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# Production Optimization through Installation of Feasible Artificial Lift Technology: A Case Study

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**Abstract**

This paper elaborates the selection of optimum artificial lift system (ALS) for a depleted well Beta TX-01. During the initial testing of well it was observed that the average gross production is 1300 BPD or we can says it as 1180 BOPD and 120 BWPD, with 39.2 API gravity and a small amount of gas is produced along which is 0.396 MMSCF/D. The reservoir pressure drops as the well is being produced. Meanwhile the water cut was rapidly increasing day by day ultimately increasing the operating cost. Electrical submersible pump (ESP) is known for its high lifting capacities, it is a best fit for shallow wells having low gas content and no sand production as in Beta TX-01. The other ALS methods seems to be unfeasible for such a scenario. The results obtained from PROSPER simulation study indicates the ESP as the suitable ALS for low reservoir pressure that is below 1500 psig, it also recommends to change the tubing size from 2-7/8 inch to 3-1/5 inch as per as the SOPs for lifting higher volume of reservoir fluids. The work over job for the installation of ESP requires major changes in the completion assembly as well as at surface. The well is then tested at different operating frequencies to choose the optimum frequency keeping the running life of ESP in mind to avoid unexpected work overs in future. Hence, ESP increased the production output from the well making the well economical to produce. The well Beta TX-01 is producing 450 BOPD on ESP at an operating frequency of 54 Hertz with intake pressure of 1085 psig, discharge pressure of 2660 psig, and motor amperage of 38 Amps.

***Keywords:*** Artificial Lift System; Jet Pump; Electrical Submersible System; Workover Operation; Design and Installation.

## 1. Introduction

Electrical submersible pump ESP is an artificial lift technology that increases the production or lifts the oil from wellbore to surface by providing centrifugal lifting force to the fluid [6].

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It is actually a multistage centrifugal pump connected to the motor through shaft that rotates to lift the fluids and it is installed in a well at a depth of several thousand feet. The main components of this unit are, motor, intake, centrifugal pump, protector, and other accessories all attached together. This unit is submersed in well to produce oil through production tubing. The well Beta TX-01 spudded in the year 2000 and drilled up to the depth of 6750 ft. at first it was producing naturally and then after the depletion converted to the hydraulic jet pump ALS in 2006, slowly and gradually water cut starts to rise and reaches up to 60%, at initial stage it was 10%. In order to increase the oil production it become need of time to select a more efficient ALS, keeping the economics in mind the decision was made to carry a work over operation. The major changes are required in the completion string to install ESP like replacing the tubing size 2.875 inch with 3.5 inch tubing, installation of recompletion spool, replacement of tubing hanger with a customized tubing hanger having space for cable penetrator to accommodate ESP cable.

## 2. Production History of Well Beta TX-01

The well was initially completed with conventional oil well completion and tested at different choke sizes the summary of which is arranged below in Table 1.

**Table 1:** Average production rates at different choke sizes for natural flow**.**

| S.NO. | Choke size (inches) | WHFP (psi) | Qo (BOPD) | Qgas (MMSCFD) | GOR SCF/STB |
|---|---|---|---|---|---|
| 1 | 32/64 | 600 | 2000 | 0.78 | 390 |
| 2 | 28/64 | 640 | 1470 | 0.68 | 463 |
| 3 | 24/64 | 675 | 1180 | 0.4878 | 413 |

The well was initially produced at a choke size of 24/64 inch with a well head flowing pressure of 675 psi producing 1180 BOPD along with 0.4878 MMSCFD gas, and 10% water production, furthermore the GOR is calculated to be 413 SCF/STB. The reservoir pressure starts to decline, observing the declining trend of the reservoir pressure it was concluded that it is a pocket reservoir and the water has already encroached. After 3 year of production pressure survey conducted and the following results were obtained shown in Table 2.

**Table 2:** Nos. and Dates of PLT/ Pressure Survey Conducted.

| S.NO | Year | BHSIP (psi) | BHSIT (°F) |
|---|---|---|---|
| 1 | 2000 | 2359 | 226 |
| 2 | 2003 | 1916 | 229 |

### *2.1 Static Bottom Hole Pressure Survey*

Conducted Static Bottom Hole Pressure and recorded WHSIP = 35 Psig. Tool Stationed at 6600.0 ft. for 02 hours. Recorded additional Stationary gradient for 15 min: each at 6660 ft., 6560 ft., 6480 ft., 6398 ft., 6235 ft., 4922 ft., 3285 ft., and 1640 ft. After pull out of hole and rig down shut-in Parameters were recorded as are shown in Table 3.

**Table 3:** Static Bottom Hole Pressure Survey data.

| | |
|---|---|
| WHSIP = 35 Psig. | BHSIP = 1489 Psi. |
| WHSIT = 100 $^0$F. | BHSIT = 226 $^0$F. |

The following Table 4 shows the jet pump performance testing parameters observed during the testing phase after the work over for installation of jet pump completed. As reservoir pressure drops and the well stops to produce, it was decided to put well on artificial lift as jet pump was the only economically viable method to be considered at that time, well was put on jet pump operation with a nozzle/throat combination of 12-A (National). It was observed that the water cut reached to 45% of the total recovery and oil produced was 885 BOPD which is 54.9% of the total volume of fluids produced.

**Table 4:** Jet pump performance testing parameters.

| | |
|---|---|
| N/T Combination | = 12-A (National) |
| P/Pressure | = 2550 |
| Engine RPM | = 1760 |
| V/Pressure | = 115Psig |
| Q gross | = 1610 BPD |
| Q oil | = 885 BPD |
| Q water | = 725 BPD |
| Oil % | = 55 |
| BS& W % | = 45 |
| Chlorides | = 40500 PPM |

**Table 5:** Jet pump performance testing parameters after changing tubing.

| | |
|---|---|
| N/T Combination | 11 – B (National) |
| P/Pressure psig | 2450 |
| Engine RPM | 1730 |
| V/ Pressure psig | 100 |
| Q gross BPD | 735 |
| Q oil BPD | 125 |
| Q water BPD | 610 |
| Operating Hrs., | 18 |
| Q oil (produced) | 95 |
| Oil (%) | 17 |
| Water (%) | 83 |

Table 5 depicts the testing parameter noted after replacement of damaged tubing with a new 2-7/8 inch tubing and the nozzle throat combination was also altered to 11-B (National). The testing was conducted in the year 2015 and water cut was 83%, producing only 17% of oil. Furthermore, that 17% of oil reduced to 13% of total recovery in the year 2016. Now operating cost of well including routine maintenance to surface jet pump unit, routine reverse out of downhole jet pump, maintenance of water treatment facility, and chemical injection for scaling and corrosion inhibition become greater than the profit earned from the production of well. After that well was at shut in position and hence the need arise to design some optimum artificial lift system for well Beta TX-01.

**3. Artificial Lift System**

The reservoir pressure keeps on declining when the reservoir fluids are produced at the surface because it is considered that most of the reservoirs are volumetric type that is why the pressure drops when well is put on production. When the reservoir pressure reaches bubble point pressure the gas starts to liberate that was in the solution form with oil at first. Here the natural drive mechanism plays an important role as it drives the oil from reservoir to the surface and keep maintaining the pressure (e.g. water drive, solution gas drive, expansion drive, etc.) without these natural drive mechanisms it become impossible to produce oil economically. The prime goal of the production engineer is to get maximum oil recovery from a well without damaging the formation that can affect the productivity and life of well. The fluctuations in the oil prices make it difficult to go for the secondary and tertiary recovery methods [1]. As per as the economics is concerned it is necessary to go for a most effective artificial lift method to recovery maximum amount of oil efficiently. In this regard most of the oil well are completed with artificial lift system completions around the world and this practice is considered to be beneficial as on the reservoir management side. There are different artificial lift systems like hydraulic jet pump, electrical submersible pumps, gas lift, intermittent gas lift, progressive cavity pump, sucker rod pump and some artificial lift system that are used in combination with oil field tools like coil tubing deployed ESPs. The application of these ALS purely depends on fluid properties, in order to choose optimum method a vast study of reservoir and fluid properties is required. In association to this there is also a need for understanding the availability of tools, facilities and services [8]. The experts design a full field model including surface facilities and wellbore configuration to get a thorough understanding of system, this helps them to better choose an optimum ALS.

**4. Selection Criteria of Artificial Lift for Beta TX-01**

As discussed earlier prior to design and installation of optimum ALS, well was producing on jet pump but the production results were not satisfying. The jet pump stands out for the consideration as optimum ALS for Well Beta TX-01. For the case of gas lift and intermittent gas lift high gas content or high gas-liquid ratios (GLR) are required, as for the continuous injection of gas, production of higher volumes of gas is required. This method is used where GORs is usually greater than 700 scf/stb [3], as far as the other ALS are concerned, those are not suitable for such a high GOR. The sucker rod pump is mostly used in North America for heavy crude oils, it is designed to deal with high viscosity fluids and pure oil wells with 0% water cut. Now the last option that can be selected for Beta TX-01 keeping the PVT properties in consideration is ESP, although for high water cut wells a special chemical injection treatment is needed to be designed otherwise saline water can cause corrosion ultimately leading to workover for retrieving ESP assembly, and obviously that is not good in economically. The ESP work over requires a lot of investment meanwhile the company can face huge lose due non productivity from the well. Although these problems can be countered by a few precautionary measures.

**5. esp system**

The electrical submersible pump (ESP), is a versatile, reliable and efficient artificial lift method for lifting moderate to high volumes of fluids from wellbores [10]. These volumes range from as low as of 150 B/D to as high as 150,000 B/D. This range can significantly be extended by variable-speed controllers, both on the low and high side. The ESP's main components include:

1. Three-phase induction motor.
2. Seal-chamber section (Protector).
3. Multi-staged centrifugal pump.
4. Power cable.
5. Surface controls.

Greatest application is in moving large volume of low GOR fluids. They are particularly popular for high rate under-saturated oil wells, high water cut wells and water supply wells. Their main limitation is gas production but improved downhole separators and procedure can now handle GORs up to 1000 SCF/STB.

