production by increasing the outflow performance of the horizontally multi-fractured well.

1.3 Methods Used

The research methods used are:

i. Review of relevant literature;
ii. Acquisition of horizontally multi-fractured well data from a field (daily rates, pressures, and completion information); and
iii. PROSPER software and Python Programming Language to optimise the production data.

1.4 Organisation of Thesis

There are five chapters in this project. The topic is stated in Chapter 1 with a brief discussion of how Artificial Lift has significantly impacted oil and gas production in recent years. It also describes the difficulties encountered and how this effort aims to resolve them. The research's goals, methodologies, and report structure are all covered in this chapter.

To provide a thorough understanding of the research focus, an overview of pertinent literature from a variety of scholars has been compiled in Chapter 2 of this thesis. Chapter 3 provides a thorough explanation of the resources and techniques employed to accomplish this thesis goals. The developed Artificial Intelligent (AI) model and the simulation programme used (PROSPER) are discussed in Chapter 3.

The results are presented in Chapter 4 of this thesis together with a discussion to clarify the significance of the findings. Chapter 5 presents the conclusions and recommendations reached in light of the fourth Chapter's findings.

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

This chapter provides an overview of what a reservoir is, the definitions of horizontal well and multi-fractured horizontal well, and the characteristics of each. In addition, there is an introduction to artificial lifts, their drivers, and the different types of artificial lifts and the description of the different types of gas lifts. Furthermore, the chapter discusses the definition and application of Artificial Intelligence (A.I.), Prosper Software, and a review of pertinent works.

2.2 Reservoir

Reservoirs, fields, and pools are three types of hydrocarbon accumulations in geological traps. A solitary bank of hydrocarbons contained in a porous, permeable subterranean formation with a single natural pressure system, known as a "reservoir," is constrained by impermeable rock or water barriers (Boyun *et al*., 2007). A "field" is a region made up of one or more reservoirs that are all connected by a structural element. One or more reservoirs are contained in discrete structures in a "pool" (Anon, 2019).

Oil, gas condensate, or gas reservoirs are the three types of hydrocarbon accumulations that are classified based on the initial reservoir state on the phase diagram (Figure 2.1). "Undersaturated oil" is defined as oil that is at a pressure higher than its bubble-point pressure (Boyun *et al*., 2007) because at a certain temperature it may dissolve more gas. A "saturated oil" has reached its bubble-point pressure and can no longer dissolve any more gas at the given temperature. In an undersaturated oil reservoir, single-phase (liquid) flow is predominant, while two-phase (liquid oil and free gas) flow is predominant in an oversaturated oil reservoir (Hughes, 2013).

The following are the classifications for oil reservoirs based on border type, which defines the driving mechanism:

2.2.1 Water-Drive Reservoir

The oil zone in water-driven reservoirs is connected to the surface groundwater system by a continuous channel (aquifer). The pressure created by the "column" of water rising to the surface collides with the impermeable barrier, which prevents the oil and gas from rising to the surface, causing the oil (and gas) to rise to the top of the reservoir (the trap boundary) (Al-Ghamdi and Ershaghi, 1996). By applying pressure, the oil and gas will be pushed toward the wellbore. When there is an active water drive, reservoir pressure will be maintained for a longer amount of time (in comparison to other drive systems) with the same oil production. In contrast to bottom-water drive reservoirs, edge-water drive reservoirs are the most sought-after kind of reservoir. The reservoir pressure may be kept above the bubble-point pressure for maximum well productivity such that the reservoir has single-phase liquid flow (Arevalo and Wattenbarger, 2001).

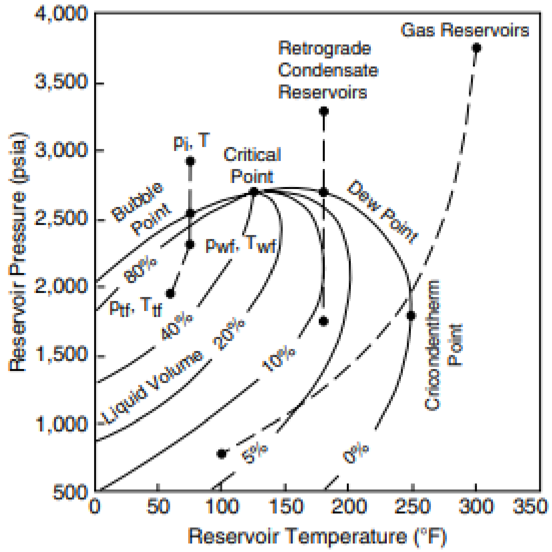


Figure 2.1 A Typical Hydrocarbon Phase Diagram (Ali *et al*., 2007)

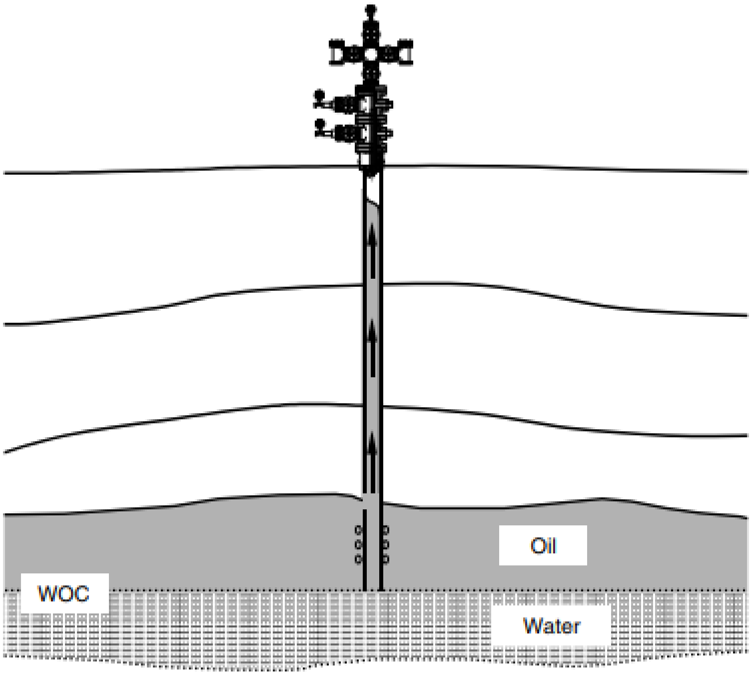


Figure 2.2 Water Drive Reservoir (Ali *et al*., 2007)

2.2.2 Gas-cap Drive Reservoir

In a gas-cap drive reservoir, the gas has emerged from the solution and ascended to the reservoir's top to create a gas cap (Figure 2.3). Oil may therefore develop behind the gas cap. The reservoir pressure will rapidly drop if the gas in the gas cap is removed from the reservoir at the start of the production phase. At times, both water and gas-cap drives could be applied to an oil reservoir (Wang, 2016).

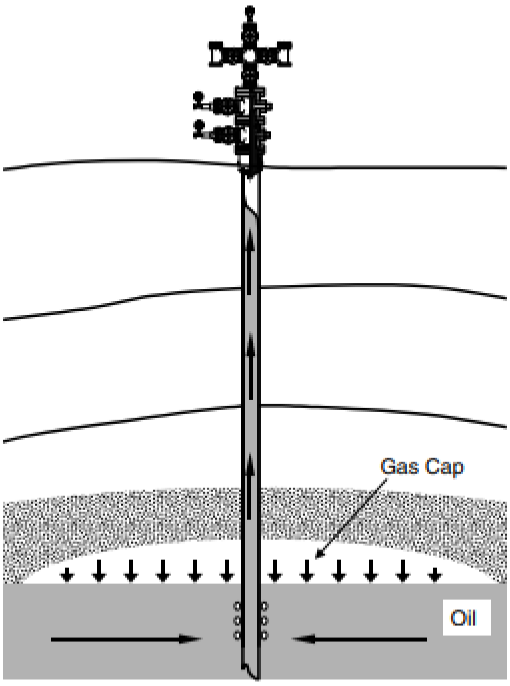


Figure 2.3 Gas-Cap Drive Reservoir (Ali *et al*., 2007)

2.2.3 Dissolved Gas Drive

"Solution-gas drive reservoir" or "volumetric reservoir" are other names for dissolved-gas drive reservoirs. The oil reservoir has a predetermined amount of oil and there are no flow restrictions around it (faults or pinch-outs). With a driving mechanism, the dissolved-gas drive keeps the reservoir gas in solution in the oil (and water) (Clarkson, 2013). The reservoir gas dissolves as a liquid in the reservoir's liquids (under atmospheric conditions). The expansion of solution (dissolved) gas in the oil serves as a modest driving mechanism in volumetric reservoirs as compared to water- and gas-drive reservoirs. As soon as the pressure falls below the bubble point pressure, gas escapes from the oil, causing an oil-gas two-phase flow. Early pressure maintenance is usually favoured to improve oil recovery in solution-gas reservoirs (Clarkson, 2013).

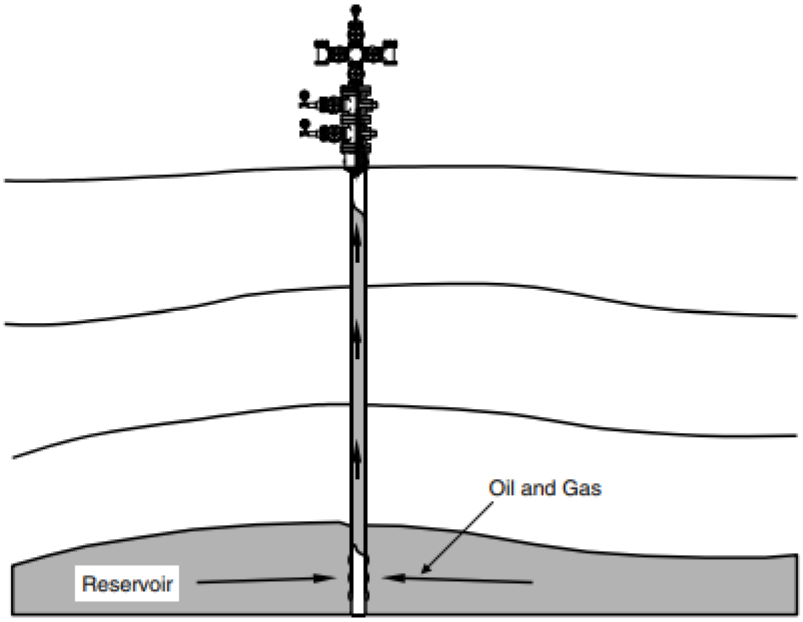


Figure 2.4 Dissolved Gas Drive Reservoir (Ali *et al*., 2007)

2.2.4 Reservoir Fluid

The reservoir fluid's qualities must also be taken into account. When sucker-rod pumping is utilized, paraffin buildup can be handled mechanically, but other artificial lift methods may require a heat or chemical solution. Jet pumps, sucker-rod pumps, and reciprocating hydraulic pumps may all malfunction in sand or particles, thus plunger lifts are not employed - loaded output (Craft and Hawkins, 1991). With only minor issues, Modest quantities of solids are produced by PCPs and gas lift. The ratio of generating gas to liquid is critical to the lift designer. If the amount of free gas at intake circumstances is considerable, gas interference might be a penalty for all types of lift, but it is an advantage for gas lift. Most major forms of lift are hampered by high fluid viscosity; however, low-temperature, shallow, and viscous fluids are readily produced by the PCP (Craft and Hawkins, 1991).

2.3 Horizontal Well

An oil or gas well must be dug at an angle of at least 80 degrees from the vertical wellbore in order to be considered a horizontal well. In recent years, this strategy has become more popular and effective in oil and gas production (Medeiros *et al*., 2010). It is used by operators to extract oil and natural gas from reservoirs with unusual or difficult-to-access shapes. During the 2010s, horizontal wells played a bigger role in fossil fuel extraction. Horizontal drilling has cut prices and improved the efficiency of oil and natural gas extraction as technology has progressed (Anon, 2021).

With more than 2 700 wells completed with horizontal extensions ranging from 1 500 to 3 500 feet, horizontal drilling for primary oil recovery has become typical in several nations. These wells are usually designed to achieve a nearly perpendicular intercept with natural fracture systems in reservoirs with a matrix that is significantly vertically fractured. Horizontal wells look to have the potential to be used in secondary or enhanced oil recovery operations (Reeves and Restrepo, 2019).

2.4 Multi-Fractured Horizontal Well

The Multi-Fractured Horizontal Well (MFHW) has shown to be an effective choice for economically producing natural gas and oil in low-permeable tight/shale formations as well as for enhancing production of huge carbonate reservoirs (Medeiros *et al*., 2010). As a result, MFHWs can be assumed to exist just by analogy. Increasing coal bed methane gas production could be a realistic solution for Reservoirs with low permeability (Valencia *et al*., 2005).

2.5 Artificial Lift

The bulk of oil reservoirs are volumetric, which implies that the predominant process when reservoir pressure reduces due to fluid production is the expansion of solution gas. If natural driving mechanisms (such as an aquifer or gas cap) or pressure maintenance mechanisms (such as water flooding or gas injection) are not available to sustain reservoir energy, oil reservoirs would ultimately be unable to create fluids at cost-effective rates (Fleshman and Lekic, 1999). The only method to get a well to produce at a high rate is to artificially decrease the bottom-hole pressure and raise the production pressure drawdown.

2.6 Drivers for Artificial Lift

The rising worldwide crude oil output despite the oil price slump, as well as fresh initiatives to seek production from mature areas, are among the primary causes driving artificial lift system expansion. Over 70% of global oil and gas output comes from mature fields (O'Brien *et al*., 2016). Artificial lift is being used in field development at a higher rate than ever before for the following reasons (Anon, 2019):

i. Matured Fields: Most oil-producing regions across the world, such as the Gulf of Mexico and the Middle East, are maturing, resulting in reservoir pressure reduction, necessitating the use of artificial lift systems like Electrical Submersible Pump (ESP), which can accommodate larger liquid volumes. Saudi Aramco, for example, uses ESPs to produce around 37% of its reserves (Lastra, 2017);

ii. Pressure Maintenance: Water flooding to maintain pressure early in the field's life results in increased water cut, which may necessitate the use of ESP devices;

iii. Satellite and subsea wells: A gathering manifold is sometimes several miles away from a marginal satellite well. Because of the great distance between these wells, a subsea boosting system is required to overcome the pressure loss in the pipe and flowlines;

iv. Long-reach horizontal wells: Horizontal wells are drilled to optimise well contact with the reservoir and production, and these often necessitate the use of an artificial lift system. In the United States alone, there are about 100 000 horizontal wells (Rassenfoss, 2018);

v. Technical innovation: The development of multiphase pumps that may now be deployed downhole or subsea has broadened the artificial lift technique's application. To handle greater GOR applications, multiphase pumps are increasingly being used (Saadawi, 2017). The tapered pump is another design that employs several different volumetric phases (large flow capability on the bottom, smaller flow capacity on top). The volume of the gaseous fluid decreases as it moves through the pump because it is compressible;

vi. Demand for higher profitability: A well with a higher rate of production yields a higher rate of return. Even if reservoir pressure is sufficient, an artificial lift system like ESP could be used to obtain the requisite economic flow rates (Nutter, 2017);

vii. Advances in artificial lift monitoring systems: Artificial lift systems are becoming more reliable because of SCADA (supervisory, control, and data acquisition) monitoring systems that operate in real-time. To avoid complete system failure, in-built systems provide pre-failure warning indicators (Woods and Lea, 2017). Advanced software systems, in combination with the use of Variable Speed Drives (VSD), aid in well optimisation and the reduction of pumped-off situations (Salis *et al*., 1996);

viii. Rigless ESP Systems: For typical ESPs in offshore applications, high intervention and work-over costs requiring rig deployment and retrieval could substantially impact the project's Net Present Value (NPV). The current trend toward retrieval and deployment using coil tubing, wireline, or 23 slickline rigless techniques provides ample incentives for these new-generation ESP systems (Gorbonov, 2017); and

ix. Multiphase ESP and Advanced Gas Handling System: A new generation of multiphase pumps has been developed and implemented in oil fields, capable of handling larger Gas Volume Fraction (GVF) of up to 80%. For subsea boosting applications, these pumps can be deployed downhole or at the riser base (Hua *et al*., 2012). Camilleri *et al*. (2011) reported well head pressure stabilisation, lower bottom hole flowing pressure, and overall system efficiency after introducing multiphase ESP systems at Congo's Likalala and Kombi fields, resulting in a 50% boost in production. Schlumberger's multiphase Advanced Gas Handling (AGH) systems can be employed in gassy wells in conjunction with ESP.

2.7 Types of Artificial Lift

The most prevalent artificial lift technologies include reciprocating and jet hydraulic pumping systems, ESP, gas lift, sucker-rod (beam) pumping, and so on. Additionally growing in popularity are Progressive Cavity Pumps (PCP) and Plunger Lifts (Gault, 1987). There are other approaches that may be used, including the electrical submersible progressive cavity pump (ESPCP), which is described as appropriate for pumping viscous oils and sediments in deviated wells. This system is similar to an ESP in that it includes a PCP as well as a motor and other component. Other solutions include beam pump system modifications, a variety of intermittent gas-lift methods, as well as more combination systems (Lopez *et al*., 2019).

As part of the overall well design, the artificial lift mechanism should be selected. The wellbore size required to achieve the desired production rate must be taken into account once the method has been decided upon. Casing programs are often developed to save costs connected with well completion, but it is subsequently found that size restrictions on artificial lift equipment prevent the predicted output from being reached (Bello *et al*., 2016). This can cause all reserves to be lost. Smaller casing sizes may result in problems with well-servicing over the long run even if expected production rates are attained. Choosing a small casing size to help with current economics may be attractive when oil prices are low. Although it is ideal to drill and complete wells with future production and lift techniques in mind, this isn't always the case (Lopez *et al*. 2019).

2.7.1 Sucker Rod Pumping

Beam pumping (Figure 2.6) is another name for sucker rod pumping. In order to raise oil from the pit's bottom to the surface, it generates mechanical energy. Field staff will find it to be efficient, easy, and simple to utilize. It can lower the pressure in a well to extremely low levels to boost oil output (Gault, 1987). Slim holes, many completions, and viscous and high-temperature fluids are all possibilities. The method might also be quickly and cheaply adapted to other wells. High friction in crooked or deviated holes, problems with solid sensitivity, low efficiency in gassy wells, a depth limit brought on by rod capacity, and bulkiness in offshore operations are all significant drawbacks of beam pumping. Pump-off controls have been improved, as well as gas separation and management (Gibbs, 1977).

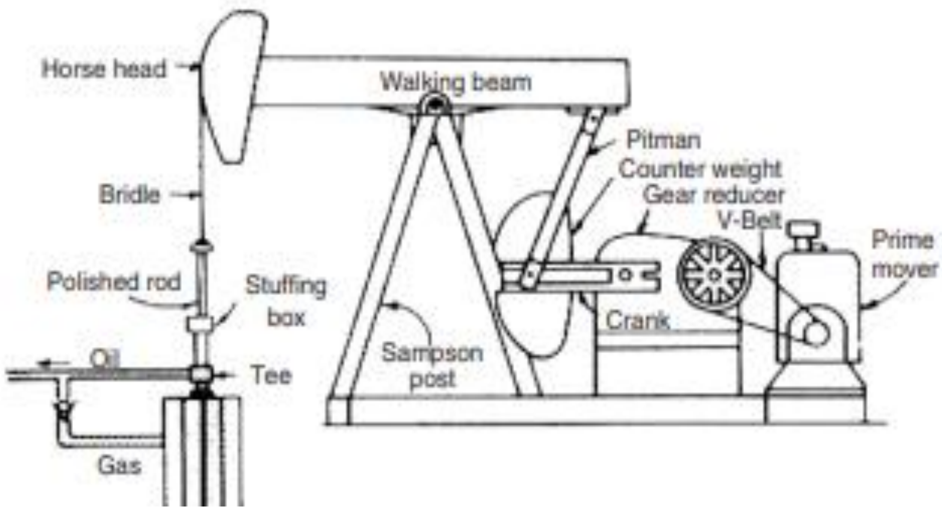


Figure 2.5 Sucker Rod Pumping System (Golan and Whitson, 1991)

Around the globe, there are more than 2 million active oil wells. A million or more wells use artificial lift. Sucker-rod pumps are used in more than 750 000 elevated wells. Sucker-rod pumps lift roughly 350,000 wells in the United States (Kramer *et al*. 1982). In the United States, stripper wells, which produce fewer than 10 barrels per day with some water cut, account for around 80% of all oil wells. Sucker-rod pumps are used to raise the majority of these stripper wells. Rod-pumped wells account for 27% of non-stripper "higher" volume wells, gas-lifted wells account for 52%, and the rest are lifted using ESPs, hydraulic pumps, and other means. Rod pumping dominates onshore activities, as evidenced by these facts 4. For offshore and higher-rate wells worldwide, ESP and gas lift utilization is much greater (Mohaghegh *et al*., 2002).

Some major considerations for Sucker-Rod Pumping Systems are:

i. Sucker-rod pump systems often experience the cyclic load fatigue that is characteristic of sucker-rod pump systems, and the distance between the surface and the downhole pump is measured by the sucker-rod string. Because corrosion causes stress concentrations that can lead to premature failures, the system, like any other artificial lift system, must be kept corrosion-free. Rod failures must be prevented for a system to be cost-effective (Gibbs, 1977);

ii. Sucker-rod devices could be used to raise moderate amounts from shallow depths and modest volumes from intermediate depths. From 7 000 feet and 14

000 feet, respectively, you can raise to 1 000 B/D and 200 bbl. Special rods may be required, and charges may be decreased, depending on the conditions (Gault, 1987);

iii. Even when fitted with rod guards, rod and/or tubing rotators, sucker-rod pumping systems are often unsuitable with deviated (doglegged) wells. Even though the angle at the bottom of the well is substantial (about 30 to 40°, up to 80°), deviated wells with smooth profiles and low dogleg severity may permit good sucker-rod pumping (Gault, 1987);

iv. The proper operation of sucker-rod pumping systems might be hampered by paraffin and scale. To counteract paraffin, special wiper systems on the rods and hot water/oil treatments are used. Early failures can be caused by hard scaling (Gibbs, 1977); and

v. The presence of free gas in the downhole pump decreases hydrocarbon output and causes additional issues (Gault, 1987).

2.7.2 Plunger Lift

Plunger lift systems are suitable for wells with a high gas-liquid ratio. They are extremely low-cost installations. The plunger cleans the tube of paraffin and scale automatically (Beauregard and Ferguson, 1981). They are, however, appropriate for low-rate wells with flow rates less than 200 B/D. Plunger lift has been used in oil wells for a long time. Recently, the use of plunger lifts on gas wells to dewater has increased. (Beauregard and Ferguson, 1981).

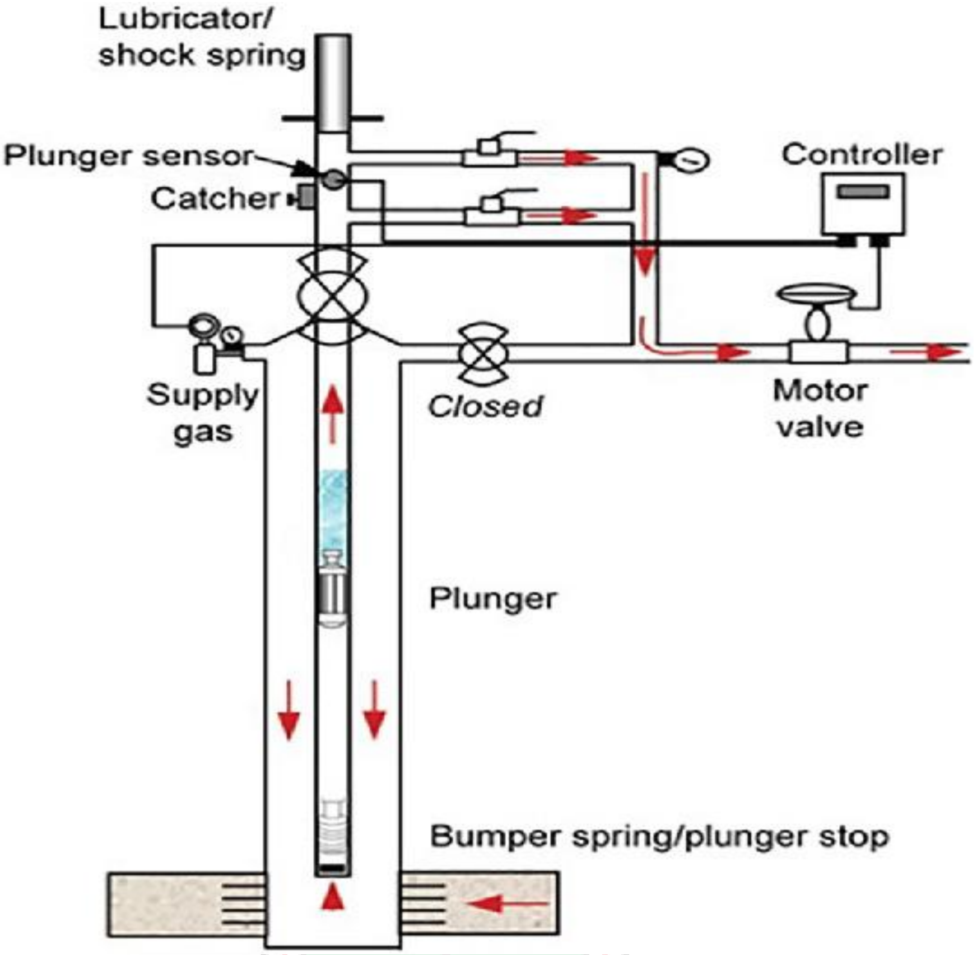


Figure 2.6 A Typical Plunger-Lift Installation (Zhao, 2012)

Gas that has liquid water and/or condensate in the form of mist is produced by high-pressure gas wells. As a result of reservoir pressure loss, the well's gas flow velocity falls, lowering the gas' carrying capacity (Beauregard and Ferguson, 1981). The liquid starts to accumulate in the well when the gas velocity drops below a certain point, and the well flow may change from annular to slug flow. Liquid loading, or the accumulation of liquids, increases bottom-hole pressure and reduces gas production rates. Low gas production rates will result in a further decrease in gas velocity. The well will eventually move into a bubbly flow regime and stop producing (Beauregard and Morrow, 1989).

2.7.3 Electrical Submersible Pump

Electrical submersible pumps (ESPs) are easy to set up and operate. They have the capability of extracting large amounts of oil from high-yielding sources. Crooked/deviated holes are not a problem. Offshore activities can benefit from ESPs. Lifting expenses are often fairly inexpensive for huge quantities (Smith, 1977). The constraints of ESP applications include the lack of high-voltage electrical supply, inapplicability to repeated completions, unsuitability for deep and high-temperature oil reservoirs, difficulty in producing gas and solids, and cost to install and repair (Ramirez et al., 2000). Oil/water separation is provided down-hole by ESP systems, which have more horsepower, can operate in hotter conditions, are employed in dual installations and as backup down-hole units. Due to sand and gas issues, new products have been created. System automation includes all of the following: monitoring, analysis, and control. (Ramirez *et al.*, 2000).

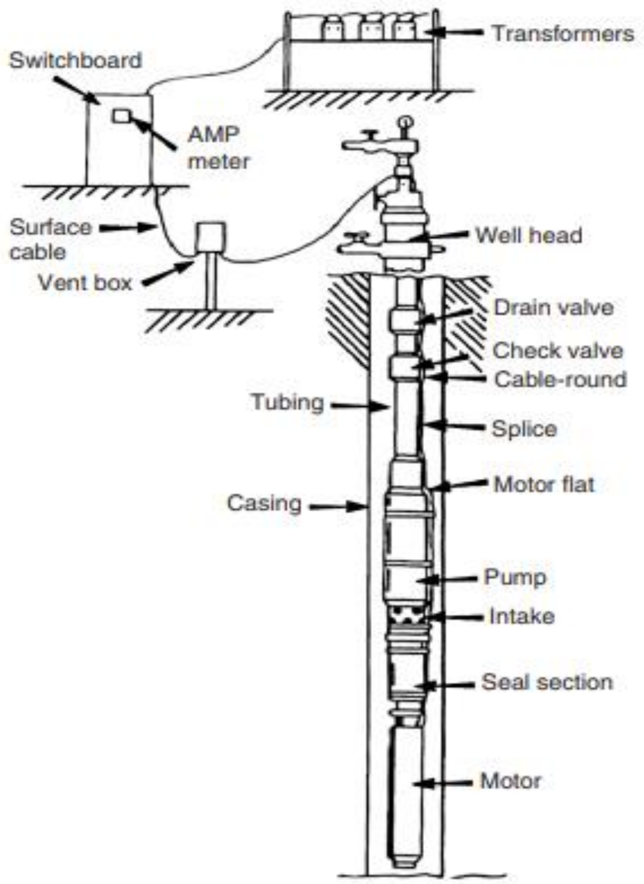


Figure 2.7 ESP Installation (Hughes, 2013).

