Analytical Study of Oil Recovery on Gas Lift and ESP Methods

by

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(13500)

Dissertation submitted in partial fulfillment of

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CERTIFICATION OF APPROVAL

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Approved by,

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Mr. M Aslam Md Yusof

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

July 2013

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgement, and that the original work contained herein have not been undertaken or done by unspecified sources or person.

YUDI SETIAWAN

ABSTRACT

Hydrocarbons usually flow from the wellbore to the surface immediately with the help of natural drive mechanism. But, when the pressure from natural reservoir drive falls to the point in which the well cannot produce on its own, a various types of oil recovery methods are taken into action. Artificial lift is one of the most widely used in oil recovery methods. However, artificial lift is very wide and varied. Furthermore, selection of this artificial lift method will maximize the potential oil recovery from developing oil field. Gas lift and ESP (Electrical Submersible Pump) are widely used in the oil and gas operation. As a result, a thorough evaluation of this artificial lift method is very crucial for long term profitability in a long run. Thus, this study aims an in-depth analysis of the behavior of oil well which requires gas lift and ESP to deliver an optimized oil production. This will be based on steady state simulation of oil producing well in Sarawak field, courtesy of PETRONAS Carigali Sdn. Bhd by using PROSPER software. Along with the simulation results, a comparison between gas lift and ESP will be identified and analyzed. This will result to a generic selection strategy of gas lift and ESP methods optimization.

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LIST OF ABBREVIATIONS

ESP	: Electrical Submersible Pump
IPR	: Inflow Performance Relationship
VLP	: Vertical Lift Performance
WHP	: Wellhead Pressure
FBHP	: Bottomhole Flowing Pressure

CHAPTER 1

INTRODUCTION

1.1 Background of Study

In exploration and production, it is not an overstatement to produce every single molecule of hydrocarbons as much as possible. The faster the hydrocarbon is delivered to the market, the quicker the owner will realize the monetary rewards. The ability of a well to produce and deliver to production target is governed by the well and the reservoir characteristics. When the reservoir pressure is high, usually at the early stage of the production, the oil can flow naturally from the wellbore to the production system without any artificial support. However, when the pressure from natural reservoir drive falls to the point in which the well cannot produce on its own, various types of oil recovery methods are considered to extract or recover the oil from the reservoir. This includes into three distinct phases which are primary, secondary and tertiary recoveries. Today, as indicated by Hazen (1990), less than 20% of the oil reserves in a typical subsurface reservoir are flowing naturally. The rest of the oil production is assisted by artificial lift mechanism or other types of oil recovery mechanism. [1]

In simple words, according to Oil and Gas Journal, the recovery mechanism can be summarized in the following figure:

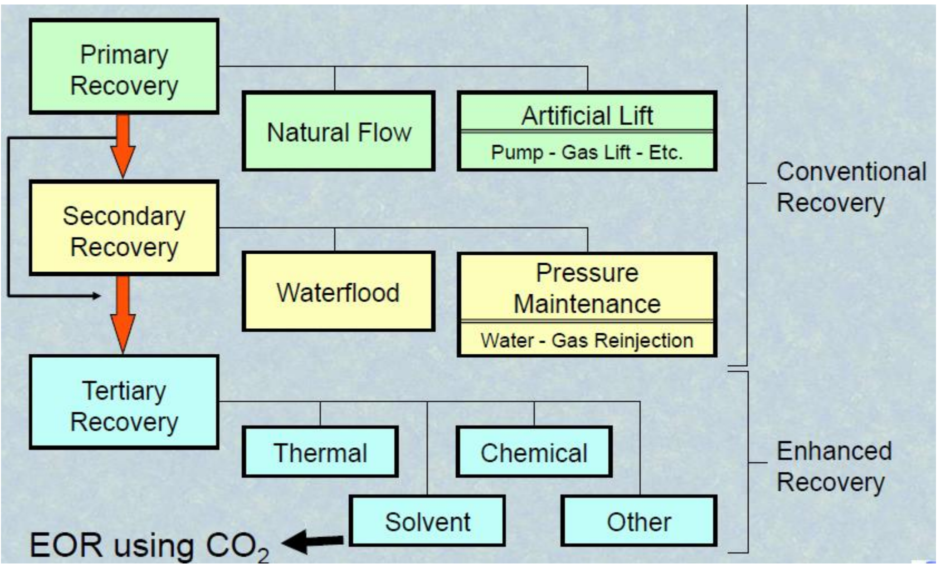


Figure 1: Drive Recovery Mechanism [2]

Artificial lift plays a fundamental role in primary recovery when the well does not have sufficient reservoir pressure to push the oil to the surface. And the artificial lift is then required to supplement the natural reservoir drive in boosting fluids out of the wellbore. However artificial lift systems are wide and varied, and yet the key success is not to choose the easiest or cheapest method but to select the most appropriate and most reliable method.

This paper will focus on an analytical and comparative study of oil recovery for selected oil wells (based on real producing well data) using gas lift and ESP (Electrical Submersible Pump) methods. As part of the study, an in-depth analysis of the behavior of oil well which requires gas lift and ESP will be developed based on steady state simulation of the well using PROSPER software to deliver an optimized oil production. Along with the simulation results, a comparison between gas lift and ESP will be identified and analyzed. This will result to a generic selection strategy of gas lift and ESP methods optimization.

1.2 Problem Statement

Gas Lift and ESP method are the two most common artificial lift methods which are widely used and selected for primary enhance oil recovery.

Selecting the most applicable artificial lift method plays a very crucial role for long term profitability of most producing oil wells. A poor choice may result in loss of production, rising safety concerns and increasing the operating cost of the well. This may also shorten the life of the producing well in a long run. Moreover, upon installation of a wrongly chosen artificial lift method, any means to rectify the issue will be very costly and involve high production downtime.

Other than that, a comparative study between gas lift and ESP has not been done before. And therefore, a strategy to optimize gas lift and ESP needs to be investigated further on this study by using steady state simulation software like PROSPER.

1.3 Objective and Scope of Study

1.3.1 Objective

Considering a real producing oil well which requires artificial lift- ESP or gas lift to boost production, the objectives of this project are:

1. To study and analyze the behavior of oil wells to improve ultimate oil recovery.
2. To develop a comparative study between gas lift and ESP for oil well production optimization.
3. To apply PROSPER in application for gas lift and ESP.

1.3.2 Scope of Study

The scope of the study for this project includes:

a. Gas lift and ESP application as an artificial lift methods
b. Simulation study of gas lift and ESP using PROSPER
c. Key performance indicator (KPI) for gas lift and ESP

1.4 The Relevancy of the Project

Selection of artificial lift plays a crucial role to deliver an optimized oil well production and also to production economics. Artificial lift as in primary recovery is the most chosen and preferred method among other drive recovery method. This is because most of the oil and gas industry’s main goal is to produce maximum profit with the lowest cost as minimum as possible, and when comes to that matter, artificial lift is one of the best solution to optimize the oil production with minimum cost. However, there are various types of artificial lift methods that need to be taken into account and consideration. And this artificial lift is not just accelerating production but is vital to the economic success of the overall development. Hence, this study will help to focus on selection of artificial lift, particularly on gas lift and ESP which are most widely used in the oil and gas industry operations. The main highlight in this study is the determination of the oil rates produces by each of the method.

This comparative study of gas lift and ESP requires reliable result of pressure or flow rate diagrams combining well inflow performance relationship with vertical lift performance curves. As a result, it must achieve the objective in which to maximize oil production at lowest production cost. Thus, the relevancy of this study is very relevant and should benefit both the company and public. Apart from that, the knowledge provided will help to understand the society, particularly fresh graduate petroleum engineers on selection of artificial lift method like gas lift and ESP on realizing the maximum potential from developing oil well at the selected artificial lift method.

1.5 Feasibility of the Project within the Scope and Time Frame

This project is feasible within the time frame provided and the main result is mainly obtained through simulation. In addition, this study is conducted into 2 stages; the first stage involves on the primary research on gas lift and ESP method in maximizing its ultimate potential for production and profitability. And the secondary stage focuses on well simulation that is being done in the computer laboratory using PROSPER software. The analysis is further conducted based on a real data field obtained in the oil and gas industry. And consequently, a comparison between gas lift and ESP is then developed to deliver an optimized oil well production.

CHAPTER 2

LITERATURE REVIEW

2.1 Artificial Lift

The hydrocarbons usually flow naturally after the tubing has been run in, the packer set and the well perforated. However, after a period of time when the pressure from natural reservoir drive mechanism is not enough to push the oil to the production, a various option of enhance oil recovery are then required to continue oil production for optimization.

The options available to optimum oil recovery are [3]:

- Artificial Lift methods,
- Secondary and tertiary oil recovery (water flooding, thermal flooding etc.),
- Pressure maintenance project (gas injection),
- Abandon the well

Artificial lift is the method used in oil well production to supplement the reservoir energy when the natural drive mechanism is no longer able to sustain the production of crude oil from reservoir to the surface. [4]

2.1.1 Artificial Lift Feasibility

Selecting the artificial lift is very crucial for the operator to understand the maximum potential obtained from developing the oil well and also for long term profitability. Therefore, it is very important to select the method of lift thoroughly. The methods that usually applied to select the most applicable artificial lift method are varied over range of operation across in the industry which includes [5]:

- Determining the most appropriate method judging from desired rates and from the required depths.
- Identify the advantages and disadvantages.
- Evaluation of costs involved from economical point of view, such as initial cost, operating costs, production capabilities, etc.

Every single artificial lift method has different key parameters that need to be evaluated for the installation over the full life cycle. But, most importantly is that the ability of the artificial lift method to produce the well at the desired rate over the required time. [6]

2.1.2 Types of Artificial Lift

Artificial lift can be categorized into two types which are using gas system and pumps system. [7]

a. Pump system
   - Electric submersible pump (ESP)
   - Beam pumping / sucker rod pump (rod lift)
   - Progressive cavity pump
   - Subsurface Hydraulics pump

b. Gas system
   - Gas lift

Each of these methods has different key attributes and parameters in contribution to increase the flow of liquid to the surface of a production well. And therefore, a thorough consideration plays a very important role because once a decision has been made for installation; any means to rectify the wrong installation issue will be very costly and involve high production downtime. [8]

In the oil and gas industry, gas lift and ESP are the most widely used in artificial lift methods. Gas lift and ESP have overcome such production engineering challenges in the Stag oil field. Stag oil field, Western Australia is one of the most challenging field environments whereby it has high gas fraction, continuous slugs with a short frequency, large volumes of sand, rapid onset of water production and rapid reservoir pressure depletion. [9]

2.2 Gas Lift

Gas lift is an artificial method that is used to lift the oil from the well to the surface whereby high-pressure gas is injected into a point down-hole in order to heighten fluid (hydrostatic) column and reduce back-pressure on the formation. [10]

2.2.1 Gas Lift System

Meanwhile, the additional work required is performed at the surface by a gas compressor. This is to increase the production rate of the well which can be illustrated in the following figure:

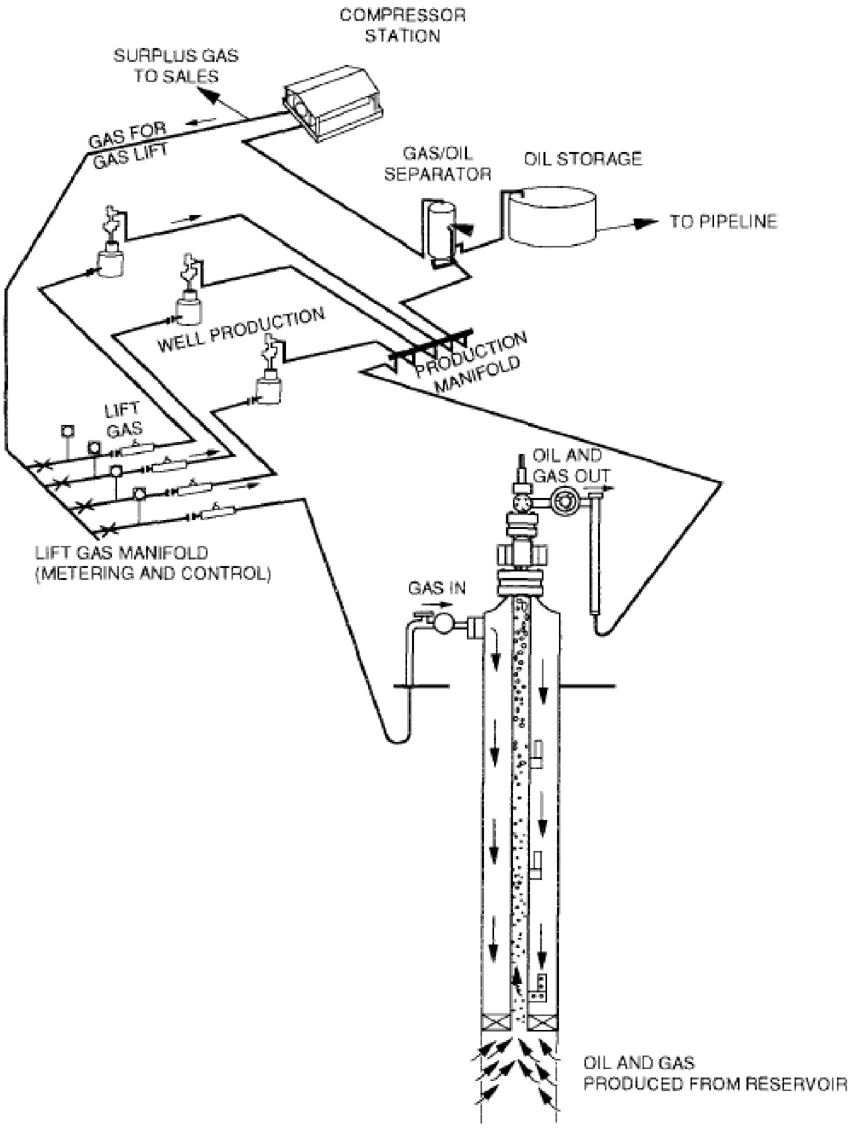


Figure 2: A typical continuous gas lift system [11]

2.2.2 Golden Rules of Gas Lift

There are several golden rules of gas lift that must be fully noted by Production Technologist, Process Engineer and Production Operation Engineer in investigating the feasibility of the project using gas lift or reviewing the performance. Those are: [12]

1. Adequate and reliable source.
2. The gas injection should be as close as possible to the top of the completion interval
3. Stable.

4. Operate with minimum back pressure at the wellhead.
5. Completion should be designed for single point lift.
6. Lift gas availability should be optimized, such as minimize compressor downtime.
7. All gas lift system designs should address future.
8. Overly conservative design assumptions should be avoided.

2.2.3 Limitations of Gas Lift

Gas lift is widely used in the artificial lift methods for its applicability and versatility and therefore it is widely used and known as the most flexible artificial lift method. However, it does not necessarily mean that gas lift has no limitation in its installation compared to other forms of artificial lift methods. These are the limitations of gas lift: [13]

- Source of gas must be adequate and reliable throughout the development life.
- Continuous gas lift is not able to decrease intake pressures to “pump off” and this will result in increasing depth and declining reservoir pressure.

2.2.4 Gas Lift Strength

Apart from its limitation, gas lift has some strength as per following: [14]

1. The best artificial lift method for handling sand or solid materials.
2. Deviated holes can be gas lifted with only minor problems.
3. The normal design leaves the tubing full opening.
4. High formations GOR are helpful rather than being a hindrance.
5. It is flexible.
6. It has low profile.

2.2.5 Gas Lift Overview

Throughout the overall review of gas lift, it can be concluded that gas lift deserves a serious consideration in the artificial lift method selection. Gas lift is a flexible system that can be applied in number of situation such as; to artificially lift well that will not flow naturally, to kick of wells and to increase production rates in naturally flowing wells.

2.3 ESP (Electrical Submersible Pump)

Another artificial lift method which plays high contribution in increasing oil production is Electrical Submersible Pump (ESP). ESP is one of the artificial lift methods that is used to lift large volume of fluids by centrifugal pumps system driven by an electric motor. It basically incorporates the electric motor and centrifugal pump unit run on a production string and connected back to the surface control mechanism and transformer via an electric power cable. [15]

2.3.1 ESP System

The ESP system can be illustrated in the following figure:

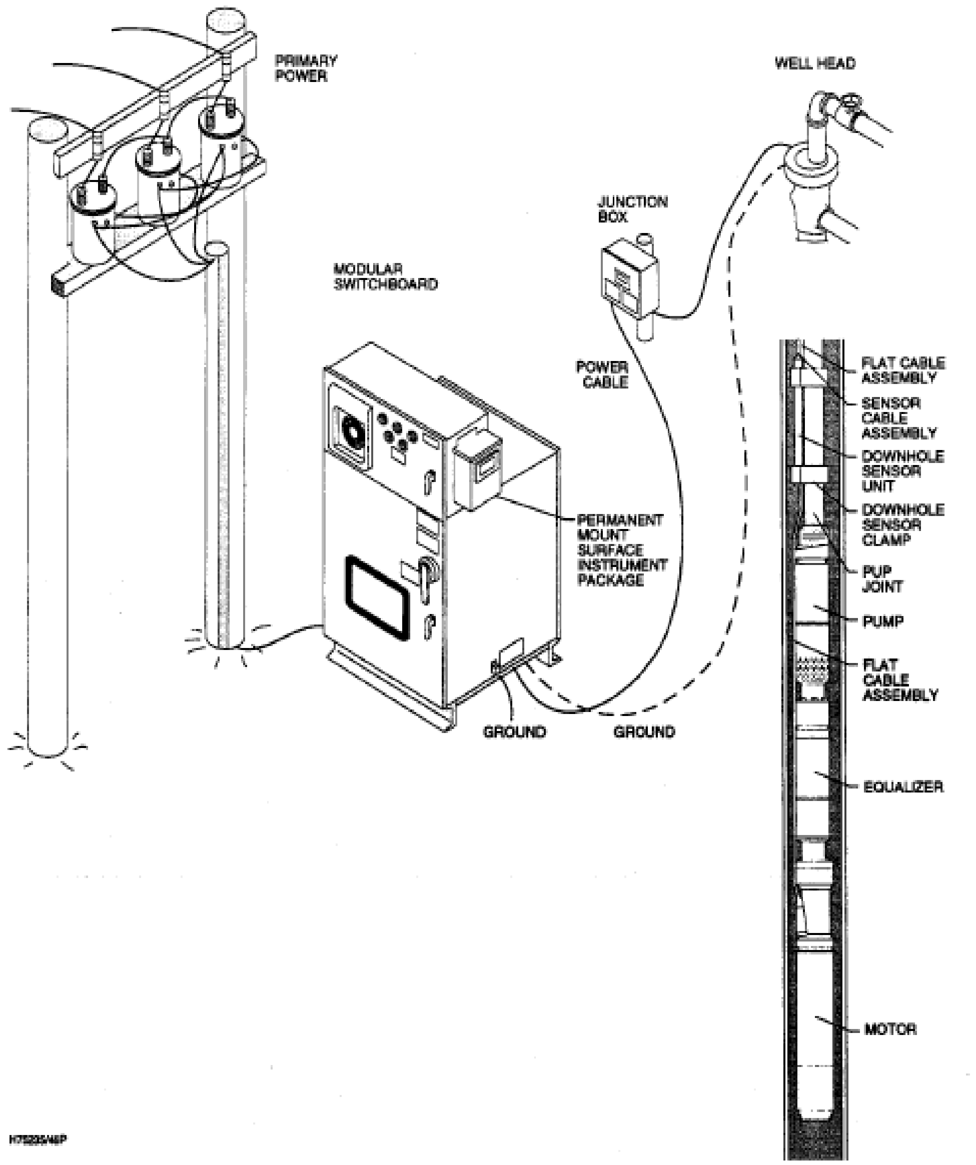


Figure 3: ESP System[16]

Electrical Submersible Pumps (ESPs) were selected as the most economic artificial lift method to lift heavy oil in offshore environment. This is based upon its reliability, flexibility and robustness to produce significantly large fluid of oil rates. In its operation, the following are the main components ESP that plays high contribution towards its performance such as; downhole electric motors, seal assembly (equalizer), pumps, accessories, cables and surface equipment. [17]

Apart from that, there are several factors affecting ESP towards its performance which includes handling and installation procedures and environmental factors such as temperature, presence of H_2S, CO2, solids, free gas, power quality, and startup/shutdown and operating procedures. [18]

2.3.2 Advantages and Disadvantages of ESP

ESP is able to pump at higher flow rate and with greater drawdown than most other type of artificial lift method. However, ESP has some advantages and disadvantages as per following: [19]

a. Advantages of ESPs:
   - Adaptable to highly deviated wells - up to 80°.
   - Adaptable to required subsurface wellheads 6' apart.
   - Permit use of minimum space for subsurface controls and associated production facilities.
   - Quiet, safe and sanitary for acceptable operations.
   - Generally considered a high volume pump.
   - Permits placing well production even while drilling and working over wells in immediate vicinity.

b. Disadvantages of ESPs:
   - Will tolerate minimal percents of sands production.
   - Costly pulling operations to correct downhole failures (DHF’s).
   - Loss of production while on a DHF
   - Not adaptable to low volumes - less than 150 B/D gross.

2.3.3 ESP Overview

Looking at the overall review of ESP, it can be concluded that ESP is considered as an effective and economical artificial lift method in the enhance oil recovery. In such a way that ESP can lift large volumes of fluid from great depth under a variety of well conditions.

