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Declaration of Authorship

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Abstract

For years, operating firms have used artificial lift optimization (ALO) technologies to boost oil and gas production. Notwithstanding these exceptional results in the oil business, conventional and unconventional gas wells have made little headway with an artificial lift. This is owing, in part, to the unavailability of artificial lift tools that can directly add energy to the gas to improve production and recoverability until now. Although wellhead compressors have proven to be helpful for operators, actual experience has demonstrated that these tools can accelerate liquid loading, especially in unconventional wells with a greater critical lifting velocity and lower production fluid density. As a result, productivity falls and early retirement occurs. Due to faster rates of decline than conventional wells, a growing proportion of unconventional shale oil and shale gas wells now contain artificial lift at the start of well production, even though mature wells are more frequently the recipients of artificial lift systems. Furthermore, field production can be increased by utilizing various ALO solutions at various stages of a well's production life. For example, to maximize estimated ultimate recovery (EUR), rod pump systems installed later in the well's life can be combined with the installation of a jet pump or an electric submersible pump (ESP) system during the early and transitional phases of the well's life, respectively. Evaluation of the initial artificial lift systems in place to find better ways to manufacture the existing assets and, as a result, strategies to optimize and reduce lifting costs for the operator. This method applies a number of filters to the user-supplied well, fluid, and field data, resulting in a summary page providing viable and preferable well specific artificial lift alternatives for future exploration.

For the extraction of hydrocarbons from underground formations, a variety of production methods might be chosen. The built into energy found within the reservoir itself can be used to lift reservoir fluids to the surface, or artificial lift techniques can be used. The primary goal of this thesis work is to pick artificial lift technologies for hydrocarbon production in the ARC field in Mexico utilizing a customized computer software program. (called PROSPER).

Referat

İllərdir ki, neft şirkətləri neft və qaz hasilatını artırmaq üçün süni qaldırıcı optimallaşdırma (ALO) texnologiyalarından istifadə edirlər. Neft biznesindəki bu müstəsna nəticələrə baxmayaraq, ənənəvi və qeyri-ənənəvi qaz quyuları süni qaldırıcı ilə çox az irəliləyiş əldə etdi. Bu, qismən hasilatı və bərpa qabiliyyətini yaxşılaşdırmaq üçün qaza birbaşa enerji əlavə edə bilən süni qaldırıcı alətlərin mövcud olmaması ilə bağlıdır. Quyu ağzı kompressorlarının operatorlar üçün faydalı olduğunu sübut etsə də, faktiki təcrübə göstərir ki, bu alətlər xüsusilə daha böyük kritik qaldırma sürəti və aşağı hasilat maye sıxlığı olan qeyri-ənənəvi quyularda mayenin yüklənməsini sürətləndirə bilir. Nəticədə məhsuldarlıq aşağı düşür. Adi quyulardan daha sürətli azalma sürətinə görə, yetkin quyuların daha çox süni qaldırıcı sistemlərin alıcıları olmasına baxmayaraq, qeyri-ənənəvi şist neft və şist qaz quyularının artan nisbəti indi quyu hasilatının başlanğıcında süni qaldırıcıdan ibarətdir. Bundan əlavə, quyunun istismar müddətinin müxtəlif mərhələlərində müxtəlif ALO hallərindən istifadə etməklə yataqda hasilat artırıla bilər. Məsələn, təxmin edilən son bərpanı maksimuma çatdırmaq üçün quyunun istismar müddətində daha sonra quraşdırılan çubuqlu nasos sistemləri quyunun istismar müddətinin erkən və keçid fazalarında reaktiv nasos və ya elektrik sualtı nasos sisteminin quraşdırılması ilə birləşdirilə bilər. Mövcud istehsalın daha yaxşı yollarını tapmaq üçün ilkin süni qaldırıcı sistemlərin qiymətləndirilməsi və nəticədə operator üçün qaldırma xərclərinin optimallaşdırılması və azaldılması strategiyaları istifadə edilir. Bu üsul istifadəçi tərəfindən təchiz edilmiş quyuya, mayeyə bir sıra filtrlər tətbiq edir və sahə məlumatları, nəticədə gələcək kəşfiyyat üçün əlverişli və üstünlük verilən quyuya xas süni qaldırıcı alternativlər təqdim edən xülasə səhifəsi yaranır.

Yeraltı laylardan karbohidrogenlərin çıxarılması üçün müxtəlif istehsal üsulları seçilə bilər. Rezervuarın özündə tapılan enerji anbarı mayelərini səthə qaldırmaq üçün istifadə edilə bilər və ya süni qaldırma üsullarından istifadə edilə bilər. Bu dissertasiya işinin əsas məqsədi fərdi kompüter proqramından istifadə etməklə Meksikada ARC sahəsində karbohidrogen istehsalı üçün süni lift texnologiyalarını seçməkdir. (proqram PROSPER adlanır).

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List of Symbols and Abbreviations

ALS: Artificial Lift System

ALO: Artificial Lift Optimization

AOP: Absolute Open Flow

BHP: Bottom Hole Pressure

ESP: Electrical Submersible Pump

GL: Gas Lift

GOR: Gas Oil Ratio

HP: Hydraulic Pump

ID: Internal diameter

IPR: Inflow Performance Relationship

NPV: Net Present Value

JP: JET Pump

OD: Outside Diameter

PVT: Pressure, Volume and Temperature

PCP: Progress Cavity Pump

SRP: Sucker Rod Pump or Beam Pump

STB: Stock Tank Barrel

VLP: Vertical Lift Performance

Introduction

We are in the era of hydrocarbons, the most accessible, cost-effective, and dependable energy source in history, which has greatly increased human longevity and standard of living. Two thirds of the energy used on earth is produced and consumed by oil and gas. The sum increases to well over 90% when coal is included.

Thanks to substantial advancements in drilling and production technology, particularly deepwater drilling, horizontal drilling, and artificial lift techniques, reserve estimates are increasing even as oil and gas are consumed. As a result, natural gas prices for consumers have dramatically decreased. Similar to this, the US shale oil boom has allowed customers to save up to $248 billion on things like gasoline and other refined items. It's fortunate because global hydrocarbon use is anticipated to increase dramatically over the next few decades, especially among developing countries.

The majority of the world's oil wells require artificial lift methods to produce oil. Artificial lift technologies include sucker rod pumps, surface driven progressive capacity pumps, electric submersible pumps, and gas lift. New lifting technologies, such as the electric submersible plunger pump and the downhole powered progressive capacity pump, have emerged in recent years. These artificial lift methods differ in terms of lifting capacity and application conditions. Electric submersible pumps, for example, are not suitable for small displacement lifting; surface driven progressive capacity pumps in deviation wells have significant eccentric wear, which shortens the pump inspection cycle; sucker rod pumps used in low production wells have low efficiency; and so on. As a result, it is critical to select an acceptable artificial lift technology, which has a significant impact on the oil well's production capacity, energy consumption, operating maintenance, and overall benefits during its existence. However, numerous complex aspects influence the choice of artificial lift technology, such as oil well productivity, fluid properties, wellbore construction, and surface environment, among others. Because oil well production varies over time, it is challenging to develop a mathematical physical model for artificial lift technique optimization.

Statement of the Problem

The problem of the research is emphasized in this area, along with the goals and objectives of the thesis project and an explanation of the value of the thesis work.

Purposes and Goals of the Thesis

In order to choose the optimal production approach for accelerating hydrocarbon output, the thesis study compares the implementation of natural drive and artificial lift methods, including natural drive case and ESP application in the ARC oilfield. Here, the goals involve simulating a well using artificial lift and natural drive cases in computer software to see how production rate increases for each instance by locating the junction point (solution node) between IPR and VLP curves. Additionally, this research aims to determine which scenario is most appropriate by examining how changes in reservoir parameters affect production rate.

Thesis Plan:

Chapter 1: This chapter consists of the major goal of this thesis study as well as important understanding about reservoir and well performance. The fundamentals of Nodal analysis and their applications in production processes are discussed. Furthermore, the determination of the drive mechanisms is also included.

Chapter 2. This chapter highlights important factors and guidelines that will help in selecting the appropriate method for efficient production.

Chapter 3. This chapter compares the various types of methods for hydrocarbon production and this is carried out with the aids of Prosper software.

Chapter 4.This chapter is about an evaluation of all the results obtained by PROSPER during model set up and concludes with recommendations on the best method to consider in order to boost and optimize hydrocarbon production.

Wellbore and Reservoir Performance

Performance of the well's inflow and wellbore flow together define a well's deliverability. The former describes the reservoir's deliverability, while the later shows the production string's resistance to flow. The estimation of feasible fluid production rates from reservoirs with predetermined production string properties is the main topic of this chapter. Nodal analysis is the name of the analysis method. To increase accuracy, the industry applies the idea piecemeal to address local flow path dimension, fluid characteristics, and heat transfer. Before doing nodal analysis on a broad scale, it is imperative to confirm the inflow performance relationship and tubing performance relationship models. (Petroleum Production Engineering Second Edition 2017).

One of the main factors influencing well deliverability is reservoir deliverability, which is the rate of oil or gas production that may be obtained from a reservoir at a specific bottom-hole pressure. Which sorts of completion and which artificial lift techniques must be utilized depend on the reservoir deliverability. It is critical to fully comprehend it in order to predict well productivity with accuracy (Boyun Guo,2018).

Reservoir deliverability is influenced by a number of factors, such as

- Reservoir pressure
- Pay zone thickness
- Reservoir boundary type and distance
- Wellbore radius
- Reservoir fluid properties
- Near-wellbore conditions
- Effective permeability

Types of Flow Regimes

Engineers working on reservoirs often make assumptions about transient, steady-state, and pseudosteady-state flows when building mathematical models that forecast reservoir deliverability. Understanding the flow characteristics enables engineers to create an inflow performance relationship, an analytical link between bottom-hole pressure and production rate (IPR). The methods for determining the IPR of horizontal, vertical, and fractured wells that extract oil and gas from reservoirs are covered in this chapter. To define fluid flow behavior and reservoir pressure distribution as a function of time, one must generally understand three types of flow regimes. Three flow regimes exist: flow in three states: Steady-state flow, Unsteady-state flow, Pseudosteady-state flow (Boyun Guo 2018).

1. If the pressure during every point in the reservoir remains constant, i.e., does not change over time, the flow regime is classified as a steady-state flow. This condition can be stated mathematically as: $(\partial p / \partial t)_i = 0$. According to this equation, the rate of pressure change with respect to time at any place is zero. The steady-state flow condition in reservoirs can only happen when the reservoir has been fully refilled and is being supported by robust aquifer or pressure maintenance operations.
2. Unsteady-state flow, also known as transient flow, is the flow of fluid when the rate of pressure changes with respect to time at any location in the reservoir is not zero or

constant. The pressure derivative with respect to time is fundamentally a function of both position i and time t, according to this statement, so $(\partial p / \partial t)_i = (\mathbf{i}, \mathbf{t})$.

3. The flowing situation is referred to as pseudosteady-state flow when the pressure at various points in the reservoir is dropping linearly as a function of time, i.e., at a constant declining rate. This definition's mathematical implication is that pressure change rates are stable throughout the range.$(\partial p / \partial t)_i$ =constant.

The Importance of Determining a Well's Inflow Performance Relationship (IPR)

Engineers use the inflow performance relationship (IPR) to evaluate reservoir deliverability in reservoirs. The IPR curve is a graphical presentation of the relationship between the flowing bottom-hole pressure and the liquid production rate. The straight-line IPR equation, which states that rate is inversely proportional to pressure drawdown in the reservoir, is probably the most straightforward and extensively used IPR equation. (Guo, B.2007) Recently only undersaturated oils are utilized for the straight-line IPR. The magnitude of the slope of IPR curve is called productivity index (PI or J), expressed as:

$$J = \frac{q}{(p_e - p_{wf})}$$

A plot of the straight-line IPR is shown in Figure 1. This figure illustrates several crucial characteristics of the straight-line IP: (Michael & Curthis H, 1991).

1. The y axis is defined by the independent variable, wellbore flowing pressure, while the x axis is defined by the dependent variable, rate.

2. No flow enters the wellbore because there is no pressure decline when the wellbore flowing pressure matches the average reservoir pressure (also known as static pressure).

3. A wellbore flowing pressure of zero corresponds to the maximum rate of flow, or absolute open flow. This term is helpful and frequently used in the petroleum sector, especially for evaluating the performance potential of other wells in the same field, even though in actuality it may not be a situation at which the well may produce (Michael & Curthis H, 1991).

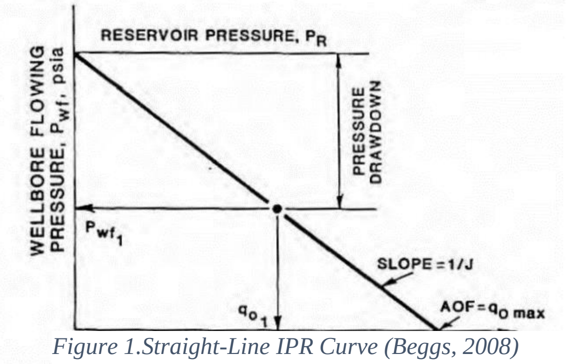


Figure 1.Straight-Line IPR Curve (Beggs, 2008)

A simplified IPR model can be developed if the reservoir pressure is higher than the bubble-point pressure and the flowing bottom-hole pressure is lower. Applying Vogel's IPR model for two-phase flow with the straight-line IPR model for single-phase flow can achieve this. The linear IPR model predicts that the flow rate at bubble-point pressure is $q_b = J(\overline{p}\text{-}p_b)$ " (Guo, 2007)

The extra flow rate brought on by a pressure lower than the bubble-point pressure is represented by the following equation using Vogel's IPR model:

$$\Delta q = q_v \left[1 - 0.2\left(\frac{p_{wf}}{p_b}\right) - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right]$$

As a result, the flow rate at a particular bottom-hole pressure lower than the bubble-point pressure is stated as

$$\Delta q = q_b + q_v \left[1 - 0.2\left(\frac{p_{wf}}{p_b}\right) - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right]$$

Well reservoir factors such as formation permeability, fluid viscosity, wellbore radius, and well skin factor, drainage area can be used to generate IPR curves. The constants (such as the productivity index) in the IPR model are determined by all these parameters. These parameters' values, however, are not always readily available. As a result, IPR curves are commonly constructed using test points (measured values of production rate and flowing bottom-hole pressure). The constants in the IPR models must be back-calculated in order to construct IPR curves using test points. The model constant J for a single-phase (unsaturated oil reservoir) can be calculated by $J = \frac{q_1}{(\overline{p} - p_{wf1})}$

where is $p_{wf1}$the measured flowing bottom-hole pressure as well as is $q_1$the tested production rate.

The problem of reservoir flow approaching the wellbore was introduced by the inflow performance relation. We haven't discussed their physical justification, only the most basic IPR linkages. Deliverability was suggested to be ranked using the productivity index as a key metric. For perfect liquids or undersaturated oils, it is also the constant of proportionality between rate and pressure decrease. The straight-line IPR and the empirical saturated IPR are combined to form the IPR of undersaturated oil wells (Guo, B. 2007).

Vertical Lift Capability (VLP)

The pressure loss in the tubulars is a crucial component influencing a well's output performance. Up to 80% of the total pressure loss in a flowing well may occur in the process of bringing the fluid to the surface, with the remainder lost in the reservoir. Vertical lift performance expresses bottomhole flowing pressure as a function of liquid rate in the wellbore during reservoir fluid production. Outflow performance is affected by a number of factors, including liquid rate, fluid type (gas-liquid ratio, water cut), fluid characteristics, and tube size (Ioannis E. Tetoros,2015).

Well Productivity Analysis Principles

In oil and gas production systems, fluid characteristics vary with location-dependent pressure and temperature. It is important to "split" a system into discrete elements (equipment parts) via nodes in order to mimic the fluid flow in that system. The methods used in petroleum engineering to forecast the pressure and rate of oil and gas production at a given node are known as NODAL analysis. The NODAL analysis is based on the idea of pressure continuity, which states that no matter what pressures are indicated by the operation of upstream or downstream equipment, there is always just one pressure value at any particular node. The pressure-flow rate relationship for upstream machinery for a specific node is known as the inflow performance relationship (IPR). The outflow performance relationship is the one for equipment downstream (OPR). The operating flow rate and pressure at the designated node are obtained by solving the equations for IPR and OPR mathematically or graphically. Hence, the OPR indicates the flow performance of the wellbore (tubing) from the bottom of the wellhole to the wellhead, whereas the IPR reflects the flow performance of the reservoir from the reservoir boundary to bottom-hole (TPR) (Guo, Boyun 2018).

From the bottom of the well to the top, the fluid must travel a course before entering surface machinery like a separator. Such a path is shown in Figure 2. It consists of a number of segments, joints, and valves, all of which result in a pressure decrease. The reservoir/wellbore system is taken into account in NODAL analysis, which also determines any constraints that can lower the hydrocarbon flow rate by calculating the pressure loss across each segment. In its most basic form, tubing performance enables determination of the necessary bottomhole flowing pressure to raise a range of flow rates to the top for a given wellhead pressure. The hydrostatic and friction pressure drops combine to create the overall pressure drop in the well. The petroleum industry uses a number of correlations for tubing performance (Beggs and Brill, 1973; Hagedorn and Brown, 1965). In a well cited article, Brown (1977) described how to calculate pressure loss in production strings for two wellhead flowing pressures. The needed bottomhole flowing pressure rises with flow rate, reflecting increased friction pressures at the higher rates (Economides & Nolte, 2000).

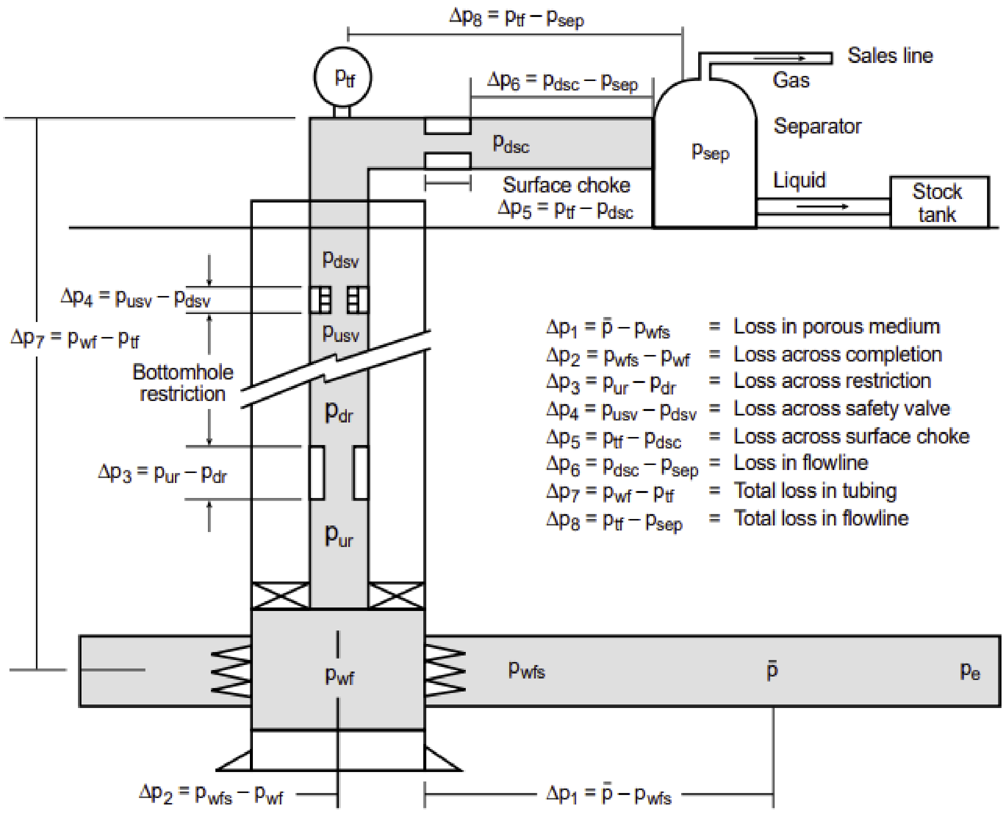


Figure 2.Pressure losses along the system Pdr = downstream restriction pressure, Pdsc = pressure downstream of the surface choke, Pdsv = pressure downstream of the safety valve, Psep = separator pressure, Ptf = tubing flowing pressure, pur = upstream restriction pressure, Pusv = pressure upstream of the safety valve, Pwfs = wellbore sandface pressure (Economides & Nolte, 2000).

If the impact of the artificial lift method on the pressure can be described as a function of flow rate, then both flowing and artificial lift wells can be subjected to the nodal analysis procedure. By appropriately altering the input and outflow expressions, the approach can also be used to analyze the performance of injection wells. (Anireju Emmanuel Dudun, 2014). The following is a partial list of potential applications:

1. Choose the flow line and tube sizes.

2. The gravel pack layout.
3. Sizing of surface chokes.
4. Sizing of subsurface safety valves.
5. The use of artificial lifts.
6. Dividing up the gas lift well injections.
7. Determining how compression gas well performance affects things.
8. Predicting how compression will affect gas well performance, etc.

Petroleum production wells

Reservoir segment, wellbore, and wellhead are the components of a naturally flowing well. (Figure 3.). Production fluids are delivered to the wellbore via the reservoir segment. The fluids have a way to get from the bottom hole to the surface due to the wellbore. The fluid production rate can be adjusted at the wellhead. A single porous and permeable subsurface rock formation that contains a distinct bank of fluid hydrocarbons and is contained by impermeable rock or water barriers is referred to be an oil or gas reservoir. Engineers categorize oil, gas condensate, and gas reservoirs based on the hydrocarbon content and initial reservoir condition. Because it can store more dissolved gas at any given temperature, an oil that is at a pressure above its bubble point is referred to as an undersaturated oil. Because it can no longer dissolve any more gas at any given temperature, an oil that has reached its bubble-point pressure is known as a saturated oil. Single (liquid) phase flow happens in an undersaturated oil reservoir. In a saturated oil reservoir, two phases (liquid oil and free gas) flow takes place (Boyun Guo 2008).

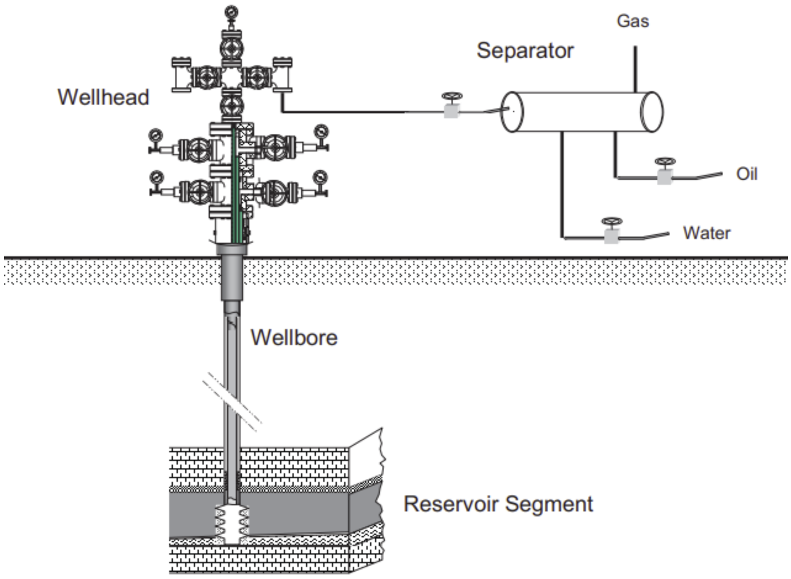


Figure 3.Oil and gas are produced by naturally flowing wells under their own pressure. (2008 by Gulf Publishing Company)

Each hydrocarbon reservoir has its own geometric form, geological rock characteristics, fluid properties, and other traits that make it unique. The boundary type, which determines the driving mechanism, is another classification used for oil reservoirs (Tarek, Ahmed. (2018). The earliest feasible determination of the drive mechanism is a fundamental priority in the reservoir's early life, since this knowledge can considerably improve reservoir management and recovery in the reservoir's middle and later life. The five different reservoir types are:

- Water drive mechanism
- Gas cap drive mechanism
- Solution gas drive
- Gravity drainage
- Combination drive mechanism

Water drive mechanism

Many reservoirs are connected to an underground water zone (aquifer). The compressed water in an aquifer expands into a reservoir and aids in pressure maintenance when reservoir pressure decreases as a result of output. The term "water drive" refers to this device. Given that water has a very low compressibility, a water drive mechanism will work well if an aquifer contacting reservoir is very large. With extremely little pressure loss at the wellbore, a powerful water drive offers very good pressure support from the aquifer (L.P. Dake, 1983).

Gas cap drive mechanism

After production and a decrease in reservoir pressure, the gas cap expansion in hydrocarbon reservoirs with gas caps exerts pressure on the oil column. The main production method, referred to as drive by gas cap, uses this pressure.This expansion enhances the production of hydrocarbons in an oil system by reducing the rate at which fluid pressure drops in the reservoir. According to the reservoir's quality and the amount of hydrocarbon withdrawn, pressure decreases. The ratio of gas to oil (GOR) rises while oil production and reservoir pressure fall steadily with production from this type of reservoir. In sand reservoirs, this mechanism, which has a recovery factor between 25% and 50%, performs less well than the water drive mechanism (Dan J. Hartmann, Edward A. Beaumont 1999).

Solution gas drive

Oil becomes saturated and liberated gas is present in a reservoir when the pressure exceeds a bubble point. The primary source of energy used to create reservoir fluid for the solution gas drive is the expansion of gas. As free gas in a reservoir cannot move until it exceeds the critical gas saturation, the generated gas oil ratio will initially slightly fall. After then, gas will start to enter a well. Where vertical permeability is great, gas may occasionally migrate up and produce a secondary gas cap, aiding in the production of oil. The solution gas drive reservoir typically has a recovery factor of between 5 and 30%. (Tarek Ahmed PhD, 2011).

Gravity drainage:

The fourth drive force that might be taken into account for a drive mechanism where natural segregation of oil, gas, and water occurs in a reservoir is gravity drainage. Although it has some potential as a drive mechanism, this method is usually only utilized in association with other drive mechanisms due to its weakness. However, it can result in extraordinarily high recoveries and is incredibly effective over extended periods of time. As a result, it is frequently utilized in combination with other drive methods. (Djebbar Tiab and Erle C. Donaldson,2011).

