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ANALYSIS OF THE APPLICATION OF THE ECONOMIC SLOPE CONCEPT FOR THE EVALUATION OF THE RATE OF GAS INJECTED FOR OPTIMAL PROFITABILITY OF GAS LIFT IN WELLS

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Abstract

Analysis of the application of the economic slope concept in determining the economically optimum gas injection rate for a gas lift process is presented in this work. The type of gas lift process used for the study is continuous gas lift. The study made use of PROSPER, a production modelling tool patented to Petroleum Experts Limited for the analysis. Well X was taken as a case for the gas lift design analysis. Reservoir, fluid and equipment data were obtained and used for the analysis. PROSPER was used to perform the gas lift equipment design and generate the IPR curve. PROSPER was also used to generate the gas lift design performance curve. Manual computations involving the economic slope concept were made based on the information read from the performance curve for the optimum gas injection rate. From the analysis, it is determined that the optimum gas injection rate for the gas lift process at Well X is 2.47MMscf/d.

Keywords: economic slope; gas lift; PROSPER; tangent; injection rate; optimum.

1. Introduction

Gas lift is a form of artificial lift where gas bubbles lift the oil from the well. In the United States, gas lift is used in 10% of the oil wells that have insufficient reservoir pressure to produce the well. In the petroleum industry, the process involves injecting gas through the tubing-casing annulus. Injected gas aerates the fluid to reduce its density; the formation pressure is then able to lift the oil column and forces the fluid out of the wellbore. Gas may be injected continuously or intermittently, depending on the producing characteristics of the well and the arrangement of the gas-lift equipment [5].

According to Wikimedia [6], the amount of gas to be injected to maximize oil production varies based on well conditions and geometries. Too much or too little injected gas will result in less than maximum production. Generally, the optimal amount of injected gas is determined by well tests, where the rate of injection is varied and liquid production (oil and perhaps water) is measured.

Although the gas is recovered from the oil at a later separation stage, the process requires energy to drive a compressor to raise the pressure of the gas to a level where it can be re-injected.

The gas-lift mandrel is a device installed in the tubing string of a gas-lift well onto which or into which a gas-lift valve is fitted. There are two common types of mandrels. In a conventional gas-lift mandrel, a gas-lift valve is installed as the tubing is placed in the well. Thus, to replace or repair the valve, the tubing string must be pulled. In the side-pocket mandrel, however, the valve is installed and removed by wireline while the mandrel is still in the well, eliminating the need to pull the tubing to repair or replace the valve.

A gas-lift valve is a device installed on (or in) a gas-lift mandrel, which in turn is put on the production tubing of a gas-lift well. Tubing and casing pressures cause the valve to open and close, thus allowing gas to be injected into the fluid in the tubing to cause the fluid to rise to the surface. In the lexicon of the industry, gas-lift mandrels are said to be "tubing retrievable" wherein they are deployed and retrieved attached to the production tubing.

The introduction of lift gas to a non-producing or low-producing well is a common method of artificial lift. Natural gas is injected at high pressure from the casing into the well and mixes with the produced fluids from the reservoir as shown in Figure 1.1. The continuous aeration process lowers the effective density and therefore the hydrostatic pressure of the fluid column, leading to a lower flowing bottom-hole pressure (Pbh). The increased pressure differential induced across the sand face from the in situ reservoir pressure (Pr), given by ($Pr - P$bh), assists in flowing the produced fluid to the surface. The method is easy to install, economically viable, robust, and effective over a large range of conditions, but does assume a steady supply of lift gas [1]. At a certain point, however, the benefit of increased production due to decreased static head pressure is overcome by the increase in frictional pressure loss from the large gas quantity present. This has the effect of increasing the bottom-hole pressure and lowering fluid production. Hence, each well has an optimal desirable gas-lift injection rate (GLIR). However, when the entire gathering network is considered, the optimal gas-lift injection rate differs from that which maximizes individual well production due to the back pressure effects (the pressure drop observed across flow lines due to common tie backs further downstream) imposed by connected wells further downstream.

As a field matures, the greater demand for lift gas in conjunction with limitations imposed by existing facilities and prevailing operating conditions (compression capacity, lift gas availability, well shut-in for workover, etc.) can prevent optimal production from being achieved. In the absence of all operating constraints, other than the available lift gas, it is necessary to optimally allocate the available lift gas amongst the gas-lifted wells so as to maximize the oil production. This is the most basic definition of the gas-lift optimization problem and is equivalent to an optimal allocation problem. Consideration of additional operating constraints, choke control for well-rate management and the treatment of difficult to produce wells, gives rise to a broader problem definition. In general, either definition can additionally accommodate an economic objective function, by inclusion of production and injection cost factors. Although the choice of objective function has been stated as the differentiator between the methods developed by some [3], in actuality, most methods can handle either definition and should not be categorized on this basis.

Kanu *et al.* [2] solved for the economic point using a method derived graphically. The optimal operating condition is said to occur when the incremental revenue from production is equal to the incremental cost of injection in each well. The production and gas-lift rates for a range of slope values are estimated for each well. These give rise to slope versus production and slope versus gas-lift rate relationships. The economic point for each well is established and the associated lift-rate and production values are obtained. Total production and the total lift gas used are established by summing the individual well solutions. The same can be performed for all slope values, allowing the relationships of Total Production and Total Lift gas to be plotted with respect to the slope. With a limited supply of gas, the amount of gas available will indicate the expected slope value from the total lift gas versus slope plot. The associated production value can be obtained from the Total production versus slope plot for the given economic slope. Similarly, the individual well responses can be read from the particular well plots.

It is worth noting that the economic slope solution is greater than the zero gradient necessary for maximal production, which indicates the benefit of optimizing for economic performance and not simply production. A 6-well model was presented by Kanu *et al.* [2], with an unlimited lift gas supply using actual and an average estimate of the well properties. While the latter simplifies the evaluation process, the solution is less accurate. The constrained lift gas solution implicitly returns an average economic slope, leading to an allocation that is not strictly correct or optimal. In general, the procedure cannot easily handle additional constraints and can prove unwieldy for high-dimensional problems and cases where the curves have to be regenerated frequently due to changing well conditions. For this, the authors note that an automated procedure is necessary.

Optimum gas injection rate for a gas lift process refers to the particular rate of gas injection into the tubing at which gas lift gas availability, production equipment and oil production are covered. It is the gas injection rate that guarantees continuous but normalized oil production which would last longer compared to when gas is injected at high rates to produce more oil.