ESP is a multistage centrifugal pump connected through a short shaft to the downhole electric motor. Each stage consists of a rotating impeller and stationary diffuser. The differential pressure or total dynamic head (TDH) developed by the pump is a function of flow rate which is relative to the head developed by each stage and obtained from manufacturers publishing: AC supply frequency 3500 Rpm at 60Hz & 2915 Rpm at 50 Hz. Sand production is detrimental and that emulsions are easily formed. To stop sand production install a gravel pack or prepacked screen for pump protection. Delivery capacity will vary according to:

- **i.** Well IPR.
- **ii.** Reservoir pressure.
- **iii.** Surface back pressure.
- **iv.** Electrical supply Frequency.

Surface equipment usually includes a three phase transformer motor controller and a well head pack-off for cable. Facilitate downhole separation of free gas and vented up the annulus.

**6. ESP Design for TX-01**

In this paper nodal analysis is done by using PROSPER petroleum expert's simulation software. The model is generated using PVT properties and completion data using Beggs and Brill, Glaso, petroleum experts 2 and Beal and his colleagues correlation. The IPR/VLP curves are matched to get a clear picture of wellbore and reservoir inflow condition for designing optimum artificial lift system and selecting best equipment. The equipment like advanced gas handlers and vortex gas separator advanced are used for downhole gas separation and these tools are selected after analyzing Dunbar curve. The tubing sizes and profiles are selected on the basis of VLP curves, further all the required information is discussed in ESP case given below.

### *6.1 Case 01 for Natural flow*

For Bubble point pressure Pb, Solubility Rs, Oil formation volume factor Bo, Glaso correlation is used and for oil viscosity Beal and his colleagues correlation is selected in the simulator. The following PVT properties are obtained shown in Table 6:

**Table 6:** PVT properties and composition of hydrocarbon fluid.

| Components | Mole Percent | Critical Temperature | Critical Pressure | Critical Volume | Acentric Factor | Molecular Weight |
|---|---|---|---|---|---|---|
| **N2** | 0.20467 | -232.51 | 477.419 | 1.43842 | 0.04 | 28.01 |
| **CO2** | 0.614 | 87.89 | 1054.74 | 1.50409 | 0.225 | 44.01 |
| **H2S** | 0.020467 | 212.09 | 1280.96 | 1.57938 | 0.1 | 34.08 |
| **C1** | 24.5602 | -116.59 | 661.049 | 1.58899 | 0.0115 | 16.04 |
| **C2** | 5.51795 | 90.05 | 702.615 | 2.37547 | 0.0908 | 30.07 |
| **C3** | 6.34168 | 205.97 | 608.886 | 3.25166 | 0.1454 | 44.1 |
| **C4** | 5.06463 | 289.49 | 528.539 | 4.21274 | 0.1868 | 58.12 |
| **C5** | 4.71731 | 372.83 | 492.845 | 4.08459 | 0.2251 | 72.05 |
| **C6** | 4.54119 | 442.109 | 449.149 | 6.41068 | 0.25352 | 84 |
| **C7** | 4.2306 | 483.247 | 411.018 | 7.30352 | 0.27118 | 94.1122 |
| **C8** | 3.95534 | 523.677 | 381.61 | 8.18188 | 0.28848 | 105.063 |
| **C9** | 3.7054 | 562.42 | 357.885 | 9.04576 | 0.30542 | 116.5 |
| **C10** | 3.47498 | 599.311 | 338.196 | 9.89516 | 0.322 | 128.24 |
| **C11-C13** | 8.93017 | 666.253 | 307.055 | 11.5389 | 0.35386 | 151.589 |
| **C14-C25** | 16.0402 | 850.533 | 250.053 | 16.3185 | 0.44446 | 228.004 |
| **C25-C50** | 7.30521 | 1205.42 | 201.744 | 25.3675 | 0.6029 | 410.936 |
| **C50+** | 0.77602 | 1789.83 | 203.261 | 34.0323 | 0.68988 | 764.653 |

There are many reservoir models offered by PROSPER Simulation software for generating IPR curve. Here Darcy's model is selected for generating IPR and mechanical skin is entered manually. The well is single branched cased hole with 7 in. casing, some parameters that are calculated by the software are noted as productivity index is 4.22 STB/day/psi, AOFP 6460 STB/day for 10% water cut and GOR is entered as 415 SCF/STB. The formation skin is 1.2 as shown in Figure 1.

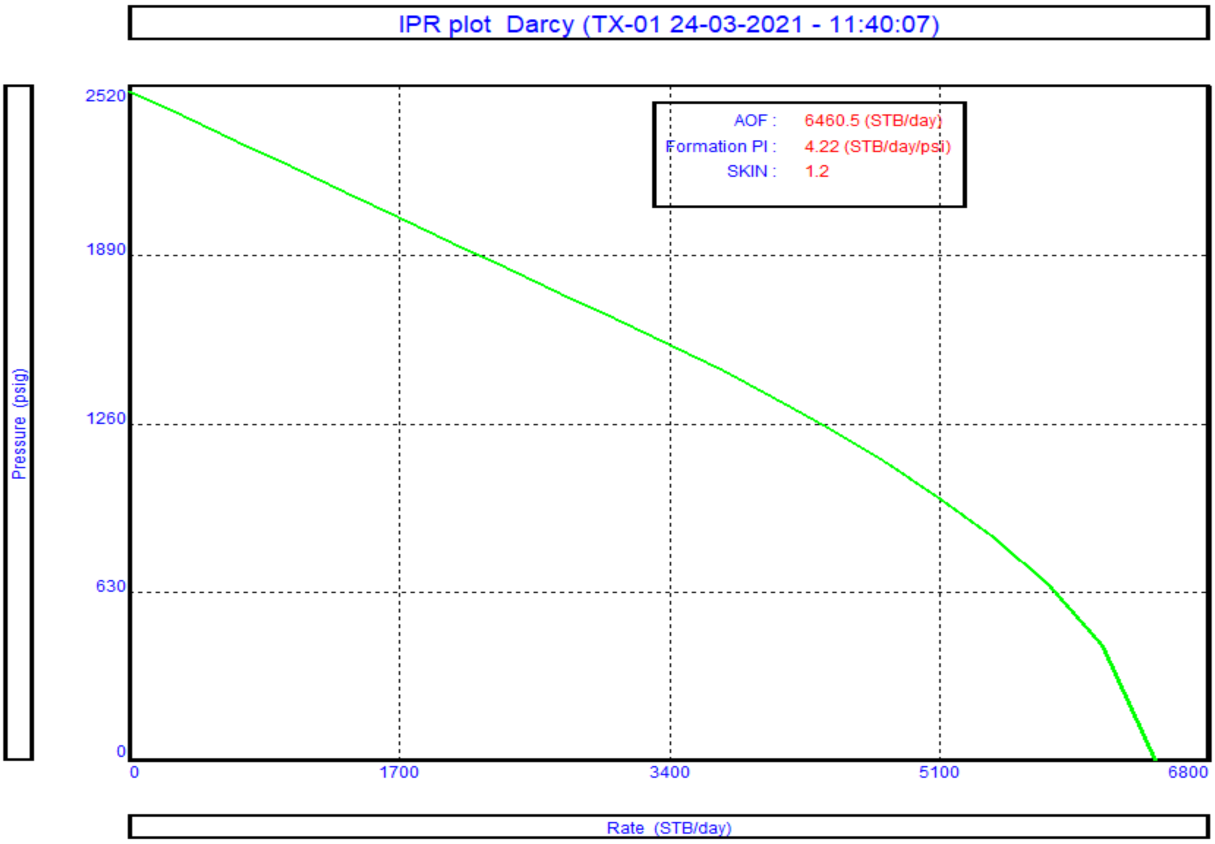


**Figure 1:** IPR for Natural Flow Well Case during Initial Life of Well.

The sensitivity of IRP Curve is plotted for different values of drainage area, water Cut and reservoir permeability. The sensitivity for drainage area (acres) is determined at (50, 60,100,200,300), it is observed that for lower values of drainage area the inflow performance is better as compared to higher drainage area or in other words we can say it as the flow rates are higher for smaller drainage areas whereas the pressure decline curve is also delayed for small drainage areas. As far as the water cut and reservoir permeability is concerned both shows favorable trend for inflow performance at higher values. For 50% water cut and 150 md reservoir permeability the inflow rate is highest meanwhile the pressure decline is depicted to be delayed. The sensitivity curves for IPR can be seen in Figure 2 given below.