Combination drive mechanism

A reservoir in real life typically has two main drive systems. Combination or mixed drives can be considered the fifth category of drives as a result. The most typical drive configuration is a weak water drive coupled to a solved gas drive (with or without a gas free cap). Combination drives are more effective when the free gas cap is used in conjunction with an active water drive. These methods have been successfully used to produce in interior regions of Northern America, Northern Africa, and Indonesia. Thus, a combination-drive mechanism, such as the one shown in Figure 4, is the form of drive that is found most frequently. . Combination-drive reservoir. (After Clark, N. J, 1969).

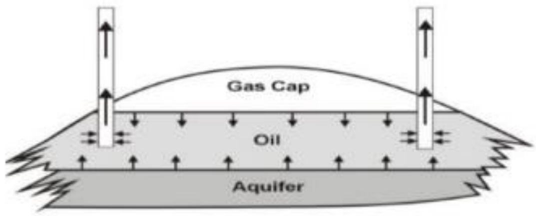


Figure 4Combination drive reservoir (Clark, 1969)

If several of the following conditions are present, combination-drive reservoirs can be identified:

a) A relatively quick pressure drop. External gas-cap expansion and/or water encroachment are not enough to keep reservoir pressures constant.
b) Water gradually invading into the reservoir's lowest portion. Wells with low structural production rates will show gradually rising rates of water production.
c) If a tiny gas cap is present, provided that it is expanding, structurally high wells will show steadily rising gas-oil ratios. The gas cap could contract as a result of the production of too much free gas, in which case the structurally high wells would show a declining gas-oil ratio. As a result of a diminishing gas cap, this circumstance should be avoided wherever feasible in order to prevent the loss of significant amounts of oil.
d) The depletion-drive mechanism may account for a sizeable portion of the total oil recovery. As pressure is dropped, solution gas will spread throughout the reservoir, increasing the gas-to-oil ratio of structurally low wells (Tarek, Ahmed, 2018).

Chapter 1. Types of Artificial Lift Methods

This chapter summarizes artificial lift methods and separates them into two main groups: pumping and gas lifting. In the second half, various artificial lift technologies are contrasted in terms of lifting capacity, system effectiveness, and other critical factors. In any circumstance, an engineer has a wide range of options when choosing the kind of lift to be employed. Although actual field circumstances like well depth, fluid characteristics, etc. may limit or even forbid the employment of many of those lifting techniques...

Pump system

- Beam pumping / sucker rod pump (rod lift)
- Electric submersible pump (ESP)
- Hydraulic Jet Pumps
- Progressive cavity pump
- Plunger lift

Gas system

- Gas lift

The choice of lift type that offers the most effective method of producing the required liquid volume from the specified wells is then the production engineer's responsibility. Following the selection of the lifting technique to be used, the installation should be completely designed for both present and future situations. Additionally, a brief history of sucker-rod pumping is given, along with instances of typical applications, a list of all advantages, and a list of particular disadvantages.

Pumping

Pumping is the process of employing a downhole pump to boost the pressure in the well in order to overcome the sum of flowing pressure losses. It is able to be further categorized based on a variety of parameters, such as the operational principle of the pump employed. The commonly accepted classification, on the other hand, is based on the method the downhole pump operates and differentiates between rod and rodless pumping (Gabor Takacs, Ph.D. 2018).

1. Positive displacement pumps (PCP, Sucker Rod, Reciprocating Hydraulic pump).

2. Dynamic displacement pumps (ESP, HSP, Jet pump).

Sucker Rod Pump

One of the most recognizable imageries of the oil and gas sector are arguably those of rod pumps, sometimes referred to as beam pumps. In actuality, they are the earliest technique for producing artificial lift oil. Sucker rod length is constrained by well depth. The pump needs to be positioned below the dynamic fluid level for wells that are less than 2500 feet deep. The deepest point is roughly 14,000 feet. The rod pump's frequent workovers and repairs are another negative. With an average lifespan of roughly one and a half years, rod strings could start to fail as soon as six to eight months after installation. To guarantee that the pumps operate as efficiently as possible, corrosion, wax, asphaltenes, as well as other particles should be effectively regulated (Sucker-Rod Pumping Handbook).

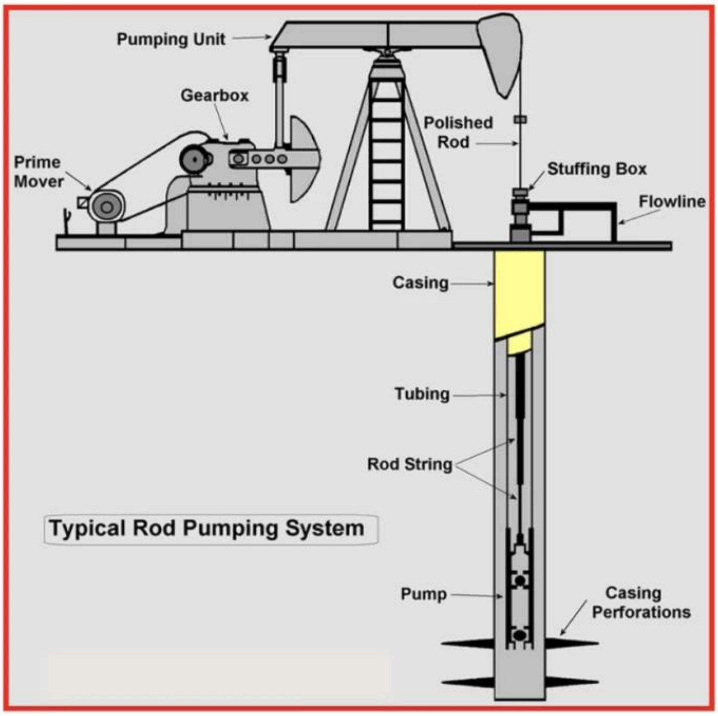


Figure 5.Beam rod pump main components (Di et al. 2018)

The System for Pumping Rods

The sucker rod pumping system's purpose is to supply energy to the downhole pump so it can lift reservoir fluids to the surface. The sucker rod pump decreases the bottom hole pressure by pumping the fluid that is flowing from the formation to the wellbore. Production rate is increased by a significant pressure difference between the formation and the wellbore. The sucker rod system is made up of surface and downhole components, as shown in Figure 5. The primary mover (gas or electric engine), the pumping unit, the polished rod, the stuffing box, the wellhead, and the flowlines are examples of surface equipment. Casing, tubing, sucker rod string, downhole pump, gas anchor (optional), seated nipple, perforated nipple, and mud anchor are among the downhole equipment. Analyze each system part right now to comprehend how it functions and how it impacts the other components of the system (Gabor Takacs 2015).

The fluid level from surface is one of the most crucial system components. The liquid load on the pump plunger increases with the distance between the fluid level and the pump intake. We refer to the well as being "pumped off" when the liquid level reaches the pump. This suggests we use all the fluid that is available for production (Guo, B. 2007).

An electric motor or a gas engine can serve as the system's primary mover and supply the system's power. The gear reducer or gearbox improves the torque available at the prime mover's slow speed shaft while lowering the high rotational speed to the necessary pumping speed. The downhole pump is operated by the pumping unit, a mechanical linkage that converts the rotary action of the gear reducer into the reciprocating motion needed. The walking beam, which operates like a mechanical lever, is its essential component. The polished rod creates a sealing surface at the wellhead to keep well fluids inside the well and joins the walking beam to the sucker rod string.The stuffing box that seals on the polished rod and the pumping tee that directs well fluids into the flowline are both parts of the wellhead assembly. The flowline is normally attached to the casing-tubing annulus through a check valve (Gabor Takacs 2015). The below is a listing of the downhole equipment:

Inside the well's tubing string is a rod string made up of sucker rods. The mechanical connection between the surface drive and the subsurface pump is provided by the rod string. The moving component of a typical sucker rod pump, the pump plunger, is directly attached to the rod string. It contains a traveling valve, also known as a ball valve, which elevates the liquid inside the tubing as the plunger moves upward. The rod string is the most important component of the pumping system since the effectiveness of the system as a whole depends on its trouble-free functioning. Pump and tubing size, pump setting depth, production rate, gas/liquid ratio, and the existence of sand, paraffin, salt, scale, and foam are taken into consideration when choosing rod strings. Sucker rod strings can be one diameter or can be tapered by employing two or three different rod sizes, usually of the same grade. The smaller rod sizes are typically placed near the bottom of the tapered rod string because they can cope with the load there and lessen the burden and stress on the top sections of the string as a whole (Gabor Takacs 2015).

You must comprehend the benefits and drawbacks of various pumping unit geometries for your well circumstances in order to enhance system efficiency. This can be accomplished by simulating the pumping system using a cutting-edge design tool like RODSTAR, which can precisely model any pumping unit geometries and allow you to compare their performance on any well. You may anticipate the output, loads, stresses, torque, and energy consumption for various pumping unit geometries for any application using such a computer software. This method of comparing pumping units is the most accurate one. Any pumping system can be precisely predicted in RODSTAR's simulations (Theta Oilfield Services Inc 2011). The application forecasts the surface and downhole dynamometer cards for the system you specify. Additionally, it calculates other useful information such as the peak gearbox torque, gearbox loading, structure loading, rod loading, pump stroke, minimum required pump length, plunger length, pump spacing, expected production rate, counterbalance needed to balance the unit, prime mover size, overall system efficiency, daily energy consumption, monthly electricity bill, and others. Additionally, RODSTAR enables you to input inflow performance data so that you can quickly design a pumping system for any pump intake pump intake pressure, compute the expected production rate, pump intake pressure, and pump condition for any rod pumping system, as well as determine the maximum production rate you can achieve. To achieve the desired production at the lowest cost, you must specify the equipment, strokes per minute, and stroke length when constructing a rod pumping system. You should pay close attention to the following factors when you choose the optimum system design for your well:

- Production Price
- Capital costs
- Gearbox loading
- Rod Loading
- System effectiveness and energy costs

The system you choose should provide the largest present value profit after tax, taking capital and running costs into account. Until recently, designing a rod system was a time-consuming process of trial and error that frequently produced a system that might be far from perfect. Just the most obvious system factors are typically taken into consideration because reaching an optimal design involves equipment and data that may not be available. Most of the time, production rate takes precedence over rod loading, gear-box loading, and energy costs. If electricity costs are high, utilizing a larger pump and a slower pumping speed can reduce them. (RODSTAR-D/V Teta Oilfield Services, Inc., 2006).

Advantages of Rod Pumping

1. Has double-valved pumps that can operate in both upstroke and downstroke
2. Could lift viscous and high-temperature oils.
3. For gas separation and fluid level soundings, systems are typically naturally vented.
4. System design that is quite straightforward.
5. Units can be inexpensively switched to other wells.
6. Effective, uncomplicated, and simple for field personnel to use.
7. Power source options include gas and electricity.

Disadvantages of Rod Pumping

1. Free gas decreases pump efficiency
2. Heavy equipment for offshoe use
3. Friction in crooked holes
4. Pump wear with solid productions (Fakher, S., Khlaifat, A., Hossain, M.E. *et al)*. A comprehensive review of sucker rod pumps' components, diagnostics, mathematical models, and common failures and mitigations (*J Petrol Explor Prod Technol* 11**).**

The function of Electrical Submersible Pump

The multistage centrifugal electrical submersible pump, often known as an ESP, is an effective and dependable artificial-lift device for raising moderate to large volumes of fluids from wellbores. These quantities range from 24 to 24,600 m3 per day (150 B/D to 150,000 B/D).ESP systems have historically been employed to pump a wide range of fluids.Aside from handling liquid petroleum products, disposal or injection fluids, fluids containing free gas, certain particles or contaminants, CO_2 and H_2S gases, or treatment chemicals, production fluids are often crude oil and brine. However, they may also be required to manage these fluids (Hamdi Youcef 2018). The electric submersible pump is a practical and versatile artificial lift technique.ESPs are pumps formed of centrifugal or dynamic pump stages. A single-stage centrifugal pump's internal schematic is shown in Figure 6.In an ESP, the centrifugal pump module is directly linked to the electric motor. This indicates a direct connection between the pump shaft and the electric motor shaft. As a result, the electric motor and pump both spin at the exact speed (Guo, B.2007).

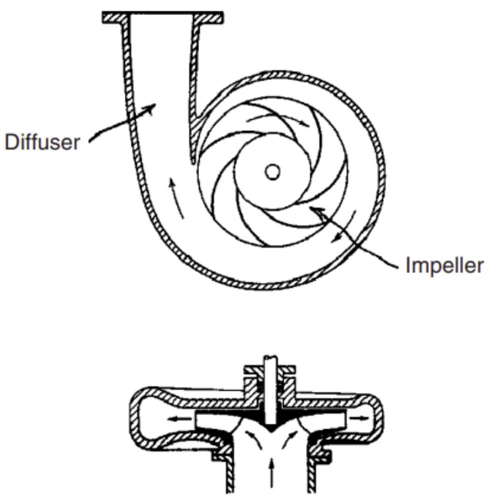


Figure 6. An internal schematic of centrifugal pump. Boyun Guo2007

ESP Run Life

The run life of an ESP is influenced by a number of things. These elements are referred to as operational environment, operation, and equipment. Modeling reliability due to the ESP is divided into three levels (Stanghelle, 2009).

Stage 1 Infant mortality: ESP installation failure (early time failure).

Stage 2 In-service failures: Operational issues

Stage 3 Wear out: failures caused by pump wear out.

The failure rates are identified and examined separately because they are unrelated to one another. Stage 1 occurs during the first two days of operation when the equipment is damaged by running into the well, connecting the electrical line incorrectly, or leaving foreign objects within the well.

Stage 2 is not time-bound and is concerned with how the equipment is used in the field. Electrical issues come under stage 2. It happens when there is an insufficient cooling system, and it may be avoided with careful oversight. The pump cable could be impacted by the pressure rotation and break.

Stage 3 is detected less frequently than the preceding stages because of a proactive maintenance workover plan (Bearden, J.2006).

The following is a list of elements that have an impact on an ESP's run time.

Design and Dimensions

An ESP unit's proper sizing is essential for having a long run life. The chosen equipment size should be used within the advised flow range. We need precise information on well productivity in order to choose the right size. The ESP will operate outside of the recommended working range in the case of selecting the incorrect size, causing the motor to burn due to overload gas locking and the ESP pump to quickly wear out (Zerrouki, T., Paul, H., Monkman, J., 2006.)

Operating Procedure:

Poor operating procedures lead to ESP failure. This may occur as a result of inadequate understanding of the device's operation or an abrupt shift in operating circumstances. Better ESP performance may result from downhole knowledge. Real-time downhole pressure and temperature data can assist, safeguard, and improve the performance of ESP.

Bottom Hole Temperature (BHT):

For the purposes of applying ESP, any bottomhole temperature greater than 105 C is considered to be high. At high temperatures, it is crucial to verify the motor assembly for clearance. The component run life could be shortened if these steps are not taken.

Sand Abrasion:

Because it wears out the stages, the creation of sand has a damaging effect on pump efficiency. Pump shaft vibration, which results in mechanical failure of the seal and burns out the motor as a result of fluid transportation, can trigger an abrupt collapse.

Casting out or reducing sand production is the answer to these later problems. A thorough grasp of sand mobilization rates is required to regulate sand production. Sand damage to the impellers and pump stages can be minimized with the use of the right material and an abrasion-resistant pump design, which can also aid to stabilize the radial shaft (Meihack, 1997).

Components of an ESP system

An ESP system is made up of several stages of centrifugal pumps connected to a submersible electric motor, as I've said earlier. Heavy duty cables that are attached to surface controls power the motor. The ESP is a comparatively effective artificial lift method. It is even more successful than sucker rod beam pumping in some circumstances. Figure 7 illustrates the subsurface and surface parts of an ESP.

- Sensor- Workers can insert a downhole sensor that transmits real-time system information, such as pump intake and discharge pressures, temperatures, and vibration, to boost efficiency.
- Electric motor-An electric motor powers the submersible pump. The amount of steps required to provide enough head pressure to lift the liquid to the surface dictates the capacity of the motor and horsepower rating. The overall length and diameter of ESP downhole devices are governed by the motor size because the motor size fluctuates. Although the motor temperature rises as it works, it is cooled by the pump's ability to pull in passing liquid. The engine is

loaded with synthetic oil for lubrication and electrical protection, which also aids in distributing heat produced more evenly[1].

- The seal-chamber- isolates and guards the motor from harmful well fluids while balancing the oil pressure inside the motor with that in the wellbore.
- Pump Intake —Standard, Reverse-Flow, & Dynamic- Well fluid enters the submersible pump through the pump intake and is sent to the impellers. Depending on the fluid parameters, particularly the gas-liquid ratio, different types of intakes are employed (GLR). Typical versions are utilized in wells that produce a very low gas-to-liquid ratio because they do not segregate gas.Suppliers utilize either a reverse-flow or rotary pump intake to segregate the gas present in a well stream with a comparatively high GLR.Additionally, it dissipates the heat that the thrust bearing produces and absorbs the axial thrust that the pump produces.

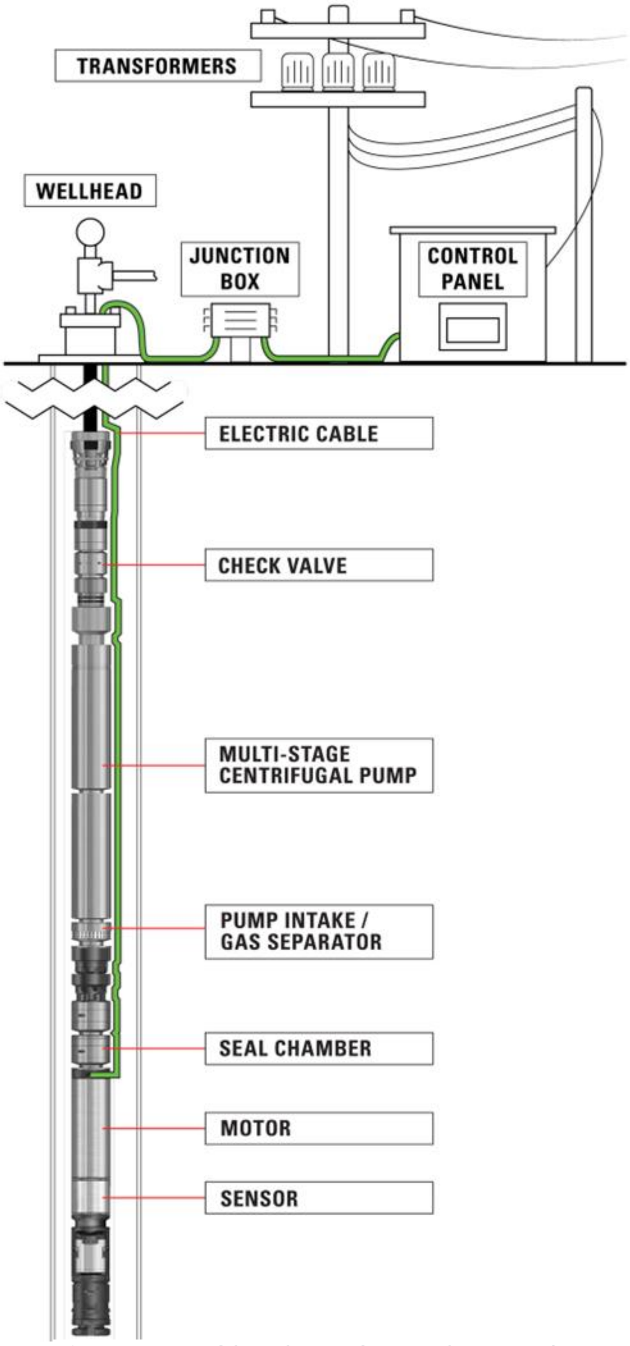


Figure7. COMPONENTS OF AN ESP SYSTEM.https://kimray.com/training/how-does-electric-submersible-pump-esp-work

- The produced fluid with free gas flows along the exterior of the reverse-flow intake screen in a reverse-flow pump intake before turning and entering through the holes at the top of the screen. Following that, it travels down to the intake ports before returning to the first pump stage.These changes in direction enable the lighter gases to naturally separate from the liquid. At the wellhead, the divided gas leaves the casing by ascending the casing annulus. The segregation of the gas from the liquids can be boosted by using longer reversing routes.

- The ESP motor- receives the necessary power from the surface via the power line. To maintain its weight and prevent mechanical wear, it will be banded or strapped to the production tubing at regular intervals from below the wellhead to the motor. It is a specifically designed power cable with an outer covering that is resistant to physical and electrical damage and suited for severe situations.
- Check valve-When the pump is not in use, a check valve is added to maintain the tubing above the pump full with liquid.

The ESP controller, electrical supply, and communication devices are surface-level components. The pump motor's appropriate electrical flow is maintained by the ESP controller. Controllers with variable speed or gentle starts are employed, based on the application. (Gabor Takacs, Ph.D 2018).

Creating ESP applications should take into account the following elements:

the well's PI

Sizes of casing and tubing

Level of a static liquid

ESPs are commonly used with high PI wells. In offshore wells, ESP techniques are becoming more and more widespread. The interior diameter (ID) of the borehole determines the outside diameter of the ESP down-hole device (Guo, B. 2007).

Equipment Installation

Checking that the workover rig is properly positioned over the well is the most crucial step in installing ESP equipment. As the electrical line is inserted through the wellhead and into the well, improper centering causes damage. The next crucial step is to check casing limits, especially in new installations; for this, a sturdy tool needs to be run to the motor's setting depth.

When run to the right depth, the tool shouldn't exhibit significant dragging and should be longer and have a greater outside diameter than the motor.

During assembly, the equipment must be lifted gently and carefully to avoid dropping it or banging it against something hard. When tailing in, the proper slings should be utilized. (Gabor Takacs, Ph.D 2018).

ESP INSTALLATIONS' POWER EFFICIENCY

The easiest way to assess the economics of an ESP or any other kind of artificial lift system is to look at the lifting costs in monetary terms per volume of liquid lifted. The largest portion of running costs is reflected by the electrical power bill because ESP devices are powered by electrical motors. This one expense has grown to be a significant part of the overall operating costs for ESP operations due to the global trend of rising electrical power prices. As a result, the constant quest for operating cost reduction can be translated to the decrease of energy losses that occur both underground and above ground (Gabor Takacs, Ph.D 2018).

Table 1.Advantages and disadvantages of ESP

THE BENEFITS OF USING AN ELECTRIC SUBMERSIBLE PUMP	DRAWBACKS OF USING AN ELECTRIC SUBMERSIBLE PUMP
Applicable to offshore operations.	Not relevant to multiple completions
Tolerant high well doglegs	Inefficient in shallow, low-volume wells
Can hoist extremely high volumes	Pump replacement requires a full workover.
Crooked/deviated holes present no issues	Cable vulnerable to harm when installed with tube
Convenient to install and operate.	It requires high voltages (1,000 V).
Treatments for corrosion and scaling are available.	Solids and gas intolerance

Hydraulic Jet Pumps

The hydraulic pumping system extracts liquid (water or oil) from a liquid reservoir on the surface, presses the liquid (power fluid) via a tubing string using a reciprocating multiplex piston pump or horizontal electrical submersible pump, and then injects the pressurized liquid down-hole. HJP's essential elements consist of nozzle, throat, diffuser. Diffuser is used to transfer fluid mixture velocity into static pressure.The power fluid is directed into the piston pump's hydraulic engine or the jet pump's nozzle, both of which are located at or below the level of the generating liquid, at the bottom of the injection tubing string (Pugh, T. 2009). The average surface injection pressures are between 2000 to 4000 psi, with some exceeding but seldom exceeding 4500 psi. The multiplex pump is powered by a diesel engine, gas engine, or electric motor. Pascal's Law, which Blaise Pascal proposed in 1653, serves as the essential operating theory for subterranean hydraulic pumps. According to the venturi effect, a corollary to Bernoulli's principle that describes the decrease in fluid pressure that happens when a liquid moves through a constricted section of pipe, the nozzle introduces a constriction in the power fluid's flow path, causing the fluid speed to boost through the nozzle. A power fluid, which is commonly refined oil, water, or a combination of oil and generated water, is carried downhole by a pump at the surface through tubing to the jet pump, where it runs through a nozzle in the pump's nose. They are extremely adaptable to different production rates. We can also use jet pumps to introduce chemicals to the power fluid, such as ethylene glycol, to prevent hydrate formation (Zhijian Liu, and Luis E. Zerpa 2016).

Why Jet Pump Is Valuable

As opposed to sucker-rod, electrical submersible pumps (ESP), or gas-lift systems, jet pump systems have a number of capabilities that have been widely covered in the literature. One significant benefit is that it will function under a variety of well circumstances, including setting depths of up to 20,000 ft and output rates of up to 35,000 B/D. The following are a few additional benefits of jet pumps over other lift mechanisms (Pugh, 2009).

1. Possess no moving parts, hence lack mechanical damage
2. The capacity to produce oil with a 6 °API.
3. Require minimum maintenance
4. Normally, free pumps can be retrieved without a rig. This is frequently the main benefit of jet pump systems over alternative methods.

5. Can function better over ESPs in wells with higher gas-to-liquid ratios.
6. An effectively in wells with deviations. They are equally dependable in curved holes as they are in straight ones, and they're able to adjust to tight curves of up to 24°/100 ft in roughness.
7. Employing corrosion-resistant alloy to construct

On the other hand, there are some drawbacks of using HJP such as; If more production than anticipated is pushed through the pump, it will cavitate or power oil systems could cause a fire as well as fluid lines with a high surface power are necessary (Pugh, 2009).