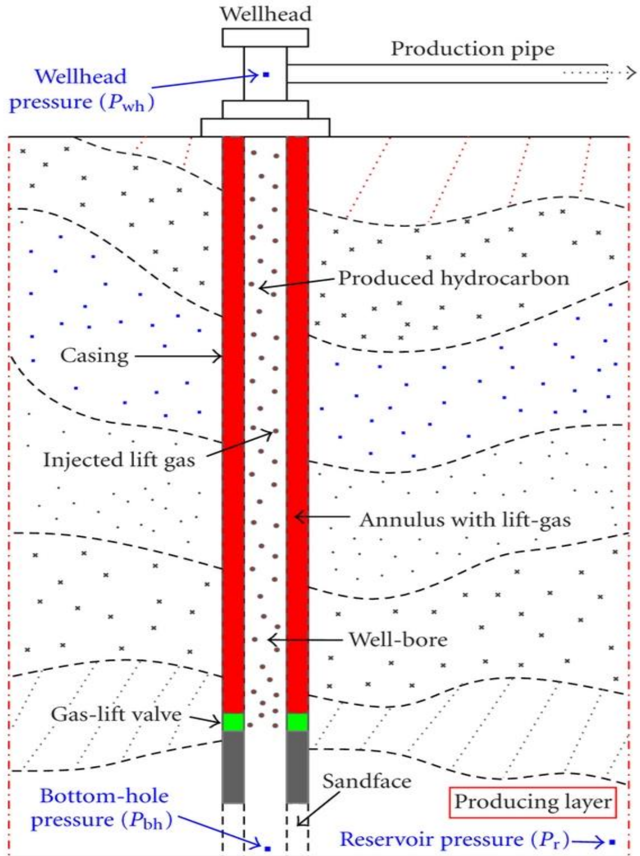

Fig 1.1 Gas Lift Well Schematic (Source: Brown, 1982)

2. Methodology

The steps of studying the optimization of the volume of gas requirement for gas lifting include: comparing the cost of an incremental amount of injected gas with the profit from the incremental production, deduction of the optimal volume of injected gas. Determination of gas lift optimization point requires economic slope concept that predicts the economic point to produce a well given a gas requirement curve. Economic slope concept is applied on the performance curve of the gas lift design. This performance curve is generated using PROSPER, a petroleum engineering software patented to Petroleum Experts Limited.

PROSPER is an advanced **Pro**duction and **S**ystems **Per**formance analysis software. PROSPER can help the production and reservoir engineer to predict the tubing and pipeline hydraulics and temperatures with accuracy and speed. PROSPER can be confidently used to model the well in different scenarios and to make forward predictions of reservoir pressure based on surface production data. It also enables existing designs to be optimized and the effects of future changes in system parameters to be assessed. PROSPER is a fundamental element in the Integrated Production Model (IPM). PROSPER is applied for the design of the gas lift system and the gas lift performance curve is generated in the process from which the optimal gas injection rate is determined through the economic slope concept. The economic slope which is the optimal economic point is given as:

$$M = C_g/(F_oP) \tag{2.1}$$

where: C_g = Cost of gas lift gas; F_o = Oil cut; P = Profit per barrel of oil produced.

2.1 The Economic Slope Procedure

The steps for the application of the economic slope concept are listed as follows:

1. Establish a gas requirement curve using the values of liquid rate and gas injection rates.

2. Draw slopes of varying degrees as tangents to each curve.
3. Obtain values of injected gas and produced liquid at the point of tangency of each slope.
4. Establish a slope-rate relationship for each well using the injection gas liquid production rate values obtained in step 3
5. Establish a slope-rate relationship for the field by totaling the rates associated with each slope and plotting the values.
6. Calculate the economic slope for each well using:

$$C_g/(F_oP) = M = Q_L/Q_g \tag{2.2}$$

where, Q_L = Liquid Production Rate; Q_g = Gas Injection Rate.

7. Use the average water cut of each field to determine the oil fraction, then obtain the average economic slope.
8. Allocate gas to each well by matching the individual well economic slope with its slope/rate relationship drawn in step 4 when the average economic slope for each well is used to allocate gas to each well, match the average economic slope to each well's slope –rate relationship.
9. Obtain the total injection gas for the field at the optimal economic point by adding all the gas injection rates associated with the calculated economic slope.
10. Using the unlimited gas availability value and entering the master plot, the corresponding average economic slope is read off. This is used on slope-rate relationship for each field to read the corresponding gas injection and liquid production rates.

3. Results

For a continuous gas lift process, the following data as shown in Tables 3.1 to 3.5 are given for the equipment and process design. These data in the tables are used on PROSPER. After the input of the data values into the various sections of PROSPER, the completely-filled PROSPER interface becomes as shown in Appendix 2.1.

Table 3.1 Reservoir and Fluid Data for the Gas Lift Design

Solution GOR	820scf/stb
Oil Gravity	34^0API
Gas Gravity	0.833
Water Salinity	150000ppm
% Sulphur, Carbon dioxide, Nitrogen	0
Reservoir Permeability	50md
Reservoir Thickness	200feet
Drainage Area	500acres
Dietz Shape Factor	31.6 (for a circular drainage area)
Wellbore Radius	0.354feet
Reservoir Pressure	520psig
Reservoir Temperature	210^0F

Table 3.2 Equipment Data (Deviation Survey)

Measured Depth (ft)	True Vertical Depth (ft)
0	0
4300	4273
4600	4528
4900	4800
11300	10350
11400	10430

Table 3.5 Equipment Data (Downhole Equipment and Dimension)

Tubing 3.958″	From 0ft to 1000ft
3″ SSSV	At 1000ft
Tubing 3.958″	From 1000ft to 11000ft
Casing 6″	From 11000ft to 11400ft

Table 3.3 Equipment Data (Geothermal Gradient)

Measured Depth (ft)	Temperature, ^{0}F
0	45
11400	210

Table 3.4 Gas Lift Design Parameters

Gas Lift Gas Gravity	0.8
Casing Pressure Drop per Valve	50psi
Maximum Liquid Rate	15000stb/day
Maximum Gas Available	5MMscf/d
Maximum Gas while Unloading	5MMscf/d
Flowing Top Node Pressure	200psig
Unloading Top Node Pressure	200psig
Operating Injection Pressure	1500psig
Kick Off Injection Pressure	1500psig
Desired dP across Valve	200psi
Maximum Depth of Injection	11000ft
Water Cut	80%
Minimum Valve Spacing	300ft
Static Gradient of Load Fluid	0.46
Minimum Transfer dP	25%
Maximum Port Size	32 (set by valve series selection)
Safety for Closure of Last Unloading Valve	0psig
DeRating Percentage for Valves/Orifice	100%

Having performed the gas lift equipment design and generation of IPR curve, the next is to generate the gas lift performance curve. This gas lift performance curve is generated by clicking Design on the PROSPER interface, then click Gas Lift and click New Well. An interface like Appendix 2.2 will appear.

After filling all the necessary data as given to you on the Gas Lift Design – New Well Interface, then click Continue and another interface like Appendix 2.3 pops up.

