International Journal of Petroleum and Geoscience Engineering
Volume 03, Issue 02, Pages 116-124, 2015

ISSN: 2289-4713

Improving Reservoir Recovery Factor Using Enhanced Electrical Submersible Pump Design; a Case Study

Monghad L. [a,]*, Safari M. [a], Jodeyri A. [b], Rayatdoost S. [c], Ghorashi S. [c]

[a] Reservoir studies and development research Division, Research Institute of Petroleum Industry
[b] Tehran Energy Consultant (TEC)
[c] Research Institute of Petroleum Industry (RIPI)

* Corresponding author.
E-mail address: Baharan.82@gmail.com

Abstract

Keywords:

Electrical Submersible Pump,
Production,
Recovery Factor.

Production from an offshore oil field – named as X – would be under natural depletion mechanism according to development plan of 25 years from 4 horizontal wells. Natural production plateau time of X oil field will be 6 years, so in order to preserve production plateau of the filed longer, it should be added some source of energy to the wells to compensate pressure drop within the wellbores. One of the practical methods is using artificial lift and for this purpose Electrical Submersible Pump (ESP) is designed for each of 4 horizontal well in this reservoir. In this paper all pump features and its designing parameters will be presented. To accomplish the sensitivity analysis on design variables, it needs to make the Inflow Performance Relationship (IPR) model, and outflow model is combined with the inflow model to get a solution point on the rate and bottom-hole pressure of the wells. Finally different values of design variables are applied to the model to investigate the possible variations of the production also its impact on reservoir recovery factor. As a result reservoir recovery factor increases to 8.91 and 11.66 percentages in scenarios of production with different type of ESPs in wells, in front of 6.6% recovery in natural depletion.

Accepted: 20 Juen2015

1. Introduction

Drilling mud, Production from an offshore oil field – named as X – would be under natural depletion mechanism according to development plan of 25 years from 4 horizontal wells. Field oil production of 10000 STB/day is employed for model constrain According to the field potential. Since minimum required well head pressure for each well is 400 psia, natural production plateau of the field will be 6 years (Production plateau starts decreasing because wells reach to well head pressure constrain). So, in order to preserve production plateau of the filed longer, it should be added some source of energy in to the well to compensate pressure drop within the wellbore. For this purpose, artificial lift can be utilized in such a way that lifting the fluids in the well to the surface with at least 400 psia well head pressure. One of the best artificial methods which can be used in offshore field is Electrical Submersible Pump (ESP). As a matter of fact, ESP is the only down-hole pump that can be used in offshore field and other down-hole pumps like SRP and PCP because of their limitation such as their weight and space cannot be used in offshore field. In this section, two types of ESP is designed in X field. In the first design, low horse power pump is used and in the second cases, high horse power pump is utilized. In this paper all pump features and its designing parameters also its impact on reservoir recovery factor will be presented.

2. Methodology

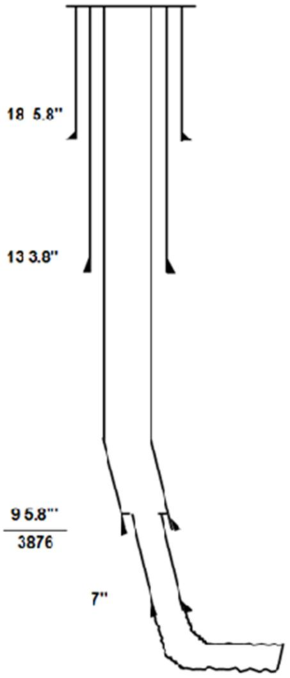
For ESP design in a typical well of this reservoir, the main inputs into the calculations are PVT parameters and tables as well as Reservoir parameters. Figure1 demonstrates the well sketch for typical prediction well in X field. According to this figure, the well is horizontal and is completed as open hole. Table also shows details deviation survey of this well.