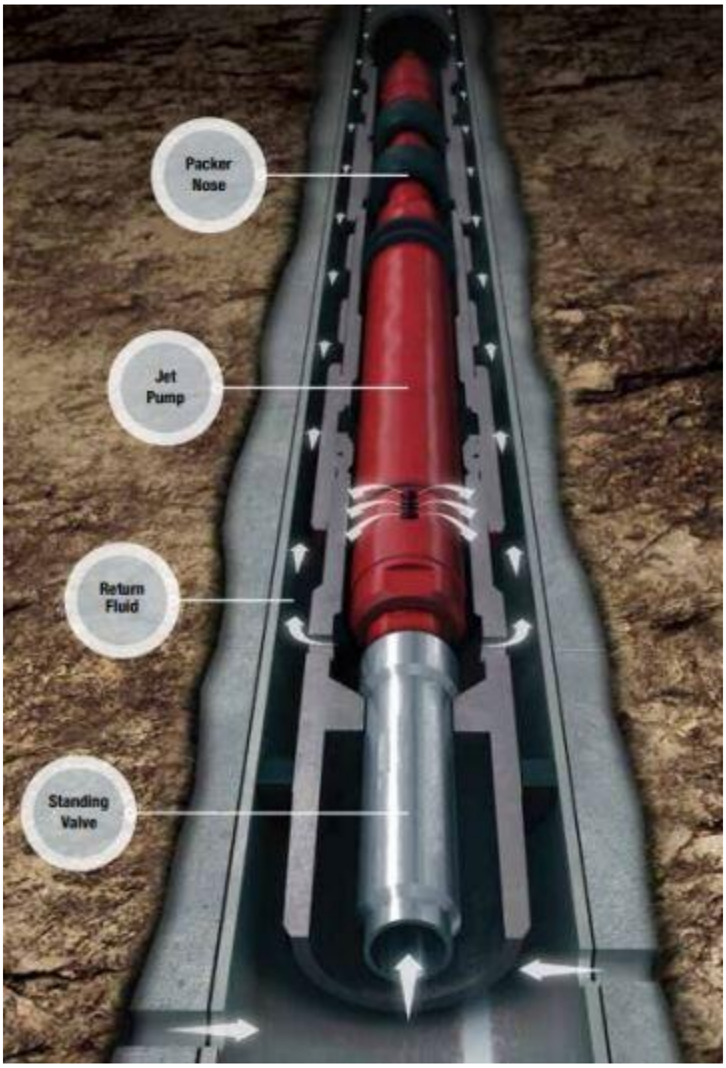


Figure 7. Jet pump (Pugh, 2009).Overview of Hydraulic Pumping (Jet and Piston). Weatherford CP.

Progressive Cavity Pumps

Positive displacement pumps like the progressive cavity pump (PCP) use eccentrically rotating single-helical rotors that spin inside of stators. A high-strength steel rod that is often double-chrome plated is used to make the rotor. The stator is made of a durable elastomer that has been molded inside of a steel casing to form two helices. A PCP system is depicted in a sketch in Fig. Systems using progressive cavity pumps can be utilized to pump heavy oils at varying flow rates. Production of solids and free gas poses only minor issues. They could be inserted into horizontal and angled wells. The progressive cavity pump is also utilized for coal bed methane, dewatering, and water source wells due to its capacity to transfer enormous volumes of water. By improving operational effectiveness while lowering energy requirements, the PCP lowers total operating expenses. Progressive cavity pumps are able to handle a range of viscosities and function more effectively and with less energy loss. Both above-grade and below-grade sump tanks benefit from progressive cavity pumps. Operators were able to empty the tank down to only a few inches of liquid at the bottom by partially submerging the pump in it. PCPs have a short operating life (2–5 years) and high cost, which are their main drawbacks. Furthermore, pump off control is really challenging (Guo, B. 2007).

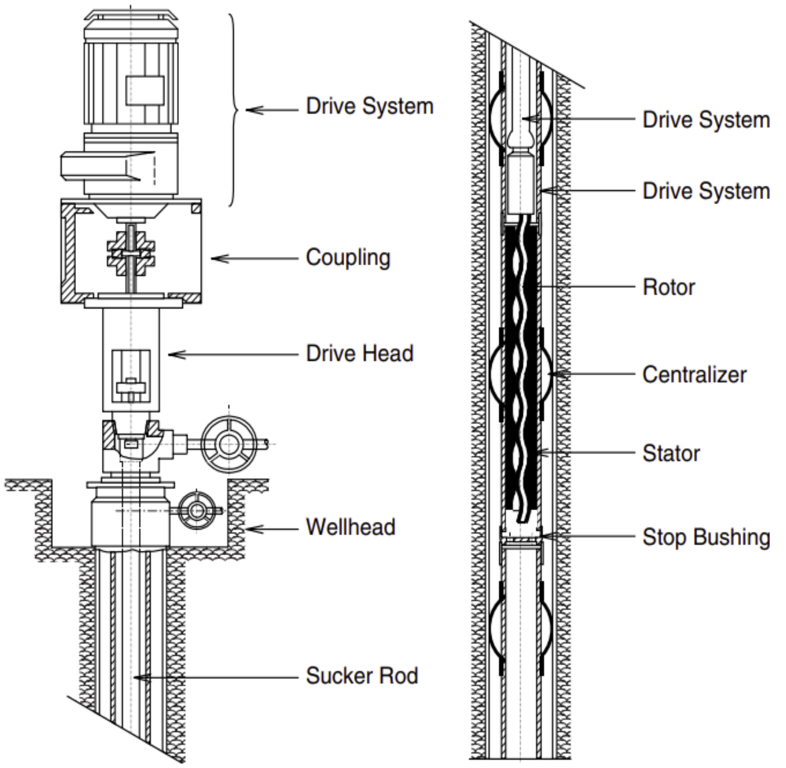


Figure 8.Visualization of a PCP system.Petroleum Production Engineering, Second Edition

PCP's advantages also include its straightforward design, great volumetric efficiency, and ability to pump viscous crude oil. Progressing cavity pumps are often adaptable, dependable, resistant to abrasive solids, and volumetrically effective. Utilizing small motors results in economical lifting costs and effective energy utilization. Progressing cavity pumps, which operate at slower rates than rod pumps, survive better and experience fewer rod or tube problems. (Oilfield Review,The Defining Series: Progressing Cavity Pumps).

Compared to other artificial lift techniques, capital expenses are often lower. Progressing cavity pumps are employed to depths of roughly 4000 ft [1220 m] and can provide up to 1700 B/D 270 m'/1. Rotating fluid displacement is the foundation for progressing cavity pumps. A rotor spins eccentrically inside of a stationary stator in this spiral design. The rotor is a very long pitch distance between thread peaks and deep circular threads on a small-diameter screw. The stator, which has one more thread and a longer pitch than the rotor, creates chambers that move in a rotating motion to almost completely eliminate pulsation[2]. The rotor is often rotated by rods attached to a surface motor, just like rod pumps. The rotor is turned by subsurface electric motors and a speed-reducing gearing in new rodless systems. A motor that rotates the rod string, which spins the rotor inside the stator, makes up the PCP drive system, which is typically positioned at the surface. However, operators may install subsurface electric motors to revolve the rotor and prevent rod and casing damage in wells that have extensive lateral portions or display a significant degree of deviation. (Guo, B. 2007). Commonly used application field:

- Pumping oil
- Slurry pumping for coal
- Pumping a viscous chemical
- Stormflow control
- Oilfield directional drilling with downhole mud motors (it reverses the process, turning the hydraulic into mechanical power)
- Pumping well water with limited energy

PLUNGER LIFT

Plunger lifts produce fluid solely from reservoir energy. Scraping can eliminate solid depositions such as paraffin wax, mineral scale, and hydrates from inside the tubing (Hassouna, Mohamed, 2013). Plunger lift can be extremely successful in wells with low bottom-hole pressure and high productivity, as well as wells with high bottom-hole pressure and low productivity. (Beauregard, 1982). The following traits should be present in the candidate wells: A GLR of 400 scf/bbl or greater per 1000 ft, adequate reservoir building pressure, and no mechanical obstacles in the tubing (Ghareeb et al., 2013). High gas-liquid ratio wells are suitable for plunger lift systems. They are affordable constructions. The plunger automatically removes scale and paraffin from the tubing. However, they work effectively for low-rate wells, which are typically less than 200 B/D. Listiak (2006) provides a comprehensive analysis of this technology. Plunger lift has historically been applied on oil wells. Plunger lift is now increasingly frequently used on gas wells to dewater them. Plunger lift systems work best in wells with high gas/liquid ratios and low bottomhole pressures (GLRs). Plunger lift systems are also an excellent fit for wells with a shut-in wellhead pressure that is 1.5 times the surface flowline pressure. Because it may be used without incurring the high cost of a work-over rig. The limitation of plunger lift is that there is a risk of the plunger reaching too high a velocity and triggering damage to the surface. During plunger lift procedures, the motor-controlled valve opens and then closes. When the surface valve is closed during shut-in, the gas flow down the flowline is shut down (O. Lynn Rowlan, James N. Mccoy ,Augusto L. Podio 2007).

Oil Wells with a High Ratio

When considering a plunger application for an oil well, the idea of "unloading a gas well" is easily extended to producing a high ratio oil well. In many instances, the wells are nearly identical. Only the functioning mechanics are altered. Again, gas is the driving force behind all plunger setups. With high gas liquid ratios, it is simple to have a plunger travel up and down the tubing in an oil or gas well. The mechanical tools used to drill a high-ratio oil well will be determined by reservoir characteristics. When the velocities in the tubing are no longer sufficient to transport the liquids to the surface, the low bottom hole pressure well will cease to flow continuously. It qualifies as a strong gas producer. The first sign of a loading issue will be erratic output, as seen on the gas sales meter. The fluid will be manufactured in tiny heads with gas spikes on the sales chart.

Despite the fact that the well does not produce constantly, the heading is consistent.

This type of well's plunger installation should be cycled as frequently as feasible. It should have a quick fall time and be made at a high rate in the manufacturing facilities This sort of operation may only produce fractions of a barrel per trip, but because we qualified the well as highly productive, the well will recover rapidly for another cycle. To reduce the flow period after the tool gets at the surface, the surface lubricator should include a shut-off on arrival mechanism. Time cycle or casing pressure controls on the flow line can be used to decide the shut-in period. (E. Beauregard, Paul L. Ferguson Ferguson Beauregard 1981).

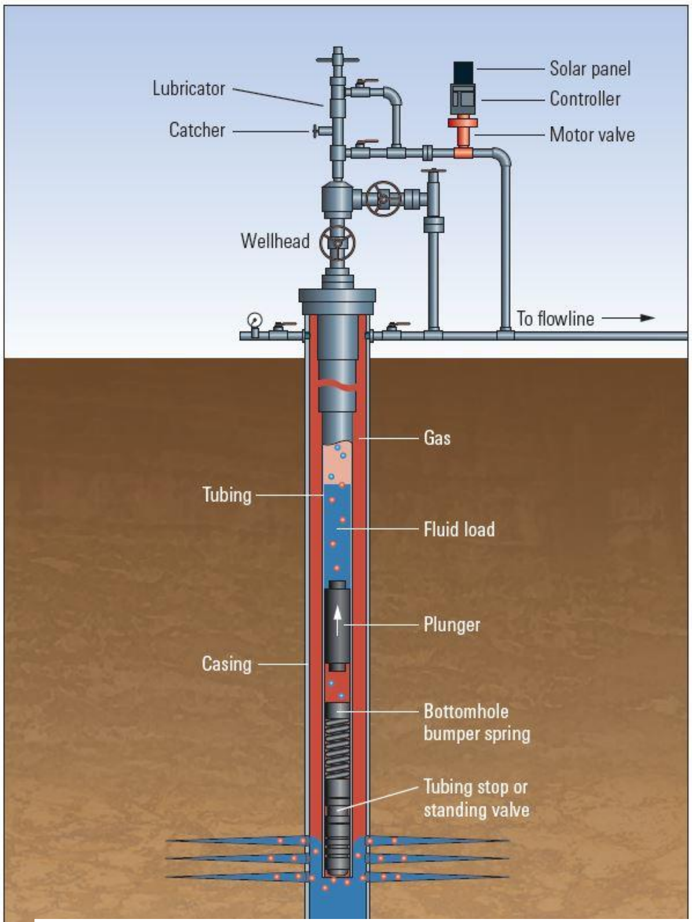


Figure 9. Typical PL configuration (Oilfield Review, 2016).

Compared to PCP and rod lift, it is more affordable and can often be fitted in a day.

List of standard plunger lift equipment:

- "Gas" is being injected into the well casing from a gas compressor.
- At the bottom of the well is the plunger. This type of plunger, called a dart plunger, is employed in the bypass phase of wells or with high levels of flow.

- The plunger is covered in well fluid.
- The casing is the exterior piping with the bigger diameter.
- Tubing is the name for the inner piping's lower diameter.
- The Christmas tree, flow line, and control valve would be above the surface (and not shown in the picture).
- Lubricator
- The lubricator contains an auto-catcher.

The Operating Principle of PL

Like other artificial lift techniques, plunger lift's goal is to remove liquids from the wellbore so that the well can be created at the lowest bottom-hole pressures possible. The mechanics of a plunger lift system are the same whether it is used in an oil well, gas lift well, or gas well. A timed control that is often attached to a high pressure control valve is used to create this kind of artificial lift.A solid plunger, a pad plunger, a brush plunger, and a flow through or continuous flow plunger are just a few examples of the various plunger kinds. They all serve the same purpose. The plunger, which is a length of steel, is lowered through the tubing to the well's floor before being allowed to ascend again. It inhibits liquid fallback by creating a piston-like contact between liquids and gases in the wellbore. A well's own energy can effectively lift liquids out of the wellbore by acting as a "seal" between the liquid and gas. When removing liquid, the rules are altered by a plunger [3].

In wells with an open annulus, the ideal wellbore configuration for plunger lift is found. In this arrangement, the plunger and liquid slug can interact freely with gas in the annular area to create lift with no constraint. Generally, the functioning of a plunger lift involves cycles of shut-in (or no-flow) and flow periods. With the plunger resting on the bottomhole bumper spring at the bottom of the well, the cycle starts in the shut-in mode. As gas gathers in the annular gap between the casing and the tubing, the surface valve is in the closed position, allowing well pressure to rise. In order to lift the plunger and the liquid slug to the surface against line pressure and friction, the well must be shut off for a sufficient amount of time to develop reservoir pressure (Oilfield Review,Slb. The Defining Series: Plunger Lift 2016).

Prediction of Production Rates Using a Plunger Lift

The decline curve analysis approach is the easiest and occasionally most precise way to identify production increases due to plunger lift. Usually, the reductions in gas and oil reservoirs are exponential, harmonic, or hyperbolic. Initial production rates are typically sufficient to produce loads that are considerably above critical and to create a decline curve. When liquid loading takes place, a noticeable reduction and divergence from the norm can be noted. The well can be unloaded using a plunger lift to restore a typical decline. Between the rates of the well when it first began loading and the rate of a protracted decline curve to the present, production increases from plunger lift will fall. Building an inflow performance curve based on the backpressure equation is another way to estimate production. If the well has an open annulus and the casing pressure is known, this is extremely useful. An accurate representation of bottom-hole pressure is provided by casing pressure. The estimated reservoir pressure, casing pressure, and current flow rate can be used to construct the IPR curve. Since the purpose of plunger lift is to reduce bottom-hole pressure by draining liquids, the pressure in the bottom-hole can be calculated in the absence of fluids. With decreased bottom-hole pressures, the rate of production could be estimated using this new pressure [4].

Concept and types of the Gas lift system

One of the most popular, dependable, and efficient artificial lift methods is this one. It is thought of as an extension of the Natural Flow Process since gas lift is preferred because most closely resembles it.

Gas is pumped into the liquid production string in a technique known as "gas lift," Normally, the liquid column is aerated through the tubing-casing annulus to lower its hydrostatic head. The fluid column pressure decreases as it rises toward the surface, causing gas to escape its solution and expand as free gas. Free gas reduces the density of the flowing fluid and further lessens the weight of the fluid column above the formation since it is lighter than the oil it displaces. The pressure differential between the wellbore and the reservoir that allows the well to flow is created by this decrease in the fluid column weight (Michael, G., & Curthis H, W. 1991). The longer the column of tubing fluid is aerated, the deeper the injection point, and the lower the bottom hole pressure. As a result, the goal of gas lift is to inject the best gas at the deepest point in the tubing. An ideal gas volume injection is crucial because any higher volume causes too much friction pressure loss in the tubing, which would otherwise cancel out the hydrostatic pressure gain.By starting a pump pressure below the well or introducing pressurized gas, gas lift techniques are utilized to lift the oil from the wellbore to the surface.. As shown in Figure 11 the gas lift system (Vinegar, 2004). Gas lift valves regulate the gas that enters the pipe to raise the fluid to the surface.

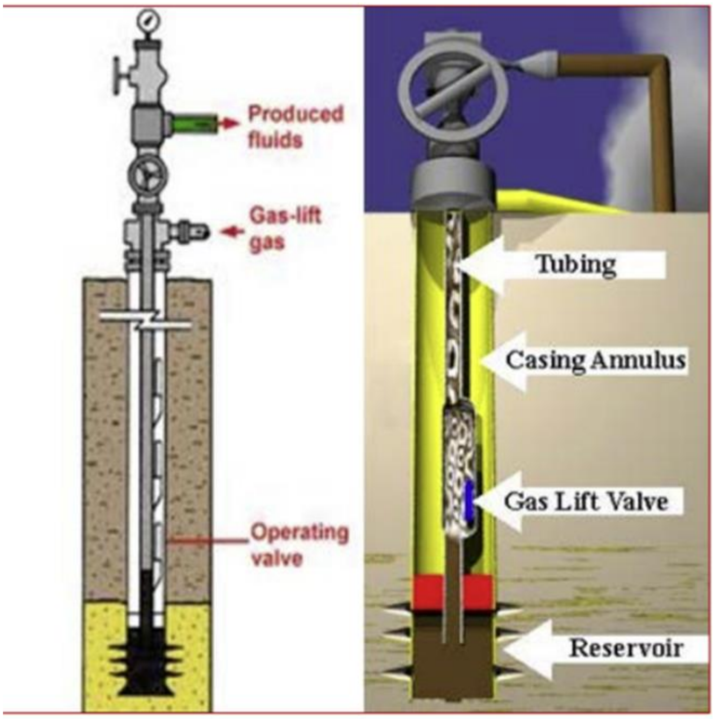


Figure 10.Gas Lift System (Vinegar, 2004)

The goal of unloading is to commence aerating a fluid column in shorter lengths at the top, close the top valve to aerate via the second valve, and so on until the injection valve is reached.This valve is configured so that it is always open. This gradual unloading is carried out to start a well with low surface injection pressure. The amount of fluids to be produced, the volume and pressure of the lift gas that is accessible, and the well reservoir's conditions all play a role in determining the type of gas lift operation that is employed, for instance when high instantaneous BHP drawdown encountered with intermittent flow would result in excessive sand production, or coning, and/or gas into the wellbore. («Schlumberger Well Completions and Productivity», 1999) To maximize production and lessen slugging effects, where gas droplets accumulate to create huge bubbles that might disrupt production, gas lift can be adjusted for a single well. In order to use the available gas as effectively as possible, gas lift can also be optimized across a number of wells (Håvard Devold 2006).

Guidelines for Gas Lifts

When determining whether a project can use gas lift or evaluating its performance, production technologists, process engineers, and production operation engineers must completely take into account a number of gas lift's golden rules (Yudi Setiawan 2013).Which are:

1. A good, trustworthy provider.

2. The gas injection must occur as near as feasible to the completion interval's peak.

3. Solid.

4. Work at the wellhead with as little back weight as possible.

5. The completion ought to be single point lift-compatible.

6. Lift gas supply needs to be improved, for example, by reducing compressor downtime.

7. Future needs should be considered in all gas hoist system designs.

8. Excessively pessimistic design suppositions should be avoided

Various Gas Lifts: Basically, this technology comes in two different forms that are both widely employed in the petroleum sector.

1. Continuous Flow Gas Lift.
2. Intermittent Flow Gas Lift

1. Continuous Flow Gas Lift: A continuous gas lift operation is characterized by a steady-state flow of aerated fluid from the well's bottom (or near bottom) to the surface (Ostvold, T. D 2014). This technique involves injecting gas into the fluid column at a reasonably high pressure downhole. By using one or more of the following methods, the gas that was injected joins the gas from the formation to lift the fluid towards the surface: Decreasing the column weight and fluid density to raise the pressure difference between the reservoir and the wellbore. For wells that produce at greater rates and where continuous flow can be maintained without excessive usage of injection gas, continuous flow gas lift will often be more effective and less affordable. A continuously lifted gas lift well operates in much the same way as a naturally flowing well. A set depth of gas is constantly injected into the tubing via a gas lift valve.The only variation between this procedure and a naturally flowing well is that the gas-liquid ratio changes at some point in the gas lift well's tubing (Slb Information Solutions 2009).
2. Intermittent Flow Gas Lift: Intermittent gas lift operation is distinguished by a start-and-stop flow from the well's bottom (or near bottom) to the surface. This flow has an unsteady condition. This system produces intermittently and is built to generate at the rate at which fluid enters the wellbore from the formation. It uses the same lifting mechanism and both surface and subsurface infrastructures as are utilized in continuous flow (Takacs, G., 2005).

It is important to comprehend the following fundamental ideas and elements in order for a gas lift system to function properly («Slb Well Completions and Productivity», 1999).

1. The well can generate fluids, but there isn't enough energy in the reservoir to bring the fluids to the surface. These fluids will rise to a level known as the static liquid level, where they should be artificially raised to the surface.
2. In order to properly inject gas into the well, the gas pressure must be sufficient. It either already has enough pressure to enable the gas lift system to work or more compression is required to increase the pressure. The required gas amounts and the well pressures will have been taken into consideration while developing the gas lift installation.
3. Mandrels that are inserted into the tubing string and have gas lift valves installed in them automatically open and close in reply to predetermined pressures. Before running the string, conventional mandrels are compared to side pocket mandrels by running them on tubing with the valve installed on the exterior half of the mandrel. The side pocket mandrel, one of Camco's key products, enables the installation and retrieval of the gas lift valves using wireline techniques. Each valve installed in the well must have its pressure set properly, its spacing in the tubing string carefully measured, and the type of valve chosen.
4. The fluids that are produced are released into a typical oil, water, and gas separator. The surface flow line should have as few restrictions as possible, and the backpressure on the separator ought to be as minimal as possible. A gas meter, either permanent or temporary, should be accessible to measure the volume of input gas and output gases. A pressure recorder must be present to monitor tubing and casing pressures during operational conditions. Salt water and generated oil are measured using fluid meters (Vazquez- Roman 2005).

Constant-Flow Gas Lift Installation Design

Adequate design is essential for a gas lift system to operate as efficiently as possible. Computers can be used to complete modern design methods, but in order for gas lift workers to use these tools effectively, they must be familiar with design fundamentals (Jadid, M.B., 2006).

There are two steps in the gas lift design process. They consist of:

1) Mandrel and/or gas lift valve spacing

2) The computation of unloading valve setting pressures.

The following items make up the essential gas lift technology equipment:

- Main operating valves
- Wire-line adaptations
- Check valves,
- Mandrels
- Surface command mechanism
- Compressors

As the well lifts from the planned operating point, the design process aims to make sure that the unloading valves are closed. A gas lift valve is intended to remain closed until specific pressure requirements in the annulus and tubing are satisfied. When the valve opens, gas or liquid can flow into the tube from the casing annulus. Additionally, gas lift valves can be set up to allow flow from the tubing to the annulus. Gas pressure in the annulus and gas and fluid pressure in the tubing are the two forces that open gas lift valves. The valve will close and stop gas flow from the annulus as long as gas and liquid discharge from the tubing continues and well conditions change (Eiman Al Munif 2016).The one valve at the point of gas injection in a continuous flow system will stay open, allowing for continuous gas injection. To regulate the point of gas injection, an operational gas lift valve is attached. To discharge the well, valves are placed above the intended injection location. They close after unloading to stop gas injection above the operational valve. In the majority of continuous flow designs, the surface choke controls gas flow while the operational gas lift valve controls pressure. Gas compressors may have been installed as booster compressors or for gas injection. There may be high-pressure gas available from high-pressure gas wells. Compression is far more expensive than subsurface gas lift machinery. When a sufficient volume of high-pressure gas is accessible for elevating wells needing artificial lift, gas lift should be the first option to be considered. Gas lift could deplete the majority of wells. This is especially true now that reservoir pressure control procedures have been implemented in the majority of significant oil fields (Slb Information Solutions 2009).

Technological Advancement

Schlumberger has recently developed new deepwater subsea high-pressure gas-lift technology to reduce the risks connected with traditional, bellows-operated gas-lift valves.Subsea high-pressure gas lift valves can boost project economics by increasing output and reliability at greater pressures. Depending on the application, these valves can be set deeper in the well using unique bellows technology to provide extra drawdown and increased production.In comparison to the previous 2,500 psi limit usually present with conventional gas lift valves, the new high-pressure gas-lift technology rates reliable bellows operation for 5,000 psi at the valve depth.The following are some of the relative benefits of gas lift: (Slb Information Solutions 2009).

- Handles large solid volumes
- Handles high flowrates
- Power source can be located remotely
- Easy to acquire downhole pressures and gradients
- Can be serviced with a wireline unit
- Ideal for deviated wells
- Corrosion is generally not an issue

System Effectivenesses

The energy efficiency of modern artificial lift techniques varies greatly, as seen in Fig. . The amount of energy needed to run the system and the quantity of hydraulic force used to bring the fluids to the surface are used to determine an artificial lift installation's overall effectiveness. The efficiency is the result of the component efficiencies added together. Power losses in the well and on the surface can also have a significant impact on the final number. The effectiveness of the lifting mechanism, such as the energy efficiency of the pump utilized, accounts for the majority of the overall efficiency. Therefore, using a highly efficient lifting mechanism is a fundamental requirement for great total energy efficiency. The progressing cavity pump, which can be more than 70% efficient at converting mechanical energy to hydraulic work, is the most energy-efficient artificial lifting device currently on the market. Progressing cavity pumps (PCP) systems are the most effective artificial lift techniques because they require only minimal surface and downhole installations and suffer from low levels of energy loss in system companents.

