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Comparative Analysis of Effectiveness in the Implementation of Natural Drive and Artificial Lift Methods for Hydrocarbon Production

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Abstract

There are different production techniques that can be applied to produce hydrocarbons from subsurface formations. Reservoir fluids can be lifted to surface by either means of natural energy available within the reservoir or by applying artificial lift methods. Even though hydrocarbons are generally produced by natural drive mechanisms at the initial stage of field development where reservoir pressures are strong enough to push hydrocarbons to surface and then suitable artificial lifting techniques are implemented when wells cannot flow naturally, artificial lifting can also be applied to maximize production rate when individual well production rate is low due to lower reservoir pressure available in the system. The main objective of this research is to do comparative analysis of effectiveness in implementation of natural drive and artificial lift methods (gas – lift and pumps) for hydrocarbon production acceleration and optimization in West Absheron oil field, which is in the Caspian Sea, by using PROSPER software package based on a fictitious well data, namely Well WA-1. The Nodal Analysis is done for natural drive case and artificial lift techniques, specifically said, electrical submersible pump method and continuous gas lifting on PROSPER. Calculated oil production rates for natural drive, ESP and continuous gas lift cases are equal to 17.6 sm^3/day, 53.8 sm^3/day and 50.8 sm^3/day respectively. Comparative analysis of the outputs obtained from this research show that implementation of artificial lift methods significantly increases oil production rate. However, considering that source for lift gas is the main challenge for gas lift application in West Absheron oilfield, it is concluded that ESP implementation in West Absheron oilfield wells is the most favorable choice.

Keywords: Production techniques, Nodal Analysis, Natural Drive, Artificial Lift.

Introduction

It is generally true that in newly developed fields, the hydrocarbons can flow naturally to the earth's surface through the production tubing due to sufficient available reservoir pressure to push reservoir fluids. However, through time the reservoir pressure may drop due to depletion if pressure maintenance actions have not been taken in the field. In these cases, reservoir fluids may not flow naturally to the surface because of insufficient reservoir pressure, or hydrocarbon production rates may not be high enough to be considered economically viable. In that case to lift hydrocarbons to the surface, artificial lift techniques can be applied. Therefore, artificial lifting helps production engineers make the “dead” wells alive and achieve increased hydrocarbon production in the producing wells (Nguyen, 2020).

The fundamental objective of this research is to comparatively analyze the implementation of natural drive and artificial lift techniques, specifically said Electrical Submersible Pump (ESP) and Continuous Gas Lift for hydrocarbon production maximization and optimization in West Absheron oilfield, which is in Absheron archipelago, the Caspian Sea. To make this comparison, a mathematical model including various sub models are created in a special computer software package, namely PROSPER, to predict the achievable hydrocarbon production rates for three different cases (natural drive case, ESP, and continuous gas lifting) based on a fictitious well data, namely Well WA-1.

Natural Drive Mechanisms

Primary hydrocarbon recovery refers to the production of hydrocarbons with the help of natural energy available in the reservoir without supplementary aid from other sources like fluid injection into the reservoir. This natural energy is also known as “natural drive mechanism”. As (Tarek & D.Nathan, 2012) states, knowledge of reservoir drive mechanism plays a vital role in understanding fluid behavior within the porous medium and future fluid production forecasting. This drive mechanism is the main energy source to push hydrocarbons towards the producing wells. Generally, six reservoir drive mechanisms are present, which provide the available natural energy support for hydrocarbon recovery: Gap gas drive; water drive; gravity drainage drive; solution gas drive; rock and liquid expansion drive; combination drive(Tarek & D.Nathan, 2012):

Artificial Lifting

Depending on the natural energy available in the reservoir, hydrocarbons naturally flow to the surface at the early stages of the field development because the reservoir pressure is high enough to support natural flow. These naturally flowing wells have sufficient energy to push hydrocarbons to the surface. However, when the wells are not capable of flowing naturally since bottom hole pressure is inadequate to overwhelm the total pressure losses along the fluid flow path or the production rate is not high enough to be economical, then artificial lift (AL) is required to be implemented (Takacs, 2015). The well cannot flow naturally because reservoir pressure is less than the hydrostatic pressure due to the liquid column in the wellbore and the well is only capable of pushing hydrocarbons up to some level. Thus, an artificial lifting must be deployed to "initiate" fluid flow in this well (Figure 1).