Basic parameters for ESP Design considered as follows:

Pump Depth: As a general, Pump setting depth in the well should be set in a manner that low amount of free gas can enter to the pump. Pump manufacturer state that, maximum 10% of the total liquid which enter to pump can be free gas. It means allowable amount of the gas that can be entering to pump should be only 10 % of the total liquid. Free gas more than 10% causes severe problem such as pump gas locking. So, the more the pump setting depth, the less the amount of gas enters to the pump. Although setting pump at higher depth decrease risk of the pump gas locking, the economic aspects should be considered too because the more the pump setting depth, the more the economic cost. There are several reasons to find the optimum pump setting depth as following: Because of the high uncertainty in X oil field and in order to avoid pump gas locking, it is better to set the pump as deep as it can. In the other hand high amount of the impurities in hydrocarbon fluid (mole percent of CO_2 and H_2S is 2.15 and 0.69 respectively) can be corrosive for Casing, so using tubing in the well can protect casing. As a result, setting the pump deeper, isolate the casing from being corrosion. To sum up, pump setting depth is set in 3600 mss near the liner hanger of 7 inch in wells of X field.

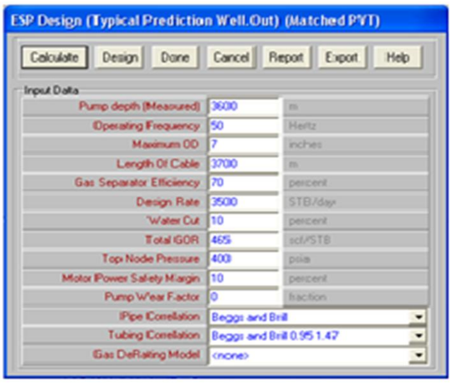
Gas Separator: Although no free gas enters to pump, reservoir depletion will be occurring by increasing production time. Consequently by falling bottom-hole pressure below bubble point pressure, solution gas can be separated from the oil and causes pump gas locking in near future. Installing gas separator which located at the pump inlet can be separate the gas to the annulus and avoid pump to be gas locked. Normal gas separator efficiency is 70% which is considered in this design.

Length of Cable: Length of the cable can be easily measures by adding pump setting depth with surface distance. In this case, pump setting depth is 3600 mss and 100 m distances is considered for surface facilities. So, 3700 meter cable is needed. It is noted that, Beggs and Brill correlation is taken as outflow correlation for study in X field. After defining the main designing parameters, Prosper calculates all design requirements such as pump intake pressure and pump discharge pressure. Figure 2 demonstrates all calculation parameters for electrical submersible pump.



Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Angle (degrees)
0	0	0	0
1000	1000	0	0
1044	1043	9.33	12.24
3876	3336	1671.37	35.94
4017	3340	1812.31	88.37
4157	3344	1952.25	88.36
4293	3348	2088.19	88.31
4430	3352	2225.14	88.33
4569	3357	2364.05	87.94
4716	3362	2510.96	88.05
4880	3369	2674.81	87.55
5063	3376	2857.68	87.81
5254	3387	3048.36	86.70
5449	3398	3243.05	86.77

Fig. 1: Prediction well sketch & table for deviation survey of prediction well.



DESIGN REQUIREMENTS		
Well Head Pressure	400	(psia)
Flowing Bottom-hole Pressure	3422	(psia)
Water Cut	10	(percent)
Pump Frequency	50	(Hertz)
Pump Intake Pressure	3176	(psia)
Pump Intake Temperature	233	(deg F)
Pump Intake Rate	4365	(RB/day)
Free GOR Entering Pump	0	(scf/STB)
Pump Discharge Pressure	3704	(psia)
Pump Discharge Rate	4294	(RB/day)
Total GOR Above Pump	465	(scf/STB)
Mass Flow Rate	1239060	(lbm/day)
Total Fluid Gravity	0.8164	
Average Down-hole Rate	4329.2	(RB/day)
Head Required	455.59	(m)
Actual Head Required	455.59	(m)
Fluid Power Required	38.84	(hp)
GLR @ Pump Intake (V/V)	0	(fraction)

Fig. 2: Represents ESP main design parameters.

Since X reservoir pressure is 4200 psia and bubble point pressure is 2700 psia, free GOR Entering Pump is zero. But as producing time increases, reservoir depletion occurs and cause separating of the solution gas from oil. So, installing gas separation in intake of pump reduces possibility of pump gas locking. As it is pointed out before, Maximum allowable free gas in pump is 10% of total liquid and by calculation, pump gas lock does not happen when maximum free gas (in pump intake) is reaching to 200 Scf/Stb. So, well gas oil ratio constrain of 600 Scf/Stb is considered in prediction model of petrel package because this gas oil ratio in pump intake pressure will be 200 Scf/Stb. After calculation all design parameters, motor and pump selection should be done. Figure 3 shows motor, pump and also cable selection parameters.