2.4 PROSPER Software

PROSPER is a well performance, design and optimization program that is designed to build a reliable and consistent well models along with the ability to address wellbore modeling visualization, PVT, VLP correlation and IPR. [20]

2.4.1 PROSPER Application

PROSPER can be used to predict pressures for various flow rates with the temperature profile along the flow path. [21]

2.4.1.1 Gas Lift

- Casing, tubing or proportional valves
- Automatic valve spacing
- Calculation of valve test rack setting pressure
- Flexible design option
- Real valve response modeling

2.4.1.2 ESP

- ESP design and diagnosis
- Design select pumps, motor and cable from database
- Viscosity effect and temperature fluid rise
- Down hole gas separation
- PVT emulsion viscosity correction option

Some of its applications used in the industry are: [22]

- Design and optimize well completions including multi lateral, multilayer, and horizontal wells
- Design and optimize tubing and pipeline sizes
- Allocate production between wells
- Monitor well performance rapidly
- Predict flowing temperatures in wells and pipelines

2.5 Production Optimization

When the life of the well recovery is no longer satisfied, production optimization is further carried out and performed. The objective of this production optimization is to enhance reservoir inflow performance or to reduce outflow performance. [23]

The understanding of reservoir inflow performance, vertical lift performance and surface facilities pressure is very important to optimize the field production performance. [24]

Production optimization refers to measuring, analysis, modeling, prioritizing and implementing actions to enhance field production such as: [25]

- Well profile management (coning, fingering and well conformance management)
- Wellbore damage removal (acidizing, fracturing)
- Well integrity (casing and cement failure prevention and remediation)
- Artificial lift optimization
- Surface facility design

Some of challenges in well production optimization in that are faced when achieving the objectives are: [26]

- Software are not integrated in the system in the expected way
- The data is either low in quality or quantity
- High cost of the project
- Lack of formal education or knowledge in petroleum production optimization engineering
- Lack of resources either time or financial

2.5.1 Production Optimization by Artificial Lift

Artificial lift systems objective is to reduce bottom hole flowing pressure and increase flow rates. As in gas lift, the main objective is to reduce net hydrostatic gradient by injecting gas lift to the downhole produced fluid. Meanwhile, in ESP system, the main objective is to boost downhole pressure by pump-assisted lift.[27]

Some of factors that affect the selection of artificial lift optimization are: [28]

- Well and reservoir characteristics (production casing size, production tubing size, annular and tubing safety system, formation depth and deviation, nature of the produce fluids, well inflow characteristics)
- Field location
- Operational problems (sand control, formation damage, bottomhole temperature, corrosion and erosion)
- Economics

Apart from that, in the implementation of artificial lift method such as gas lift and ESP, there are certain environmental and geographical considerations that may be overriding. For instance, gas represents a significant problem for ESP, while in gas lift it utilizes the enrgy contained in the produced gas and supplements this with injected gas as a source of energy. [29]

2.6 Summary

After all, in comparison between gas lift and ESP, both have their own strengths and weaknesses. Briefly speaking, gas lift can handle gas and solids better than ESP. However, its big disadvantage is inability to achieve low operating bottom-hole pressure. Meanwhile, ESP provides higher production rates, lower operating bottom-hole and high efficient, but poor at handling sand problem.

Apart from that, with the help of PROSPER's sensitivity calculation features, it enables the existing well designs to be optimized also the effects of future changes in system parameters to be assessed.

CHAPTER 3

METHODOLOGY

3.1 Project Activities

The methodology that is being used to evaluate and accomplish the project is explained in the following:

3.1.1 Data Gathering and Analysis

1. Obtain all the data required, consisted of oil well producing data from Sarawak field, courtesy of PETRONAS Carigali Sdn. Bhd. Five of oil wells will be carried out for further investigation to fit this study.
2. Ensure the availability tools and equipment, consisted of PROSPER software which is accessible in block 15.
3. Understand the system analyzing in PROSPER. This will be further useful to understand well performance by using PROSPER software and set up PROSPER model for oil well in such procedure; input the PVT values, draw the phase diagram, draw the down hole, construct the IPR, matching the model to a well test and performing the calculation of well performance, gradient transverse and vertical lift performance curves.

3.1.2 Case Study of Optimization of an Oil Well using PROSPER

Review the base case reservoir model. This reflected the water cut increase and decline of reservoir pressure will have significant impact on oil production. In this case study, the minimum of oil recovery is set to be not less than 1500 stb/day. It means that any well that producing oil rate below than 1500 stb/day will not be considered as an economic oil well producer.

In addition, there are 5 wells that are being investigated for this case study and each of them has different sets of reservoir and well characteristics as per following:

a. Well A: high reservoir pressure (4520 psia), high GOR (924.6 scf/stb) and no water cut (0%),
b. Well B: moderate reservoir pressure (3015 psia), low GOR (400 scf/stb) and high water cut (80%)
c. Well C: moderate reservoir pressure (3275 psia), moderate GOR (704.6 scf/stb) and moderate water cut (25%)
d. Well D: high reservoir pressure (4000 psia), high GOR (820 scf/stb) and high water cut (80%)
e. Well E: low reservoir pressure (2600 psia), low GOR (500 scf/stb) and low water cut (5%)

3.1.3 Well Modeling

1. Developing a well performance model using PROSPER
   The following procedure is used to develop oil well model using PROSPER:
   a. Input technical data
      The technical data that are required are PVT lab data, well test data, VLP data and IPR data.
   b. Generate the IPR curve
      This IPR curve plays an important role to understand the relation between the flowing bottomhole pressure and oil production rate.

    c. Perform PVT matching

       In PROSPER, it is significant and required to match the PVT, VLP and IPR measured data with the theory or correlation data upon its system analysis performance. This is to provide that the data is correct and consistent.

2. Simulate Base Case Forecast under Various Operating Conditions:
    a. Reservoir pressure
    b. Water cut
3. Evaluate Various Development Options to Optimize Oil Production

    Evaluate results from the sensitivity parameters to determine the best compromise choice of variables on which to build a base case oil well optimization:

    a. Changing wellhead pressure
    b. Changing tubing diameter size
    c. Changing artificial lift method parameter

3.1.4 Discussion

Design the comparison between gas lift and ESP method. The comparison should identify both the optimum and maximum production rates achieved from each of the artificial lift method, and also the key performance indicator (KPI) that influences the final selection of gas lift and ESP.

3.2 Important Dates

FYP 1:

No.	PROJECT ACTIVITIES	WEEK													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Topic Selection & Preliminary Research														
2	Topic Selected and Prepare Preliminary Report														
3	Prepare Oral Defense Presentation														
4	Literature review studies														
5	Procurement of software														
6	Plant data acquisition														
7	Draft Interim Report preparation														
8	Final Interim Report preparation														
9	Laboratory Activities 1 (during sem break): Gas Lift	DURING SEMESTER BREAK													
10	Laboratory Activities 2 (during sem break): ESP	DURING SEMESTER BREAK													

= Preliminary Report Submission = Project Defense Presentation

= Draft Interim Report Submission = Final Interim Report Submission

Table 1: Key Milestone for FYP 1

FYP 2:

No.	ACTIVITY (Tasks To Do)	WEEK													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Project Work Continues														
2	Submission of Progress Report														
3	Project Work Continues														
4	Pre-SEDEX														
5	Submission of Draft Report														
6	Submission of Dissertation (Soft Bound)														
7	Submission of Technical Paper														
8	Oral Presentation														
9	Submission of Project Dissertation (Hard Bound)														

Table 2: Key Milestone for FYP 2

3.3 Key Milestone and Gantt-Chart

The project Gantt-Chart can be found in Appendix A.

3.4 Tools Required

Software	Description	
PROSPER	PROSPER is a well performance, design and optimization	

Table 3: Software Used

3.5 Data Required

The data required is obtained from oil producing well in Sarawak field, courtesy of PETRONAS Carigali Sdn. Bhd.

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Data Gathering and Analysis

PROSPER is an advanced Production and system Performance analysis which is used to assist production or reservoir engineering to predict tubing and pipeline hydraulics and temperature with accuracy and speed. With the help of PROSPER powerful sensitivity calculation feature, the oil well model can be optimized. And this will fit the objective of this project in which to study and analyze the behavior of oil wells to improve ultimate oil recovery as well as to develop a comparative study between gas lift and ESP for oil well production optimization

Apart from that, the aim of this project is to apply and set up PROSPER model for oil well with the following procedure:

1. Input the PVT values,
2. Draw the phase diagram,
3. Draw the down hole,
4. Construct the IPR,
5. Matching the model to a well test, and
6. Performing the calculation of well performance, gradient transverse and vertical lift performance curves.

In PROSPER; the system analysis can be illustrated as the following figure:

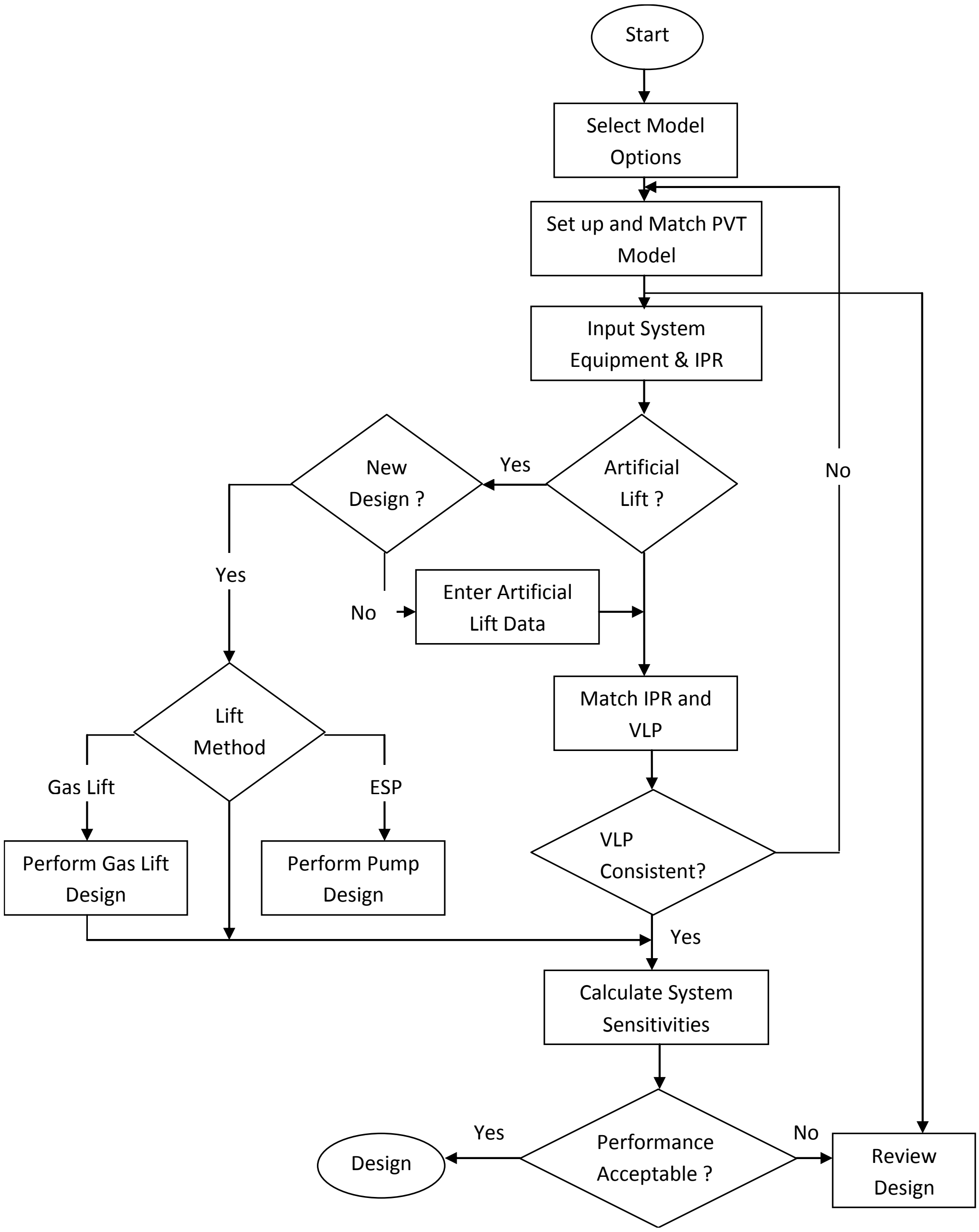


Figure 4: System Analysis Using Prosper

4.2 Case Study of Optimization of an Oil Well Using PROSPER

The well used in this case study is a producing oil well in Sarawak field, courtesy of PETRONAS Carigali Sdn Bhd. Three of oil wells will be carried out for further investigation to fit this study for oil well optimization. The well will be designated as Well A, Well B and Well C. This oil well reached its peak production in 1994 and since then the oil production is decreasing due to an increase of water cut as well as a decrease in reservoir pressure. The economic limit of this well is 1500 stb oil/d. It means that any oil well producing at rates lower than that will not be considered as it is beyond of economical point of view.

4.3 Well Modeling

4.3.1 Developing a Well Performance Model Using PROSPER

The PROSPER main screen is divided into 6 sections:

1. Options Summary
2. PVT Data
3. IPR Data
4. Equipment Data
5. Analysis Summary
6. PROSPER Version

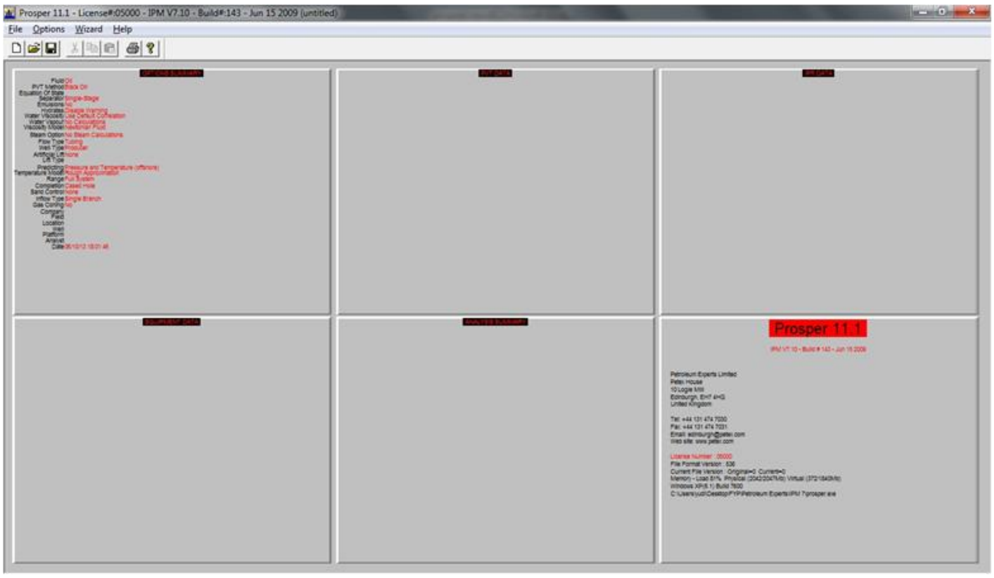


Figure 5: PROSPER Main Screen

The calculation of well production rates by the simultaneous solution of the well inflow (IPR) and outflow (VLP) relations is represented by PROSPER analysis.

4.3.2 Well A

Well A was completed in 1989 as an oil producer. POSPER software is used to predict the well performance. Fluid data (PVT), reservoir data (IPR) and down hole equipment description (VLP) are provided.

The following is the system summary for oil well A:

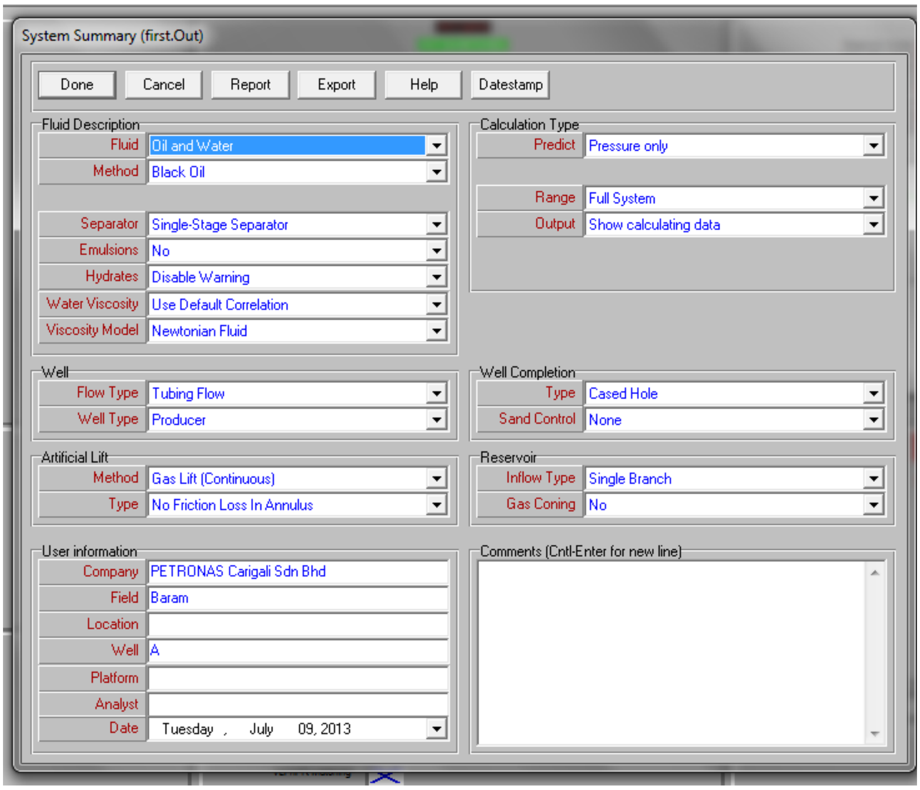


Figure 6: System Summary

4.3.2.1 Input Technical Data

The following technical data are required in order to develop a well model in PROSPER:

1. PVT Lab Data and Well Test Data

Parameter	Value
Solution GOR	924.6 scf/stb
Oil Gravity	32 API
Gas Gravity	0.7

Water Salinity	20000 ppm
Impurities (CO2, N2, H2S)	(0, 1.2, 0.11)
Bubble Point Pressure	5017.7 psia
Temperature	220 deg F

Table 4: PVT Input Data

Pressure (psia)	Gas Oil Ratio (scf/stb)	Oil FVF (rb/stb)	Oil viscosity (centipoises)
14.73	0	1.0437	2.557
264.73	38.7	1.0668	1.3614
814.73	125.2	1.1099	1.2108
1414.73	217.3	1.1529	1.0573
2014.73	313.4	1.1963	0.9183
2614.73	415.7	1.2414	0.7962
3214.73	525.9	1.2891	0.6905
3814.73	646	1.3402	0.5994
4414.73	777.9	1.3958	0.5207
4887.12	892	1.4435	0.4662
4914.73	899	1.4464	0.4632
4963.73	911.4	1.4515	0.4579
5014.73	924.6	1.457	0.4525
5114.73	924.6	1.4548	0.4583
5214.73	924.6	1.4527	0.4641

Table 5: PVT Lab Data

Parameter	Value
Tubing Head Pressure	1000 psia
Tubing Head Temperature	90 deg F
Water Cut	0 %
Liquid Rate	2000 stb/d
Gauge Depth Measured	11916 feet
Gauge Pressure	3200 psia
Reservoir Pressure	5000 psia
GOR	1350 scf/stb

Table 6: Well Test Data

2. VLP Input Data

Measured Depth (ft)	True Vertical Depth (ft)
0	0
6959.97	6575.95
7058.4	6664.49
7294.69	6881.33
7672.76	7239.79
9911.16	9332.69
10102.9	9505.34
10294.6	9668.63
10486.4	9820.85
10678.1	9960.44
10869.8	10085.9
11061.6	10196
11253.3	10289.6
11445	10365.6
11636.8	10423.3
11828.5	10462.2
12020.2	10481.7
14354.6	10491.3
14382.6	10492.4

Table 7: Deviation Survey

Equipment Type	True Vertical Depth (feet)	Temperature (deg F)
Manifold (Wellhead)	0	60

Table 8: Surface Equipment

Equipment Type	Measured Depth (ft)	Internal Diameter (in)	Roughness (in)	Rate Multiplier
Xmas Tree (Well	0	N/A	N/A	N/A

Head)				
Tubing	14382	4.32	0.03	1

Table 9: Downhole Equipment

Measured Depth (ft)	Static Temperature (deg F)
0	60
14382	220

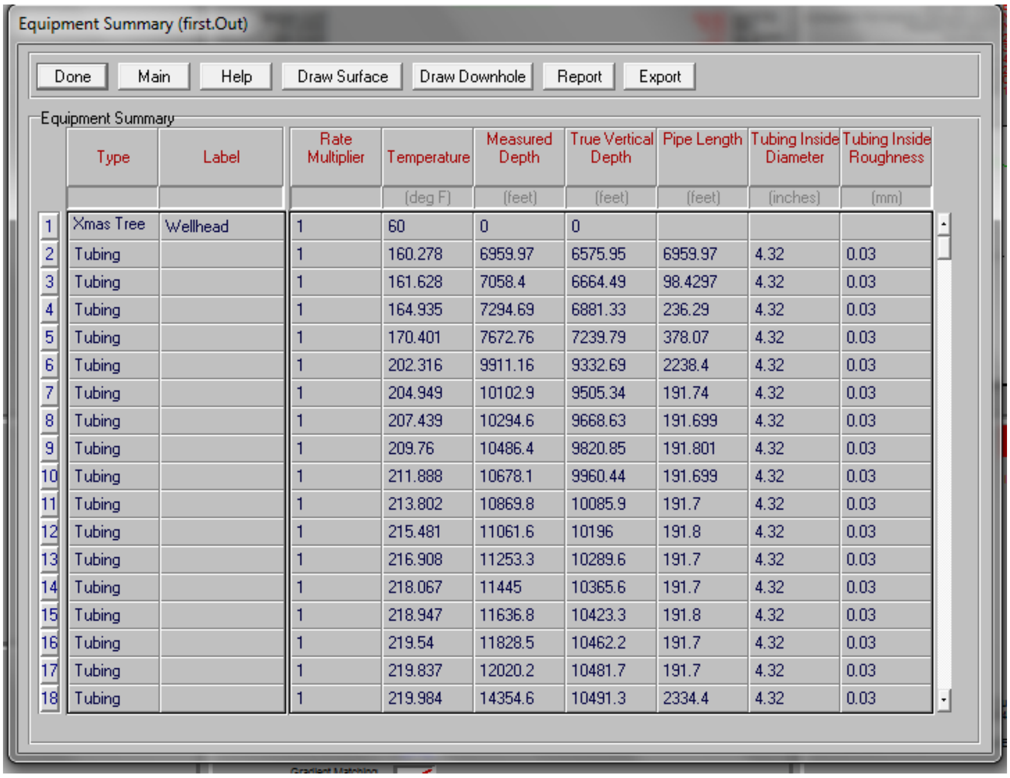
Table 10: Temperature Survey

3. IPR Input Data

IPR Model	Darcy
Reservoir Pressure	4520 psia
Reservoir Temperature	220 deg F
Water Cut	0%
Total GOR	1350 scf/stb
Compaction Permeability Reduction Model	No
Relative Permeability	No
Reservoir Permeability	40 md
Reservoir Thickness	42feet
Drainage Area	150 acres
Dietz shape factor	31.6
Wellbore radius	3.5 inches
Mechanical Skin	6