This interface of Calculated Rate would have to generate the values of GLR injected, Liquid rate, Oil rate, VLP and IPR pressures, Gas lift design injection rate and Oil production. Click Get Rate to see all these values as shown in Appendix 2.4.

The last step on PROSPER is to click on Plot to generate the Gas Lift Design Performance Curve. Choose four different points on the performance curve and draw tangents at the four points. Also, draw lines with which to generate the slopes of the tangents at the four points. This is shown in Fig 3.1.

Having drawn lines of tangent to the Gas Lift Design Performance Curve Plot at the four chosen points, the slopes of the tangents at those four points are presented in the table at the corresponding Oil Produced, Q_o and Gas Injected, Q_g

Table 3.5 Slopes of the tangents

Tangent	Slope	Q_g	Q_o
A	0.114	6.15	1487
B	0.380	4.20	1421
C	0.853	2.79	1308
D	1.417	1.75	1162

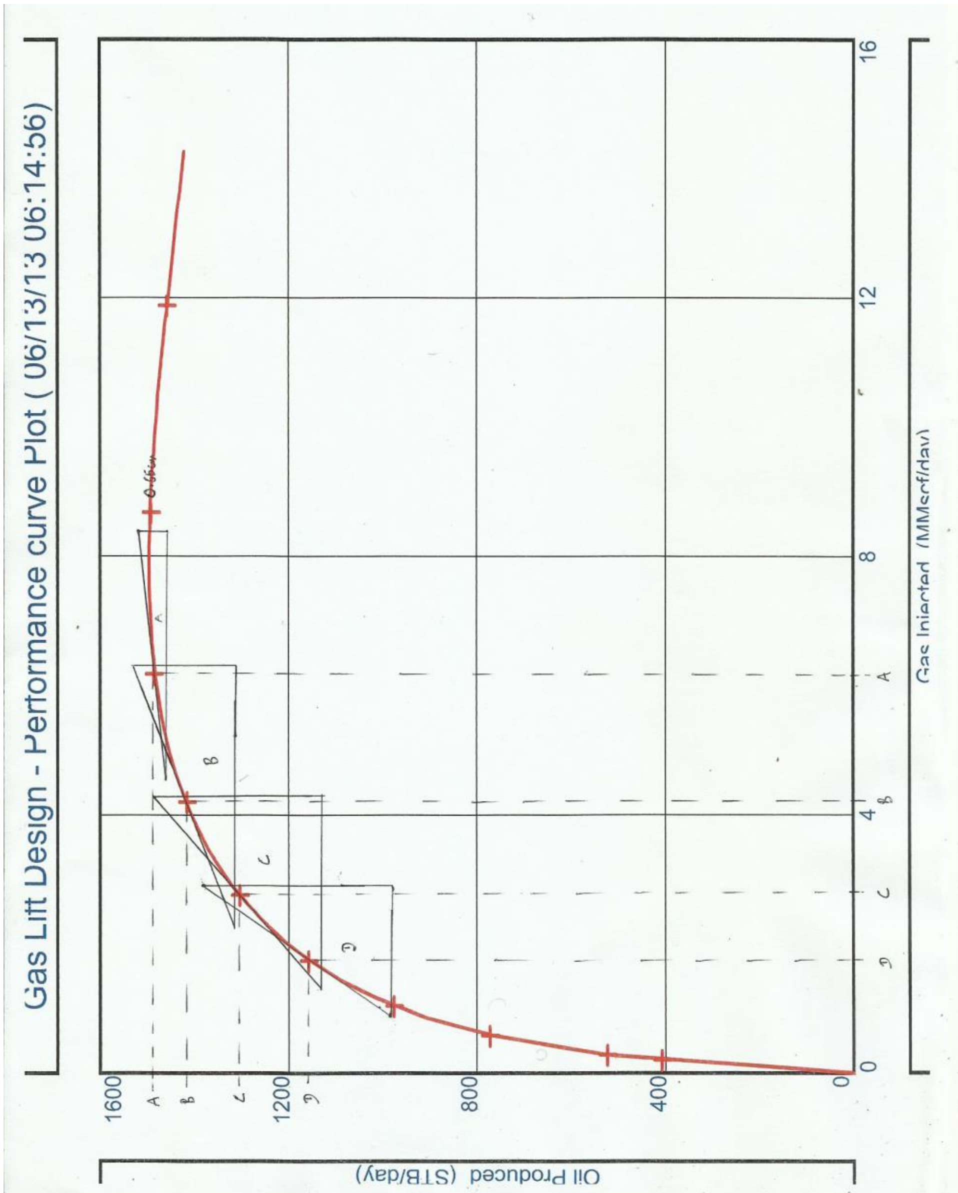

Fig. 3.1 Gas Lift Design Performance Curve with the Lines and Tangents at the Chosen Points (Source: Petroleum Experts Limited)

The plot of slope against Q_g is as shown in Fig 3.2 below:

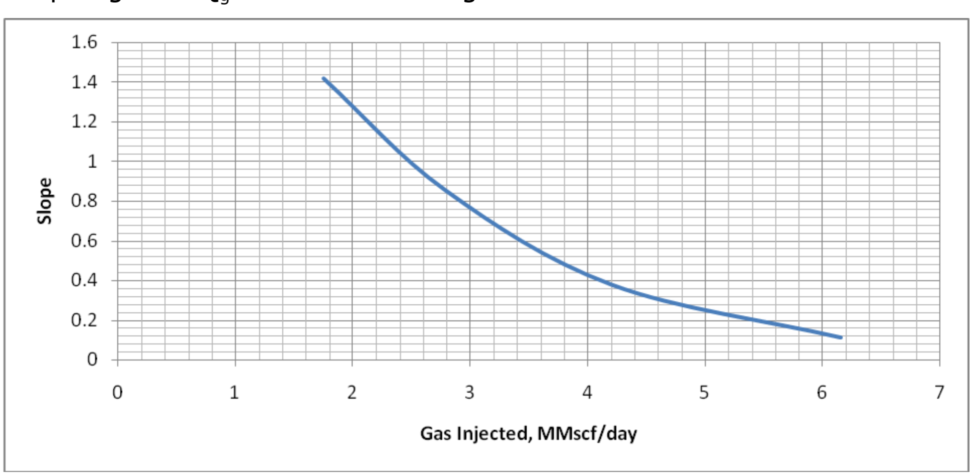

Fig. 3.2 Plot of Slope against Gas Injected, MMscf/day

Having made the plot of slope of the tangents against Gas Injected, the Economic Slope, M is then computed as shown:

$M = C_g/(F_oP)$

where: C_g = Cost of gas lift gas = \$1/MMscf; F_o = Oil cut = $1 - F_w = 1 - 0.8 = 0.2$; P = Profit per barrel of oil produced = \$5/bbl; $M = 1/(0.2 * 5) = 1$.