Some major ESP Advantages are (Ramirez *et al*., 2000);

i. Highly deviated wells may be accommodated; however, the horizontal setting must be in a straight part;

ii. Ability to accommodate the need for subsurface wellheads to be spaced at a maximum of 6 feet apart for surface-location density;

iii. Allow for subsurface controls and related production facilities to occupy the least amount of area feasible;

iv. It must be peaceful, secure, and hygienic for proper operations in an offshore location with environmental concerns;

v. Typically, this pump is referred to as a high-volume pump; and

vi. Activities related to pressure maintenance and secondary recovery can support increased volumes and water reductions.

Some major disadvantages of ESP are (Ramirez *et al*., 2000);

i. Will only stand up to little quantities of solids (sand), but there are specialized pumps available with hardened surfaces and bearings that will wear out less quickly and last longer.;

ii. In order to remedy downhole issues, particularly in an offshore context, expensive pulling operations and lost output must be performed.;

iii. Below 400 B/D, power efficiency plummets significantly, and ESPs aren't especially adaptable at speeds below 150 B/D.; and

iv. For equipment with a moderate to high output rate, a casing size of at least 412 inches or larger is necessary.

2.7.4 Hydraulic Piston Pump

Hydraulic piston pumping systems can raise enormous amounts of liquid from great depths by pumping wells down to relatively low pressures. Crooked holes are only a minor annoyance. The power source might be either natural gas or electricity (Jiao, 1990). They can be used for multiple completions as well as offshore operations. Their significant drawbacks include fire hazards and high costs associated with power oil systems, as well as issues with power water treatment and excessive solids production (Ramirez *et al*., 2000).

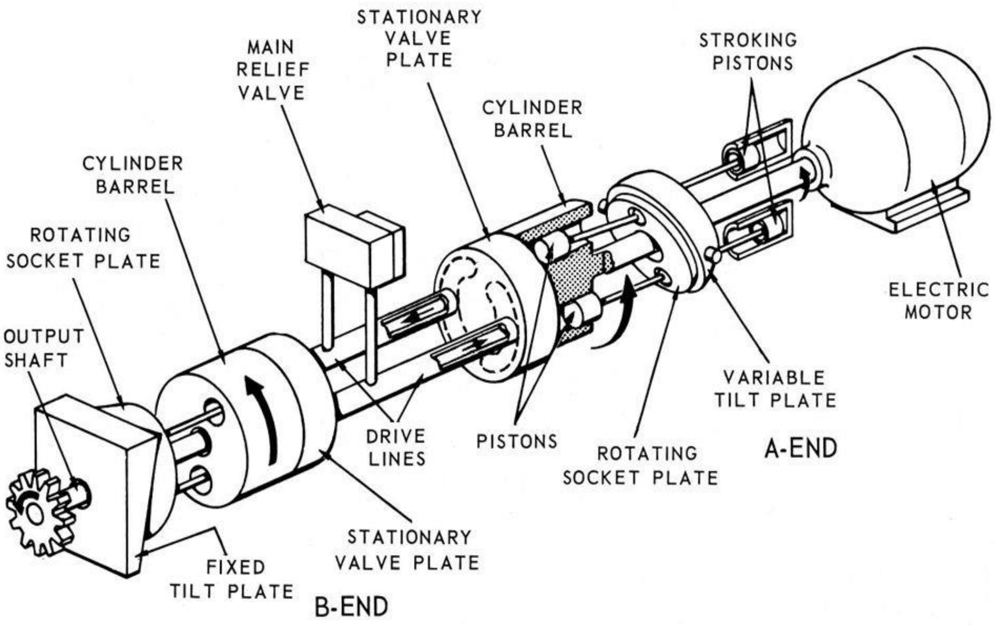


Figure 2.8 Hydraulic Piston Pump (Anon, 2019)

Hydraulic pumps are divided into two types: jet pumps and reciprocating positive-displacement pumps. A jet pump is depicted in Figure 10.7. The nozzle for jet pumps receives high-pressure power fluid that is sent down the tube, where the pressure energy is converted to velocity head (kinetic energy) (Ramirez *et al.*, 2000). The production fluid is entrained by the high-velocity, low-pressure power fluid in the pump's throat. In order for the mixed fluids to flow to the surface, a diffuser lowers the velocity and raises the pressure (Jiao, 1990).

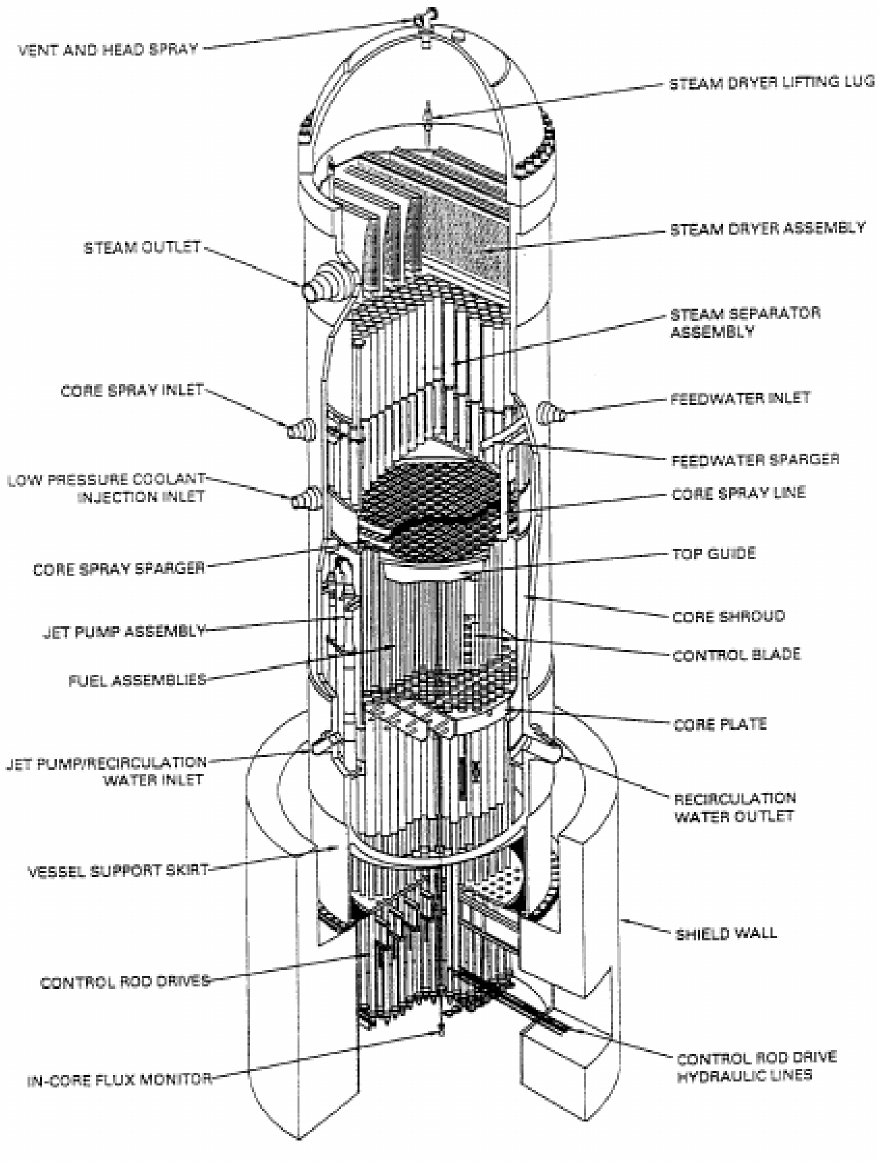


Figure 2.9 Hydraulic Jet Pump (Anon, 2019)

A reciprocating hydraulic engine is directly coupled to the pump piston or plunger in a positive-displacement pump. A reciprocating hydraulic pump is depicted in Figure 10.8. To drive the engine, a power fluid (oil or water) is injected down the tube string. The pump piston or plunger sucks fluid from the wellbore via a standing valve. Used production fluid and tubing strings may be connected to the casing or another kind of casing (Jiao, 1990).

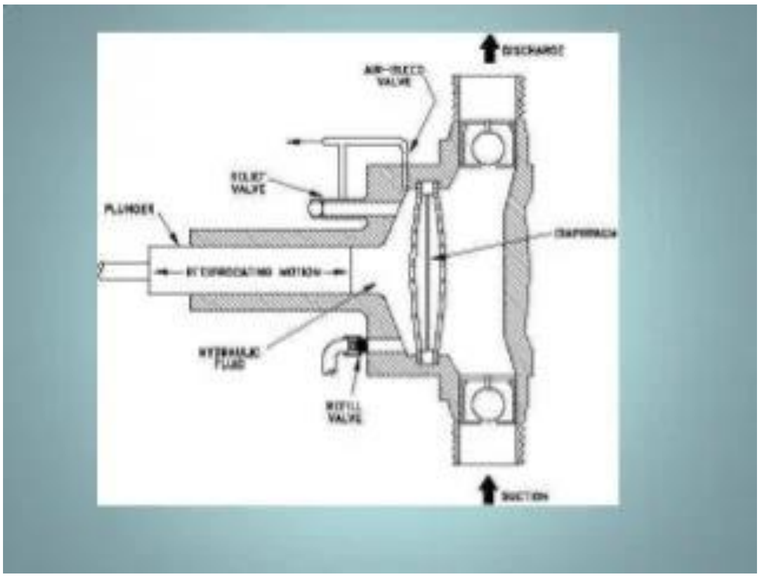


Figure 2.10 Positive-Displacement Pump (Anon, 2021)

Some major Hydraulic Piston Pump advantages are (Wrinkler and Blann, 2007);

i. The most noticeable and important characteristic of hydraulic pumps is their ability to be pumped in and out of wells. On offshore platforms, in rural places, and in populated and agricultural areas, it is especially alluring;

ii. Positive-displacement pumps can operate at least 17 000 feet below the surface. Around 9 000 feet is the maximum working fluid level for jet pumps;

iii. Production may be changed from 10% to 100% of the pumps' full capacity by altering the power-fluid rate. 20% to 85% of the rated speed is the preferred speed range. The pump's lifespan will be significantly shortened if it is operated at its maximum rated speed;

iv. Hydraulic-free pumps normally have no trouble with deviated wells. Even though jet pumps may be advantageous for flowline installations;

v. Jet pumps with reinforced nozzle throats are capable of producing sand and other solid materials.

vi. When utilised properly, positive-displacement pumps can handle viscous fluids. To further help the oil rise to the top, the power fluid can be heated or diluents added; and

vii. To prevent corrosion, corrosion inhibitors may be added to the power fluid. Salt accumulation may be decreased by adding fresh water.

Some major Hydraulic Piston Pump disadvantages are (Wrinkler and Blann, 2007);

i. Particle removal from the power fluid is essential for positive-displacement pumps. Surface-plunger pumps are similarly impacted by solids in the power fluid. On the other side, jet pumps are particularly forgiving of poor power fluid quality;

ii. Positive-displacement pumps require fewer repairs on average than a jet, sucker rod, and ESP pumps. This is primarily down to the quality of the power fluid, but positive-displacement pumps, on average, operate from greater depths and at higher strokes per minute than beam pumps. Without particles or if not subjected to cavitation, Jet pumps, on the other hand, have a very extended pump life before repairs are necessary. Because of their poor efficiency and excessive energy consumption, jet pumps are notorious;

iii. Positive-displacement pumps may pump from a low BHP in the absence of gas interference and other problems (100 psi). Low intake pressures prevent jet pumps from working, particularly when the pressure is below the cavitation pressure. When installed at 10 000 ft, jet pumps demand roughly 1 000 psi BHP, and when put at 5 000 ft, they require approximately 500 psi; and

iv. Due to the daily control of pump speed and the need to prevent it from becoming excessive, positive displacement pumps require more maintenance than jet pumps and other artificial lifts. Power-fluid cleaning systems need to be maintained frequently to keep them functioning at their optimum. Additionally, well testing is more difficult.

When should a positive-displacement hydraulic pump be used instead of a jet? Because the jet system's pressure drawdown capability is inferior to that of the reciprocating pump, if the flowing (pumping) BHP is sufficient, one viable approach is to use jet pumps (Wrinkler and Blann, 2007). Other elements, in addition to those stated earlier, come into play. Due to its low pump efficiency, which is often less than 35 percent, Jet pumps have significant energy consumption costs but minimal pump maintenance costs. If a cost-free system is accessible and the pumps can be immediately recovered (typically less than 30 minutes) without tugging the tubing, a higher pump failure rate for both systems may be acceptable (Lea, 2007).

2.7.5 Progressive Cavity Pump

A positive displacement pump called a progressive cavity pump (PCP) has a single helical rotor that rotates eccentrically within a stator. Typically, a double-chromed high-strength steel rod is used to make the rotor. The stator is a double-helical elastomer that is produced inside a steel casing (Mathews *et al*., 2007). Heavy oils may be lifted using progressive cavity pumping systems at varying flow rates. Production of solids and free gas has relatively minor obstacles. Both vertical and horizontal wells can benefit from them (Greg, 2018). Due to its ability to transport massive amounts of water, the progressive cavity pump is also used for water source wells, dewatering, and coal bed methane. By improving efficiency and using less energy, the PCP lowers total running expenses. PCPs have two significant drawbacks: a limited lifetime (between two and five years) and a high cost (Flatern, 2015).

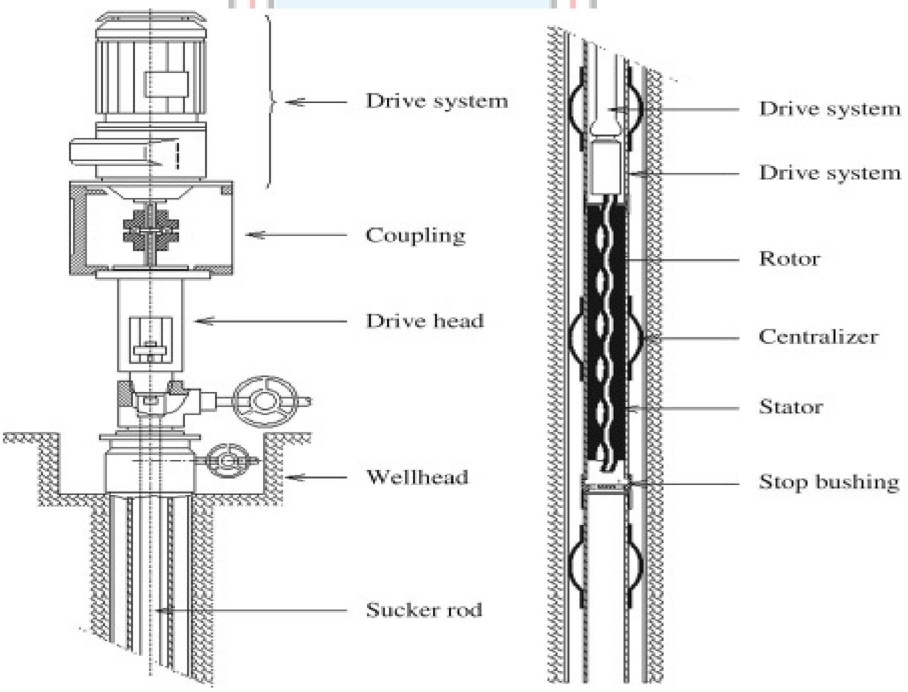


Figure 2.11 Progressive Cavity Pump (Maricic, 2008)

The PCP has a simplistic design and is built to last. If the pump is not subjected to chemical assault or extreme wear, or if it is not deployed at depths greater than 4 000 to 6 000 ft, its low working rates (300 to 600 rev/min) allow it to operate for lengthy periods downhole (Greg, 2018). Since there are no valves to clog, stick, or wear out, the pump down there just has one working component. The pump is not blocked by paraffin, gypsum, or scale, can handle sandy and abrasive formation fluids, and resists gas lock. (Maricic, 2008).

The ESPCP system is designed to solve difficulties associated with traditional rotating-rod PCP systems. This is not a new system, despite the modest number of units installed. It's been around for a while in Russia, and it was also accessible from an ESP dealer a few years ago (Brown, 1980).

Some major advantages of the Progressive Cavity Pump are (Al-Momin *et al.*, 2015);

i. The pumping system can be used in horizontal and deviated wells;
ii. The pump is capable of handling solids, although the rotor covering will deteriorate over time;
iii. With a looser rotor/stator fit, the pump can handle very viscous fluids in a production well;
iv. Several of the components for the ESPCP are pre-made ESP components.;
v. With the help of a variable-speed controller and a low-cost downhole-pressure sensor, the production rates can be adjusted;
vi. In the right circumstances, the PCP can outperform existing artificial lift methods in terms of power efficiency;
vii. The PCP can be installed in a deviated well's straight portion; and
viii. The use of an ESPCP removes revolving rods and the complications that come with rotating rods in a deviated well.

Some major advantages of the Progressive Cavity Pump are (Al-Momin *et al.*, 2015);

i. The stator material will have a maximum temperature and may deteriorate due to H_2S and other chemical reactions;
ii. PCP pumps that are turned on and off frequently might generate a variety of issues;
iii. The best efficiency occurs when gas is separated, even if it does not gas lock;
iv. If the unit pumps from the well or if gas runs constantly through the pump for a short period of time, the stator will most likely be irrevocably damaged by overheating caused by gas compression.; and
v. The gearbox in an ESPCP can also fail if wellbore fluids or particles leak inside it, or if it wears out too quickly.

A PCP should be considered for a low-pressure well with particles and/or heavy oil at a depth of less than approximately 6 000 feet if the well temperature is not excessive (75 to 150 °F normal, about 250 °F or higher maximum) (Li *et al.*, 2017). Even if there are no issues, a PCP could be a good choice due to its great power efficiency. If the application is offshore, or if drawing the well is prohibitively expensive and the well has likely deviated, it is important to think about ESPCP. There is a method known as ESPCP for wire lining a failing pump out of the well while leaving the seal section, gearbox, motor, and cable in place for ongoing operation. (Ren *et al.*, 2014).

2.8 Gas Lift

A complete gas lift system consists of a gas compression station, a gas injection manifold with injection chokes and time cycle surface controllers, a tubing string with associated operating and unloading valves, and a down-hole chamber (Guo *et al.*, 2007). Gas lift is widely utilized around the world, and it dominates production in the Gulf Coast of the United States. The vast majority of these wells use the continuous-flow gas lift. The following issues are addressed in this section: When should continuous flow be used? Why should a gas lift be used? When should intermittent lift be used? (Guo *et al.*, 2007).

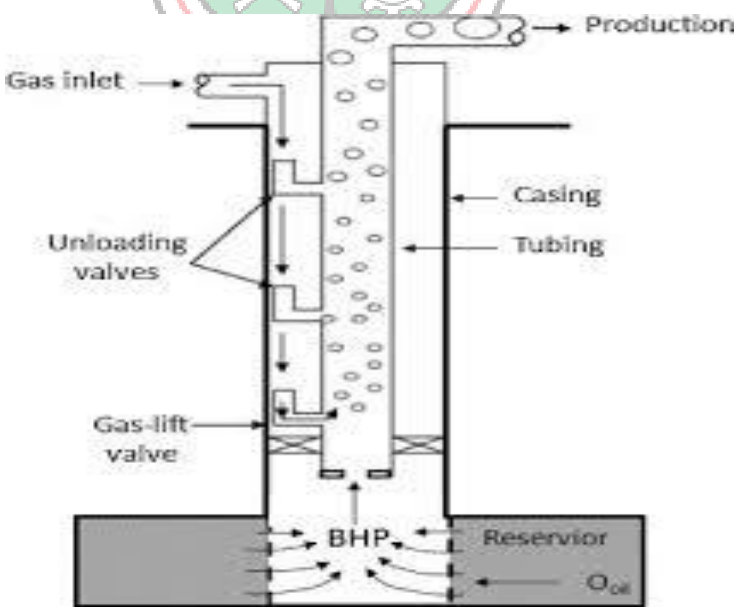


Figure 2.12 Configuration of A Typical Gas Lift Well (Yuantao, 2019)

Gas lift technology enhances the oil production rate by pumping compressed gas into the bottom segment of tubing through the casing–tubing annulus and a hole inserted in the tubing string. Once within the tube, the compressed gas affects the flow of liquids in two ways: (a) the energy of expansion pushes the oil to the surface, and (b) the gas aerates the oil, decreasing its effective density and facilitating its ascent to the surface (Namdar, 2019).

In oil fields that produce sand- and gas-filled oil, the gas lift method is often used. Deviated or crooked holes don't cause any issues. The depth of the well is not a constraint. Additionally, it works well for offshore operations. Lifting several wells at once is often rather economical (Namdar, 2019). However, it does necessitate the usage of lift gas in or near oil fields. When using gas compression equipment to raise small fields with a small number of wells, it is often inefficient. Because of advancements in pressure control and automation systems, individual wells and gas lift systems can now be maximized (Mahdiana and Khamehchi, 2015).

2.9 Types of Gas Lift

The gas lift technique relies on the installation of specially designed gas lift valves within the tube. These valves, which are placed throughout the whole length of the tubing, provide passageways for the injected gas to go from the casing to the tubing (Ma and Wu, 2010). They can be made to look like a shaft and have a wire rope at either end. The traction winch lowers them to the desired locations. They can also be pulled out with the traction winch. Although there are several types of gas lifts, the following are the main two;

2.9.1 Continuous Gas Lift

Continuous-flow gas lift is indicated for high-volume and high-static BHP wells where alternative artificial lift methods could cause serious pumping issues. It is a great fit for offshore formations with a lot of water-drive, or waterflood reservoirs with high gas/oil ratios and good PIs (GORs) (Hamedi *et al*., 2011). Gas lift is particularly appealing when high-pressure gas is available without compression or when gas costs are cheap. Continuous-flow gas lift augments the produced gas with extra gas injection, lowering the tubing's intake pressure and, in turn, the formation pressure (Ismail and Trjangganung, 2014).

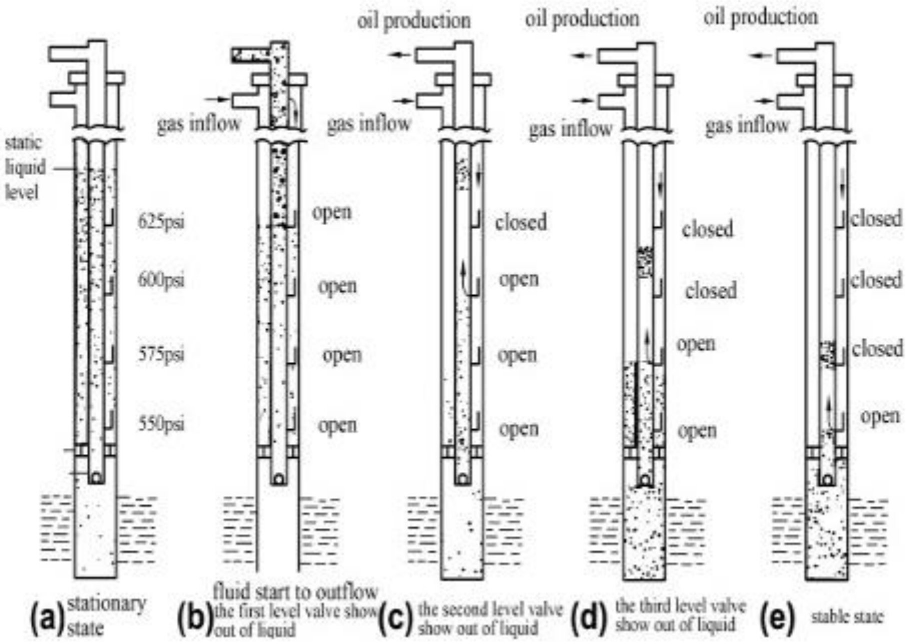


Figure 2.13 Continuous Gas Lift System (Guo *et al.*, 2007)

It is essential to have a steady supply of high-quality high-pressure lift gas. If the gas lift is to be maintained successfully throughout the well's producing life, this supply is required. In many fields, the amount of gas produced decreases as the amount of water cut increases, necessitating the use of an external source of gas (Hansen, 2012). During the first phase of facility design, the gas-lift pressure is usually fixed. In an ideal world, the system would lift from just above the producing zone. When the lift supply is cut off or the pressure abruptly changes, wells may produce erratically or not at all. If the gas contains corrosives or excessive liquids that might break valves or fill low places in delivery lines, the gas's ability to escape will be hampered or even prevented. If the fundamental conditions for gas are not satisfied, gas lift is not a practical lifting technique (Hsu and Chen, 2003).

Continuous-flow gas lift lowers production rates because it places comparatively high back pressure on the reservoir as compared to pumping techniques. Furthermore, when compared to some artificial lift technologies, power efficiency is poor, and this results in large increases in both the original capital cost of compression and the operating energy expenditures (Sharma *et al*., 2012).

Some major advantages of the Continuous Gas Lift are (Zerafat *et al*., 2009);

i. The best artificial lift technique is gas lift for handling solid materials like sand. Even with sand management in place, sand is still produced by many wells. In the gas-lift system, the produced sand has no mechanical impact apart from the PCP type of pump; nevertheless, even a little quantity of sand plays havoc with other pumping methods;

ii. It is straightforward to elevate holes that are crooked or deviated thanks to gas lift. Considering that offshore platform wells are normally drilled in one direction, this is very important;

iii. Wireline equipment may be used in conjunction with gas lift, and such downhole equipment is easily and affordably maintained. Through the tube, maintenance repairs may be carried out thanks to this function;

iv. In the typical gas-lift configuration, the tube is visible. Consequently, it is possible to use BHP surveys, sand sounding and bailing, production logging, cutting, paraffin, and other methods;

v. Gas-lift systems benefit from high-formation GORs, whereas other artificial lift systems suffer. Compared to pumped gas, which significantly reduces the volumetric pumping efficiency of all other pumping techniques, produced gas needs less gas for injection;

vi. The gas lift may be customized. There is a broad variety of volumes and lift depths that may be achieved with basically the same well equipment. In certain situations, switching to annular flow is simple to handle very large volumes;

vii. A central gas-lift system may easily power an entire field or a lot of wells. Centralization eases well control and testing while lowering overall capital expenses;

viii. A gas-lift system is discrete and has a low profile. The apparatus for surface wells is the same as that for flowing wells, with the exception of injection-gas metering. Keeping a low profile is often desirable in urban environments;

ix. Equipment for subsurface wells is economically priced. Repair and maintenance expenses for subsurface equipment are often minimal. The equipment may be easily removed for repair or replacement. Large well workovers are particularly unusual;

x. Gas lift can be installed alongside subsurface safety valves and other surface equipment. The well can be easily shut in by using a surface-controlled subsurface safety valve with a 14-in. control line; and

xi. Even if only mediocre data is provided at the time of design, a gas lift can nevertheless function admirably. This is advantageous because the spacing design is usually finalized and tested before the well is completed.