Table 11: IPR Input Data

To summarize, the following figure are the system summary of the input data for well A:



	Type	Label	Rate Multiplier	Temperature (deg F)	Measured Depth (feet)	True Vertical Depth (feet)	Pipe Length (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (mm)
1	Xmas Tree	Wellhead	1	60	0	0			
2	Tubing		1	160.278	6959.97	6575.95	6959.97	4.32	0.03
3	Tubing		1	161.628	7058.4	6664.49	98.4297	4.32	0.03
4	Tubing		1	164.935	7294.69	6881.33	236.29	4.32	0.03
5	Tubing		1	170.401	7672.76	7239.79	378.07	4.32	0.03
6	Tubing		1	202.316	9911.16	9332.69	2238.4	4.32	0.03
7	Tubing		1	204.949	10102.9	9505.34	191.74	4.32	0.03
8	Tubing		1	207.439	10294.6	9668.63	191.699	4.32	0.03
9	Tubing		1	209.76	10486.4	9820.85	191.801	4.32	0.03
10	Tubing		1	211.888	10678.1	9960.44	191.699	4.32	0.03
11	Tubing		1	213.802	10869.8	10085.9	191.7	4.32	0.03
12	Tubing		1	215.481	11061.6	10196	191.8	4.32	0.03
13	Tubing		1	216.908	11253.3	10289.6	191.7	4.32	0.03
14	Tubing		1	218.067	11445	10365.6	191.7	4.32	0.03
15	Tubing		1	218.947	11636.8	10423.3	191.8	4.32	0.03
16	Tubing		1	219.54	11828.5	10462.2	191.7	4.32	0.03
17	Tubing		1	219.837	12020.2	10481.7	191.7	4.32	0.03
18	Tubing		1	219.984	14354.6	10491.3	2334.4	4.32	0.03

Figure 7: Equipment Summary

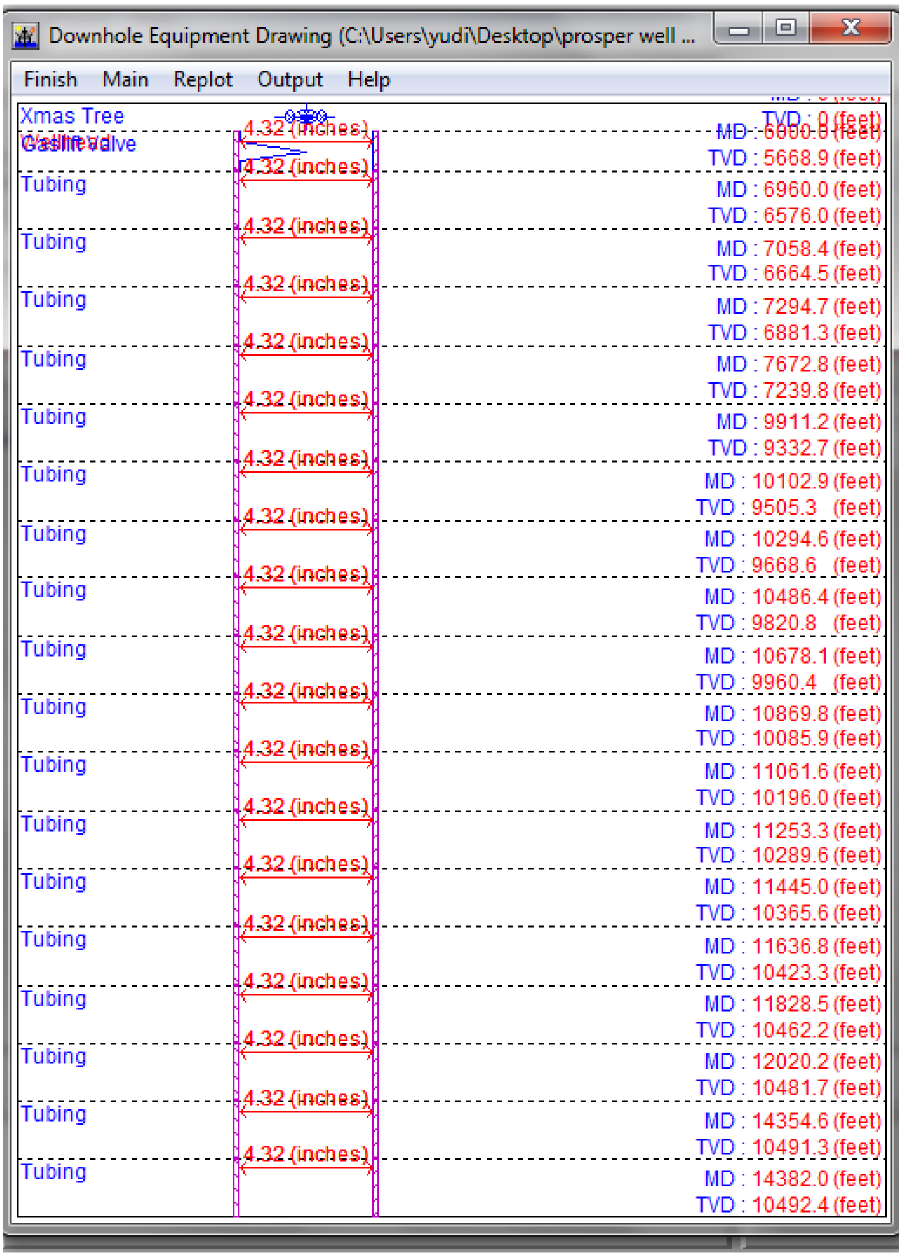


Figure 8: Downhole Equipment

Figure 9: IPR Summary

4.3.2.2 Generate the IPR Curve

In the IPR section, the formation inflow performance may be expressed as the graphical representation of the relation between the flowing bottomhole pressure and oil production rate. This can be illustrated in the following figure:

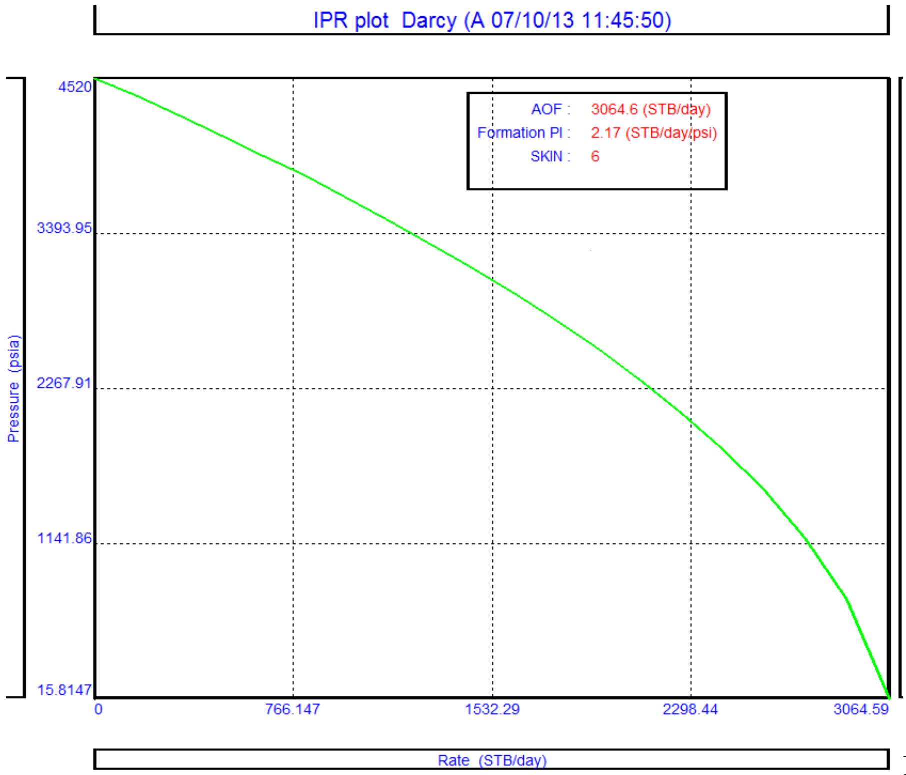


Figure 10: IPR Plot

In this example of well A, it can be observed that the Absolute Open Flow potential (AOF) is around 3064.6 stb/day. This AOF indicates that the maximum production rate is achieved when the bottomhole pressure approaches zero.

In addition, the productivity index in this well A is computed as 2.17 stb/day/psi. This production index indicates the ratio of production rate in well A to its drawdown pressure.

Apart from that, it is observed that the mechanical skin is shown as 6. This positive skin denotes as any phenomenon that causes a distortion of the flow lines from the perfectly normal to the flow direction or a restriction to flow. The causes of positive skin is normally mechanical causes (partial completion, inadequate number of perforations), phase changes (reduction of relative permeability of the desired fluid), turbulence and damage to the natural reservoir permeability

4.3.2.3 Perform PVT Matching

In PROSPER, it is important to check if the PVT data is matched or not. The purpose of this PVT matching is to compare the values predicted by the correlation (theory) with the measured lab data, therefore the adjustment factors for the correlation can be found. This matching process will highlight inconsistencies in input data to minimize the overall difference. And if the percentage differences obtained are found to be large, it means that some of the input data like PVT, IPR and VLP data are incorrect.

In this example of well in well A, the PVT matching can be summarized as figures below:

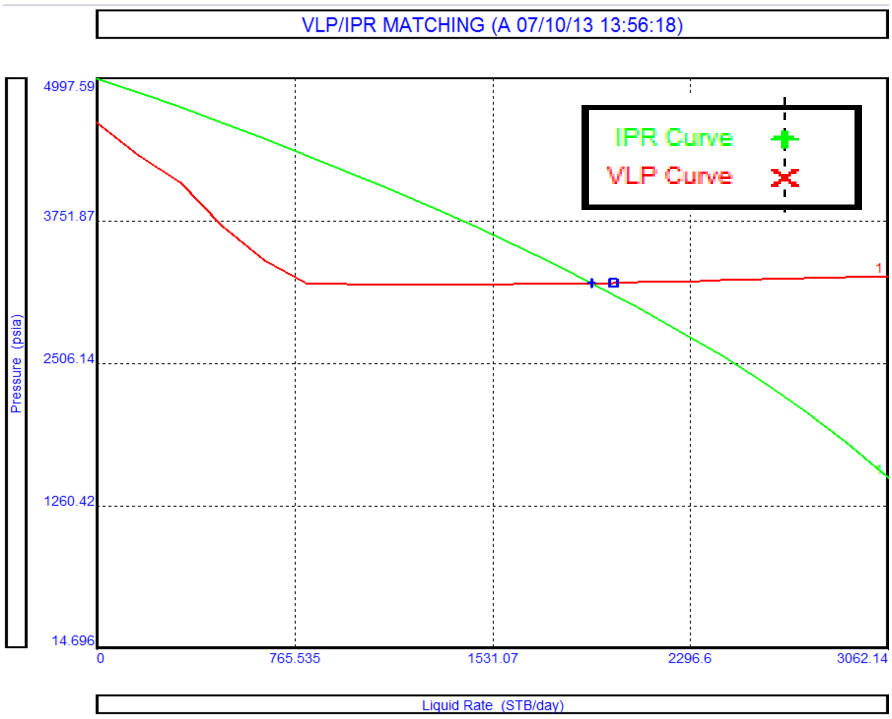


Figure 11: VLP/PVT Matching

	LIQUID RATE (STB/day)			BOTTOM HOLE PRESSURE (psia)		
	Measured	Calculated	% Difference	Measured	Calculated	% Difference
1	2000.0	1916.6	-4.17	3208.75	3205.36	-0.10618

Figure 12: VLP/PVT Matching Calculation

As per shown in the figure above, there are only -4.17% difference between measured liquid rate and simulated liquid rate whereas for bottom hole pressure, the difference is only -0.10618%. This percentage is less than 1%, thus the percentage difference is considered small and acceptable. Therefore, the well model is validated and eligible for further analysis.

4.3.3 Simulate Base Case Forecast under Various Operating Conditions

The production optimization goal is mainly to increase productivity and improve the overall asset value while satisfying all physical and financial constraint. And in order to deliver well optimization, it is essential to do simulation base case forecasting under various operating condition. In this study, different ranges of reservoir pressures and water cut is set to be base case scenario. This base case operating simulation will fit the objective of this study in which to analyze the behaviour of oil well in order to improve the ultimate oil recovery.

In this example of well A, the maximum economic water cut is set to be maximum to 20% in a range of reservoir pressure between 1000 psia - 4000 psia. In the oil production as the time goes by, the water cut is increasing meanwhile the reservoir pressure is declining. The oil rate targeted is set to be produced at its economic rate (1500 stb/d) and any oil rate below than that will not be further considered or investigated.

To summarize, the following table are the oil rates obtained from this base case analysis:

Parameter	Range
Reservoir Pressure (psia)	1000, 2500, 4000
Water Cut (%)	10, 15, 20

Table 12: Reservoir Pressure and Water Cut Range

4.3.3.1 Well A before Using Gas Lift and ESP

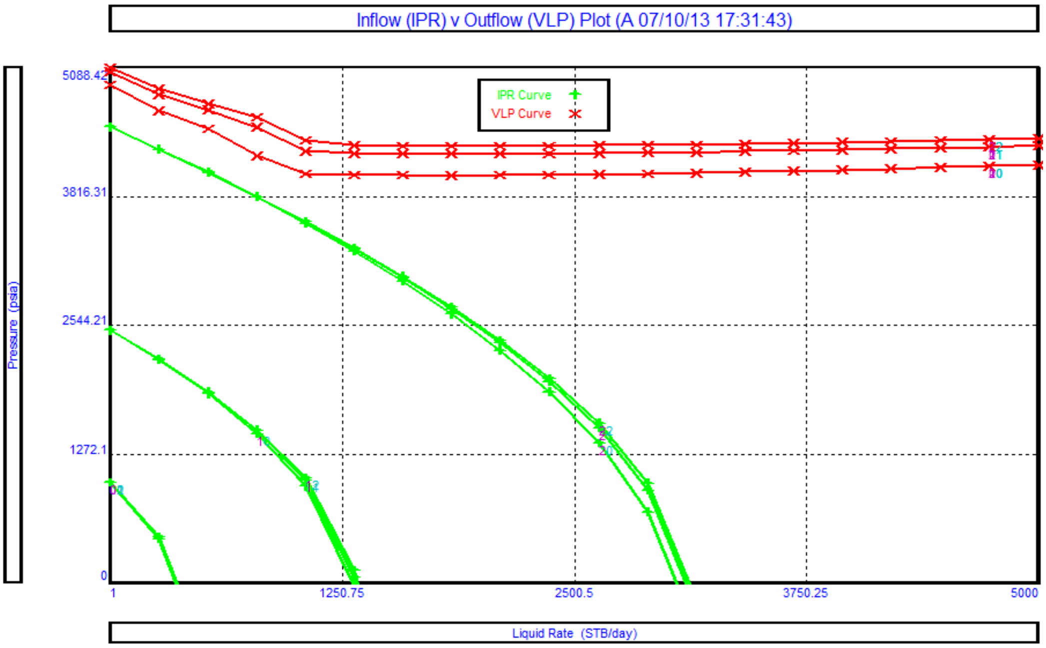


Figure 13: IPR VS VLP before using Gas Lift and ESP

Reservoir Pressure (psia)	**Water Cut (%)**		
	0	15	20
	Oil Rate (stb/d)		
4500	0	0	0
2500	0	0	0
1000	0	0	0

Table 13: Oil Rates Produced before using Gas Lift and ESP

4.3.3.2 Well A after Using Gas Lift

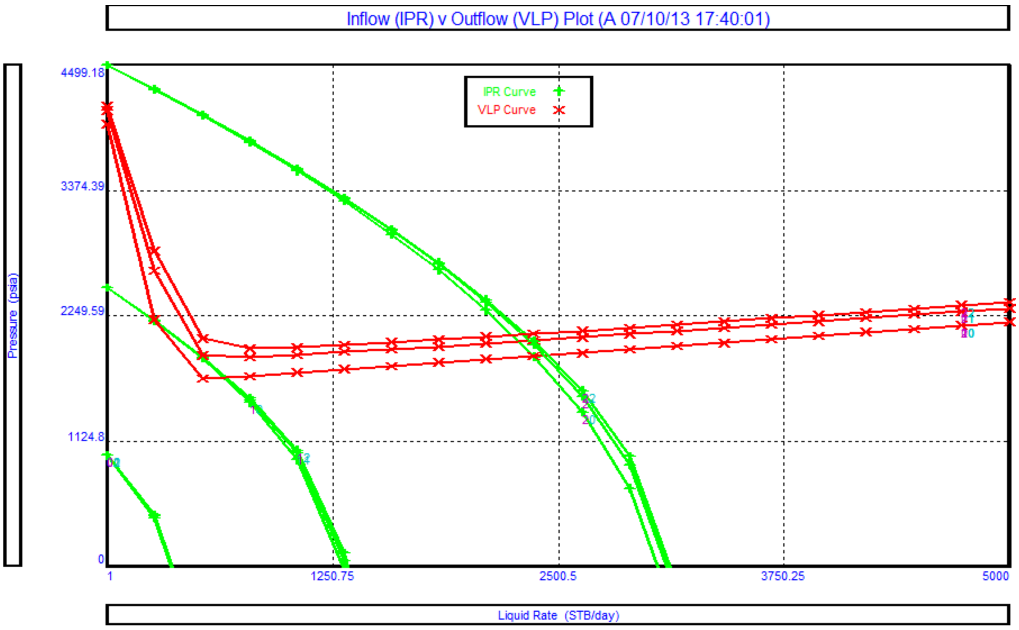


Figure 14: IPR VS VLP after using Gas Lift

Reservoir Pressure (psia)	Water Cut (%)		
	0	15	20
	Oil Rate (stb/d)		
4500	2366.9	1990.5	1859.3
2500	644.7	0	0
1000	0	0	0

Table 14: Oil Rates Produced after using Gas Lift

4.3.3.3 Well A after Using ESP

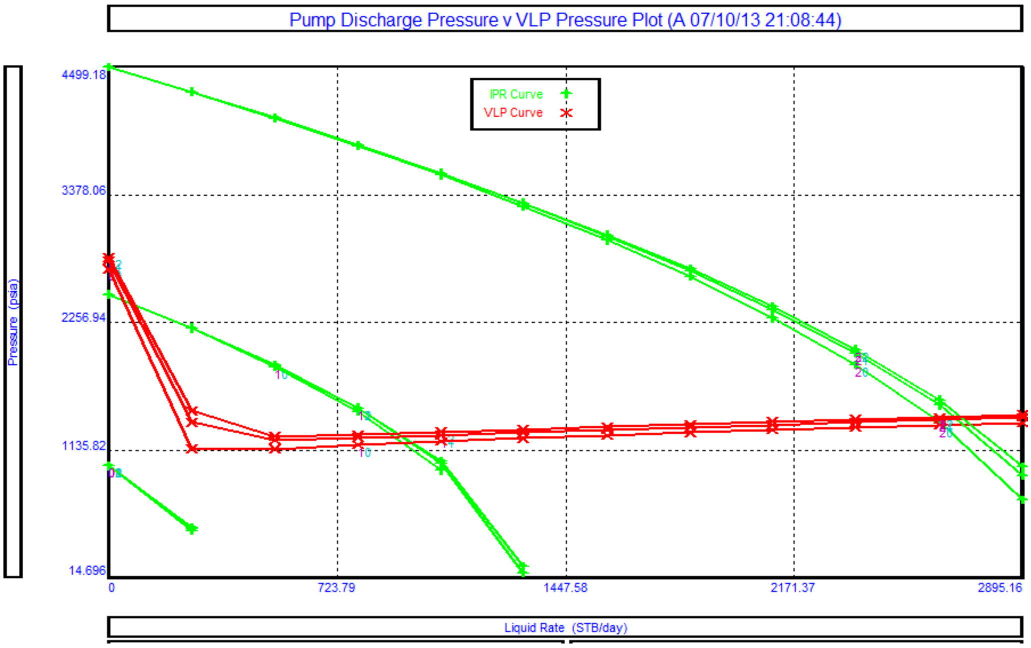


Figure 15: Pump Discharge Pressure VS VLP Pressure Plot

Reservoir Pressure (psia)	**Water Cut (%)**		
	0	15	20
	Oil Rate (stb/d)		
4500	2271.8	1844.6	1704.8
2500	910.5	801.2	757.0
1000	0	0	0

Table 15: Oil Rates Produced after using ESP

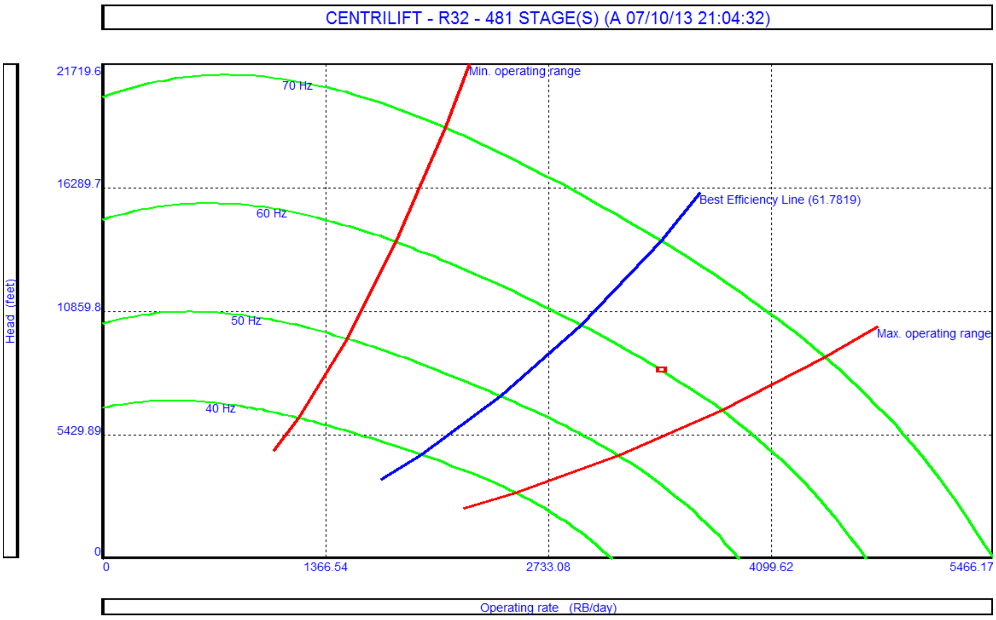


Figure 16: Pump Performance Curve

Pump performance curve describes the relation between flow rate and head for the actual pump. In this well A, the best efficiency line for pump performance curve is calculated as 61.7819.

