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Artificial Lift Method Selection and Design to Enhance Well Production Optimization: A Field case study

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Abstract

The oil and gas production rate normally declines due to several parameters, so the artificial lift technique is effective and requires energy to lift the fluid column in the wellbore and optimize production. There are various techniques used recently but the two techniques applicable in the oil and gas industry are gas lift and electrical submersible pumping. Gas lift technique aims to lower flowing bottomhole pressure and decrease the density of the well fluid in the tubing by injecting high-pressure gas from the annulus. Thus, producing a pressure differential that allows flowing the fluid from the wellbore to the surface. On the other hand, ESP lifts the fluid in the wellbore by exposing it to centrifugal force and rotation in each pump stage that changes kinetic energy to potential energy. The design for ESP and gas lift were performed using Prosper software to enhance the production. Prosper is an artificial lift software simulator that troubleshoots, designs and evaluates lifting mechanisms for field optimization and digital oil field system. The analysis of ESP and Gas lift were conducted to choose a suitable method for the determined field. Typical gas injection rates are computed to ensure extreme oil production and sensitivity analysis of water cuts is directed which yields the greatest water cut for upgrading the total oil production. Field data were obtained from existing two wells horizontal and vertical that stopped due to reduction in reservoir pressure, thus required to apply artificial lift methods to lift wellbore fluids to surface and production facilities. The analyzed results showed that, after comparing the maximum oil production rate for both horizontal and vertical wells, the ESP system provided an increase in oil production compared to the gas lift method in this field. Both wells are increasing significantly in terms of production when using ESP systems. Both wells have a total liquid rate, which lies well within the production range of the pump between the minimum and the best efficiency line curve.

Keywords: *Electrical submersible pump, Prosper software; Artificial lift methods Well performance, Gas lift.*

1. Introduction

The production stage plays an important role in producing oil and gas. Once a reservoir starts to produce, it will flow naturally for some period. Oil wells that are flow naturally by natural energy are called flowing wells. This natural energy is provided by the pressure differential between reservoir and wellbore to lift the fluids to the surface. In order for the fluid to be lifted from the bottom of a well to the surface facilities, sufficient energy must be required to overcome the friction losses in the system [1].

Optimizing the production rate from flowing wells is one of the most important roles of the artificial lift methods [2]. The gas lifting method uses a compressed gas that is injected from the surface to certain points in the tubing. This gas will lower the density of the fluid column in the tubing causing a reduction in the wellbore pressure and therefore increasing production. The pumping method, on the other hand, involves setting the pump at a certain depth inside the tubing that will cause it to be submerged below the liquid level. This pump will lower the wellbore pressure and hence increase the drawdown, causing more production [3-4].

There are a various techniques for artificial lift that are usually utilized which are sucker rod or beam pumping, gas lift, electric submersible pumping, and hydraulic pumping [5]. The determination of artificial lift method must relies on upon a few factors, for example, well depth, accessibility of gas, production rate required, hole deviation, and so forth [6].

In the early phase of oil productions from a flowing well, the reservoir liquids being lifted from the wellbore to the surface by method of naturally flowing [7]. As indicated by API gas lift manual, the pressure differential of reservoir and surface production facilities cause the oil to be delivered from a well [8]. As the time goes and the oil fields get to be develop, the reservoir pressure will drains and the well will have lacking vitality to lift the oil to the surface [9].

The artificial lift techniques kick off the dead wells to begin reproduced again and to enhance the oil production rate from the wellbore to the surface [10]. By applying the artificial lift techniques, the inactive well can be producing once more. The artificial lift techniques should be pick carefully and relies on upon numerous elements which incorporates reservoir pressure, well depth, capability of well and sort of the produced liquid [11, 3]. Inappropriate choosing of artificial lift system can cause decreasing of production and cause high working expense [12].

Electrical Submersible Pumps are the vertical alignment of centrifugal pumps in the borehole which increases the velocity of wellbore fluids by impellers. The kinetic energy produced by the impellers is transformed into pressure energy by the diffuser and pumps the fluid [13]. An Electrical Submersible Pump is a multi-stage stacked centrifugal pump whose stages are determined by bottom hole pressure and desired flow rate. The arrangement of each stage of an ESP System consists of an impeller and diffuse [14].

As the liquid comes into the well it must flow preceding the motor and into the pump. This oil flow past the motor helps in the cooling of the motor. The liquid then enters the intake and is passed into the pump. Every stage (impeller/diffuser mix) subjoins pressure or head for the liquid at a given rate. The liquid will build up sufficient pressure, as it achieves the highest point of the pump, to be displaced to surface and into the separator or flow line [15-16].