Some major disadvantages of the Continuous Gas Lift are (Zerafat *et al*., 2009);

i. High back pressure in a continuous gas lift may significantly reduce production. This issue becomes more problematic as depths increase and static BHPs decrease. A 10 000-ft well with a static BHP of 1 000 psi and a PI of 1.0 bpd/psi would be challenging to raise using the traditional continuous-flow gas-lift method. Special techniques, however, are feasible for such wells;

ii. Gas lift usually requires significant construction expenditures and high energy operating costs since it is inefficient. Compressors may be pricey and take longer to supply. When used on offshore platforms, the compressor is heavy and takes up space. Additionally, onshore distribution networks could be expensive. Larger flowlines and separators may be necessary due to increased gas consumption;

iii. Throughout the project's lifespan, enough gas supply is required. It may be required to convert to another artificial lift method if the field runs out of gas or if gas gets too expensive. There must also be enough gas for quick start-ups;

iv. Operating and maintaining a compressor may be expensive. Reliable operation requires competent compressor mechanics and professional operators. Less than 3% of the time should be spent without a compressor;

v. Lifting low-gravity oil (less than 15°API) is more difficult because to greater friction, gas fingering, and liquid fallback. Gas expansion's cooling impact might make things much worse. Furthermore, the cooling effect will make any paraffin issues worse; and

vi. You need reliable data in order to produce a decent design. Operations may be obliged to continue utilizing an ineffective design that prevents the well from operating at maximum capacity if the appropriate equipment is not available.

Frozen and hydrate difficulties in injection gas lines, caustic injection gas, severe paraffin problems, changing suction and discharge pressures, and wireline problems are all potential gas-lift operational issues that must be overcome (Khishvand and Khamehchi, 2012). Changes in well conditions, including losses in BHP and PI; deep high-volume lift; and valve interference are all issues that must be addressed (multi-pointing). Furthermore, a dual gas lift is difficult to use and frequently results in inefficient lift efficiency. Finally, emulsions forming in the tubing must be resolved, which might be hastened when gas enters against the tubing flow (Krishnamoorthy *et al*., 2019).

2.9.2 Intermittent Gas Lift

Even though some systems may produce up to 500 B/D, the intermittent gas-lift technique is mainly utilized on wells that produce modest amounts of fluid (about 150 to 200 B/D). It's common practice to choose intermittent lift wells with a high PI and low BHP or a low PI and high BHP (Krishnamoorthy et al., 2019). When liquid loading is an issue and gas well rates have fallen to low levels, an intermittent gas lift might be employed in lieu of a continuous one. If a sufficient supply of high-quality, low-cost gas is available, the intermittent gas lift would be a great choice for extracting fluids from sand-producing, moderately shallow, high-GOR, low-PI, or low-BHP wells. Many of the advantages and disadvantages of intermittent gas lifts are the same as those of continuous-flow gas lifts, and the primary issues to consider are the same (Krishnamoorthy *et al*., 2018).

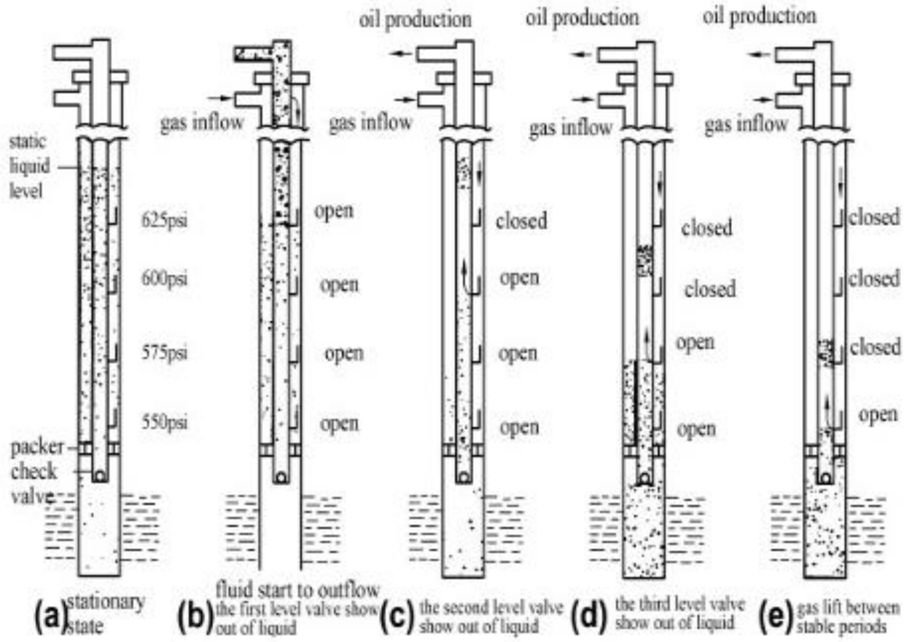


Figure 2.14 Intermittent Gas Lift (Namdar, 2019)

Some major advantages of the Intermittent Gas Lift are (Namdar, 2019);

i. The producing BHP of intermittent gas lift is often lower than that of continuous gas lift; and
ii. It can handle small amounts of fluid while producing low BHPs.

Some major disadvantages of the Intermittent Gas Lift are (Namdar, 2019);

i. Low-volume wells are only capable of intermittent gas lift. An 8 000-foot well with 2-inch nominal tubing, for example, can rarely produce more than 200 B/D with an average producing pressure of less than 250 psig;
ii. The average generating pressure of a typical intermittent lift system is still rather high as compared to rod pumping, however the producing BHP may be decreased by employing chambers. For wells with a high PI but low BHP, chambers are suitable;
iii. There is not enough power efficiency. Per barrel of the generated fluid, more gas is often consumed as compared to continuous flow gas lift. The fallback of a proportion of liquid slugs being lifted by gas flow also grows as depth

and water cut expand, making the lift mechanism even less effective. If necessary, plungers may be used to lessen liquid fallback;

iv. Wells with sand control can be harmed by rate and BHP fluctuations. The sand that is created may clog the tube or the standing valve. In addition, pressure oscillations in surface facilities present challenges with gas and fluid handling; and

v. Gas lift that occurs regularly usually necessitates frequent modifications. To improve output while keeping the lift gas requirement low, the lease operator must change the injection rate and period regularly.

A gas lift provides several advantages that make it the ideal artificial lift option; however, there are some drawbacks and potential issues. It is possible to employ either continuous flow for high-volume wells or intermittent flow for low-volume wells; switching from one to the other is simple (Neely *et al*., 1981). The gas lift may be used to inject backflow into injection wells, kick off wells, and discharge water from gas wells. Gas lift merits serious attention as a method of artificial lift when compared to well-run pumping systems, however it is not energy-efficient, and continuous gas lift does not achieve a low BHP at the formation (Khasanov *et al*., 2010).

Gas lift production is a type of artificial lift that makes full use of the reservoir's natural energy. This is because it possesses the following characteristics:

i. Flexibility: This is first and foremost flexible to a broad range of output. Consider the South China Sea's continuous gas lift as an example. The same production string might be modified to produce between 95 and 1590 m3, which is hard to do using traditional artificial lift oil production techniques. Only the depth of the gas lift valve, the volume of the gas injection, and the pressure of the gas injection must be altered for the gas lift system to respond to changing production needs. It does not need carrying tubing string or redesigning, in contrast to other artificial lift systems (Presly, 2012);

ii. Economy: The gas lift eliminates the need to transport tubing string and other downhole equipment, and the major equipment is mounted on the platform, making maintenance easier and allowing the use of natural gas as a fuel source with low overall running costs. When oil production drops, the wire rope can be used to replace the gas lift valve and boost output. Because the gas lift system has fewer moving components, the repair cycle is longer and the economic efficiency is higher (Hughes, 2013); and

iii. Adaptability: There are several uses for gas lift, including huge dogleg wells, large inclination wells, sand wells, wells with a high gas-to-oil ratio, and wells with waxy and scaly surfaces (Khasanov *et al*., 2010).

However, there are several restrictions to the creation of gas lifts. For instance, in order for the gas source to generate adequate gas, the quantity of dissolved gas in the oilfield must be kept to a low (10% for a typical gas lift). Due to the need for a certain level of bottom hole flowing pressure, it is not appropriate for low-pressure wells. Additionally unsuccessful for heavy oil and emulsified oil wells is the gas lift method (Khasanov *et al*., 2010).

2.10 Artificial Intelligence

Artificial intelligence is a contentious topic since it touches on issues such as brain architecture and human intelligence, which we humans are yet unaware of. Artificial intelligence is widely used in computer systems with the right software and hardware (Murray *et al*., 2006). As a consequence, it looks to the uninformed to be a science fiction tale. Artificial intelligence is often referred to as machine intelligence. Security and optimum performance may be improved, and physical assets or oilfield equipment can be made more accessible, thanks to mobile asset tagging (Murray *et al*., 2006). Examples of this are LISP (List and Symbol Processing) and PROLOG (Logic Programming).

The two main domains of artificial intelligence study are Artificial Neural Networks (ANNs) and classical artificial intelligence (Gharbi and Mansoori, 2005). Artificial intelligence refers to a system that enables computers and machines to respond in the same way that people do (Dodiya and Shah, 2021). Techniques based on artificial intelligence (AI) are based on human-like abilities like thinking and learning. The logic grows more realistic when the amount of data is repeated and becomes more complex. Artificial intelligence is a complicated subject. It must cope with both human intelligence and things that people cannot comprehend (Namdar, 2019).

2.11 Prosper Software

The PROSPER programme is the industry standard for developing and optimising single well performance. It is capable of simulating the majority of well completions as well as artificial lifting techniques (Beggs, 2008). Nodal Analysis can be used to do sensitivity analyses in a variety of operating scenarios. PROSPER constructs a model for every part of the producing well system that affects overall performance, followed by performance matching tests on each model subsystem. This approach ensures that the computation is as accurate as possible thanks to the software (Evinger and Muskat, 1942). This MSc thesis' computations were all performed using PROSPER.

A new generation of multiphase pumps that can handle larger gas volumes is now available. By covering each aspect of well bore modeling, such as PVT (fluid characterisation), VLP correlations (for computing flowline and tubing pressure loss), and IPR (internal pressure loss), PROSPER is intended to assist in developing trustworthy and consistent well models (reservoir inflow) (Clegg, 2007).

By simulating each element of the producing well system, the user may examine the performance of each model subsystem. Once a well system model has been validated to actual field data, PROSPER can accurately model the well in various circumstances and produce forward reservoir pressure estimates based on surface production data. Using the given PVT, well, and reservoir data, the chapter demonstrates how to build a reliable model (Ruiz, 2014).

PROSPER allows for extensive flow assurance analysis at the well and surface pipeline level. By adjusting PVT, multiphase flow correlations, and IPR to match observed field data, PROSPER's special matching features let you create a consistent model before applying it to prediction (sensitivities or artificial lift design (Karassik, 2001).

2.12 Relevant Works Reviewed

The research studies that inspired the thesis focus on using artificial intelligence and neural network analysis to improve operational performance and efficiency in the oil and gas sector are summarised below.

2.12.1 Artificial Lift Selection Using Machine Learning

The human-assisted artificial lift selection procedure entails iterating numerous design parameters. Furthermore, the human-curated selection needed unbiased, repeatable, and reliable decision-making. The human limits are the ability to incorporate the lesson learned from a previous mistake into a new design and the inability to look back on previous performances. The method of supervised machine learning can be used to improve the selection process. By incorporating prior performances and lessons learned from installations into machine learning, this strategy can reduce the life-cycle cost of artificial lift wells. The information is organized into a dataset. The data is pre-processed to establish which wells are "Good" and "Bad" based on their life-cycle costs, and then utilized to train and validate classification algorithms. For future artificial lift selection and present well performance evaluation, the most basic and accurate model is used. Finally, the performance of additional wells is incorporated regularly to train the model further (Ounsakul *et al.*, 2019).

In the continuing field trial, the artificial lift suggested by machine learning is expected to reduce life-cycle costs. The selection model displays several discrepancies in the currently installed artificial lift in terms of assessing tools. This prompts the operator to investigate any potential issues. However, in the event of a false alert, subject matter experts must still provide enough contact. As a result, the found pattern for selecting appropriate artificial lifts will aid in improving field production. Furthermore, machine learning's infinite learning power allows fresh data to be included in an existing dataset, allowing the model to respond to dynamic changes in field conditions. To summarize, the machine learning approach is more complete than the traditional process, which uses only a few tables for artificial lift selection and ignores the significance of the data acquired (Ounsakul *et al.*, 2019).

Artificial Intelligence (AI) is an emerging technology that is capable of producing ground-breaking breakthroughs. The artificial intelligence movement in the oil and gas business is discussed in this study. It is a promising technique for resolving difficult human problems. Finally, giving the oil and gas business a long-term competitive advantage (Ounsakul *et al*., 2019).

2.12.2 Artificial Lift System Optimisation Using Machine Learning Applications

Artificial Lift Optimisation (ALO) systems are being used in the oil industry for a variety of applications such as well monitoring and control, reservoir management, production optimisation, predictive maintenance, artificial lift, and flow assurance, multiphase pumping systems, and so on.

In recent years, the oil and gas industry has seen numerous advancements that have impacted the businesses and economies linked with the industry. Unplanned shutdowns and equipment failures have a significant impact on many businesses, especially given the present hydrocarbon price swings. ALO systems are also driven by powerful current technology such as real-time analysis and predictive maintenance (Fahad *et al*., 2020).

In order to maximize the extraction of hydrocarbons from potentially depleted reservoirs that call for external support to raise reservoir fluid from the subsurface to the surface using an artificial lift system, this paper discusses a number of applications and techniques where machine learning and artificial intelligence have been used. In a nutshell, the key topics of this research are the applications of AI and ML using a self-trained system for artificial lift selection, predictive maintenance, equipment malfunctioning detection, and so on. The workflow for each of these tactics is discussed along with its effectiveness when used with existing operations (Fahad *et al*., 2020).

2.12.3 Artificial Intelligence Applications in Reservoir Engineering: A Status Check

This article provides a comprehensive overview of artificial intelligence applications for reservoir engineering difficulties. To demonstrate the intelligence systems' robustness, research tasks such as proxy model construction, artificial intelligence-assisted history-matching, project design, and optimisation are offered. The breakthroughs' accomplishments demonstrate the AI techniques' advantages in terms of high computational efficacy and strong learning capabilities. As a result, reservoir engineers can more efficiently complete a variety of difficult and time-consuming tasks by implementing intelligence models. However, it is not yet wise to replace traditional reservoir engineering models with intelligent systems, because the technology's flaws cannot be overlooked. The current tendency in reservoir engineering research and industry practices is to build a handshake protocol between traditional models and intelligent systems. More robust solutions may be achieved with much lower computing overheads if both strategies were combined (Ertekin and Sun, 2019).

2.12.4 Detecting Failures and Optimising Performance in Artificial Lift Using Machine Learning Models

This study goes over the various sorts of artificial lift difficulties that have been diagnosed and forecasted using machine learning methods, such as tubing and pump failure, as well as sucker rod pump and gas injection performance that is suboptimal. The presentation covers the several types of suboptimal performance periods that can be identified, as well as the impact they have on well performance. Artificial lifts, specifically sucker rod pumps and gas lifts, will be the emphasis of the presentation (Pennel *et al*., 2018).

Utilizing production data from Bakken wells that had been operating for more than a year, machine learning models were created. For analysis and profiling, time series sensor and controller data from 800 wells was transferred to an Amazon Web Service (AWS) cloud platform. Experts in each lift type examined failure and performance data to identify failure causes and sub-optimal performance times. Numerous machine learning and artificial intelligence algorithms, including as neural network models, gradient-boosted trees, and random forests, were trained using these events. These models were used to identify and forecast the problem situations. To rank and evaluate each model's performance, lift type, and issue condition, the models' combined performance was assessed (Pennel *et al*., 2018).

Data science, machine learning, and artificial intelligence are revolutionizing businesses by maximizing machine performance by harnessing enormous low-cost computing power. Artificial lift is a practical use case because of the increasing number of sensors and signals offered by contemporary controllers, enhanced data communication, lower costs for processing and data storage, and the complexity of surface and downhole difficulties in unconventional wells. The diagnostic models for tube and pump failures proved to be quite accurate, with diagnostic model accuracy exceeding 99 percent and precision ranging from 50 to 60 percent. Over a range of asset lifespans from 100 to 600 days, the long-term tubing failure model produced an estimated estimation error of 31 days. More than 90% of inferior performance models were accurate. The model's performance offers the wells a high-confidence interaction that enables them to respond to issue states more rapidly, save downtime, and boost pump efficiency (Pennel *et al*., 2018).

CHAPTER 3

MATERIALS AND METHODS USED

3.1 Introduction

This section presents how the research was conducted, including the tools and techniques used to collect and analyse data. The materials employed includes; the prosper software, well data and production data. The artificial lift selection techniques, PROSPER software setup and the Random Forest algorithm and its pseudocode are the methods used in this section.

3.2 Materials/Equipment

3.2.1 PROSPER Software

The industry-standard software for single well-performance design and optimization is called PROSPER. The majority of well completion types and artificial lifting techniques are modeled using it. It allows for the use of Nodal Analysis to do sensitivity evaluations for a variety of operating circumstances. This chapter presents trustworthy models using readily accessible PVT, well, and reservoir data.

3.2.2 Data

In this thesis, the model developed is based on an offshore well. As a result of a long production cycle, reservoir pressure has dropped to very low levels rendering the well unproductive. To bring back the well to production implementation, an artificial lift design is needed.

3.2.3 Well Data

Well data available consists of PVT data, reservoir geometry data, fluid property data, and production data. According to the PVT data, the reservoir fluid directly flashed (separated in a single step) from reservoir circumstances to standard conditions. According to its API gravity, oil can be described as volatile and relatively easy to flow in a pipeline. All wells deviate horizontally. The wells data is presented in Tables 3.1 to 3.5 below.

Table 3.1 PVT Data for Osprey and Hawk Well.

Parameters	**OSPREY**	**HAWK**
Pressure Estimate (psi)	5 400	5 650
Reservoir Temperature (deg F)	225	225
GOR (scf/bbl)	335.72	275

(Source: Pankaj *et al.*, 2021)

Table 3.2 Production Data for Osprey and Hawk well.

Parameters	**OSPREY**	**HAWK**
TVD (ft)	7 638.6	7 516.6
Spacing	1 400	1 000
No. of Stages	28	68
No. of Clusters	252	1 020
No. of Clusters per Stage	9	15
Pre-Refrac Completion No. of Stages	20	
Pre-Refrac Completion No. of Clusters	60	
Initial Completion No. of Clusters per Stage	3	
No. of Total Proppant (lbs)	13 514 540	38 064 782
Total Fluid (bbls)	275 579	596 128
Lateral Length (ft)	5 883	10 672
Top Perf (ft)	8 030	7 824
Bottom Perf (ft)	13 913	18 496

Sandface Temp (deg F)	225	225
Static Wellhead Temp (deg F)	70	60
Tubing ID (in)	2.441	1.995
Tubing OD (in)	2.875	2.375
Tubing Depth (ft)	6 825	7 325
Casing ID 1 (in)	4.67	4.778
Casing Footage 1 (ft)	6 941	7 549
Casing ID 2 (in)	2.992	4.276
Casing Footage 2 (ft)	6 307	11 060
Casing Depth (ft)	13 248	18 609
Configuration Change (Days Since First Prod)	1 602	460

(Source: Pankaj *et al.*, 2021)

Table 3.3 Fluid Property Data for Osprey and Hawk well.

Parameters	**OSPREY**	**HAWK**
Water Saturation	0.26	0.271
Oil Saturation	0.74	0.729
Gas Saturation	0	0
Gas Specific Gravity	0.9513	0.9936
CO_2	0.0217	0.0217
H_2S	0	0
N_2	0.0045	0.0045

(Source: Pankaj *et al.*, 2021)

Table 3.4 Wellbore Surface data for Osprey and Hawk well.

Parameters	OSPREY	HAWK
Condensate Gravity (API)	34.6	37.29
Dew Point Pressure (psi)	1 370	1 211.37
Sep. Temperature (deg F)	100	100
Sep. Pressure (psi)	100	100
Oil Gravity (API)	34.6	37.29
Initial GOR (scf/bbl)	275	335.72
Bubble Point Pressure (psi)	1 370	1 211.369

(Source: Pankaj *et al.*, 2021)

Table 3.5 Reservoir Geometry data for Osprey and Hawk well.

Parameters	OSPREY	HAWK
Net Pay (ft)	78	47.17
Wellbore Diameter (ft)	0.7	0.07
Skin	0.5	0.5
Porosity	0.063	0.063

(Source: Pankaj *et al.*, 2021)

3.2.4 Production Data

The Daily Oil Production data recorded at the Osprey Well (graphically displayed in Appendix A) in Table 3.6 below. The initial Daily Oil Production rate was over 750 STB within the first 50 days. It gradually decreased due to a decline in reservoir pressure, primarily the main source of energy driving the Osprey well. At 1 140 days, a Progressive Cavity Pump lift method was employed to booster production.

Table 3.6 Daily and Cumulative Oil Production of Osprey Well (Pankaj et al., 2021).

Time (Days)	Daily Oil Volume	Cumulative Oil Production
1	504.39	504.39
5	678.06	3141.43
10	710.58	7130.94
15	735.32	10521.54
20	604.32	13914.14
30	403.06	18662.86
50	125.16	24822.53
80	260.40	33310.07
100	232.47	37977.47
130	171.99	43705.63
160	162.70	48465.33
190	126.06	52225.81
200	123.40	53499.99
220	118.07	55880.11
230	120.15	56950.12
240	43.35	57940.93
250	91.78	58281.45
300	95.12	63455.20
400	70.51	71861.43
500	61.75	78617.95
600	60.08	84346.44
700	52.56	89421.64
800	56.74	93872.07
900	41.72	97903.17
1000	37.08	101432.58
1100	0.00	104041.53
1200	357.23	139080.43
1300	281.67	167065.02
1400	130.00	197202.06
1600	188.33	226966.97
1700	154.64	244650.10
1800	161.41	257901.81
1900	115.00	268767.48
2000	108.33	279508.59
2100	108.00	289677.88
2170	0.00	294610.88

(Table generated from appendix A)

Table 3.6 (generated from Appendix A) also represents the cumulative oil production of the total amount of oil recovered from the reservoir over 2 170 days. From this graph, recovered oil was around 100 000 STB at 1 140 days and with an introduction of a secondary lift technology, it increased the total oil recovered to about 300 000 STB at 2 170 days.

Table 3.7 (generated from appendix B) shows the Daily Oil Production data from the Hawk well. There was little to no production during the first 10 days and a small amount of production (less than 50 STB) after 31 days. The electrical Submersible Pump lift method was introduced and it enhance production to about 1 200 STB and dropped off shortly after 103 days.

Table 3.7 Daily and Cumulative Oil Production of Hawk Well (Pankaj *et al*., 2021).

Time (Days)	Daily Oil Volume	Cumulative Oil Production
1	0.00	0.00
5	4.00	98.00
10	17.00	1040.00
15	48.00	5437.00
20	61.00	11983.00
30	48.00	24787.00
50.375	545.00	44787.25
80.375	640.00	66833.25
100.375	587.00	79234.25
130.375	0.00	92787.21
160.375	0.00	92787.21
190.375	0.00	92787.21
200.375	0.00	92787.21
220.375	664.57	101374.16
230.375	587.91	106923.21
240.375	580.83	113228.08
249.375	438.33	117716.30

(Table generated from appendix B)

Table 3.7 (generated from appendix B) also represents the cumulative oil production of the total amount of oil recovered from the reservoir over 2 170 days. From this graph, recovered oil was around 22 000 STB at 32 days. On day 35 of production, an artificial lift technology was introduced to improve the production of the well. This increased the total oil recovered to about 800 000stb at 184 days.

3.3 Methods

3.3.1 Artificial Lift Selection

The majority of the Artificial Lift (AL) selection methods utilized for vertical wells in conventional reservoirs should be taken into account when choosing AL methods for horizontal wells in unconventional reservoirs. No matter if the lift method is used with vertical or horizontal wells in conventional or unconventional reservoirs, its advantages and disadvantages are the same for each (Panbarassan, 2017). Each lift method maintains the same design in order to get the technical parameter (such as GL valve spacing, gas volume for gas lift systems, and pump size, length, horsepower, etc. for submersible pumps). The two key differences between AL for vertical wells in conventional reservoirs and AL for horizontal wells in unconventional reservoirs are the selection procedure and operations throughout the production period (Panbarassan, 2017).

In the first stage of a typical artificial-lift selection procedure, called screening, a wide range of artificial lift techniques is evaluated for their applicability in terms of fluid types, reservoir characteristics, and operating environment. A more thorough evaluation of these possibilities is made when a limited selection of practical lift techniques has been narrowed down by projecting their performance over the course of the field's lifetime. Simple spreadsheet computations to fully integrated asset models linking thorough reservoir, well, and facility models are all possible methods for producing such estimates. The size and complexity of the field play a significant role in the technology selected for forecasting. The following stage is to conduct an economic analysis to help choose the preferred lift techniques at the end (Mohammed and Nasr, 2016). The production profile is used in the economic analysis to provide net-present-value estimations, which take into account the capital and operational costs related to each lift technique. The following are just a few of the industry screening techniques that are readily available:

i. Screening by Charts;
i. Screening by Advantages and Disadvantages;
ii. Screening by Attributes; and
iii. Screening by Expert Systems (Lea and Nickens, 1999).

Depending on the unique reservoir characteristics and operational environment, several parameters will be taken into account during the first screening of artificial-lift technologies. Common artificial-lift selection standards include:

i. Well productivity;
ii. Operability;
iii. Environmental effects;
iv. Solid handling;
v. Well-design compatibility;
vi. Flow assurance;
vii. Reliability;
viii. Gas handling;
ix. Facilities requirements;
x. Power requirements;
xi. Temperature limits;
xii. Reservoir access;
xiii. Local knowledge/support;
xiv. New-technology risk; and
xv. Workover cost.

To analyse and choose the best Artificial lift method for this project, a fully integrated asset model that couples a thorough reservoir, well, and facilities model was used. The AI model was created using the Python programming language and fed with data gathered from Hawk and Osprey. The model's detailed flowchart is provided in Figure 3.1:

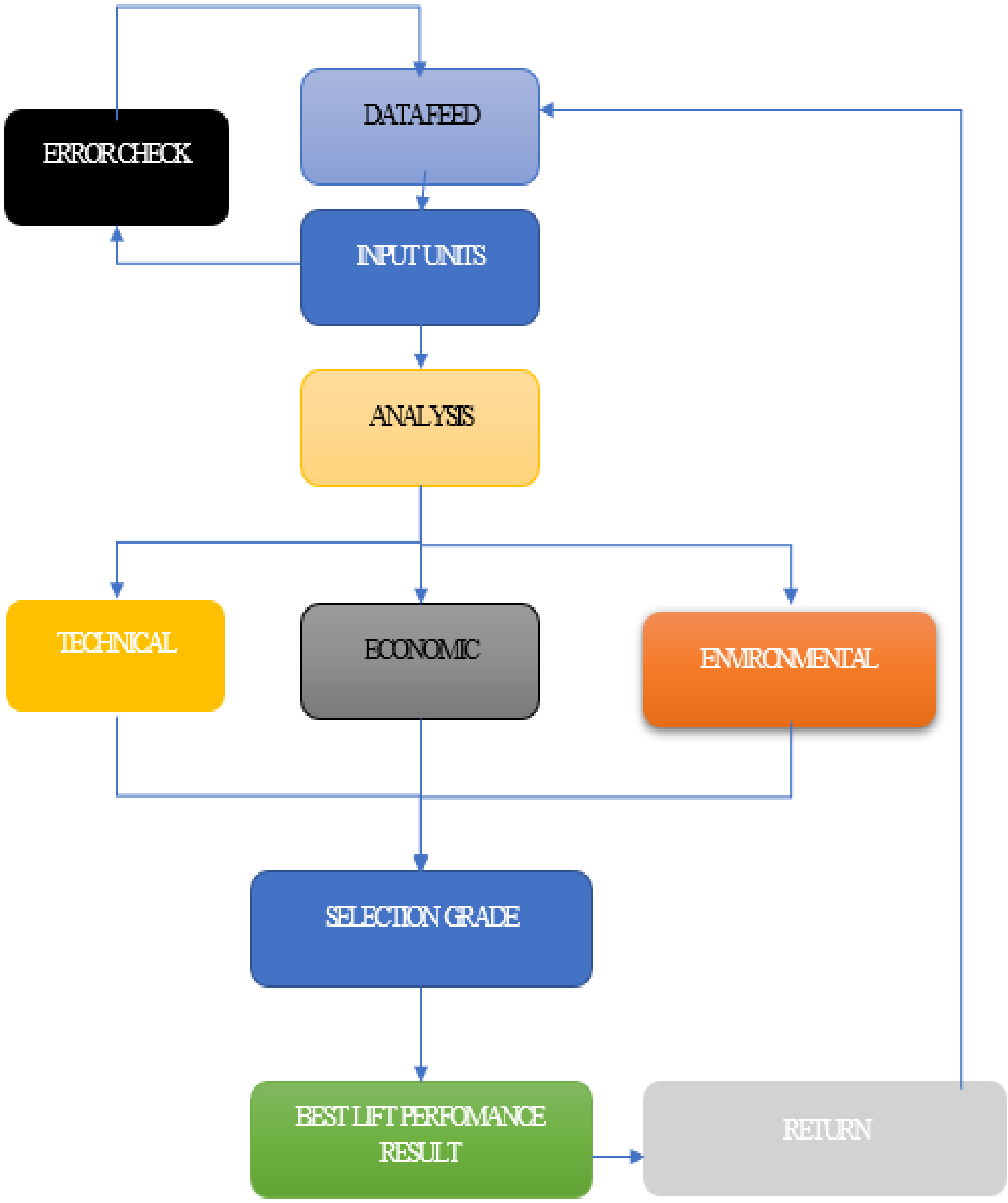


Figure 3.1 Flow Chat of Artificial Intelligence Process

3.3.2 Data Feed

In this section of the AI model, the data presented in previous sections of this thesis is inputted into the model. Although some parameters can be left unprovided, required fields must be imputed to proceed to the next sections.