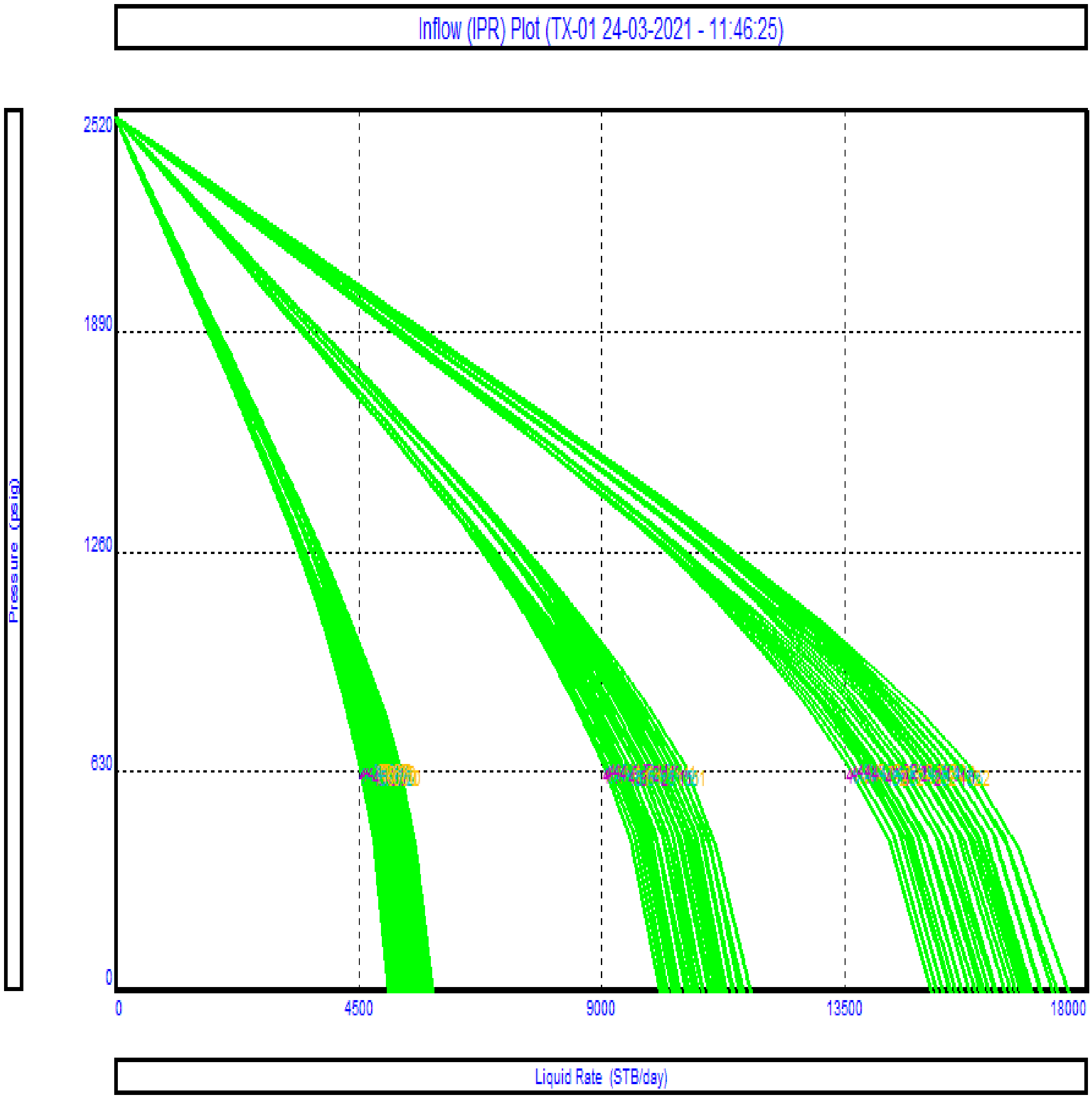


**Figure 2:** Sensitivity IPR Plot.

The well profile can be seen in figure 3, the tubing size is 2-7/8 inches with inner diameter 2.441 inches and set up to a depth of 6300 ft. The well is mono-bore with production casing of 7 inches having inner profile of 6.094 inches and setup to a depth of 6750 ft. the rat hole measured as 450 ft.

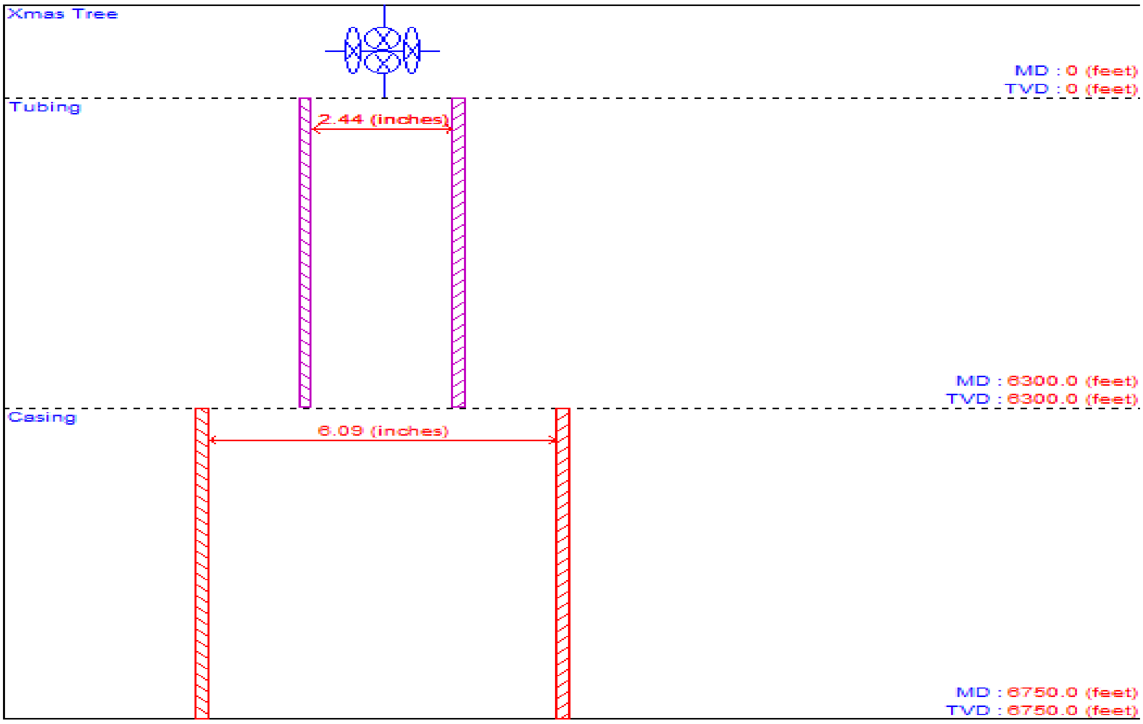


**Figure 3:** Well Profile for Conventional Completion.

The sensitivity of VLP Curve is plotted for different values of first node pressure (wellhead), gas oil ratio (GOR) and tubing pipes sizes/ diameter. It can be clearly seen from the graph Figure 4 that for high well head pressure the bottom hole pressure is also high that is obvious and for high values of gas oil ratio a plummet can be seen in VLP curve, it can be concluded that low gas oil ratios shows better vertical lift performance, for higher gas volume there is high probability for slug flow. The VLP curve portrays a plunge for larger tubing diameters, in order to select optimum tubing size a thorough understanding of IPR/VLP and associated parameters is must.

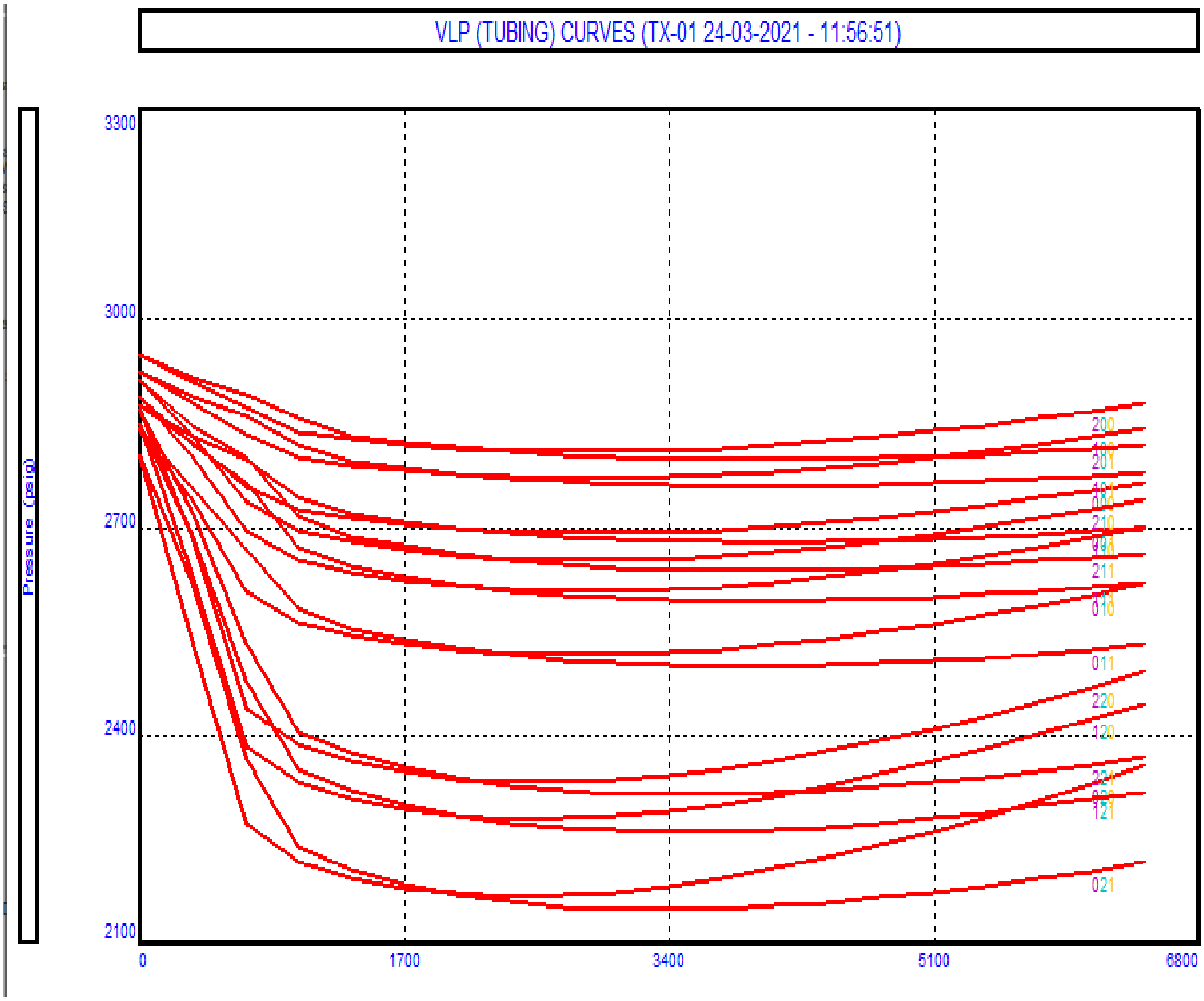


**Figure 4:** Sensitivity Curves for VLP.

After IPR/VLP curves matching the absolute open flow potential is calculated as 6500 STB/day and the liquid rate is 1670 STB/day with 10% water cut. After analyzing the curves it is suggested that a larger diameter tubing can produce higher crude oil volume and pressure depletion can be countered by adjusting choke sizes. At this point optimum artificial lift system is required for the well.