Having gotten the Economic Slope as M = 1, move to Fig 3.2, the plot of slope against gas injected and trace the corresponding Gas Injected on the x-axis at the particular Slope of 1 on the y-axis. This is shown in Fig 3.3 as 2.47.

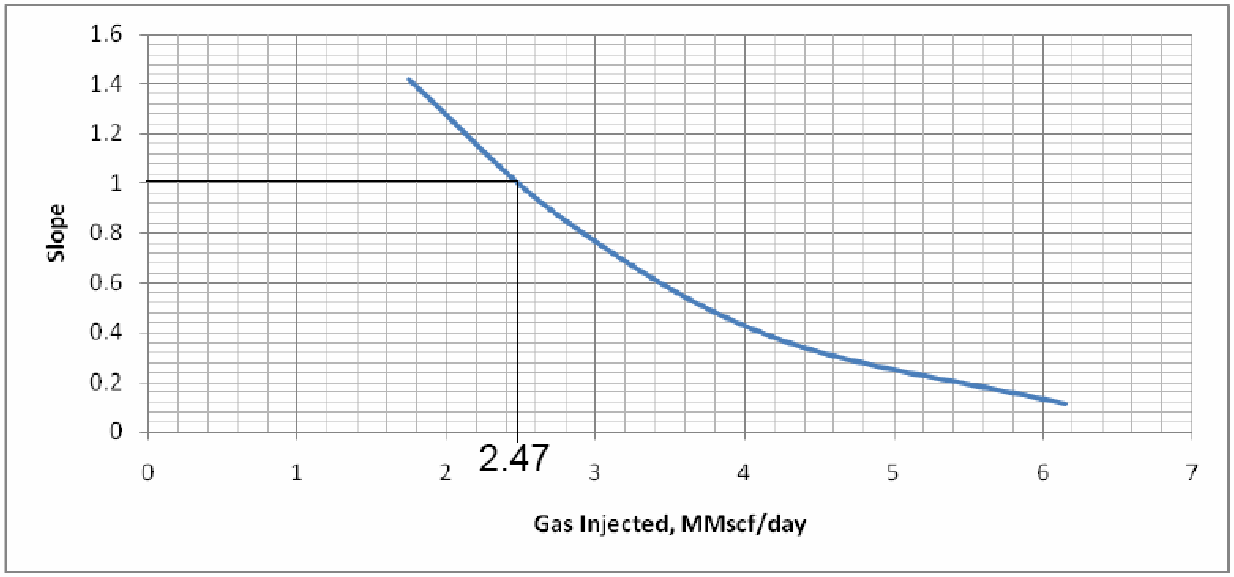

Fig. 3.3 Gas Injected at the Slope of 1

From the analysis performed above, it is seen that the amount of gas injected for optimal profitability is 2.47MMscf/day.

3.1 Equipment Design and Inflow Performance Curve for the Gas Lift

For better analysis of the gas lift process, the equipment design of the gas lift process is performed and is as shown in Fig 3.10. The equipment design process involves double-clicking Equipment Data on the PROSPER interface as shown in Appendix 2.1, an interface as shown in Appendix 2.5 pops up:

Then click All to highlight the whole input data, click Summary to give an interface like Appendix 2.6. Then click Draw Downhole to produce the equipment design as shown in Appendix 2.7.

The Inflow Performance Relation Curve is generated by double-clicking IPR Data on the main PROSPER interface as shown in Appendix 2.1, and clicking on Plot to get the IPR Curve as shown in Appendix 2.8.

4. Conclusion

At the end of the analyses, observations were made, which revealed that in gas lift processes, the desired gas injection rate might not necessarily be the optimum gas injection rate.

The following conclusions can be drawn based on the findings:

1. Gas lift equipment and process design can be performed to predict rates, generate the performance curve and other parameters during the gas lift process.
2. The generated gas lift performance curve can be used to know the amount of gas injection required to achieve any oil production level.
3. Despite the fact that the operator might want to inject more gas so as to produce more oil, he has to perform this economic slope analysis to know the particular gas injection rate needed for optimum gas lift process.

Nomenclature

bbl	Barrel	Pbh	Flowing bottom-hole pressure
C_q	Cost of gas lift gas	ppm	Parts per million
F_o	Oil cut	psig	Pounds per square inch
GLIR	Gas lift injection rate	PVT	Pressure-volume-temperature
GLR	Gas-liquid ratio	Q_q	Gas Injection Rate
GOR	Gas-oil ratio	Q_L	Liquid Production Rate
IPR	Inflow Performance Relation	Q_o	Oil Production Rate
M	Economic slope	scf	Standard cubic foot
md	Milidarcy	SSSV	Subsurface safety valve
MMscf/d	Million standard cubic foot per day	stb	Stock tank barrel
P	Profit per barrel of oil produced	VLP	Vertical lift performance
Pr	Reservoir pressure	^{0}F	Degree Fahrenheit

References

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[4] Petroleum Experts Limited: PROSPER; An Integrated Production Modeling Software.

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[6] Wikimedia Foundation Inc., (2013): Gas Lift; www.wikipedia.org; retrieved December 28, 2013.