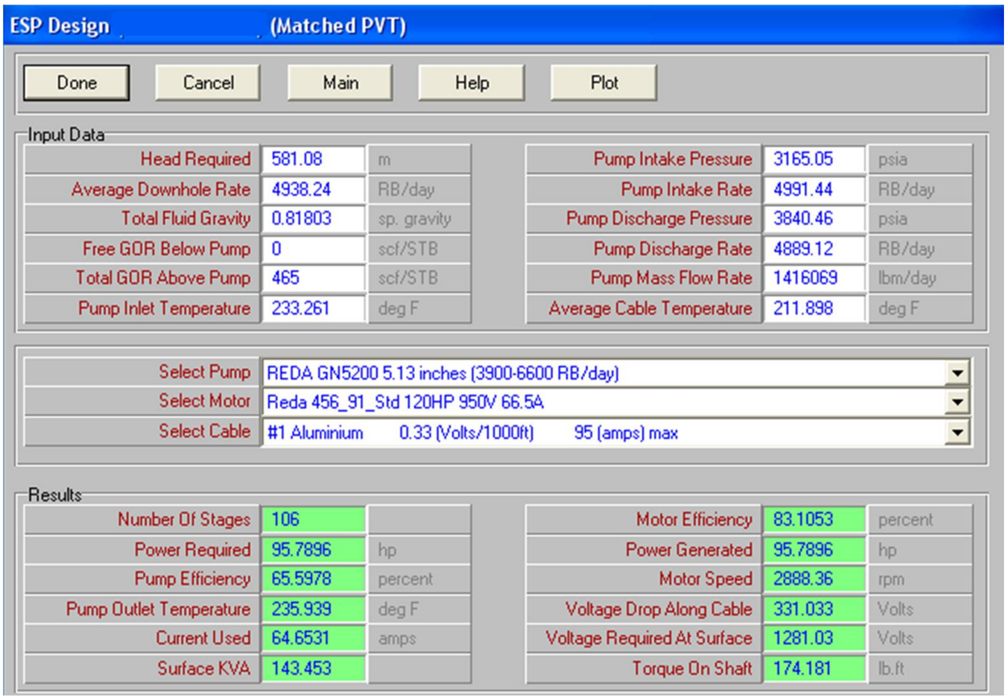


Fig. 3: Motor, pump and also cable selection.

Since X field located is an offshore field and providing electrical facilities accomplish with many limitation, one important consideration for motor selection is motor voltage that low voltage motor should be selected. **Error! Reference source not found.** shows the selected variables for generation of the VLP (VFP) tables.

Table 1: Selected variables for calculation of VLP curves.

WHP, psig	100	300	600	800	1000
GOR, SCF/STB	200	400	600	800	1000
WCT, %	0	10	20	30	50

Error! Reference source not found. exhibits generated VLP curves for all variables showed in

Table 1. The VLP tables can be exported for Eclipse simulator afterwards. In the following, it will be investigated how the production is affected by following items: The sizes of Tubing string and Motor operation frequency variation. To accomplish the sensitivity analysis on mentioned variables, we are going to need to make the Inflow Performance Relationship (IPR) model. In order to do that, Because of having PI and corresponding reservoir pressure from well test and static pressure analyses on the same date as test points, PI entry model is selected among the most precise models of inflow into a well. Afterwards, the outflow model is combined with the inflow model to get a solution point on the rate and bottom-hole pressure of the well. The different values of above variables can then be applied to the model to investigate the possible variations of the production.