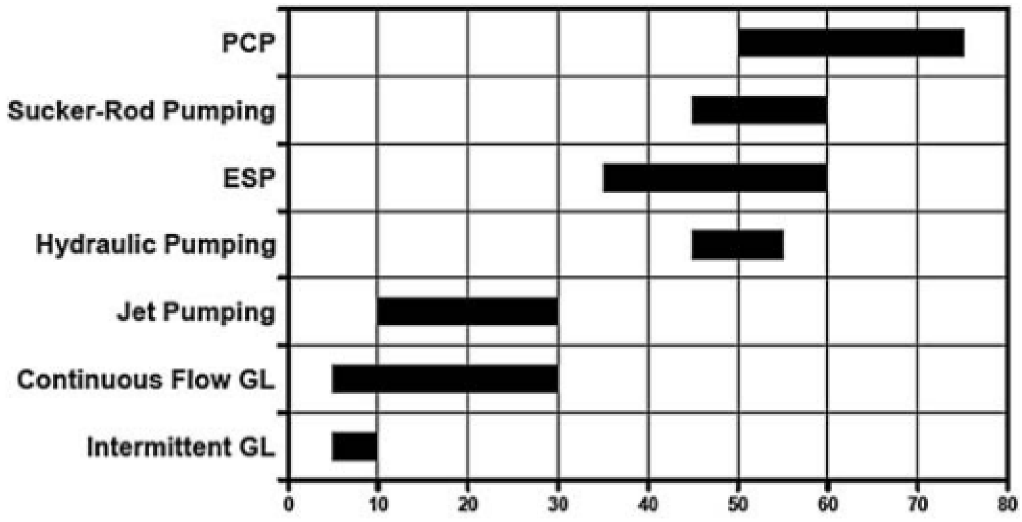


Figure 11.Energy effectiveness of artificial lift techniques. (Gabor Takacs, Ph.D 2018)

It makes sense that the number of PCP installations is rapidly increasing, regardless of where well conditions fall within their application limits.Sucker-rod pumping and ESP installations come next, as shown in Fig. 12, with maximum system efficiencies of roughly 60%.Positive displacement hydraulic pumping setups typically have power efficiency of around 50%. With maximums around 30%, jet pumping and continuous flow gas lifting are artificial lift techniques that are considerably less effective. The least efficient lift method in terms of energy use is intermittent gas lift (Gabor Takacs, Ph.D 2018).

Chapter 2. Criteria for Selecting Artificial Lifts

Before making a decision, it is important to take into account the fluid's qualities, the environment, operational and investment costs, and any potential production issues. Table 2 offers assistance in making a preliminary choice of potential candidates and in ruling out any approaches that are inapplicable under the circumstances.

Table 2.Comparison of artificial lift methods (SPE petroleum engineering handbook, vol. IV: Society of Petrooleum Engineers; 2007)

All method	SR pumping	Gas Lifting	ESP	PCP	Hydraulic Pumping	Jet Pumping	Plunger Lift
Maximum operating depth,ft	16,000	18,000	15,000	12,000	17,000	15,000	19,000
Maximum operating rate,bpd	6,000	50,000	60,000	6,000	8,000	20,000	400
Maximum operating temperature, F	550	450	400	250	550	550	550
Gas handling	Fair to Good	Excellent	Fair	Good	Fair	Good	Excellent
Solids handling	Fair to Good	Good	Fair	Perfect	Fair	Good	Fair
Fluid gravity,API	$>8^0$	$>15^0$	$>10^0$	$<40^0$	$>8^0$	$>8^0$	$>15^0$
Offshore application	Limited	Perfect	Perfect	Limited	Good	Excellent	N/A

In the conventional artificial lift problem, the kind of lift has already been chosen, and the engineer's challenge is to use that system with the specific well. The more fundamental query, however, is how to decide which kind of artificial lift to use in a certain field.

To get the most out of developing any oil or gas field, the operator must choose the most cost-effective artificial lift technique. (Bernt Ståle Hollund 2010). In the past, a wide range of techniques have been employed by the industry to choose the method of lift for a particular area, including:

- Determining which techniques will lift at the needed rates and from the required depths.
- Analyzing lists of benefits and drawbacks.
- The selection and rejection of AL systems using "expert" software.
- An analysis of startup expenses, ongoing costs, manufacturing capacity, etc. using economics as a selection tool.

When choosing an artificial lift technique, the operator should take into account all of these options, especially for a massive, protracted project.

The key criteria for choosing artificial lift techniques are:

- To increase production rate.
- Downhole flowing pressure.
- The gas-liquid GOR.
- Features of PVT generating fluid.

The following things should also be taken into account:

I. Operating situations:
   - Casing size restriction
   - Well depth.
   - Intake capacity (minimum bottom hole flowing pressure).
   - Adaptability of the artificial lift system, surveillance.
   - testing, and time cycle or pump off controllers.

II. Well conditions:
   - Ability to handle sand
   - Solids, and corrosion as well as scale
   - Temperature limit.
   - The ability to lift both high and low volumes of fluid.
   - Handling of highly viscous fluids.

III. Circumstances (a fresh field exploration, potential well, presence well, existence of gas): For a new field discovery, there may be a wide range of options, and production facilities and well design can minimize limits.
   - A new well in an existing field is limited by the infrastructure already in place, which reduces options.
   - Lift selection options are limited by an existing well's numerous fixed constraints, such as completion, well integrity, site accessibility, distance between wells, etc [5].

Well and Reservoir Characteristics

Table 3 presents reservoir considerations for selection of artificial lift types.

Table 3.Reservoir considerations in selection an artificial lift methods

IPR	A well's production potential is defined by a well inflow performance relationship.
Liquid production rate	When choosing a lift technique, the projected production rate is a deciding factor. Positive displacement pumps are often limited to rates of 4000-6000 B/D.
Water cut	High water cuts necessitate a lift technique that can transfer massive amounts of fluid.
Gas- liquid ratio	In general, a high GLR reduces the effectiveness of pump-assisted lift.
Viscosity	Viscosities less than 10 cp are typically not taken into consideration when choosing a lift technique: High-viscosity fluids can be challenging, especially when sucker rod pumping
Formation volume factor	To reach the desired surface production rate, the amount of total fluid that must be lifted depends on the ratio of the reservoir volume to the surface volume.
Reservoir drive mechanism	Depletion drive reservoirs: late-stage production may require pumping to produce low fluid volumes or injected water Water drive reservoirs: high water cuts may cause problems for lifting Systems Gas cap drive reservoirs: increasing gas-liquid ratios may affect lift Efficiency

Other reservoir problems	Abrasion and/or clogging can be brought on by sand, paraffin, or scale. Corrosion can occur when H2O, CO2, or salt water are present. Down-hole emulsions can lower lifting effectiveness and raise backpressure. High bottom hole temperatures might have an impact on downhole machinery.

Table 4 presents well considerations in selection an artificial lift methods for each artificial lift type.

Table 4.Considerations when determining an artificial lift technique

Well depth	**The amount of surface energy required to transport fluids to the surface depends on the well depth, which may also impose restrictions on sucker rods and other machinery.**
Completion type	Performance of the inflow is impacted by completion and perforation skin variables.
Casing and tubing sizes	The production tube size is constrained by small-diameter casing, which also restricts other alternatives. Production rates will be limited by tubing with a small diameter, yet larger tubing might allow for too much fluid fallback.
Wellbore deviation	Beam pumping applications may be restricted by highly deviated wells.

Economics

The following economic variables affect the choice of an artificial lift type:

- Capital Costs
- Monthly operating expenses
- The duration of installed equipment
- additional equipment
- Production life,
- Work over budget
- Number of wells that need installation of artificial raise

Initial capital costs are crucial to the installation of the necessary artificial lift types. However, throughout the well's lifetime, operating costs take precedence over initial capital expenditures. The statistics show that only 1% of the project's overall value is made up of the initial capital investment.But 6% of the total project costs go toward operating expenses. Therefore, it is important to ensure the installation of dependable machinery that results in lower running expenses and higher production costs.Energy reliability and efficiency (which require the purchase of extra gas) are two important factors that affect operational costs.Work over expenses depend on the operating field's location (remote fields have higher costs), as well as the contract terms with the service provider. The number of wells that need installation of artificial lift types is another important aspect that will have an impact on operating costs. The number of workers required for equipment control and installation will have an impact on operating cost (Elshan Aliyev 2013).

Table 5.Lift Methods Costs: Low Rate Case

Parameters	Beam	Hydraulic	Gas Lift	ESP
Target Rate (bbl/day)	1000	1000	1000	1000
Initial Installation ($)	141000	173000	239000	105000
Energy Efficiency (%)	58	16	15	48
Intake Pressure (psi)	900	900	900	900

Work over Cost ($/day)	1000	1000	1000	1000
Maintenance Costs ($/month)	200	2900	600	225

Selection Based on Net Present Value

The best artificial lift method can be chosen by considering the lifetime economics of the available options. The economics are dependent on a number of variables, including the failure rate of the system's parts, fuel costs, maintenance costs, inflation rates, and the anticipated profit from oil and gas production. The first step in using the NPV as a comparison tool is to have a solid understanding of the expenses involved with each methodology, as well as their benefits and drawbacks, and any additional costs that may be required. Before analyzing the economic analysis to better assess the effectiveness of a particular installation, there should be a design for each possible system because energy costs are included in the NPV analysis (Clegg, 2007).

$$NPV = \sum_{i=1}^{n} \frac{WI(Q_{HC} * P_{HC} - Cost - Tax)i}{(1+k)^{i}}$$

where:

WI = work interest

Q = oil rate

P = oil price

Cost = all costs, operation (Opex) and capital (Capex)

Tax = governmental taxes

k = depreciation rate of the project (percent)

Chapter 3. Building And Matching the Well Model in Prosper

The ARC field produces oil and gas via WE1 wells. The long-term plan for the ARC field, optimization of oil well output in the ARC field, and the efficiency of gas production to improve oil well production are all factors driving the implementation of this research. The goal of this research is to examine oil wells in the ARC Field that have the potential to boost production through Artificial Lift and to obtain results of Artificial Lift designs for appropriate and efficient well candidates.

PROSPER INFORMATION

One of the most critical aspects of well analysis is evaluating whether wells may be capable of producing at a higher rate than the existing one. PROSPER, a well-modeled software, is intended to help ensure that well models are accurate and consistent. It also handles every component of well modeling, including PVT (fluid description), VLP correlations (for computing flow-line and conduit pressure loss), and IPR (reservoir inflow). PROSPER can match PVT, point flow correlations, and IPR to field data in a variety of ways, allowing the well model to be developed before it is employed in prediction sensitivity or artificial lift design. PROSPER provides for thorough surface pipeline performance and design considerations in the following areas: flow regimes, pipeline stability, and pipeline sizing. It works like this. The main PROSPER screen, which is separated into five sections, contains all of the options, PVT data, equipment data, IPR data, and computation outline. The theory of integrated production modeling IPM is used when PROSPER is used to create well models. In well modeling, PROSPER is the link between the reservoir model and the surface model. It is the link between the two. It demonstrates how the well works, as well as how the reservoir and vertical rise function. We will develop a well model before employing the well matching method by entering false information into the well check. The well analysis is then carried out in each component of the assembly system to evaluate whether it is producing less than it should. The ability to demonstrate how well flow and performance are currently connected is a crucial aspect of well analysis (IPR). To be successful, it is critical to employ the correct well check information and the correct IPR model for the analysis. Well performance modeling is an important aspect of crude oil engineering research. The PVT model for generated fluids, the reservoir IPR model, and the VLP model are all merged in this model to create a hybrid model (Vamsi Krishna Kudapa ,ORCID,Mohammed).

Technical approach

After collecting all data for the reservoir simulation model related to reservoir fluid properties is taken Electrical Submersible Pump Design in Vertical Oil Wells Research Article with some additional parameters, and table containing the data needed for the software is created for well. The Prosper software is used to enter the data, and the model with the lowest error rate is chosen. The program then uses the black oil model, which functions at the expense of the characteristics of the other reservoir fluids, to match the input values.

Due to pressure losses from the sand face to the surface, Table 3 shows the reservoir and fluid parameters for an oil well that is producing from a black oil reservoir but has low productivity. In order to maximize oil productivity from wells, suitable technique is designed.

The reservoir has a high oil potential, and a significant amount of oil might be delivered to the well bore. Nevertheless, this oil would need to be artificially raised to the surface. The input fluid parameters are shown in Table 6 in order to correspond with the reservoir data.(Abdelhady A, Gomaa S*, Ramzi H, Hisham H, Galal A and Abdelfattah A).

Table 6. Reservoir and fluid properties

Properties,Unit	**Value**
Reservoir pressure, atm	89
Bubble point pressure, psi	3600
Reservoir Temperature, F	250
Gas Oil Ratio, scf/stb	800
Water cut, %	50
API	35
Gas specific gravity	0.78
Water salinity, ppm	80.000
Oil FVF, bbl/stb	1.45
Oil viscosity, cp	0.3

Reservoir permeability ,md	20
Reservoir thickness ,m	15
Drainage area,m^2	820000
Dietz shape factor, unitless	23.9
Skin factor, unitless	2
Wellbore radius, inches	9
TD,m	780
MD,m	560

Input PVT Data in PROSPER software is shown below table 7.

Table 7.Input PVT Data

PVT properties, Unit	Value
Solution GOR, scf/STB	800
Oil gravity ,API	35
Gas gravity,sp	0.78
Water salinity,ppm	80000
Mole percent H2S, %	0
Mole percent CO2 ,%	0
Mole percent N2,%	0

At this section, we examine how various assumptions affect the use of artificial lift techniques at a mature oil field in Mexico.

Analyses of the cases

This field has black oil with a gravity range of 35 degrees API and is made up of multiple small reservoirs that are dynamically segregated from one anothers. In practically all reservoirs, the fluid is homogeneous. The majority of reservoirs and wells are generally in the process of being depleted, and as a result, reservoir pressure and production are falling rapidly. According to the field's current development plan, this field will produce from about 20 wells through the middle of 2023.

The field challenges

Different scenarios have been considered in order to maintain production from these reservoirs, and due to the field's rapid development, artificial fluid lifting was given the most thought. The production network and surface facilities used by all the reservoirs in this field are the same.

The reservoirs being studied include a carbonate cretaceous reservoir with a powerful aquifer, a few medium-sized sand bodies that have already been exhausted, and newly discovered ones with high pressure. The primary concern with this asset is whether artificial lift techniques are economically viable to exploit the reservoir fluid and maximize the recovery factor on top of these complexity that we are unable to capture with standard process.

System Summary for Natural Drive Case

The wells data and reservoir data ara provided. The following processes are conducted in the software for Natural Drive Case, Electrical Submersible Case, and Well 1 to build IPR and VLP curves and obtain the intersection point between these curves based on input data. This is the stable flow point.

The Well Model

Building a Model for Well-Performance PROSPER is used

There are 6 areas on the PROSPER primary screen:

1. Options Summary
2. PVT Data
3. IPR Data
4. Equipment Data
5. Analysis Summary
6. PROSPER Version

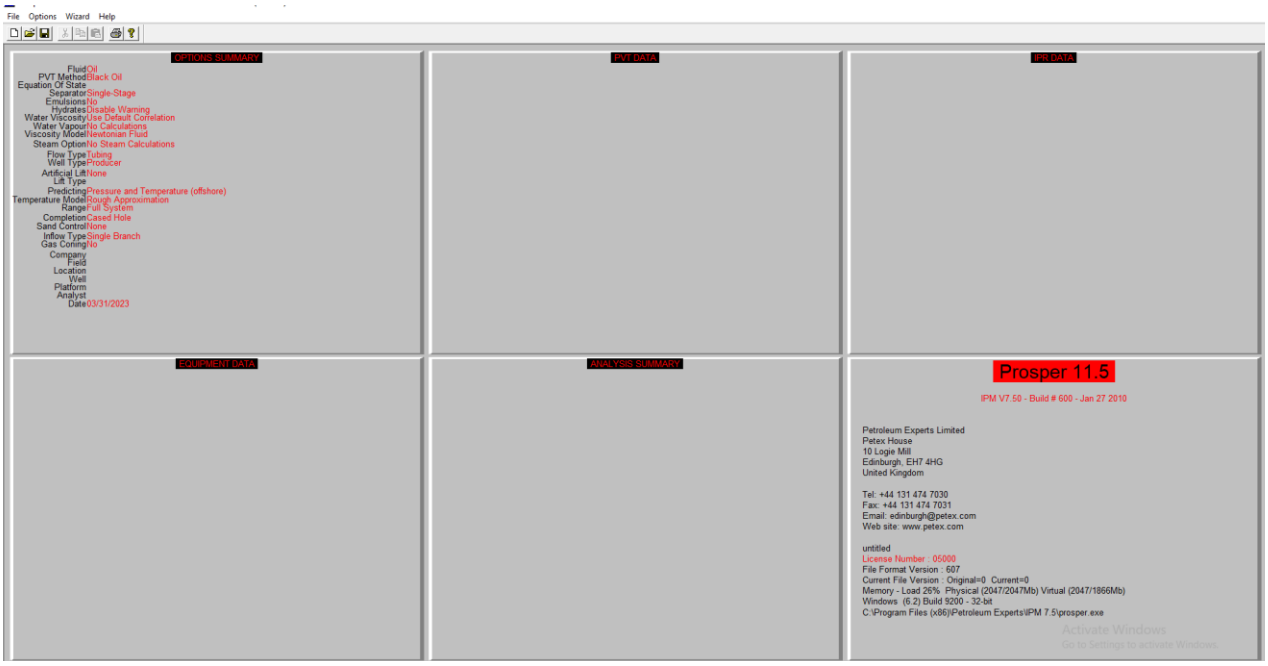


Figure 12.PROSPER Main Screen.

Model Configuration for Natural Drive Case

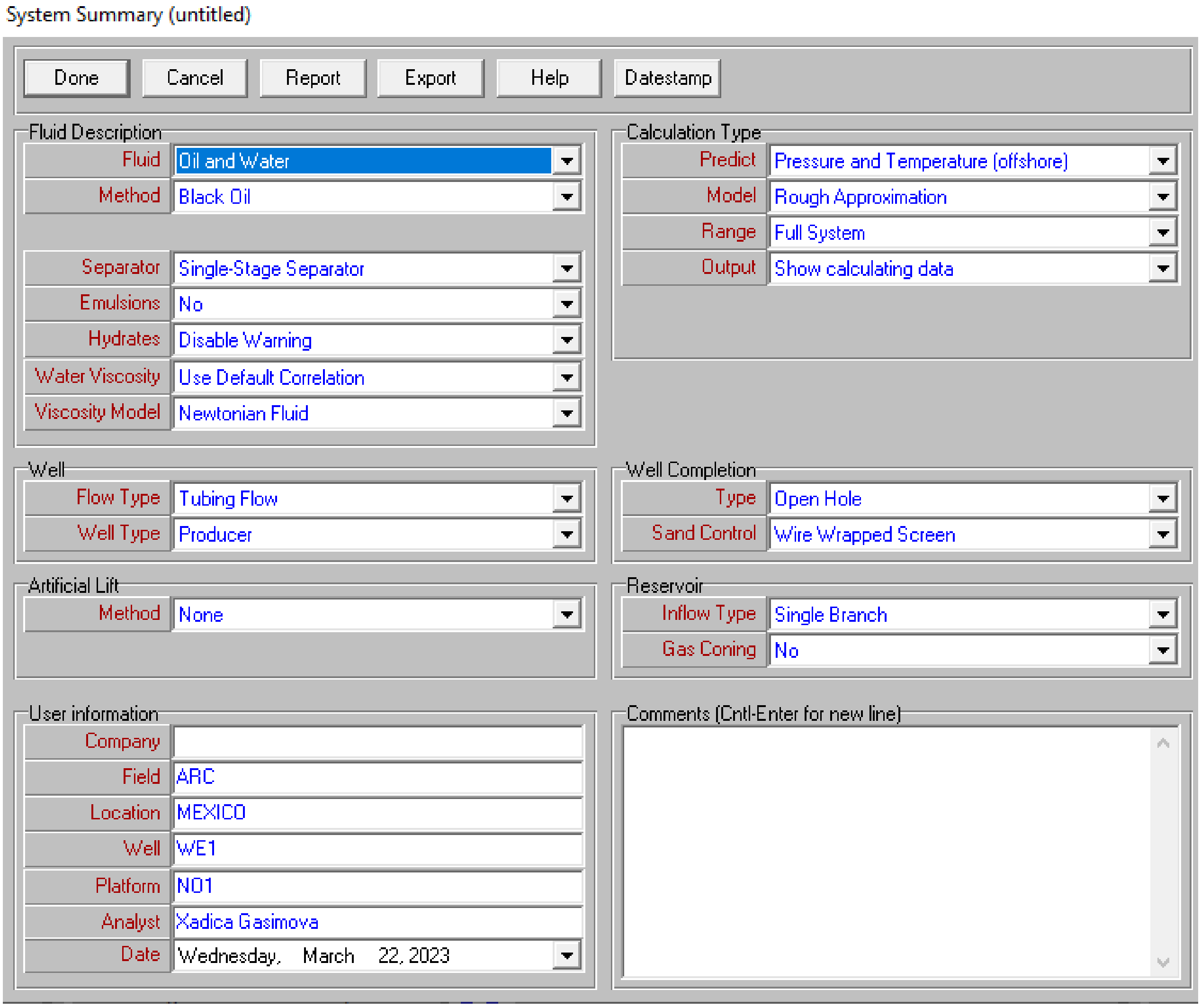


Figure 13.PROSPER Main Screen

Firstly, we pinpoint that fluid description is correctly fulfilled. Then we choose a type of flow. At the left end of the page, we can fill in information about user. When simulating fluid flow in pipelines, all phases of the rheology of the fluids moving through the wellbore are regarded as Newtonian ones. For the temperature, pressue calculations, the Rough Approximation model is selected. Because temperature variations have an impact on calculations of pressure drops, well temperature modeling is crucial. The initial model is created for a natural drive scenario, with no artificial lift mechanism chosen. To address the issue of sand output, the wells in this oilfield in Mexico are finished as open holes with wire-wrapped sand screens.

PVT data for this case

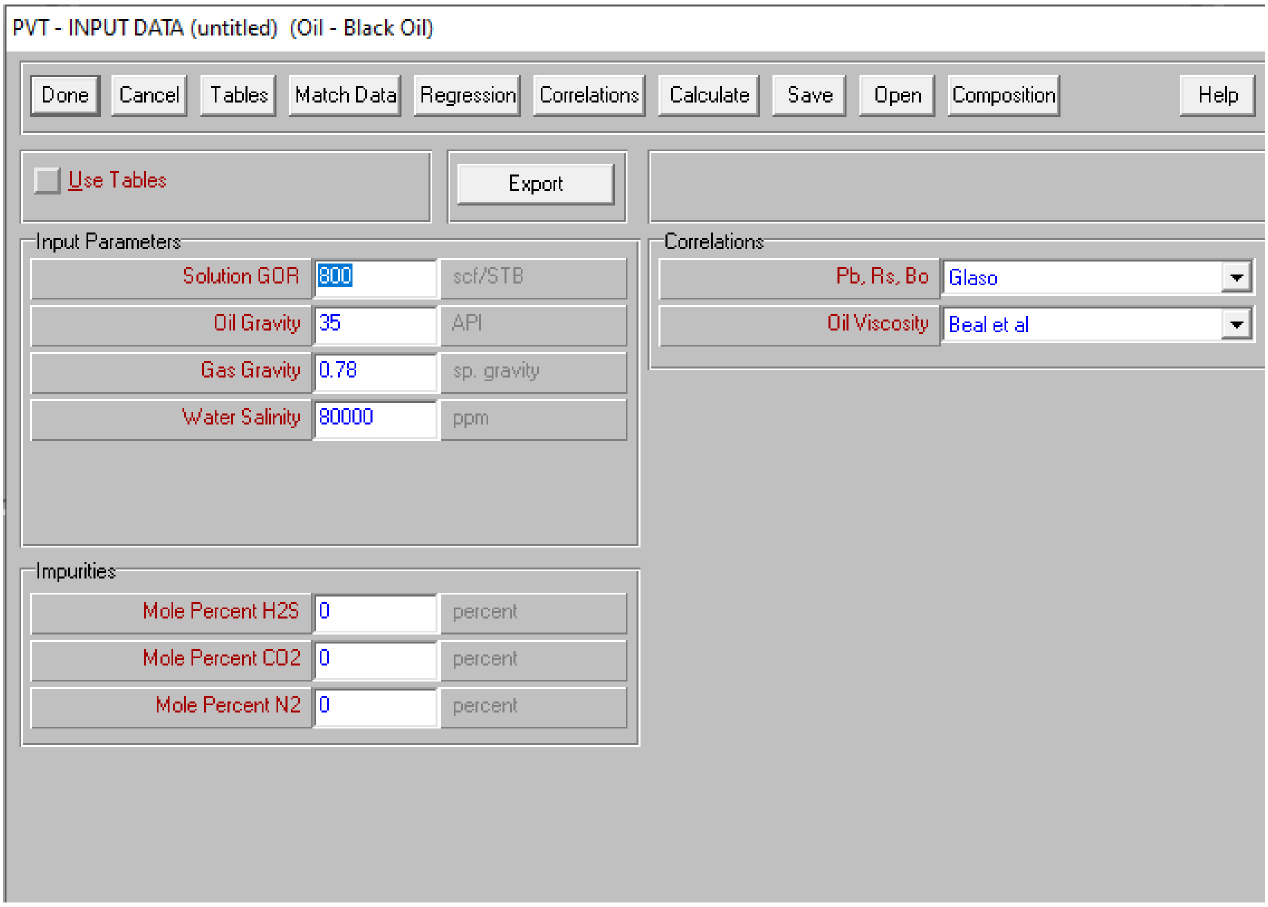


Figure 14.PVT input data

The following step is to match the existing laboratory PVT measured data with the black oil correlations. The Well WE1 PVT data entry requirements are described in this section for the chosen Black Oil model. To accurately forecast how the properties of reservoir fluid vary as a function of pressure and temperature, this input data is required. Either the basic fluid properties data can be entered into the PROSPER software along with PVT laboratory readings, and PROSPER will select the best correlation to match the measured laboratory data, or the basic fluid properties data and some traditional black oil model can be entered into the software. Many writers have constructed black oil correlations based on experimental data of various crude oil/natural gas mixes to estimate the Pb, Bo, GOR. The built-in correlations for the calculation of viscosity are those created by:

- Beal et al
- Beggs et al
- Petrosky et al

- Egbogah et al
- Bergman and Sutton

The following correlations are used in the GOR calculation:

- Glaso’s correlations
- Standing’s correlations
- Lasater’s correlations
- Vasquez and Beggs’ correlations
- Petrosky et al correlations
- Al-Marhoun’s correlations

Reservoir Inflow Performance Curve (IPR) Model

The Reservoir Inflow Performance curve is described in this part. . The practical dependence between the flow rate and the pressure drawdown, also known as the inflow performance relationship, is used to monitor the inflow to the wellbore. The software use the Vogel's model below the bubble point and the Darcy's equation above the bubble point.Vogel's method is one of the most often used techniques for creating inflow curves.The "Darcy" model is applied here. To build the IPR curve, production rates at varied drawdown pressures are used. It illustrates the reservoir's capacity to provide fluid to the well bore. With the aid of the Prosper program, a file status page that displays the application options chosen in summary format as well as entered PVT and IPR data is displayed.