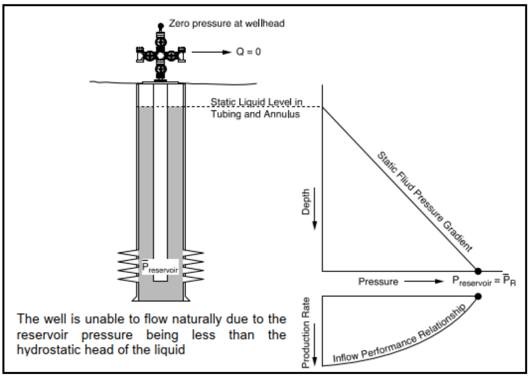

Figure 1.Typical well profile which is naturally unable to flow (Production Technology - 1, 2015)

There are mainly two artificial lift methods in production engineering. It can be either downhole pumping or gas lifting (Michael & Curthis H, 1991). In the case of downhole pumping a specially designed pump is lowered into the well and it operates at the bottom. This downhole pump aids the movement of hydrocarbons from the bottom hole to the wellhead by eliminating the back pressure when the fluids flow through the production tubing. In case of gas lifting, natural gas is injected into the tubing/casing annulus and from the annulus, injected gas flows into production tubing through gas lift valves inserted into the production tubing, and this injected gas mixes with the fluid column within the tubing, reduces its density and thus hydrostatic pressure at the formation rock.

A general definition for reservoir deliverability is the fluid (oil or gas) production rate can be achieved from a reservoir at a determined bottom hole pressure. Reservoir deliverability is a key element in petroleum production engineering, and it plays a fundamental role in the selection of well completion type and artificial lift methods. In reservoir deliverability modelling, the relationship between bottom hole pressure and fluid production rate is analyzed, and this relationship in petroleum engineering is also called the "Inflow Performance Relationship (IPR)" (Guo, 2007).

Wellbore flow performance is an essential tool to evaluate the performance of the production tubing by plotting the fluid production rate versus flowing bottom hole pressure. In literature outflow performance relationship is also called tubing performance relationship (TPR) or vertical lift performance (VLP). VLP is used to determine required bottom hole flowing pressure to transfer fluids flowing at different flow rates to the surface. (Lyons, 2016) There are eight pressure drops in the flow path of formation fluid and the fluid must overcome all pressure losses present within the system to move to the surface facility equipment (Figure 2; (Economides & Nolte, 2000). VLP allows the production engineers to minimize pressure losses along the flow path and maximize the well production. To plot VLP for a typical well, either wellhead pressure or flowing bottom hole pressure is fixed at a given flow rate. Then the pressure drop along the production tubing is calculated based on correlations or engineering charts. Then flowing bottom hole pressure is plotted against production rate and the resultant relationship gives VLP curve (Michael & Curthis H, 1991).

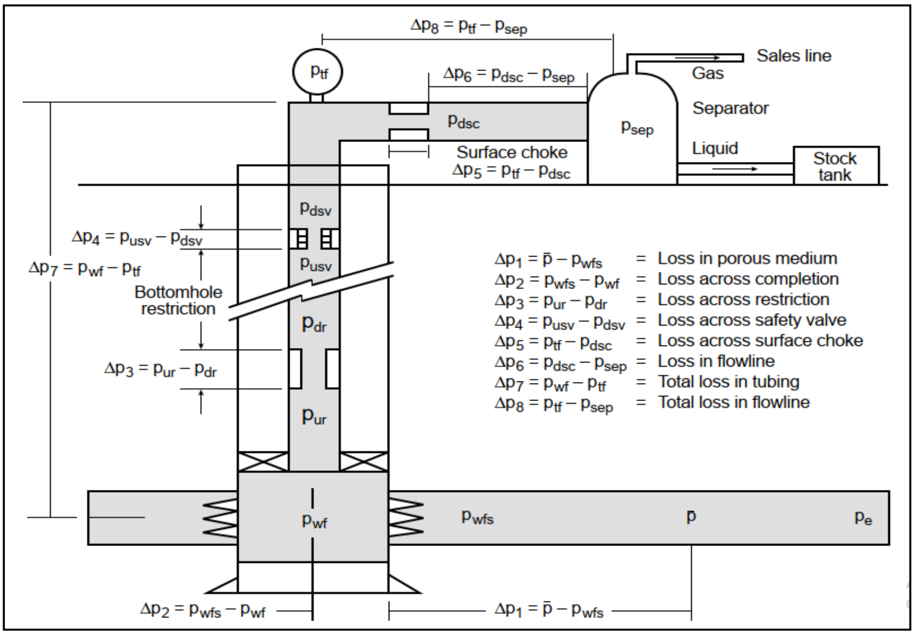

Figure 2. Pressure losses along the system (Economides & Nolte, 2000)