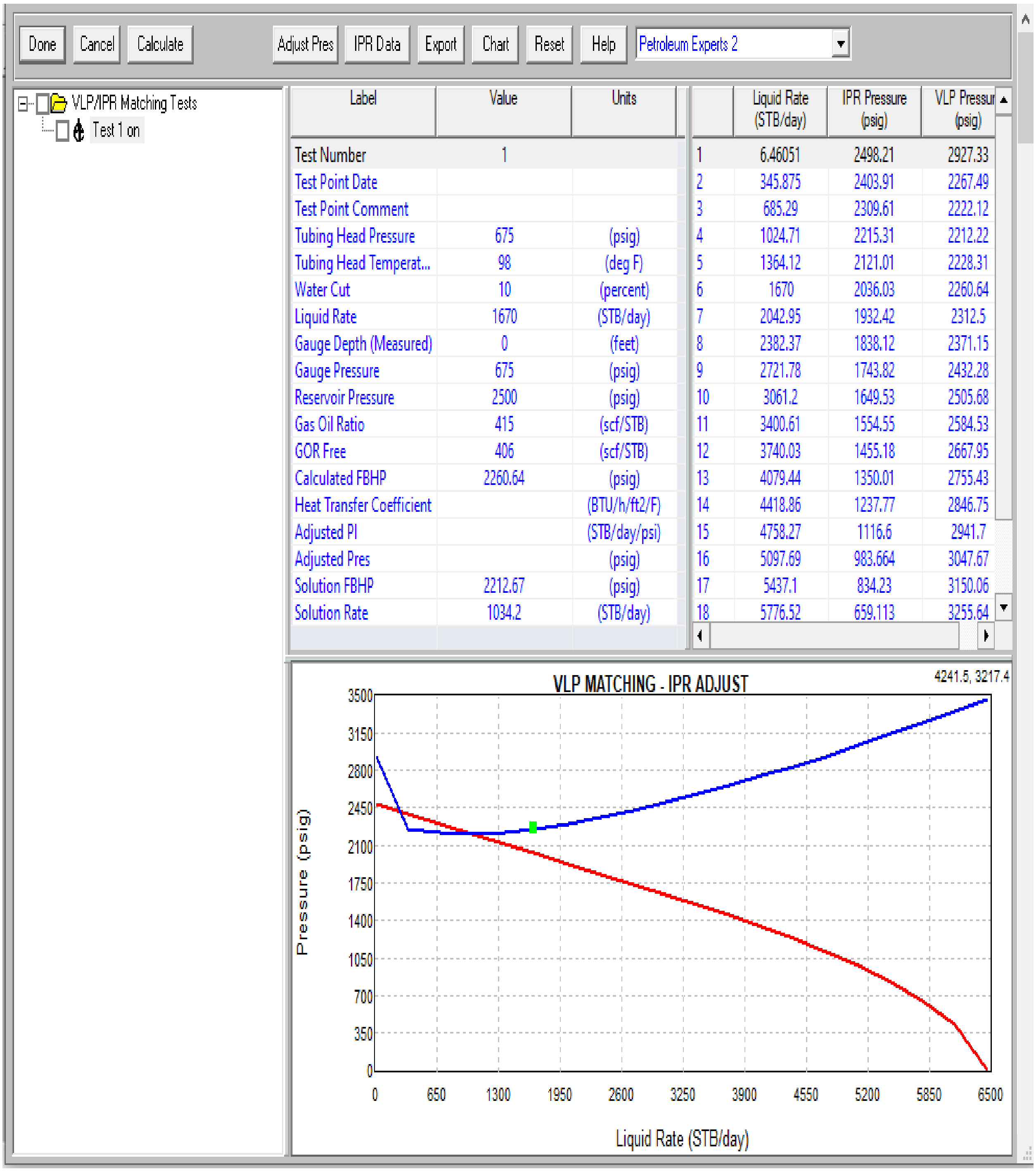


**Figure 5:** IPR VLP Curves Adjusted for Natural Well Flowing Case.

### *6.2 Case 02 for Jet Pump*

There are many reservoir models offered by PROSPER Simulation software for generating IPR curve. Here Darcy's model is selected for generating IPR and mechanical skin is entered manually. The well is single branched cased hole with 7 in. casing, some parameters that are calculated by the software are noted as productivity index is 5.62 STB/day/psi, AOFP 5262.2 STB/day for 83% water cut and GOR is entered as 450 SCF/STB. The formation skin is 1.3 as shown in Figure 6.

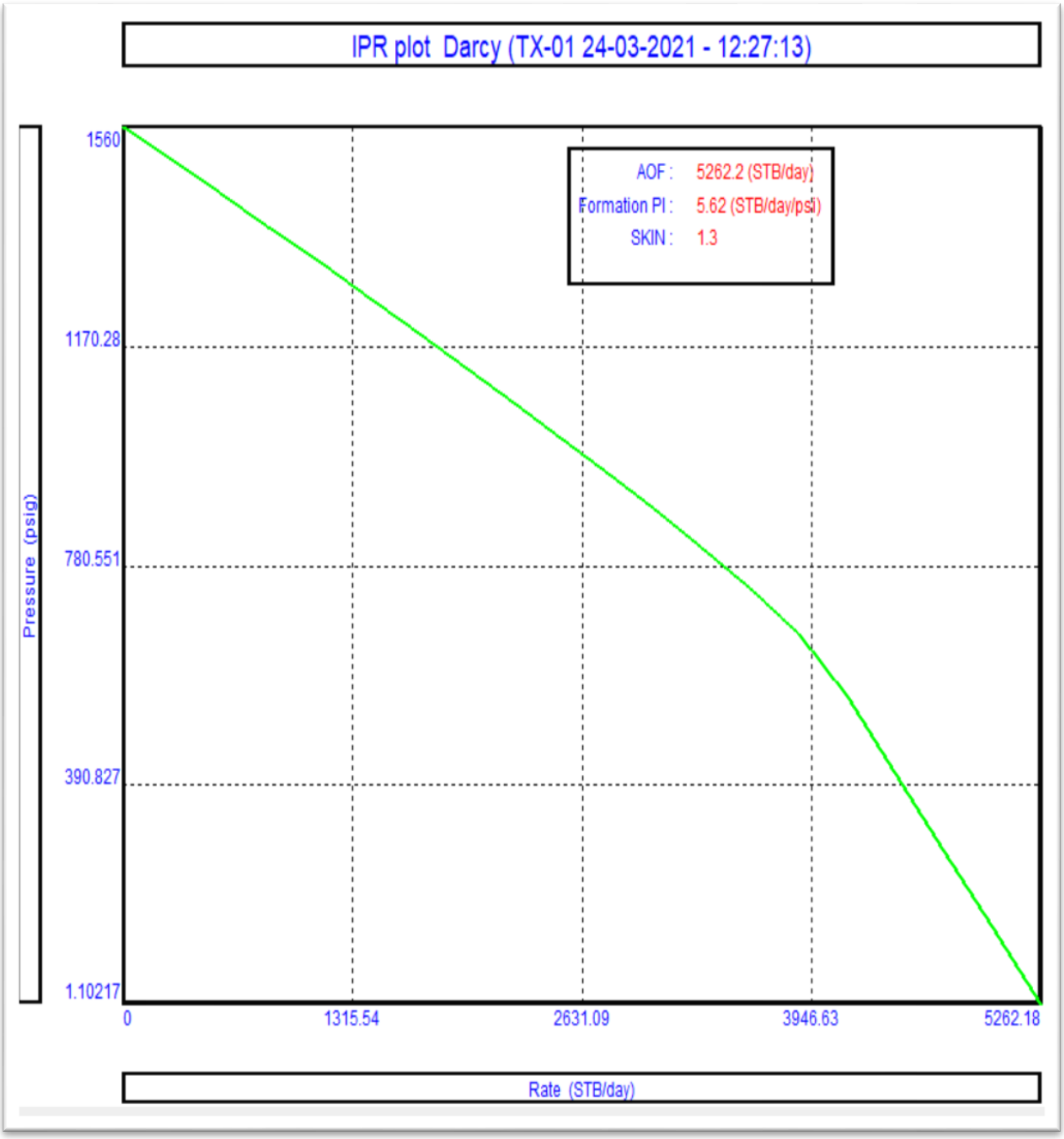


**Figure 6:** IPR Curve for Jet Pump Case.

The well profile can be seen in figure 7, the tubing size is 2-7/8 inches with inner diameter 2.441 inches and set up to a depth of 6300 ft. The jet pump is installed at the depth of 6227 ft. with a lowest profile of 2 inches diameter. The well is mono-bore with production casing of 7 inches having inner profile of 6.094 inches and setup to a depth of 6750 ft. the rat hole measured as 450 ft.