3.3.3 Input Units

Due to the difference in most field units, this model includes a section to key in units corresponding to the data inputted above. Conversion of units into a standard unit is done in this section before the model proceeds to analyse the data as shown in Table 3.8.

Table 3.8 Input Design Parameters

Input Design Parameters	**Value**	**Unit**
Setting Depth	12 120	Ft
Initial Liquid Production rate	2 500	BLPD
DLS at a certain Depth	7-9	°/100 ft
Kick-off Point	11 600	Ft
WC	24	%
Gas Liquid Ratio	450	Scf/Stb
Oil Gravity	42	°API
Reservoir Fluid Temperature	270	°F
Later production rate	300	BLPD

(Source: Pankaj *et al.*, 2021)

3.3.4 Analysis

The model analyses the data in three different forms (Technical, Economic, and Environmental). The decision-making criteria take into consideration results from all three forms of analyses to grade the various Artificial Lift Methods.

3.3.5 Technical

The technical section involves the analysis of data parameters that controls the mode of operation of the Artificial Lift. Table 3.9 summarizes some operational parameters.

Table 3.9 Operational Parameters for Artificial Lift Systems

Parameter	Sucker Rod pump	Gas Lift	Hydraulic Lift	Electrical Submersible Pump	Progressive Cavity Pump
Operating Depth, m	30 – 3 500	1 524 – 4 572	2 286 – 5 182	305 – 4 572	600 – 1 829
Operating volume	5 – 5 000 BPD	200 – 50 000 BPD	50 - 4 000 BPD	200 – 30 000 BDP	5 – 4 500 BDP
Operating Temperature °F	100 – 550 °F	100 – 400 °F	120 – 500 °F	100 – 400 °F	75 – 250 °F
Typical Deviation deg/100 ft	0 - 8	NA	0 - 8	0 - 8	0 – 8
Maximum Deviation, deg/100 ft	< 15	< 70	< 24	< 15	< 15
Fluid Gravity	-	> 15 °API	> 8 °API	> 18 °API	> 25 °API
Corrosion Handling	Good to Excellent	Excellent	Good	Good	Fair
Gas Handling	Fair to Good	Good	Fair	Fair to Good	Good
Solids Handling	Fair to Good	Good	Fair	Poor to Fair	Excellent
System Efficiency, %	40 – 60 %	10 – 30 %	10 – 30 %	35 – 60 %	40 – 70 %
Offshore Application	Limited	Excellent	Good	Excellent	Good

(Source: Pankaj *et al.*, 2021)

3.3.6 Economic

This part of the model analyses the costs associated with building the best technology as well as the costs associated with each system to be taken into consideration. Table 3.10 presents a cost analysis of some Artificial lift methods.

Table 3.10 Economic Considerations for Different Lift Methods

Lift Comparison	Gas Lift	Electrical Submersible Pump	Sucker Rod Pump	Progressive Cavity Pump
Artificial Lift Assemble	$145,387	$49,784	$150,210	$144,500
Work Over cost	$19,280	$19,280	$19,280	$19,280
Surface Equipment	$57,398	$18,555	$14,268	$24,072
Electrical Surface Equipment	$8,400	$9,940	$6,875	$9,940
Metering	$62,000	$0	$0	$0
Surface Electrical Labor	$6,000	$7,900	$6,000	$6,000
Artificial lift Labor	$14,642	$110,235	$8,800	$7,620
Total Capital Cost	$313,107	$215,694	$205,433	$211,412

(Source: Pankaj *et al.*, 2021)

3.3.7 Environmental

The field's location - onshore or offshore - is taken into account in the environmental section. The Environmental part will show if the AL will operate well or poorly when applied depending on the best selection system.

3.3.8 Selection Grade

The various Artificial lift technologies are ranked according to the outcomes of the algorithm in the model's selection grade section. This section provides a summary of the various lift techniques and the simulation results that correlate to them as shown in Figure 3.6.

```
============= RESTART: E:\Artificial_Lift_project\lift selection.py ============
[[----------- OPERATING DEPTH---------]]
Operating depth is in the range of Sucker Rod Pump and is equivalent to = 7638.6
OD =  7638.6
Operating Depth not is not in range for PROGRESSIVE CAVITY PUMP 7638.6
OD =  7638.6
Operating depth is in the range of GAS LIFT and is equivalent to = 7638.6
OD =  7638.6
Operating depth is in the range of HYDRAULIC LIFT and is equivalent to = 7638.6
OD =  7638.6
Operating depth is in the range of JET PUMP and is equivalent to = 7638.6
OD =  7638.6
Operating depth is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 7638.6
OD =  7638.6
[[----------- OPERATING VOLUME---------]]
Operating Volume is in the range of Sucker Rod Pump and is equivalent to = 330
OV =  330
Operating Volume is in the range of PROGRESSIVE CAVITY PUMP and is equivalent to = 330
OV =  330
Operating Volume is in the range of GAS LIFT and is equivalent to = 330
OV =  330
Operating Volume is in the range of HYDRAULIC LIFT and is equivalent to = 330
OV =  330
Operating Volume is in the range of JET PUMP and is equivalent to = 330
OV =  330
Operating Volume is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 330
OV =  330
```

Figure 3.6 Sample of Grading from Artificial Lift (A. I.) Model

3.3.9 Best Performance Lift Results

After choosing a method, this model's final step is to produce the best performance lift results. It demonstrates the most effective technique for the operation and includes an evaluation of the costs and challenges of using it in various environments (offshore or onshore).

3.3.10 Artificial Intelligence-Assisted Screening Criteria Artificial Lift

Table 3.11 shows the Input Design and Operating Parameters used in the Artificial Intelligence Assisted Screening Criteria for Artificial Lift selection. The Searching and Sorting algorithms were used to process the given dataset. In a one-dimensional array, a specific key element is searched for. The input is made up of a group of components as well as the important component. Therefore, evaluating the essential factor concerning each member of the group. The data is sorted in a specific order using the sorting algorithm. Figure 3.3 shows the AI screening application Graphical User Interface.

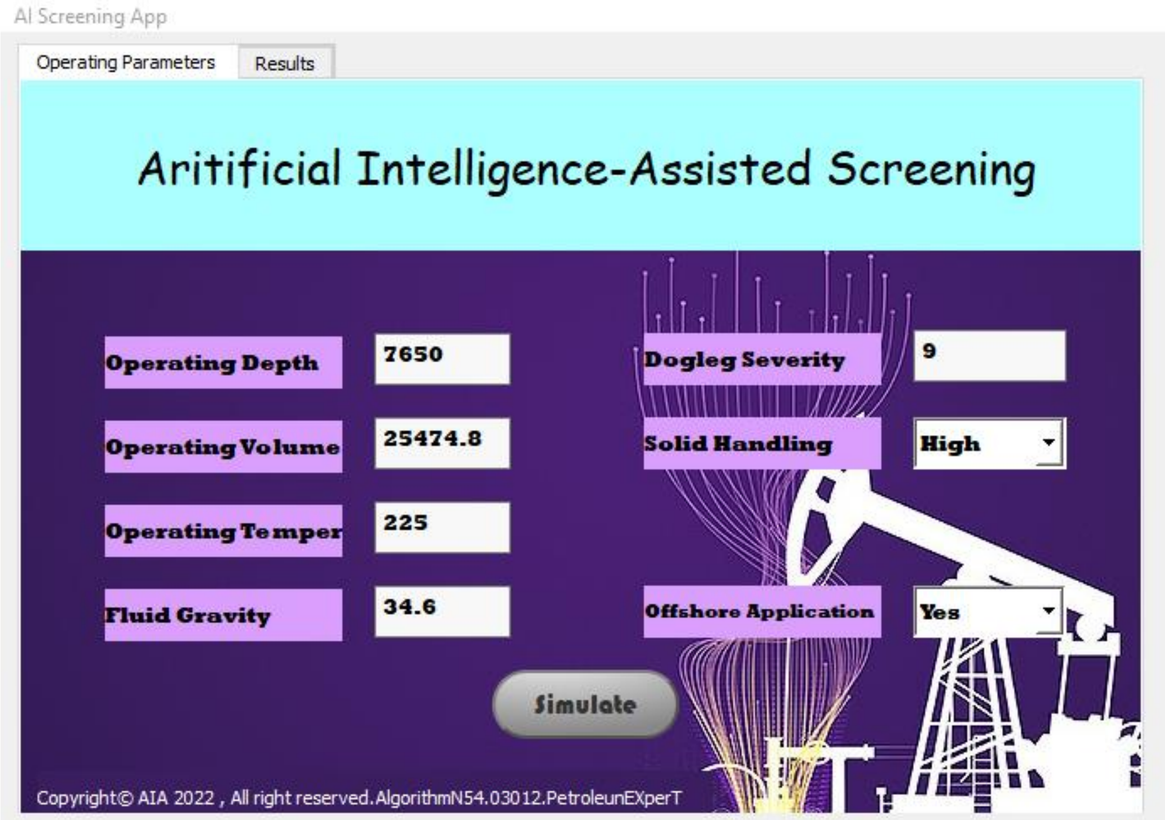


Figure 3.3 Artificial Intelligence-Assisted Screening Application Interface

3.3.11 Random Forest Algorithm

The Artificial Intelligence Algorithm used in the screening app is known as the Random Forest Algorithm. The supervised learning approach includes the well-known machine learning algorithm Random Forest. It may be used for machine learning problems requiring both regression and classification. It is based on the concept of ensemble learning, which is a technique for combining several classifiers to handle challenging problems and improve model performance (Anon, 2023).

As the name suggests, Random Forest is a classifier that averages numerous decision trees over various subsets of the supplied information to improve the predicted accuracy of the dataset. The random forest takes predictions from each decision tree and predicts the outcome based on the votes of the majority of projections rather than relying just on one decision tree. Higher accuracy and overfitting are avoided by the increased number of trees in the forest (Anon, 2022). Figure 3.4 shows the decision tree of a regular Random Forest Algorithm

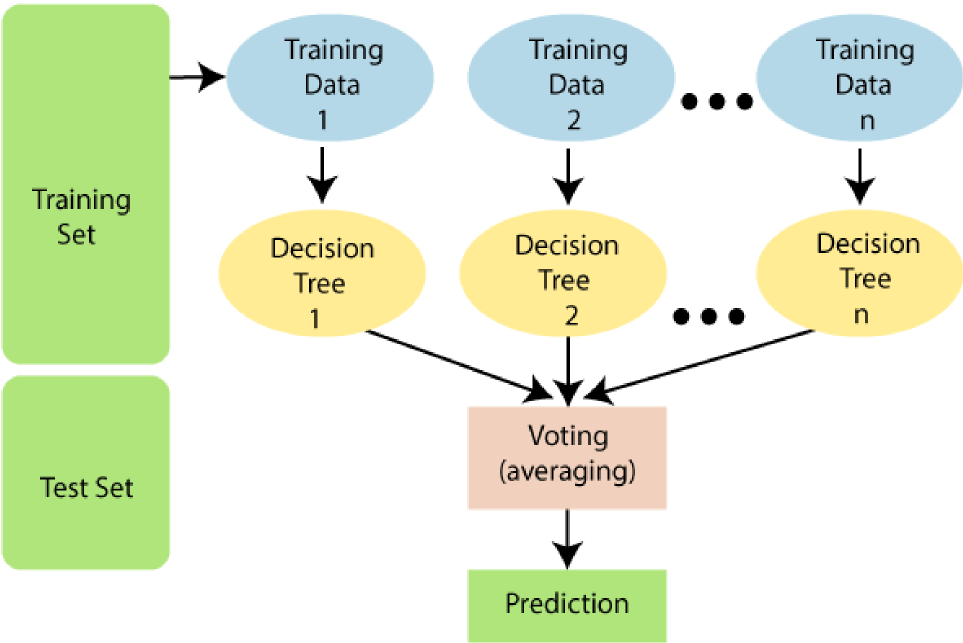


Figure 3.4 Random Forest Decision Tree (Anon, 2022)

Table 3.11 Input Design and Operating Parameters for Osprey Well and Hawk Well

Input and Operating Design Parameters	Osprey Well (Value)	Hawk Well (Value)	Unit
Operating Depth	7 650	7 500	Ft
DLS at a certain Depth	9	7	°/100ft
WC	40	25	%
Gas Liquid Ratio	335.75	275	Scf/Stb
Oil Gravity	37.29	34.6	°API
Operating Volume	25 474.8	21 501	BPD

Solids	High	High	
Operating Temperature	225	225	°F

3.4 PROSPER Setup

The PROSPER software is a tool for modelling well performance, design, and optimisation that is used in the global oil and gas sector today. The best lift technology is then simulated using PROSPER software to achieve the best design strategy and optimal inflow and outflow performance of the lift technology after being chosen from the Artificial Intelligence model as the best lift technology. Figure 3.5 shows the interface of the PROSPER simulator.

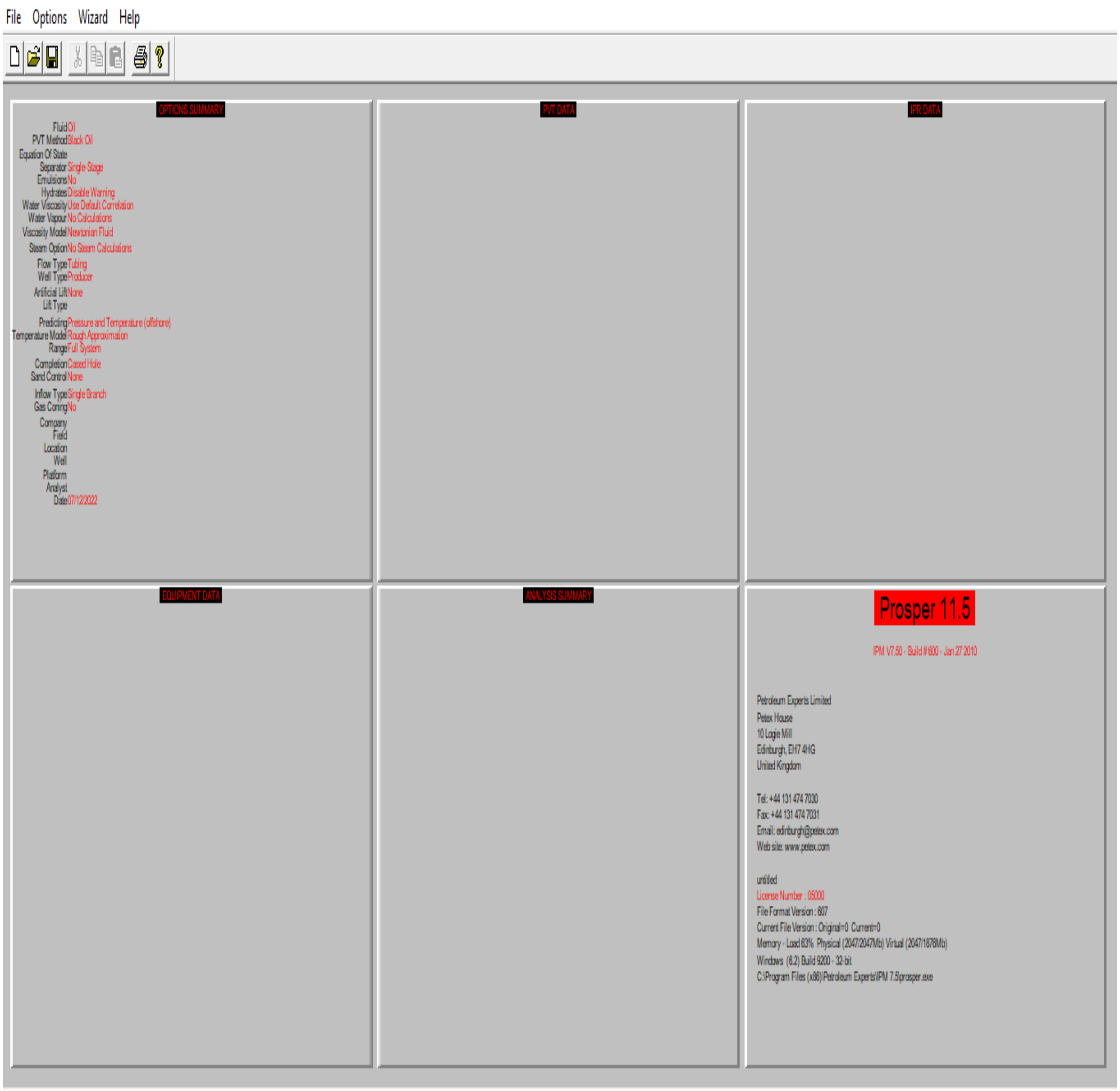


Figure 3.5 Prosper Simulator Display

3.4.1 System Summary

The System Summary provides input for fluid description, well type and artificial methods to be used. In this section, the main characteristics of the well are entered as shown in Fig 3.6.

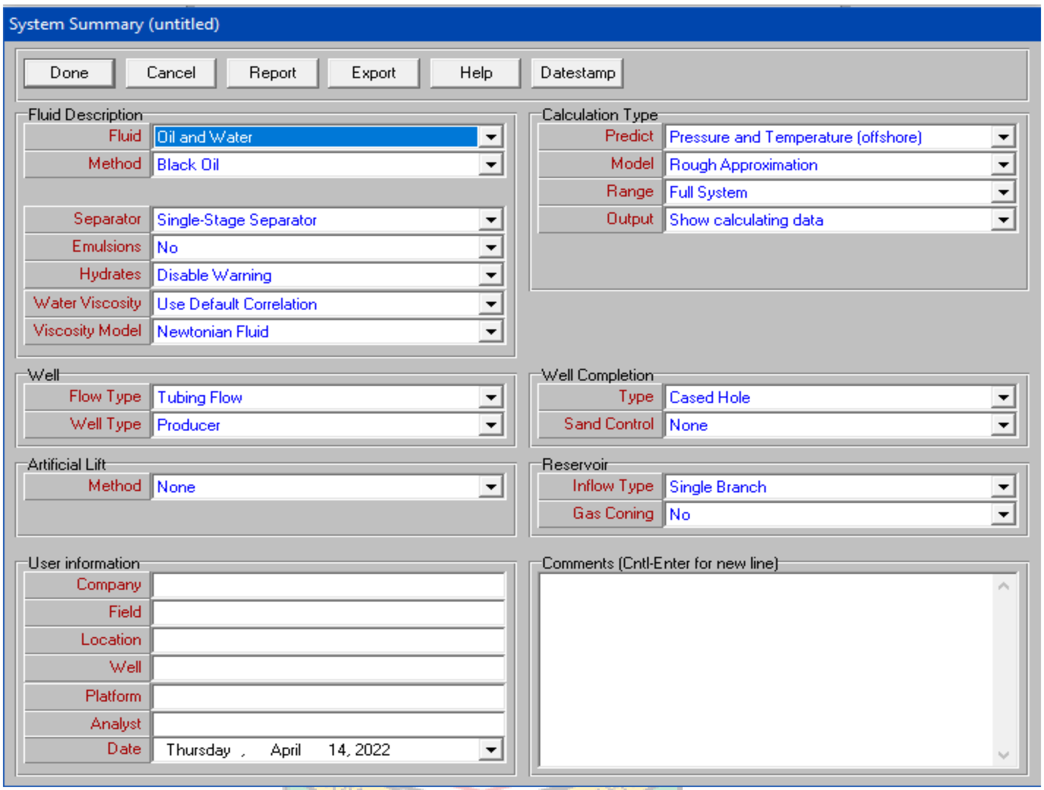


Figure 3.6 PROSPER Simulation System Summary Dialog

3.4.2 PVT Data Input

This section considers the solution gas oil ratio, oil gravity, gas gravity, water salinity, impurities, and the correlations used. The reservoir fluid's thermodynamic behaviour is roughly described by these data as shown in Figure 3.7.

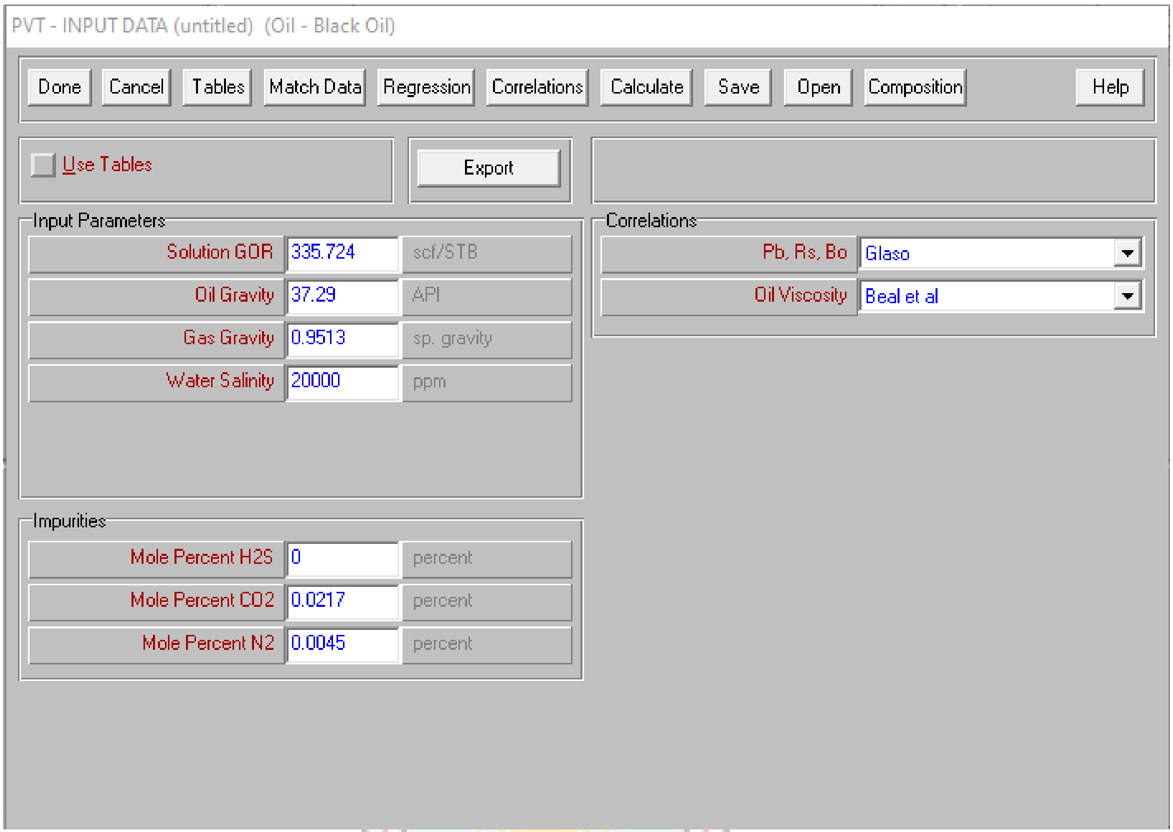


Figure 3.7 PVT – INPUT DATA Dialog

To forecast the Pb, Bo GOR, and oil-based on experimental data of different crude oil/natural gas mixes, many authors have constructed black oil correlations. Surface data, Pb, and/or Tres can be used as the input variables for these correlations. Several built-in correlations are supported by PROSPER for the calculations of the aforementioned attributes. More specifically, the following correlations are used to calculate Pb, Bo, and GOR:

i. Glaso's correlations;
ii. Standing's correlations;
iii. Lasater's correlations;
iv. Vasquez and Beggs' correlations;
v. Petrosky *et al* correlations; and
vi. Al-Marhoun's correlations.

When all of the relevant data has been entered, the software calculates the aforementioned PVT properties and compares them to the experimental values that have been added before moving on to the matching procedure. When PROSPER runs a nonlinear regression, it modifies the correlations to best fit the PVT data obtained in the lab (Test point). The correlations are given a multiplier (Parameter 1) and a shift (Parameter 2) by the nonlinear regression technique.

Additionally, the standard deviation, which reflects the overall closeness of fit, is shown. The fit is better when the standard deviation is lower. The model with parameter 1 closest to unity and parameter 2 closest to zero provides the best overall performance (Riuz *et al.*, 2014).

3.4.3 Equipment Data

A thorough explanation of the well's trajectory, surface and downhole equipment, geothermal gradient, and typical heat capacity is provided in this section of PROSPER as shown in Figure 3.8.