Appendix 2: Figures from SW PROSPER

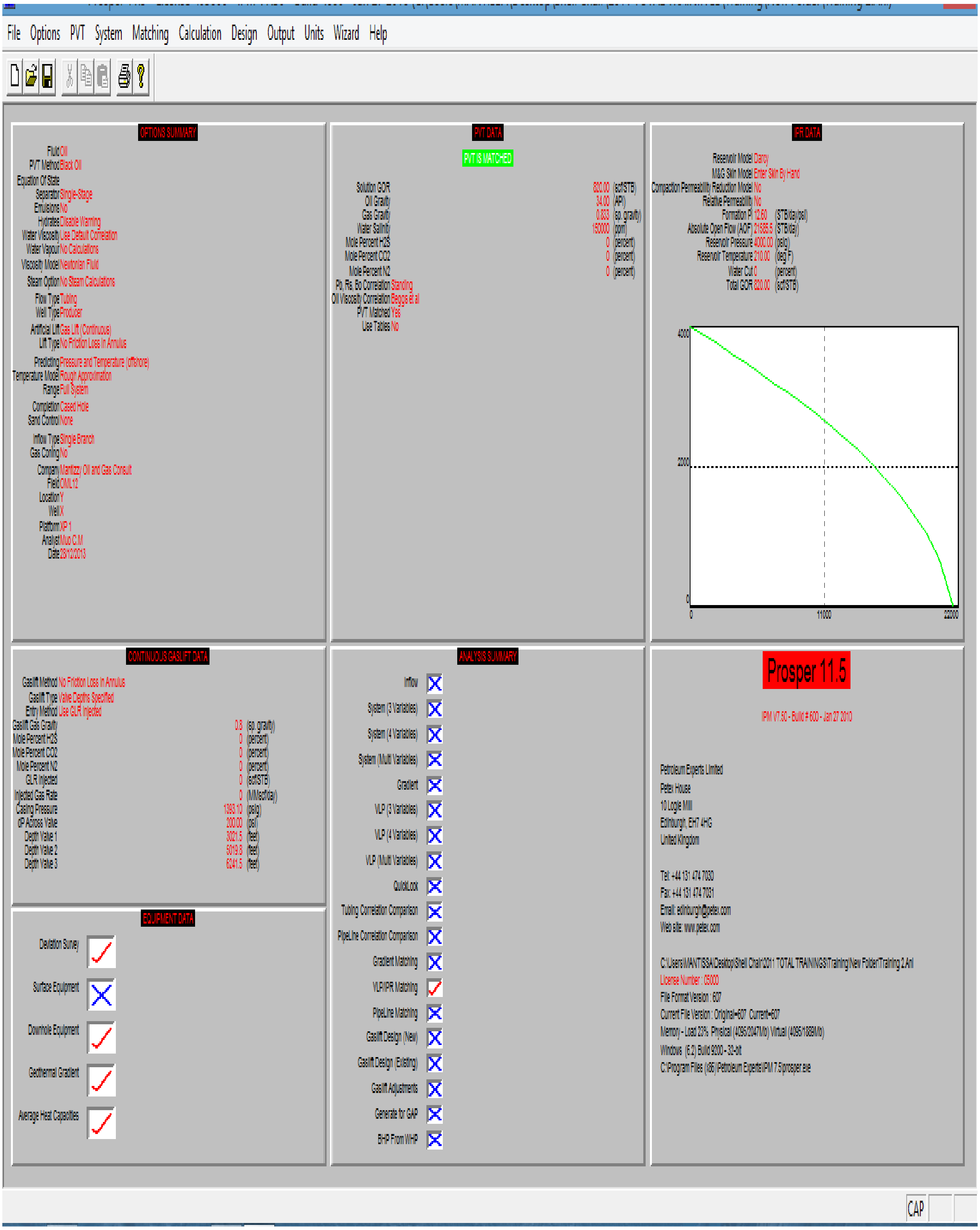


Fig. 2.1 PROSPER Interface after Input of Values, PVT Matching, Equipment Design and IPR Curve Generation (Source: Petroleum Experts Limited)

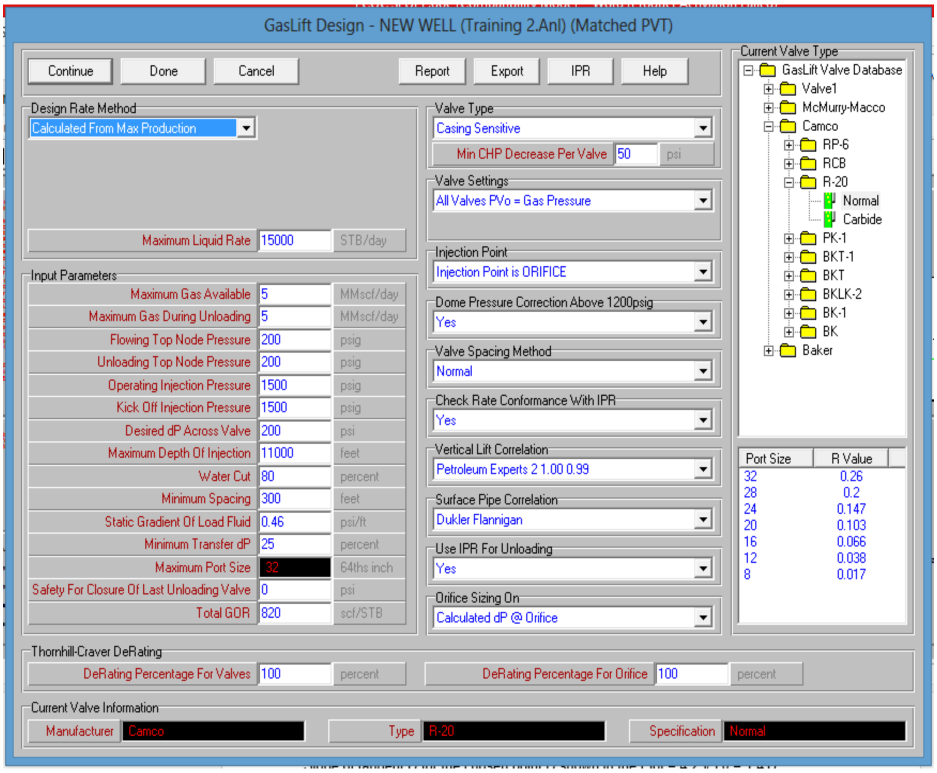


Fig. 2.2 PROSPER Interface for Gas Lift Design – New Well (Source: Petroleum Experts Limited)