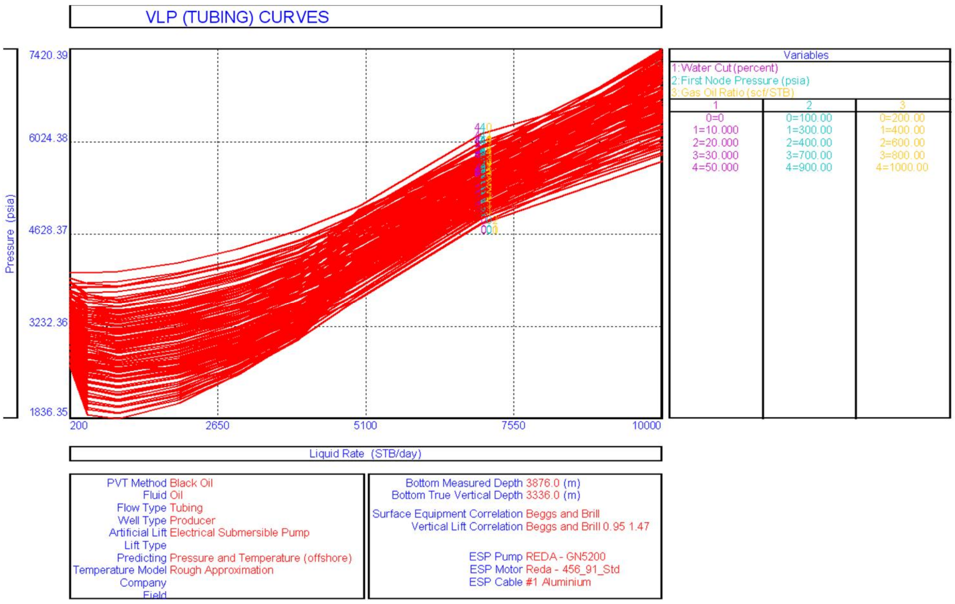
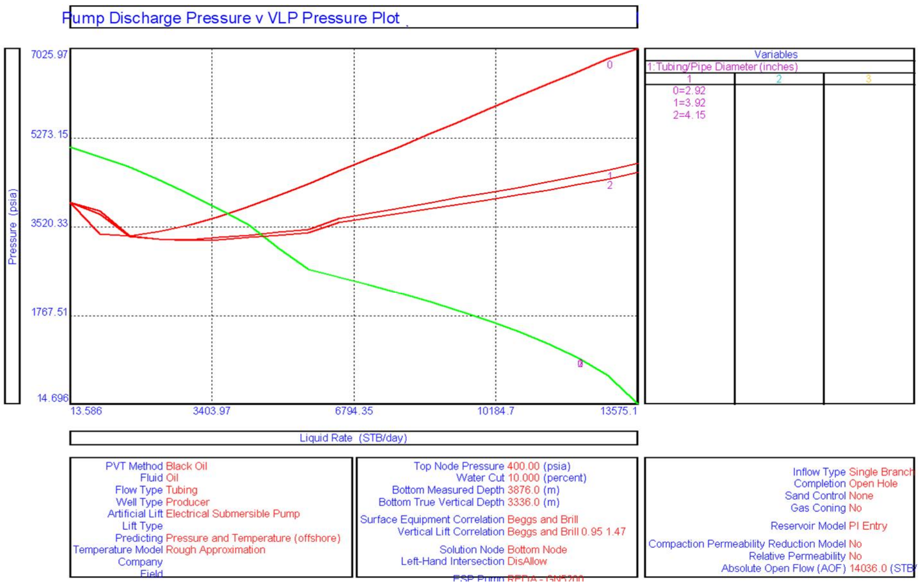
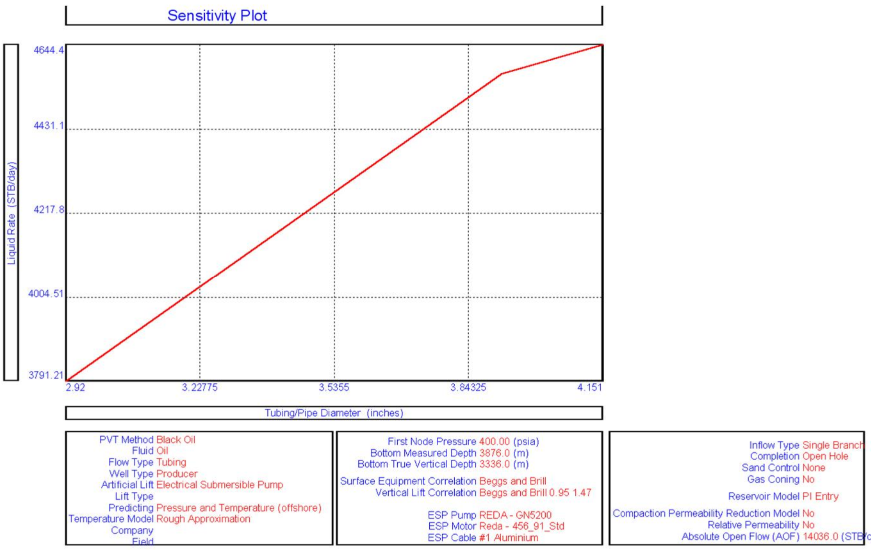


Fig. 4: VLP curves for all cases.

