

Production Optimisation in the Niger Delta Basin by Continuous Gas Lift – A Case Study of Iduo-Well-A06

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Abstract: Iduo-Well-A06 with 58*106STB initial oil reserve was producing at 5,000 STB/day rate with 31/2 inches tubing in 1993. After 5 years of production the rate dropped to 1,200STB/day at 50% water-cut and 831 psig average reservoir pressure. Gross production recorded in 1998 was 2.8*106 STB, leaving about 55.2*106 STB reserve. Hence, there was need for reserve recovery. This work seeks to design a continuous gas lift technique using PROSPER® software to increase production rate. Therefore, models were constructed to determine the best-fit correlation for PVT matching. Design input parameters were: operating pressure of 1,900 psig, minimum valves spacing of 500ft, and the differential pressure across valves of 250 psig. The valve type used was casing sensitive. Results showed that Glasco and Beal et al correlations were found to be best-fit. Furthermore, the optimal production rate of 4,601,57 STB/day was achieved with 8.0MMscf/day continuous gas injection rate at 20% water cut using 41/2 inches tubing. Also, unloading and operating valves depths were 3,952.75ft and 7,577.72ft, respectively. Further injection rate increase yielded lower production rate, as 4,524.01STB/day production rate was achieved using 9 MMScf/day optimal injection at 1,865.1 Psi minimum pressures.

Index Terms: PROSPER®Software, Continuous Gas lift, Production Optimization, Productivity Index.

SYMBOLS and Notations

PVT	Pressure Volume Temperature
STB/day	Stock Tank Barrel per day
BHFP	Bottom Hole Flowing Pressure
CGLPC	Continuous Gas Lift Performance curve
FBHP	Flowing Bottom-Hole Pressure
IGL	Intermittent Gas Lift
IPR	Inflow Performance Relationship
PI	Productivity Index
q	Oil Flow Rate
μ	Liquid Viscosity
β	Liquid Volume Factor
K	Effective Permeability
dl	Increase in Length
dp	increase in Pressure
h	Oil Formation Thickness
P_e	Boundary Pressure
P_{wf}	Bottom Hole Flowing Pressure
r_e	Drainage Radius of Well
r_w	Radius of Well Bore
S	Saturation fraction
Scf	Standard Cubic Feet

VLP	Vertical Lift Performance
Ppm	Parts per Millions
$\Delta\rho$	Density difference of Water and oil
Δp	Differential Pressure
B_o	Oil formation factor,

1. Introduction

Iduo-Well-A06 is thinning-out, with increasing water production and decreasing reservoir pressure. To increase production rate, the operator decided to start an artificial lift project, due to increased water cut and availability of lift gas.

Continuous-flow gas-lift allows the injection of gas into the production string to aerate the reservoir fluids which lowers the bottom hole flowing pressure (BHFP). Any reduction in BHFP causes the reservoir to respond with increased flow rate. Consequently, once the piping system is fixed, the extent of reduction in the BHFP depends on two parameters-the amount of gas injected and the depth of injection. Although the increased volume of gas injected should yield higher production, there is an upper limit to the volume of gas injected. This upper limit can be an economic limit of gas injection beyond which the cost of gas

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injection supersedes the price of extra oil produced as discussed by Kanu et al, [1]. The economic limit is beyond the scope of this discussion. There is a physical limit of gas injection too, which results in the reversal of the tubing gradients caused by the increased irreversible pressure losses in the tubing. Consequently, a sensitivity analysis on the volume of gas injected should always be carried out before any decision is made regarding this parameter. The second parameter that significantly affects the efficiency of continuous-flow gas-lift design is the depth of injection. The maximum depth of injection achievable in a gas-lift design is a function of surface injection pressure and rate, if all other variables remain constant. Once the surface injection pressure is fixed, the depth of injection can be controlled by altering the differential pressure at the point of injection. The lower this differential pressure, the lower the point of injection will be before buttonhole injection starts.

This work presents the maximum production rate achievable for Iduo oil well using gas lift, the optimum lift gas injection rate and depth, depth of the operating and unloading valves and the minimum pressure achieved at the defined valve depth.

2. Background

2.1 Artificial Lift

Artificial lift denotes to the use of non-natural means to increase the flow of liquids, such as crude oil or water, from a production well. Usually this is accomplished by the use of a mechanical device inside the well (known as pump or velocity string) or by reducing the weight of the hydrostatic column by injecting gas into the liquid some distance down the well. Artificial lift is desirable in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface, but often used in naturally flowing wells (which do not technically need it) to increase the flow rate above what would flow naturally. The produced fluid can be oil, water or a mix of oil and water, usually mixed with some amount of gas.