Gas lift is a type of artificial lift in which the displaced gas is initially compacted and afterward injected into the tubing string through annuls between tubing and casing then when this lift gas goes into tubing then because of extension it pushes the oil lift to the surface along these lines lessening the bottom hole pressure because of decrease in thickness since lighter segments of gas will blend with viscous oil [17-18]. In the vast majority of the oil and gas industries gas lift innovation is being applied on the grounds that it is exceptionally suggested for veered deviated wells having warped holes, oil containing sand and gassy oil wells. The other vital value of gas lift technology is that the operational expense for lifting generally bigger number of well is low given that lift gas supply is inside of the region of oil field [19-20].

2. Methodology

The design for ESP and gas lift were performed using Prosper software to enhance the production. Prosper is an artificial lift software simulator that troubleshoots, designs and evaluates lifting mechanisms for field optimization and digital oil field system. The analysis of ESP and Gas lift were conducted to choose a suitable method for the determined field. Typical gas injection rates are computed to ensure extreme oil production and sensitivity analysis of water cuts is directed which yields the greatest commercial water cut for upgrading the total oil production. Field data were obtained from existing two wells horizontal and vertical that stopped due to reduction in reservoir pressure, thus required to apply artificial lift methods to lift wellbore fluids to surface and production facilities.

The created model in this project is based upon an on land well named X. Because of the long existence of the reservoir, its pressure has declined to a low level and subsequently, production almost seizes. Subsequently, it is important to introduce an artificial lift system keeping in mind the end goal to enhance the production and drag out the well's lifespan.

2.1. Field and well data

The field is located in the Marib-Shabwa Basin, south-east of the prolific Jannah field. The well data are obtained from two wells, one is vertical well y and the second one is horizontal well x. The horizontal well trajectory is deviated well and by using the build and hold type to build the inclination angle. The setting depth of kick the off point (KOP) is at 1,200ft and the angle build rate is 2.5 degrees per 100ft. The maximum inclination angle was 45 degrees and the true vertical depth (TVD) was 11,500 ft. The azimuth angle keeps no change because the well is 2D. As there was no estimation, roughness of the pipelines is accessible, the standard estimation of 0.0006 in will be utilized. The tubing inside diameter was 4.052 inch.

The data of the reservoir is shown in Table 1. The Dietz shape variable is determined as 30.9, a quality that compares to the state of the drainage area which is roughly square and the well is put in the middle. The skin factor was assessed to be 0.5. The noted temperature gradient as 1.6522 ^{o}F/100ft. Along these lines, temperature of the reservoir can be ascertained by multiplying temperature by the TVD and including the surrounding temperature.

The accessible PVT data is identified with an immediate glimmer (single stage detachment) of the reservoir liquid from reservoir statuses down to standard situations. As indicated by its API gravity, the oil can be arranged as unstable and generally simple to stream in a pipeline. At present, reservoir statuses were under saturated, meaning the reservoir pressure was above bubble point as shown in Table2.

Table 1. Reservoir properties

PVT properties	Value
Reservoir pressure (Pr)	3100 psig
Reservoir permeability (K)	*100 mD*
Drainage area (A)	493 scf/stb
Thickness (h)	100 ft
Dietz shape factor	30.9
Skin factor (S)	0.5

Table 2. PVT liquid properties

PVT properties	Value
API gravity	38.7 API
Bubble point pressure	2,200 psig
GOR	493 scf/stb
Specific gravity of the gas	0.798
Density	694 kg/m^3
Water salinity	80000 ppm
Viscosity	0.41 cP

3. Results and discussion

The designed ESP system needs to consider the prediction of future performance of the well when the operating conditions, according to the existing reservoir, the minimum production rate required to sustain an economically vital well is 2,000 stb/day.

3.1. Designing ESP system for vertical well-y

In order to start designing ESP for vertical well, ESP parameters were inserted such as pump depth, operating frequency, maximum OD, length of cable, gas separator efficiency, design rate water cut, total GOR, top node pressure, motor power safety margin, pump wear factor, pipe correlation, and tubing correlation. As mentioned in Table 3.