IPR and VLP curves are used to evaluate production capacity of a well. This evaluation in production engineering is known as Nodal Analysis where the well deliverability is analyzed based on reservoir performance and well performance. In the nodal analysis a solution node is selected within the system (Tetoros, 2015). At the solution node the system is divided into two sections. Either bottom hole or wellhead can be selected as a solution node. If for example, bottom hole is selected as a solution node that means fluid flow from reservoir into the bottom hole of the well is regarded as inflow, that is reflected in IPR curve, and the fluid flow from the bottom hole to the wellhead through the production tubing is regarded as outflow, which is displayed in VLP curve. The intersection point of IPR and VLP curves provide the stabilized flow rate which is also the natural flow point or operating point. It should be noted that when these two curves are not intersecting, that means the well will not naturally flow and some artificial lifting should be taken into consideration (Economides & Nolte, 2000).

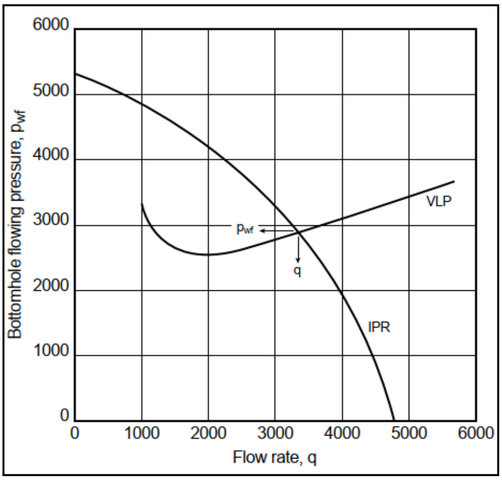

Figure 3. Typical IPR and VLP curves to predict natural flow (Economides & Nolte, 2000)

Study Area

The study area of this research is West Absheron oil field, which is located in the Caspian Sea, 40 km north of the Absheron Peninsula (Figure 4.). Structurally it is an anticline uplift in the north-west-south-east direction, and its core is composed of sediments of the Balakhany Unit of the Productive Series (PS). Productive Series is the main hydrocarbon bearing rock succession in South Caspian Basin and based on the microfauna composition, it is divided into Lower Productive Series and Upper

Productive Series. On the basis of lithological composition, Lower Productive Series include Kala Suite, Pre-Kirmaki Suite, Kirmaky Suite, Kirmaky Suite, Post-Kirmaky Sand Suite and Post-Kirmaky Clay Suite.

Figure 4. Location of West Absheron Oilfield

Upper Productive Series is subdivided into Fasila Suite, Balakhany Suite, Sabunchy Suite and Surakhany Suite (Abdullayev & Leroy, 2016). The dimensions of the main reservoir rock are 11x4 km. Stratigraphic succession of West Absheron field was discovered and studied through drilled wells and seismic works and it has turned out that, from Cretaceous sedimentary complex till Quaternary sediments are present in sedimentary succession of West Absheron field. Main hydrocarbon bearing rock successions are Kirmaky Suite and Pre-Kirmaky Suite of PS. In the West Absheron oilfield, the first oil was extracted in 1985, when Post-Kirmaki Suite was perforated in Well#35 (initial production rate was 61 tons of oil per day). The field has been in production since 1985. Initial reserve estimation in the West Absheron field based on Russian Federation Classification Scheme has revealed that commercial reserves under C1&C2 category was 64635 thousand tons of crude oil, 2587 million m^3 of dissolved gas and volume of recoverable reserves was 12359 thousand tons of crude oil, 2035.5 million m^3 of dissolved gas. Updated reserve estimation in 01.01.2022 has revealed that commercial reserves under C1&C2 category is 63884.4 thousand tons of crude oil, 2561.1 million m^3 of dissolved gas and volume of recoverable reserves is 11608.4 thousand tons of crude oil, 2009.1 million m^3 of dissolved gas. In total, 74 wells were drilled in the field as of 01.01.2022 and from these wells 750.6 thousand tons of crude oil, 25.9 million m^3 of dissolved gas and 27.6 thousand m^3 of water has been produced. 3.1% of recoverable crude oil reserves under C1&C2 category has been extracted.