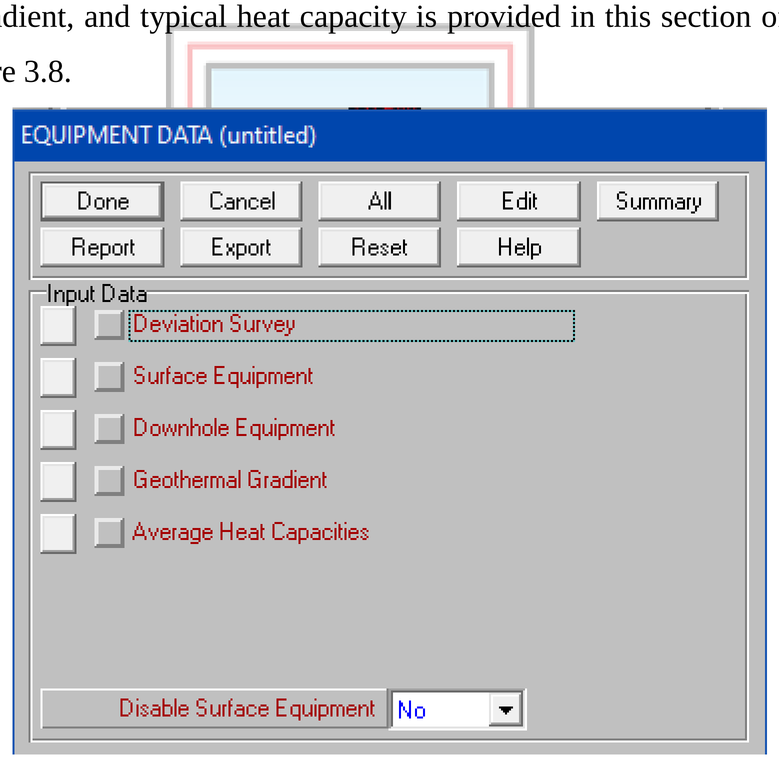
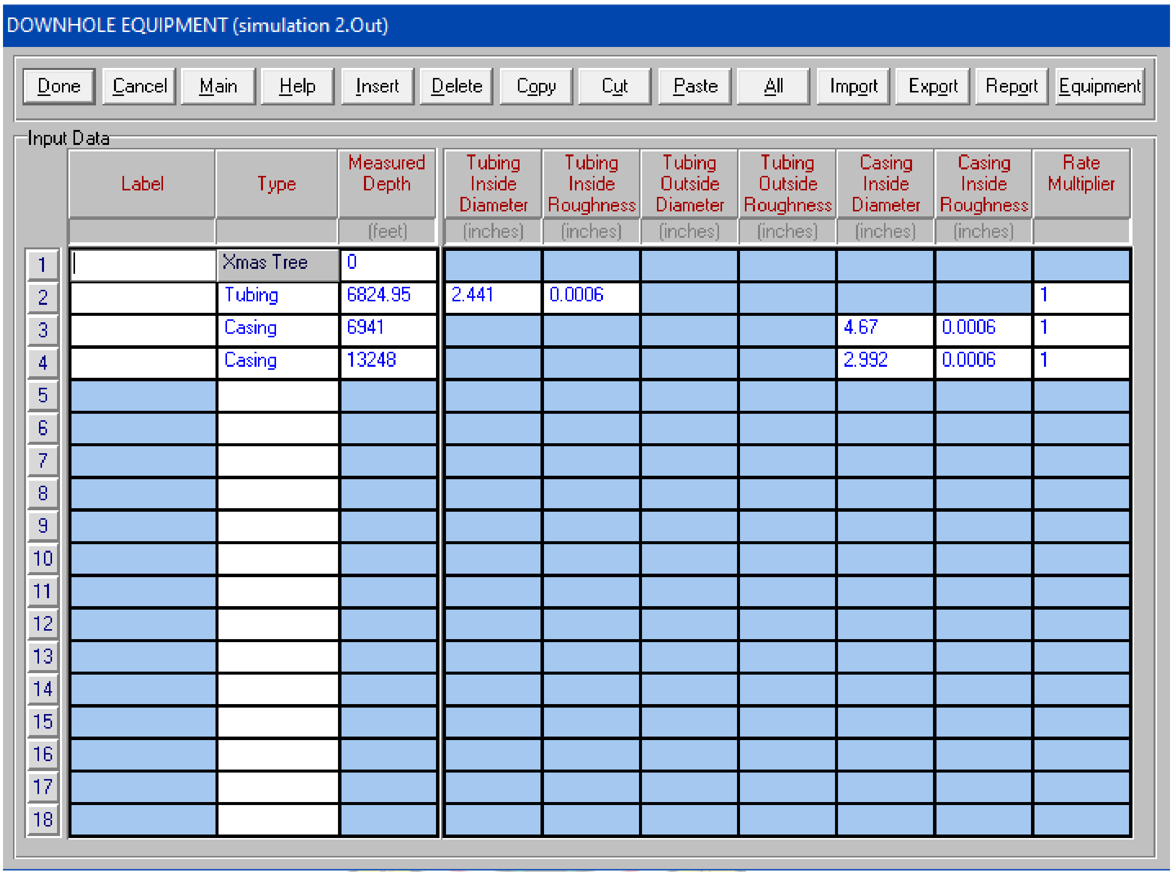


Figure 3.8 PROSPER Equipment Data

3.4.5 Downhole Equipment Data

Calculating the Vertical Lift Performance Relationship (VLP) of the well as well as the pressure and temperature gradients require a description of the well's equipment, similar to the deviation survey. The "Rough Approximation" model's computations are dependent on the tubing ID. To calculate frictional pressure losses during production, the ID and interior roughness of the tubing are also used as shown in Figure 3.9. Also, the surface equipment is specified in Figure 3.10.



	Label	Type	Measured Depth (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	6824.95	2.441	0.0006					1
3		Casing	6941					4.67	0.0006	1
4		Casing	13248					2.992	0.0006	1
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										

Figure 3.9 Downhole Equipment Data

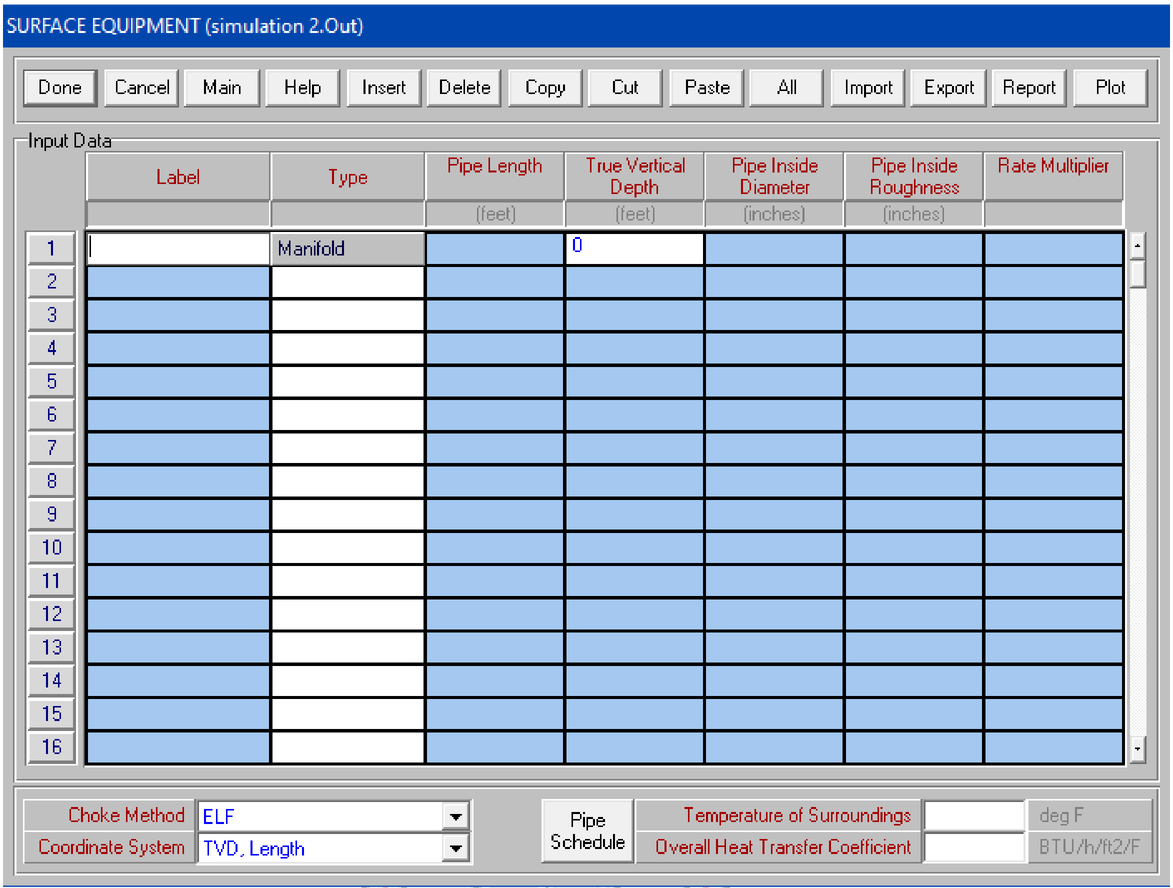
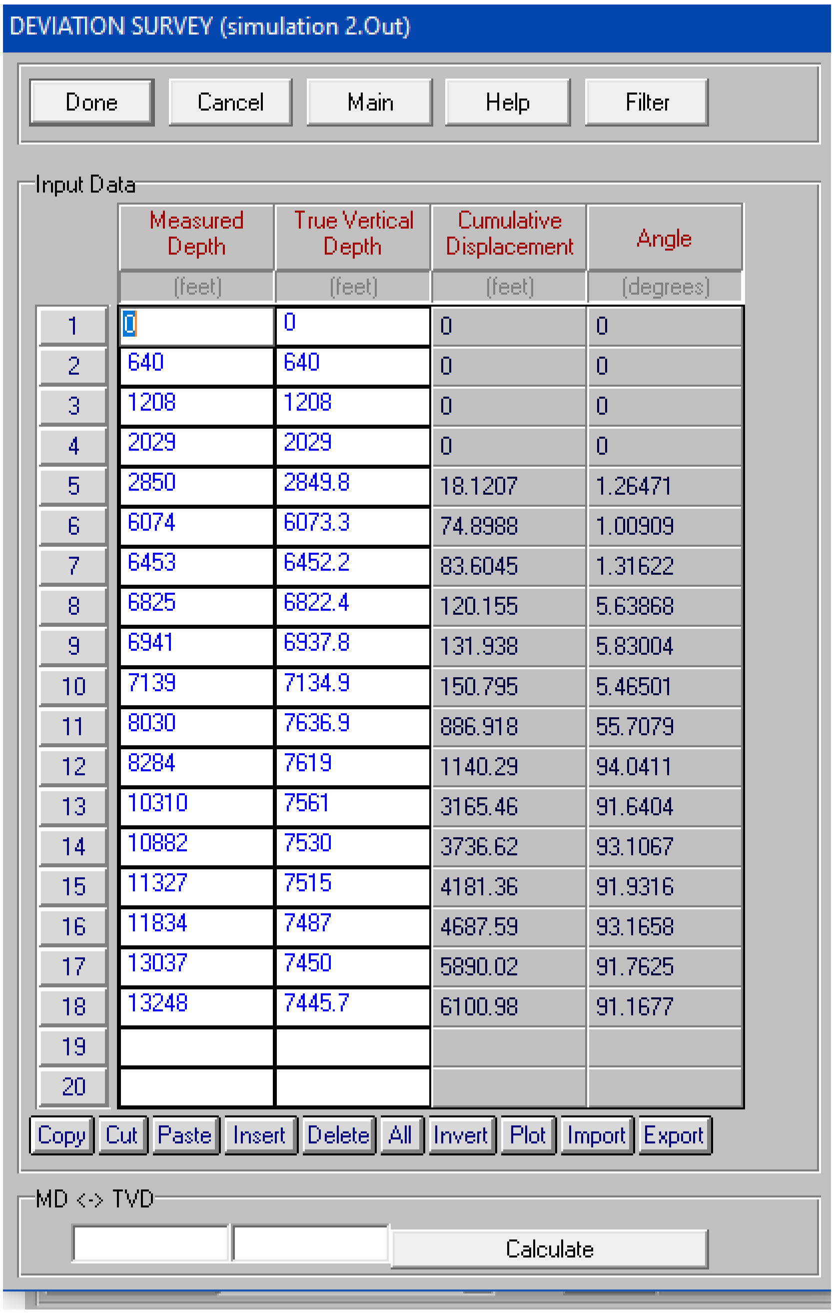


Figure 3.10 Surface Equipment Data

3.4.5 Deviation Survey Data

For the programme to accurately duplicate the deviation survey (TVD) in Figure 3.11, it requires pairs of Measured Depth (MD) and True Vertical Depth. While MD refers to the full length of the well (from the point of interest up to the well's first point at the surface), TVD refers to the vertical distance from the point of interest to the surface. PROSPER plots the well's track using a linear interpolation method between two successive MD locations. Two data points are adequate for each part of the well that is straight.

For the VLP section computations to be valid, a constant deviation survey is required. Since the pressure drop due to gravity (or vertical elevation) only depends on the change in elevation and the fluid density, the TVD of the well is crucial for this calculation. Every piece of machinery inserted into production tubes is constantly explained in terms of MD.



	Measured Depth (feet)	True Vertical Depth (feet)	Cumulative Displacement (feet)	Angle (degrees)
1	0	0	0	0
2	640	640	0	0
3	1208	1208	0	0
4	2029	2029	0	0
5	2850	2849.8	18.1207	1.26471
6	6074	6073.3	74.8988	1.00909
7	6453	6452.2	83.6045	1.31622
8	6825	6822.4	120.155	5.63868
9	6941	6937.8	131.938	5.83004
10	7139	7134.9	150.795	5.46501
11	8030	7636.9	886.918	55.7079
12	8284	7619	1140.29	94.0411
13	10310	7561	3165.46	91.6404
14	10882	7530	3736.62	93.1067
15	11327	7515	4181.36	91.9316
16	11834	7487	4687.59	93.1658
17	13037	7450	5890.02	91.7625
18	13248	7445.7	6100.98	91.1677
19				
20				

Figure 3.11 Deviation Survey Data from PROSPER setup

3.5 Pseudocode

The Pseudo code for Artificial Lift Selection Criteria Using Random Forest Algorithm is detailed below.

Precondition: A training set **S** = (x1, y1), . . ., (xn, yn), features **F**, and number of trees in forest **B**.

function RandomForest (S, **F**)

H ← ∅

for i ∈ 1, . . ., **B do**

$S^{(i)}$ ← A bootstrap sample from S

h_i ← RandomizedTreeLearn ($S^{(i)}$, **F**)

H ← **H** ∪ {h_i}

end for

return H

end function

function RandomizedTreeLearn (S, **F**)

At each node:

f ← very small subset of F

Split on best feature in f

return the learned tree

end function

import **math**

import **numpy** as **np**

INITIALIZING

Key (For Relative Values)

Excellent = 100<X>80

Good = 80>X>60

Fair To Good = 60>X>50

Fair = 50

Poor = X<50

Key (For Solids)

High = 1

Medium = 0

Low = -1

if OD >= 110 **and** OD <= 16000:

Display "Operating depth is in the range of SUCKER ROD PUMP"

else:

Display "'Operating Depth is not in range for SUCKER ROD PUMP"

if OD >=200 **and** OD<=6000:

Display "Operating depth is in the range of PROGRESSIVE CAVITY PUMP"

else:

Display "Operating Depth is not in range for PROGRESSIVE CAVITY PUMP"

if OD >= 5000 **and** OD <=15000:

Display "Operating depth is in the range of GAS LIFT"

else:

Display "Operating Depth is not in range for GAS LIFT"

if OD >= 7500 **and** OD <=17000:

Display "Operating depth is in the range of HYDRAULIC LIFT"

else:

Display "Operating Depth is not in range for HYDRAULIC LIFT"

if OD >= 5000 **and** OD <=15000:

Display "Operating depth is in the range of JET PUMP"

else:

Display "Operating Depth is not in range for JET PUMP"

if OD >= 1000 **and** OD <=15000:

Display "Operating depth is in the range of ELECTRIC SUBMERSIBLE PUMP"

else:

Display "Operating Depth is not in range for ELECTRIC SUBMERSIBLE PUMP"

Lift Scores = [Initialize Scoring for Artificial Lift]

List Names = List of Artificial lift Names

Maximum Lift scores = **maximum value** of Lift Scores

position = list (List Names and values) and index position of maximum Lift scores

Display "Position of Artificial Lift from Highest to Lowest Order"

Display (.......................... BEST LIFT METHOD................................)

Display (Operating Depth, Maximum Lift Score Name, Range)

Display (Operating Volume, Maximum Lift Score Name, Range)

Display (Operating Temperature, Maximum Lift Score Name, Range)

Display (Fluid Gravity, Maximum Lift Score Name, Range)

Display (Dog leg Severity, Maximum Lift Score Name, Range)

Display (Solids Handling, Maximum Lift Score Name, Range)

Display (Offshore Applicability, Maximum Lift Score Name, Range)

Economic Consideration

Get Value **for** Artificial Lift Assembly

Get Value **for** Work over cost

Get Value **for** Surface Equipment

Get Value **for** Electrical Surface Equipment

Get Value **for** Metering

Get Value **for** Surface Electrical Labor

Get Value **for** Artificial lift Labor

Sum of Cost

Display "Total Capital Cost for installing Artificial lift"

Calculate CAPEX and OPEX

Reserves = OOIP

Recoverable Reserve Estimate = OOIP * Recoverable Factor

Net Income = Gross Income - Taxes (50%)

Display "Net Income"

NB. 50% tax (Nguyen, 2020**).**

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Introduction

Result and discussion sections are critical components of any scientific research paper. This section presents the findings of the research on the osprey and hawk wells, which includes screening results on operating depth and operating volume, dog leg severity, solid handling, the best lift selection, inflow performance relations, cost evaluation, screening results comparison, formation PI analysis and the economic implications of selecting the artificial lift method.

4.2 Screening Results on Operating Depth and Operating Volume

Figure 4.1 shows results from the Artificial Intelligence (AI) Assisted Screening Criteria on the Operating Depth and Operating volume for the Osprey well. From the result, the operating depth was higher than the operating depth range for Progressive Cavity Pump (PCP) whereas Sucker Rod Pump, Gas Lift, Hydraulic Lift, Jet Pump, and Electrical Submersible Pump satisfied the Operating Depth condition of the well (Refer Table 3.9). Considering the Operating volume, only the Gas lift and Electrical Submersible Pump satisfied the operating volume condition.

```
[[----------- OPERATING DEPTH---------]]
Operating depth is in the range of Sucker Rod Pump and is equivalent to = 7650
OD =  7650
Operating Depth not is not in range for PROGRESSIVE CAVITY PUMP 7650
OD =  7650
Operating depth is in the range of GAS LIFT and is equivalent to = 7650
OD =  7650
Operating depth is in the range of HYDRAULIC LIFT and is equivalent to = 7650
OD =  7650
Operating depth is in the range of JET PUMP and is equivalent to = 7650
OD =  7650
Operating depth is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 7650
OD =  7650
[[----------- OPERATING VOLUME---------]]
Operating Volume not is not in range for Sucker Rod Pump 25474.8
OV =  25474.8
Operating Volume not is not in range for PROGRESSIVE CAVITY PUMP 25474.8
OV =  25474.8
Operating Volume is in the range of GAS LIFT and is equivalent to = 25474.8
OV =  25474.8
Operating Volume not is not in range for HYDRAULIC LIFT 25474.8
OV =  25474.8
Operating Volume not is not in range for JET PUMP 25474.8
OV =  25474.8
Operating Volume is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 25474.8
OV =  25474.8
```

Figure 4.1 AI Operating Depth and Operating Volume Results for the Osprey well.

The Operating Depth and Operating Volume for the Hawk well as determined by the Artificial Intelligence (AI) Assisted Screening Criteria are shown in Figure 4.8 of the report. As a result, the Progressive Cavity Pump’s (PCP's) operating depth was higher than its operating depth range, whereas the Sucker Rod Pump, Gas Lift, Hydraulic Lift, Jet Pump, and Electrical Submersible Pump all met the well's operating depth requirements (Refer Table 3.10). Only the Gas Lift and Electrical Submersible Pump satisfied the operating volume criteria when taking into account the operational volume.

```
[[---------- OPERATING DEPTH---------]]
Operating depth is in the range of Sucker Rod Pump and is equivalent to = 7500
OD =  7500
Operating Depth not is not in range for PROGRESSIVE CAVITY PUMP 7500
OD =  7500
Operating depth is in the range of GAS LIFT and is equivalent to = 7500
OD =  7500
Operating depth is in the range of HYDRAULIC LIFT and is equivalent to = 7500
OD =  7500
Operating depth is in the range of JET PUMP and is equivalent to = 7500
OD =  7500
Operating depth is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 7500
OD =  7500
[[---------- OPERATING VOLUME---------]]
Operating Volume not is not in range for Sucker Rod Pump 21501
OV =  21501
Operating Volume not is not in range for PROGRESSIVE CAVITY PUMP 21501
OV =  21501
Operating Volume is in the range of GAS LIFT and is equivalent to = 21501
OV =  21501
Operating Volume not is not in range for HYDRAULIC LIFT 21501
OV =  21501
Operating Volume not is not in range for JET PUMP 21501
OV =  21501
Operating Volume is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 21501
OV =  21501
```

Figure 4.2 AI Operating Depth and Operating Volume Results for the Hawk well

4.3 Screening Results on Dog Leg Severity and Solid Handling

Figure 4.3 shows results for the Dog Leg Severity (DLS) and Solid Handling for the Osprey well. The Gas Lift and Hydraulic lift systems were the only lift system that satisfied the DLS operating condition. Moreover, considering the high solid content of the well, the Progressive Cavity Pump, Gas lift, and Hydraulic Jet Pump were in the operable range to handle high solids.

```
[[----------- Dog Leg Severity (DLS) ---------]]
 Dog Leg Severity (DLS) not is not in range for Sucker Rod Pump= 9
DLS =  9
 Dog Leg Severity (DLS) not is not in range for PROGRESSIVE CAVITY PUMP= 9
DLS =  9
 Dog Leg Severity (DLS) is in the range of GAS LIFT and is equivalent to = 9
DLS =  9
 Dog Leg Severity (DLS) is in the range of HYDRAULIC LIFT and is equivalent to = 9
DLS =  9
 Dog Leg Severity (DLS) not is not in range for JET PUMP= 9
DLS =  9
 Dog Leg Severity (DLS) not is not in range for ELECTRIC SUBMERSIBLE PUMP= 9
DLS =  9
KEY (FOR SOLIDS)
    ====================================
    HIGH     = 1
    MEDIUM   = 0
    LOW      = -1

[[----------- SOLIDS (SH) ---------]]
 SOLIDS (SH) not is not in range for Sucker Rod Pump Solid Handling

 SOLIDS (SH) is in the range of PROGRESSIVE CAVITY PUMP Solid Handling
                 Excellent Handling

 SOLIDS (SH) is in the range of GAS LIFT Solid Handling
                 Good Handling

 SOLIDS (SH) not is not in range for HYDRAULIC LIFT Solid Handling

 SOLIDS (SH) is in the range of JET PUMP Solid Handling
                 Good Handling

 SOLIDS (SH) not is not in range for ELECTRIC SUBMERSIBLE PUMP Solid Handling
```

Figure 4.3 AI Dog Leg Severity (DLS) and Solids Handling (SH) Results for the Osprey well

Figure 4.4 shows results for the Dog Leg Severity (DLS) and Solid Handling for the Hawk well. All lift systems satisfied the DLS condition but only the Progressive Cavity Pump, Gas lift, and Hydraulic Jet Pump were in operable range to handle high solids.

```
[[----------- Dog Leg Severity (DLS) ---------]]
 Dog Leg Severity (DLS) is in the range of Sucker Rod Pump and is equivalent to = 7
DLS =  7
 Dog Leg Severity (DLS) is in the range of PROGRESSIVE CAVITY PUMP and is equivalent to = 7
DLS =  7
 Dog Leg Severity (DLS) is in the range of GAS LIFT and is equivalent to = 7
DLS =  7
 Dog Leg Severity (DLS) is in the range of HYDRAULIC LIFT and is equivalent to = 7
DLS =  7
 Dog Leg Severity (DLS) is in the range of JET PUMP and is equivalent to = 7
DLS =  7
 Dog Leg Severity (DLS) is in the range of ELECTRIC SUBMERSIBLE PUMP and is equivalent to = 7
DLS =  7
KEY (FOR SOLIDS)
    ====================================
    HIGH     = 1
    MEDIUM   = 0
    LOW      = -1

[[----------- SOLIDS (SH) ---------]]
 SOLIDS (SH) not is not in range for Sucker Rod Pump Solid Handling

 SOLIDS (SH) is in the range of PROGRESSIVE CAVITY PUMP Solid Handling
                 Excellent Handling

 SOLIDS (SH) is in the range of GAS LIFT Solid Handling
                 Good Handling

 SOLIDS (SH) not is not in range for HYDRAULIC LIFT Solid Handling

 SOLIDS (SH) is in the range of JET PUMP Solid Handling
                 Good Handling

 SOLIDS (SH) not is not in range for ELECTRIC SUBMERSIBLE PUMP Solid Handling
```

Figure 4.4 AI Dog Leg Severity (DLS) and Solids Handling (SH) Results for the Hawk well

4.4 Screening Results for Best Lift Selection

Figure 4.5 and Figure 4.6 show the Final Artificial Intelligence (AI) Assisted Screening Results for the selection of the best lift system for both wells. From Figure 4.5, the Osprey well had an operating depth of 7 650 ft, an Operating Volume of 25 474.8 Bpd, an operating temperature of 225 °F, an Oil API gravity of 37.29, DLS of 9 °/100 ft, and a High Solid content. The Osprey well was therefore in range with all the operating parameters of a gas lift method. The gas lift has good performance in an offshore environment, making it more favourable.

```
........................... BEST LIFT METHOD.................................

                            Selection
OPERATING DEPTH >>>>>> Gas Lift (7 650) >>>>>> Range (5 000 - 15 000) >>>>> Good
OPERATING VOLUME >>>>>> Gas Lift (2 474.8) >>>>>> Range (200 - 50 000) >>>>> Good
OPERATING TEMPERATURE >>>>>> Gas Lift (225) >>>>>> Range (100 - 400) >>>>> Good
FLUID GRAVITY >>>>>> Gas Lift (37.29) >>>>>> Range (>15) >>>>> Good
Dog Leg severity >>>>>> Gas Lift (9) >>>>>> Range (>8) >>>>>> Good
Solids >>>>> Gas Lift (High) >>>>>> Range (Low - High)>>>>>> Good
OFFSHORE APPLICATION >>>>> Gas Lift (EXCELLENT)>>>>> Range (EXCELLENT) >>>> Good
>>>
```

Figure 4.5 Artificial lift Selection using AI for Osprey Well

On the other hand, the Hawk had a working depth of 7 500 feet, an operational volume of 21 501 Bpd, a temperature of 225 degrees, a gravity of 34.6 API, a DLS of 7 °/100 feet, and a high solids content. As a result, the Hawk well is operable in all circumstances involving gas lift. Because of its excellent offshore performance and stable solid handling characteristics, the gas lift is more favourable.

```
........................... BEST LIFT METHOD...............................

                            Selection
OPERATING DEPTH >>>>>> Gas Lift (7 500) >>>>>> Range (5 000 - 15 000) >>>>> Good
OPERATING VOLUME >>>>>> Gas Lift (21 501) >>>>>> Range (200 - 50 000) >>>>> Good
OPERATING TEMPERATURE >>>>>> Gas Lift (225) >>>>>> Range (100 - 400) >>>>> Good
FLUID GRAVITY >>>>>> Gas Lift (34.6) >>>>>> Range (>15) >>>>> Good
Dog Leg severity >>>>>> Gas Lift (7) >>>>>> Range (>8) >>>>>> Good
Solids >>>>> Gas Lift (High) >>>>>> Range (Low - High)>>>>>> Good
OFFSHORE APPLICATION >>>>> Gas Lift (EXCELLENT)>>>>> Range (EXCELLENT) >>>> Good
>>>
```

Figure 4.6 Artificial lift Selection using AI for Hawks Well

4.5 Inflow Performance Relations

Figure 4.7 and Figure 4.8 represents the IPR curves for Osprey and Hawk Wells at the initial stage of production. From Figure 4.7, reservoir pressure of 2 500 psia, reservoir temperature of 180 °F, water cut of 80%, and a Total GOR equivalent to 336 scf/STB yielded an Absolute Open Flow Potential (AOF) of 25 474.8 STB/day and Formation Productivity index (PI) of 20.89 STB/Day/psi. Similarly, Figure 4.8 shows an AOF of 21 501.1 STB/day within Hawk well alongside a Formation Productivity index (PI) of 13.22.