Any liquid-producing reservoir will have a 'reservoir pressure': some level of energy or potential that will force fluid (liquid, gas or both) to areas of lower energy or potential. The concept is similar to that of water pressure in a municipal water system. As soon as the pressure inside a production well is decreased below the reservoir pressure, the reservoir will act to fill the well back up, just like opening a valve on a water system. Depending on the depth of the reservoir and density of the fluid, the reservoir may or may

not have enough potential to push the fluid to the surface - a deeper well or a heavier mixture results in a higher pressure requirement.

Most oil production reservoirs have sufficient potential to naturally produce oil and gas - which are light - during the early phases of production. Water - This is heavier than oil and much heavier than gas - often will eventually encroach into production, possibly causing the well to stop flowing entirely. Also, reservoir pressure will decrease as many reservoirs deplete, reducing the natural flow to below a profitable rate. At some point, economics can justify the cost of an artificial lift plan to continue or increase production. Most water-producing wells, by contrast, will need artificial lift from the very beginning of production because they do not benefit from the lighter density of oil and gas [2].

Although there are several methods to achieve artificial lift, the two main categories of artificial lift include gas lifts and pumping systems

2.2 Gas Lift System

Gas lift is a method of lifting fluid where relatively high pressure (250 psi minimum) gas is used as the lifting medium through a mechanical process. It is a form of artificial lift. The need of artificial lift is required when the pressure of well is not enough as to maintain the oil production with satisfactory economic return. This situation is typical in mature oil field where increasing water cut or decreasing reservoir pressure eventually causes well to cease natural flow. Less reservoir pressure leads to less bottom hole flowing pressure means less energy to lift up the hydrocarbon liquid. In order to solve this problem, two different approaches are generally used. First approach is to increase bottomhole flowing pressure with the aid of bottomhole well pumping. Second one is to reduce fluid column density in the well bore by injecting compressed gas which is called gas lift [3].

Gas lift is a very popular form of artificial lift, especially for offshore platforms. Its flexibility cannot be equalled by any other form of artificial lift [2].

In a typical gas lift system, compressed gas is injected through gas lift mandrels and valves into the production string. The injected gas lowers the hydrostatic pressure in the production string to re-establish the required pressure differential between the reservoir and well bore, thus causing the formation fluids to flow to the surface [3].

Gas lift can be controlled for a single well to optimize production, and to reduce slugging effects where the gas droplets collect to form large bubbles that can upset production [4].

There are two phases to a gas lift operation: (1) unloading and (2) operating. The objective of unloading is to leverage the injection pressure by sequentially injecting gas through deeper unloading valves until the operating valve is reached. The operating phase should be a single-point injection through the operating valve over a range of injection rates [5].

Gas lift designs for subsea wells have several requirements that are not normally encountered in traditional gas lift designs. First, because the cost of intervention in a subsea well is considerably higher than for a traditional completion, the subsurface gas lift equipment must be designed with special attention to reliability and longevity. Secondly, the sizing of the port in the operating valve must anticipate production conditions for the life of the well. Normally, failed equipment or a change in production conditions would be dealt with by using light intervention methods (i.e. wire line or coiled tubing) to place new equipment into the side pocket mandrels [6]. Gas lift was practiced in the United States for oil production over 100 years ago. The system used a valve design that was patented and given the name of "oil ejector" [7]. Gas lift can also be optimized over several wells to use available gas in the most efficient way [4].

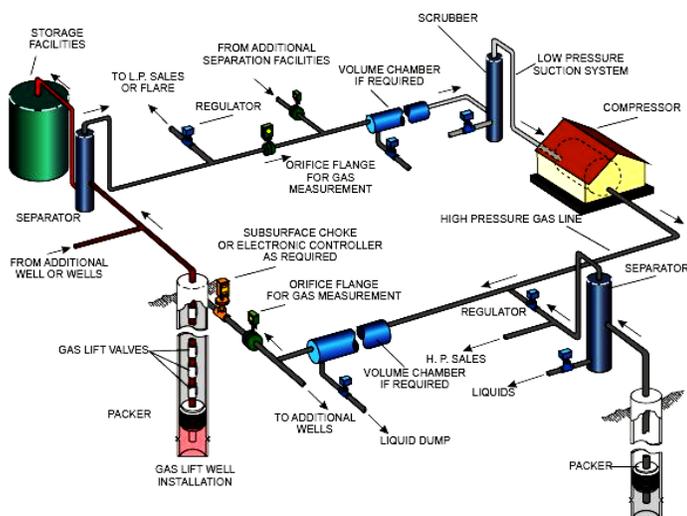


Figure 1, General Gas Lift System [3]