Table 3. ESP input design data for vertical well-y

Input design data			
Pump depth	10000 feet	Design rate	10000 STB/day
Operating frequency	70 Hertz	Water cut	40 percent
Maximum OD	6 inch	Total GOR	493 SCF/STB
Length of cable	10000 feet	Top node pressure	264 psi

In order to perform the ESP design PROSPER was calculated the above parameters. Table 4 shows parameters required to choose pump system

Table 4. ESP design calculation for vertical well-y

ESP design calculation for vertical well-y			
Pump intake pressure	887 psi	Pump discharge rate	11870 Rb/STB
Pump intake temp	226 deg F	Total GOR above pump	493 scf /STB
Pump intake rate	17429 Rb/day	Average downhole rate	12838 Rb/day
Free GOR entering pump	308 scf/STB	Head required	8118 feet
Pump discharge pressure	3549 psi	Average cable temp	194 deg F

To assess either downhole gas separation required. Sensitivity option was selected to visualize the Dunbar plot which is relation that can be interpreted as if the test point is above the red curve, then downhole gas separation is not required. Otherwise, down hole separation is not recommended since test point above the red curve as seen in Figure 1.

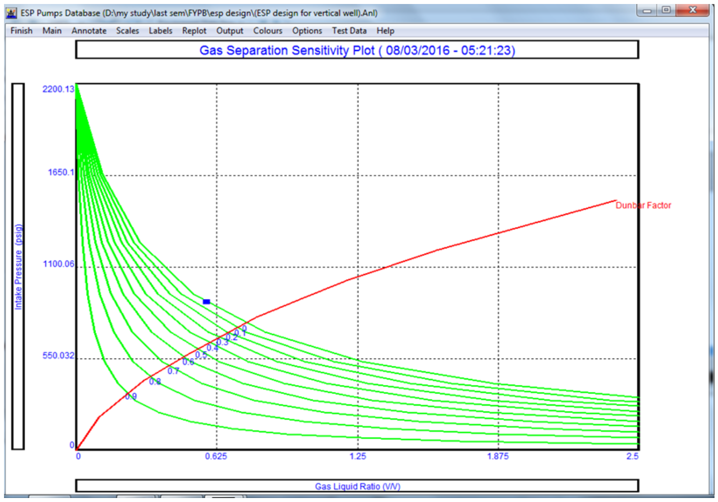

Fig 1. Gas separation sensitivity plot (vertical well-y)

By referring to the above plot no need for downhole gas separation because the test point is above the Dunbar factor curve. Based on ESP design calculation in Table 4 the pump intake pressure is 887.799 psig and input design rate was 10000 STB/day .According to theses pump type was selected.

Table 5. ESP selection screen for (vertical well-y)

Results for selected equipment			
Number of stages	117	Motor efficiency	83 percent
Power required	790 hp	Power generator	790 hp
Pump efficiency	73 percent	Motor speed	4002 rpm
Pump outlet temp	233 deg F	Voltage drop along cable	507 volts
Current used	124 amps	Voltage required at surface	4427 volts

To see the pump performance curve plot it was plotted as obvious in Figure 2 the operating rate verse head (feet) the red point referred to operating point. As minimum range of operating is shown in Figure 2 which is produced 7000 bbl/day at 70 Hz and 13,200 bbl/day as maximum oil production rate . Also the best line of efficiency is at the optimum point of operating where the efficiency curve at the highest level of the pump.

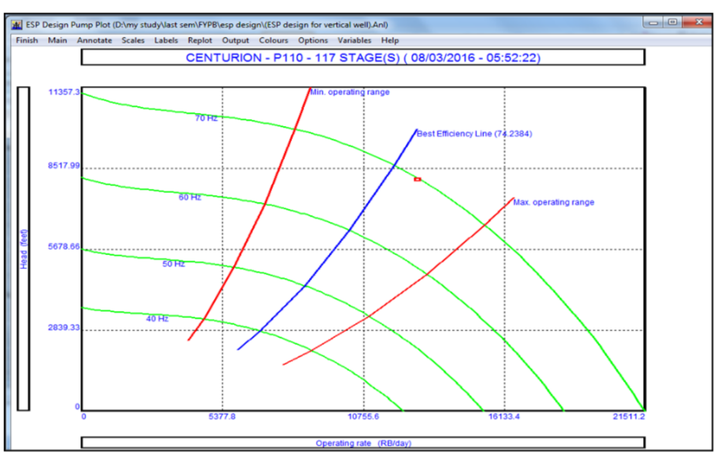

Fig 2. Pump efficiency curves for Centurion 562 P110 (vertical well-y)

3.2. Designing ESP system for horizontal well-x

After inserting well data for PVT and IPR and Equipment to perform the ESP design and calculation, all parameters required to choose pump system as detailed in Table 6.