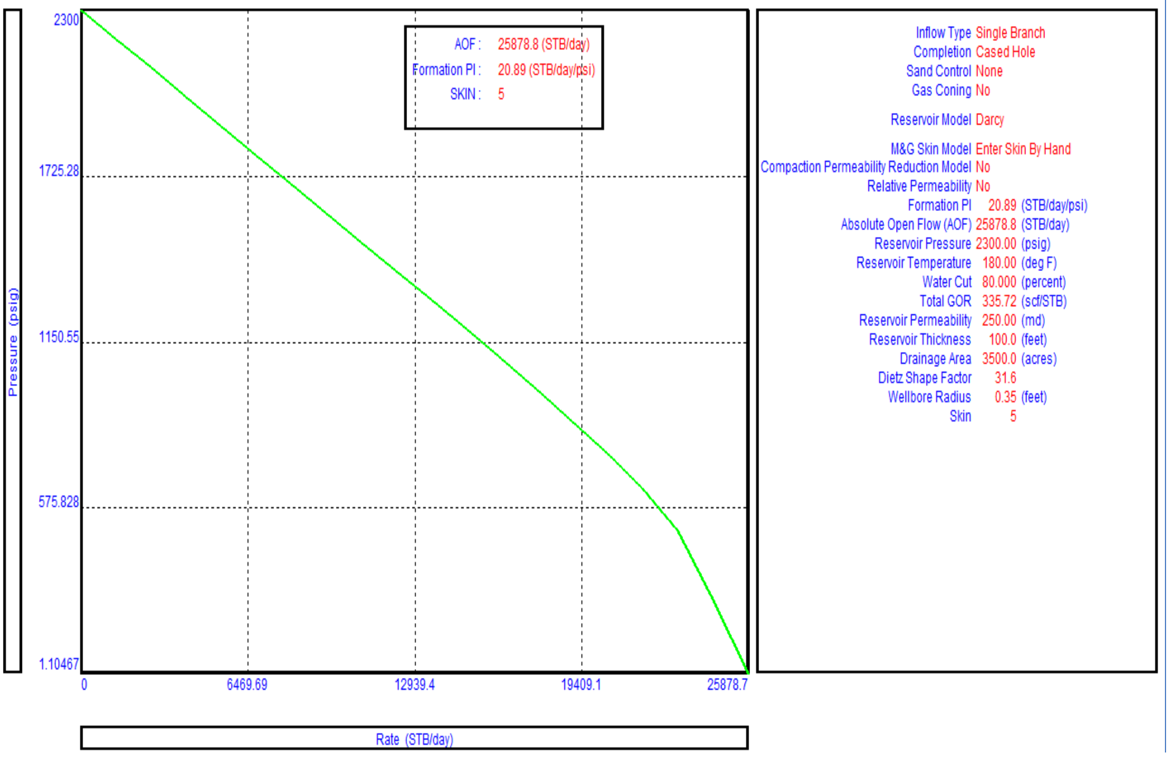


Figure 4.7 IPR curve at Initial Production within Osprey Well

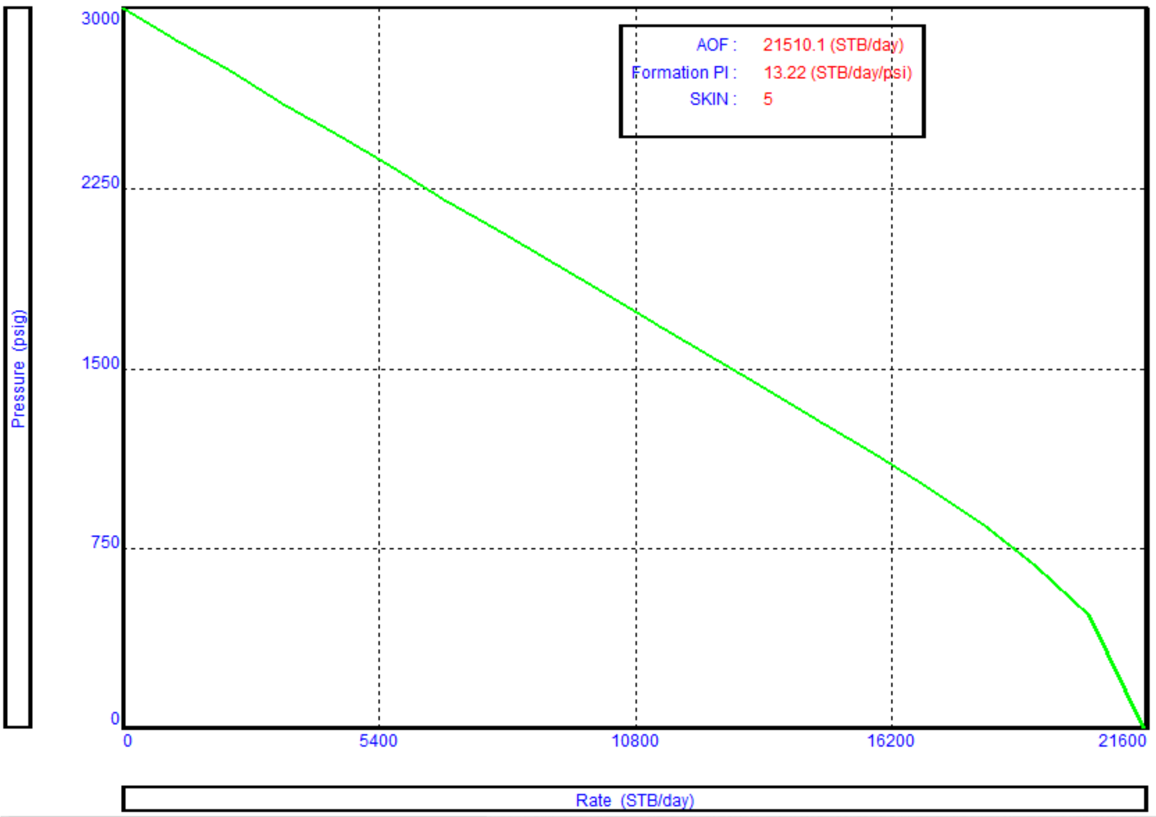


Figure 4.8 IPR curve at Initial Production within Hawk Well

Figure 4.9 and Figure 4.10 show the IPR curves of both the Osprey and Hawk field after primary production. In Figure 4.9, the Formation PI of the Osprey well dropped to 7.72 STB/Day/psi and the Absolute Open Flow Potential Also dropped to 11 490.7 STB/day. The Formation PI of the Hawk wells dropped as well to 9.51 STB/Day/psi and its AOF reduced to 6 610.4 STB/day as shown in Figure 4.10.

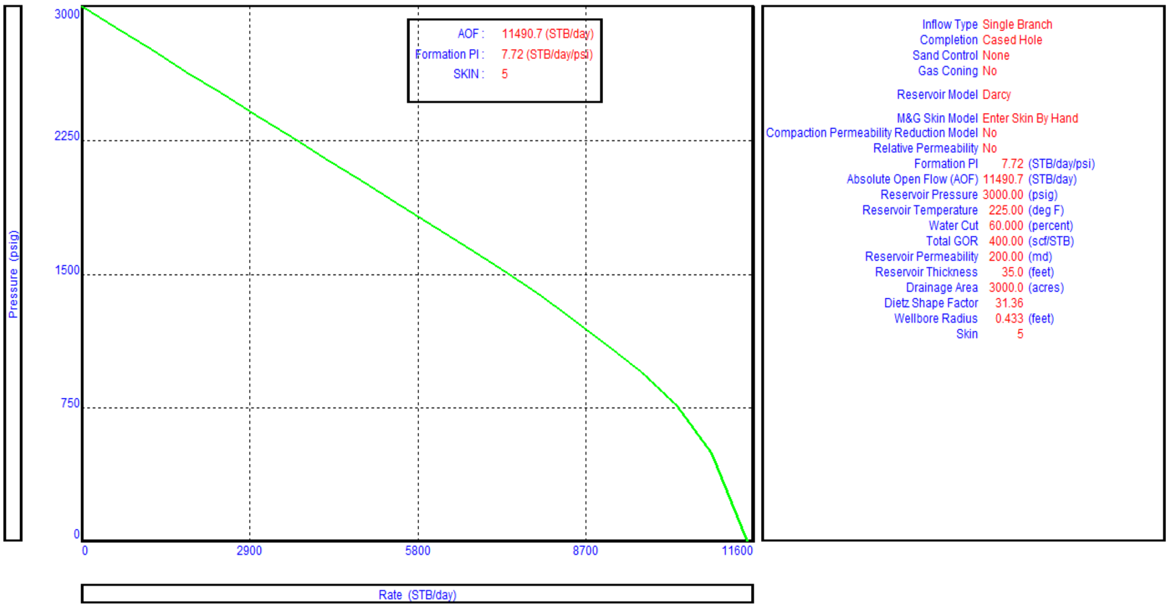


Figure 4.9 IPR curve after Primary Production within Osprey Well

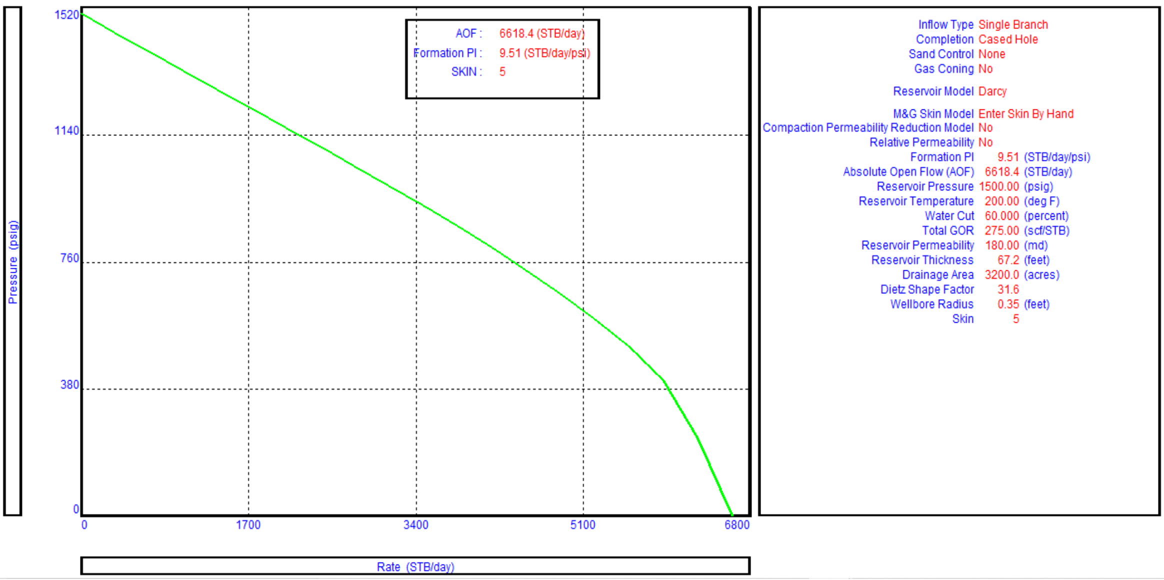


Figure 4.10 IPR curve after Primary Production within Hawk Well

4.5.1 IPR versus VLP Plot

As a result of poor performance in the Osprey and Hawk wells, the IPR versus Vertical lift Performance plot shows that there is no production within these wells. There is no production when the IPR and VLP do not intersect. In Figure 4.11 the IPR and VLP curves obtained from the Osprey well after primary productions do not intersect indicating zero production. Similarly, the IPR and VLP curves from the Hawk well do not intersect meaning there is no production as shown in Figure 4.12.

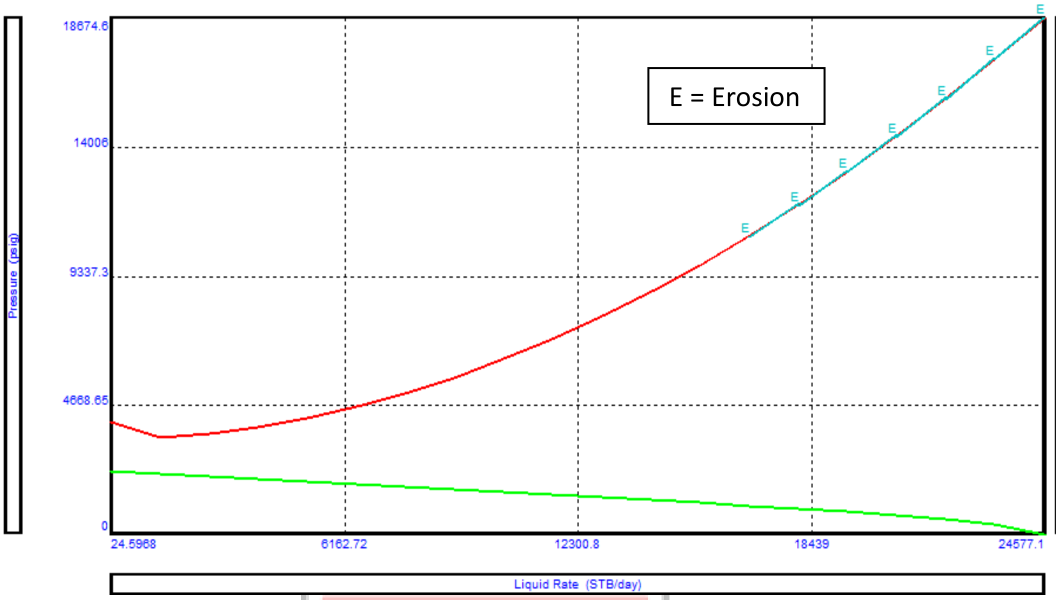


Figure 4.11 IPR vs VLP for Osprey Well

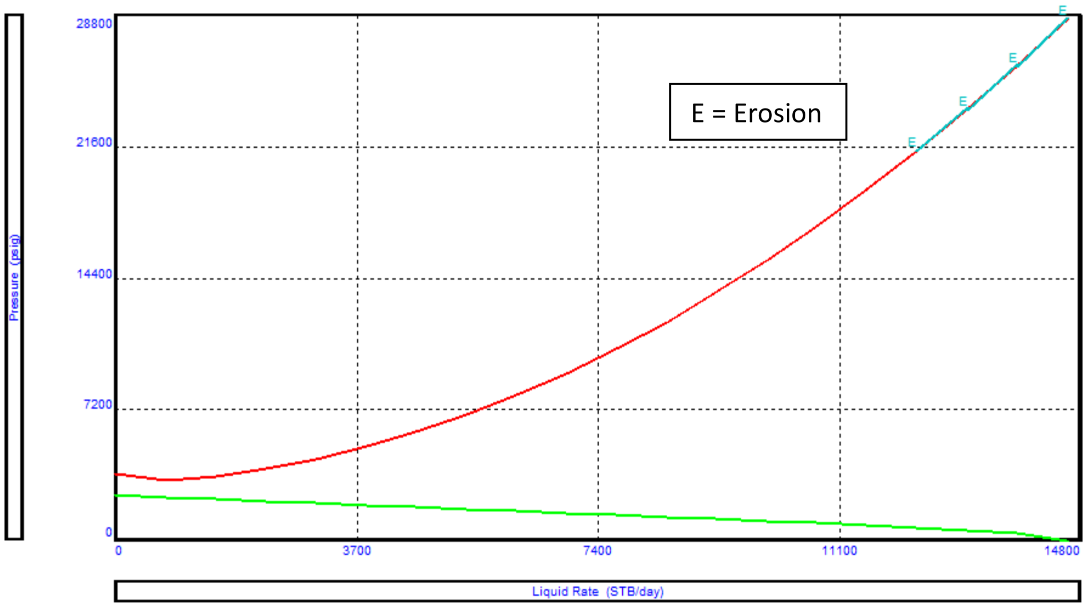


Figure 4.12 IPR vs VLP for Hawk Well

4.6 Results of Artificial Lift

After introducing the artificial lift method, the future IPR versus VLP curves for Osprey and Hawk wells are shown in Figure 4.13 and Figure 4.14 respectively gained by performing pressure sensitivity analysis. The oil flow rate desired is about 7 950 STB/day at a pressure of 3 100 psi. The Osprey well becomes unproductive when the pressure is below 2 090 psi.

From Figure 4.14, the oil flow rate desired is about 7 075 STB/day at 3 300 psi. The well will become dead at pressures below 2 250 psi. Both wells at lower pressures may still produce little amounts of oil. Further research could be conducted on the well to aid the artificial lift employed to increase production.

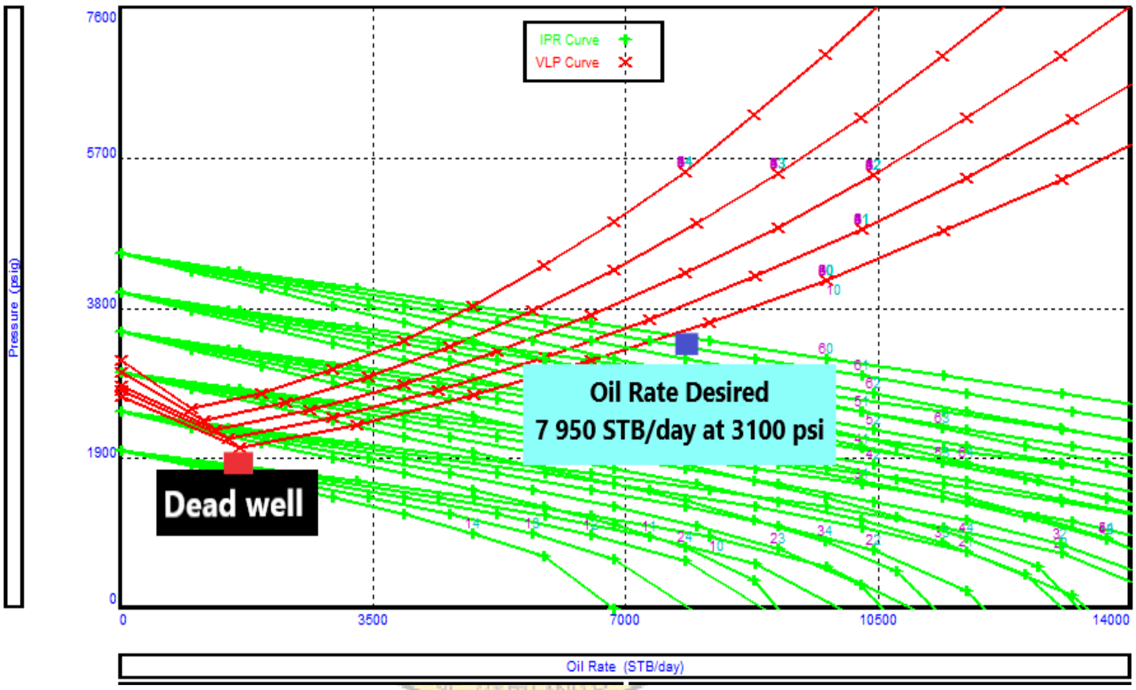


Figure 4.13 Future IPR Curve for Osprey Well

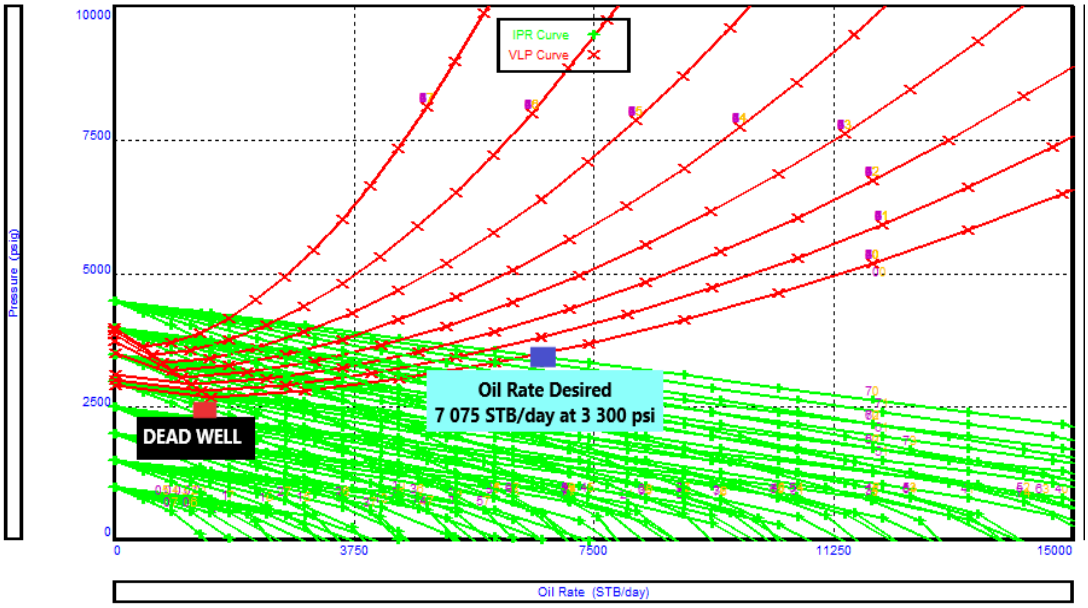


Figure 4.14 Future IPR Curve for Hawk Well

Figure 4.15 and Figure 4.16 further show the IPR curve after the application of the gas lift method. Osprey had an AOF of 63 319.3 STB/day and a Formation PI of 12.90 STB/day/psi and the Hawk well had an AOF of 40 600.2 STB/day with a Formation PI of 13.82 STB/day/psi.

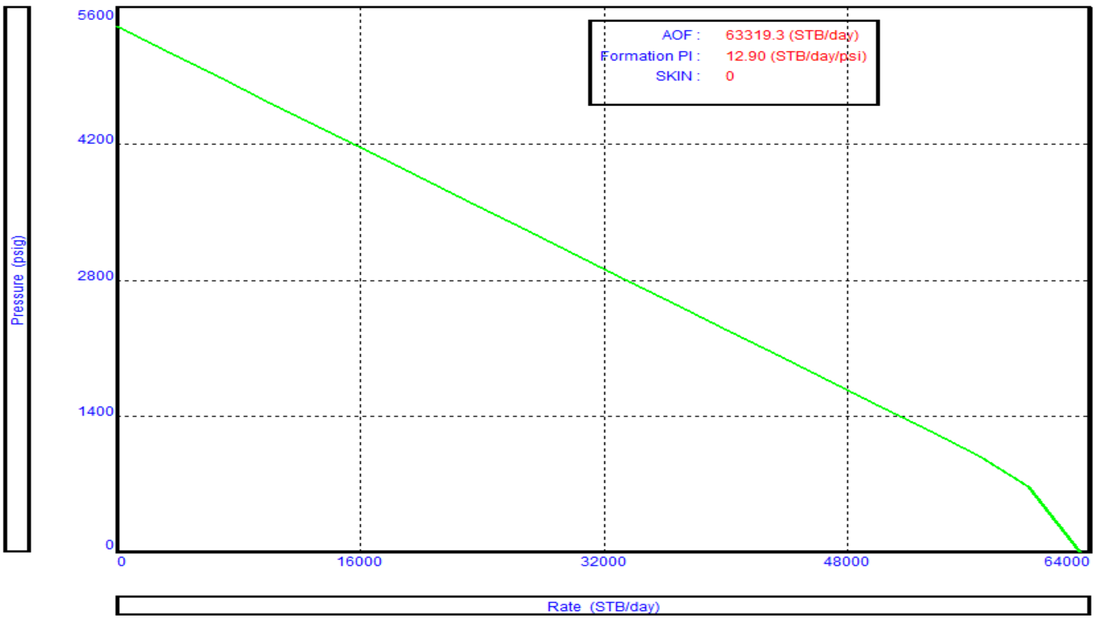


Figure 4.15 IPR Curve for Osprey Well after Gas Lift Introduction

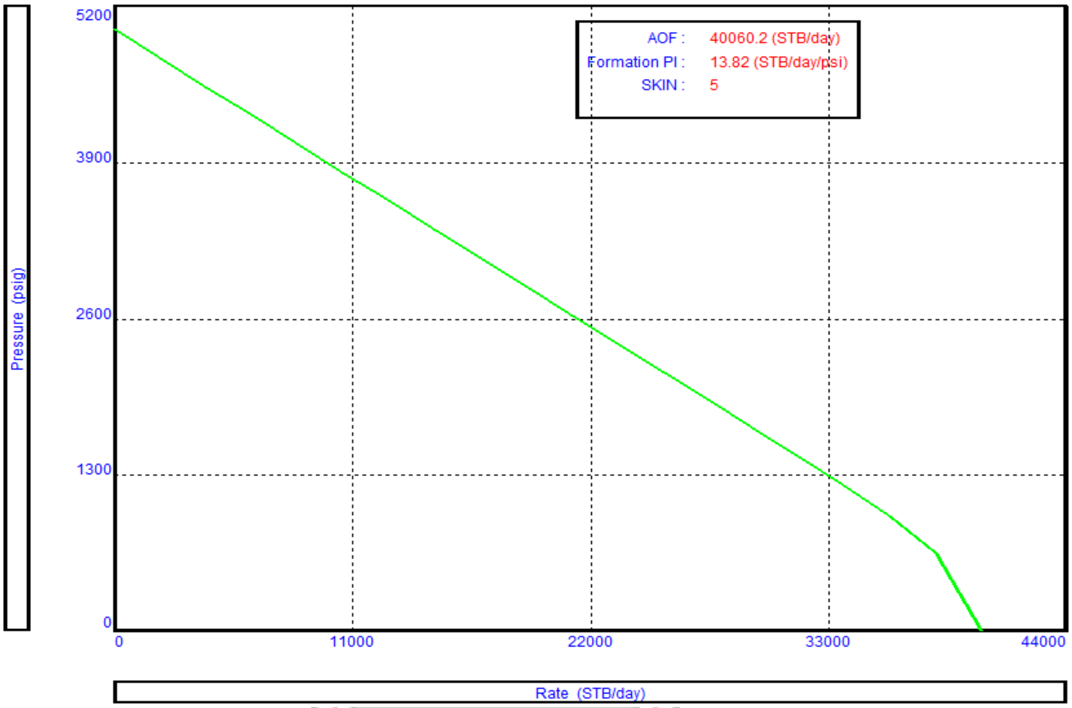


Figure 4.16 IPR Curve for Hawk Well after Gas Lift Introduction

4.6.1 IPR versus VLP Plot After Artificial Lift installation

Figure 4.17 and Figure 4.18 shows the IPR versus VLP plot of both the Osprey and Hawk wells. The figure shows an intersection between the IPR and VLP curves indicating that there is production.

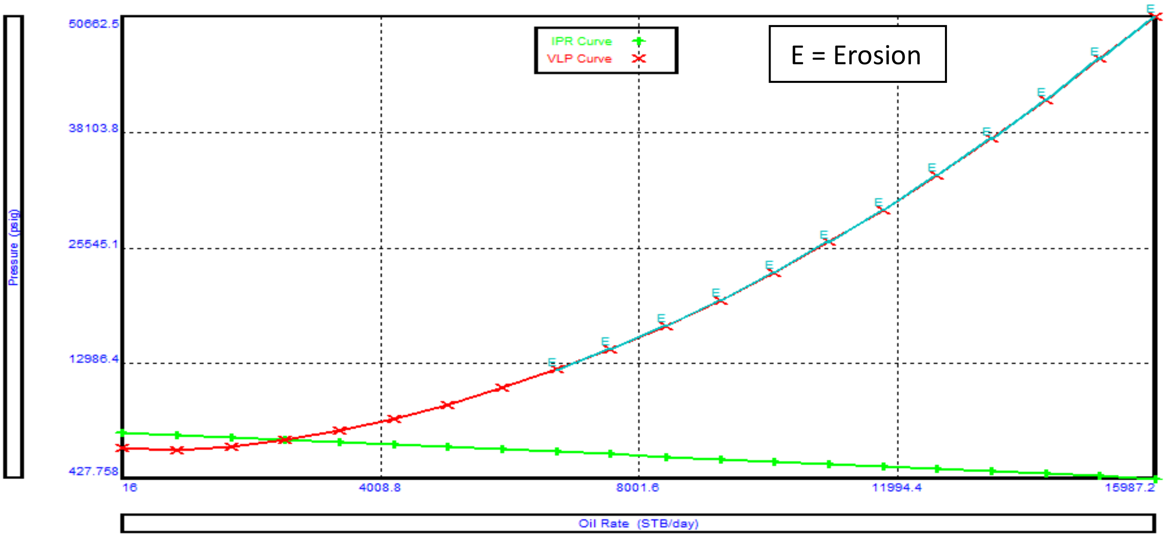


Figure 4.17 IPR versus VLP Curves After Gas Lift Installation on Osprey Well

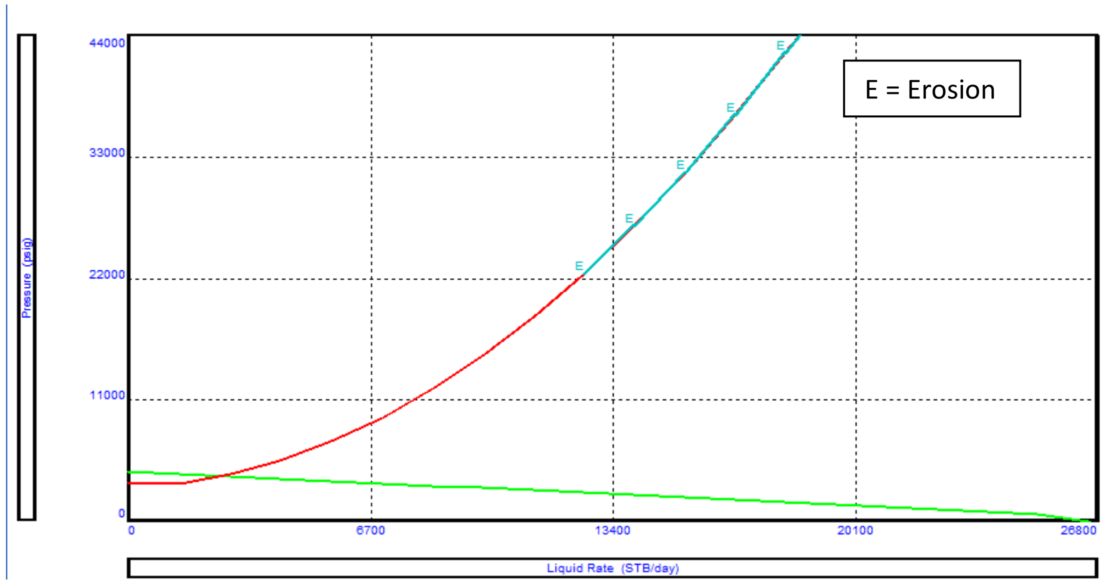


Figure 4.18 IPR versus VLP Curves After Gas Lift Installation on Hawk Well

4.6.2 Vertical Lift Performance Evaluation

Further analysis was performed to show the VLP curve which is presented in the diagrams below. Figure 4.19 And figure 4.20. Describes the VLP Tubing Curves of the Osprey and Hawk wells. At over 7 800 psi the Osprey well exceeds its erosional velocity and becomes unsafe to produce. On the other hand, the Hawks well exceed its erosional velocity at 22 600 psi.