2.3 System Prerequisite of gas lift

When reviewing the performance of an existing gas lift system or investigating the feasibility of a potential gas lift

system the following rules must be observed:

- The success of any gas lift system depends on an adequate and reliable source of quality lift gas throughout the period when gas lift is required.
- The gas injection point should be as close as possible to the top of the completion interval.
- Gas lift systems should operate with minimum back pressure at the wellhead.
- Lift should be as stable as possible.
- All gas lift system should address future, as well as present operating conditions.
- Overly conservative design assumptions should be avoided- design factors should reflect the availability and quality of design data.
- Lift gas availability should be optimised to enable the system to operate near continuously in the most profitable configuration (example, minimise compressor downtime).
- Gas lift systems should be designed with all modes of operation in mind.
- Surveillance and control should be considered as an integral part of any system. The ability to control gas lift distribution is essential for efficient gas lift operation [8].

2.3.1 Advantages of Gas Lift Method

Some advantages of the gas lift method of artificial lift include:

- Operating depths in excess of those attainable with rod pumps;
- High fluid production rates;
- Not affected by solids in produced fluids;
- No heavy or unusual accessory equipment at the wellhead;
- Not mechanically affected by the inclination of the wellbore [7].

2.3.2 Gas Lift Optimization

Production optimization has been an engineering practice since the early 1980s [2]. The goal of gas lift is to deliver the fluid to the top of the wellhead while keeping the bottom-hole pressure low enough to provide high pressure drop between the reservoir and the bottomhole. Reduction of bottomhole pressure due to gas injection will normally increase fluid (Oil) production rate, because gas injection lighten the fluid column, therefore larger amount of fluid flow along the tubing. However, injecting too much amount of gas increases the bottomhole pressure which decreases the oil production rate. This is happened because high gas injection rate causes slippage, where gas phase moves faster than liquid, leaving the liquid phase behind. In this condition, less amount of liquid will flow along the tubing. Hence, there should be an optimum gas injection rate [9]. The optimum gas injection point for maximum oil production has been shown by a continuous gas lift Performance curve (CGLPC).

The injection gas is typically conveyed down the tubing-casing annulus and enters the production train through a gas-lift valve. The gas-lift valve position, operating pressures and gas injection rate are determined to ensure maximum well productivity by specific well conditions [10].

2.4 Well Performance

2.4.1 Inflow Performance

Engineers are often called upon to predict the pressure-production behaviour of oil and gas wells to determine their productive capacity. Having an idea of the pressure-rate behaviour enables the engineer to evaluate various operating scenarios to ascertain the optimum production scheme and to design and install surface and subsurface production equipment when necessary. Knowledge of the pressure-rate behaviour can be quite helpful in designing and evaluating stimulation treatments or any operation that improves flow efficiency. Inflow performance relationships (IPRs) are pressure-rate relationships used to predict performance of oil and gas wells. Vogel2 was one of the first to propose an IPR for predicting the performance of vertical oil wells. This IPR was immediately accepted in the industry because it was easy to apply and yielded reasonable results [11]. The IPR is a key input for integrated studies and optimisation of well/reservoir performance [12].

IPR curves are easy to obtain in continuous flow, because with only two different pairs of values - bottom hole flowing pressure (measured or estimated) and its corresponding rate - Vogel's equation is directly defined. However, in

Intermittent Gas Lift (IGL) wells, the BHFP is an instantaneous value continuously changing, and therefore the inflow rate is also changing, so a special analysis is needed [13].

The IPR describes pressure drawdown as a function of production rate, where drawdown is defined as the difference between static and FBHP. The simplest approach to describe the inflow performance of oil wells is the use of the productivity index (PI) concept. It was developed using the following assumptions [14]:

- Flow is radial around the well;
- A single-phase liquid is flowing;
- Permeability distribution in the formation is homogeneous;
- The formation is fully saturated with the given liquid.