Methodology

Generation of inflow performance relationship (IPR) and vertical lift performance (VLP) curves for this study is achieved using PROSPER software package that is designed to obtain inflow/outflow performance curves, create IPR and VLP models, select best artificial lift method, do well perforation design and so on based on the minimum required input data. The software also enables to input real production history data to increase the accuracy of models generated on. The software is a product of Petroleum Experts Limited (PETEX), located in UK and one of most widely used software in the petroleum industry (IPM PROSPER User Manual,Version 11.5, January 2010).

Required Data

The data needed to perform calculations and make final decision is as follows:

- PVT data
- Reservoir Data
- Equipment data: this includes downhole equipment, deviation survey, geothermal gradient, and average head capacities
- Gas lift data for gas lift case
- ESP data for ESP case

Summary of required input data is given in Table and Table 2.

Table 1. PVT data

PVT properties	Value	Unit
Solution GOR	31.632	m^3/m^3
Oil gravity	806.509	kg/m^3
Gas gravity	0.65	sg
Water salinity	76580.7	ppm
Mole percent H2S	0	%
Mole percent CO2	0.2	%
Mole percent N2	0	%

Table 2.Reservoir and wellbore properties

Properties	Value	Unit
Reservoir pressure	82	atm.
Reservoir temperature	34	°C
Water cut	5	%
Total GOR	31.632	m^3/m^3
Reservoir permeability	30	mD
Reservoir thickness	13	m
Drainage area	750000	m^2
Dietz shape factor	31.6	unitless
Skin factor	3	unitless
Wellbore radius	6	inches

Model Setup

To do simulations for natural drive and artificial lift techniques in PROSPER software, a fictitious offshore well named WA-1, in the West Absheron field is modelled. Based on the offset wells data and reservoir data provided, 750 meters deep, deviated wellbore is designed. To produce IPR and VLP curves and get the intersection point (which is stable flow point) between these curves based on input data for Well WA-1, the following steps are followed in the software for Natural Drive Case, Electrical Submersible Case and Gas Lift Case.

Building Natural Drive Model

IPR and Equipment Data

To generate inflow performance relationship curve that represents reservoir performance PVT data is required to accurately predict how the properties of reservoir fluid change as a function of pressure and temperature. It should be noted that in the PROSPER software either the basic fluid properties can be inserted and based on some traditional black oil model correlations (e.g., Glaso, Beggs, Petrosky etc.) the software can calculate fluid properties or basic fluid data and PVT laboratory readings can be introduced into the software and PROSPER can choose the best correlation to match the measured laboratory data. For this research basic PVT input data including GOR, API gravity, Gas gravity, water salinity and impurities present in reservoir fluid is introduced into the software and then laboratory measurement data taken from offset wells are entered to match PVT test data to the Black Oil correlations that are available on PROSPER. It is found that the best correlation with respect to Well WA-1 input data for Bubble point pressure, GOR and Oil FVF is Glaso correlation which has the smallest standard deviation. For the oil viscosity, the best correlation is Beal et al which has the smallest standard deviation based on the available data provided. Then to construct IPR curve Darcy Model is selected due to its simplicity and ease of convergence. Then the software applies Darcy's flow equation when the flowing bottom hole pressure is above the bubble point pressure and the Vogel's solution when the flowing bottom hole pressure is equal or below the bubble point pressure. IPR curve is generated on software and it is obvious that absolute open flow (AOF) is 76.3 sm^3/day, and the formation productivity index (PI) is 1.76 sm^3/day/bar (Figure 5). Then equipment data including deviation survey, surface equipment, downhole equipment, geothermal gradient, and average heat capacity values are entered to make calculations of pressure and temperature profiles along the modelled well.