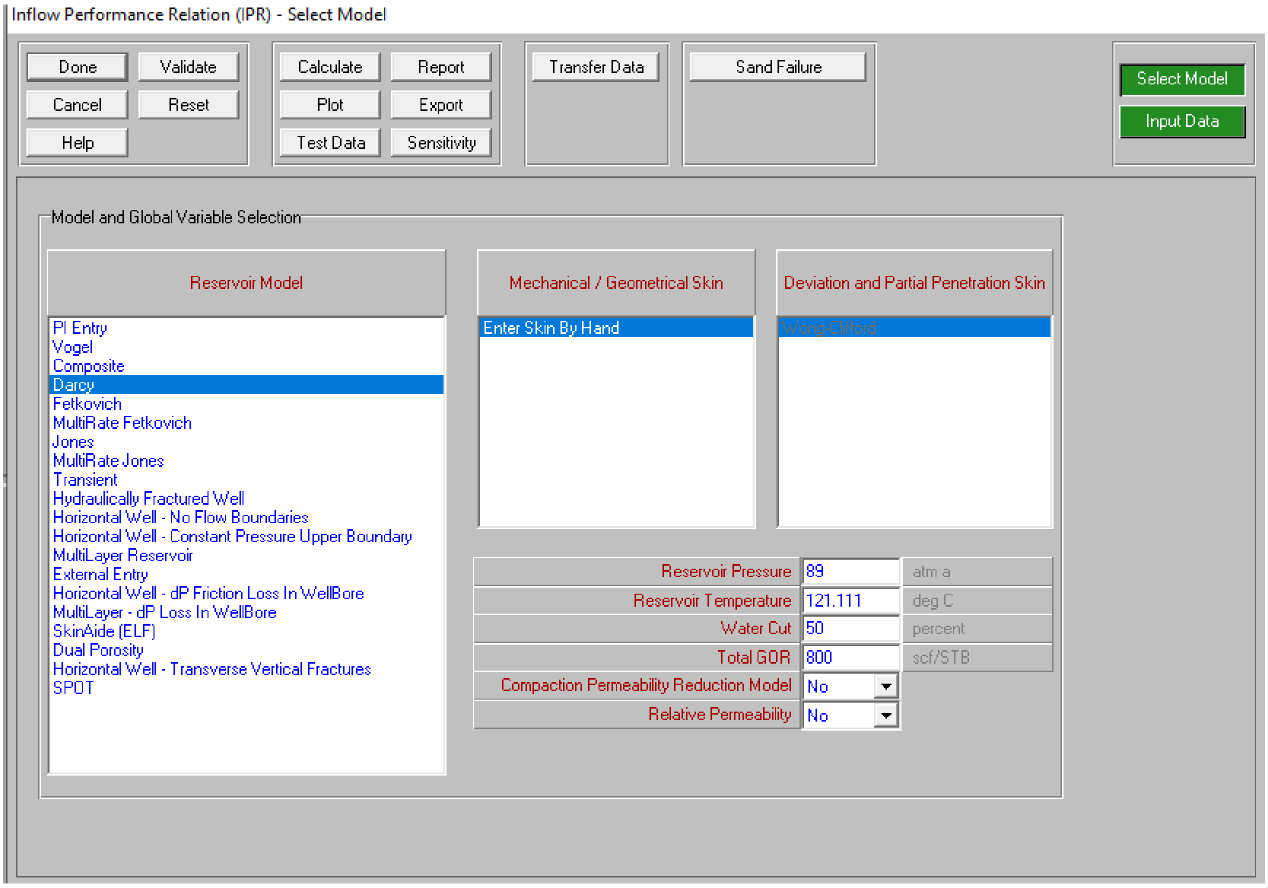


Figure 15.IPR data input

Then we click input data section and fulfill below parameters for Darcy reservoir model. When choosing the reservoir model on PROSPER, you must provide the mechanical skin value. For this simulated well, the anticipated skin value is 2. It should be mentioned that skin worth varies from well to well.

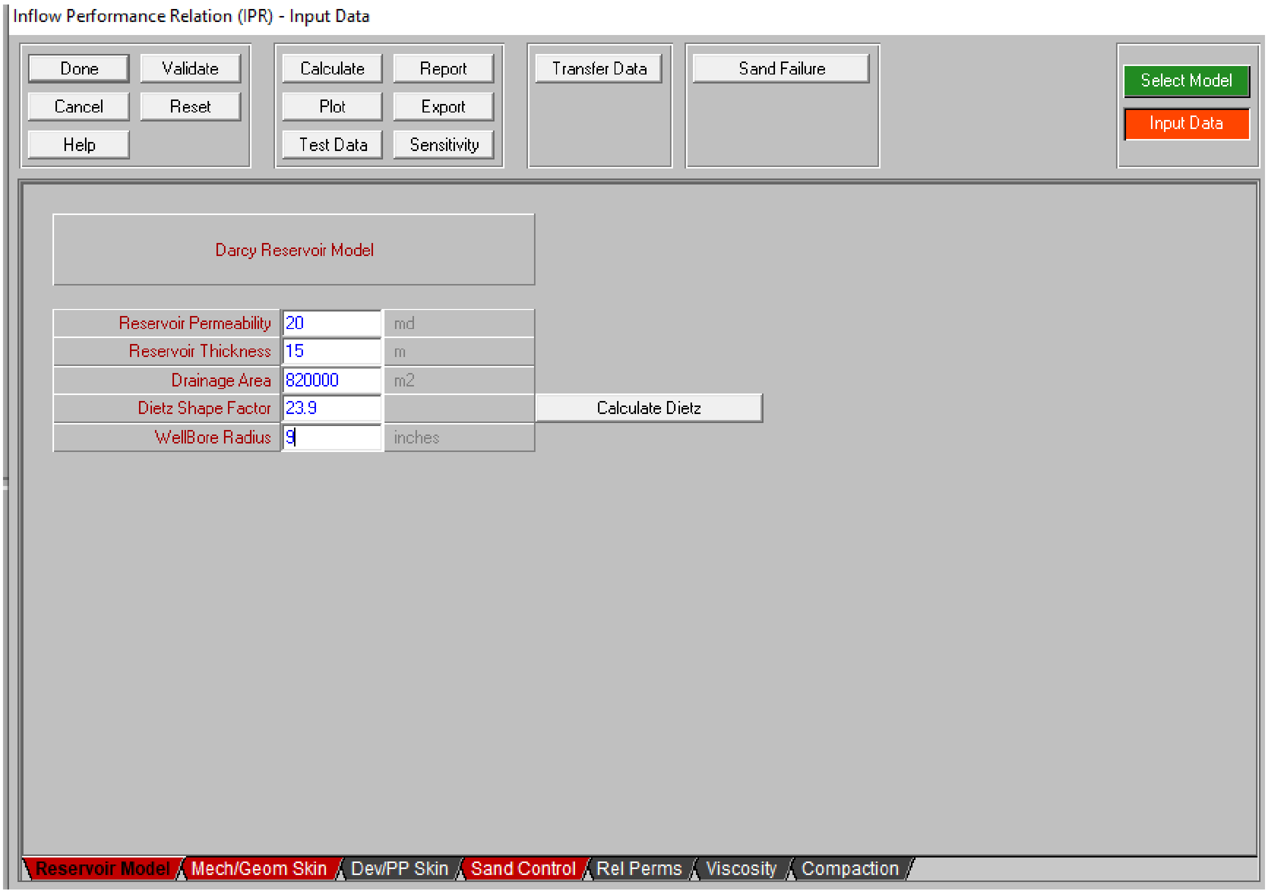


Figure 16.Model input screen for the Darcy reservoir

The essential input data for the wire-wrapped sand screen must be entered after choosing that option, as shown in the associated figure 18:

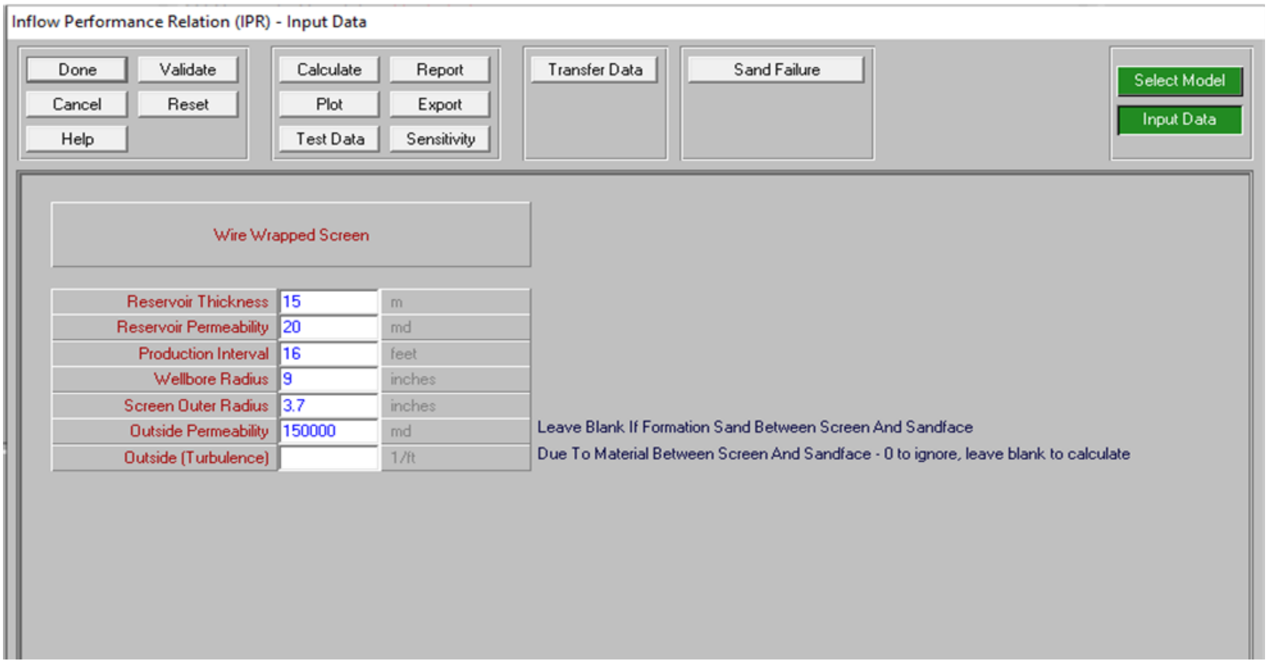


Figure 17.Wire-wrapped screen input data

The software calculates the previously mentioned PVT properties after taking into account the entirety of the available data as well as the "Calculate" option is used for building the IPR curve.

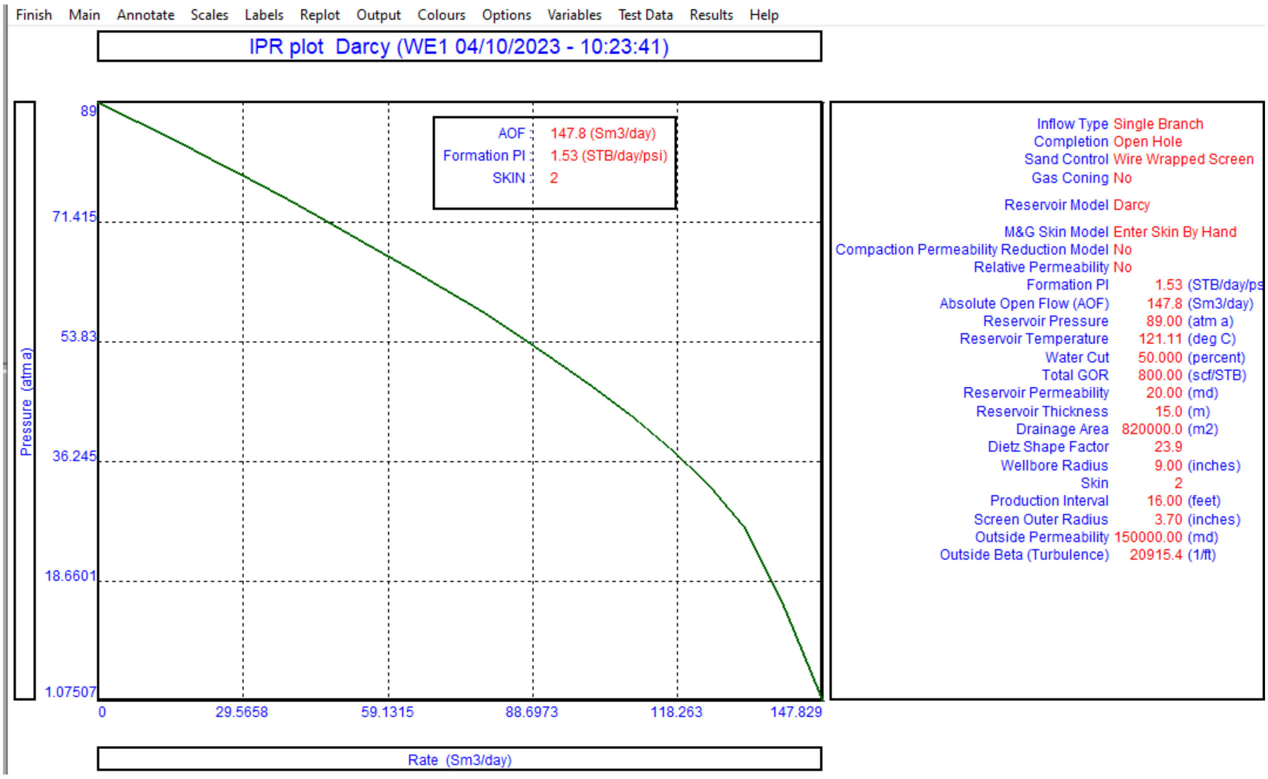


Figure 18.Plot of IPR according to Darcy Reservoir Model.

According to figure 19 observed in the above , the estimated absolute open flow (AOF) 147.8 sm3 /day and the formation productivity index (PI) is 1.53 STB/day/psi.

Equipment Data Input

A comprehensive description of the well's trajectory, surface and downhole equipment, geothermal gradient, and typical heat capacities is provided in this part of PROSPER. (Fig 20.)

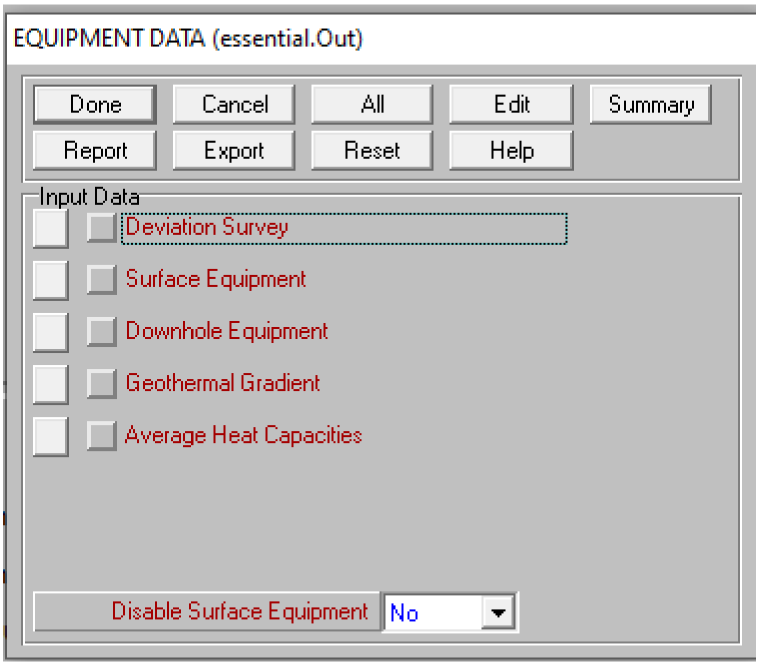
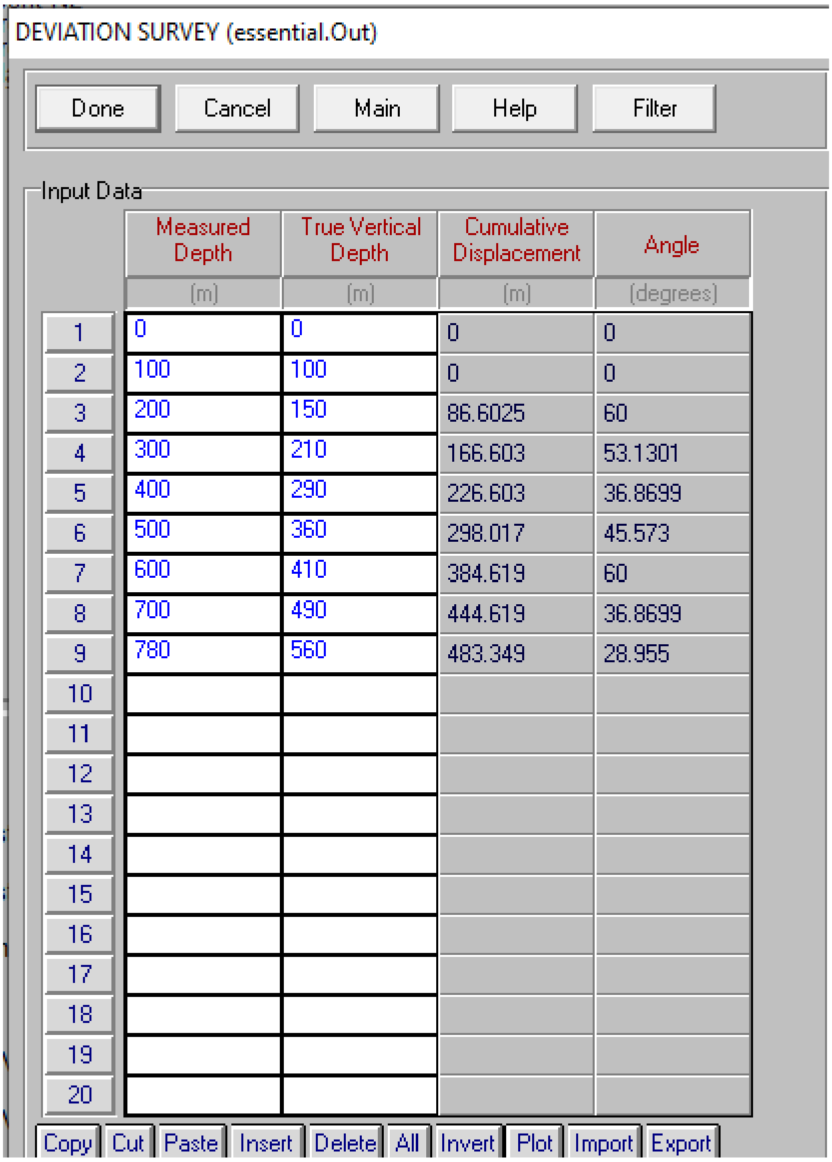


Figure 19.Equipment data input main screen

Deviation Survey

The well is a typical "build and hold," as mentioned in the introduction to the well data . A constant angle step is used to build an inclination angle below this position.

The well reaches the target depth by maintaining the necessary maximum inclination angle constant. The software needs pairs of measured depth Measured Depth (MD) and True Vertical Depth (TVD) in order to recreate the deviation survey. (TVD). TVD is the vertical distance from the point that is relevant to the surface, whereas MD is the overall length of the well (from the point of interest up to the first point of the well at the surface). PROSPER plots the well's trajectory using a linear interpolation method between two successive MD points. Two data points are adequate for each portion of the well that is straight. In this instance, as many data points as possible were added to the well's section where the inclination angle is being constructed in order to accurately represent the well's curvature. Due to the creation of a straight line in the well's concluding section, very few matches of depths were provided. Since the pressure drop due to gravity (or vertical elevation) only relies on the change in elevation and the fluid density, the well's.TVD is crucial for this calculation. Accurate MD values have a direct impact on the delicate problem of frictional pressure loss and the creation of the associated temperature profile.



	Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Angle (degrees)
1	0	0	0	0
2	100	100	0	0
3	200	150	86.6025	60
4	300	210	166.603	53.1301
5	400	290	226.603	36.8699
6	500	360	298.017	45.573
7	600	410	384.619	60
8	700	490	444.619	36.8699
9	780	560	483.349	28.955
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Figure 20.Well's trajectory description

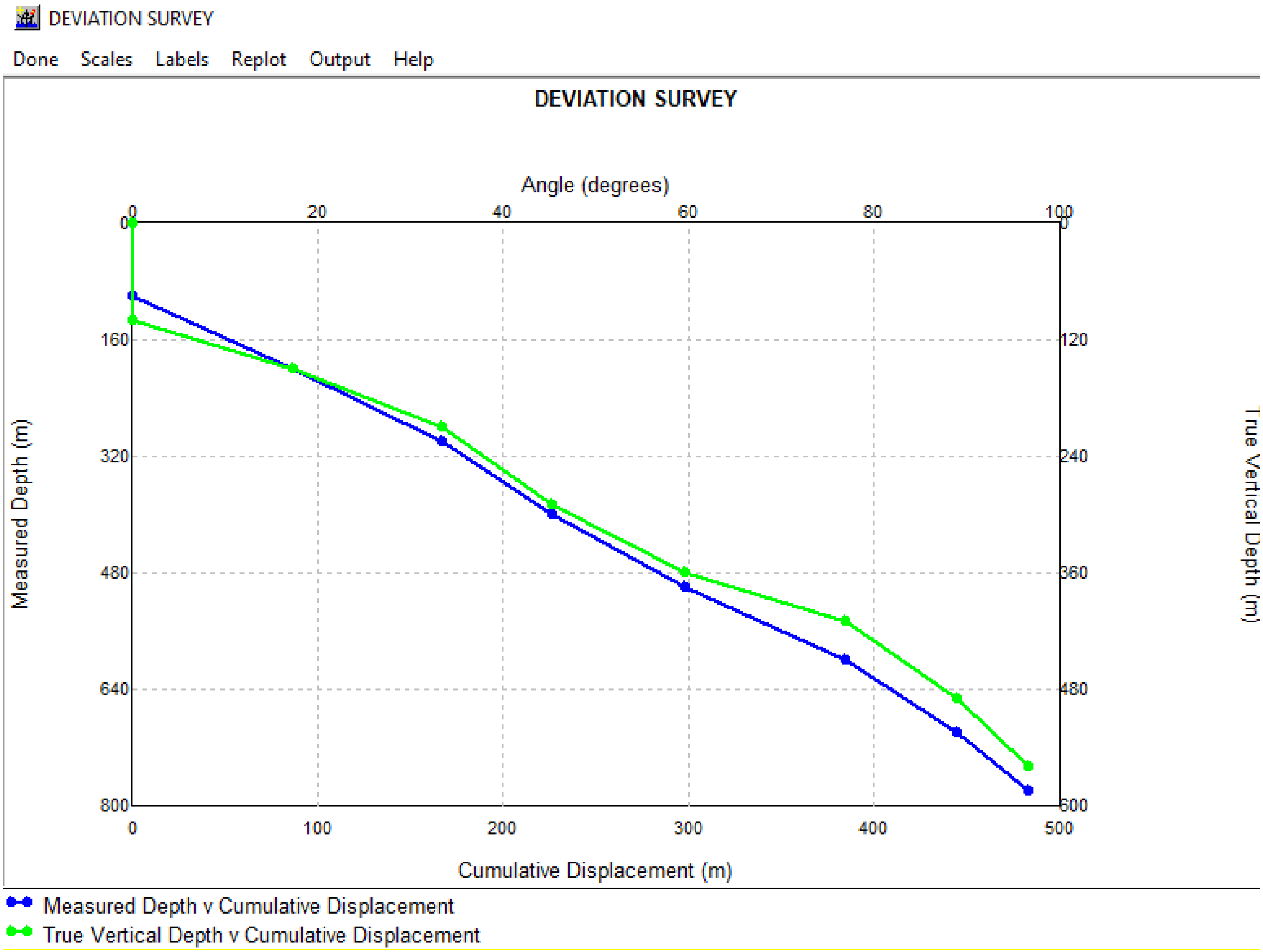


Figure 21.The well profile. The cumulative displacement is shown on the x axis, while the measured depth is shown on the y axis.

Surface equipment

The set top node for the Nodal analysis calculations was chosen to be at the wellhead because the wellhead pressure was given during the well tests. The manifold TVD was adjusted to 0' TVD as a result.