4.3.3.4 Overview

From all the figures shown above, it is observed that the intersection of inflow and outflow satisfy the condition when oil is produced. The intersection of each intake curve with the IPR plotted above is to show a comparison of flow rates provided or not provided by gas lift and ESP methods.

To summarize, the following table provides detailed information for each base case scenario:

Scenario	Minimum Economic Production Rate Produced	Maximum Economic Production Rate Produced
Without gas lift and ESP	0 (no oil production)	0 (no oil production)
With Gas Lift	644.7 stb/d at 2500 psia with 0 %WC	2366.9 stb/d at 4500 psia with 0 %WC

With ESP	757 stb/d at 2500 psia with 20% WC	2271.8 stb/d at 4500 psia with 0 %WC

Table 16: Economic Base Case Condition

Looking at the overall review of each base case scenario, it can be concluded that gas lift and ESP has its own strength and limitations. For example, in term of giving higher volume of oil production, gas lift is considered as more economical than ESP. However, when comes to condition such higher water cut, ESP is an effective method to lift large volume of oil when gas lift is not capable.

4.3.4 Evaluate Various Development Options to Optimize Oil Production

Production optimization refers to various activities of measuring, analyzing, modeling, prioritizing and implementing actions to enhance productivity of a field. And therefore, a good understanding on well performance is important to optimize the field production performance. Well performance is the relationship between fluid flow rate and pressure drawdown between the wellbore and formation pressure. A well performance analysis is not only useful for identifying specific solution for a given well IPR and tubing performance, but also very useful in an experiment with number of different options in IPR modifications, well design and operational conditions, such as:

1. Wellhead pressure,
2. Tubing diameter
3. Artificial lift parameter

In this study, a further analysis is required to optimize oil production. And this can be done by evaluating various development options as per mentioned previously; changing the value of wellhead pressure (WHP), using different tubing sizes and selection of different artificial lift method. This selection of the most suitable artificial lift method will play a very significant role in this production optimization. Thus, this will fit the objective of this study in which to develop a comparative study between gas lift and ESP for oil well production optimization.

To summarize, the operating rates produced by each analysis are provided in the following table.

Parameter	Range
Wellhead Pressure (psia)	1200, 1300, 1400, 1500
Tubing Diameter (in)	2, 2.7, 3.6, 5
Water Cut (%)	10, 20, 30, 40
Gas Lift gas Injection Rate (MMscf/day)	1, 1.6, 2.3, 3
Pump Operating Frequency (Hertz)	45, 55, 65, 75

Table 17: Range of Parameter Base Scenario

4.3.4.1 Changing Wellhead Pressure (WHP)

4.3.4.1.1 Well A before using Gas Lift and ESP

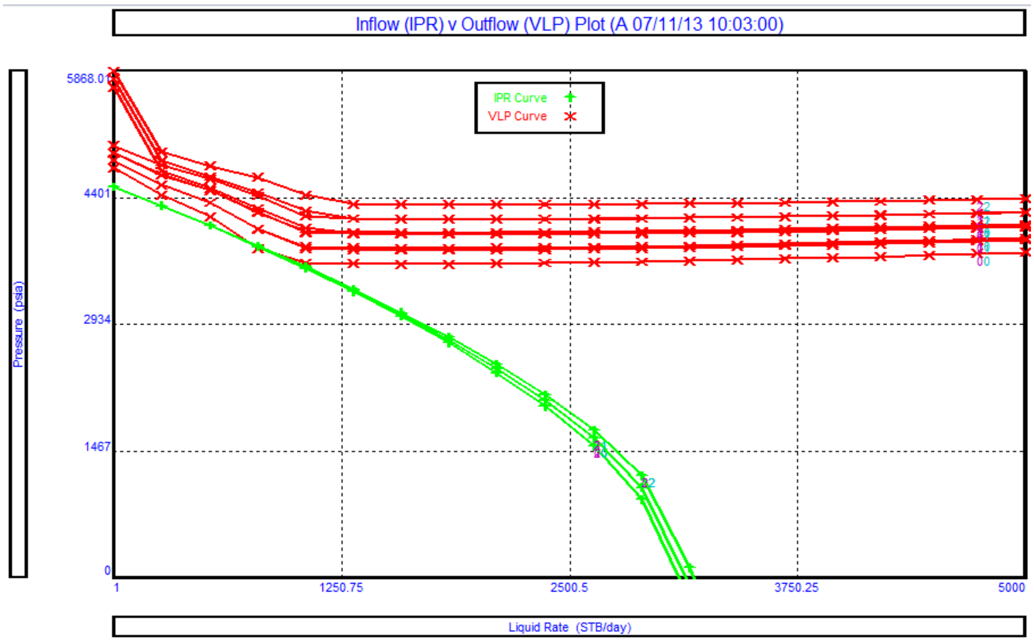


Figure 17: IPR VS VLP for changing WHP before using gas lift and ESP

WHP (psia)	Water Cut (%)			
	10	20	30	40
	Oil Rate (stb/d)			
1500	0	0	0	0
1400	0	0	0	0
1300	0	0	0	0
1200	765.2	0	0	0

Table 18: Oil Rates at different WHP and WC before using Gas lift and ESP

4.3.4.1.2 Well A after using Gas Lift

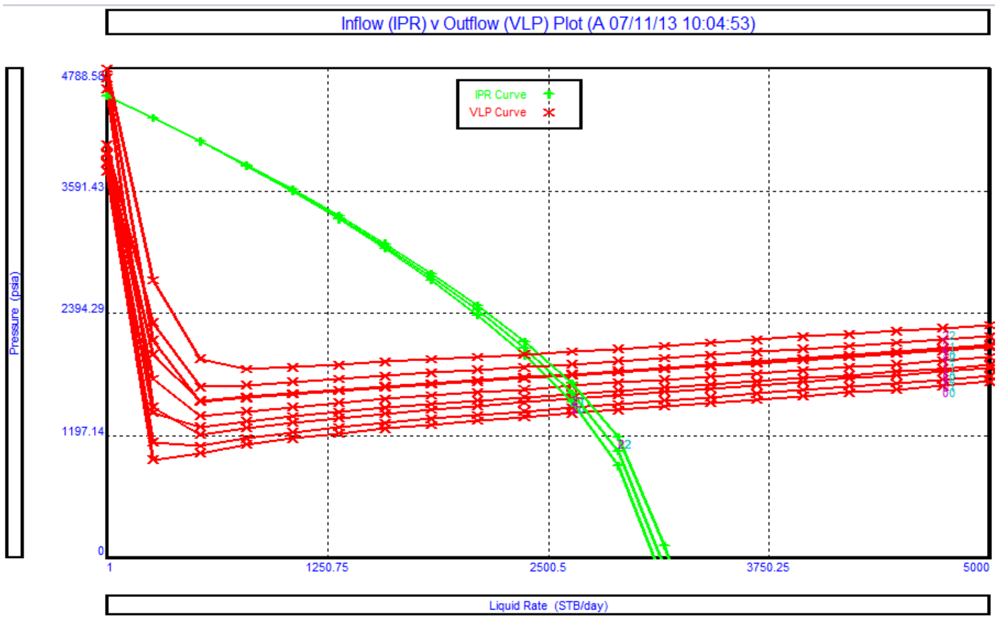


Figure 18: IPR VS VLP for changing WHP after using Gas Lift

WHP (psia)	**Water Cut (%)**			
	10	20	30	40
	Oil Rate (stb/d)			
1500	2136.3	1875.6	1601.7	1315.5
1400	2234.9	1978.9	1711.0	1429.8
1300	2329.5	2075.2	1809.3	1529.1
1200	2408.0	2155.6	1892.3	1617.9

Table 19: Oil Rates at different WHP and WC after using Gas Lift

4.3.4.1.3 Well A after using ESP

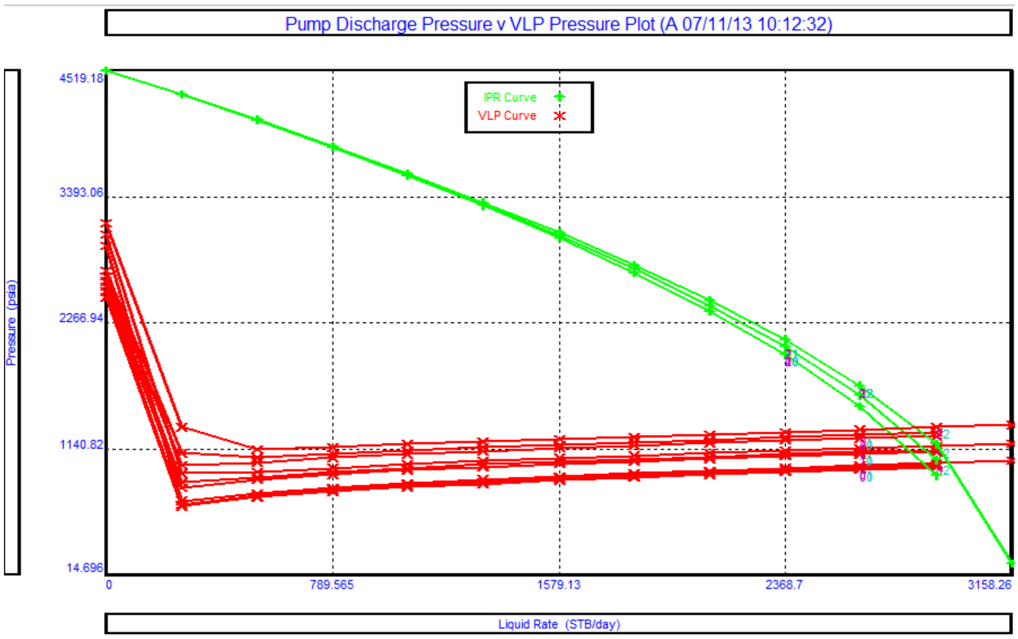


Figure 19: Pump Discharge Pressure VS VLP for Changing WHP after Using ESP

WHP (psia)	**Water Cut (%)**			
	10	20	30	40
	Oil Rate (stb/d)			
1500	2006.5	1723.9	1470.9	1254.9
1400	2161.9	1870.9	1573.7	1284.8
1300	2279.0	2008.2	1703.3	1401.0
1200	2384.6	2124.1	1846.7	1532.4

Table 20: Oil Rates at different WHP and WC after using ESP

4.3.4.1.4 Overview

As per shown in the figures and tables above, it is observed that by changing wellhead pressure from 1,500 to 1,200 psia, the operating rates produced become higher. However, when the water cut is increasing to maximum 40%, the oil rates obtained are decreasing.

4.3.4.2 Changing Tubing Size

4.3.4.2.1 Well A before using Gas Lift and ESP

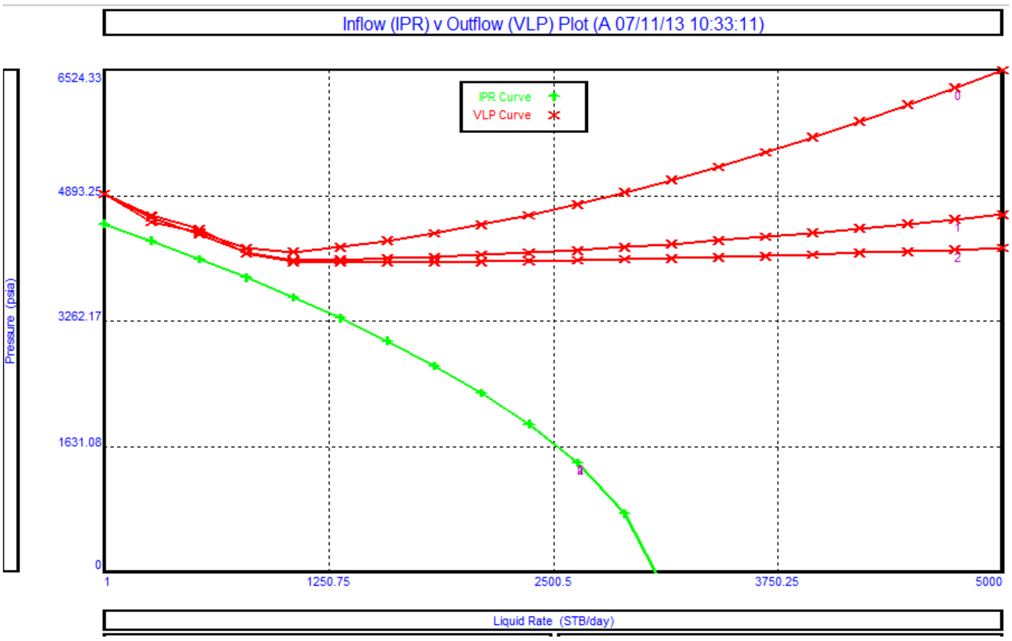


Figure 20: IPR VS VLP for Changing Tubing Size before using Gas Lift and ESP

Tubing Size ID (in)	Oil rate (stb/day)
2	0
2.7	0
3.6	0
5	0

Table 21: Oil rate at various Tubing Internal Diameter Sizes before using Gas Lift and ESP

4.3.4.2.2 Well A after using Gas Lift

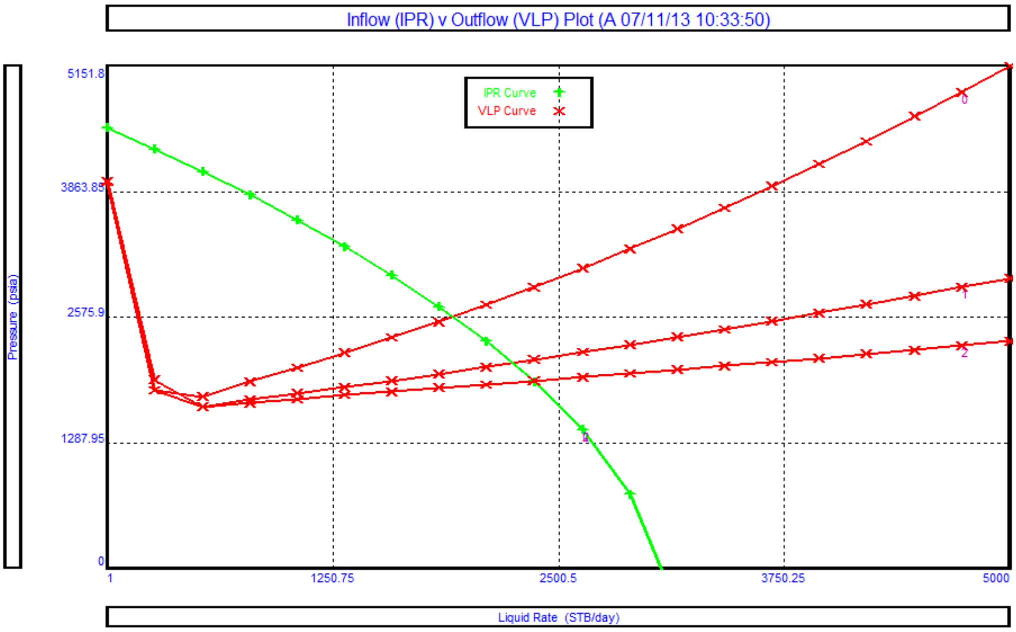


Figure 21: IPR VS VLP for changing Tubing Size after using Gas Lift

Tubing Size ID (in)	Oil rate (stb/day)
2	1917.7
2.7	2318.9
3.6	2365.4
5	2389.4

Table 22: Oil Rate at various Tubing Internal Diameter Size after using Gas Lift

4.3.4.2.3 Well A after Using ESP

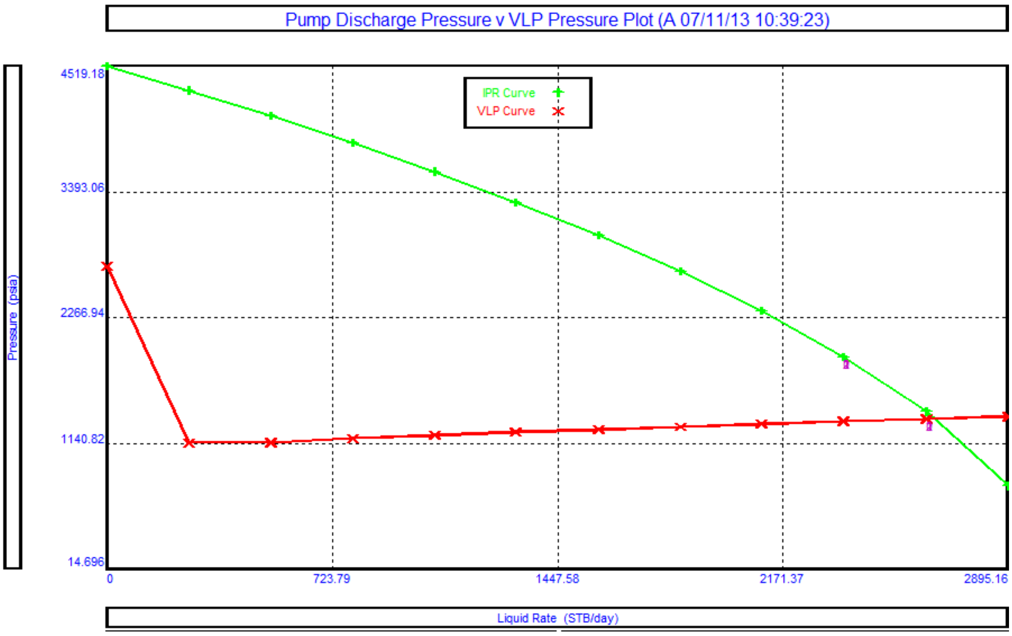


Figure 22: Pump Discharge Pressure/ VLP for changing Tubing Size after using ESP

Tubing Size ID (in)	Oil rate (stb/day)
2	2286.4
2.7	2291.6
3.6	2293.7
5	2294

Table 23: Oil Rate at Various Tubing Internal Diameter Size after using ESP

4.3.4.2.4 Overview

It is observed that by changing various sizes of tubing internal diameter (ID), the oil rates increment obtained are small and not too much significant. Thus, it is not recommended to change the tubing size in this well.

4.3.4.3 *Changing Artificial Lift Method Parameter*

4.3.4.3.1 Changing Gas Injection Rate Gas Lift

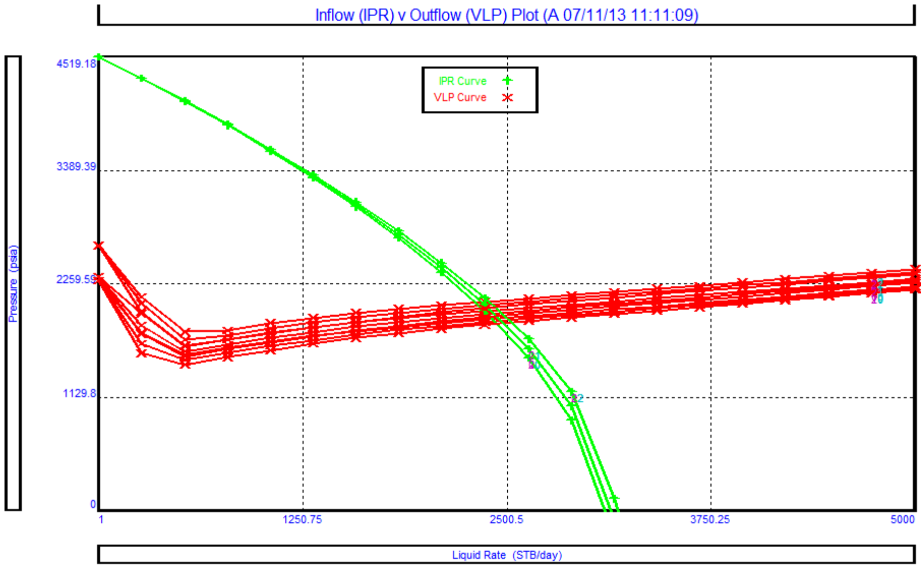


Figure 23: IPR VS VLP for changing Gas Lift Rate

Gas Injection (MMscf/day)	**Water Cut (%)**			
	10	20	30	40
	Oil Rate (stb/d)			
1	2170.8	1925.0	1674.3	1418.7
1.6	2183.4	1938.2	1688.3	1435.2
2.3	2195.3	1950.6	1701.3	1448.1
3	2205.1	1960.8	1711.5	1458.4

Table 24: Oil Rate with various Gas Injection Rates

It is observed that increase in gas injection rate gas lift will result increase in oil rate production.

4.3.4.3.2 Changing Pump Operating Frequency ESP

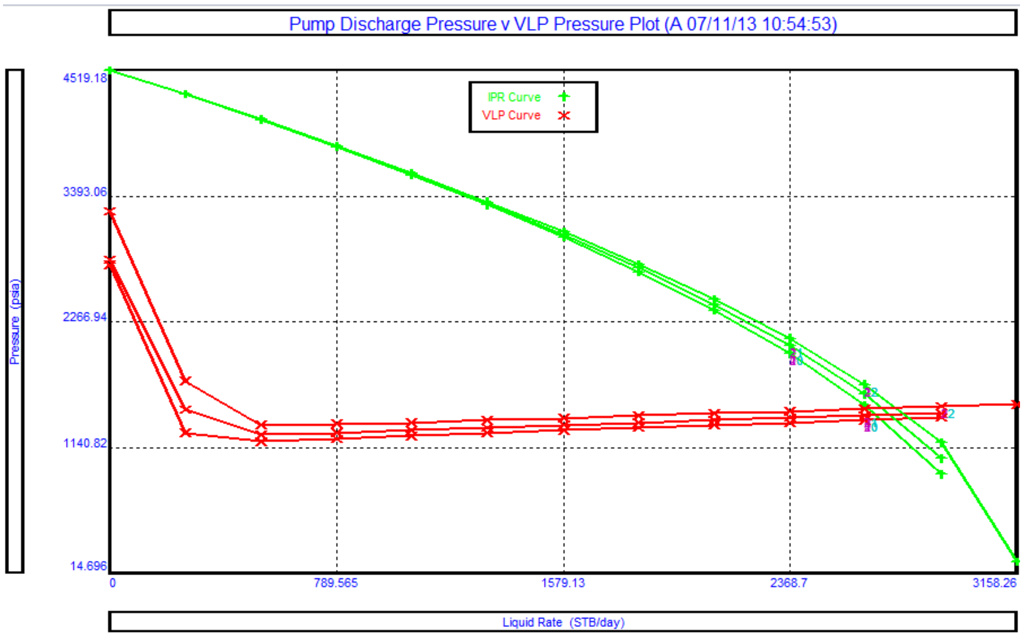


Figure 24: Pump Discharged Pressure/VLP for changing Pump Operating Frequency

Pump Operating Frequency	**Water Cut (%)**			
	10	20	30	40
	Oil Rate (stb/d)			
45	2006.2	1723.6	1443.6	1161.8
55	2006.4	1723.8	1467.9	1250.5
65	2006.7	1724.0	1471.9	1398.5
75	2123.5	1885.1	1646.7	1554.1

Table 25: Oil Rate with Various Pump Injection Rates

It is observed that increase in pumps operating frequency ESP will result increase in oil rate production.