Tubing Size: different tubing outer diameters that are varied in the well model to investigate the effect of tubing sizes on the production wells are 5, 4.5 and 3.5 in. Figure 5 and Figure 6 show the solution points of the inflow-outflow system and the sensitivity plot for varied tubing diameters respectively (The diameters shown in the figures are ID's). Considering the oil rate variations of the sensitivity plot indicates that a 5" tubing gives the maximum production in such wells. But in order to avoid liquid hold up in future (it has been checked in simulation model), it is better to use 3.5" tubing with pump. But generally, different tubing sizes don't significantly change the production (only 700bbl/day changes).



Fig/ 5: System solutions for varied tubing size.



Fig/ 6: Oil rate vs. varied tubing size.

Motor operation frequency variation: various motor operation values that are varied in the well model to investigate the effect of motor operation frequency variations on the production of wells are 40, 50 and 60 Hertz. It should be mentioned that purpose of motor operation frequency sensitivity analysis is to simulate the effect of motor speed into production of the well. Figure 7 and Figure 8 show the solution points of the inflow-outflow system and the sensitivity plot for varied motor operation frequency values. Focusing on the oil rate variations of the sensitivity plot indicates that different motor operation frequency values significantly change the production. It means increasing motor operation frequency from 40 to 60 scf/STB results in increased amount of 1200 bbl/day in production.

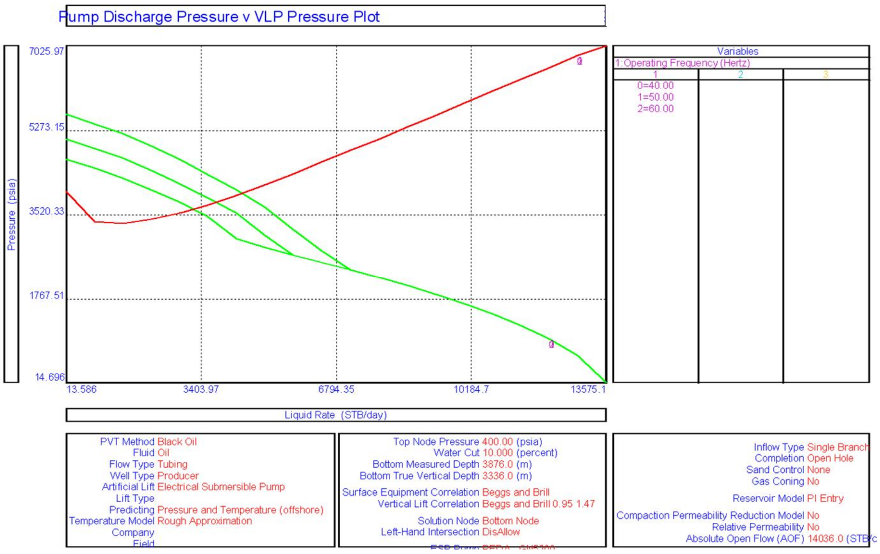


Fig. 7: System solutions for varied motor operation frequency values.

Figure 9 shows field oil production rate for different cases of natural depletion and artificial lift. According to relative plots using ESP with 60 HP motor would increase the production plateau time to 8 years however it can be reached to 9.5 years in case of using ESP with power of 120 HP. It is important to know that the wells will be shut in scenario of 120 HP pump, because reaching to GOR constrain of pump. Reservoir recovery factor increases to 8.91 and 11.66 in scenarios of production with ESP in front of 6.6% recovery in natural depletion.