Table 6. ESP design calculation for (horizontal well-x)

ESP design calculation for (horizontal well-x)			
Pump intake pressure	1324 psi	Pump discharge rate	11952 Rb/STB
Pump intake temp	227 deg F	Total GOR above pump	493 scf /STB
Pump Intake Rate	14195 Rb/day	Average downhole rate	12544 Rb/day
Free GOR entering pump	213 scf/STB	Head required	4170 feet
Pump discharge pressure	2723 psi	Average cable temp	196 deg F

To estimate either downhole gas separation required. Sensitivity option was selected to visualize the Dunbar plot which is in this case is not required. As the test point is above the Dunbar factor curve shown in Figure 3.

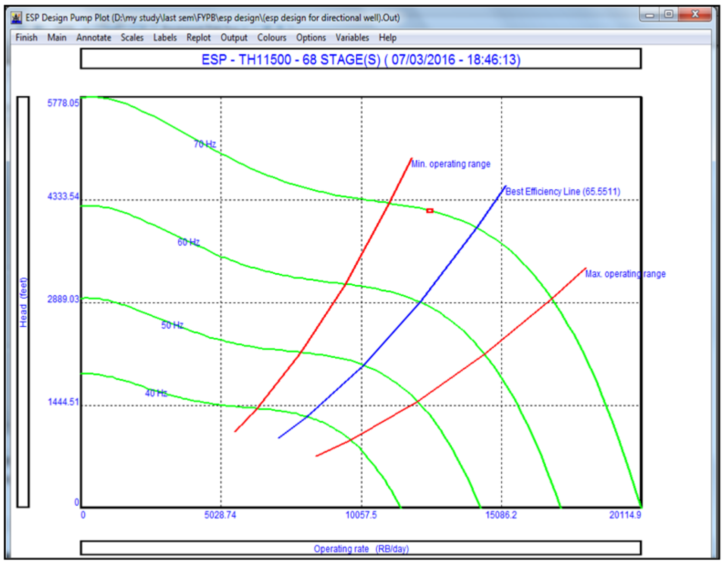

Fig 3 Gas separation sensitivity plot (horizontal well-x)

Based on ESP design the pump was selected which is (ESP 562 TH11500) and the fluid power required which is 298.04 (hp) the motor was selected which has the 432 HP. Horsepower and head coefficients are received by the ESP 562 TH11500 which is placed into the data base of PROSPER. The pumps curves were calculated using previous coefficients by the software which will simulate any condition. Figure 4.

Results for selected equipment (horizontal well-x)			
Number of stages	68	Motor efficiency	90 percent
Power required	466 hp	Power generator	466 hp
Pump efficiency	64 percent	Motor speed	4097 rpm
Pump outlet temp	234 deg F	Voltage drop along cable	343 volts
Current used	106 amps	Voltage required at surface	2968 volts

Horsepower and head coefficients are received by the ESP 562 TH11500 which is placed into the data base of PROSPER. The pumps curves were calculated using previous coefficients by the software which will simulate any condition. Figure 4.

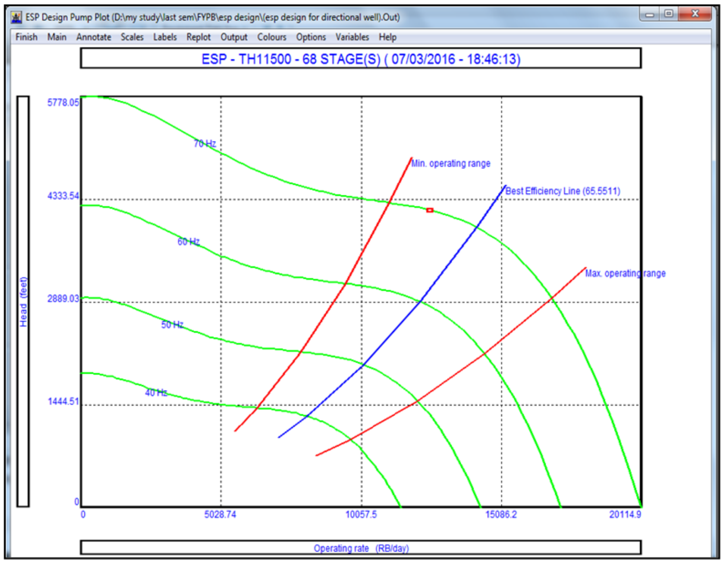

Fig. 4 Pump curves for ESP 562 TH11500 (horizontal well-x)

Table 7. Results for selected equipment (horizontal well-x)

3.3. Summary result of designing ESP system for (horizontal and vertical well-x)

As maximum oil production rate for horizontal well was 14500 bbl/day and minimum range of operating which is produced 9500 bbl/day at 70 Hz. Also the best line of efficiency is at the optimum point of operating where the efficiency curve at the highest level of the pump is. The production is increasing significantly in this well which is compared to nature flow. In vertical and horizontal wells have fluid rate which depends on the range of operating for the pump in between of low and best efficiency curve. This means that good capacity still handling more liquid. However, after designing ESP production rate for horizontal well is greater than the vertical well.