The flow through a porous media is given by the Darcy equation:

$$\frac{q}{k} = \frac{k dp}{\mu dl} \quad (1)$$

Using the assumptions above it can be written as

$$q = \frac{0.007088kh}{\mu\beta \ln\left(\frac{r_e}{r_w}\right)} \quad (2)$$

Most parameters on the right hand side are constant, which permits collecting them into a single coefficient called (PI).

2.4.2 Productivity Index (PI)

The productivity of a well should be an indication or measure of the producing quality of the strata within the drainage radius of the well [15].

PI is one of the important characteristics of a well's inflow performance which depends on the reservoir and fluid properties. From Equation [1],

$$PI = \frac{q}{p_e - p_{wf}} = \frac{2\pi kh}{\mu\beta} \frac{1}{\ln(r_e - r_w) + S} \quad (3)$$

$$q = PI(p_e - p_{wf}) \quad (4)$$

2.4.3 Tubing Performance

Production rates at various bottomhole pressures are used to construct the tubing performance curve which reflects the ability of the completion system to deliver production up the well bore and completion equipment [3].

Analysis of a Tubing performance or vertical lift performance (VLP) of a well is an important part of the well design. It allows selecting the well completion correctly corresponding to lifting methods and to evaluate well's performance. Accurate modelling of vertical lift performance is critical to predict a realistic production rate during the blow down phase [16].

3. Prosper[®] Approach and System Analysis

A robust PVT model for the reservoir fluid was constructed by entering laboratory PVT data and adjusting the correlation model until it fits the measured data for improving the accuracy of forward prediction.

The following flow chart gives an outline of the calculation steps required to carry out a system analysis using Prosper and the work had been performed according to this procedure.

3.1 Preparation of Well Model in Prosper[®]

Prosper Programme makes models for each component of the producing well system separately which contributes to overall performance, and then allows to verify each model subsystem by performance matching. In this way, the program ensures that the calculation is as accurate as possible. Once the system model has been tuned to real data, Prosper is confidently used to model the well in different scenarios and to make forward predictions of reservoir pressure based on surface production data.

3.2 Quality Checking of PVT Data

For preparing the well model in Prosper, the following PVT input data of Black oil model had been entered in Prosper program. The PVT method used was Single Stage Flash of Recombined Reservoir Fluid. The PVT inputs Parameter are: Solution Gas Oil Ratio – 500(scf/STB), Oil Gravity- 39 (API), Gas Gravity -0.798 (sp. Gravity), Water Salinity-100000 (ppm), Mole per cent H₂S-0 Mole per cent CO₂-0 and Mole per cent N₂-0.

Flash data, not differential liberation data had been used for matching. Where only differential liberation data is available, a PVT simulation program can be used to calculate the flash properties using a model that has been matched to the lab data.

4. Gas lift design

4.1 Performance Curve

While performing the gas lift design, the best compromise between some objectives were sought:

- Gas was injected as deep as possible.
- Depth and number of unloading valves were determined.

The operating injection pressure is set to 1900 psig. Desired dP across valves (250 psig) is entered to ensure well and gas injection system stability. Minimum spacing between valves is set to 500 feet.

Valve settings is chosen to "PVC = Gas Pressure". Then PROSPER sets valve dome pressure to balance casing pressure at depth. Unloading valves will close when the casing pressure drops below this value. For this study a "Camco BK Normal" valve is chosen from the PROSPER database.

The software calculates which port sizes that will generate optimal production. A valve from another manufacturer would maybe require different port sizes, but PROSPER still calculates the same optimal production. Therefore the