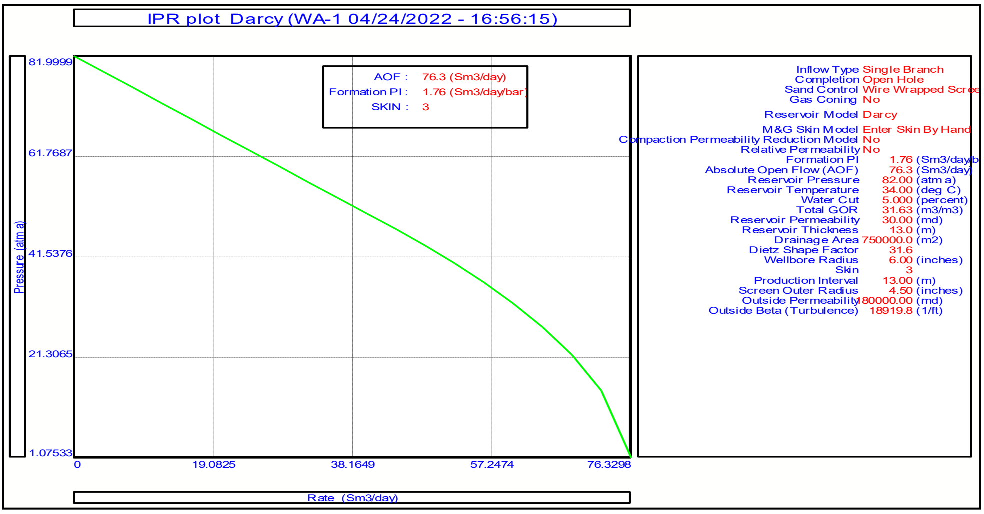

Figure 5.IPR plot based on reservoir Darcy model

Building ESP model

To model ESP artificial lift method on PROSPER, several input parameters should be entered into the software. In the system summary window firstly ESP method is selected as an artificial lift technique. Because IPR and PVT modelling is same as the natural drive case, ESP designing is directly followed by inserting required input parameters on design menu of PROSPER and then considering the best efficiency of the pump, a combination of appropriate pump, downhole motor, and cable from the list that PROSPER suggests achieving the target flow rate is selected.

Building Continuous Gas lift model

Modelling of continuous gas lift system on PROSPER starts with selecting gas lift (continuous) option on system summary menu. Here again IPR and PVT data remain same as for the Natural Drive Case and ESP Case. Then on the design menu of PROSPER required parameters for continuous gas lift system are introduced. A gas lift valve is selected from the PROSPER database which is visible on the right-hand side of the data input screen. For this scenario, Camco R-20 Normal Valves with port sizes in a range of 8 to 32 64 $^{\text{ths}}$ inch are selected. It should be stated that PROSPER tries to define which port sizes will deliver the optimal production rate and it means that the type of valve included on the software is not a big issue if the valves are casing sensitive.

Results

Natural Drive Model

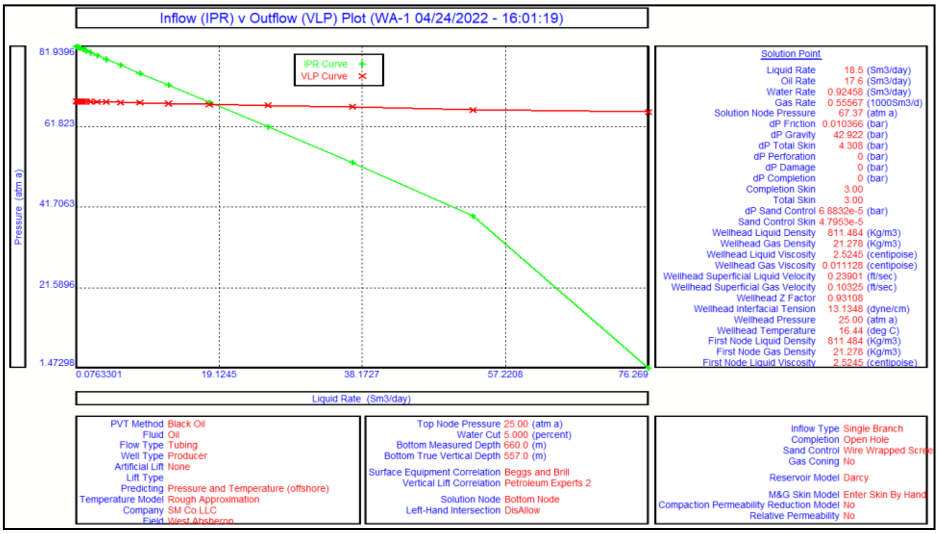

Figure 6. IPR and VLP curves plot for natural drive case

Input parameters for natural drive case generate a production profile without artificial lift technique for WA-1 well with an oil production rate equal to 17.6 sm^3/day. The relationship between IPR and VLP curves and these two curves are intersecting at one point, meaning that this well can flow naturally (Figure 6). However, the calculated flow rate is low and the main reason for that is having high pressure drop due to gravity (Figure 6). Sensitivity analysis on changing reservoir pressure values is performed to see how well production rate is affected. While the reservoir pressure decreases, well production rate decreases as well (Figure 7). However, if the reservoir pressure falls to 65 atm., then the well will not flow naturally and the intersection points between IPR and VLP curves will not be achieved.