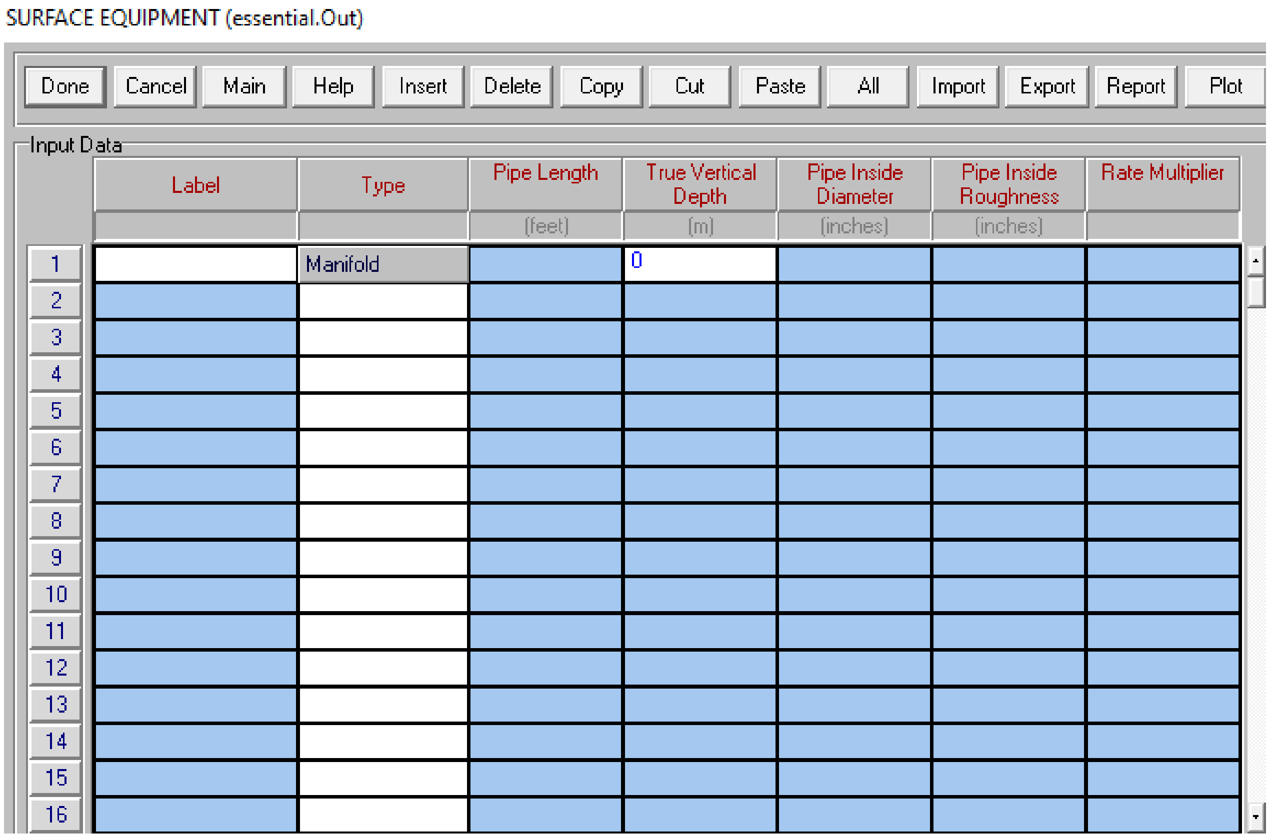
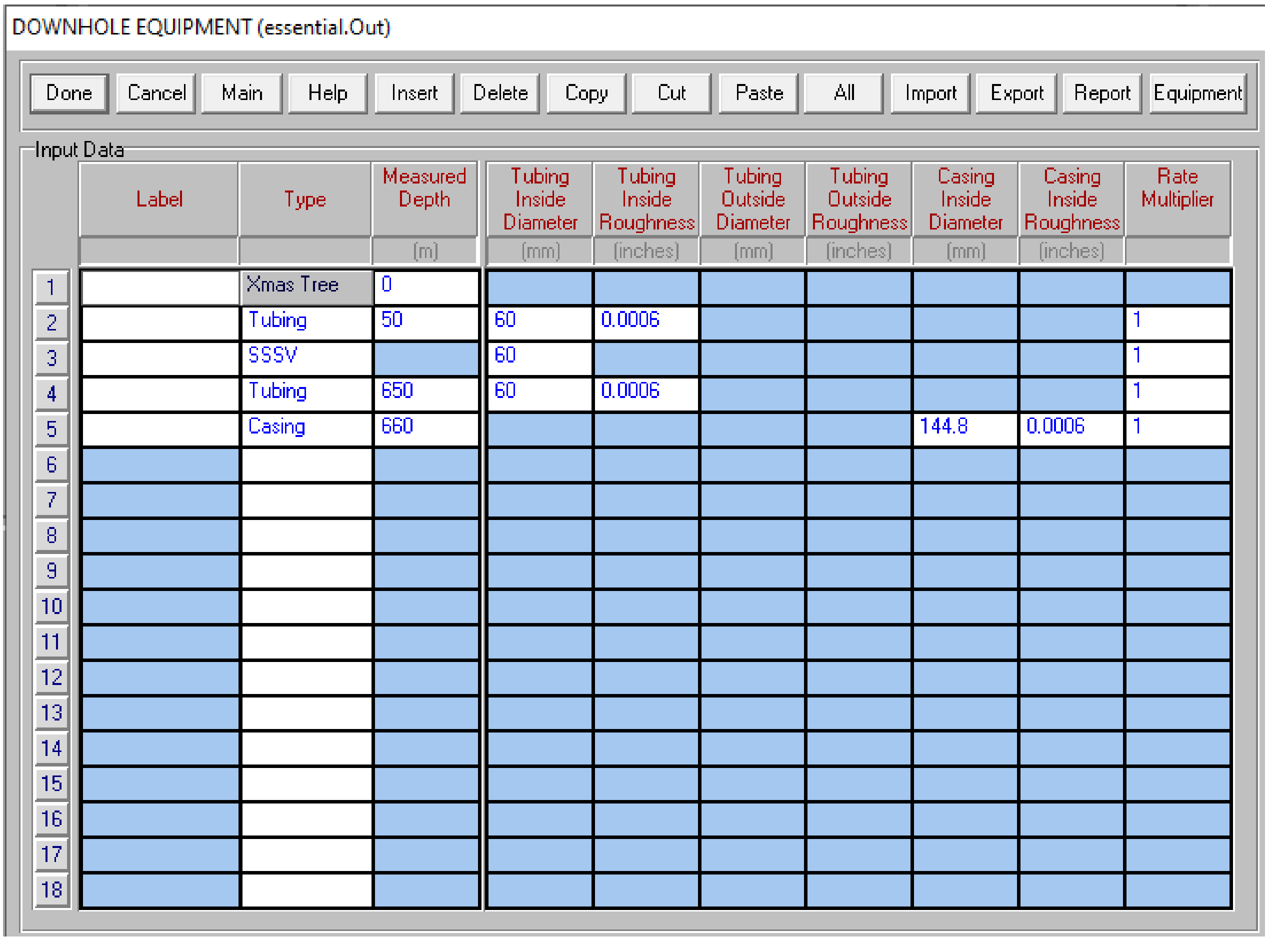


Figure 22.Surface Equipment data input screen

Downhole equipment

Calculating the VLP of the well as well as the pressure and temperature gradients requires a description of the well's equipment, similar to the deviation study. As was previously mentioned, the "Rough Approximation" model's computations are dependent on the tubing ID. In order to calculate frictional pressure losses during manufacturing, the ID and interior roughness of the tubing are also used. In addition, wells on the this oilfield have a 144.8 mm ID (Inside Diameter) / 177.8 mm OD (Outside Diameter) casing that is placed at the top of the reservoir section before a 142.9 mm open hole section is drilled through the reservoir interval. The reservoir portion is next traversed by a wire-wrapped sand filter measuring 122.7 mm OD, which is then hung inside the 169.8 mm casing. Finally, 68 mm OD/60 mm ID production tubing is dropped about 5 meters above the sand screen packer. Because the completion of this oilfield required only a single production tubing, the rate multiplier value was kept at 1. The downhole machinery for the model well on PROSPER is schematically illustrated in the accompanying figure.


DOWNHOLE EQUIPMENT (essential.Out)

Done | Cancel | Main | Help | Insert | Delete | Copy | Cut | Paste | All | Import | Export | Report | Equipment

Input Data

	Label	Type	Measured Depth (m)	Tubing Inside Diameter (mm)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (mm)	Tubing Outside Roughness (inches)	Casing Inside Diameter (mm)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	50	60	0.0006					1
3		SSSV		60						1
4		Tubing	650	60	0.0006					1
5		Casing	660					144.8	0.0006	1
6										
7										
8										
9										
10										
11										
12										
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14										
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Figure 23.Downhole Equipment data input screen

Below (Fig.24) is a graphic illustration of the downhole equipment as determined by PROSPER:

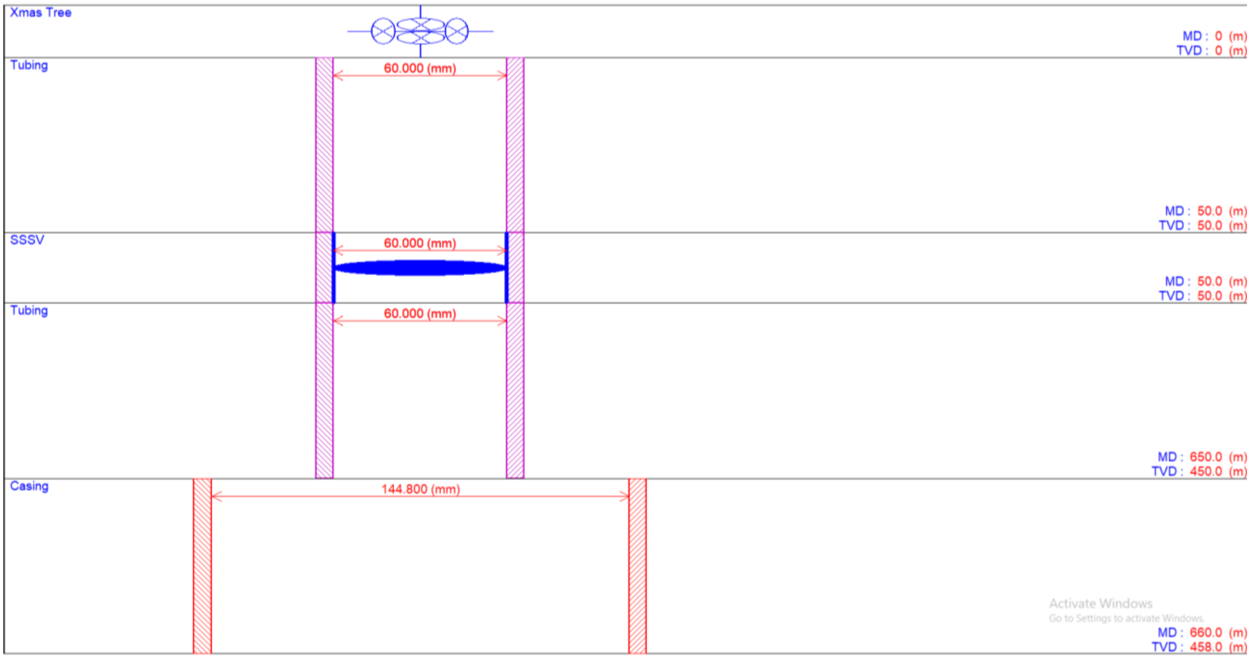


Figure 24.Simple schematic of the downhole equipment

Geothermal gradient

PROSPER can calculate the creation temperature at any depth using the geothermal gradient. By including the known temperatures at the surface and in the reservoir, it is possible to approximate the temperature curve roughly. A measured depth or a true vertical depth can be used to describe the depth at which each temperature is recorded. Following a linear interpolation of all the user-provided points, PROSPER models the temperature distribution of the formation at different depths. At least two data values must be added due to the linear interpolation. The predefined number of 7.8 is chosen for the model's total heat transfer coefficient.

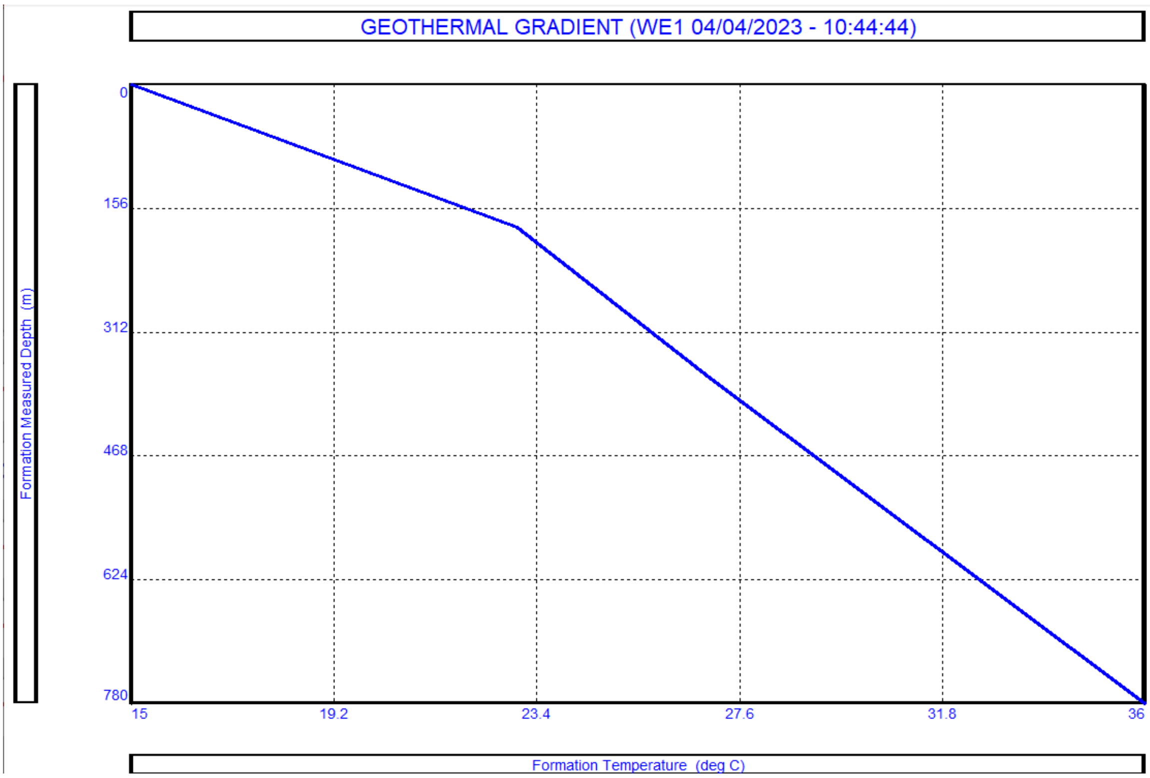


Figure 25.Plot of a geothermal gradient

Average heat capacities

The "Rough Approximation" temperature model calculates the heat released when the fluid changes temperature using the typical heat capacities of water, oil, and gas. The default values of Cp for oil, water, and gas can be used to provide a good estimate. However, since their composition varies and their properties consequently change with depth, it should be noted that Cp for oil and gas is not a constant number. (Figure 27.)

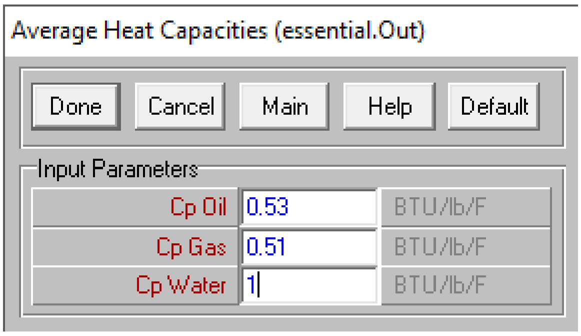


Figure 26.Average heat capacities data input screen

System computations

The last stage on PROSPER is the generation of VLP and IPR curves, as well as the determination of the solution node, which is the intersection point of these two curves. The input parameters are used to calculate the reservoir response (IPR curve) and the tubing response (VLP curve) in this case. PROSPER system calculations and solution node details are depicted in the image below.

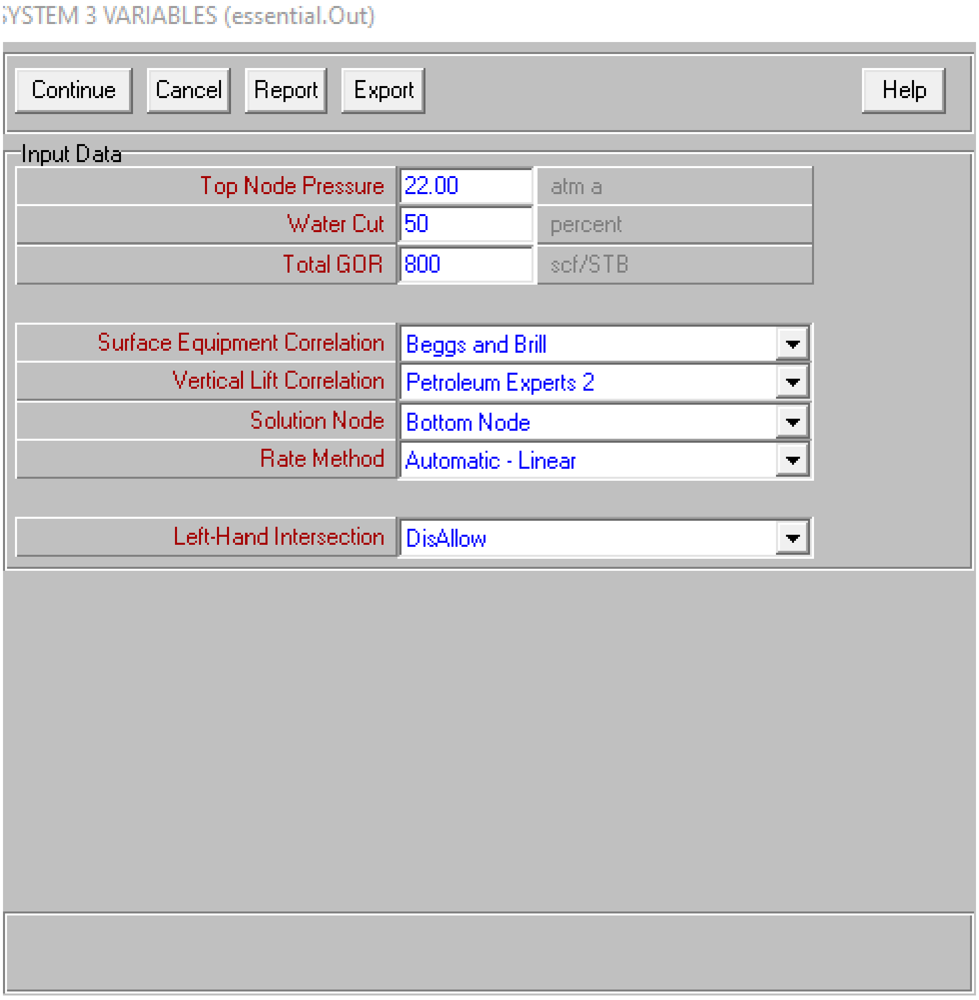


Figure 27.Data input screen for system computations

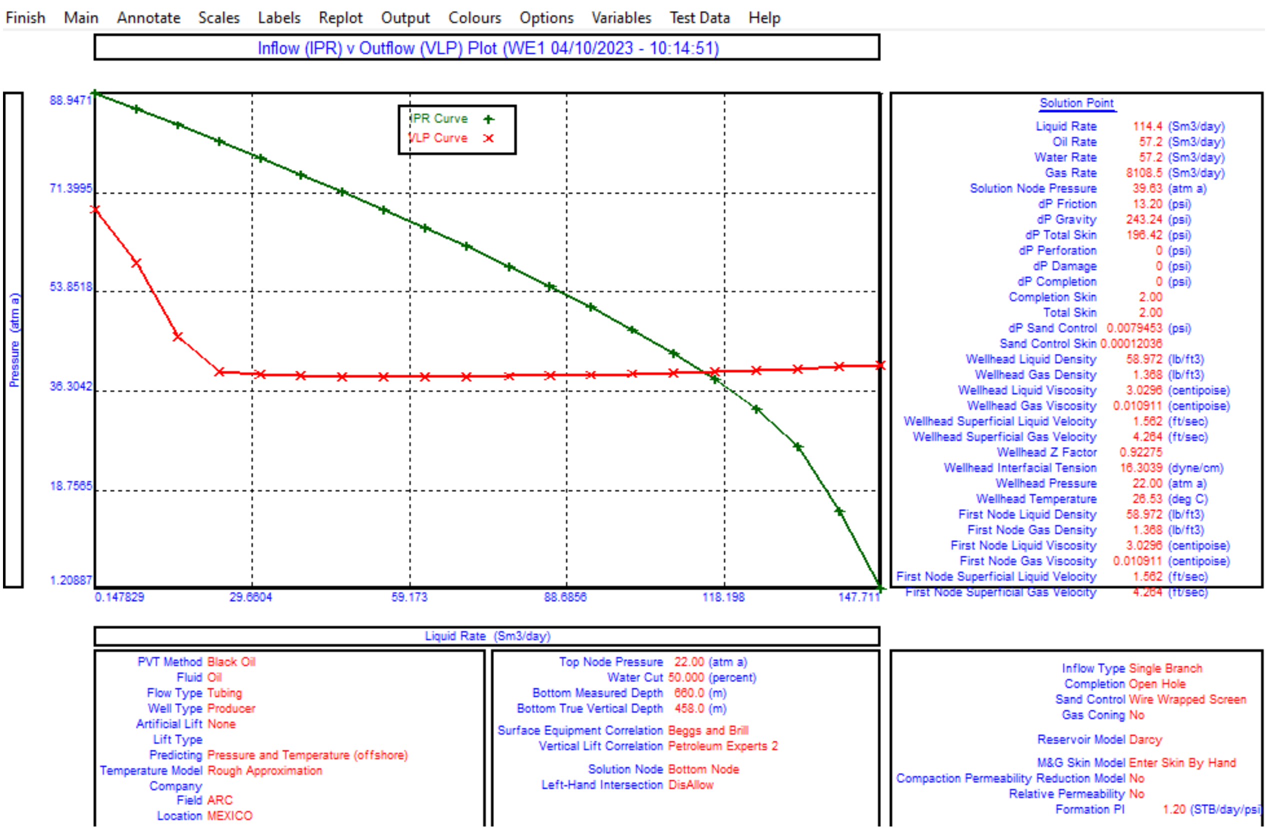


Figure 28.IPR and VLP curves for the natural drive situation

The oil rate and bottom hole flowing pressure (BHFP) are 57.2 sm^3 /day and 39.63 atm, respectively, as shown in the image above. It implies that depending on the input parameters, the designed well can flow naturally. The table that comes with it also contains information about the solution nodes:

Table 8.Details of the solution node for a naturally flowing well

Amount	Unit	Parameter
114.4	sm^3 /day	Liquid Rate
57.2	sm^3 /day	Oil Rate
54.2	sm^3 /day	Water Rate
8108.5	sm^3 /day	Gas Rate
39.63	atm	Solution Node Pressure
13.20	psi	dP Friction
243.24	psi	dP Gravity

Simulated results of altered reservoir pressure, water cut, and GOR

Resulting from a change in reservoir pressure

In order to do the effect of pressure reduction on outflow performance, the program is given three different reservoir pressure values in addition to the existing reservoir pressure of 89 atm, and the computed results are shown in the table below:

Table 9.System sensitivity analysis conclusions regarding reservoir pressure depletion

Parameter	Reservoir Pressure (89 atm)	Reservoir Pressure (70 atm)	Reservoir Pressure (60 atm)	Reservoir Pressure (37 atm)	Unit
Liquid Rate	114.4	67.8	49.9	-------	sm^3/day
Oil Rate	57.2	33.9	24.9	-------	sm^3 /day
Water Rate	50.9	31.9	22.9	-------	sm^3 /day
Gas Rate	8108.5	4803.7	3533.9	--------	sm^3 /day

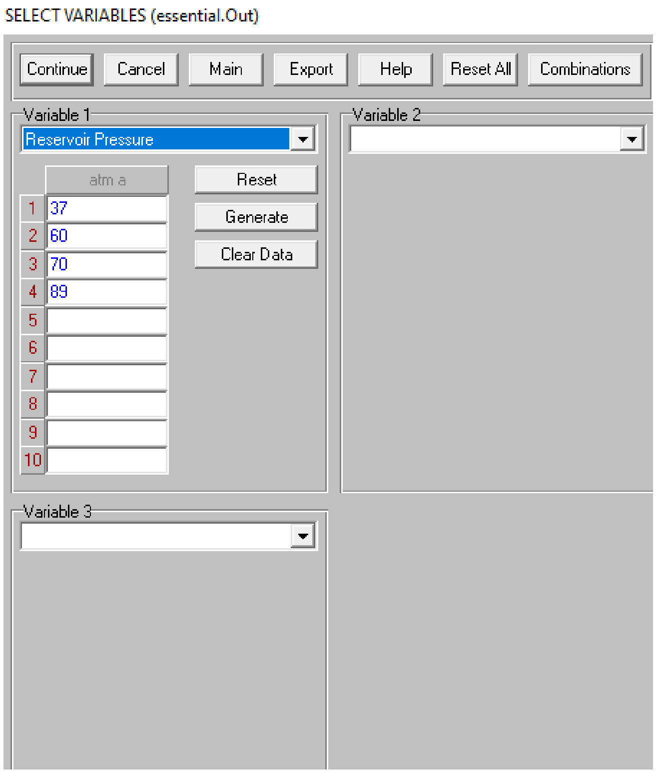


Figure 29.Variables selection screen

The statistics shown in the table above make it readily apparent that when reservoir pressure falls, so does well production rate. The well won't flow naturally, though, if the reservoir pressure drops to 39 atm since the point where it converges between the IPR curve and VLP curve won't be reached (Figure 31.) Impacts of changing reservoir pressure on IPR & VLP curves.

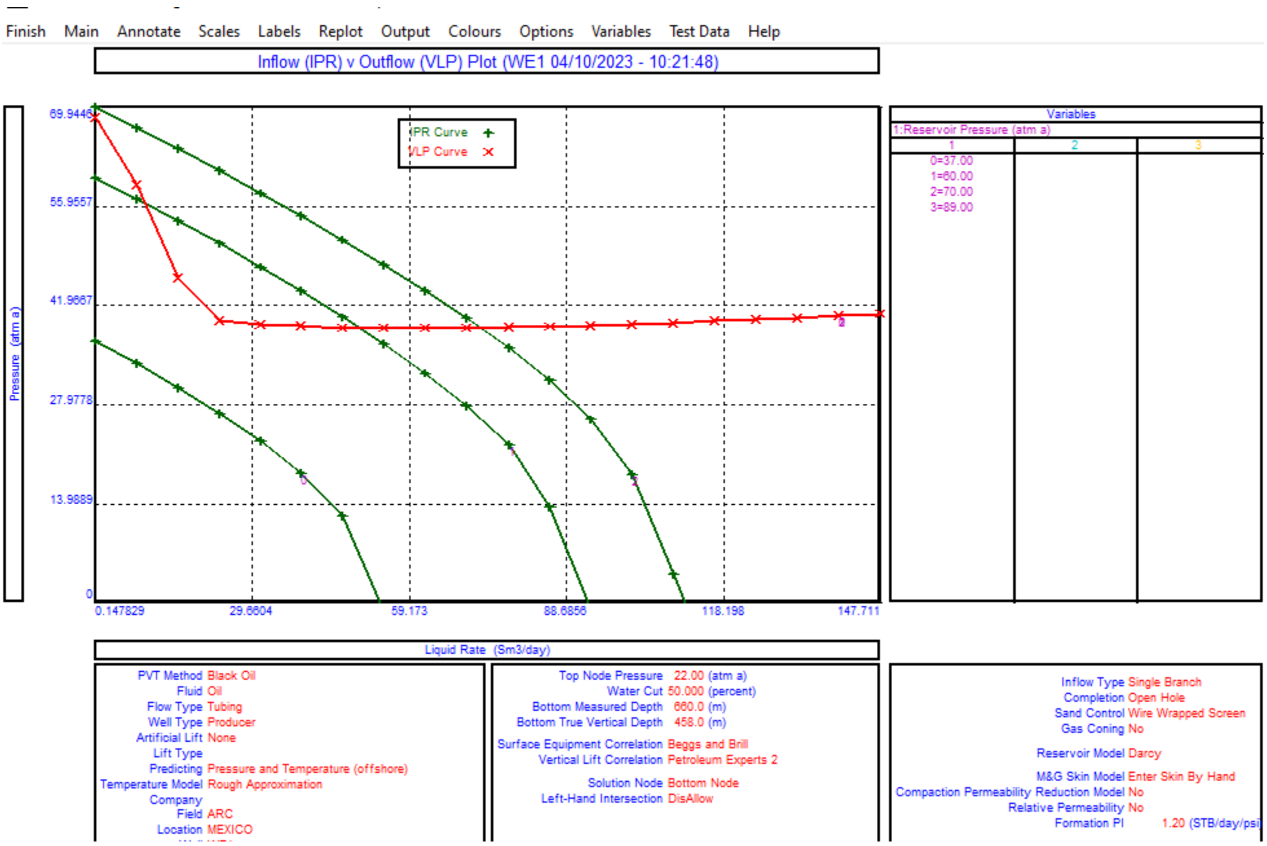


Figure 30.Impacts of changing reservoir pressure on IPR & VLP curves

Resulting from a change in Water Cut

The software displays three possible reservoir water cut values in addition to the current water cut, which is 50%, and the computed outcomes are shown in the table below.