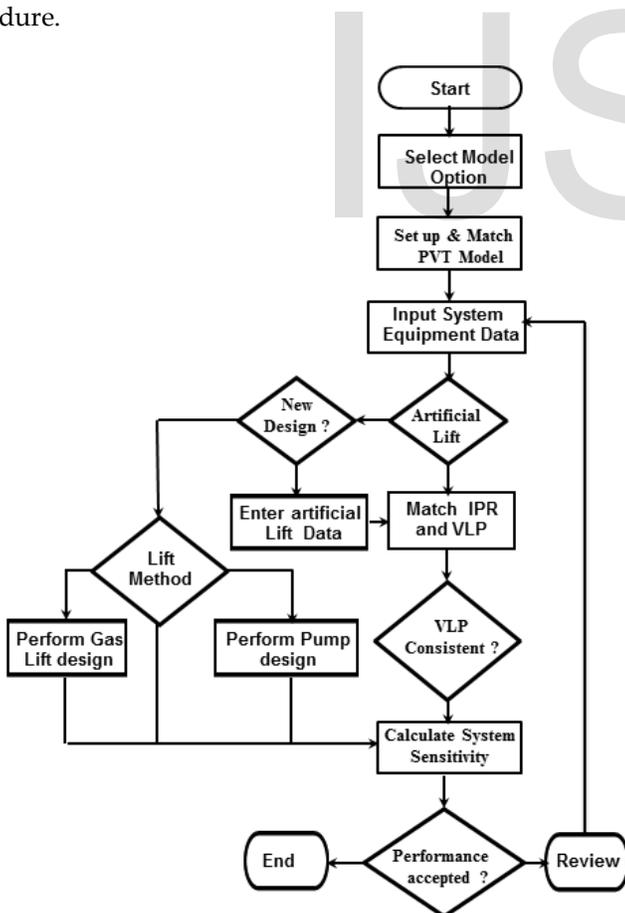


Figure 2 Systems Analysis Using Prosper[®]

choice of type is not that important as long as it is casing sensitive.

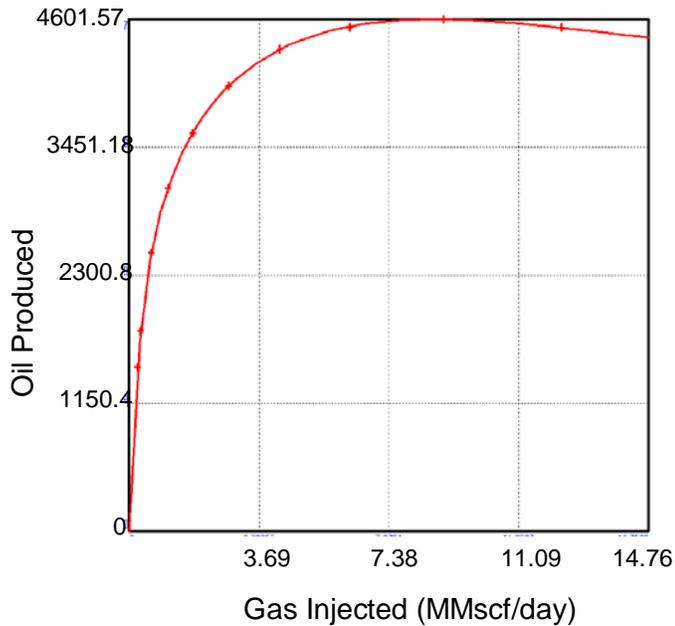


Figure 3, Gas Lift performance Curve

The performance curves give us a plot of oil produced versus the gas injected. The injection gas rate of 8.0MMscf/day gave the highest production rate of 4601.57 STB/day. This is the optimum point of injection in terms of revenue. That point is where the incremental additional cost of compressing gas equals the incremental revenue of the additional oil produced. A further increase in injection rate to 9MMscf gave a maximum production of 4524.01 STB/day this is a decrease in oil rate hence 8.0MMscf/day is the economic optimum gas injection rate which yields the maximum oil production. In case the available gas is higher than the optimum gas required, the programme will only inject the optimum gas into the well.

A PVT plot with GOR versus Pressure had been drawn to check the consistency with the match data. From the plot diagram, it had been observed that the Black oil model had been properly matched with the PVT match data.

4.2 Correlation Comparison and Selection

To match the vertical lift performance, correlation for the multiphase flow was turned to enable matching the down-hole pressure measurement so that the intersection of VLP/IPR will match the production rate as per well test data. The IPR model used is Darcy the available parameters

is dependent on the IPR in use. Pressure was adjusted to match the IPR most important correlations had been primarily considered for rough quality check. Those are Glaso and Beal et al correlations. The well correlation comparison is as shown in figure 4.