4.3.5 Well B

Well B was completed in 1992 as an oil producer. POSPER software is used to predict the well performance. Fluid data (PVT), reservoir data (IPR) and down hole equipment description (VLP) are provided. The following is the system summary for oil well B:

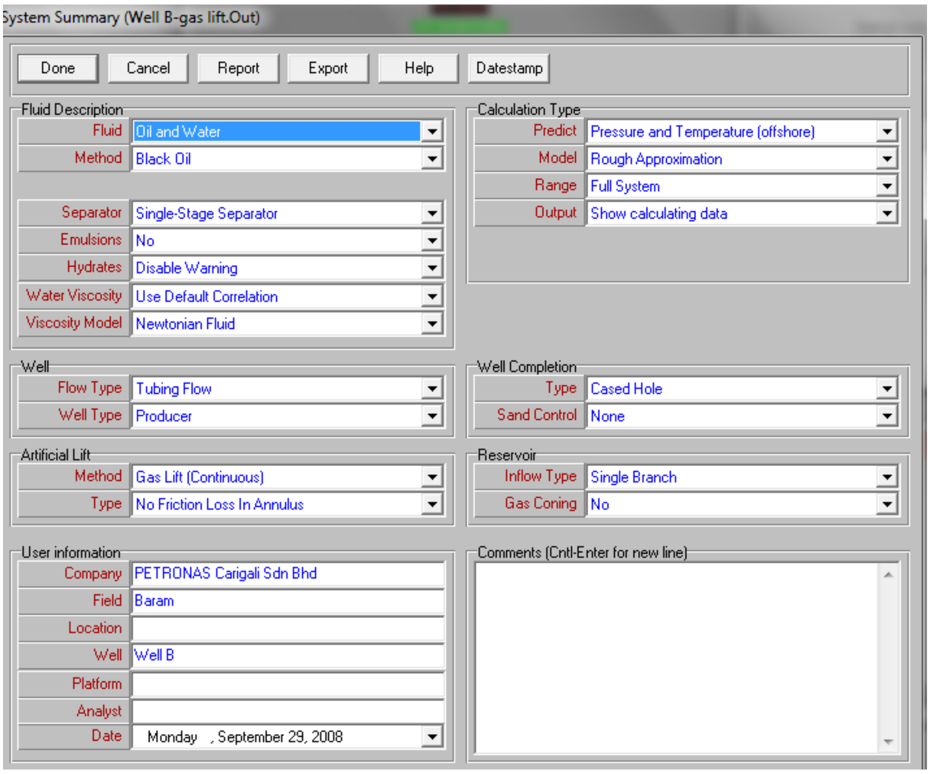


Figure 25: System Summary

4.3.5.1 Input Technical Data

1. PVT Lab Data and Well Test Data

Parameter	**Value**
Solution GOR	400 scf/stb
Oil Gravity	30 API
Gas Gravity	0.75
Water Salinity	80000 ppm
Impurities (CO2, N2, H2S)	None
Bubble Point Pressure	2514.7 psia
Temperature	200 deg F

Table 26: PVT Input Data

Pressure (psia)	**Gas Oil Ratio (scf/stb)**	**Oil FVF (rb/stb)**	**Oil viscosity (centipoises)**
1514.7	237	1.138	1.34
2014.7	324	1.178	1.15
2514.7	400	1.214	1.01

3014.7	400	1.207	1.05
4014.7	400	1.198	1.11

Table 27: PVT Lab Data

Parameter	Value
Tubing Head Pressure	264.696 psia
Tubing Head Temperature	158.5 deg F
Water Cut	30 %
Liquid Rate	8290 stb/d
Gauge Depth Measured	7000 feet
Gauge Pressure	2349.7 psia
Reservoir Pressure	3741.26 psia
GOR	400 scf/stb

Table 28: Well Test Data

2. VLP Input Data

Measured Depth (ft)	True Vertical Depth (ft)
0	0
8000	8000

Table 29: Deviation Survey

Equipment Type	Measured Depth (ft)	Internal Diameter (in)	Roughness (in)	Rate Multiplier
Xmas Tree (Well Head)	0	N/A	N/A	N/A
Tubing	7000	3.992	0.0018	1
Casing	8000	8.3	0.0018	1

Table 30: Downhole Equipment

Measured Depth (ft)	Static Temperature (deg F)
0	70
8000	200

Table 31: Geothermal Gradient

3. IPR Input Data

IPR Model	Darcy
Reservoir Pressure	3014.7 psia
Reservoir Temperature	200 deg F
Water Cut	80%
Total GOR	400 scf/stb
Compaction Permeability Reduction Model	No
Relative Permeability	No
Reservoir Permeability	150 md
Reservoir Thickness	100feet
Drainage Area	340 acres
Dietz shape factor	31.6
Wellbore radius	4.248 inches
Mechanical Skin	2

Table 32: IPR Input Data

To summarize, the following figure are the system summary of the input data for well B:

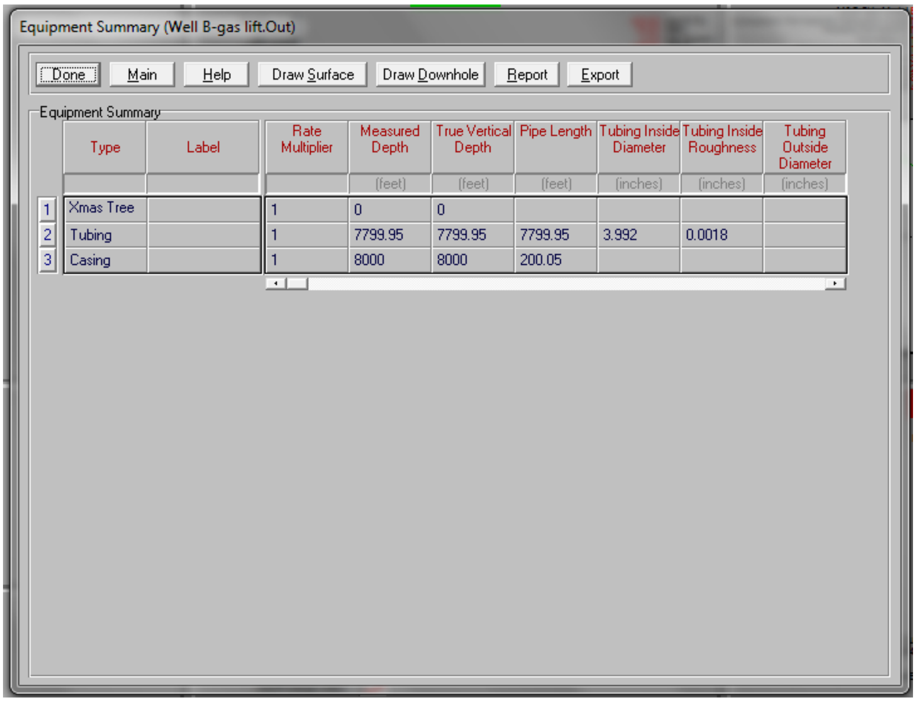


Figure 26: Equipment Summary

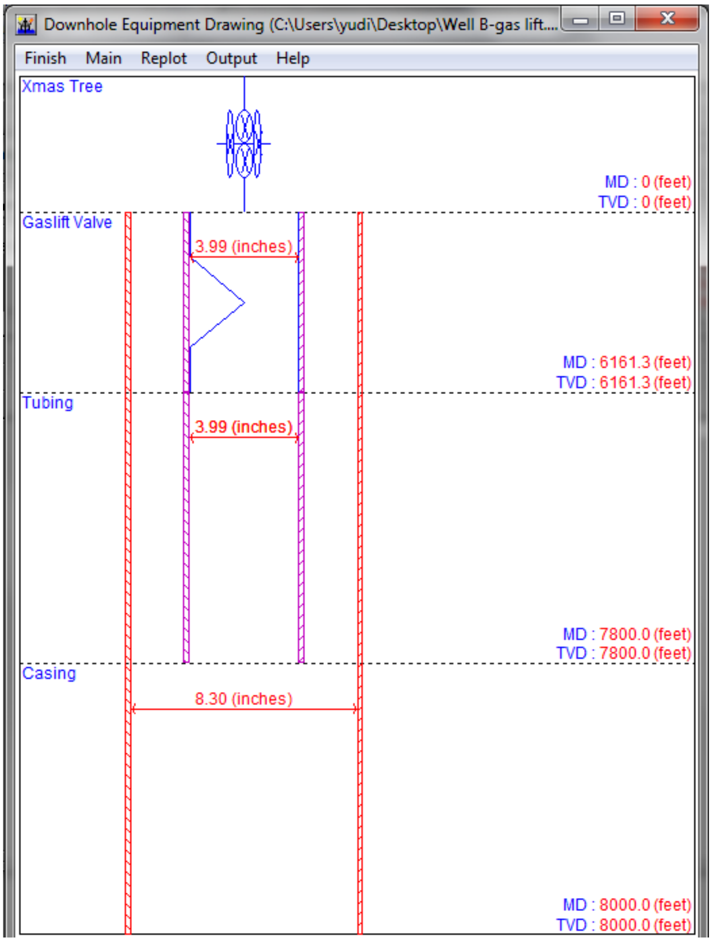


Figure 27: Downhole Equipment

Inflow Type	Single Branch	
Completion	Cased Hole	
Sand Control	None	
Gas Coning	No	
Reservoir Model	Darcy	
M&G Skin Model	Enter Skin By Hand	
Compaction Permeability Reduction Model	No	
Relative Permeability	No	
Formation PI	10.51	(STB/day/psi)
Absolute Open Flow (AOF)	18792.4	(STB/day)
Reservoir Pressure	3014.70	(psia)
Reservoir Temperature	200.00	(deg F)
Water Cut	80.000	(percent)
Total GOR	400.00	(scf/STB)
Reservoir Permeability	150.00	(md)
Reservoir Thickness	100.0	(feet)
Drainage Area	340.0	(acres)
Dietz Shape Factor	31.6	
Wellbore Radius	4.25	(inches)
Skin	2	

Figure 28: IPR Summary

4.3.5.2 Generate the IPR Curve

A well's inflow performance relationship defines its production potential. In this well B, the IPR is expressed as the following figure:

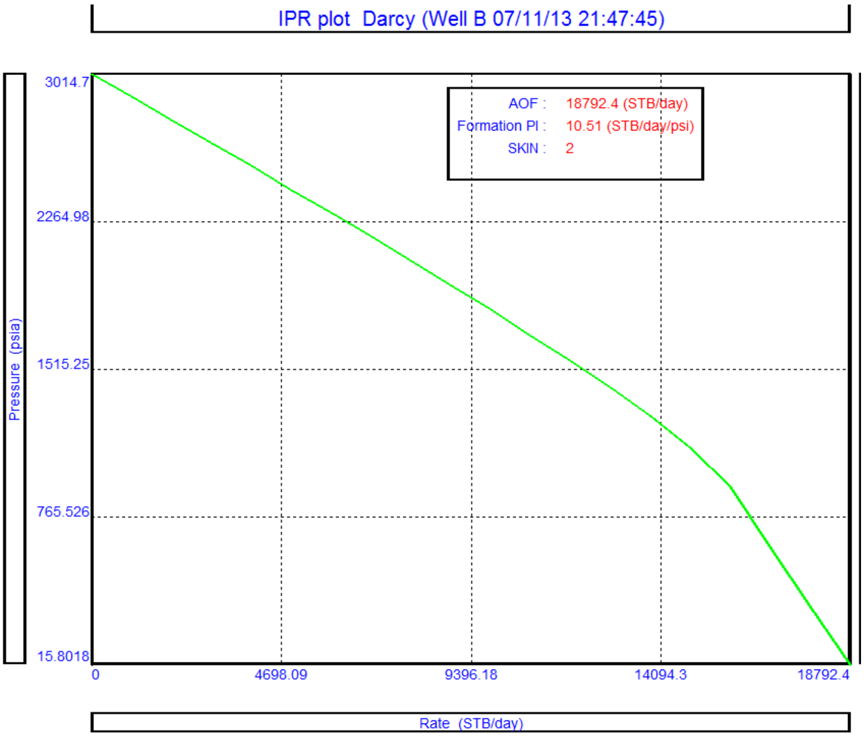


Figure 29: IPR Plot

In this example of well B, it can be observed that the Absolute Open Flow potential (AOF) is around 18792.4 stb/day. This AOF indicates that the maximum production rate is achieved when the bottomhole pressure approaches zero.

In addition, the productivity index in this well B is computed as 10.51 stb/day/psi. This production index indicates the ratio of production rate in well B to its drawdown pressure.

Apart from that, it is observed that the mechanical skin is shown as 2. This positive skin denotes as any phenomenon that causes a distortion of the flow lines from the perfectly normal to the flow direction or a restriction to flow. The causes of positive skin is normally mechanical causes (partial completion, inadequate number of perforations), phase changes (reduction of relative permeability of the desired fluid), turbulence and damage to the natural reservoir permeability

4.3.5.3 Perform PVT Matching

In this example of well B, the PVT matching can be summarized as figures below:

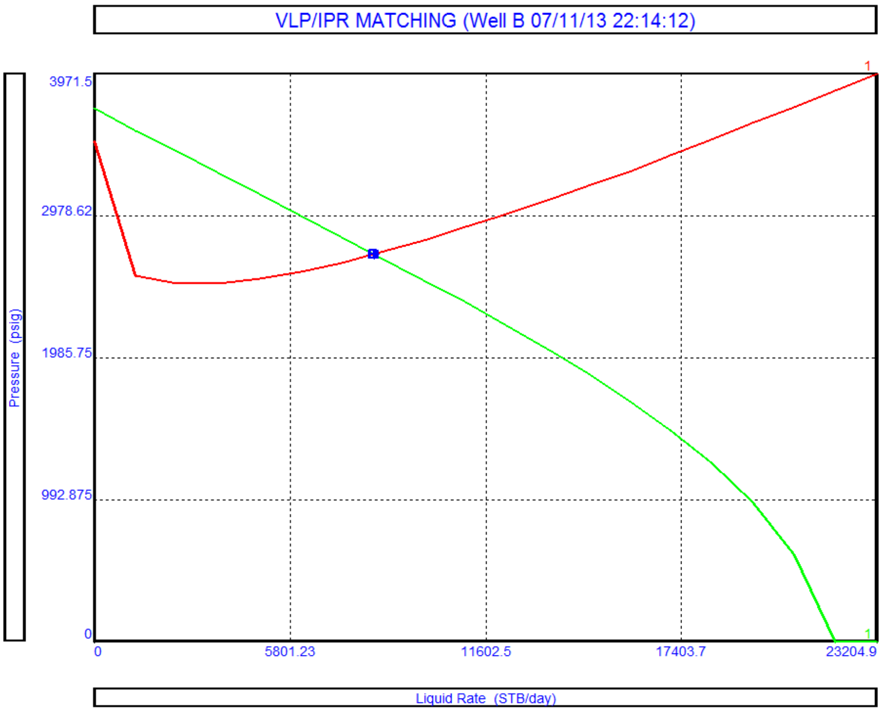


Figure 30: VLP/PVT Matching

	BOTTOM HOLE PRESSURE (psig)			LIQUID RATE (STB/day)		
	Measured	Calculated	% Difference	Measured	Calculated	% Difference
1	2706.43	2706.96	0.019548	8290.0	8297.6	0.092226

Figure 31: VLP/PVT Matching Correlation

As per shown in the figure above, there are only 0.092226% difference between measured liquid rate and simulated liquid rate whereas for bottom hole pressure, the difference is only 0.019548%. This percentage is less than 1%, thus the percentage difference is considered small and acceptable. Therefore, the well model is validated and eligible for further analysis.

4.3.6 Simulate Base Case Forecast under Various Operating Conditions

In this example of well B, the maximum economic water cut is set to be maximum 50% in a range of reservoir pressure between 3500 psia - 5000 psia. In the oil production as the time goes by, the water cut is increasing meanwhile the reservoir pressure is declining. The oil rate targeted is set to be produced at its economic rate (1500 stb/d) and any oil rate below than that will not be further considered or investigated.

To summarize, the following table are the oil rates obtained from this base case analysis:

Parameter	Range
Reservoir Pressure (psia)	3500, 4000, 4500, 5000
Water Cut (%)	30, 36, 43, 50

4.3.6.1 Well B before Using Gas Lift and ESP

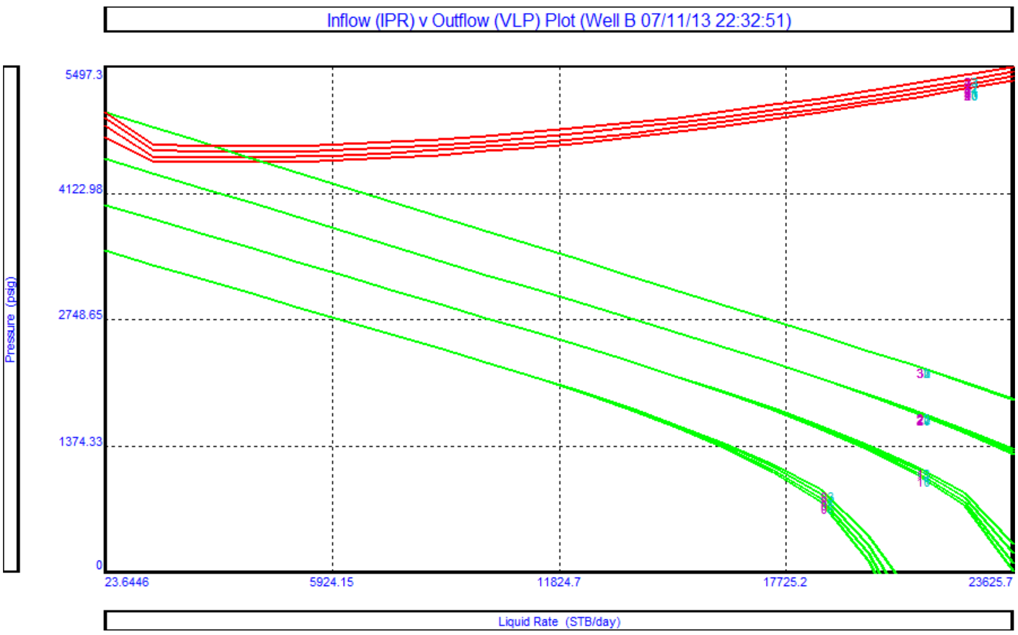


Figure 32: IPR VS VLP before using Gas Lift and ESP

Reservoir Pressure (psia)	Water Cut (%)			
	30	36	43	50
	Oil Rate (stb/d)			
5000	2906.7	2424.0	1893.4	1419.4
4500	0	0	0	0
4000	0	0	0	0
3500	0	0	0	0

Table 33: Oil Rates Produced before Using Gas Lift and ESP

4.3.6.2 Well B after Using Gas Lift

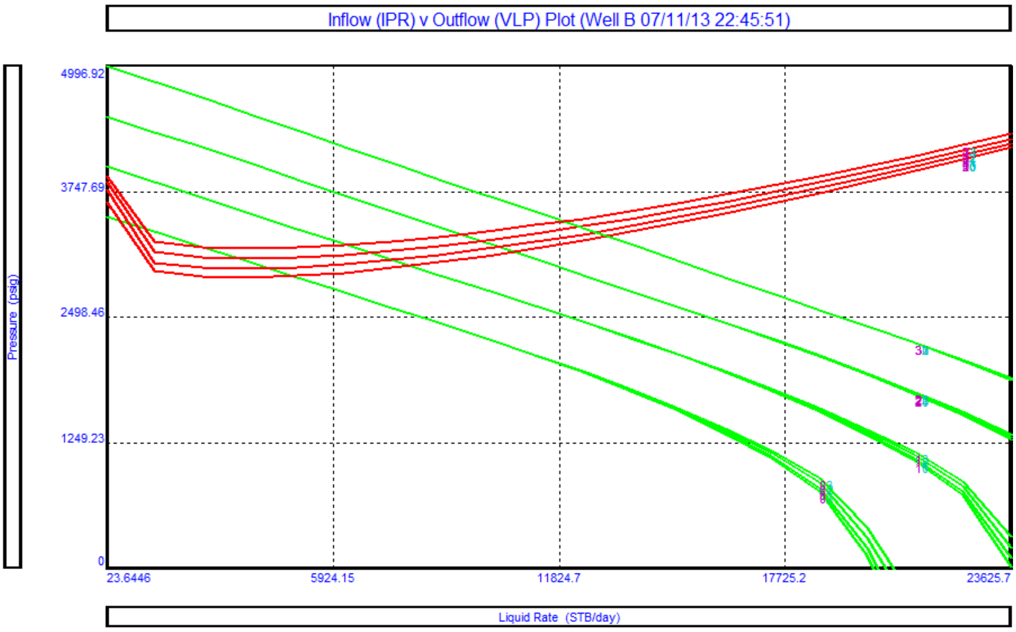


Figure 33: IPR VS VLP after Using Gas Lift

Reservoir Pressure (psia)	Water Cut (%)			
	30	36	43	50
	Oil Rate (stb/d)			
5000	9132.8	8157.5	7042.4	5958.0
4500	7440.2	6569.1	5582.0	4634.1
4000	5577.5	4811.7	3948.3	3143.2
3500	3417.9	2726.1	1965.6	1257.4

Table 34: Oil Rates Produced after Using Gas Lift

4.3.6.3 Well B after Using ESP

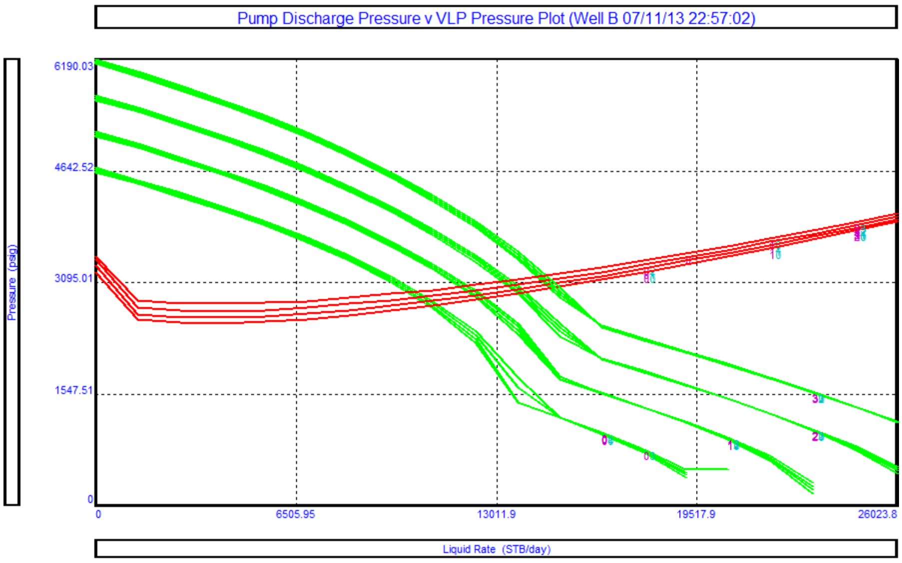


Figure 34: Pump Discharge Pressure VS VLP Pressure Plot

Reservoir Pressure (psia)	Water Cut (%)			
	30	36	43	50
	Oil Rate (stb/d)			
5000	10319.7	9414.8	8362.8	7309.4
4500	9594.2	8732.3	7733.9	6738.1
4000	8689.2	7900	6972.3	6050.6
3500	7591.3	6869.8	6038.4	5216.2

Table 35: Oil Rates Produced after Using ESP

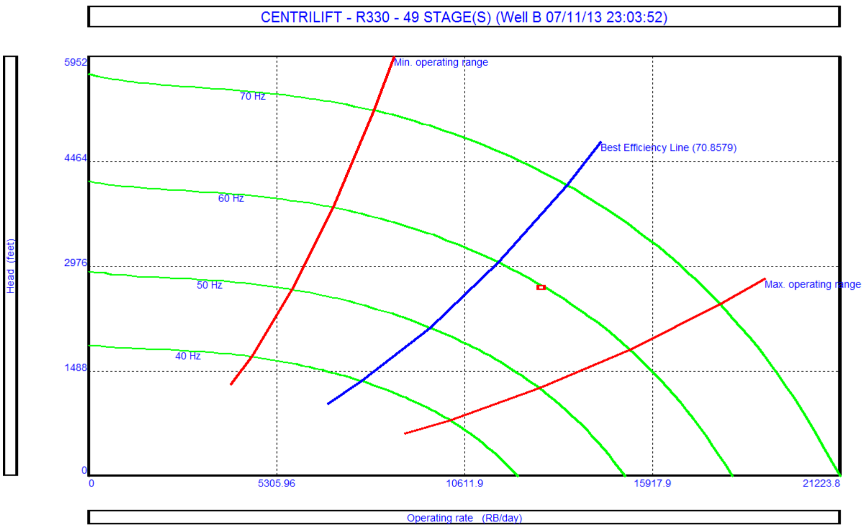


Figure 35: Pump Performance Curve

Pump performance curve describes the relation between flow rate and head for the actual pump. In this well B, the best efficiency line for pump performance curve is calculated as 70.8579.