Table 10.System sensitivity analysis outcomes with regard to increasing water cut.

Parameter	Water Cut (50%)	Water Cut (60%)	Water Cut (70%)	Unit
Liquid Rate	114.4	113.3	108.7	sm^3 /day
Oil Rate	57.2	45.3	32.6	sm^3/day
Water Rate	50.9	68	76.1	sm^3/day
Gas Rate	8108.5	6425.8	4622.0	sm^3 /day

Constantly expanding water cut causes a decrease in the rate of both oil production and water production (total liquid production), as greater pressure is required to get heavier fluids to the top due to an increase in water cut in the reservoir.

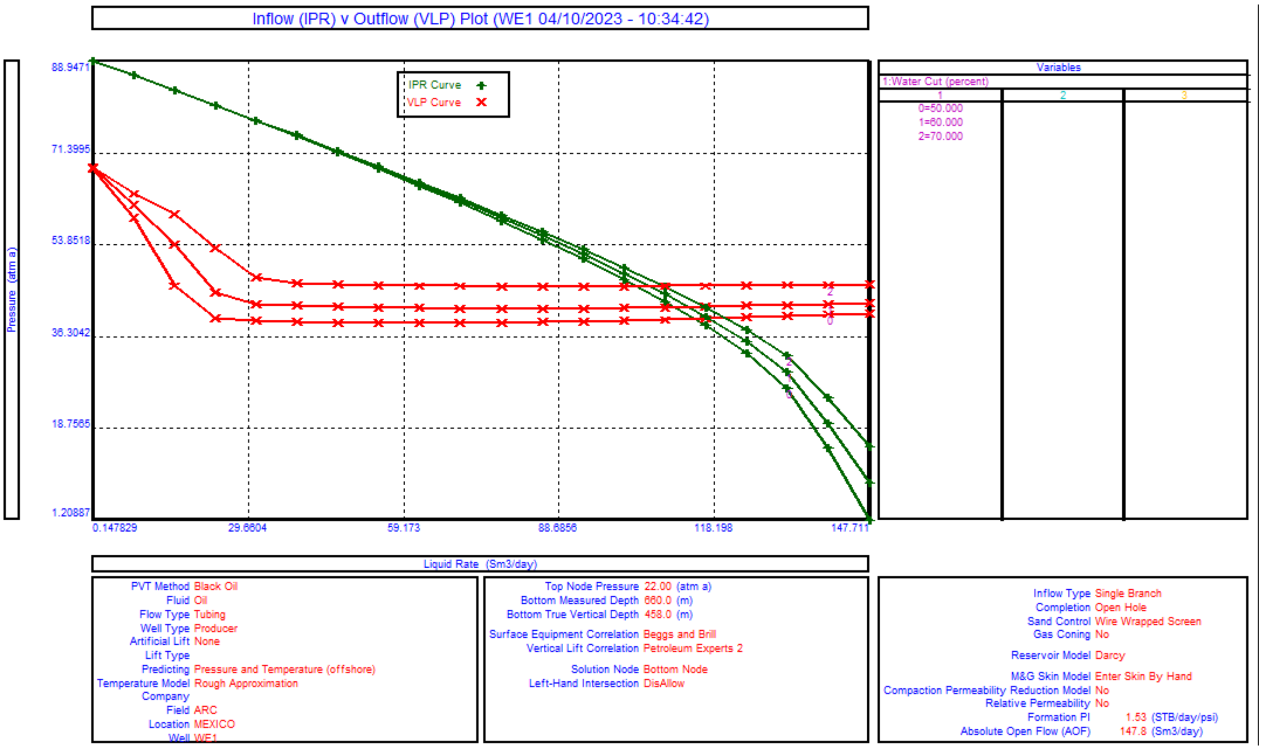


Figure 31.Impacts of increasing water cut on IPR & VLP curves.

Model Configuration for ESP Case

This part goes into detail on the ESP design process for various reservoir pressures and water cut levels. In Chapter 2, fundamental information and the ESP's operating concept were already discussed. Consequently, a well with ESP is modelled using PROSPER in this part by doing the following steps:

System summary for ESP design case

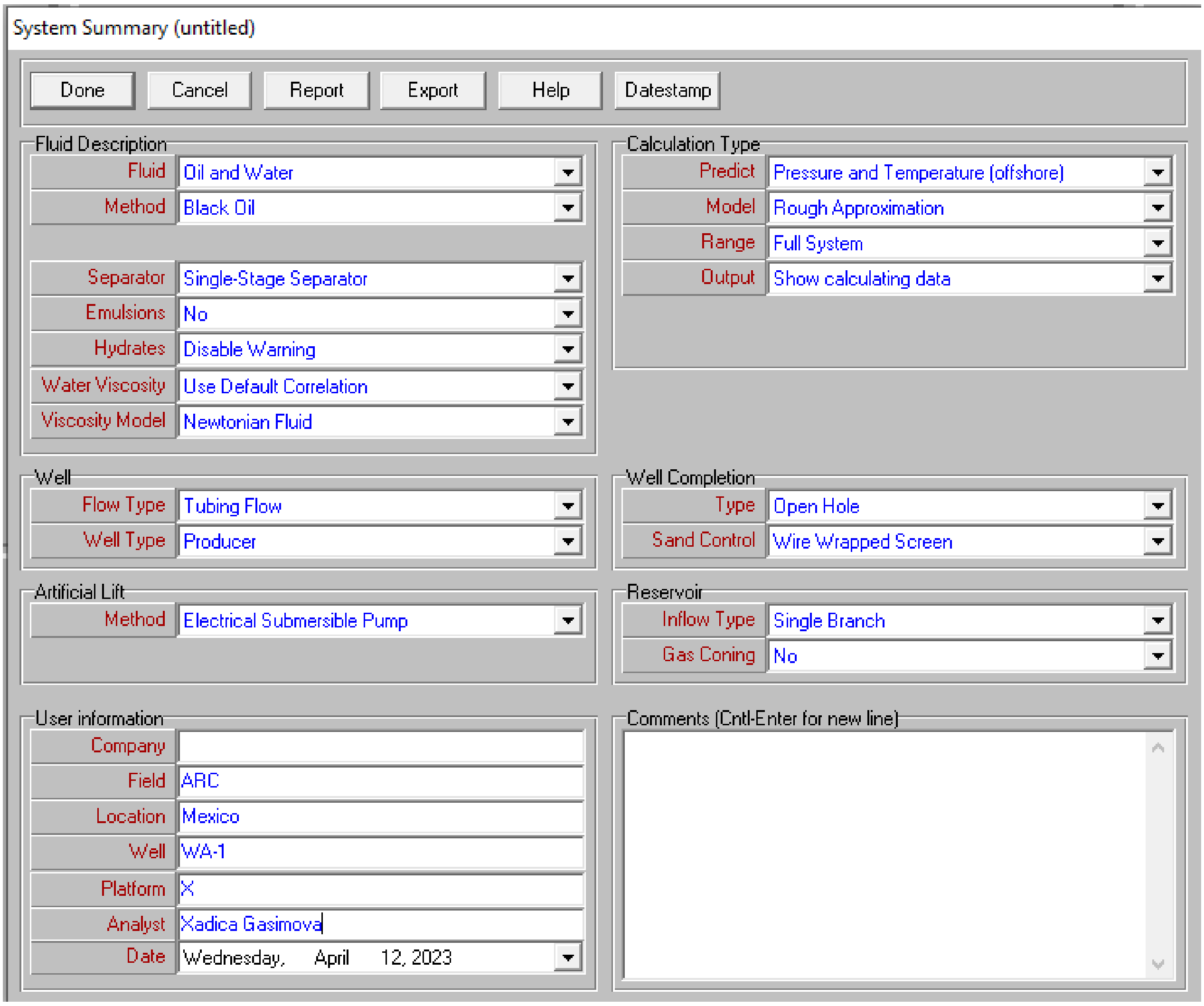


Figure 32.System Summary for ESP on PROSPER

PVT and IPR data for ESP case

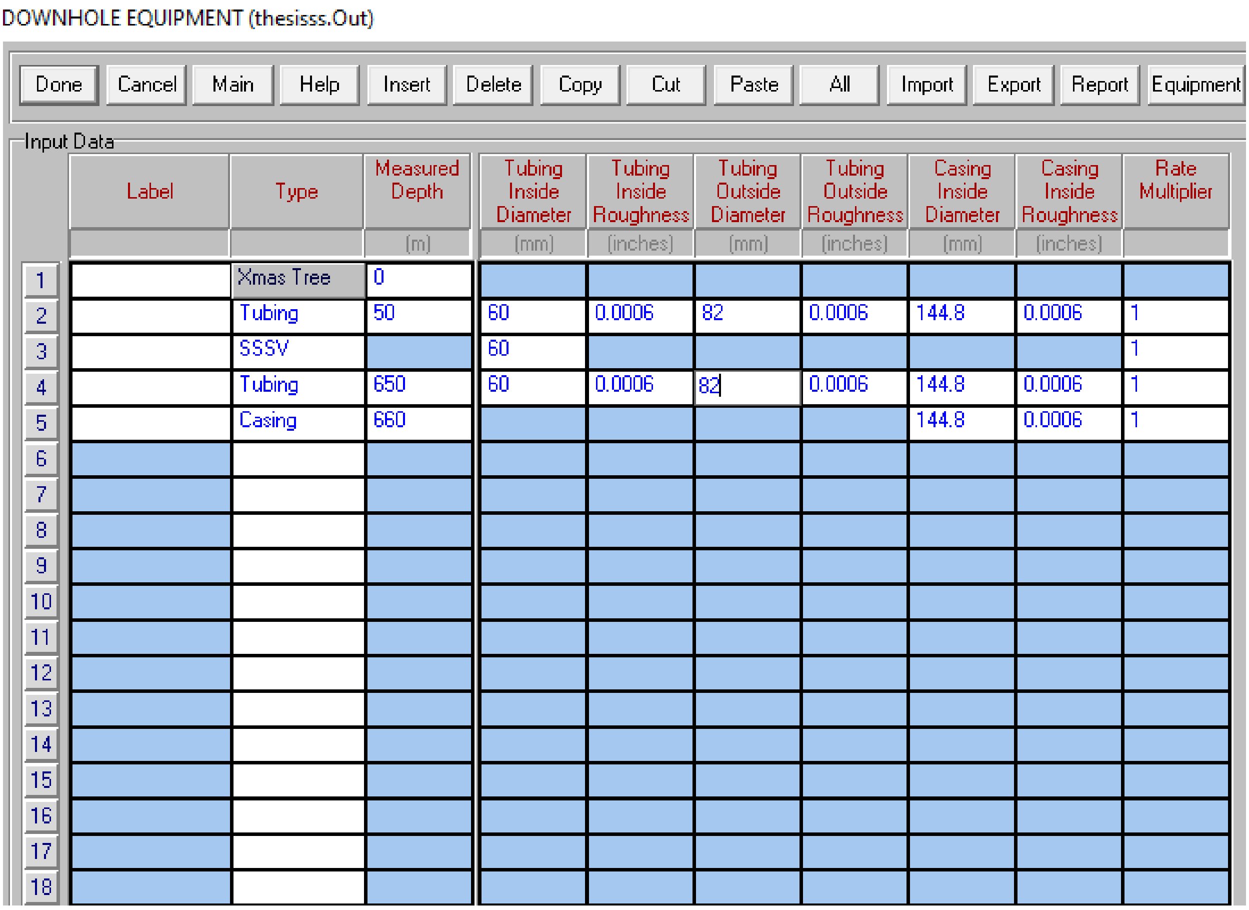
The two parts are the same as they were in the Natural Drive Case.

Equipment Data

Except for the downhole equipment, where the tubing outer diameter must be filled to conduct ESP design, all subsections in this component stay unchanged

Downhole equipment

The following figure shows a screen capture from the section on downhole equipment:



DOWNHOLE EQUIPMENT (thesisss.Out)

Done | Cancel | Main | Help | Insert | Delete | Copy | Cut | Paste | All | Import | Export | Report | Equipment

Input Data

	Label	Type	Measured Depth (m)	Tubing Inside Diameter (mm)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (mm)	Tubing Outside Roughness (inches)	Casing Inside Diameter (mm)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	50	60	0.0006	82	0.0006	144.8	0.0006	1
3		SSSV		60						1
4		Tubing	650	60	0.0006	82	0.0006	144.8	0.0006	1
5		Casing	660					144.8	0.0006	1
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Figure 33.Data for the ESP case's downhole equipment

ESP design process

The PROSPER model requires that the PVT data be matched with the matching parameters using the appropriate correlation. There are numerous relationships that might be relevant. In order to get the optimal correlation to represent the features of the reservoir fluid, Prosper software will go through numerous iterations.

The primary input information for the ESP design stage is found in this section. Here, the ESP design window has specific settings as follows:

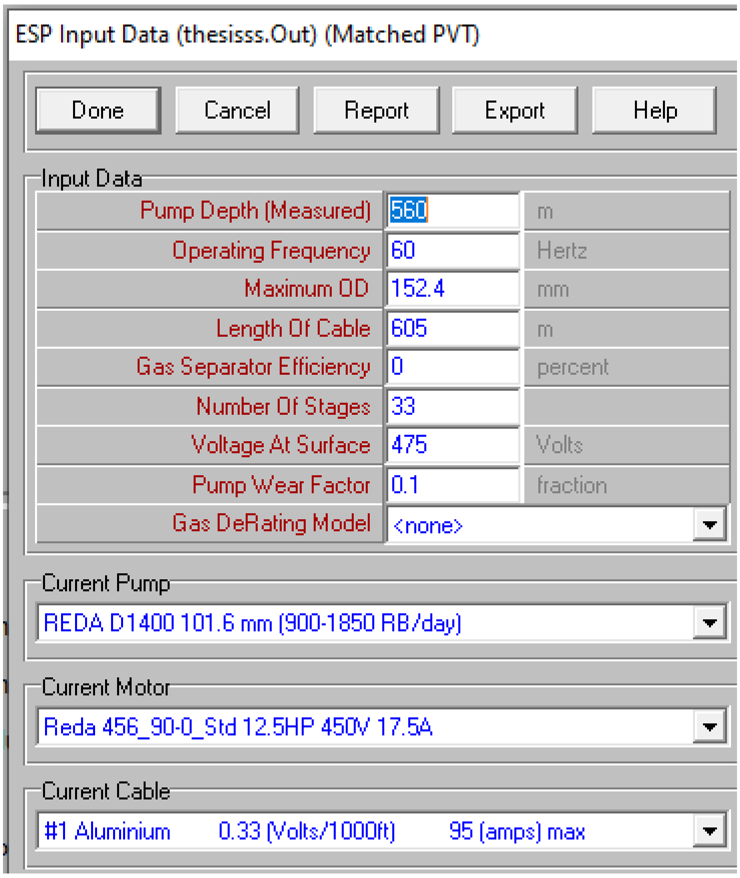


Figure 34.ESP design input data screen

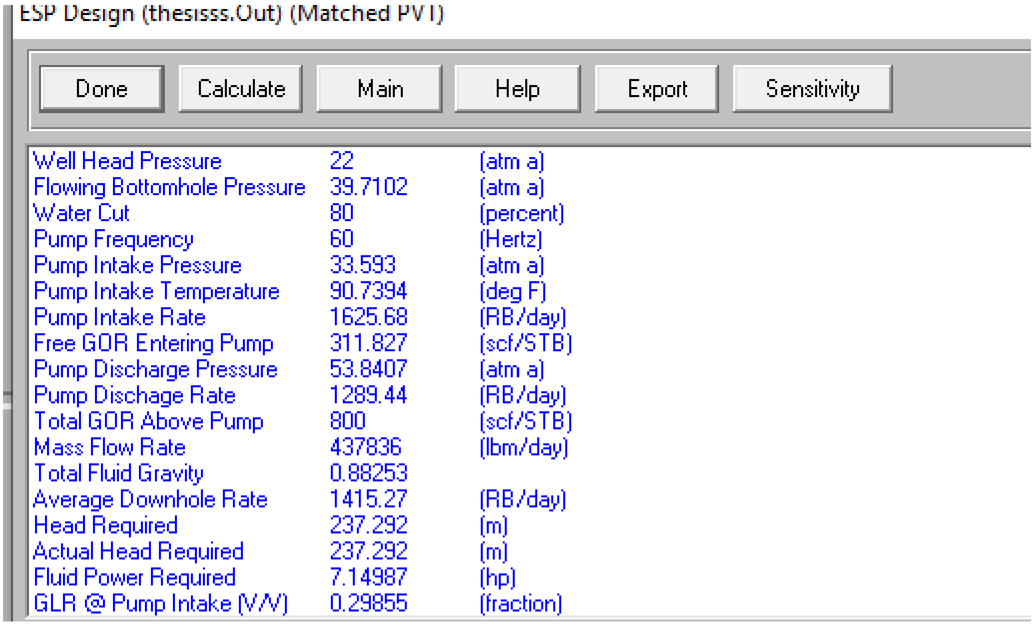
The frequency of the pump is chosen at 60 hertz since electrical submersible pumps typically run at this frequency.

When there is free gas and a gas separator is put at the pump inlet, the gas separator efficiency displays how well the gas is separated. It can be left at 0, and the Dunbar Criterion will be used to determine whether or not this input value is appropriate for this design. It should be noticed that when the design operating point is above the red line representing the Dunbar Factor, the inserted gas separator efficiency value is satisfactory and a downhole gas separator is not required.

Pump wear factor, which takes wear into account, calculates the difference between the specified pump performance and the manufacturer's performance curve.Typically, a wear factor of 0.1 is included to mimic a 10% reduction in the necessary pump head.

To exceed pump motor power requirements, a safety margin for motor power is included. A safety margin of 10% is added to the required pump motor power based on industrial experience.

Following the inclusion of the necessary parameters, ESP design calculations are carried out, and all the parameters required to choose a suitable pump system are displayed on the screen:



Well Head Pressure	22	(atm a)
Flowing Bottomhole Pressure	39.7102	(atm a)
Water Cut	80	(percent)
Pump Frequency	60	(Hertz)
Pump Intake Pressure	33.593	(atm a)
Pump Intake Temperature	90.7394	(deg F)
Pump Intake Rate	1625.68	(RB/day)
Free GOR Entering Pump	311.827	(scf/STB)
Pump Discharge Pressure	53.8407	(atm a)
Pump Dischage Rate	1289.44	(RB/day)
Total GOR Above Pump	800	(scf/STB)
Mass Flow Rate	437836	(lbm/day)
Total Fluid Gravity	0.88253	
Average Downhole Rate	1415.27	(RB/day)
Head Required	237.292	(m)
Actual Head Required	237.292	(m)
Fluid Power Required	7.14987	(hp)
GLR @ Pump Intake (V/V)	0.29855	(fraction)

Figure 35. Results of the ESP design calculation

Sensitivity Analysis for Gas Separation:

This stage is followed by a sensitivity analysis to determine whether a downhole gas separator is necessary. The relationship that exists between pump input pressure and gas liquid ratio is depicted in the next figure, with the operating point indicated in dark blue:

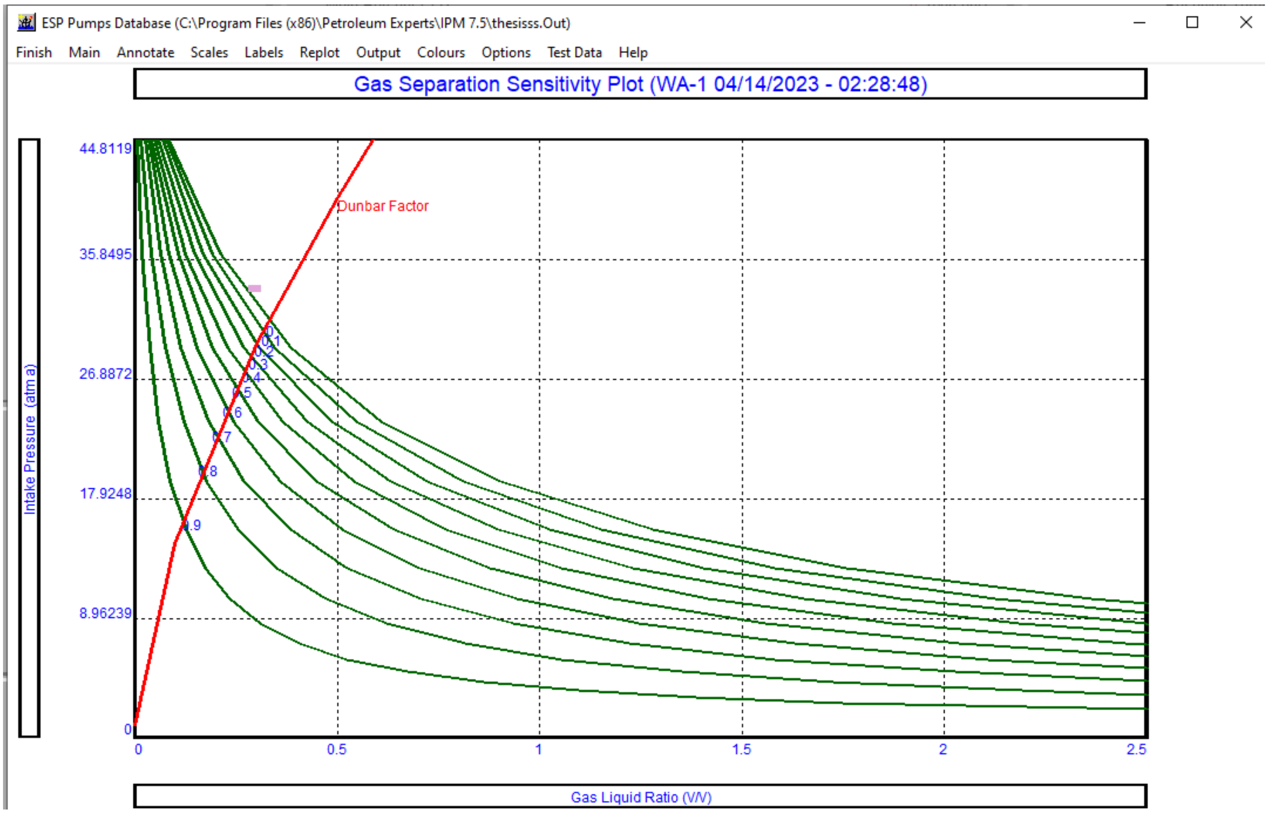


Figure 36.Gas Separation Sensitivity Check-1

Match point is given in purple. The design operating point is, as can be determined from the figure, just above the red-lined Dunbar Factor line. If we implies downhole gas separator ,due to this, a gas separator efficiency of 50% is selected, and a new sensitivity assessment is carried out.

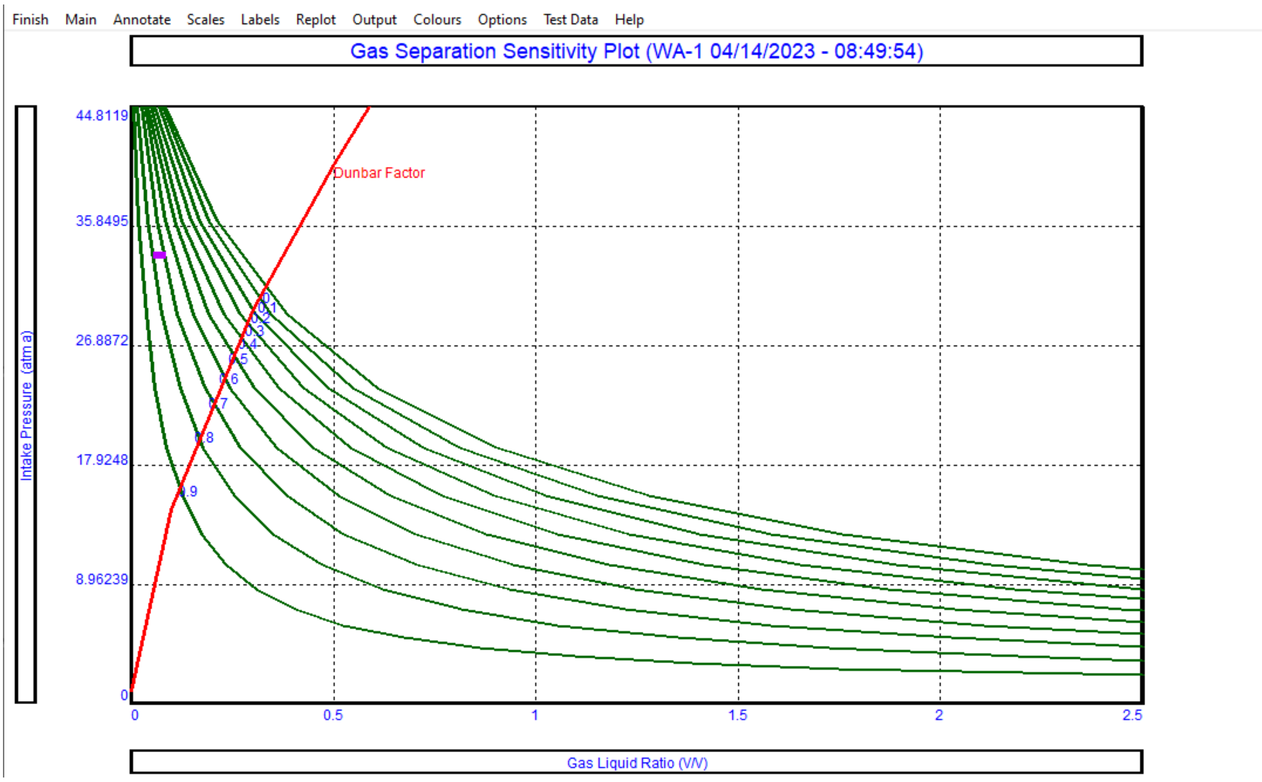


Figure 37.Gas Separation Sensitivity Check-2

The ESP design step can now be accomplished.