4.2.1 Pressure versus Measured Depth Plot

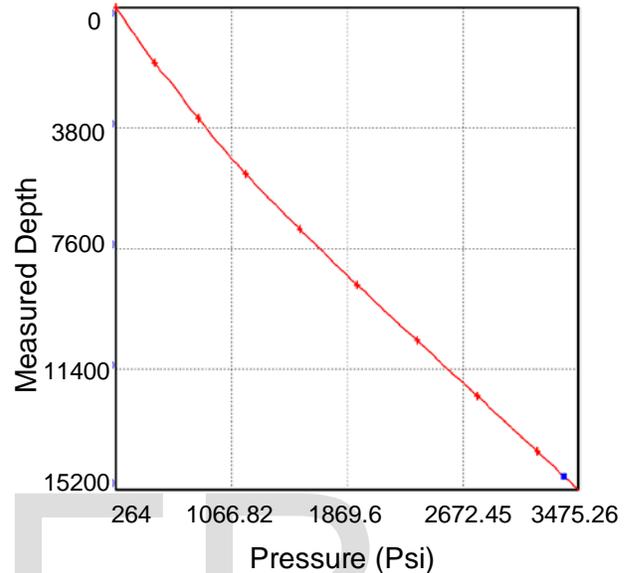


Figure 4, Correlation Comparison Plot

It can be observed from Figure 4 that greater well depths measured were associated with higher pressure, though not proportionately, but corroborating Pascal pressure - depth classic relationship.

4.2.2 IPR Matching

This feature was used to check the consistency of the bottomhole pressure data used in the VLP matching and to adjust the IPR to match the measured data. When the desired correlation (PE 2) had been selected, Prosper calculated the VLP for a range of rates and pressure at the sand face for each active test point that had been entered in the VLP matching screen. Once the calculation was completed, the IPR input screen was represented.

When the test point was not consistent with the IPR model, Productivity index (PI) had been adjusted in PI entry model until a match is obtained. Matching both the VLP and IPR to actual test data ensured that the Prosper well model was capable of accurately reproducing the currently known producing conditions. Bellow is the VLP/IPR matching curve

To match the vertical lift performance, the multiple flow correlation was turned in order to match a downhole pressure measurement to enable the intersection of VLP/IPR match the production rate. The IPR model in use determines the available parameters for matching. For this study Darcy IPR was used Pressure or permeability could be used. Thus Pressure was adjusted to match IPR and the GOR was checked to ensure test data is same with PVT data since the reservoir is still under saturated. The inflow performance relationship is as shown in Figure 5 below with skin of 3 and productivity index of 10.88stb/day/psi which gave an absolute open flow of 16000.7stb/day.

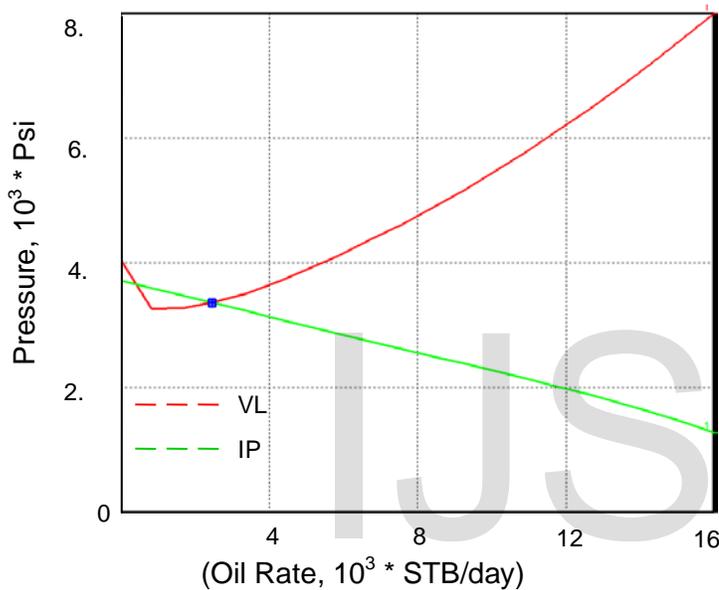


Figure 5, VLP/IPR matching curve

4.2.3 Positioning of valves

While designing the valve system PROSPER was set to check whether the solution rate is achievable with respect to the IPR. Figure 6 shows the result for valve spacing design.