4.3.6.4 Overview

To summarize, the following table provides detailed information for each base case scenario:

Scenario	Minimum Economic Production Rate Produced	Maximum Economic Production Rate Produced
Without gas lift and ESP	1419.4 stb/d at 5000 psia with 50 %WC	2906.7 stb/d at 5000 psia with 0 %WC
With Gas Lift	1257.4 stb/d at 3500 psia with 50 %WC	9132.8 stb/d at 5000 psia with 30 %WC
With ESP	5216.2 stb/d at 3500 psia with 50% WC	10319.7 stb/d at 5000 psia with 30 %WC

Table 36: Economic Base Case Condition

4.3.7 Evaluate Various Development Options to Optimize Oil Production

To summarize, the operating rates produced by each analysis are provided in the following table.

Parameter	Range
Wellhead Pressure (psia)	900, 1033, 1166, 1300
Tubing Diameter (in)	2.5, 3, 4, 4.5
Water Cut (%)	30, 45, 55, 70
Gas Lift gas Injection Rate (MMscf/day)	2.5, 3, 5, 7
Pump Operating Frequency (Hertz)	45, 55, 65, 75

Table 37: Range of Parameter Base Scenario

4.3.7.1 Changing Wellhead Pressure (WHP)

4.3.7.1.1 Well B before Using Gas Lift and ESP

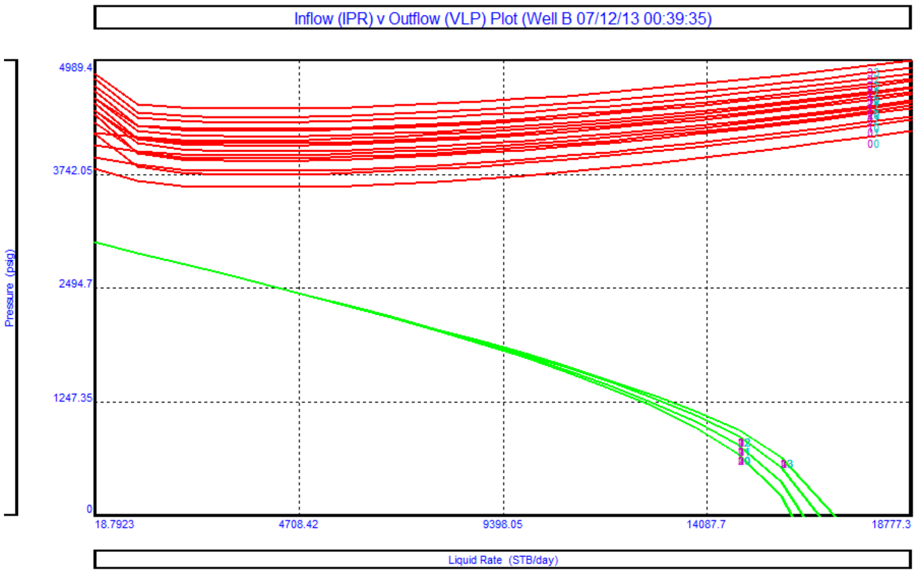


Figure 36: IPR VS VLP for Changing WHP before Using Gas Lift and ESP

WHP (psia)	Water Cut (%)			
	30	45	55	70
	Oil Rate (stb/d)			
1300	0	0	0	0
1166	0	0	0	0
1033	0	0	0	0
900	0	0	0	0

Table 38: Oil Rates at different WHP before Using Gas Lift and ESP

4.3.7.2 Well B after using Gas Lift

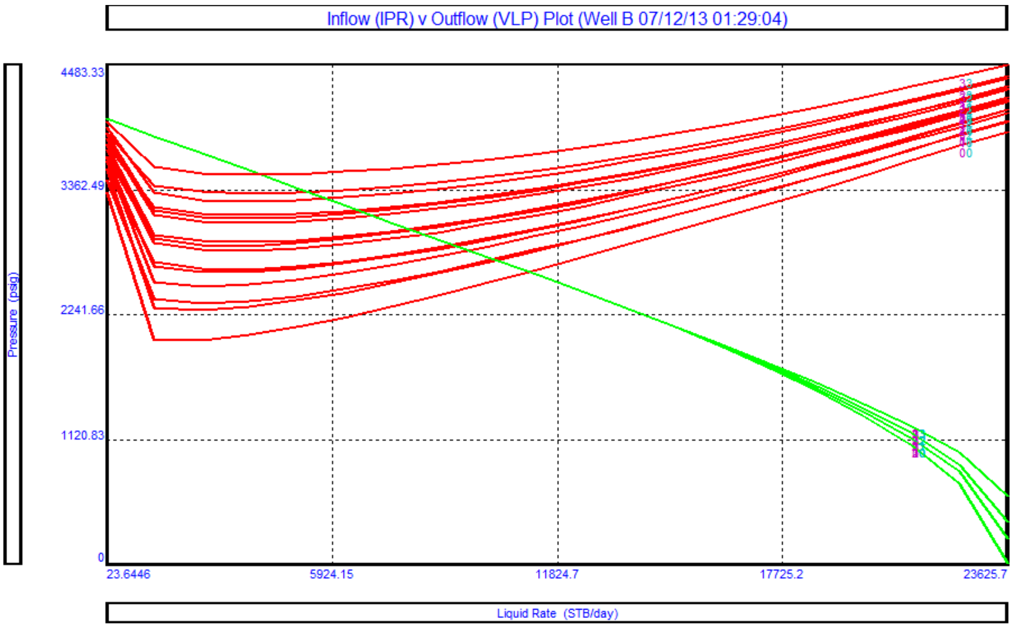


Figure 37: IPR VS VLP for Changing WHP after Using Gas Lift

WHP (psia)	**Water Cut (%)**			
	30	45	55	70
	Oil Rate (stb/d)			
1300	5577.5	3711.7	2598.5	1212.2
1166	6375.4	4390.6	3162.9	1590.0
1033	7103.7	5050.6	3752.6	1986.2
900	7740.8	5630.1	4285.6	2414.6

Table 39: Oil Rates at different WHP after Using Gas Lift

4.3.7.2.1 Well B after Using ESP

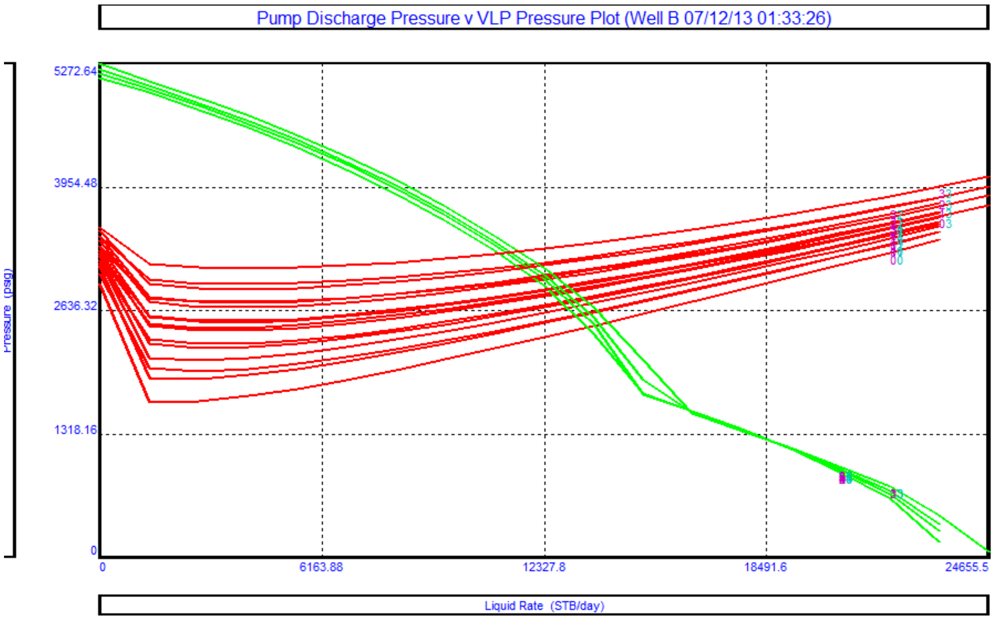


Figure 38: Pump Discharge Pressure VS VLP for Changing WHP after Using ESP

WHP (psia)	**Water Cut (%)**			
	30	45	55	70
	Oil Rate (stb/d)			
1300	8689.2	6708.1	5398.2	3486.1
1166	8952.8	6945.7	5609.5	3634.3
1033	9212.2	7173.8	5809.3	3776.2
900	9452.5	7385.7	5998.4	3920.3

Table 40: Oil Rates at different WHP after Using Gas Lift

4.3.7.3 Overview

As per shown in the figures and tables above, it is observed that by changing wellhead pressure from 1,300 to 900 psia, the operating rates produced become higher. However, when the water cut is increasing to maximum 70%, the oil rates obtained are decreasing.

4.3.7.4 Changing Tubing Size

4.3.7.4.1 Well B before Using Gas Lift and ESP

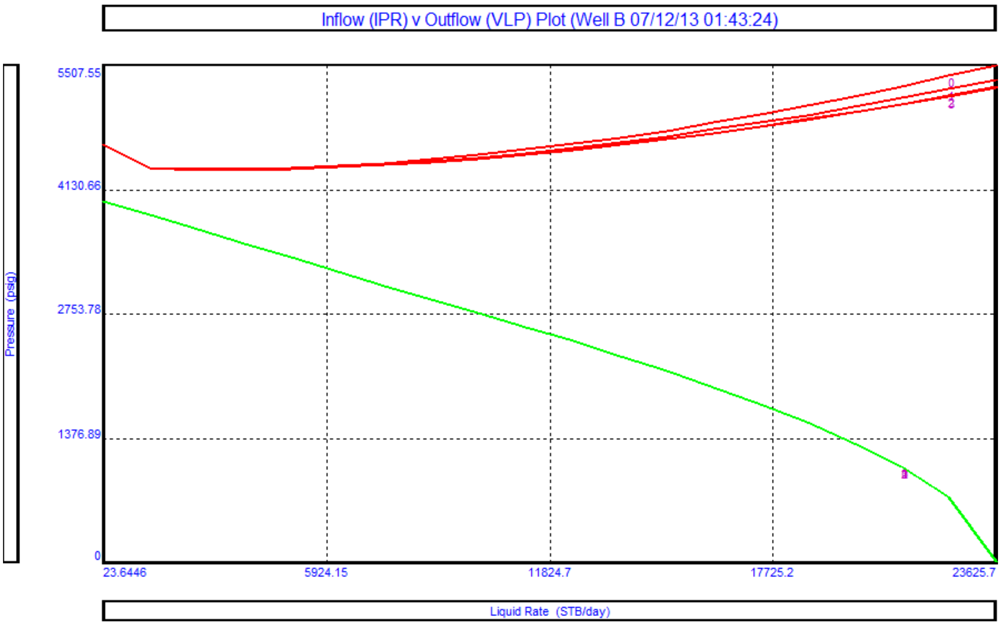


Figure 39: IPR VS VLP for Changing tubing Size before Using Gas Lift and ESP

Tubing Size ID (in)	Oil rate (stb/day)
2.5	0
3	0
4	0
4.5	0

Table 41: Oil Rate at Various Tubing Internal Diameter Sizes before Using Gas Lift and ESP

4.3.7.5 Well B after Using Gas Lift

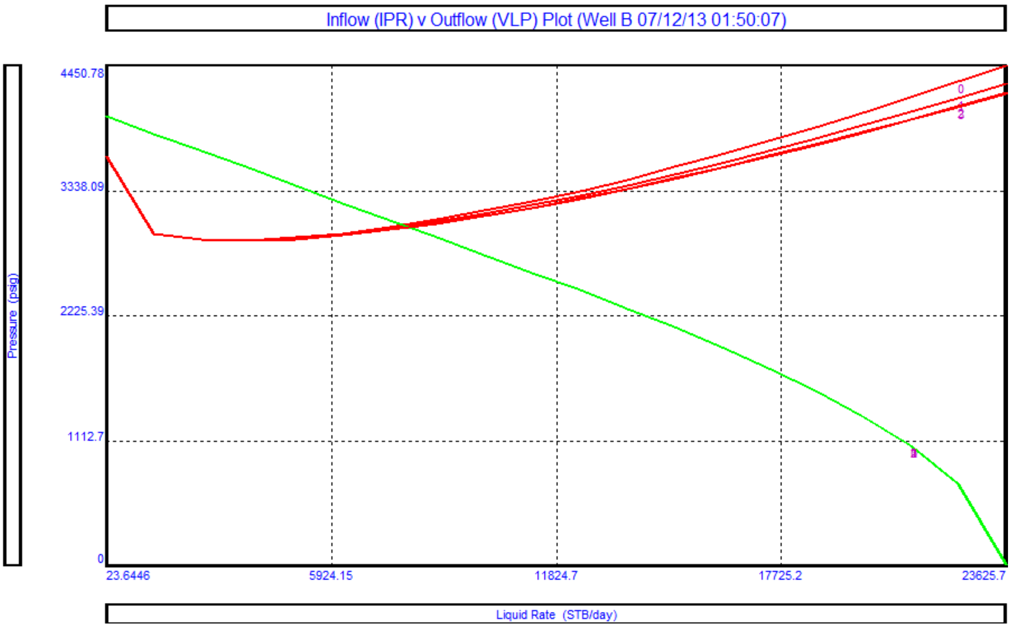


Figure 40: IPR VS VLP for Changing tubing Size after Using Gas Lift

Tubing Size ID (in)	Oil rate (stb/day)
2.5	5454.2
3	5528.3
4	5566.6
4.5	5571.8

Table 42: Oil Rate at Various Tubing Internal Diameter Sizes after Using Gas Lift

4.3.7.6 Well B after using ESP

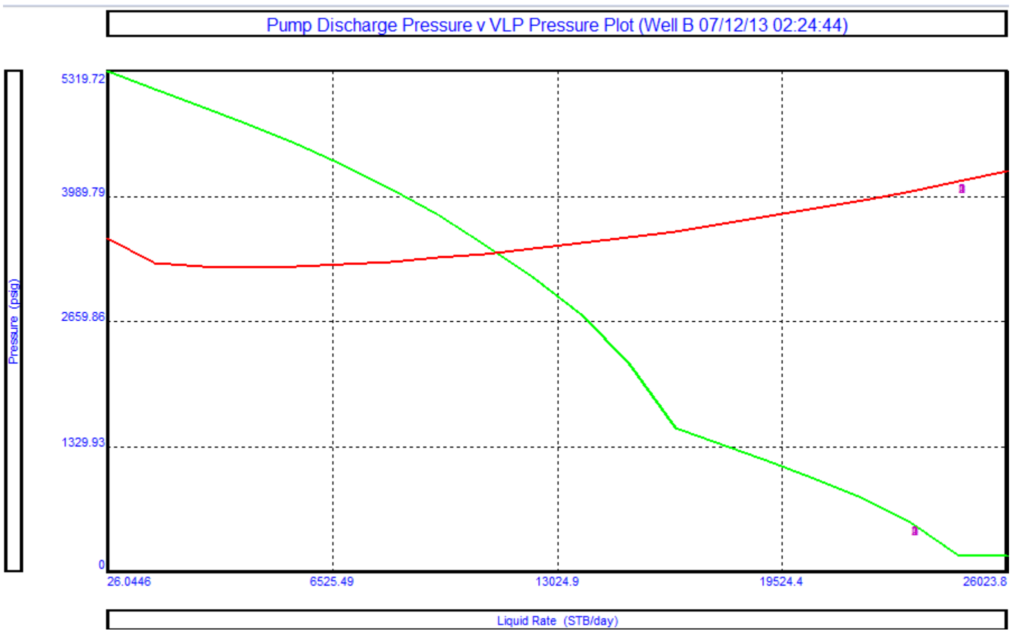


Figure 41: Pump Discharge Pressure VS VLP Pressure after using ESP

Tubing Size ID (in)	Oil rate (stb/day)
2.5	2263.8
3	2265.4
4	2275.3
4.5	2279.2

Table 43: Oil Rate at Various Tubing Internal Diameter Sizes after Using ESP

4.3.7.7 Overview

It is observed that by changing various sizes of tubing internal diameter (ID), the oil rates increment obtained are small and not too much significant. Thus, it is not recommended to change the tubing size in this well.

4.3.7.8 Changing Artificial Lift Method Parameter

4.3.7.8.1 Changing Gas Injection Rate Gas Lift

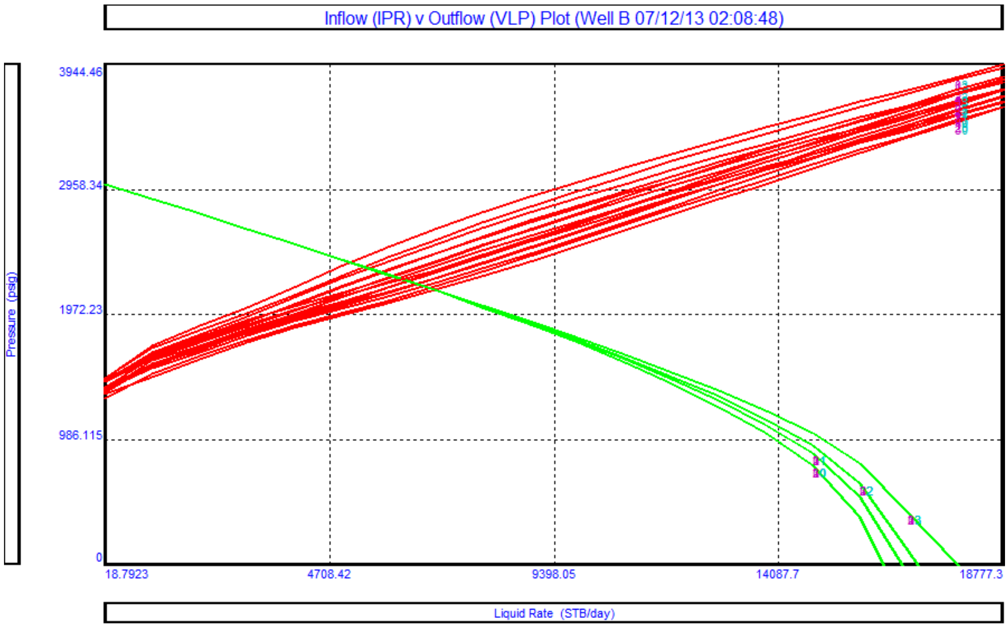


Figure 42: IPR VS VLP for Changing Gas Lift Rate

Gas Injection (MMscf/day)	Water Cut (%)			
	30	45	55	70
	Oil Rate (stb/d)			
2.5	4316.4	3194.4	2502.7	1553.7
3	4458.6	3326.0	2620.3	1640.7
5	4757.5	3599.9	2869.2	1828.1
7	4838.3	3678.4	2939.9	1880.7

Table 44: Oil Rate with Various Gas Injection Rates

It is observed that increase in gas injection rate gas lift will result increase in oil rate production.