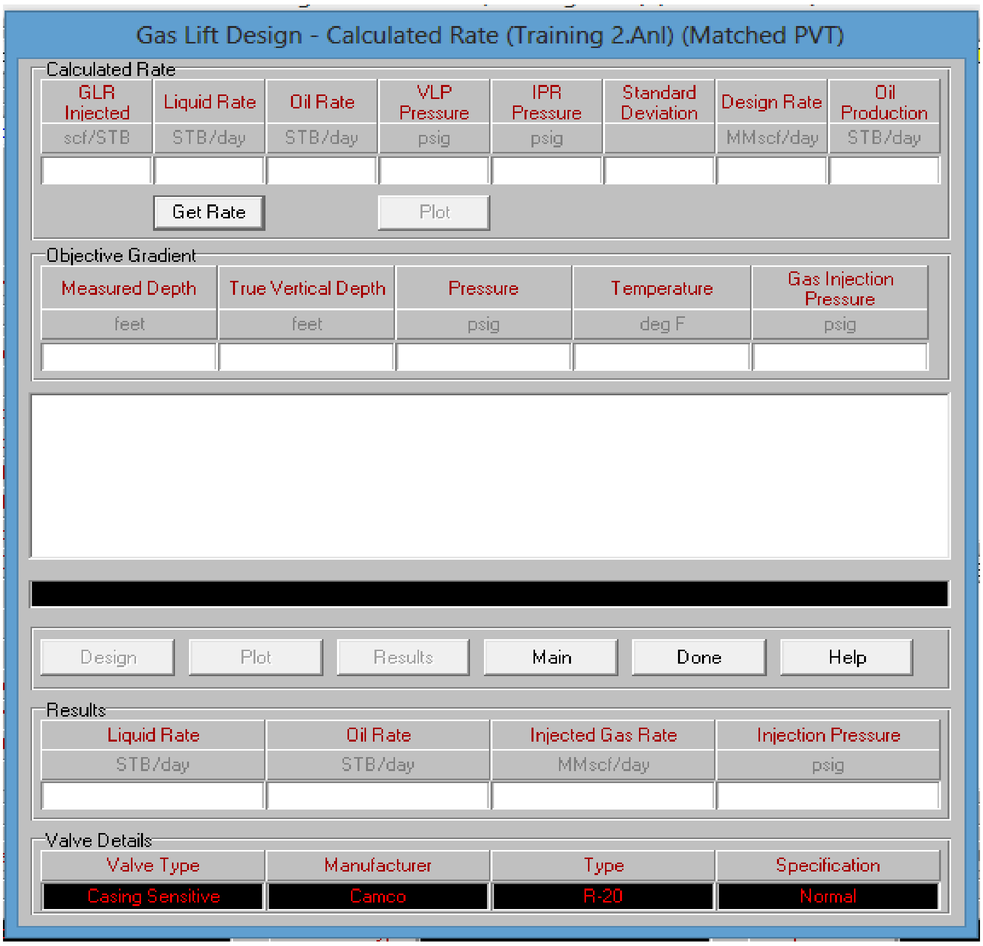


Fig. 2.3 PROSPER Interface for Gas Lift Design – Calculated Rate (Source: Petroleum Experts Limited)

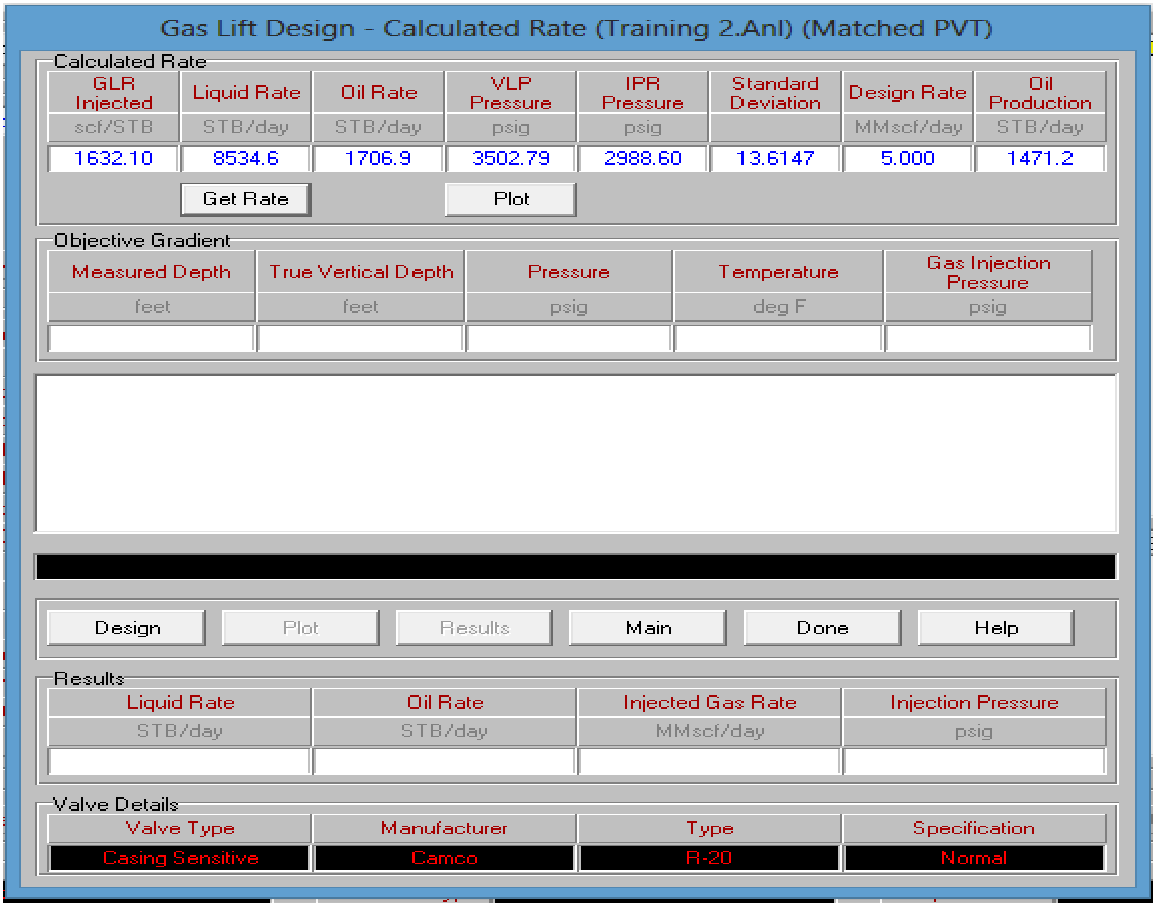


Fig. 2.4 PROSPER Interface for Gas Lift Design – Calculated Rate, with the Calculated Values (Source: Petroleum Experts Limited