3.4. Design continuous gas lift system for (horizontal and vertical well)

At the point when demonstrating a gas lift well various parameters must be inserted into the System. Pressure injection in the operation was set to2,000 psi. Required dP crosswise over valves 100 psi, is entered to guarantee well and system of gas injection is stable. Distance between valves was minimized and set to 250 ft. The static gradient of load fluid of0.45 psi/m. additionally greatest injection depth for every well was set. The most utilized valve sort is the casing sensitive, which is likewise picked here. Valve settings is decided to "Pvc = Gas Pressure". At that point PROSPER sets valve vault pressure at depth to adjust casing pressure. Emptying valves will close when there dropping of casing pressure beneath this value. For this study from the database of the PROSPER (Camco) Normal valve is selected the software computes that port sizes that will create ideal production as shown in Tables 8 and 9 respectively

Table 8. Gas lift design calculation for (horizontal well-x)

Gas lift design calculation for (horizontal well-x)			
GLR Injected	1726 scf/STB	Valve number 1	4332 feet MD 3643 feet TVD
Liquid rate	9337 STB/day	Valve number 2	7966 feet MD 6213 feet TVD
Oil rate	5602 STB/day	Valve number 3	10129 feet MD 7742 feet TVD
VLP	3543 psi	Valve number 4	11169 feet MD 8478 feet TVD
Design rate	8 MMscf/day	Operating valve 5	11537 feet MD 8738 feet TVD
Oil production	4149 STB /day		

Table 9. Gas lift design results

Gas lift design results			
Liquid rate	6914 STB /day		
Oil rate	4148 STB/day		
Injection gas rate	2.48716 MMscf/day		
Injection pressure	1600 psi		

By referring to the above data after the valve spacing process, the final operating conditions are visible. A constant gas injection rate of 6.043 MMscf/day with an injection pressure of 1650 psi can deliver 3905.77 STB/day of oil. A valve from another producer would perhaps require diverse port sizes, yet PROSPER still computes the same ideal production. Thus, the option of the type is not that significant when it is sensitive casing Gas lift design calculation screens for both horizontal and vertical wells are shown in Tables 10 and 11 respectively

Table 10. Gas lift design calculation screen for (vertical well-y)

Gas lift design calculation screen for (vertical well-y)			
GLR injected	3314 scf/STB	Valve number 1	3707 feet MD 3704 feet TVD
Liquid rate	4512 STB/day	Valve number 2	6712 feet MD 6708 feet TVD
Oil rate	2707 STB/day	Valve number 3	9049 feet MD 9044 feet TVD
VLP	3135 psi	Valve number 4	10801 feet MD 10794 feet TVD
Design rate	7.86 MMscf/day	Operating valve number 5	12000 feet MD 11992 feet TVD
Oil production	2179 STB /day		

Table 11. Gas lift design results

Gas lift design results			
Liquid rate	3605 STB /day	Injection gas rate	7.38257 MMscf/day
Oil rate	2163 STB/day	Injection pressure	1600 psi

Based on the figure below at the bottom of the designing screen and after the valve spacing process, the final operating conditions are visible. A constant gas injection rate of 7.38 MMscf/day with an injection pressure of 1600 psi can deliver 2164 STB/day of oil. Presently PROSPER can compute a gas lift curve of performance. Figures 5 and 6 demonstrate the curves for vertical as well as horizontal well-x conditions.