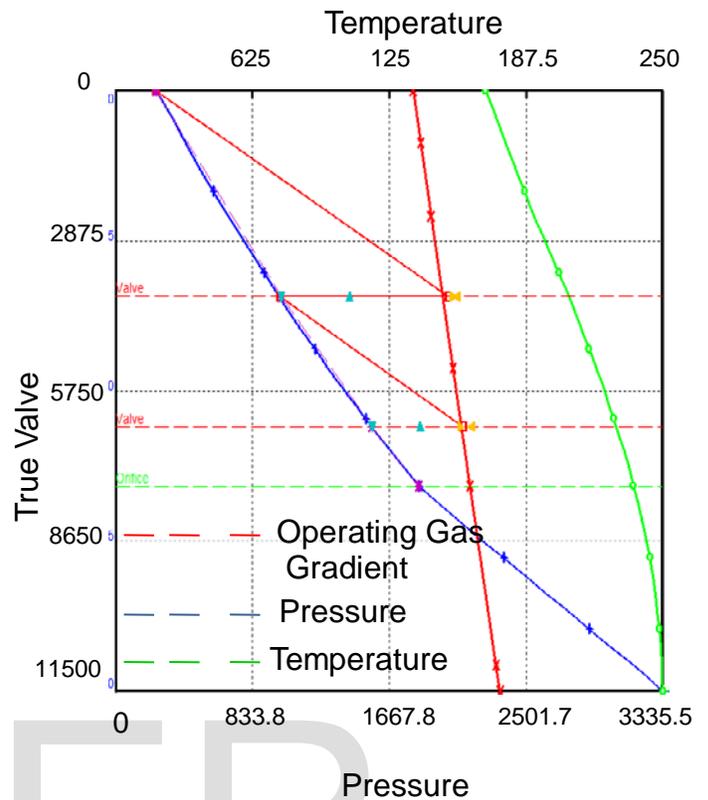


Figure 6, Valve Spacing for Well A-06

The result from gas lift design showed that: (a) Depth unloading valve – 3952.75ft, Unloading port valve (64th) – 24inches, Depth 2nd Unloading valve -6440ft, 2nd Unloading port valve (64th) is 24inches, Depth of operating valve is 7577.72ft, operating valve port (64th) size is 24inches, Oil rate with gas lift is 4557.44(STB/day).

The minimum pressure of 1865Psi was achieved at the optimal gas rate of 7.00MMscf/day.

4.3. Sensitivity

To optimize a system it is pertinent to carry out sensitivity analysis on the key parameters that affects the well's productivity. In this study four parameters were used in the prosper sensitivity analysis for production optimization test, they are tubing diameter, oil flow rate, gas lift injection rate.

4.3.1 Tubing Diameter

To investigate the effect of tubing diameter on oil flow rate a sensitivity analysis was run using variable tubing diameter to calculate production rate for each tubing size. Hence, the oil flow rate for 2³/₈ inches tubing diameter was ob-

tained as 2258.8 STB/day, 2⁷/₈ inches tubing diameter was 2709.2, 3¹/₂ inches tubing diameter was 3347.0, and for 4¹/₂ inches tubing diameter oil flow rate was obtained as 4601.57 STB/day. The results show that a larger tubing size gives an increased production.

4.3.2 Gas Lift Injection Rate

To investigate the effect of gas lift injection rate a sensitivity analysis was run with variable gas lift injection rate. Hence Oil rate for 1, 1.5, 2, 2.5, 3, 5, 8, 9, 10 MMscf/day was obtained as 2955.2, 3383.7, 3698.0, 3911.8, 4072.9, 4458.1, 4601.57, 4524.01 and 4473.01 STB/day respectively.

5. Conclusion

❖ Obtaining the optimum gas injection rate is important because excessive gas injection rate reduces oil production rate and increases operation cost. To obtain the optimum gas injection and oil production rate, Iduo well A-06 had been modelled properly. Flash data of recombinated reservoir fluid had been used for PVT matching. Glasco and Beggs et al correlations were found best-fit correlation for PVT matching.

❖ The available well test data had been considered for quality checking. Since the reservoir parameter is continuously changing from inception of production, current well test data was the focus for quality checking of well test data. In this work, it was found that current well test data for the well had been matched with calculated data in Prosper.

❖ For correlation comparison of VLP, Petroleum Expert 2 was found very close to well test data for the well test. Parameter 1 and 2 was close to unity. Thus PE-2 correlation had been used for VLP matching in Prosper.

❖ Iduo well A-06 currently producing 1200 STB/day of oil without gas lift with water cut of about 50% in a 3¹/₂ inches tubing size. From the design economically optimum oil production rate of 4601.57STB/day was achieved with gas lift optimum injection rate of 8.0MMscf/day with 20% water cut in a 4¹/₂ inches tubing.

❖ From the design, depth of unloading valve is 3952.75ft and operating valve depth is 7577.72ft. The minimum pressure achieved at optimal gas injection rate is 1865.1Psi.

Recommendation

The design should be replaced with an intermittent gas lift when the reservoir pressure becomes very low.

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