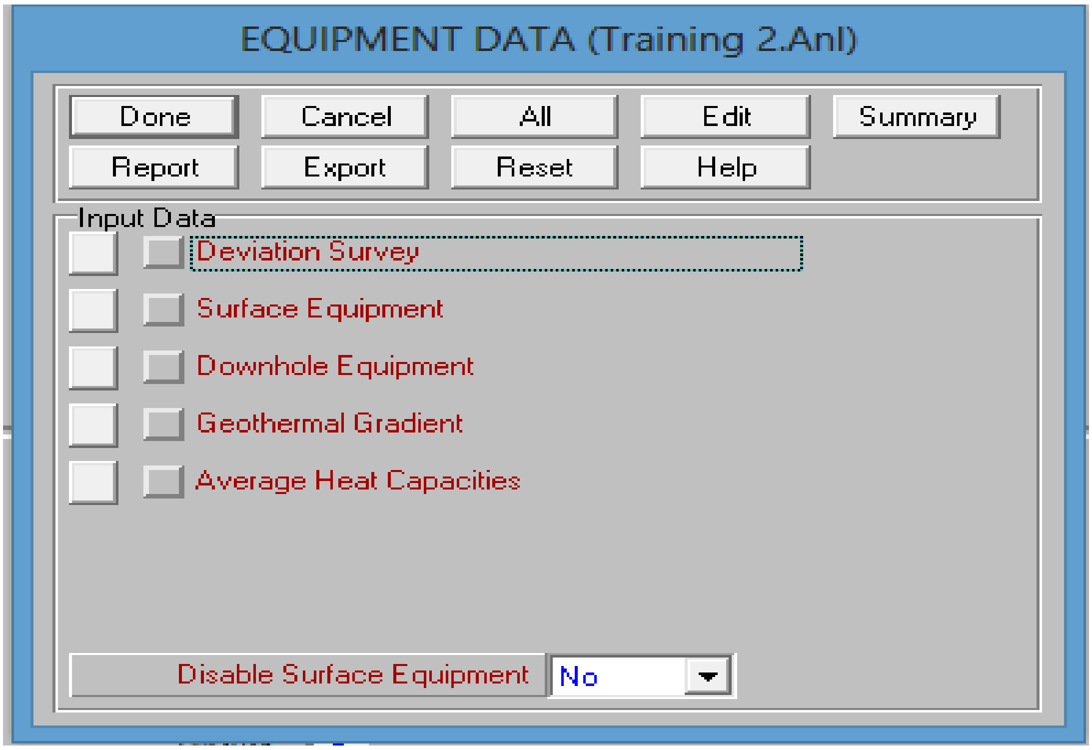
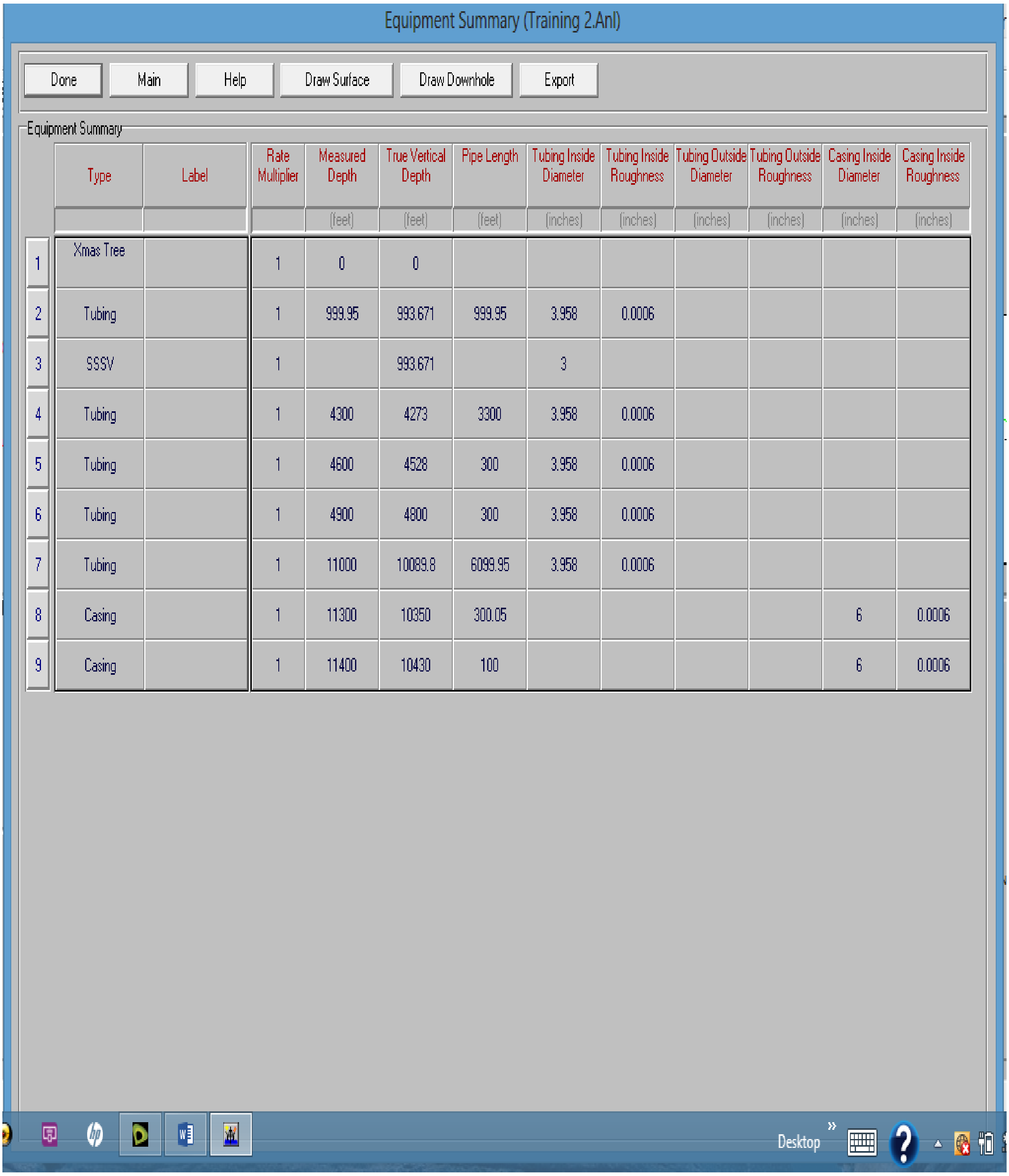


Fig. 2.5 PROSPER Interface – Equipment Data (Source: Petroleum Experts Limited)



	Type	Label	Rate Multiplier	Measured Depth (feet)	True Vertical Depth (feet)	Pipe Length (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)
1	Xmas Tree		1	0	0							
2	Tubing		1	999.95	993.671	999.95	3.958	0.0006				
3	SSSV		1		993.671		3					
4	Tubing		1	4300	4273	3300	3.958	0.0006				
5	Tubing		1	4600	4528	300	3.958	0.0006				
6	Tubing		1	4900	4800	300	3.958	0.0006				
7	Tubing		1	11000	10089.8	6099.95	3.958	0.0006				
8	Casing		1	11300	10350	300.05					6	0.0006
9	Casing		1	11400	10430	100					6	0.0006

Fig. 2.6 PROSPER Interface – Equipment Summary (Source: Petroleum Experts Limited)