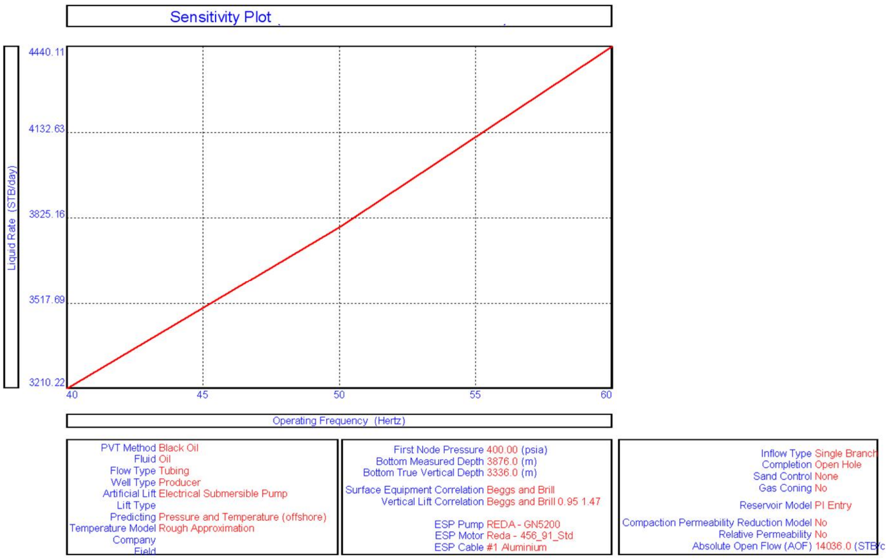


Fig. 8: Oil rate vs. varied motor operation frequency values.

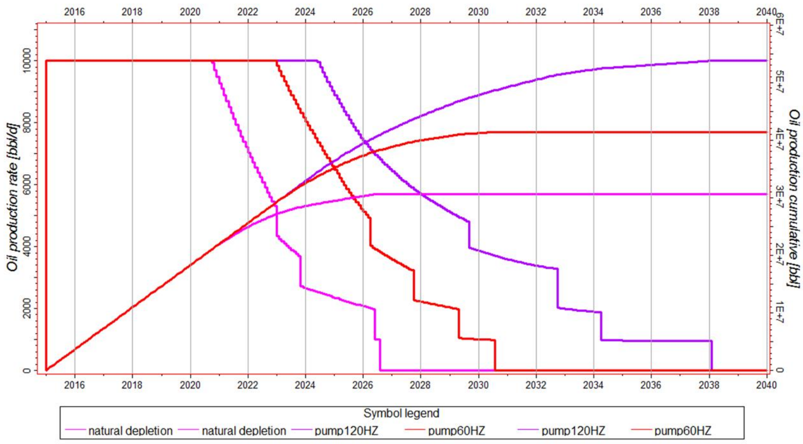


Fig. 9: Field oil production rate and cumulative production for natural depletion and ESP.

3. Conclusions and Recommendations

For utilizing electrical submersible pump in wells in X field, the following items can be wrapped up; Installing ESP in 3600m causes producing of 3500bbl/day. Since pump Gas locking is a major reason for pump break down, very precise calculation should be done for evaluation amount of free gas in pump intake in period of pump working days. Although using high horse power (HP) pump is expensive, production improvement will be more than the low HP pump. Different tubing sizes do not significantly change the production rate so the optimum size for preventing liquid hold up in the wells is 3 1/2" tubing. Different motor operation frequency values significantly change the production. It should be mentioned that it is better to use surface variable frequency drive (VFD) to be able altering the motor frequency drive during ESP working.

Reference

[1] Thomas O., Allen P., Production operation, 2005.

[2] Mayhill T.D. Simplified Method for Gas-Lift Well Problem Identification and Diagnosis. SPE 5151 presented at the 49th Annual Fall Meeting of the Society of Petroleum Engineers of ATME, Houston, 1974.

[3] Kami E.J., Mach J., Brown K.E. Economic Approach to Oil Production and Gas Allocation in Continuous Gas Lift. *SPE JPT* 1981; 33 (10): 1887-1892.

[4] Fang W.Y. Lo K.K. A Generalized Well-Management Scheme for Reservoir Simulation. *SPERE*, 1996; 11 (2): 116-120.

[5] Caicedo S. ESP Lab Test with Heavy Oil at Intevep’s Artificial Lift Simulator Facility. SPE Gulf Coast ESP Workshop, 1997.