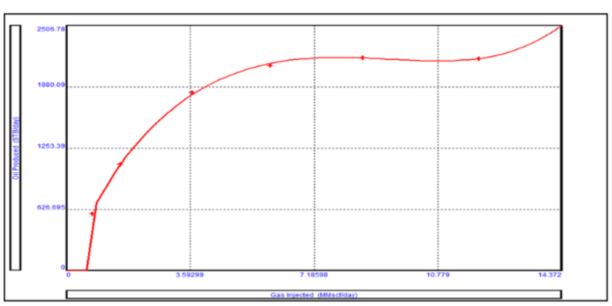

Fig. 5. Gas lift performance curve for (horizontal well-x)

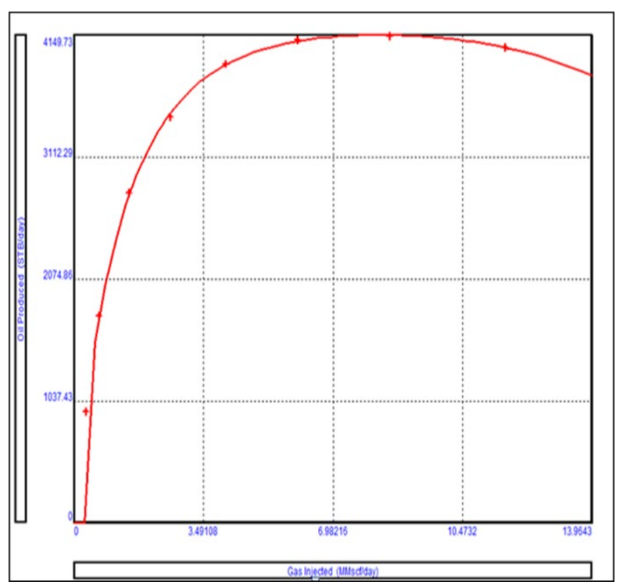

Fig 6. Gas lift performance curve for (horizontal well-x)

The execution curves plot a plot of injection of gas versus production of oil the rate of gas injection that gives the most rate of production can be found, in spite of the fact that won't be the ideal purpose of injection as far as income. That point is the place the incremental extra cost of gas compress rises to the incremental income of the extra oil delivered. The economic ideal injection of gas rate is frequently found to one side of the maximum rate of production in such a curve. At the point when taking a gander at the curve it is clear that none of the wells will achieve greatest production with an injection rate of 6.043 MMscf/day.

Vertical x-well is delivering in a more extreme piece of its curve, yet a higher increase in injection rate into this well won't increase the production total. Horizontal well-x delivers bigger amount of oil volumes, so regardless of the fact that we inject more gas into Vertical well-y, and get a bigger percentual increment of out of this well, horizontal well-x will give more oil with the same injected gas. This demonstrates the significance of a full system investigation.

3.5. Gas lift valves distribution for (horizontal well-x and vertical well-y)

Valve separating is not influenced by the decision of emptying strategy (tubing or casing sensitive), however of whether the well IPR is utilized for calculating the emptying rate or not. At the point when outlining the valve system PROSPER can be set to check whether the arrangement rate is achievable as for the IPR. In the event that fundamental the design rate is decreased and the spacing estimation is rehashed. Figures 7 and 8 demonstrates the consequence of valve dividing plan for horizontal and vertical well-y.