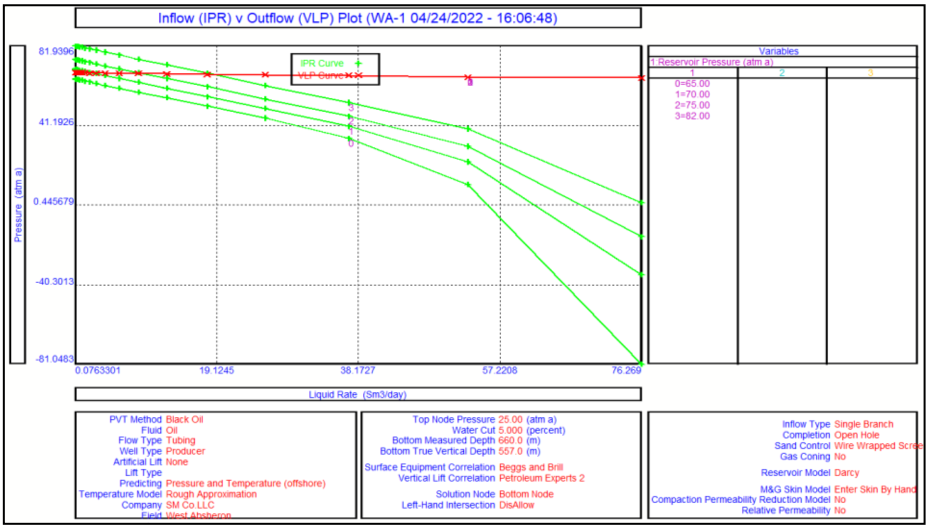

Figure 7. Sensitivity analysis based on changing reservoir pressure

ESP Model

Obtained design results are included in the software to perform system calculations and create IPR and VLP curves. To do that on PROSPER System ESP data menu should be filled up by obtained design results and then the vertical lift performance curve is generated, and intersection point between Pump Discharge Pressure (PDP) curve and VLP curve is achieved which shows the solution point of ESP-lifted well (Figure 8). It should be noted that Pump Performance should be examined to see if the operating point lies at or near the Best Efficiency Line. The pump performance is highest when the operating rate corresponds to the Best Efficiency Line. If the operating point is above or below the Best Efficiency Line, then the pump efficiency decreases (Oilfield Review, 2016). For this reason, care must be given to select the best combination of pump, motor, and cable to be sure that we are at the Best Efficiency Line. By this way we are sure that the pump will deliver highest efficiency. Taking the best performance of the pumps into consideration, REDA DN440 (101.6 mm OD) pump which is manufactured by Schlumberger is selected to achieve the best efficiency. The performance curve of this pump is given, and it is obvious that operating point given as a red dot perfectly lies on the Best Efficiency Line (Figure 9).