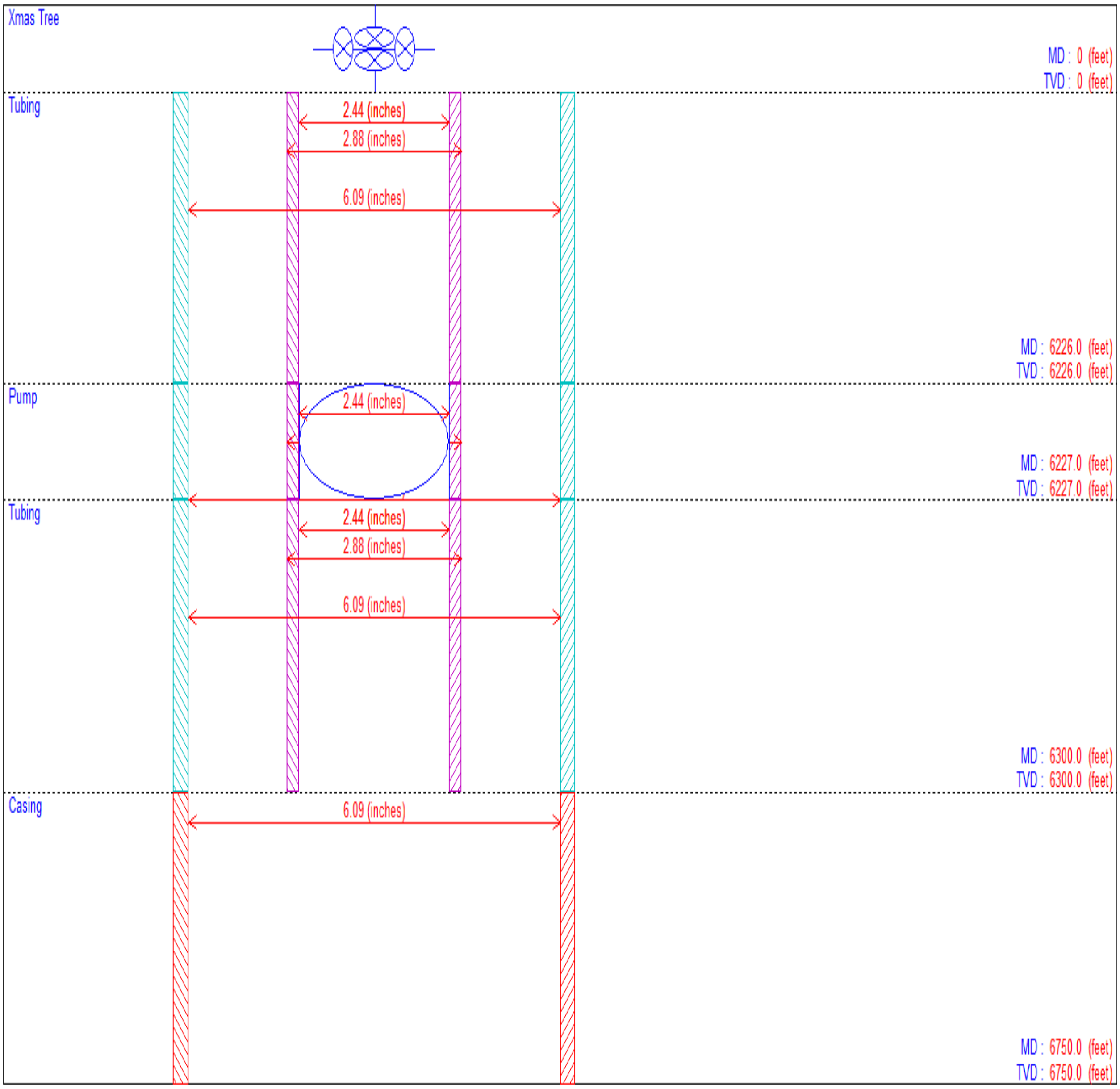


**Figure 7:**Well Profile for Jet Pump Well.

A sensitivity case graph is generated for variable reservoir pressures and water cuts i.e. reservoir pressure is taken as (1400, 1500, and 1600) and water cut values are (70, 80, and 85). The graph depicts for higher values of reservoir pressure and water cut, the pressure decline is delayed, meanwhile producing higher liquid volumes, same can be seen in Figure 8.

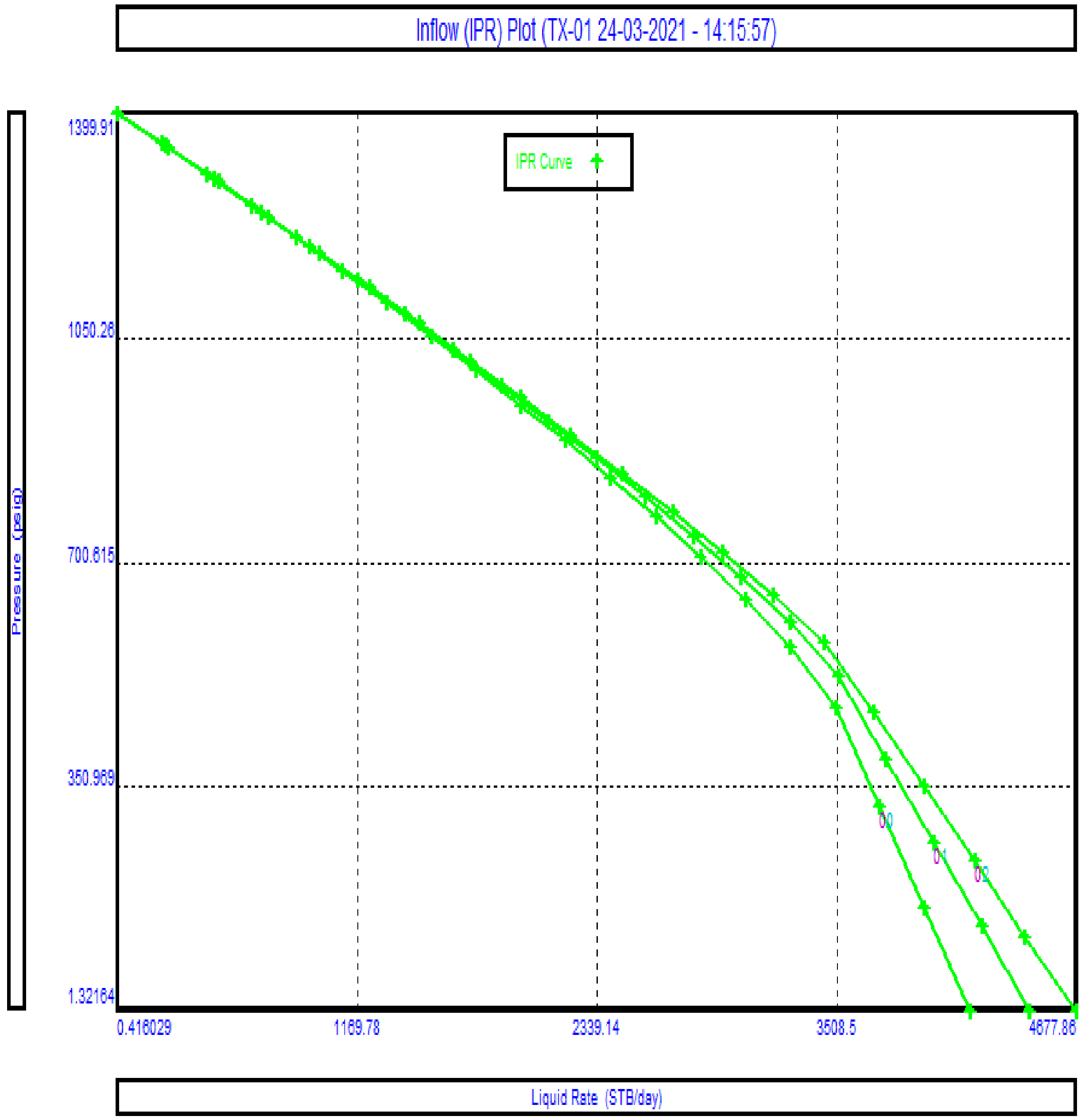


**Figure 8:** Sensitivity for IPR curves.

The sensitivity of VLP Curve is plotted for different values of jet pump installation of depth and power fluid injection pressure. It can be clearly seen from the graph Figure 9 that for lower injection pressures a plummet can be seen in VLP curve, it can be concluded that higher injection pressure yield higher volumes of fluids meanwhile delaying pressure drop, although the depth of jet installation does not having significant effect on VLP curves. Here the bottom hole pressure is 1550 psi with 83% water cut and the correlation used for surface equipment is Beggs and Brill.

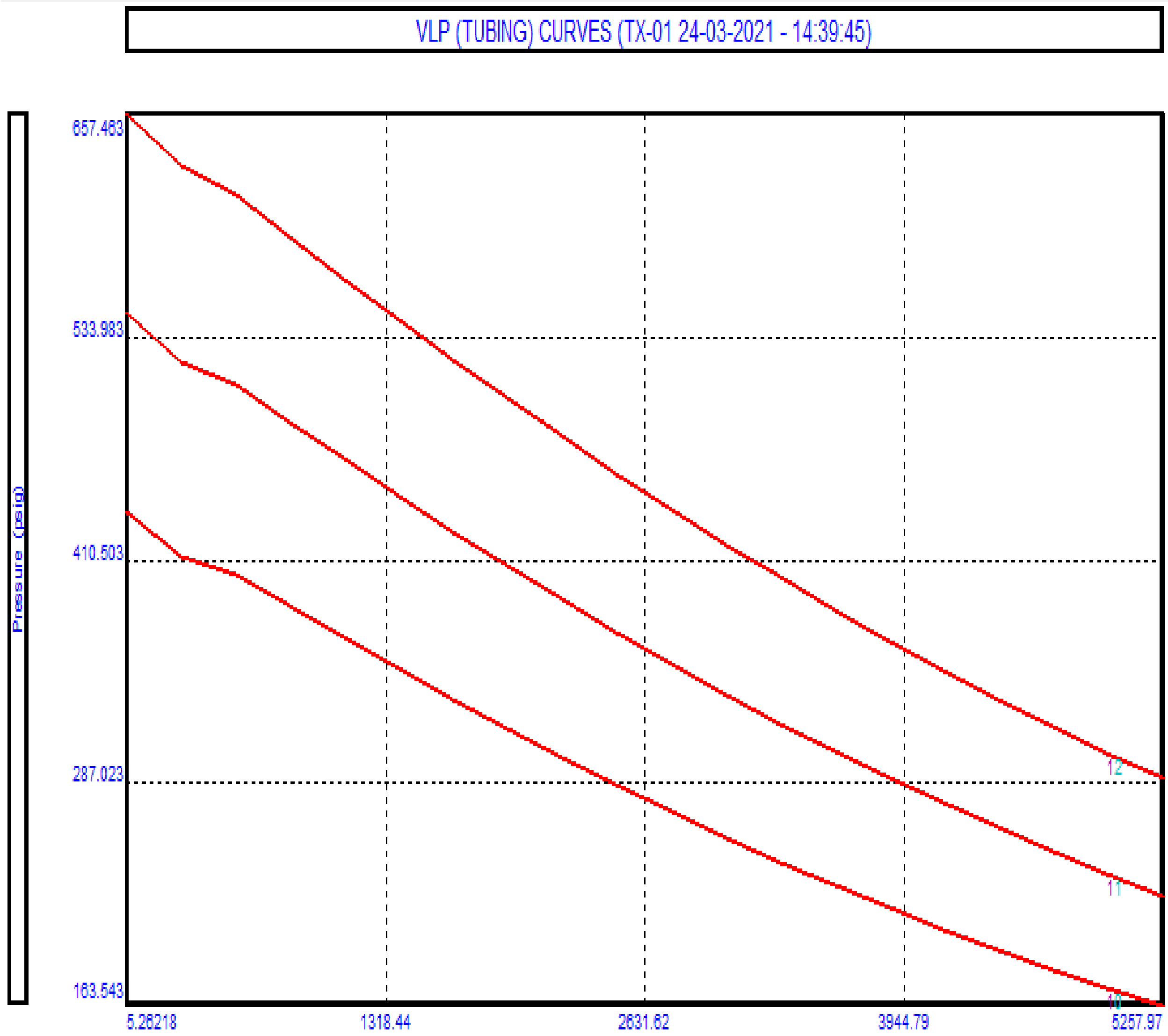


**Figure 9:** Sensitivity for VLP Curves.

The graph in figure 10 is pressure vs measured depth graph for jet pump case tubing injection-annular production. The N/T combination is nozzle (11) throat (2), as it can be seen in graph that at the depth of 6300 ft. as the fluid enters the tubing the pressure rises rapidly and reaches to 2520 psi and then pressure starts to drop linearly as the fluid moves up to the surface. The correlation used is Beggs and Brill correlation for surface equipment.