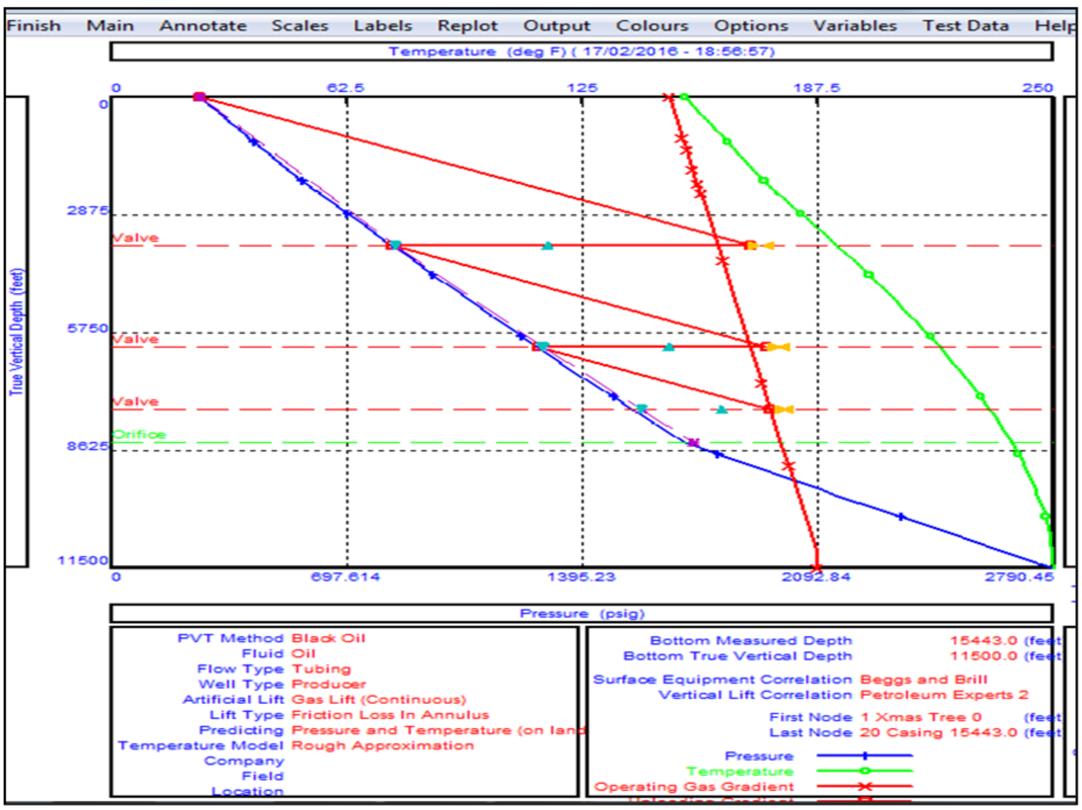

Fig. 7. Valves distribution for (horizontal well-x)

The space of valve calculation is done as following:

For the tubing, that already designed with gas rate injection, a pressure navigate is computed from the surface and downwards utilizing the gas lifted streaming gradient (blue line). A comparable plot is made for the pressure of casing (red line in the right).The depth of injection [hole valve] is where the depth of casing gradient less and flowing tubing pressure are equals less pressure loss designed across the orifice. Nonetheless, depth of injection is regularly restricted by the design of well, for instance by a weak casings or production packer.

The shallowest emptying valve is set at the depth that adjusts the tubing stack liquid pressure (left red line) with the pressure of casing at same depth. Assist emptying valves are put by navigating down like this between gas lift tube and the case pressure gradient lines. Valves are put ever more deep until the internal valve space similar with a pre-set least, or the most extreme injection depth has been come to.

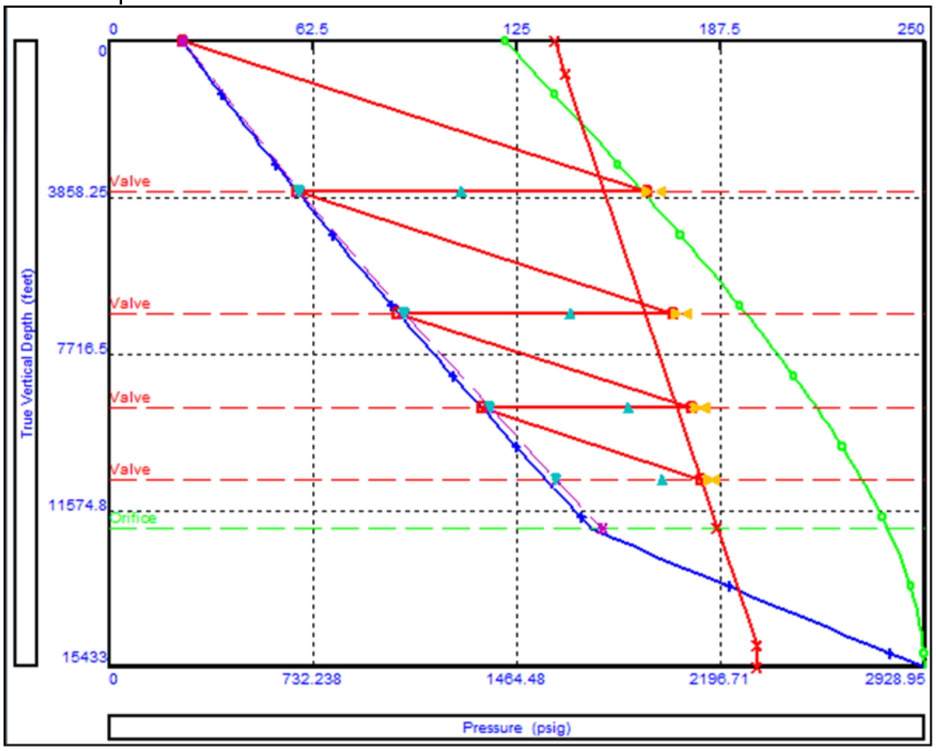

Fig. 8. Valves distribution for (vertical well-y)

Once the primary design is finished, software can re-figure the streaming tubing gradient utilizing the current working valve depth. This was a bit much for horizontal and vertical well-y in light of the fact that both wells could inject at the pre-set greatest injection depth.