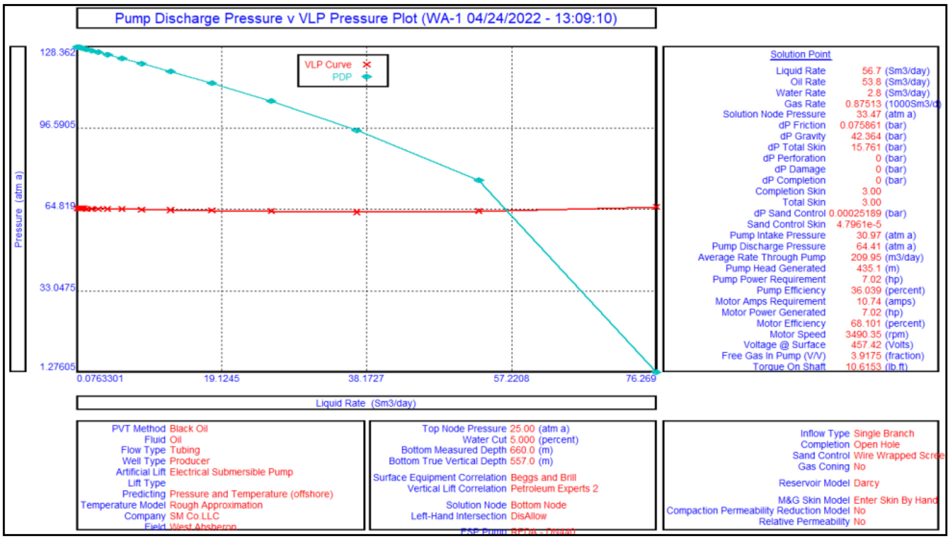

Figure 8. Pump Discharge Pressure vs VLP plot for ESP-lifted well

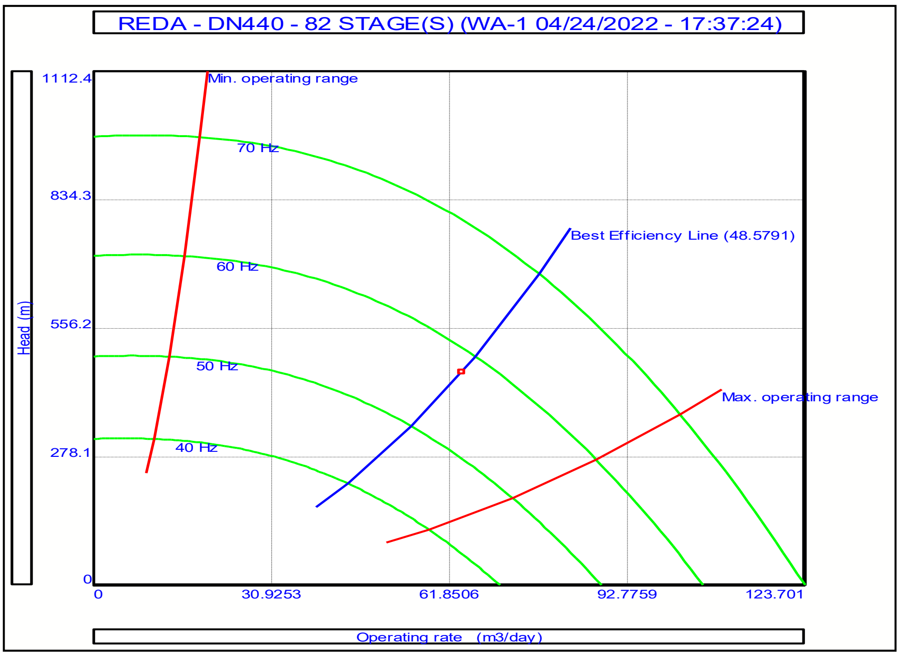

Figure 9. Performance Curve of REDA DN440 ESP

Pump Discharge Pressure is given in blue curve and VLP is shown in red curve, from wellhead to the pump discharge (Figure 8). It is obvious that the calculated liquid rate and oil rate by PROSPER for this case is 56.7 sm^3/day and 53.8 sm^3/day respectively (Figure 8).

Continuous Gas Lift Model

The obtained results on continuous gas lift method show that there is a significant increase on well production rate compared to natural drive case as well (Figure 10). It becomes clear that 2 unloading valves and one orifice type valve are required for this gas lift design. During the valve positioning calculations, the oil rate is checked for the conformance with the IPR and if necessary, the design rate is reduced by the software. It is worth mentioning that PROSPER checks the available gas injection rate to achieve designed rate and if the amount of available gas is less than required gas injection rate, then target oil production is reduced. All calculation results related to the gas lift valve positioning procedure were shown in Table 3:

Table 3.Gas lift valve positioning results

Valve Number	*Valve Type*	*Measured Depth (m)*	*True Vertical Depth (m)*	*Valve Opening Pressure (atm)*	*Valve Closing Pressure (atm)*	*Gas Lift Gas Rate (10000 sm^3/d)*	*Port Size (64^{ths} inch)*
1	Valve	222.103	219.114	61.1765	60.6364	1.56207	8
2	Valve	429.575	392.181	58.6963	57.7194	8.94982	12
3	Orifice	600	515			15.6208	11

As a final step, obtained design results are included in the software to perform system calculations and create IPR and VLP curves. To do that on PROSPER System Gas Lift data menu should be filled up with lift gas properties, determined gas lift valve depths and designed injection pressure values. Finally, the vertical lift performance curve is generated, and intersection point between IPR curve and VLP is achieved:

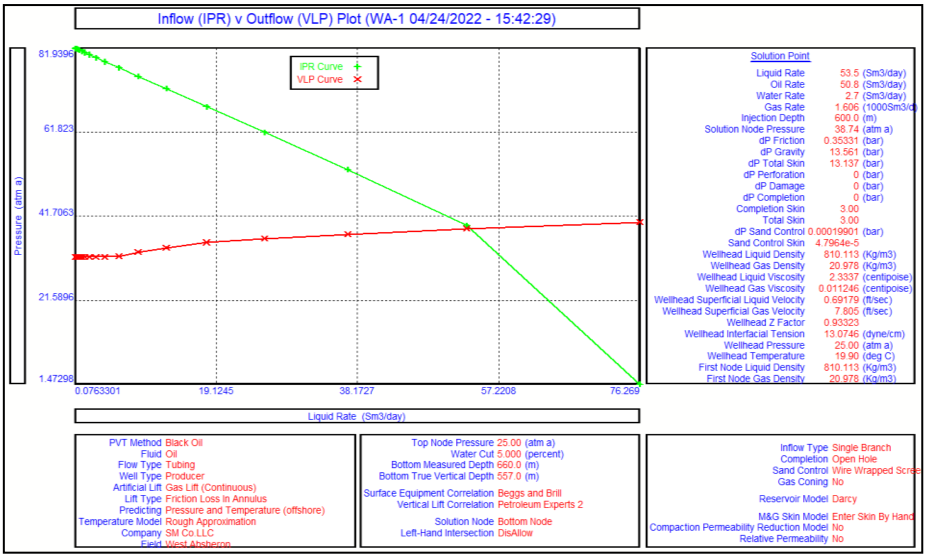

Figure 10. IPR and VLP plot for gas lift case

IPR is given in green curve and VLP is shown in red curve, and it is obvious that the calculated liquid rate and oil rate by PROSPER for this case is 53.5 sm^3/day and 50.8 sm^3/day respectively (Figure 10).

Discussion and Conclusions

The obtained results show that in case of natural drive case the modelled well oil production rate is equal to **17.6 sm^3/day**. However, if artificial lift techniques are applied, the production rate is significantly increased. So that for ESP case REDA DN440 pump which is manufactured by Schlumberger is modelled on PROSPER and the system calculations yield that oil production rate is equal to **53.8 sm^3/day**. Finally designing of continuous gas lift is modelled on PROSPER and it turns out that continuous gas lift system with 2 unloading valves and 1 operating valve with 15620.8 sm^3/day injection rate and 53.1954 atm injection pressure can produce oil equal to **50.8 sm^3/day**. From the obtained results, it is obvious that application of ESP and continuous gas lifting yields higher production rates and by this way production enhancement and optimization can be achieved in West Absheron oilfield. However, for the application of continuous gas lifting, the biggest obstacle is the unavailability of source gas for West Absheron oilfield. That means gas should be obtained from somewhere else, possibly from a nearby gas producing field that requires much more investment before the system goes online. What is more, a gas lift compression station, pipeline network and required surface facilities should be installed in the field as well, leading to increased CAPEX of this plan and in this case, application of gas lift system seems unfavorable. ESP implementation for hydrocarbon production enhancement and optimization in West Absheron oilfield among the three cases seems the most suitable choice. However, for the ESP case, a detailed planning is highly demanded to realize this project because ESPs have a limited lifetime, and there will be a need to change the downhole completion (workover, maintenance) in ESP lifted wells when they experience failure, leading to increased OPEX later in the project. Comparing this factor to that of gas lifting system, it should be noted that gas lifting is a very simple, commonly applied artificial lift method where little can go wrong. From the obtained results and specifically unavailability of source gas and required infrastructure in the study area, it can be deduced that implementation of ESPs to maximize and optimize hydrocarbon production in West Absheron oilfield seems to be superior choice.

Recommendations

It should be emphasized that although the modelling done on PROSPER for this research is successful and the most suitable option to optimize and maximize the hydrocarbon production in West Absheron oilfield can be concluded which is ESP implementation, in reality this planning is far too complex and production optimization should be done for every well individually considering the available input data for each well. In case of field production optimization and enhancement, more sophisticated software is required to make an integrated approach considering the surface network of present wells and available subsurface data.

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