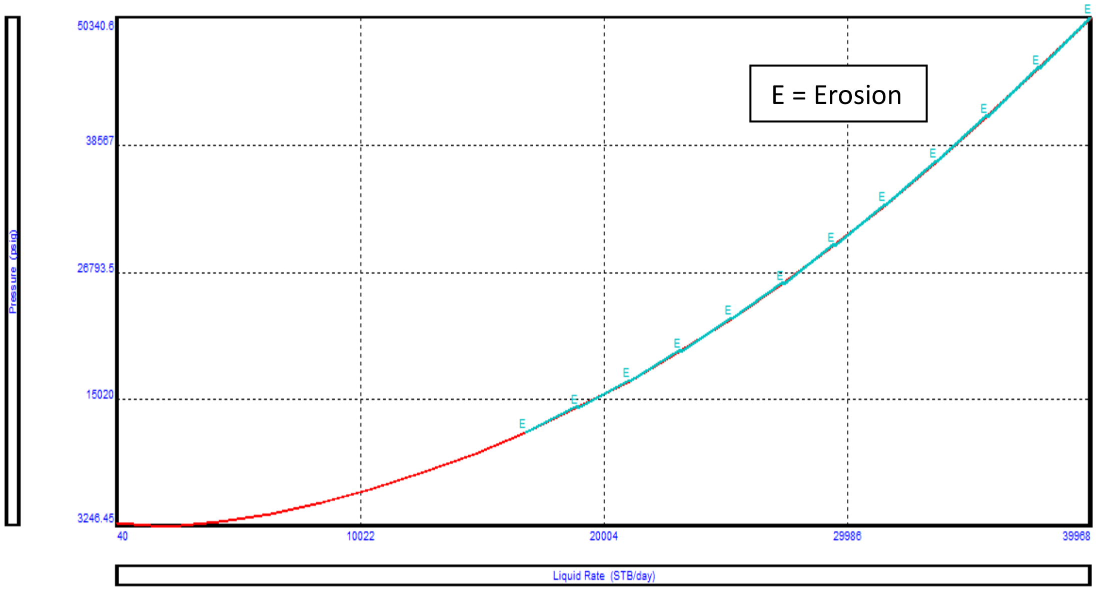


Figure 4.19 VLP Tubing Curve for Osprey Well

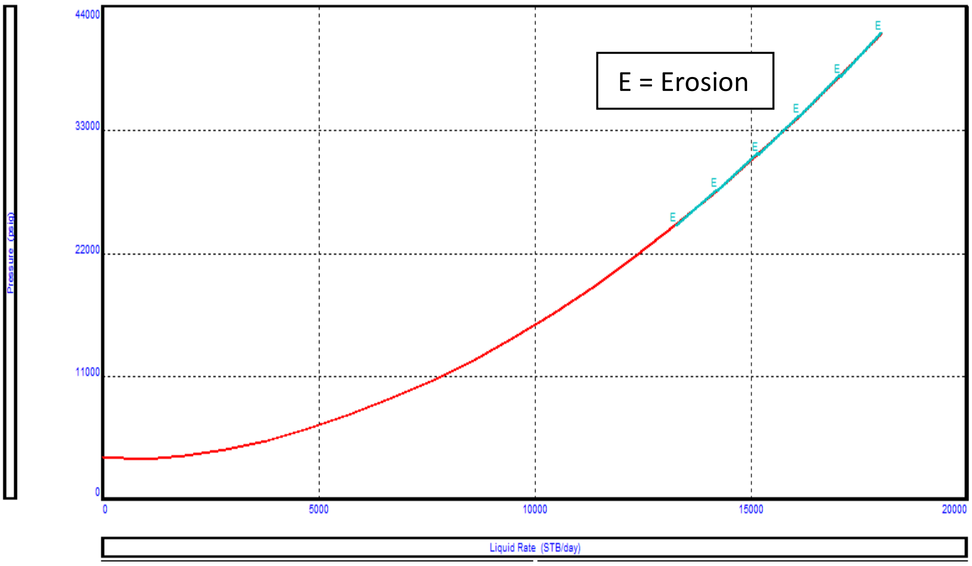


Figure 4.20 VLP Tubing Curve for Hawk Well

4.7 Equipment Design

Figure 4.21 show the downhole equipment design for the Osprey well. The Tubing is set at about 6 563ft TVD with an inner diameter of 2.44 inches. It has two casing completions set at 7 677.7 ft and 10 492.7 ft respectively.

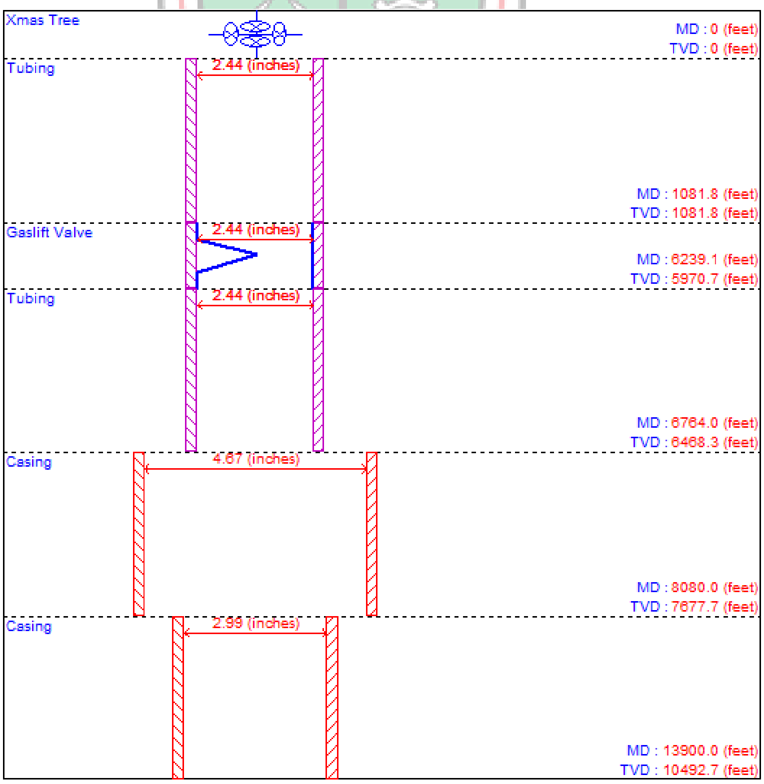


Figure 4.21 Equipment Design for Osprey Well

The downhole equipment design for the Hawk well is shown in Figure 4.22. The inner diameter of the tube, which has an approximate TVD of 6 126.4 feet, is 2.0 inches. Two casing completions are present, each at a different height of 9 056.4 and 12 500 feet.

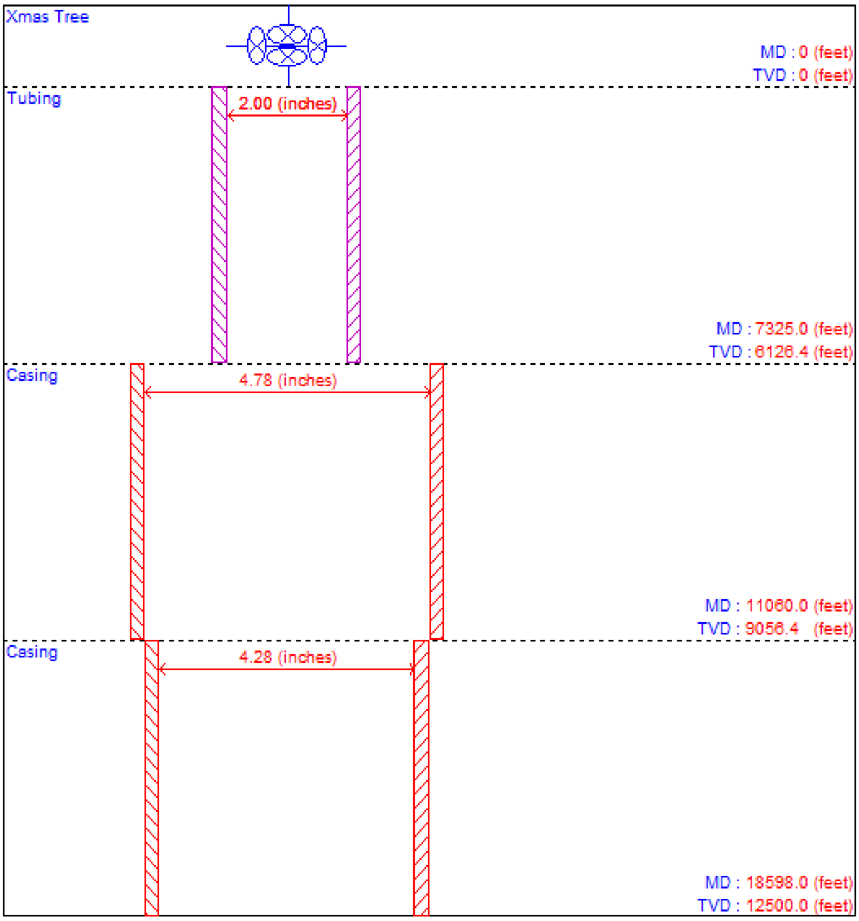


Figure 4.22 Equipment Design for Hawk Well

4.8 Gas Lift Design

The Gas lift Design for the Osprey Well is shown in Figure 4.23. the valve spacing is automatically calculated by PROSPER software. It consists of three valves and an orifice. From Figure 4.24 the first valve is set at a TVD of 2 963.8 ft, the second valve is set at a TVD of 5 412.05 ft and the third valve is set at a TVD of 7 320.87 ft. the Camco R20 valve type was used in the Gas lift Design.

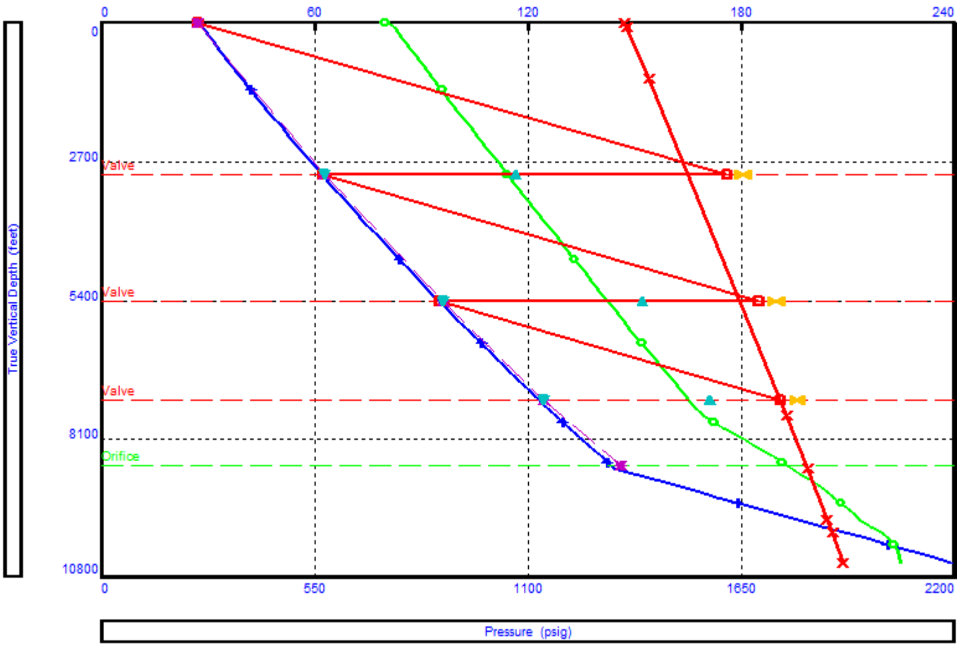
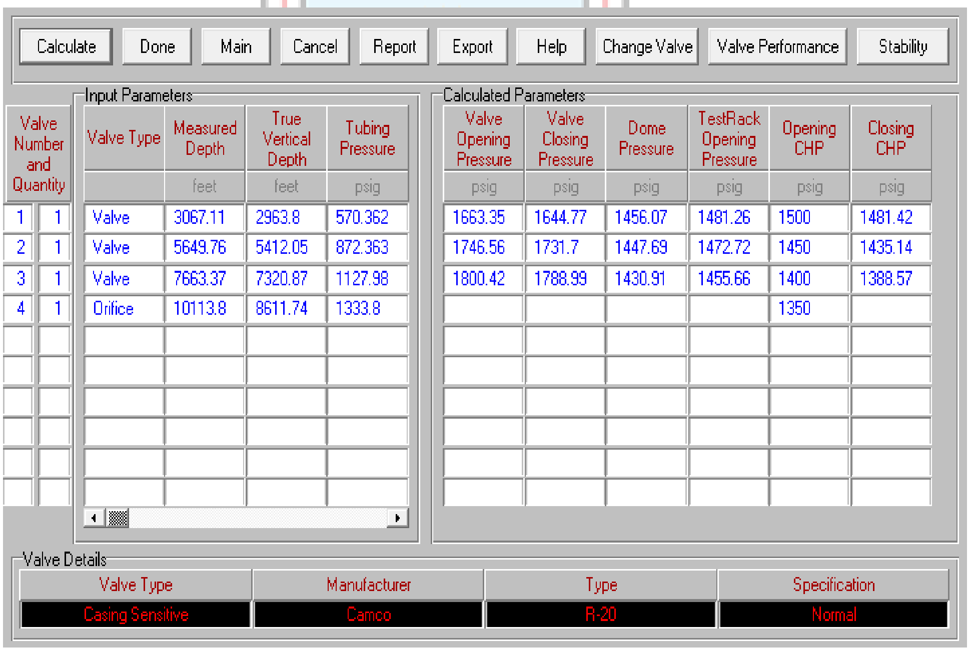


Figure 4.23 Gas Lift Design for Osprey Well



Valve Number and Quantity		Valve Type	Measured Depth	True Vertical Depth	Tubing Pressure	Valve Opening Pressure	Valve Closing Pressure	Dome Pressure	TestRack Opening Pressure	Opening CHP	Closing CHP
			feet	feet	psig	psig	psig	psig	psig	psig	psig
1	1	Valve	3067.11	2963.8	570.362	1663.35	1644.77	1456.07	1481.26	1500	1481.42
2	1	Valve	5649.76	5412.05	872.363	1746.56	1731.7	1447.69	1472.72	1450	1435.14
3	1	Valve	7663.37	7320.87	1127.98	1800.42	1788.99	1430.91	1455.66	1400	1388.57
4	1	Orifice	10113.8	8611.74	1333.8					1350	

Valve Type	Manufacturer	Type	Specification
Casing Sensitive	Camco	R-20	Normal

Figure 4.24 Gas Lift Design Results for Osprey Well

Figure 4.25 depicts the gas lift design for the Hawk Well. The valve spacing is determined using PROSPER software automatically. According to Figure 4.26, the first valve has a TVD of 2 179.47 feet, the second is fixed at 3 999.07 feet, the third is placed at 5 465.19 feet, and the final valve is fixed at 6 607.94 feet. The Gas lift Design utilized Camco R20 valves.

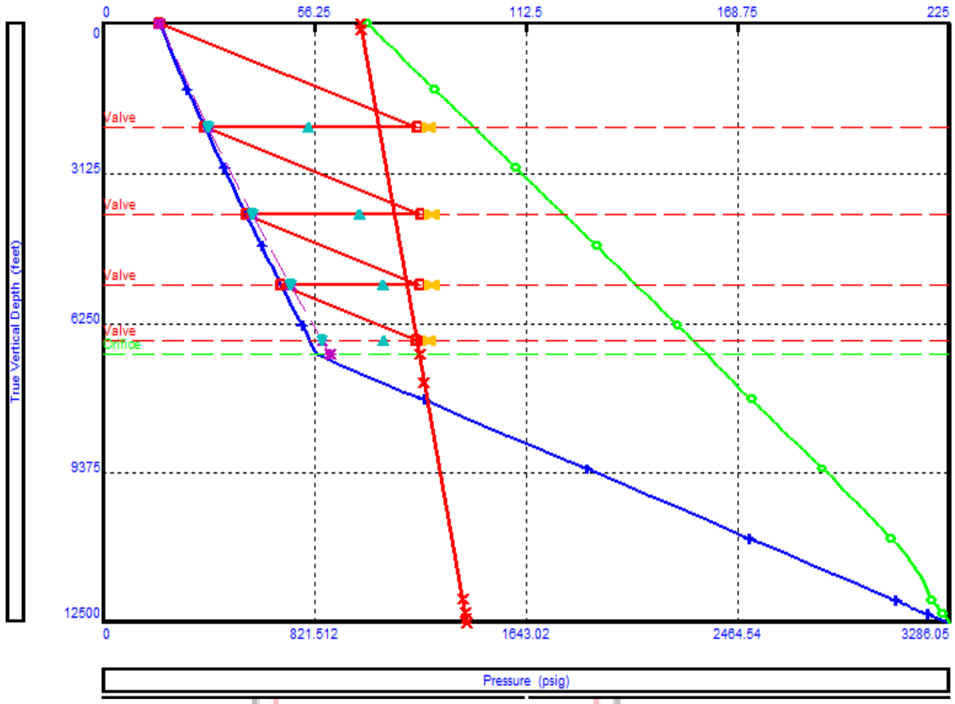
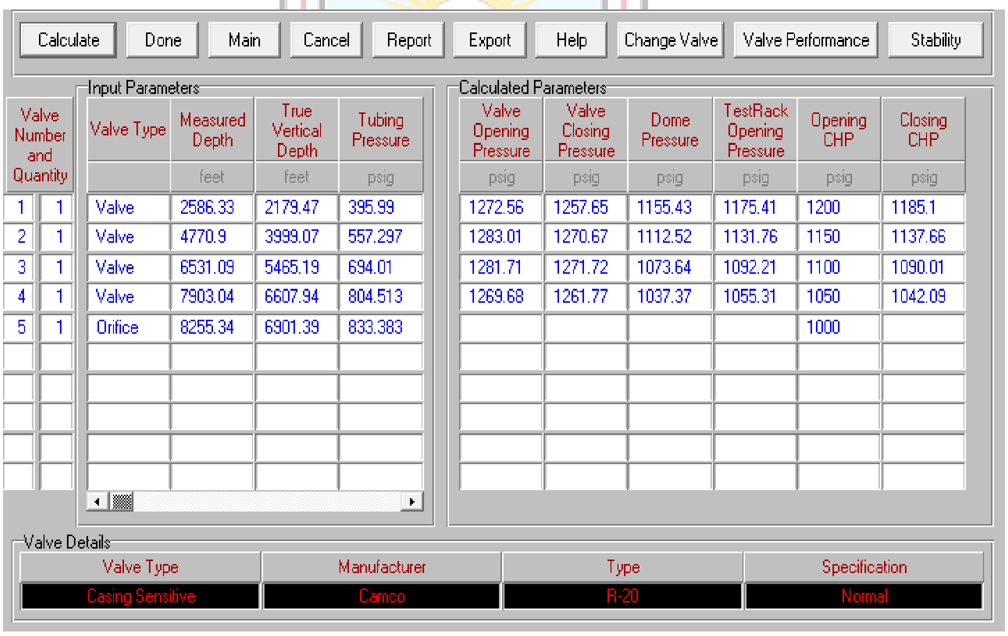


Figure 4.25 Gas Lift Design for Hawk Well



Valve Number and Quantity		Valve Type	Measured Depth (feet)	True Vertical Depth (feet)	Tubing Pressure (psig)	Valve Opening Pressure (psig)	Valve Closing Pressure (psig)	Dome Pressure (psig)	TestRack Opening Pressure (psig)	Opening CHP (psig)	Closing CHP (psig)
1	1	Valve	2586.33	2179.47	395.99	1272.56	1257.65	1155.43	1175.41	1200	1185.1
2	1	Valve	4770.9	3999.07	557.297	1283.01	1270.67	1112.52	1131.76	1150	1137.66
3	1	Valve	6531.09	5465.19	694.01	1281.71	1271.72	1073.64	1092.21	1100	1090.01
4	1	Valve	7903.04	6607.94	804.513	1269.68	1261.77	1037.37	1055.31	1050	1042.09
5	1	Orifice	8255.34	6901.39	833.383					1000	

Valve Details

Valve Type	Manufacturer	Type	Specification
Casing Sensitive	Camco	R-20	Normal

Figure 4.26 Gas Lift Design Results for Hawk Well

Figure 4.27 shows the sensitivity plot for the Osprey Well, its maximum Gas injection rate was 10.05 MMscf/day.

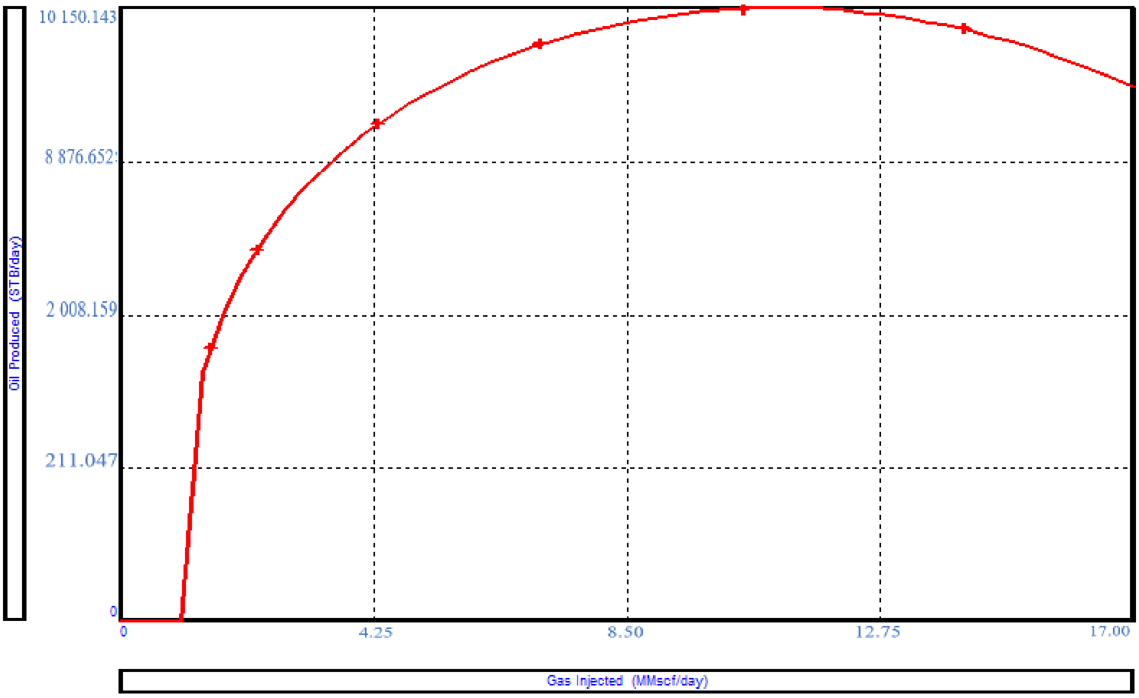


Figure 4.27 Maximum Gas Injection Sensitivity Plot for Osprey Well

The sensitivity map for the Hawk is shown in Figure 4.28. The maximum rate of gas injection was 8 MMscf per day.

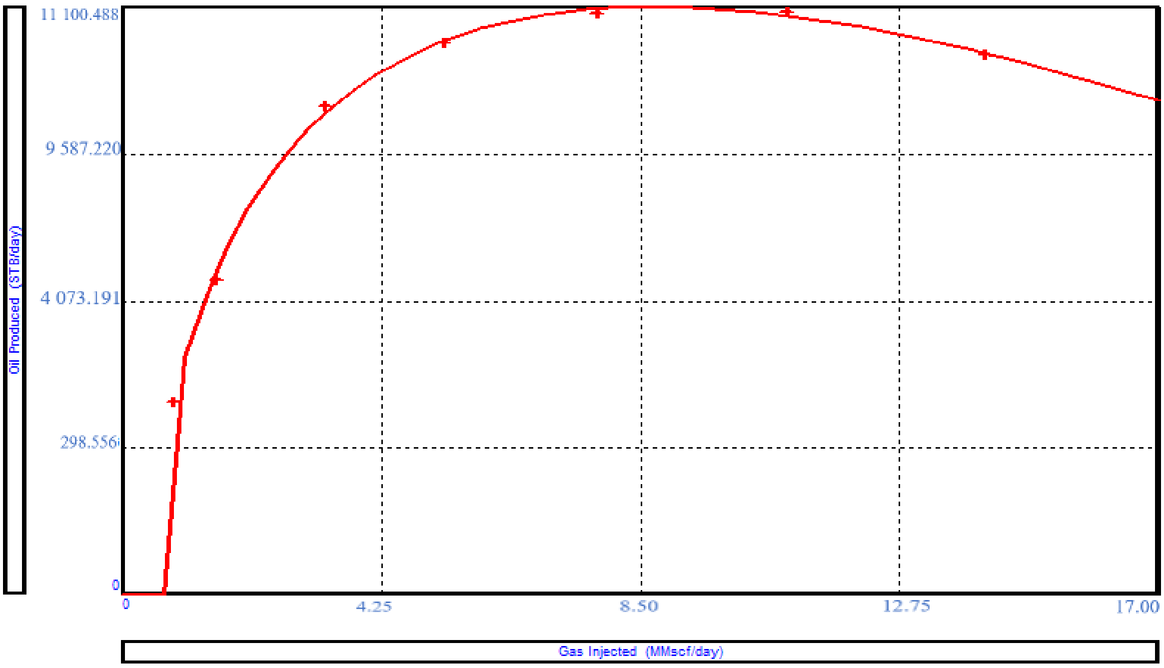


Figure 4.28 Maximum Gas Injection Sensitivity Plot for Hawk Well

4.9 Choke Performance

The choke performance of the Osprey and Hawk well is shown in Figures 4.29 and Figure 4.30. The inventor, Stephane Rastoin of ELF (Now Total), built the ELF model on Perkin's (SPE 20633) methodology and discharge coefficients discovered during the Tulsa University Artificial Lift Project. This method is also advised to determine pressure drops downhole for subsea safety valves and restrictions. Unless otherwise instructed, the choke approach should always be used. The flow rate is simply a function of the upstream or tube pressure at critical flow circumstances. With the ELF method, the critical pressure is 252.151 psig, a critical rate of 22 400 STB/day, and a choke setting of 0.95853 inches for the Osprey well. The Hawk well had a critical pressure of 342.285 psig, a critical rate of 17 436.9 STB/day, and a choke setting of 1.03636 inches.