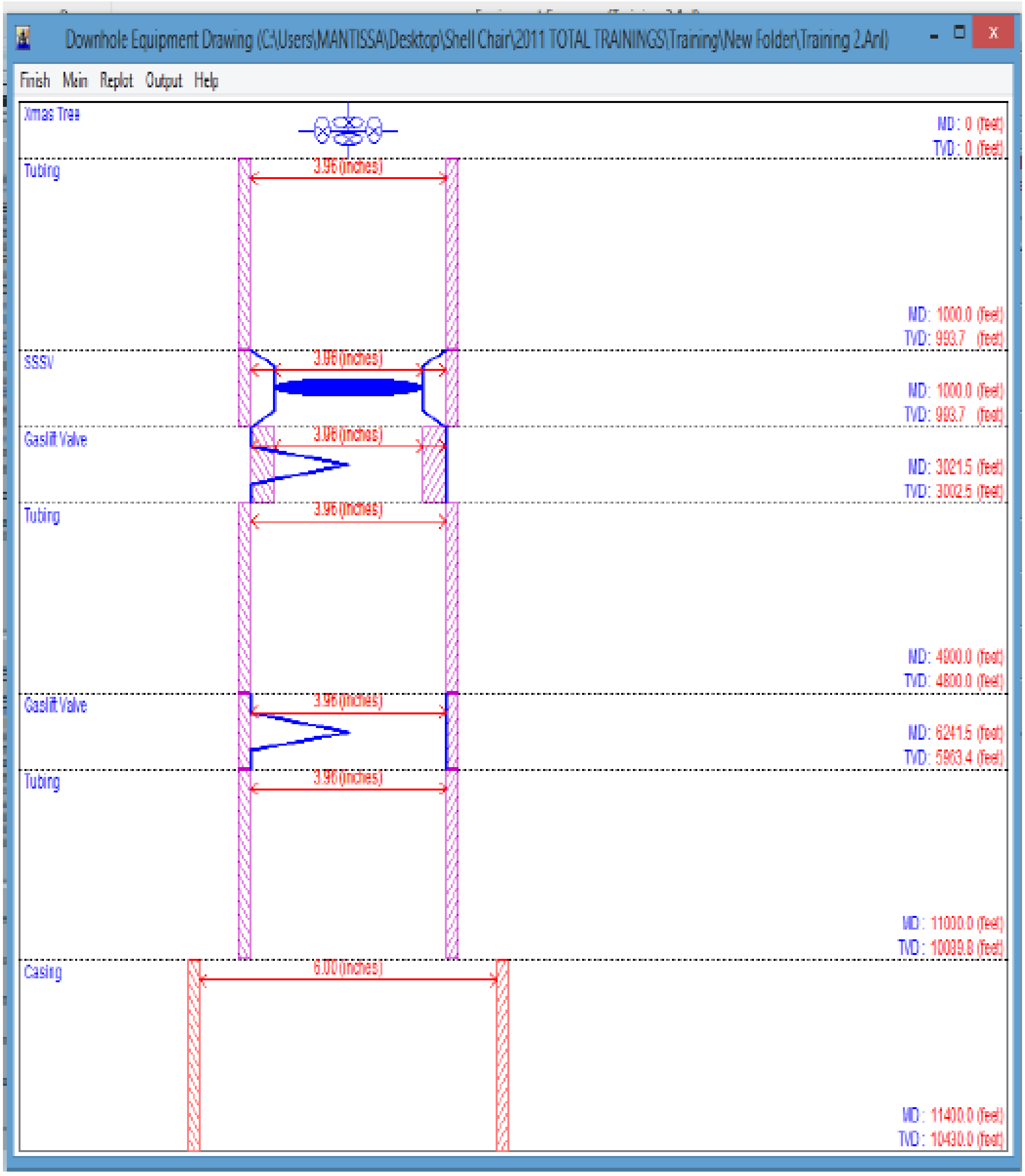


Fig. 2.7 PROSPER Interface – Equipment Design, (Source: Petroleum Experts Limited)

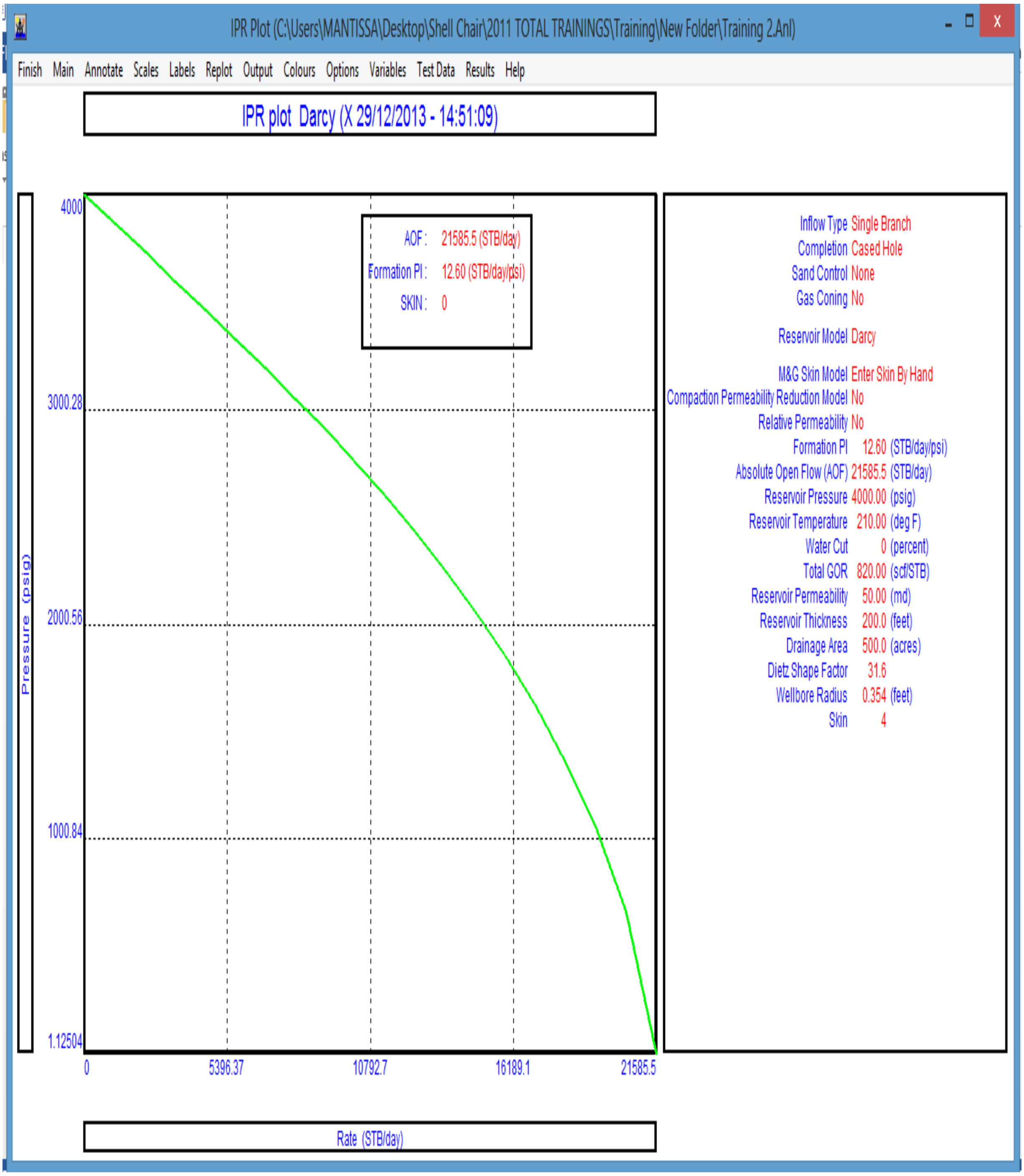


Fig. 2.8 PROSPER Interface – IPR Curve (Source: Petroleum Experts Limited)