3.6. Investigate the applicability of suitable method for production improvement

There are many considerations in order to analyze the relevance of suitable strategy for production enhancement using gas lift system or ESP. After the continuous gas lift been designed for the horizontal and vertical x-well, the result that was obtained is shown in the Table 12.

Table 12. Production rate for both (horizontal and vertical x-well) using gas lift

Results of designing gas lift	Horizontal well-x	Vertical well-y
Unloading valve1 depth ,ft (md)	4309.62	3707.2
Unloading valve2 depth ,ft (md)	7793.47	6708.37
Unloading valve3 depth ,ft (md)	9961.54	9044.05
Operating valve depth, ft (md)	11094.2	12000
Oil production rate bbl/day	3905.77	2163.51

From the Tables 12 and13, basically the results are showing that both wells are increasing significantly in term of production due to the gas injection. This is a combination of operating valve setting depth, gas lift injection, and pressure and load fluid density. This data show that, the deeper setting depth of the operating valve, the more oil production. The obtained oil production rate from horizontal x-well after installing continuous gas lift was 3905.77 bbl/day. However, 2163.51 bbl/day was the result of oil production rate from vertical x-well which is less than the horizontal. After the ESP simulation been designed for the horizontal and vertical x-well, the result that was obtained is shown in the Table 12.

Table 13. Production rate for both (horizontal and vertical well-y) using ESP

Results of designing ESP	Horizontal well-x	Vertical well-y
Maximum oil production bbl/day	14500	13200
Minimum oil production bbl/day	9500	7000
Number of stages	68	117

4. Conclusions and recommendations

This research work has successfully design ESP and continuous gas lift system for a well whose immediate operating conditions are affecting its productivity and it is about to seize flowing. A mathematical model, consisting of many sub models, were created using prosper to predict achievable fluid production rates in various operating conditions. The modelling of all parameters such as the IPR curve, the PVT data, downhole Equipment and the temperature profile along the well were thoroughly analyzed. Although, during the VLP/IPR matching process, deviations between modelled and measured data were observed. Prosper offered the opportunity to adjust the average reservoir pressure and the skin factor. The investigation of these two variables showed that both parameters can be adjusted individually without any significant effect on the validity of the model. The investigation includes adjustment of the IPR in terms of reservoir pressure. Results showed no significant deviations in the liquid rates. This means that both parameters, for this system, almost has equally affected the inflow performance of the well and its engineer's choice, which parameter is more suitable to be altered.

The reservoir pressure is adjusted and calculations continued with the revised value of pressure. As far as the ESP and gas lift design process is concerned, sensitivity analysis on tubing diameters up to 4.5" shows that the gasoline slip result on the good deliverability, which might lead to significant productivity reduction for enhanced tubing diameters, is minimal. Therefore, the new production tubing, upon which the gas lift design took place, is chosen to be the maximum possible, i.e. 4.5" ID Due to casing identity limit 6.4" ID as a way to maximize production. However, for future recompletions, the tubing size must be reconsidered when larger quantities of gas (gas lift gas and gas coming out of solution) are anticipated. There is a positive effect of setting the valves deeper. When the compressor outlet pressure is limited, the fluid density in the well is important. The valves can be set deeper with a less dense fluid, and this can also make the difference in number of unloading valves needed.

VRR versus time relationship gave a clear identification of the injection process monitoring correlated with decline curve analysis as well as the total oil, gas and water production was controlled and evaluated throughout 30 years of the simulation process. It can be concluded that an enough water and gas is required to be injected to replace the specified fraction of the reservoir volume (VRR=1). The VRR ratio was maintained on range of 1.5-1.2 and 2.0-1.4 in both scenarios respectively. Hence, the alternative method of injection gas and water using the injection wells to replace the fluid volume that was produced by the producers were successfully integrated.

Finally, the comparative analysis results showed significant productivity increase for both wells when artificial lifts are implemented. The gas lift method can be applicable but no better than using ESP. When using ESP both wells have a good total liquid rate, which lies well within the production range of the pump between the minimum and the best efficiency line, which means there is still a good capacity for producing more fluid. Comparing the maximum oil production rate for both horizontal and vertical x-wells. The oil rate for the horizontal is 14500 bbl/day, which is greater than the vertical production rate, which is 13200 bbl/day. ESP system provided an increase in oil production compared to gas lift method in this field.

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