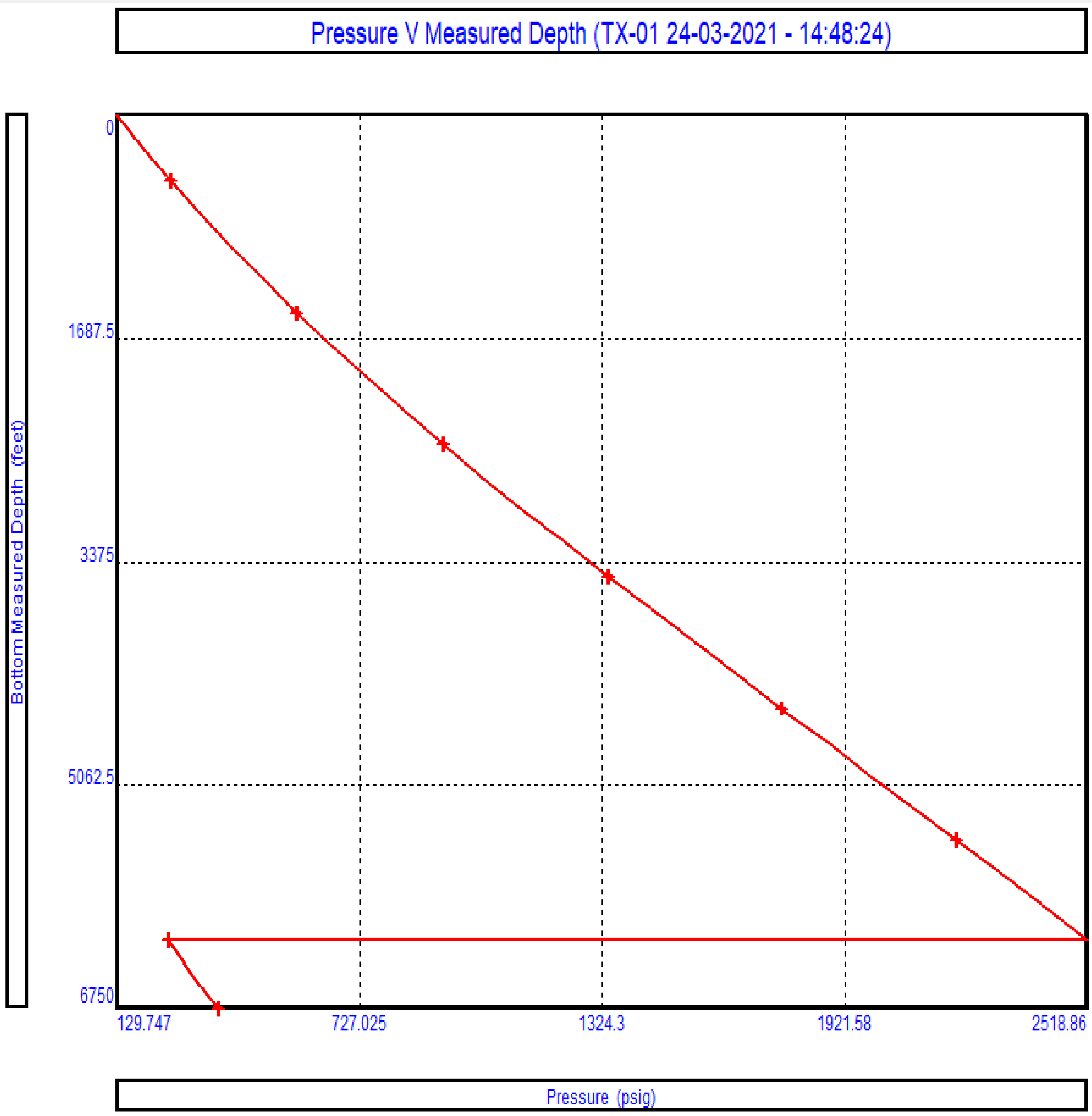


**Figure 10:** Pressure vs Measured Depth Plot.

### *6.3 Case 03 for ESP*

There are many reservoir models offered by PROSPER Simulation software for generating IPR curve. Here Darcy's model is selected for generating IPR and mechanical skin is entered manually. The well is single branched cased hole with 7 in. casing, some parameters that are calculated by the software are noted as productivity index is 5.27 STB/day/psi, AOFP 3933 STB/day for 84% water cut and GOR is entered as 430 SCF/STB. The formation skin is 1.3 as shown in Figure 11.

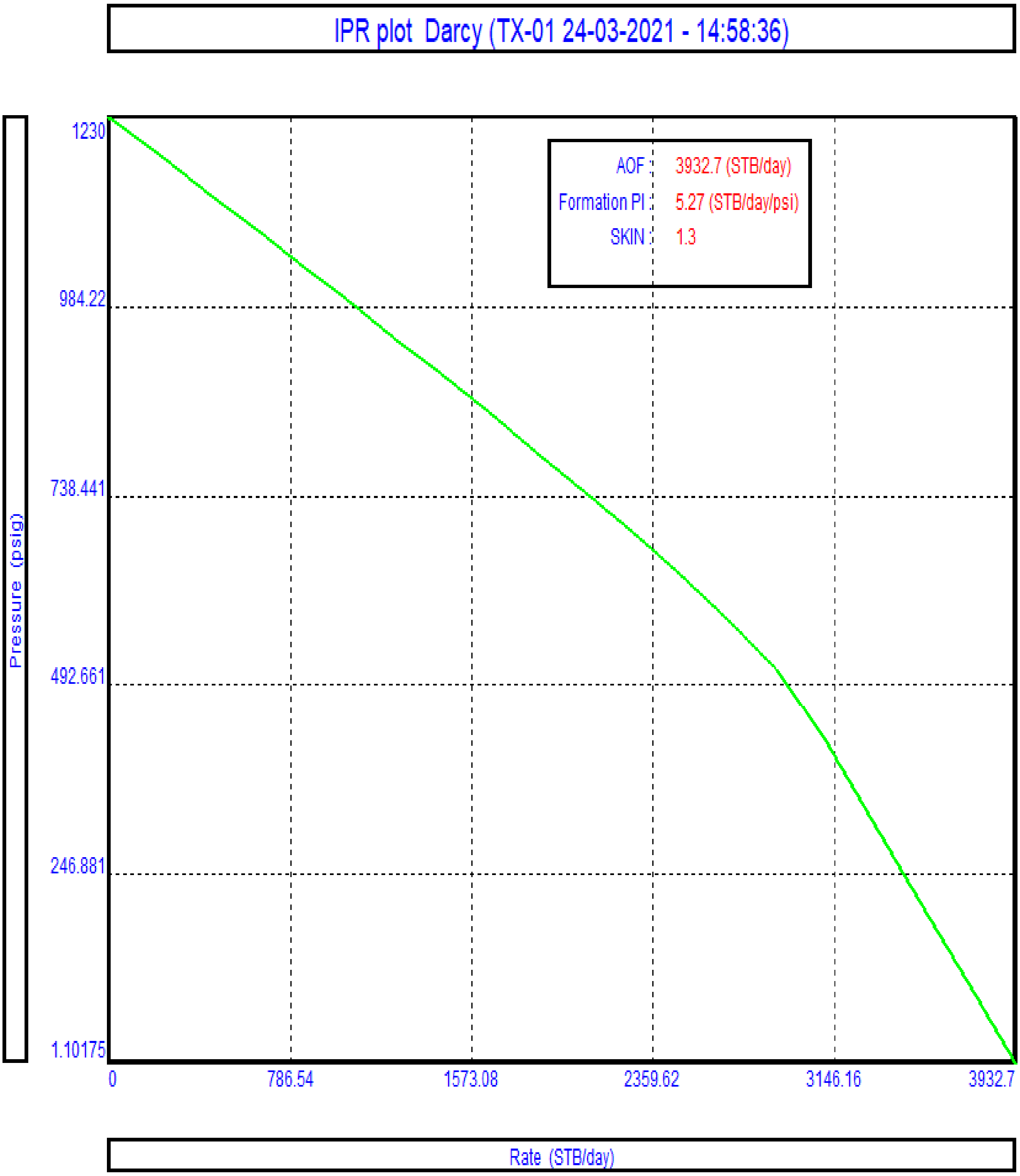


**Figure 11:** IPR curve for ESP case.

As the graph shows in Figure 12 the blue point below the Dunbar factor line shows that the completion assembly requires a downhole gas separator for better efficiency of ESP. The advanced gas handler is installed to separate out the gas by lowering flow pressure and the free gas is flowed through the annulus, this gas can be treated for the use or can be flared depends on the composition and impurities present.