4.3.7.8.2 Changing Pump Operating Frequency ESP

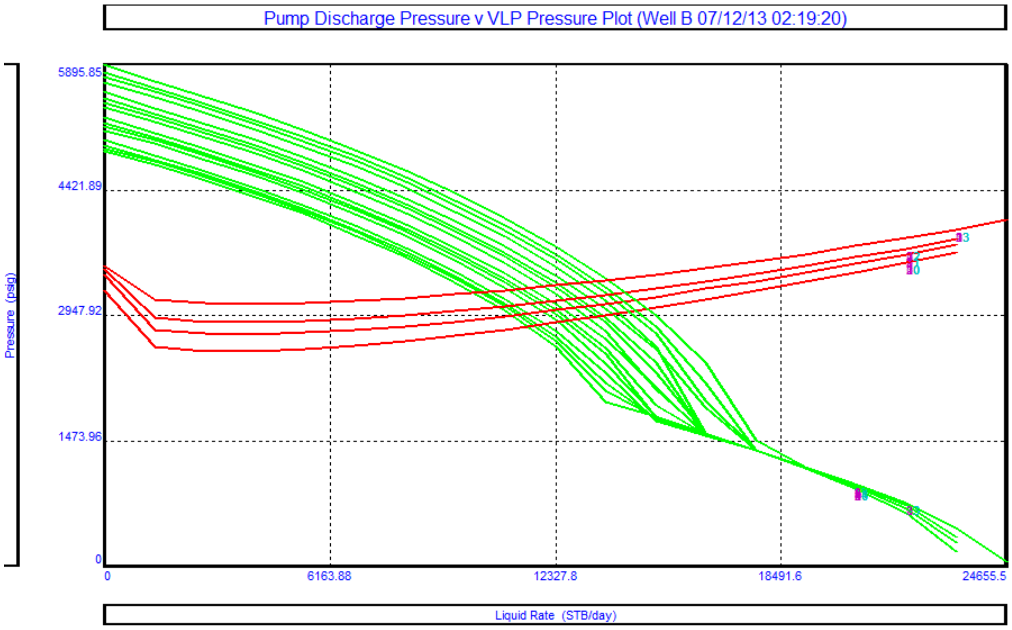


Figure 43: Pump Discharged Pressure/VLP for changing Pump Operating Frequency

Pump Operating Frequency	Water Cut (%)			
	10	20	30	40
	Oil Rate (stb/d)			
45	2006.2	1723.6	1443.6	1161.8
55	2006.4	1723.8	1467.9	1250.5
65	2006.7	1724.0	1471.9	1398.5
75	2123.5	1885.1	1646.7	1554.1

Table 45: Oil Rate with Various Pump Injection Rates

It is observed that increase in pumps operating frequency ESP will result increase in oil rate production.

4.3.8 Well C

Well C was completed in 1995 as an oil producer. POSPER software is used to predict the well performance. Fluid data (PVT), reservoir data (IPR) and down hole equipment description (VLP) are provided. The following is the system summary for oil well C:

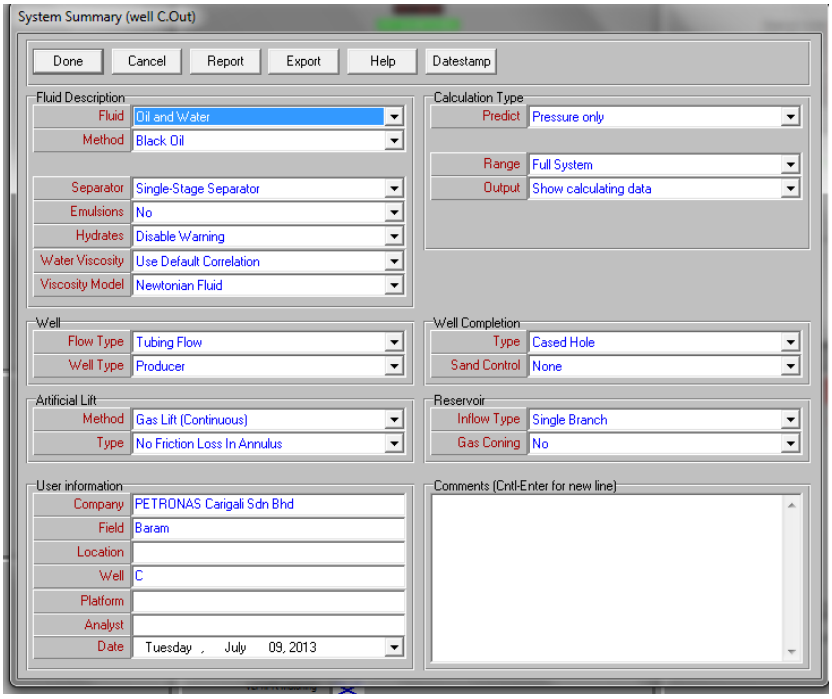


Figure 44: System Summary

4.3.8.1 Input Technical Data

1. PVT Lab Data and Well Test Data

Parameter	Value
Solution GOR	704.6 scf/stb
Oil Gravity	34 API
Gas Gravity	0.7
Water Salinity	30000 ppm
Impurities (CO2, N2, H2S)	(0, 1.2, 0.11)

Bubble Point Pressure	3518.6 psia
Temperature	225 deg F

Table 46: PVT Input Data

Pressure (psia)	Gas Oil Ratio (scf/stb)	Oil FVF (rb/stb)	Oil viscosity (centipoises)
1414.73	217.3	1.1529	1.0573
2014.73	313.4	1.1963	0.9183
2614.73	415.7	1.2414	0.7962
3214.73	525.9	1.2891	0.6905
3814.73	646	1.3402	0.5994
4414.73	777.9	1.3958	0.5207

Table 47: PVT Lab Data

Parameter	Value
Tubing Head Pressure	860 psia
Tubing Head Temperature	110 deg F
Water Cut	25 %
Liquid Rate	2725 stb/d
Gauge Depth Measured	11916 feet
Gauge Pressure	3200 psia
Reservoir Pressure	4750 psia
GOR	11750 scf/stb

Table 48: Well Test Data

4. VLP Input Data

Measured Depth (ft)	True Vertical Depth (ft)
0	0
7121.49	6722.06

7219.92	6811.3
7455.78	7028.54
8304.88	7822.68
8493.57	7990.71
8635.09	8112.35
8776.61	8229.47
9034.78	8433.24
10745.5	9770.87
10934.5	9907.88
11123.5	10036.5
11265.2	10126.8
11407	10211.1
11548.7	10289
11690.5	10360
11832.3	10423.8
11974	10480
13507.9	11026
15655.9	11738.3

Table 49: Deviation Survey

Equipment Type	True Vertical Depth (feet)	Temperature (deg F)
Manifold (Wellhead)	0	50

Table 50: Surface Equipment

Equipment Type	Measured Depth (ft)	Internal Diameter (in)	Roughness (in)	Rate Multiplier
Xmas Tree (Well Head)	0	N/A	N/A	N/A
Tubing	14640	2.992	0.03	1

Table 51: Downhole Equipment

Measured Depth (ft)	Static Temperature (deg F)
0	60
13507	228
15655	236

Table 52: Temperature Survey

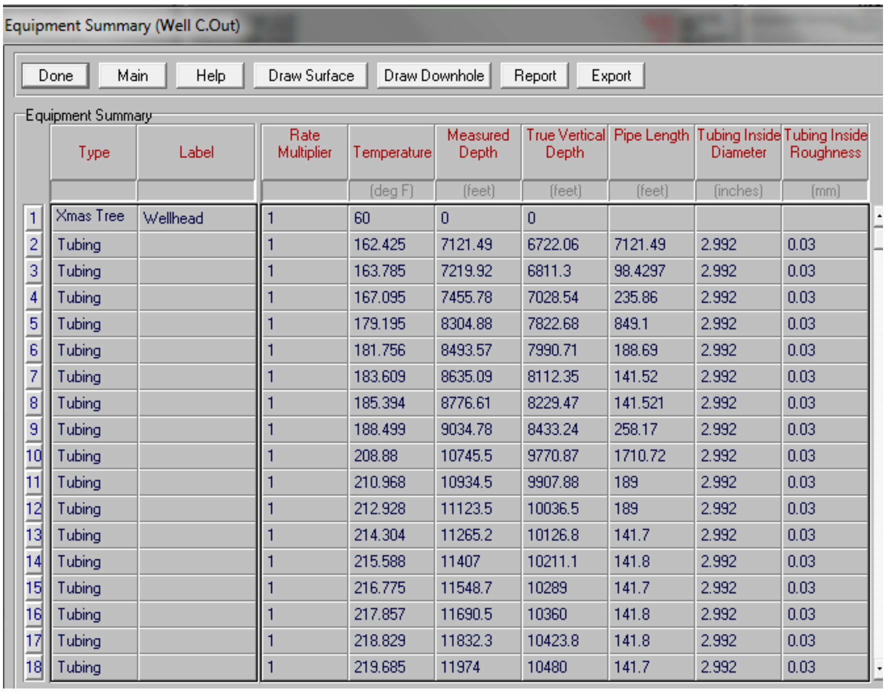
5. IPR Input Data

IPR Model	Darcy
Reservoir Pressure	3275 psia
Reservoir Temperature	250 deg F
Water Cut	25%
Total GOR	1150 scf/stb
Compaction Permeability Reduction Model	No
Relative Permeability	No
Reservoir Permeability	60 md
Reservoir Thickness	75feet

Drainage Area	170 acres
Dietz shape factor	31.6
Wellbore radius	3.5 inches
Mechanical Skin	6

Table 53: IPR Input Data

To summarize, the following figure are the system summary of the input data for well C:



Equipment Summary (Well C.Out)

Done | Main | Help | Draw Surface | Draw Downhole | Report | Export

Equipment Summary

	Type	Label	Rate Multiplier	Temperature	Measured Depth	True Vertical Depth	Pipe Length	Tubing Inside Diameter	Tubing Inside Roughness
				(deg F)	(feet)	(feet)	(feet)	(inches)	(mm)
1	Xmas Tree	Wellhead	1	60	0	0			
2	Tubing		1	162.425	7121.49	6722.06	7121.49	2.992	0.03
3	Tubing		1	163.785	7219.92	6811.3	98.4297	2.992	0.03
4	Tubing		1	167.095	7455.78	7028.54	235.86	2.992	0.03
5	Tubing		1	179.195	8304.88	7822.68	849.1	2.992	0.03
6	Tubing		1	181.756	8493.57	7990.71	188.69	2.992	0.03
7	Tubing		1	183.609	8635.09	8112.35	141.52	2.992	0.03
8	Tubing		1	185.394	8776.61	8229.47	141.521	2.992	0.03
9	Tubing		1	188.499	9034.78	8433.24	258.17	2.992	0.03
10	Tubing		1	208.88	10745.5	9770.87	1710.72	2.992	0.03
11	Tubing		1	210.968	10934.5	9907.88	189	2.992	0.03
12	Tubing		1	212.928	11123.5	10036.5	189	2.992	0.03
13	Tubing		1	214.304	11265.2	10126.8	141.7	2.992	0.03
14	Tubing		1	215.588	11407	10211.1	141.8	2.992	0.03
15	Tubing		1	216.775	11548.7	10289	141.7	2.992	0.03
16	Tubing		1	217.857	11690.5	10360	141.8	2.992	0.03
17	Tubing		1	218.829	11832.3	10423.8	141.8	2.992	0.03
18	Tubing		1	219.685	11974	10480	141.7	2.992	0.03

Figure 45: Equipment Summary

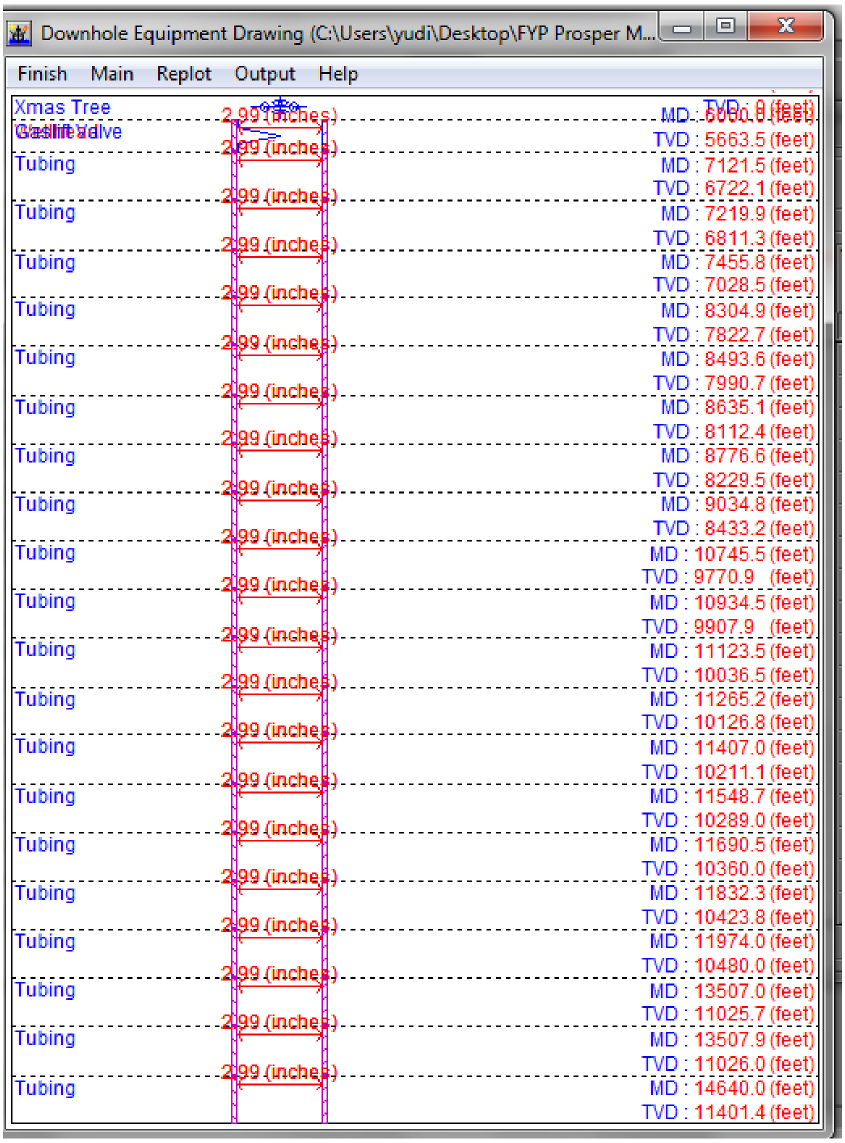


Figure 46: Downhole Equipment

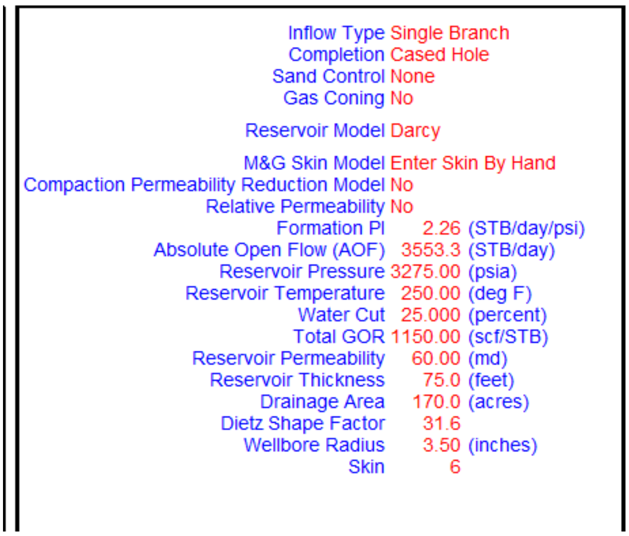


Figure 47: IPR Summary

4.3.8.2 Generate the IPR Curve

A well's inflow performance relationship defines its production potential. In this well C, the IPR is expressed as the following figure:

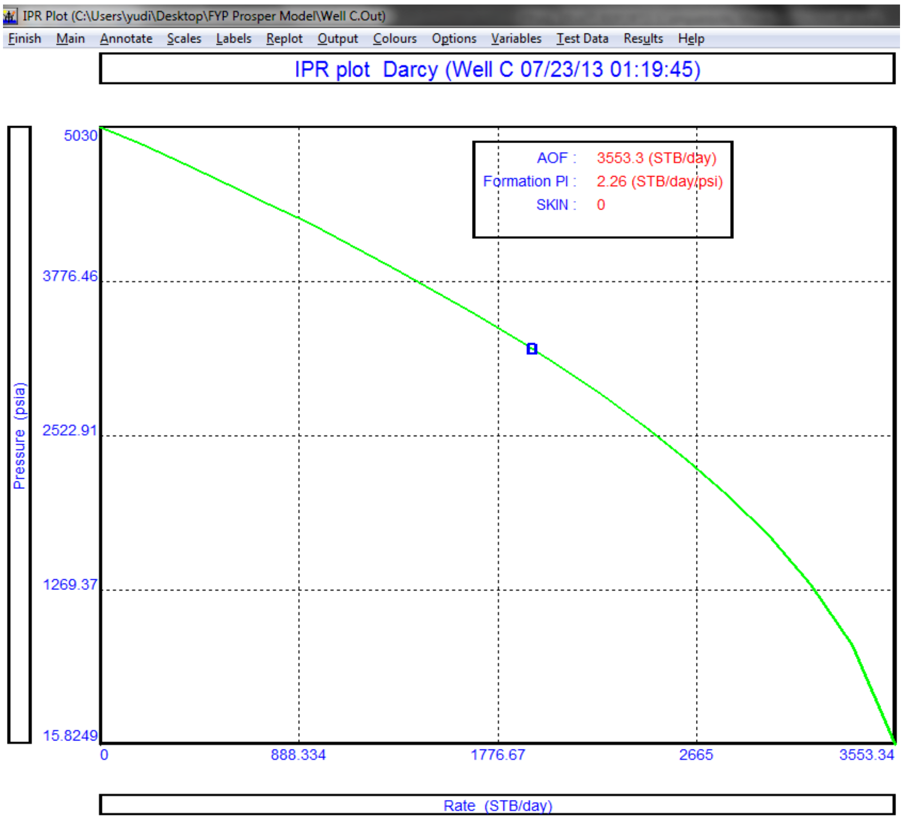


Figure 48: IPR Plot

In this example of well C, it can be observed that the Absolute Open Flow potential (AOF) is around 3553.3 stb/day. This AOF indicates that the maximum production rate is achieved when the bottomhole pressure approaches zero.

In addition, the productivity index in this well C is computed as 2.26 stb/day/psi. This production index indicates the ratio of production rate in well C to its drawdown pressure.

4.3.8.3 Perform PVT Matching

In this example of well C, the PVT matching can be summarized as figures below:

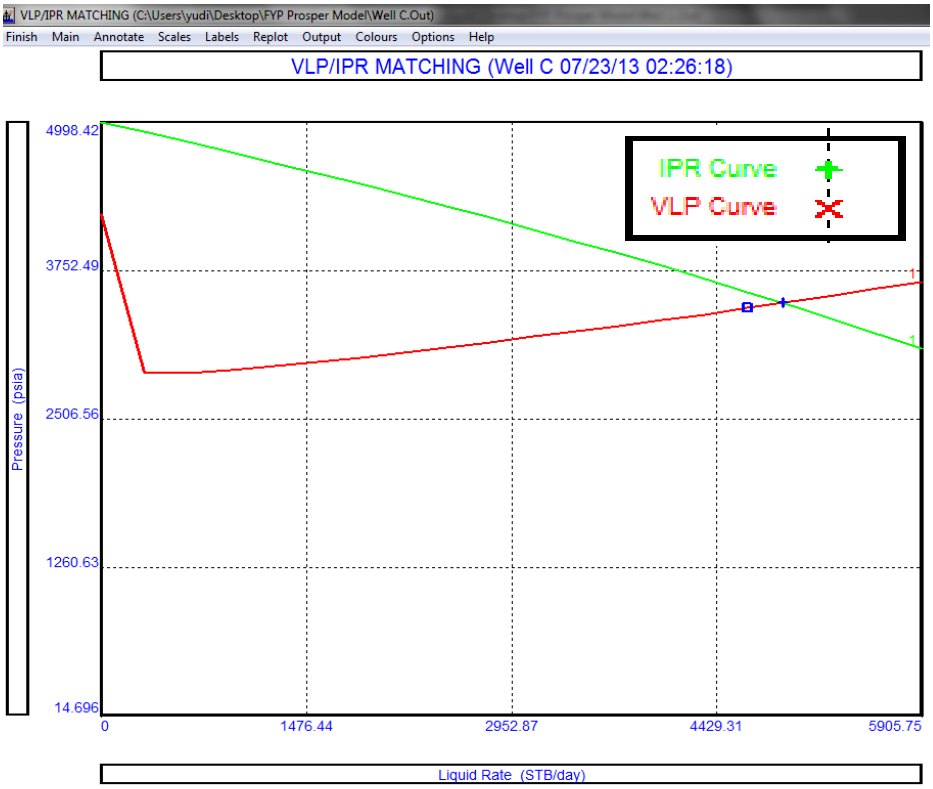


Figure 49: VLP/PVT Matching

	LIQUID RATE (STB/day)		
	Measured	Calculated	% Difference
1	4658.0	4911.7	5.45

	BOTTOM HOLE PRESSURE (psia)		
	Measured	Calculated	% Difference
1	3435.70	3479.30	1.27

Figure 50: VLP/PVT Matching Calculation

As per shown in the figure above, there are 5.45 % difference between measured liquid rate and simulated liquid rate whereas for bottom hole pressure, the difference is only 1.27%. This percentage difference is still considered small and acceptable. Therefore, the well model is validated and eligible for further analysis.

4.3.9 Simulate Base Case Forecast under Various Operating Conditions

In this example of well C, the maximum economic water cut is set to be 45% and in a range of reservoir pressure 2500 psia - 4750 psia. In the oil production, as the time goes by, the water cut is increasing meanwhile the reservoir pressure is declining. The oil rate targeted is set to be produced at its economic rate (1500 stb/d) and any oil rate below than that will not be further considered or investigated.