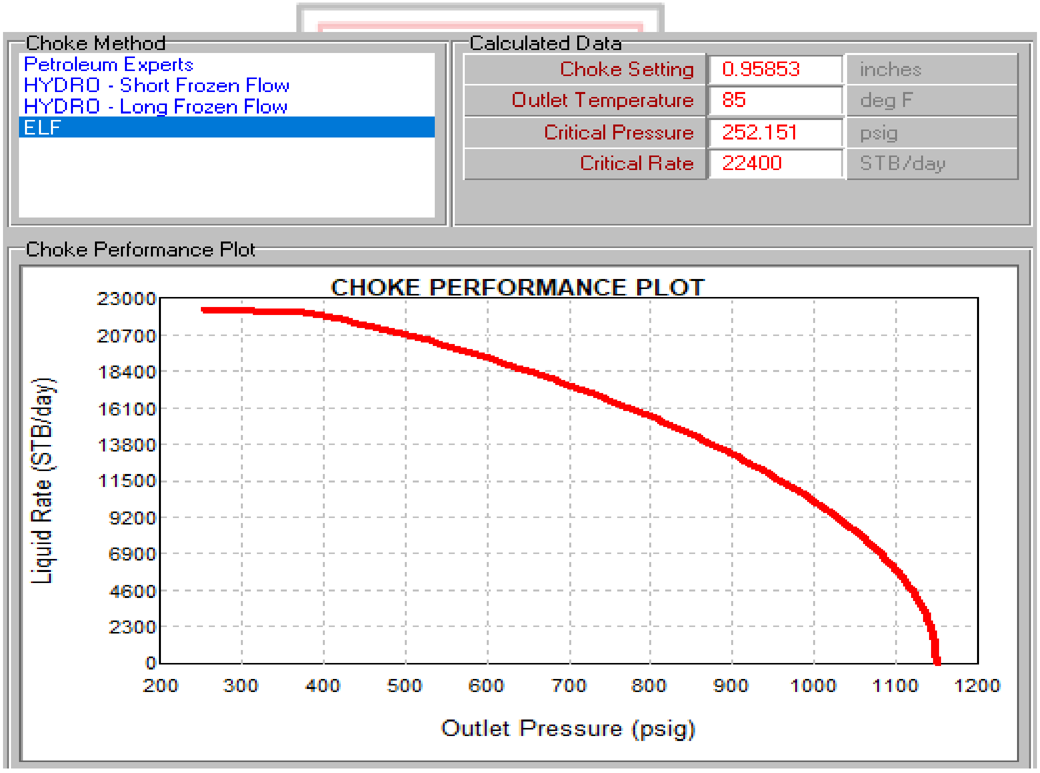


Figure 4.29 Choke Performance Plot for Osprey Well

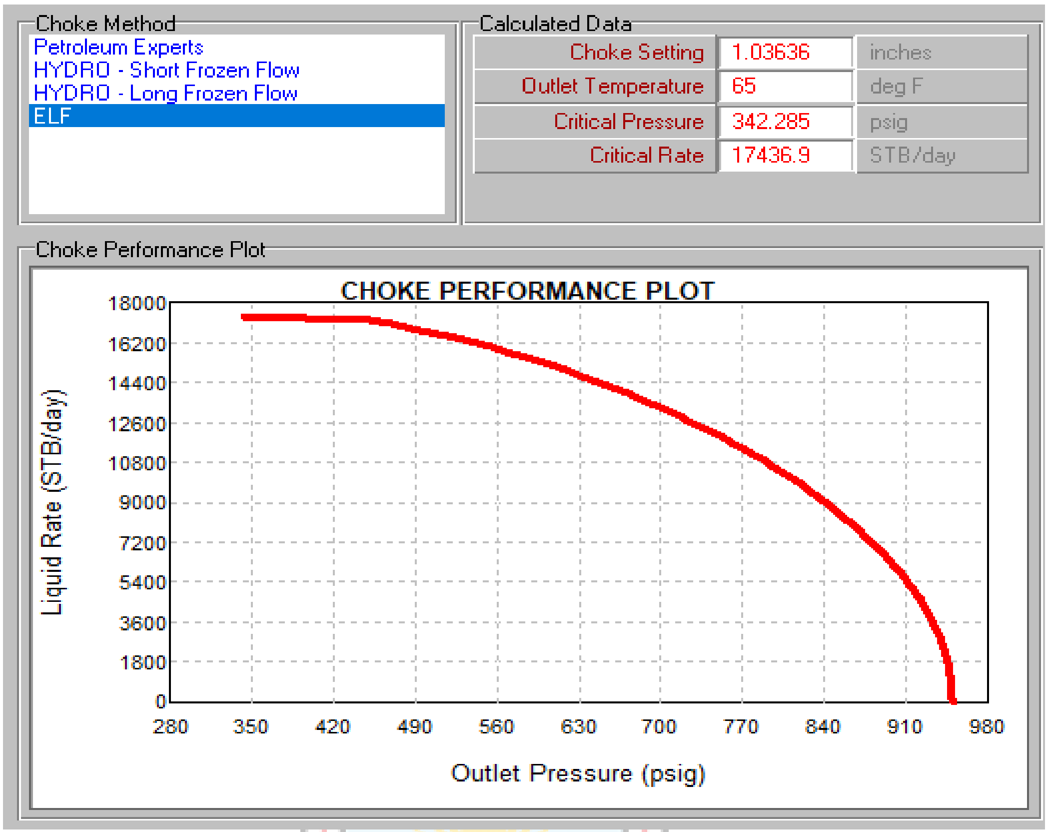


Figure 4.30 Choke Performance Plot for Hawk Well

4.10 Cost Evaluation

Figure 4.31 below shows the Total capital cost estimated by the Artificial Intelligence (AI) Assisted Screening Criteria for the best lift method selected. Gas lift technology was estimated to cost about $313,107.00.

```
    ECONOMIC CONSIDERATION
    ======================

Enter Value for Artificial Lift Assembly: 145387
Enter Value for Work over cost: 19280
Enter Value For Surface Equipment: 57398
Enter Value for Electrical Surface Equipment: 8400
Enter Value for Metering: 62000
Enter Value for Surface Electrical Labor: 6000
Enter Value for Artificial lift Labor: 14642
----------Total Capital Cost---------
Artificial Lift Assembly = 145387
Work over cost = 19280
 Surface Equipment = 57398
Electrical Surface Equipment = 8400
Metering = 62000
Surface Electrical Labor = 6000
Artificial lift Labor = 14642
 Total Capital Cost for installing Gas lift = 313107
>>> |
```

Figure 4.31 AI Economic Estimate for the Best Lift Selected (Gas Lift)

4.11 Screening Results Comparison

Table 4.1 and Table 4.2 Show the results of artificial lift screening by Chart of Osprey and Hawk well performed by Nguyen T. on wells from the Eagle Ford Basin. 'Y' indicates applicability whereas 'N' indicated not applicable. Based on criteria including liquid production rate, setting depth, and other variables ESPs might be an excellent candidate. However, due to the excessive DLS of 7-9°/100 ft on the chosen setting depth of 12 120 ft, the ultimate result for ESPs is zero, indicating that they are disqualified. Raising the pump setting depth over the kick-off point of about 11 600 feet must be taken into consideration for ESPs to function (Nguyen, 2020).

Table 4.1 Artificial Lift Selection Screening by Chart for Osprey Well

Input	Sucker Rod Pump	Electrical Submersible Pump	Gas Lift	Progressive Cavity Pump	Reciprocating Progressive Cavity pump	Plunger Lift
Target Liquid Rate	N	Y	Y	N	N	N
Setting depth	N	Y	Y	N	N	Y
Max. expected GLR	Y	Y	Y	Y	Y	Y
DLS Impact in operation	Y	Y	Y	Y	Y	Y
Casing OD	Y	Y	Y	Y	Y	Y
API	Y	Y	Y	Y	Y	Y
Anticipated Line	Y	Y	Y	Y	Y	Y
Downhole Temperature	Y	N	Y	Y	Y	Y
DLS impact in setting depth	Y	N	Y	Y	Y	Y
DLS impact passes through	Y	Y	Y	Y	N	Y
Scale	Y	Y	Y	Y	Y	Y
Corrosion	Y	Y	Y	Y	Y	Y
Solids	Y	Y	Y	Y	Y	Y
Paraffins and/or asphaltenes	Y	Y	Y	Y	Y	Y

Max. Expected GLR	Y	Y	Y	Y	Y	Y
Offshore	Y	Y	Y	Y	Y	Y
High-Pressure gas source	Y	Y	Y	Y	Y	Y

(Source: Nguyen, 2020)

According to the results of the simulation, the presence of solids, GLR, and water cut substantially affect the lift efficiency of the Electrical Submersible Pump method. The Eagle Ford's low liquid production rates and shallow pump setting settings are to blame. The equipment's preset depth is around 12 120 feet. Results for PCP, PL, and rodless PCP (RLPCP) are comparable (Nguyen, 2020).

Table 4.2 Artificial Lift Selection Screening by Chart for Hawk Well

Input	Sucker Rod Pump	Electrical Submersible Pump	Gas Lift	Progressive Cavity Pump	Reciprocating Progressive Cavity pump	Plunger Lift
Target Liquid Rate	N	Y	Y	N	N	N
Setting depth	N	Y	Y	N	N	Y
Max. expected GLR	Y	Y	Y	Y	Y	Y
DLS Impact in operation	Y	Y	Y	Y	Y	Y
Casing OD	Y	Y	Y	Y	Y	Y
API	Y	Y	Y	Y	Y	Y
Anticipated Line	Y	Y	Y	Y	Y	Y
Downhole Temperature	Y	N	Y	Y	Y	Y
DLS impact in setting depth	Y	N	Y	Y	Y	Y
DLS impact pass-through	Y	Y	Y	Y	N	Y
Scale	Y	Y	Y	Y	Y	Y
Corrosion	Y	Y	Y	Y	Y	Y
Solids	Y	N	Y	Y	Y	Y
Paraffins and/or asphaltenes	Y	Y	Y	Y	Y	Y

Max. Expected GLR	Y	Y	Y	Y	Y	Y
Offshore	Y	Y	Y	Y	Y	Y
High-Pressure gas source	Y	Y	Y	Y	Y	Y

(Source: Nguyen, 2020)

4.12 Formation PI Analysis

The analysis of Formation PI before and after the implementation of the Artificial Lift System is presented in Table 4.3 below. While the Hawk well sees a 46% increase in formation PI, the Osprey well receives a 67% increase.

Table 4.3 Analysis of Formation PI on Wells After Installation of Artificial Lift System

Well	Productivity Index Before Artificial Lift (STB/day/psi)	Productivity Index After Artificial Lift (STB/day/psi)	Percentage Increase (%)
Osprey	7.72	12.90	67
Hawks	9.51	13.82	46

4.13 Economic Analysis

The purpose of this profitable study is to guarantee that using the above-selected artificial lift technique will result in the greatest possible long-term economic advantage. It allows one to determine if a project is profitable or not, which is a capital-making tool for investment decisions. It also allows one to do an economic analysis that contrasts the choice to immediately conduct research with the anticipation of future profits. The economic analysis is based on CAPEX investment, which includes abandonment costs, and OPEX expenditures (operating costs), economics-related hypotheses Price of oil, inflation type of contract, cost of oil, profit of oil, royalties, and taxes (Table 4.4 and Table 4.5).

Table 4.4 CAPEX Expenses for a Gas Lift Well

Item	**Value**
Total Capital Cost	$313,107.00
Incremental Capital cost	$202,872.00
Monthly rental	$184,896.00
Monthly electric cost	$102,600.00
Failure frequency	$241,200.00
Expected TLOE per month	$528,696.00
Total CAPEX	**$1,573,000**

(Source: Nguyen, 2020)

Table 4.5 OPEX Expenditure for a Gas Lift Well

Item	**Value**
Maintenance and Replacements	$350,000
Operating Staff	$33,000
Power & Utilities	$150,00
Shut-Down Expenses	$3,900,000
Total CAPEX	**$4,430,000**

(Source: Nguyen, 2020)

The outcomes of the projected future income for both Osprey and Hawk wells are shown in Table 4.7. The Osprey well recorded a Net Income of $51.51 million from a total gross income estimate of over $90 million. The Hawk well recorded a Net Income of $54.59 million with a net pay zone of 78 ft which is slightly higher than that of Osprey's with a net pay zone of 67.17 ft. Table 4.7 shows the analysis for the Gross Income for Osprey and Hawk wells.

The net incomes of the Osprey and Hawk wells before the introduction of the A.I. screening selection are shown in Table 4.8. and Figure 4.32. The Osprey well recorded a Net Income of $10 million with the introduction of the Progressive Cavity pump. The Hawk well also had a Net Income of $3 million with the introduction of the Electric submersible pump. The Gas Lift net incomes after the A.I selection has a higher net income (as shown in Table 4.7) as compared to the Progressive Cavity Pump and the Electric Submersible Pump.

$$Gross\_Income = Oil_r * n * O_p \tag{4.1}$$

where, Oil_r is the Oil rate desired, n is the number of production days and O_p is the oil price.

Table 4.6 Gross Income Analysis

Item	**OSPREY**	**HAWK**
Oil rate desired (stb/day)	7 950	7 075
n (days)	189.03	231.65
Op	$60	$60
Gross Income	$90,166,729.80	$98,335,948.30

Table 4.7 The Economic Analysis of Osprey and Hawk Wells

Financial Index	**Osprey**	**Hawk**
Gross Income	90,166,729.80	$98,335,948.30
Expenses (CAPEX + OPEX)	$1,573,000.00	$1,573,000.00
Taxation	$37,083,364.90	$42,167,974.15
Net Income	$51,510,364.90	$54,594,974.15

Table 4.8 The Economic Analysis of Osprey and Hawk Wells Before A.I Screen Selection.

Financial Index	**Osprey (Progressive Cavity Pump)**	**Hawk (Electric Submersible Pump)**
Gross Income (Cumulative Oil Production × Op)	$17,676,652.80	$7,062,978
Profit (Gross Income – Capital Cost)	$17,465,240.80	$6,847,284.00
Taxation of Profit (42%)	$7,335,401.14	$2,875,859.28
Net Income (Profit – Tax)	$10,129,839.66	$3,971,424.72

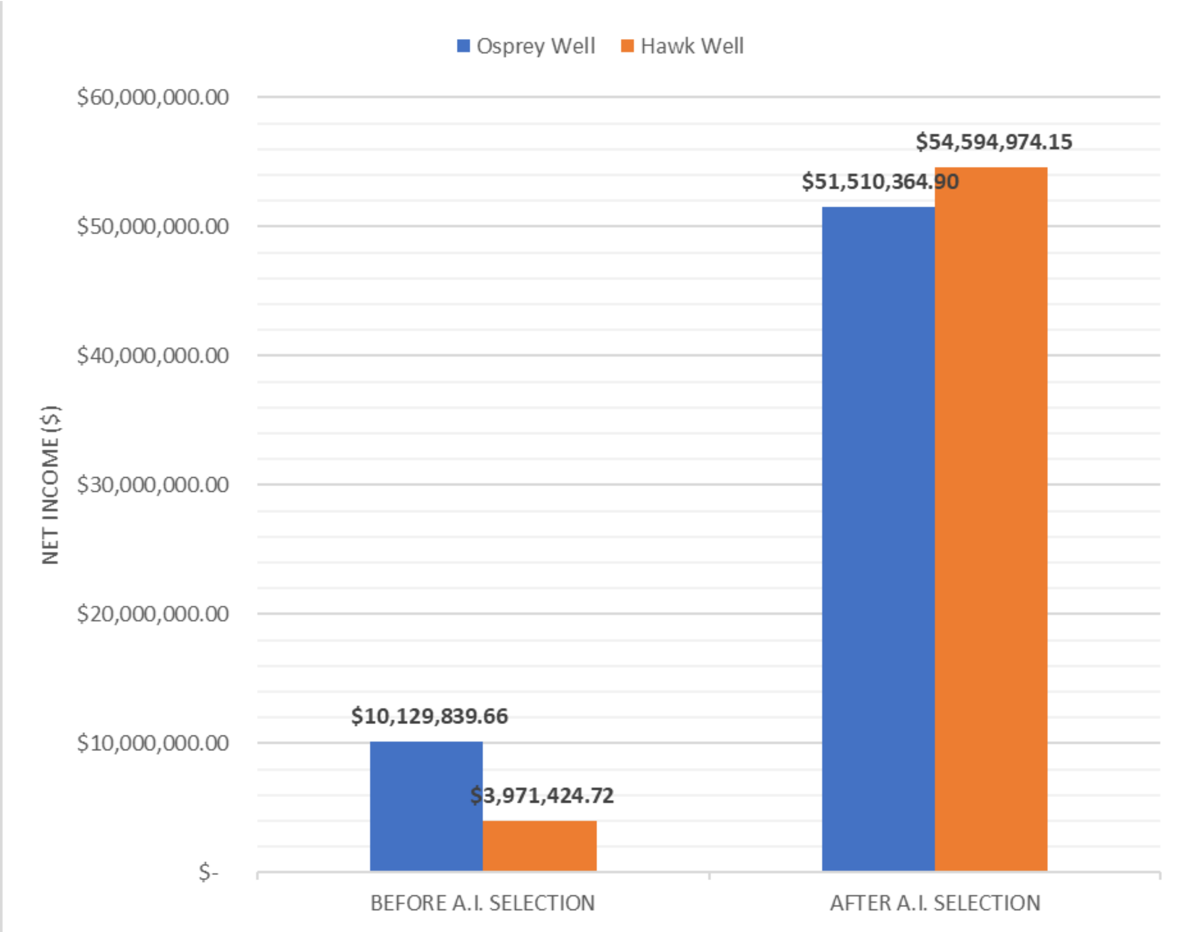


Figure 4.32 Net Income before and after A.I. screening selection

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The conclusions drawn at the end of this thesis are the following;

i. The application of AI for screening and choosing the optimum well-lift technique. According to the outcomes of the AI model, it was discovered that choosing a Gas lift is the greatest option for raising the production rate in both wells.

ii. Based on the economic analysis, the Gas Lift net incomes after the A.I. screening selection has a higher net income as compared to the Progressive Cavity Pump and the Electric Submersible Pump.

iii. Despite using a contemporary completion design, the Osprey well's production drop was caused by long production days. Low initial production from the Hawk well was followed by a shut-in time as a result of its inadequate output.

iv. The Formation PI for the Osprey well increased significantly by about 67% and its AOF increased from 25 474.1 STB/day to 63 319.3 STB/day while the Hawk wells Formation PI increased to about 46% with an AOF of 21 501.1 STB/day to 40 600.2 STB/day.

5.2 Recommendations

The following are the recommendations made:

i. More simulations to be run for additional lift methods and use them with the decision matrix.

ii. The approach used (A.I. screening selection) is recommended for use in artificial lift selection for a given well.

iii. Use actual field data to test and validate the decision matrix. A new field development scenario would be appropriate to evaluate the decision matrix's screening skills in particular.

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APPENDICES

APPENDIX A

DAILY AND CUMMULATIVE OIL PRODUCTION FROM OSPREY WELL

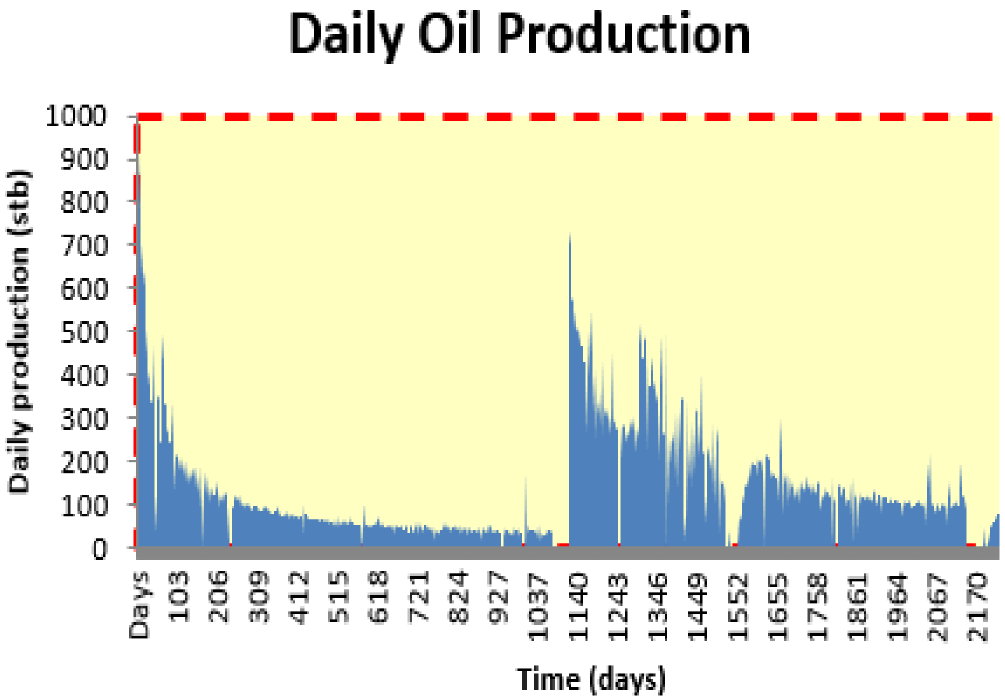

Figure A Daily Oil Production from Osprey Well (Pankaj *et al.*, 2021)

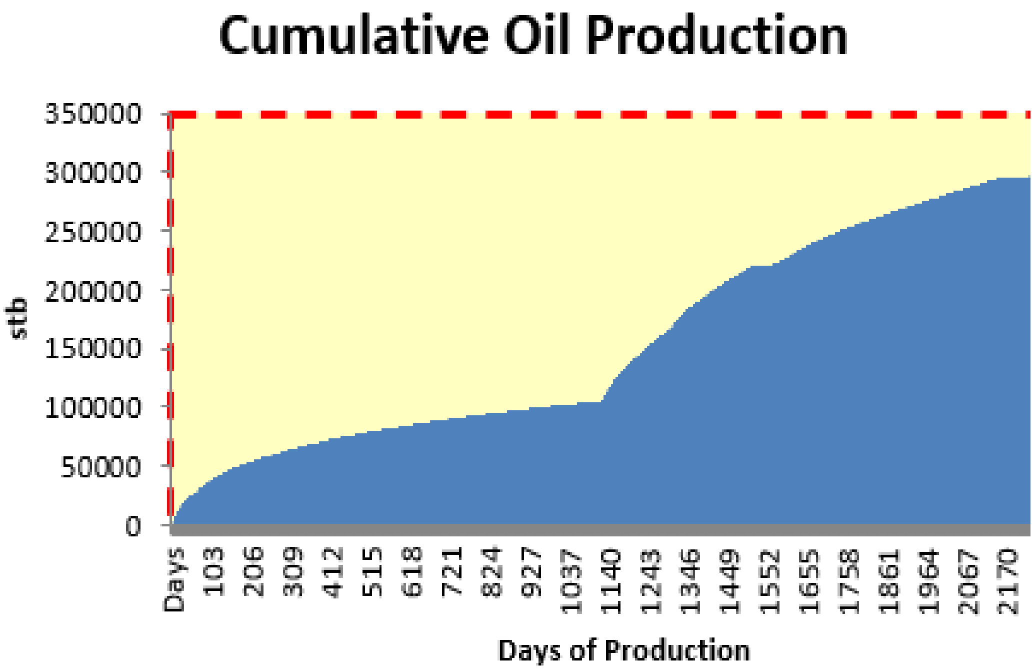

Figure AB Cumulative Oil Production from Osprey Well (Pankaj *et al.*, 2021)

APPENDIX B

DAILY AND CUMMULATIVE OIL PRODUCTION FROM HAWK WELL

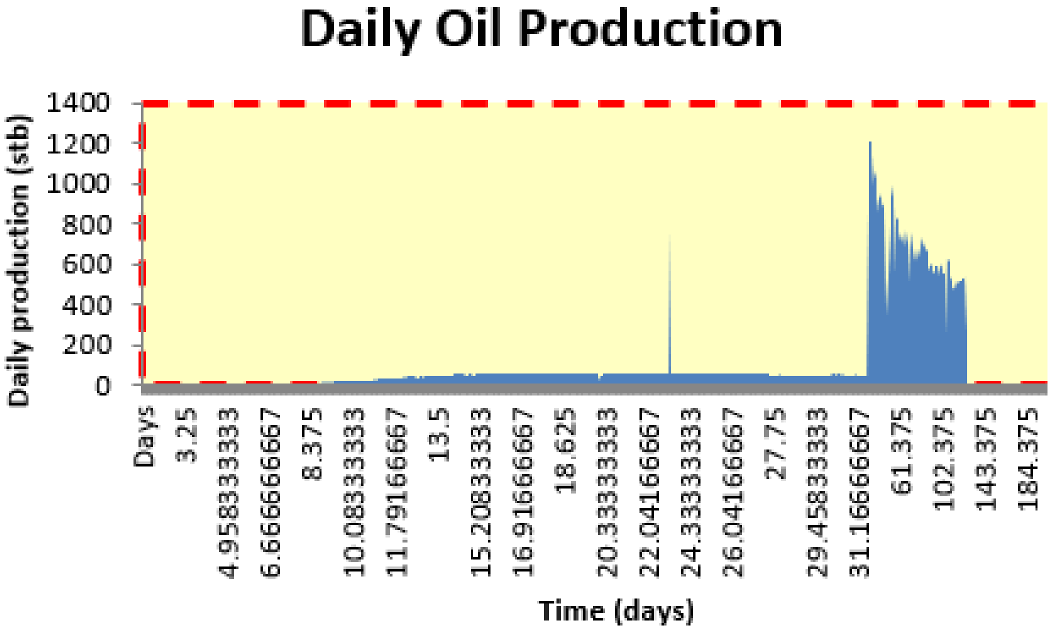

Figure B Daily Oil Production from Hawk Well (Pankaj *et al.*, 2021)

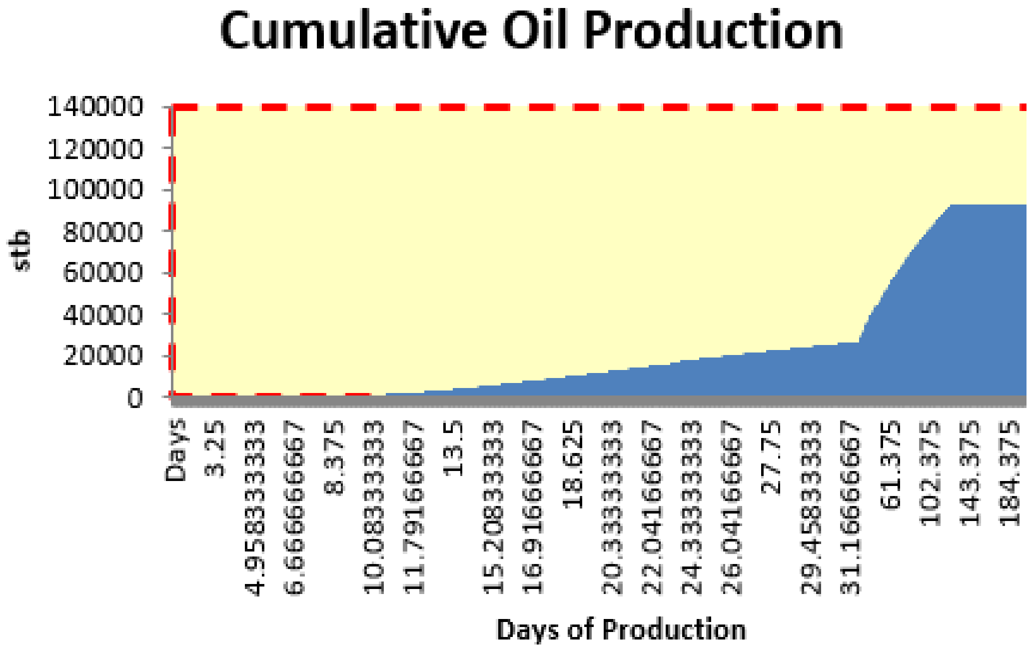

Figure BB Cumulative Oil Production from Hawk Well (Pankaj *et al.*, 2021)

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