Pump, Motor, and Cable decision-making

Following completion of the necessary calculations and sensitivity checks, we have to opt for the best pump, downhole motor, and cable combination from a list provided by PROSPER in order to meet the desired flow rate. Consider that Pump Performance should be investigated to see whether the operating point is at or close to the Best Efficiency Line. When the operating rate is in line with the Best Efficiency Line, the pump performs at its best. Pump efficiency declines if the operating point is above or below the Best Efficiency Line. The PROSPER's final ESP design stage is displayed in the next figure:

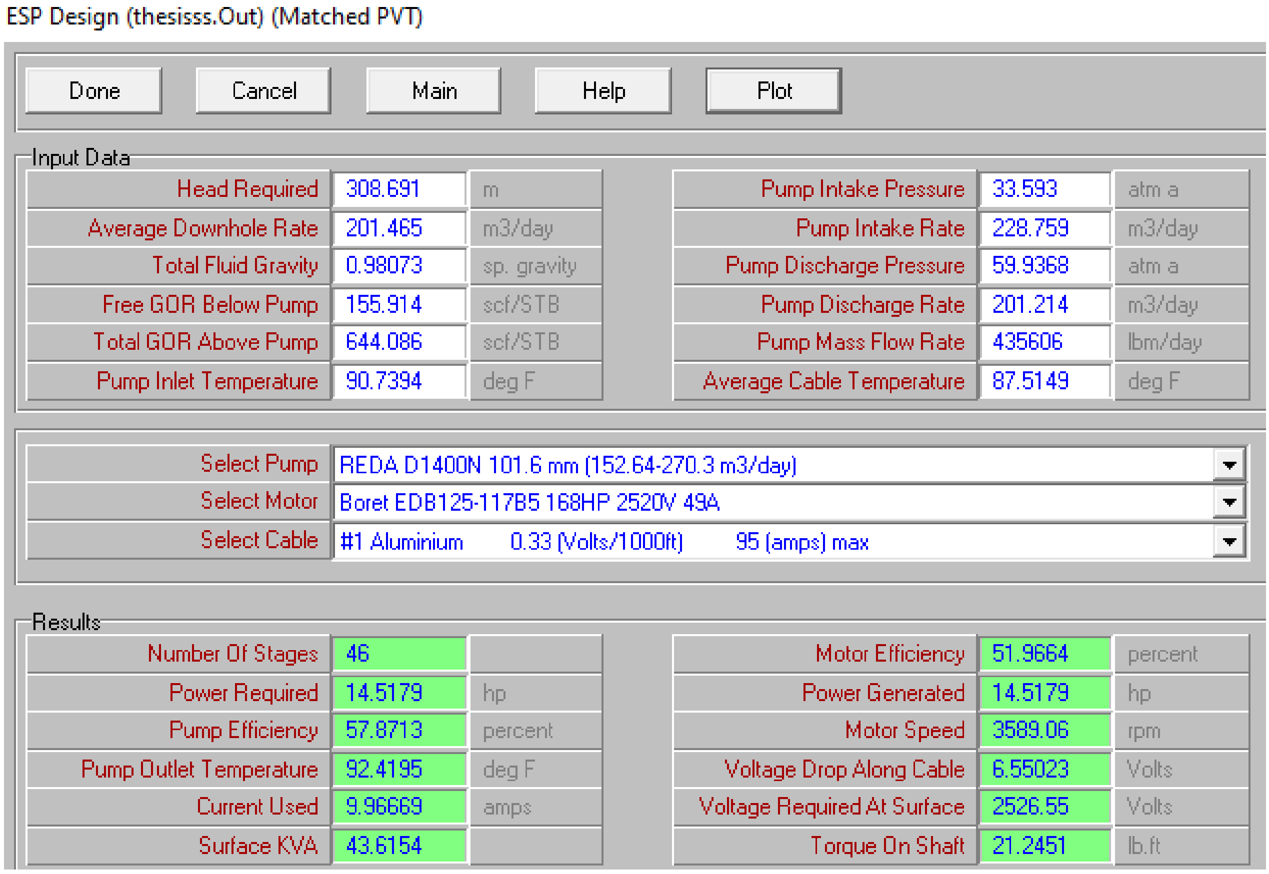


Figure 38.ESP, Motor and Cable Selection Screen

A combination of a pump, motor, and cable is chosen from a list provided by PROSPER as the last step in the ESP design process. The Schlumberger REDA D1440 (101.6 mm OD) pump, which offers the finest performance among the pumps, is chosen to provide the most efficiency.

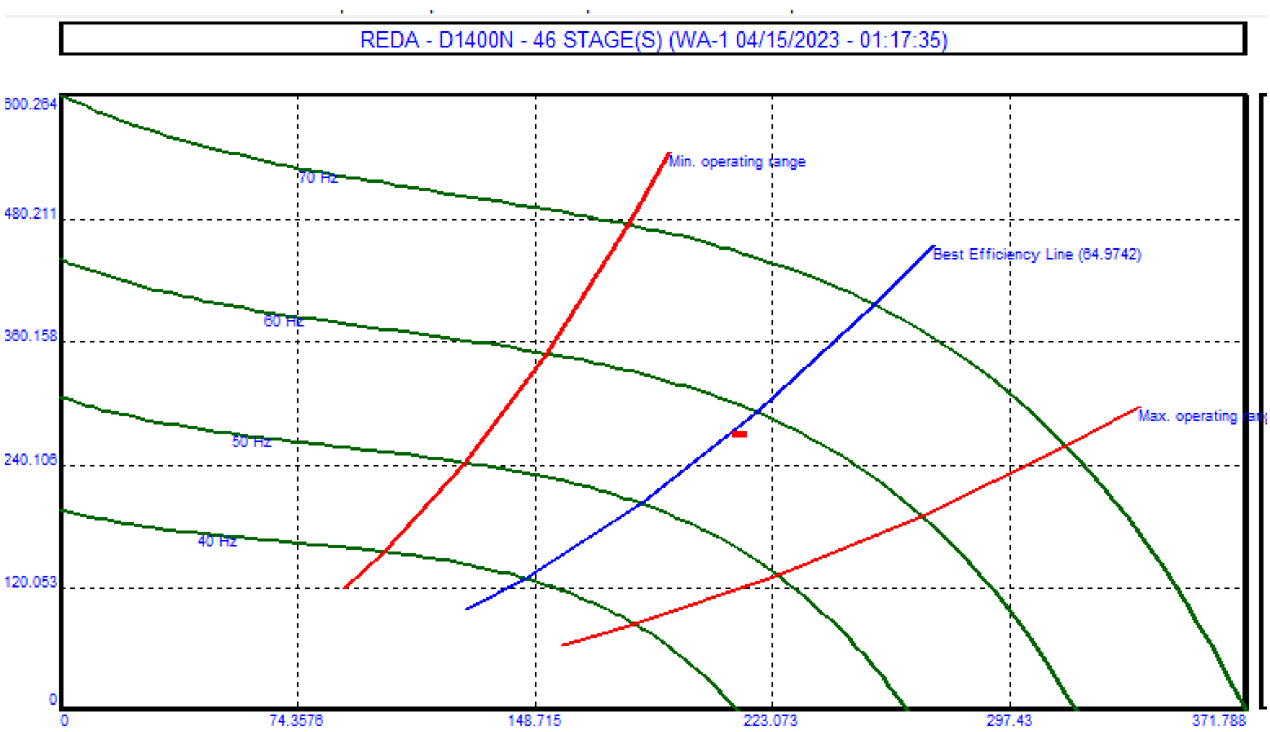


Figure 39.Performance Curve of REDA1440

System Computations

During the final stage, the program incorporates the design results that were acquired to carry out system calculations and produce IPR and VLP curves. The PROSPER System's ESP data menu needs to be filled out as shown in the accompanying figure in order to accomplish so. The vertical lift performance curve is constructed in the last stage, and the intersection point between the Pump Discharge Pressure (PDP) curve and the VLP curve is obtained, revealing the well's solution spot:

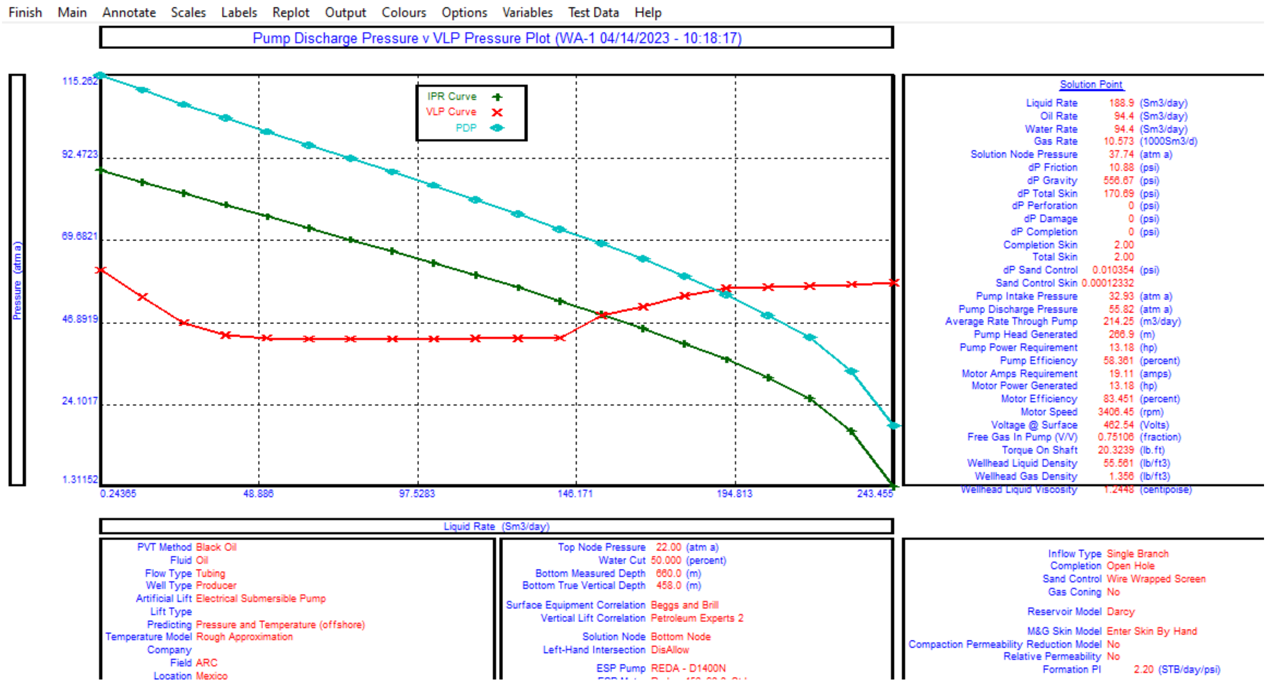


Figure 40.Pump Discharge Pressure vs VLP Plot for ESP-lifted well

From the wellhead to the pump discharge, the Pump Discharge Pressure is displayed in the picture above as a blue curve, the IPR as a green curve, and the VLP as a red curve. The liquid rate and oil rate determined by PROSPER for this scenario are clearly shown in the above figure to be 188.9 sm^3 per day and 94.4 sm^3 per day, respectively. In order to get the best performance out of the pump, the ESP case is modelled on PROSPER.

Resulting from a change in reservoir pressure

If pressure control is not done, the reservoir pressure will drop as the fluids are produced. This is taken into account, and the program includes three different reservoir pressure values in addition to the existing reservoir pressure of 89 atm. The outcomes are shown in the table below:

Table 11.Results of the reservoir pressure depletion system sensitivity analysis (ESP case)

Parameter	Reservoir Pressure (89 atm)	Reservoir Pressure (70 atm)	Reservoir Pressure (60 atm)	Reservoir Pressure (37 atm)	Unit
Liquid Rate	188.9	124.8	91.6	-------	sm^3/day
Oil Rate	94.4	62.4	45.8	-------	sm^3/day
Water Rate	90.4	60.3	40.9	-------	sm^3/day
Gas Rate	10.573	6.652	4.650	--------	1000sm^3/day

Based on the information gathered, it can be concluded that production rate declines when reservoir pressure falls. The well won't flow, and production stops, if the reservoir pressure drops to 37 atm. It indicates that modifications to the downhole design will be required.

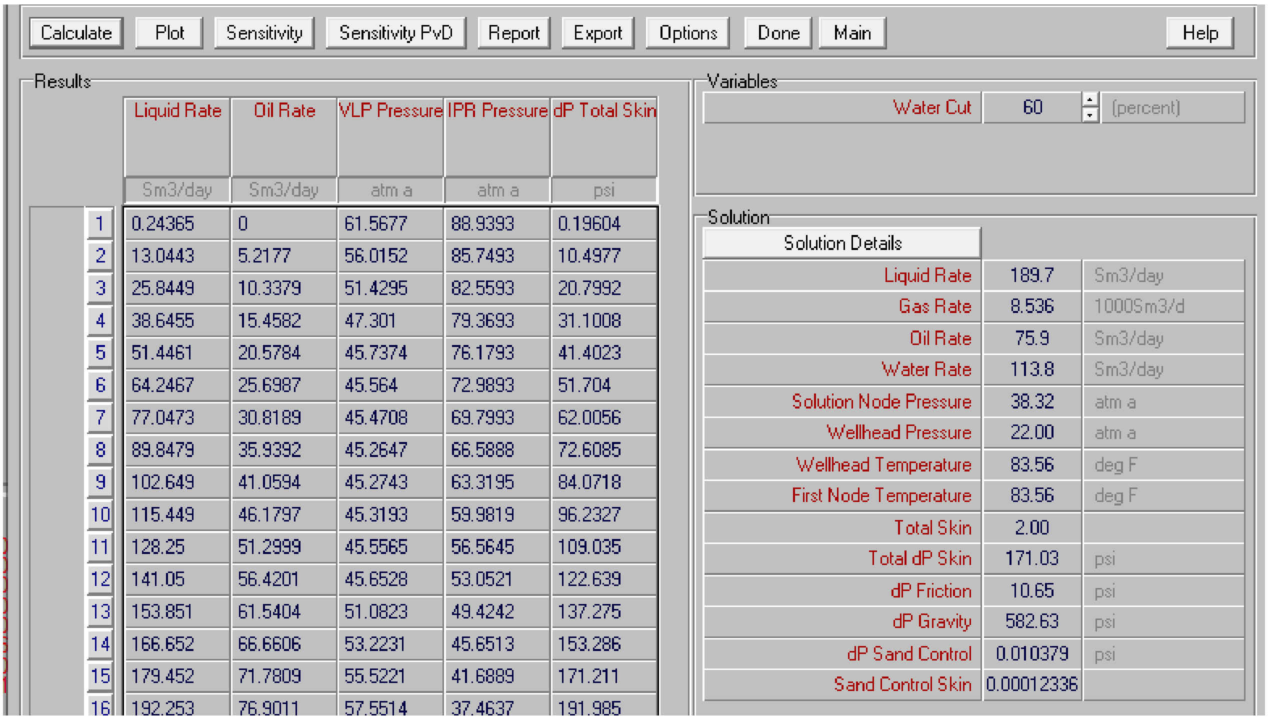
Resulting from a change in water cut

In order to simulate the effects of increasing water production, three different reservoir water cut values, along with the current water cut, which is 50%, are given on the software. The calculated results are shown in the table below. As it was mentioned above, reservoir depletion will result in increasing water cut values over time.

Table 12.Results of the reservoir pressure depletion system sensitivity analysis (ESP case)

Parameter	Water Cut (50%)	Water Cut (60%)	Water Cut (70%)	Unit
Liquid Rate	188.9	189.7	190.5	sm^3 /day
Oil Rate	94.4	75.9	57.2	sm^3/day
Water Rate	90.4	113.8	133.4	sm^3/day
Gas Rate	10.573	8.536	6.462	sm^3 /day

The table that is provided indicates clear that increasing water cut has little effect on overall liquid production. However, there is a big increase in the rate of water production and a sharp fall in the rate of oil production, which is appropriate.



	Liquid Rate (Sm3/day)	Oil Rate (Sm3/day)	VLP Pressure (atm a)	IPR Pressure (atm a)	dP Total Skin (psi)
1	0.24365	0	61.5677	88.9393	0.19604
2	13.0443	5.2177	56.0152	85.7493	10.4977
3	25.8449	10.3379	51.4295	82.5593	20.7992
4	38.6455	15.4582	47.301	79.3693	31.1008
5	51.4461	20.5784	45.7374	76.1793	41.4023
6	64.2467	25.6987	45.564	72.9893	51.704
7	77.0473	30.8189	45.4708	69.7993	62.0056
8	89.8479	35.9392	45.2647	66.5888	72.6085
9	102.649	41.0594	45.2743	63.3195	84.0718
10	115.449	46.1797	45.3193	59.9819	96.2327
11	128.25	51.2999	45.5565	56.5645	109.035
12	141.05	56.4201	45.6528	53.0521	122.639
13	153.851	61.5404	51.0823	49.4242	137.275
14	166.652	66.6606	53.2231	45.6513	153.286
15	179.452	71.7809	55.5221	41.6889	171.211
16	192.253	76.9011	57.5514	37.4637	191.985

Solution Details		
Liquid Rate	189.7	Sm3/day
Gas Rate	8.536	1000Sm3/d
Oil Rate	75.9	Sm3/day
Water Rate	113.8	Sm3/day
Solution Node Pressure	38.32	atm a
Wellhead Pressure	22.00	atm a
Wellhead Temperature	83.56	deg F
First Node Temperature	83.56	deg F
Total Skin	2.00	
Total dP Skin	171.03	psi
dP Friction	10.65	psi
dP Gravity	582.63	psi
dP Sand Control	0.010379	psi
Sand Control Skin	0.00012336	

Figure 41.Example screen of system variables of water cut for 60 percent

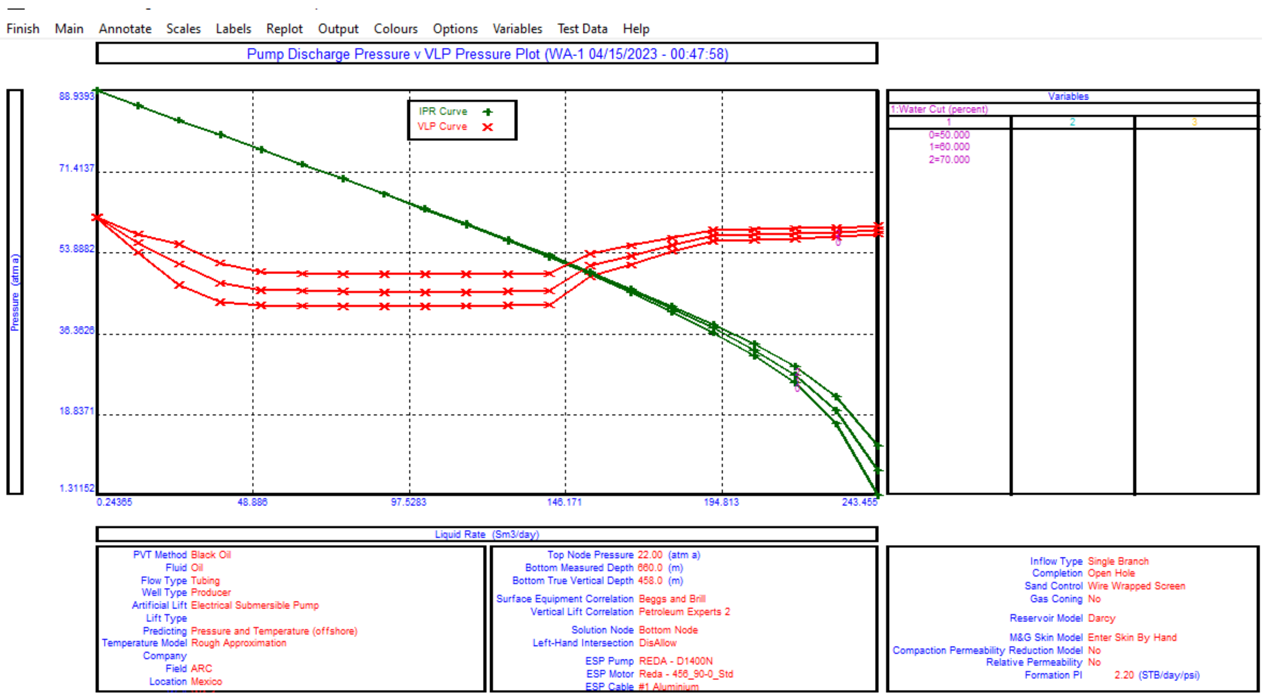


Figure 42.. Impacts of increasing water cut on PDP & VLP curves for ESP

Resulting from a change in operating Frequencies

Sensitivity analysis based on three distinct operating frequencies is carried out to determine the effects of different operating frequencies, and the calculated outcomes are shown in the table as follows:

Table 13.Results of system sensitivity analysis on different operating frequencies for ESP

Parameter	Operating frequency (40 Hertz)	Operating frequency (50 Hertz)	Operating frequency (60 Hertz)	Unit
Liquid Rate	155.9	171.6	188.9	sm^3 /day
Oil Rate	78.0	85.8	94.4	sm^3/day
Water Rate	76.1	84.3	92.1	sm^3/day
Gas Rate	9.505	10.048	10.573	sm^3 /day

Higher output rates are achieved by raising the operating frequencies. The next figure shows how different operating frequencies affect VLP and PDP curves as well as solution nodes:

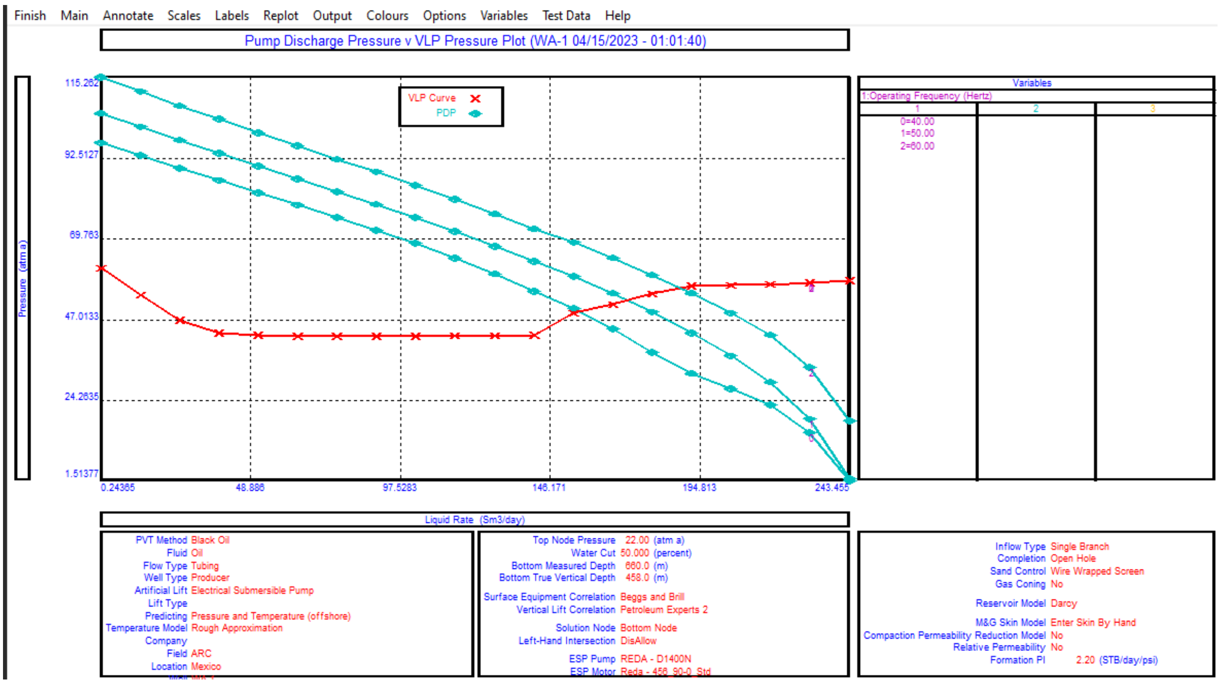


Figure 43.Impacts of different operating frequencies on PDP & VLP curves for ESP .

Chapter 4. Conclusions

The software receives all necessary data from PVT, deviation survey, geothermal temperature profile, and downhole equipment, and then creates the IPR curve. Following the modeling of the natural drive case, the ESP case, and the continuous gas lift case, the operating points at the intersection of the IPR and VLP curves are obtained for each scenario using the system calculations menu. The obtained findings demonstrate that the well modelled oil production in the natural drive case for the oil rate and bottom hole flowing pressure (BHFP) are 57.2 sm3 /day and 39.63 atm, respectively. However, the production rate is dramatically raised when artificial lift techniques are used.It is clear from the data that applying ESP results in increased production rates, and that this can be used to improve and optimize production. Given that ESPs have a limited existence and that it will be necessary to replace the downhole ESP lifted wells, careful planning is essential to completing this project. In order to get the best performance out of the pump, the ESP case is modelled on PROSPER. The system calculations show that the oil production rate is equal to 94.4 sm3 /day. Assessments of sensitivity are also carried out for every scenario separately, and it is evident that water cut, and altering reservoir pressure have a negative impact on oil output.

Recommendations

The PROSPER modeling used for this research was effective and the best choice for maximizing and optimizing hydrocarbon output. More advanced software is needed to make an integrated approach when it comes to field production optimization and enhancement, taking into account the surface network of existing wells and available subsurface data.

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