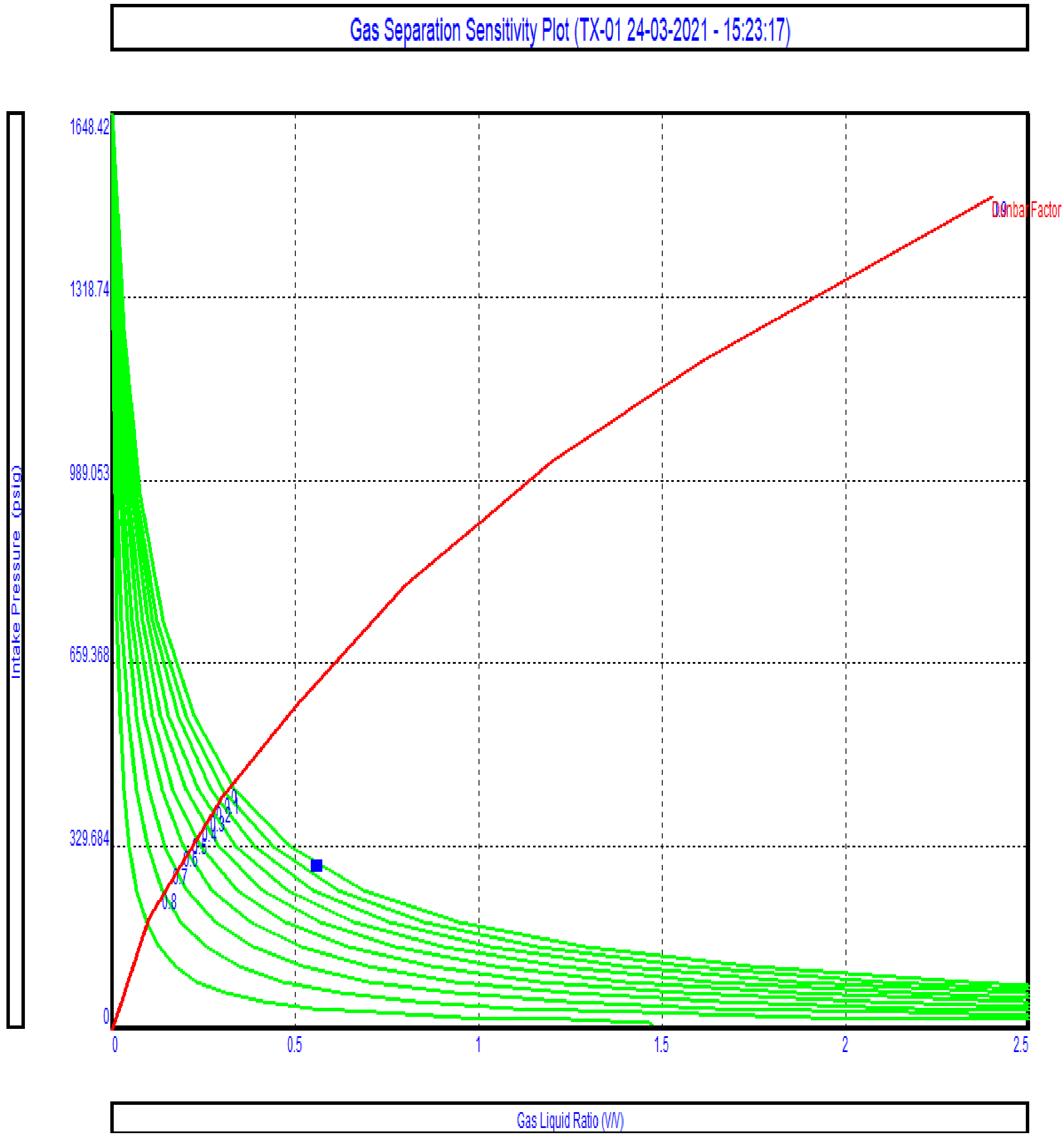


**Figure 12:** Dunbar Plot of Gas Separator Sensitivity.

The following ESP performance curve in figure 13 shows the efficiency of ESP at different operating frequencies i.e. 40, 50, 60, 70 hertz for variable liquid head values. The operating frequency value entered for simulation was 55 Hertz and the software calculated it to be 63 Hertz for the best efficiency. The ESP is Centrilift R38 with 401 stages, one stage comprises of a diffuser and an impeller. At 63 Hertz frequency the AOFP is 6100 STB/day for 55 Hertz it would be 5200 STB/day with a 3-1/2 inches tubing size.

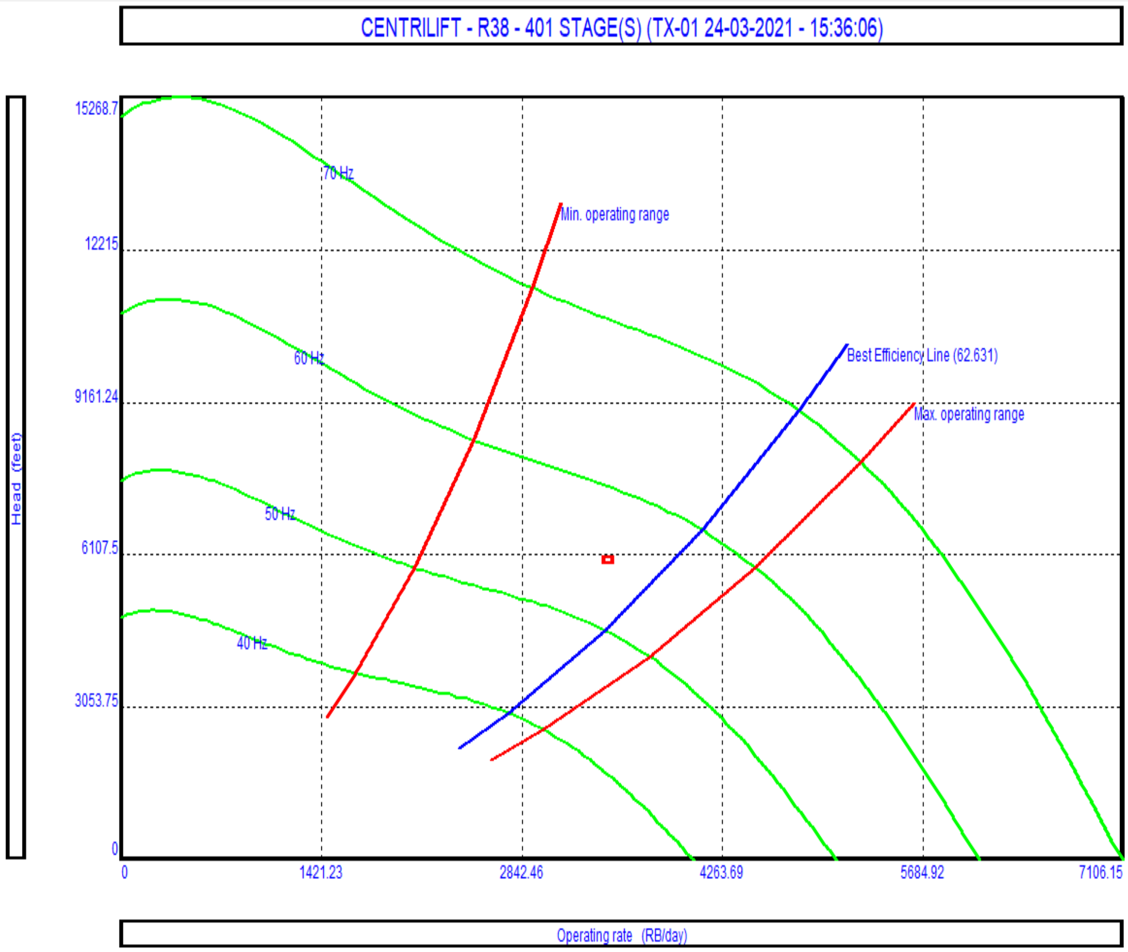


**Figure 13:** ESP Performance Curve.

## 7. Well Completion Recommendations

In contrast to jet pump the rating and lifting capacity of ESP is high, it is designed to lift high volumes, so according to the stimulated data, the 2-7/8 inch tubing is replaced with 3-1/2 inch tubing size considering the tubing stresses and pressure rating. As it was already mentioned that the well is 7 inch mono-bore this tubing size is fit for the purpose.

During Running-in of ESP make sure that no torque is given to the assembly and special precautionary measures should be taken to avoid damage of cable or chemical line (SS tube). While making up flange connections of ESP assembly use clean cloth and gloves to avoid any particles residue in internal assembly. The assembly process should be carried out with care specially when making-up connections of motor shafts with coupling, slake the assembly slowly to avoid damage of shaft or couplings.

No restriction were installed in the completion assembly to assure smooth fluid flow. A customized recompletion spool was installed at the X-mas tree to accommodate ESP assembly tubing hanger, this recompletion spool serves as tubing head spool. For the installation of Feed through Penetrator in tubing Hanger standard torque should be provided to the penetrator to avoid any leakage through the penetrator. The cable integrity test should be conducted at every 20 joints.

## 8. Work-over Job

The work over was carried for the installation of ESP but before installation some pre-installation operations are carried out in order to make sure that the well is properly cleaned and perforation are producing up to the mark. In this regard three additional zones are perforated and acid washed through coil tubing to remove the debris.

Pick-up 7" RTTS Packer along with Re-entry Guide and make up with drill string. Start RIH with 3-1/2" drill pipes down to 6480 ft. Meanwhile Spot coiled tubing unit and related equipment. Set 7" RTTS packer at 6480 ft., behind good cement (Avoid packer setting against casing collar). Prepare 100 bbl. 3%$NH_4Cl$ as per recipe.

Make-up 3-1/8", 5K, Gate valve above drill pipe using compatible X-overs. R/up Coiled tubing unit with provision of circulation cross below CT BOP. Pressure / pull test CT as per service company requirement in presence of production engineer. Complete CT BHA with Jet Blaster. Correlate CT depth. Start RIH CT at slow speed (5-10 M/Min) for first 100 M then increase to 15-20 M/Min. Trickle with nitrified 3%$NH_4Cl$ brine to keep Jet blaster clear. Connect waste line with Circulation cross and direct returns to waste pit. RIH coiled tubing down to Top of Perforations. Prepare 30 bbl. 9% Formic Acid as per recipe. Switch to 30 bbl. 9% Formic Acid, Pump nitrified 9% Formic Acid, once Acid is at nozzle, reciprocate across perforations @ 0.8-0.9 BPM with Nitrogen @ 450 Scf/Min (Make at least 02 up and down Passes- Adjust CT Speed). Once acid is Nozzle out, Station coiled tubing at Top of perforations. Pump 20 bbl. 3%$NH_4Cl$ nitrified brine followed by hole volume of Nitrified Rig Brine. (Pumping Rate 0.8-0.9 BPM with Nitrogen @ 450 SCF/Min). Circulate out Normal Rig Brine and Pump acid out of Hole, observe returns at surface, once $P_H$ and Sp.Gr. of return Rig brine equalize mud tank.

**Table 7:** Recipe for Perforation Acid Wash.

| **Perforation Wash Recipe** | | | |
|---|---|---|---|
| **9% Formic Acid** (Required Quantity: 30 Bbl. or 1260 Gal) | | | |
| **Sr.** | **Description** | **Quantity/1000 Gal** | **Required Quantity** |
| 1 | Formic Acid | 90 Gal | 113 Gal |
| 2 | Corrosion Inhibitor | 05 Gal | 6.3 Gal |
| 3 | Chelating Agent | 05 Gal | 6.3 Gal |
| 4 | Surfactant | 02 Gal | 2.5 Gal |
| 5 | Reducing Agent | 10 lb. | 12 lb. |
| 6 | Diluter (Water) | 888 Gal | 1120 Gal |
| **3% NH4Cl Brine with Surfactant** (Required Quantity: 100 Bbl. or 4200 Gal) | | | |
| 1 | Ammonium Chloride | 216 Gal | 920 lb. |
| 2 | Diluter (Water) | 996 Gal | 100 bbl. |

Observe the well is Static. POOH coiled tubing up to surface and rig down CT unit. Make 7” casing scrapper + junk sub trip down to 6560 ft. to remove any obstruction and POOH. Pick-up ESP assembly and RIH 3-1/2” CS Hydril 10.3 PPF tubing with ESP assembly with Power Cable down to **6168 ft.** under the supervision ESP specialist**.**

**Note**

i. Prior RIH, Drift, Clean and Measure Tubing Joints.
ii. During RIH Insure Cable safety and secure with Clamps and Buckles.
iii. During RIH, Carry out Cable Integrity Test after each 20 Joints, and Electrical Insulation test at End of RIH.

**Table 8:** ESP Performance Parameters.

| VSD Output Freq: (Hz) | Pump Intake Press: (PSI) | Pump Discharge Press: (PSI) | Pump Differential Pressure (PSI) | ESP Motor (A) | Pump Intake Temp: (degC) | ESP Motor Winding Temp: (degC) | WHP (PSI) | WHT ºC | Casing Press: (PSI) | Q Gross (bpd) | Q Oil (bpd) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 55.0 | 1111.9 | 2567.5 | 1455.6 | 37.3 | 108.4 | 122.1 | | | | | |
| 55.0 | 1112.6 | 2576.6 | 1464.0 | 37.2 | 108.4 | 122.0 | | | | | |
| 55.0 | 1112.1 | 2566.3 | 1454.2 | 37.4 | 108.4 | 122.2 | | | | | |
| 55.0 | 1112.2 | 2577.4 | 1465.2 | 37.2 | 108.4 | 122.1 | | | | | |
| 55.0 | 1111.4 | 2566.4 | 1455.0 | 37.4 | 108.4 | 122.2 | | | | | |
| 55.0 | 1111.2 | 2595.6 | 1484.4 | 37.2 | 108.4 | 122.0 | | | | | |
| 55.0 | 1111.3 | 2547.9 | 1436.6 | 37.4 | 108.4 | 122.1 | | | | | |
| 55.0 | 1111.9 | 2582.2 | 1470.3 | 37.1 | 108.4 | 122.0 | | | | | |
| 55.0 | 1112.0 | 2602.1 | 1490.1 | 37.1 | 108.4 | 122.1 | | | | | |
| 55.0 | 1111.0 | 2570.2 | 1459.2 | 37.3 | 108.4 | 122.1 | | | | | |
| 55.0 | 1111.6 | 2576.4 | 1464.8 | 37.1 | 108.4 | 122.0 | | | | | |
| 55.0 | 1111.4 | 2560.7 | 1449.3 | 37.3 | 108.4 | 122.1 | | | | | |
| 55.0 | 1111.6 | 2573.3 | 1461.7 | 37.2 | 108.4 | 122.0 | | | | | |
| 55.0 | 1110.9 | 2572.6 | 1461.7 | 37.2 | 108.4 | 122.1 | | | | | |
| 55.0 | 1111.5 | 2567.7 | 1456.2 | 37.2 | 108.4 | 122.0 | | | | | |
| 55.0 | 1110.4 | 2576.7 | 1466.3 | 37.2 | 108.4 | 122.0 | | | | | |
| 55.0 | 1111.6 | 2575.8 | 1464.2 | 37.1 | 108.4 | 122.1 | 200.0 | 90.0 | 180.0 | 2800 | 500 |

Installation of Feed through Penetrator in Hanger and attach pigtail, Land hanger & secure with tie-down screws. R/Down BOP, R/Down 9” x 13-3/8” DSAF. Install protector Plate. Install shoulder nipple. N/Up complete X-Mass tree on shoulder nipple. Complete surface connection and Start well bore Clean-up through ESP. Test the well with ESP.

## 9. Comparison of Well Performance (Jet Pump vs ESP)

The performance testing of jet pump shows 83% water cut while producing only 17% of oil that was 160 BOPD. Now operating cost of well including routine maintenance to surface jet pump unit, routine reverse out of downhole jet pump, maintenance of water treatment facility, and chemical injection for scaling and corrosion inhibition become greater than the profit earned from the production of well. After installation of ESP on well Beta TX-01 the production rate was increased by three times now, the oil rate is 500 STB/day meanwhile the water production also increased that caused water handling and treatment problems. The operating cost of well is also raised by 2x (2 times) but the profit earned can overcome the expenditure. The Table 8 shows the parameters like pump intake, pump discharge and production rates for the first month of performance testing The Figure 14 shows the pressure vs frequency graph for four different factors i.e. Pump differential Pressure, pump discharge pressure, pump intake pressure and VSD output frequency. The pump intake pressure and VSD output frequency shows steady trend whereas some fluctuations can be observed in pump differential pressure and pump discharge pressure line. At 55 Hz frequency the VSD output frequency curve overlaps the pump discharge pressure curve.

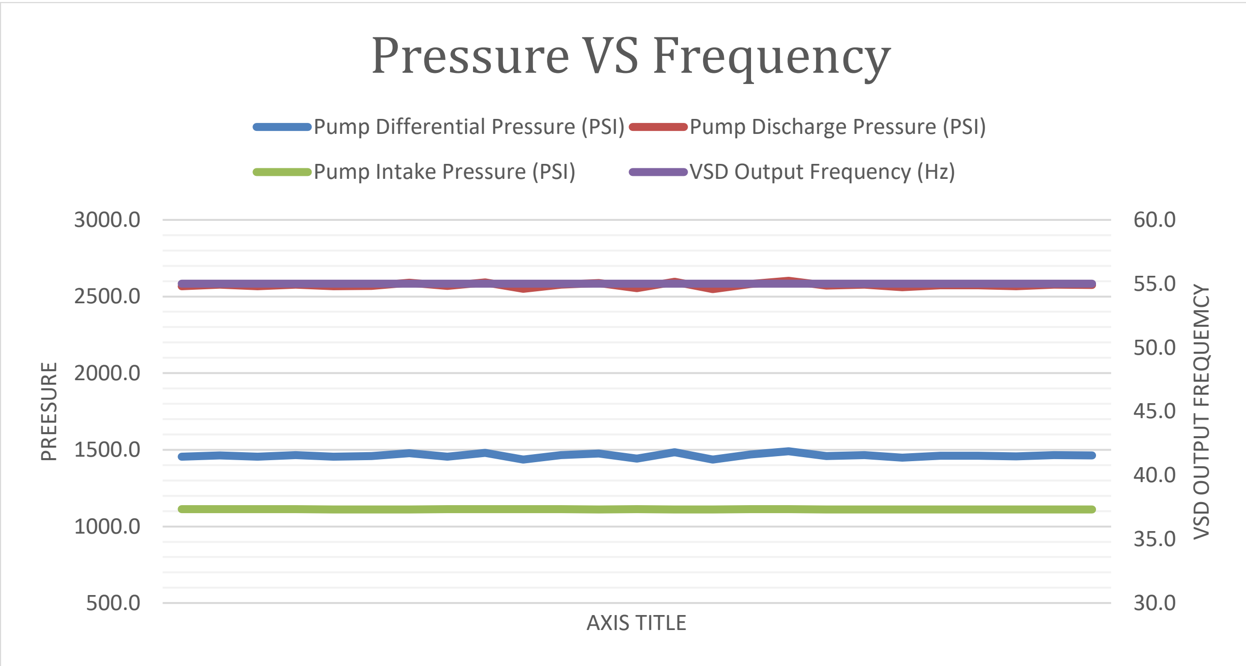


**Figure 14:** Pressure Vs frequency Graph.

## 10. Conclusion

- The well Beta TX-01 shows low oil production rates due to low reservoir pressures and high water cuts.
- The well was already producing artificially on jet pump so, a more feasible and optimum ALS was required.
- After the thorough study of well dynamics ESP was selected to be the best fit for the well.

- Observing the simulation data and considering the lifting capacity of ESP the 2-7/8 inch tubing was replaced with 3-1/2 inch tubing size.
- After the work over the well flowed through ESP for cleanup.
- The performance evaluation carried out and the ESP production data obtained was compared to Jet pump production data.
- The Production was remarkable enhanced after installation of ESP.
- The ESP was tested at different operating frequencies and the result were satisfying.
- The water production from the well also increased resulting in water management issues.
- The production Span of Beta TX-01 was also extended over natural flowing period of the well.

## 11. Recommendations

Designing smart completions utilizing inflow control devices in combination with ESP can reduce the water cut up to a remarkable extent. Furthermore the ESPs perform better with low water cut wells.

## 12. Nomenclature

| | |
|---|---|
| BPD | Barrels Per Day |
| BOPD | Barrels of Oil per Day |
| MMSCF/D | Million Standard Cubic Feet per Day |
| ESP | Electrical Submersible Pump |
| Psi | Pound per Square Inch |
| Amps | Amperes |
| Ft. | Feet |
| SCF/STB | Standard Cubic Feet per Stock Tank Barrel |
| PLT | Production Logging Tool |
| N/T | Nozzle/Throat |
| PPM | Pounds Per Million |
| GLR | Gas Liquid Ratio |
| GOR | Gas Oil Ratio |

| | |
|---|---|
| IPR | Inflow Performance Relationship |
| VLP | Vertical Lift Performance |
| CT | Coil Tubing |
| SCF/Min | Standard Cubic Feet per Minute |
| BPM | Barrels per Minute |
| Sp.Gr. | Specific Gravity |
| Gal | Gallon |
| RIH | Run in Hole |
| DSAF | Double Stud Adapter Flange |
| N/up | Nipple Up |
| R/Down | Run Down |
| POOH | Pull Out of Hole |
| ALS | Artificial Lift System |
| VSD | Variable Speed Drive |

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