To summarize, the following table are the oil rates obtained from this base case analysis:

Parameter	Range
Reservoir Pressure	2500, 3625, 4750
Water Cut	20, 32, 45

Table 54: Reservoir Pressure and Water Cut Range

4.3.9.1 *Well C before Using Gas Lift and* ESP

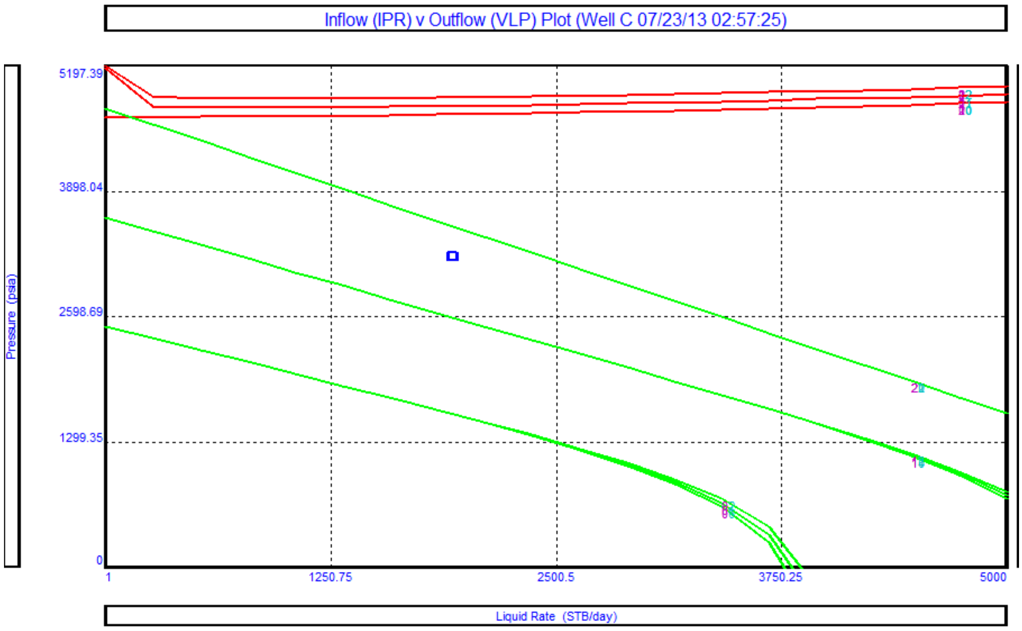


Figure 51: IPR VS VLP before using Gas Lift and ESP

Reservoir Pressure (psia)	Water Cut (%)		
	20	32	45
	Oil Rate (stb/d)		
4750	109.5	0	0
3625	0	0	0
2500	0	0	0

Table 55: Oil Rates Produced before using Gas Lift and ESP

4.3.9.2 Well C after Using Gas Lift

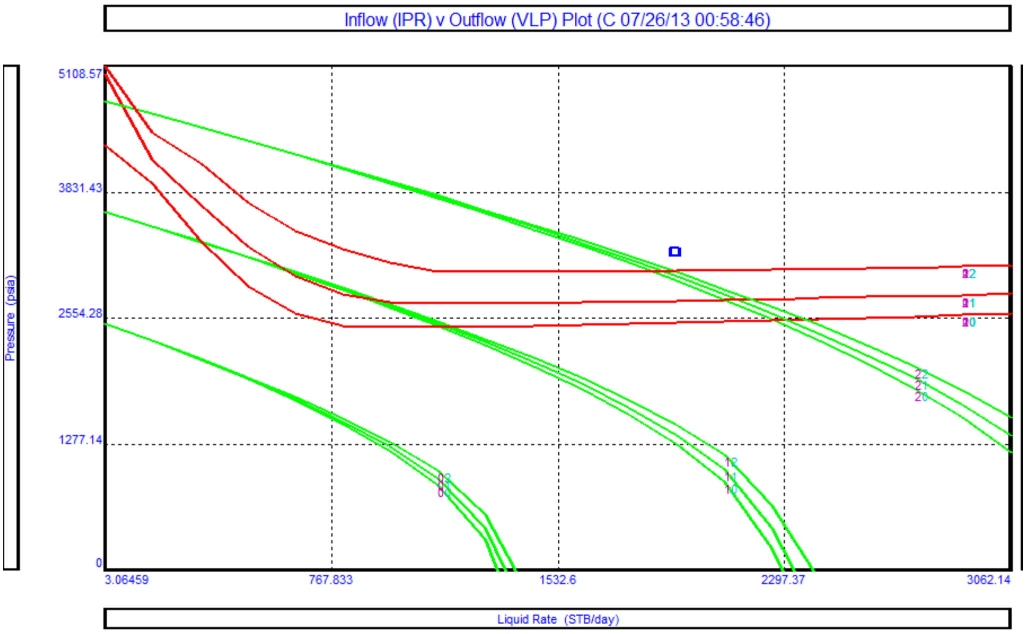


Figure 52: IPR VS VLP after using Gas Lift

Reservoir Pressure (psia)	Water Cut (%)		
	20	32	45
	Oil Rate (stb/d)		
4750	1811.1	1457.1	1057.1
3625	910.9	617.8	0
2500	0	0	0

Table 56: Oil Rates Produced after using Gas Lift

4.3.9.3 *Well C after Using* ESP

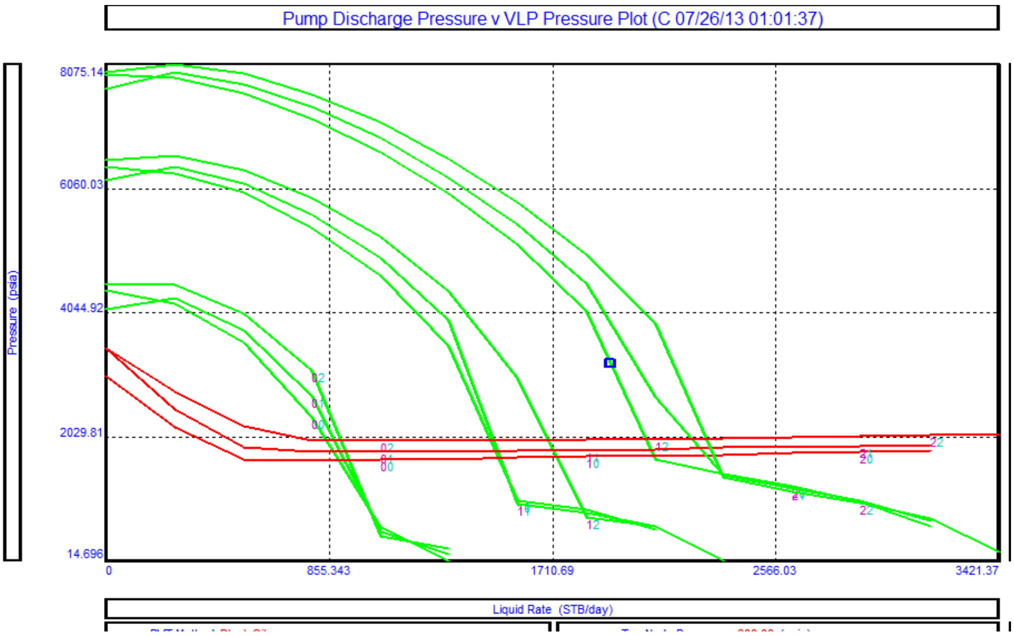


Figure 53: Pump Discharge Pressure VS VLP Pressure Plot

Reservoir Pressure (psig)	**Water Cut (%)**		
	20	32	45
	Oil Rate (stb/d)		
4750	1680.2	1549.4	1266.2
3625	1205.6	1022.9	933.2
2500	714.2	611.5	495.7

Table 57: Oil Rates Produced after using ESP

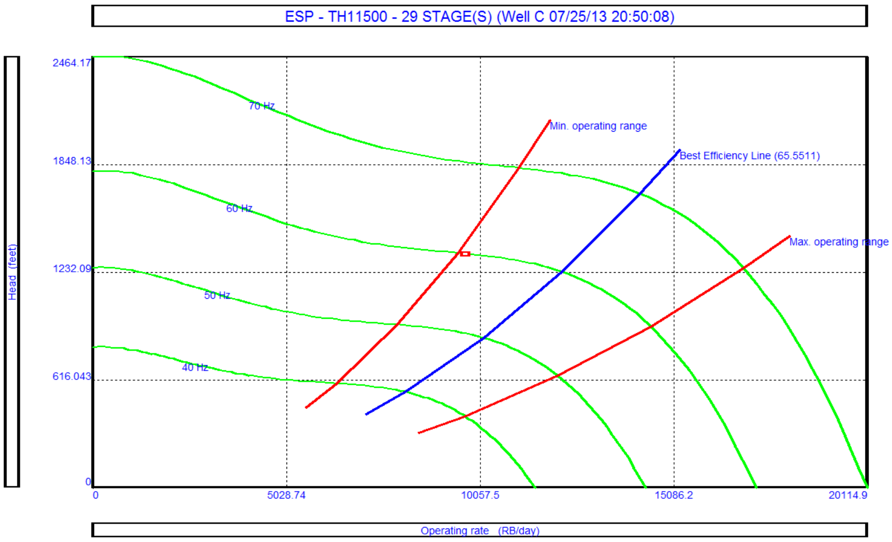


Figure 54: Pump Performance Curve

Pump performance curve describes the relation between flow rate and head for the actual pump. In this well C, the best efficiency line for pump performance curve is calculated as 65.5511.

4.3.9.4 Overview

To summarize, the following table provides detailed information for each base case scenario:

Scenario	Minimum Economic Production Rate Produced	Maximum Economic Production Rate Produced
Without gas lift and ESP	0 (no oil production)	109.5 stb/d at 4750 psia with 20 %WC
With Gas Lift	617.8 stb/d at 3625 psia with 32 %WC	1811.1 stb/d at 4750 psia with 20 %WC
With ESP	495.7 stb/d at 2500 psia with 45 %WC	1680.2 stb/d at 4750 psia with 20 %WC

Table 58: Economic Base Case Condition

4.3.10 Evaluate Various Development Options to Optimize Oil Production

To summarize, the operating rates produced by each analysis are provided in the following table.

Parameter	Range
Wellhead Pressure (psia)	500, 666, 833, 1000
Tubing Diameter (in)	2, 2.7, 3.6, 5
Water Cut (%)	20, 33, 46, 60
Gas Lift gas Injection Rate (MMscf/day)	1, 1.6, 2.3, 3
Pump Operating Frequency (Hertz)	45, 55, 65, 75

Table 59: Range of Parameter Base Scenario

4.3.10.1 Changing Wellhead Pressure (WHP)

4.3.10.1.1 Well C before using Gas Lift and ESP

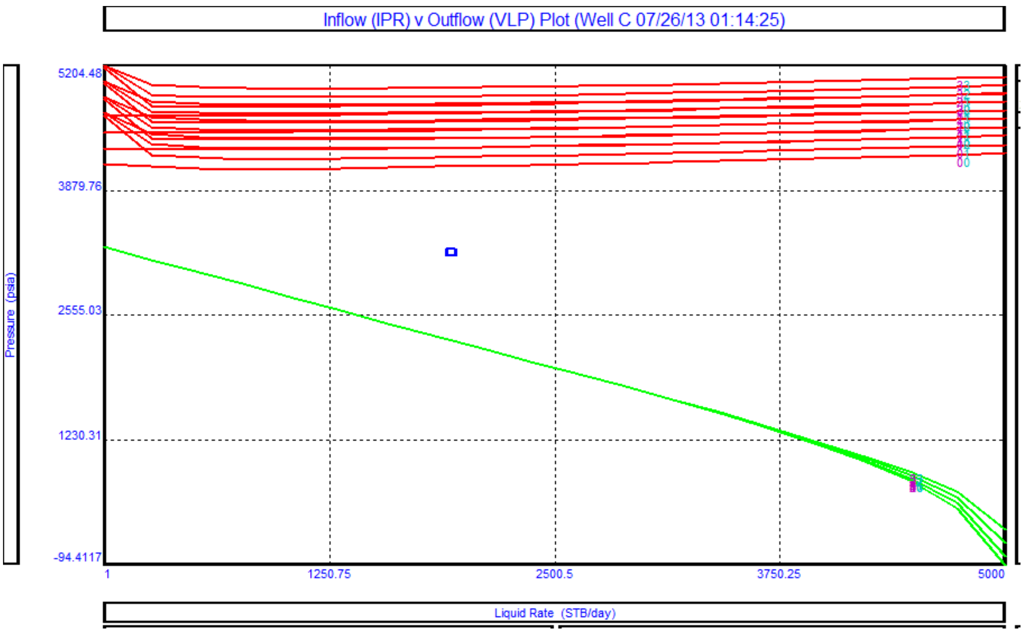


Figure 55: IPR VS VLP for changing WHP before using gas lift and ESP

WHP (psia)	Water Cut (%)			
	20	33	46	60
	Oil Rate (stb/d)			
1000	0	0	0	0
833	0	0	0	0
666	0	0	0	0
500	0	0	0	0

Table 60: Oil Rates at different WHP and WC before using Gas lift and ESP

4.3.10.1.2 Well C after using Gas Lift

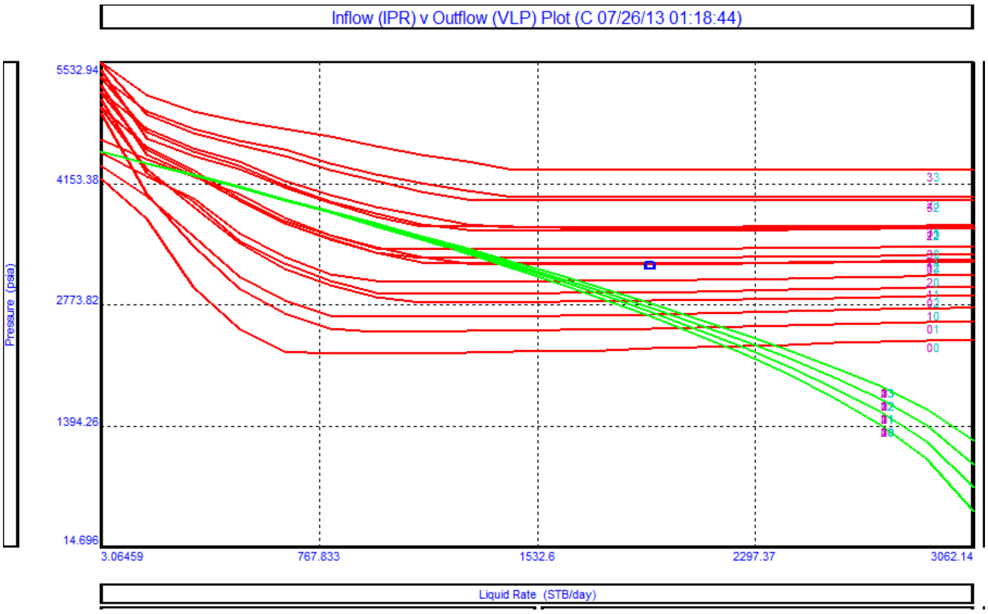


Figure 56: IPR VS VLP for changing WHP after using Gas Lift

WHP (psia)	Water Cut (%)			
	20	33	46	60
	Oil Rate (stb/d)			
1000	993.7	0	0	0
833	1271.4	906.8	0	0
666	1530.9	1158.1	772.9	0
500	1756.5	1386.6	994.6	592.7

Table 61: Oil Rates at different WHP and WC after using Gas Lift

4.3.10.1.3 Well C after using ESP

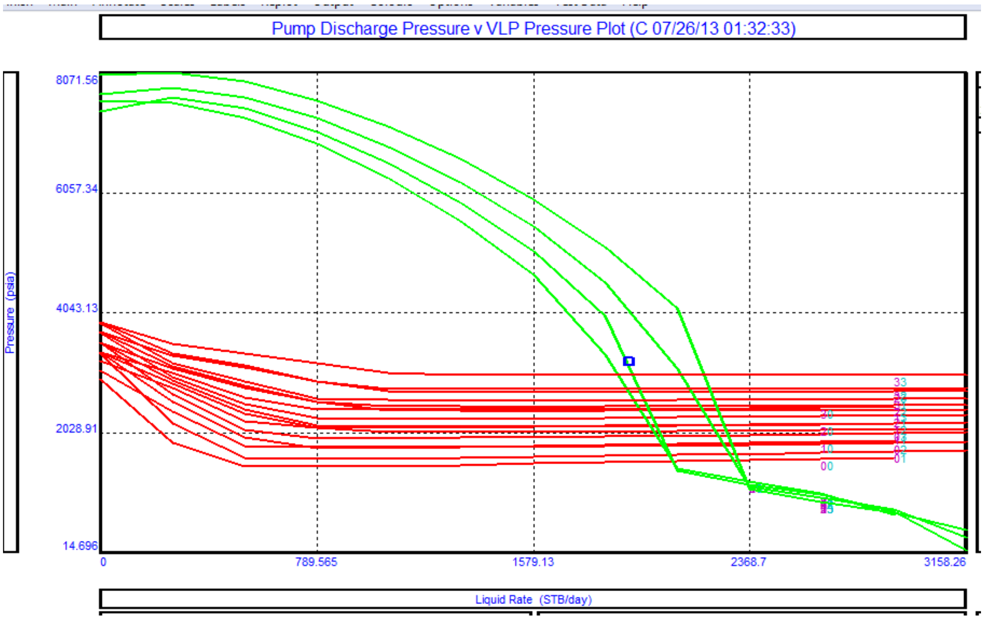


Figure 57: Pump Discharge Pressure VS VLP for Changing WHP after Using ESP

WHP (psia)	**Water Cut (%)**			
	20	33	46	60
	Oil Rate (stb/d)			
1000	1574.2	1324.1	1147.6	881.3
833	1605.8	1343.9	1168.3	891.1
666	1638.9	1364.8	1190.3	901.9
500	1670.9	1386.2	1213.9	913.7

Table 62: Oil Rates at different WHP and WC after using ESP

4.3.10.1.4 Overview

As per shown in the figures and tables above, it is observed that by changing wellhead pressure from 500 to 1,000 psia, the operating rates produced become higher. However, when the water cut is increasing to maximum 60%, the oil rates obtained are decreasing.

4.3.10.2 Changing Tubing Size

4.3.10.2.1 Well C before using Gas Lift and ESP

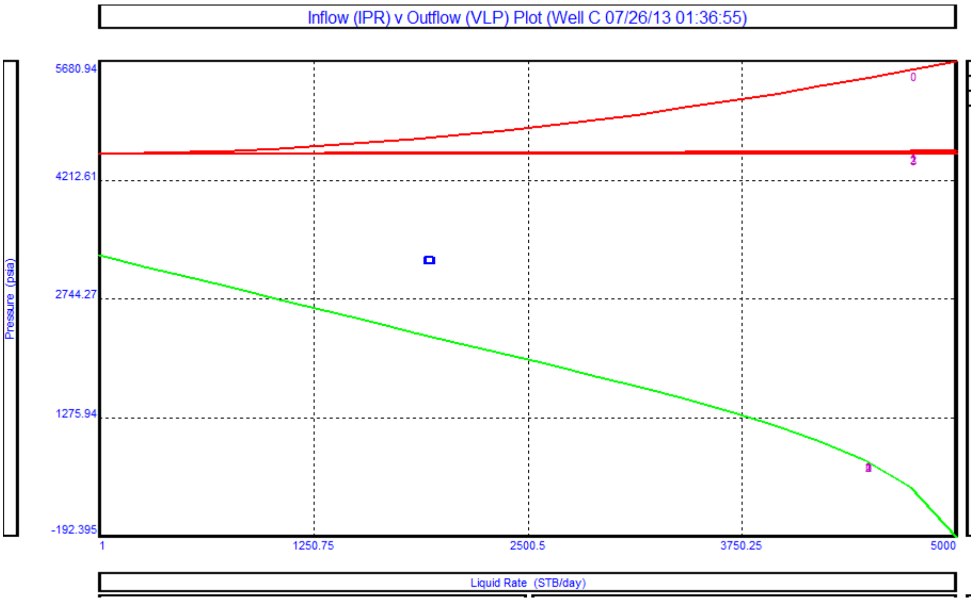


Figure 58: IPR VS VLP for Changing Tubing Size before using Gas Lift and ESP

Tubing Size ID (in)	Oil rate (stb/day)
2	0
4	0
6	0
8	0

Table 63: Oil rate at various Tubing Internal Diameter Sizes before using Gas Lift and ESP

4.3.10.2.2 Well C after using Gas Lift

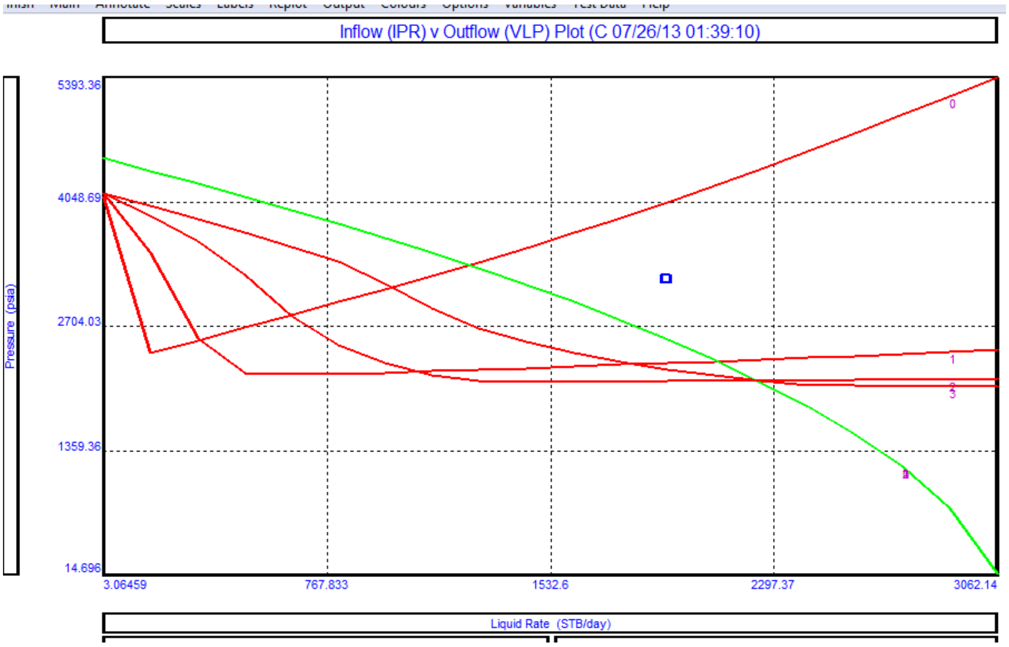


Figure 59: IPR VS VLP for changing Tubing Size after using Gas Lift

Tubing Size ID (in)	Oil rate (stb/day)
2	2056.6
4	2183.7
6	2207.5
8	2250.8

Table 64: Oil Rate at various Tubing Internal Diameter Size after using Gas Lift

4.3.10.2.3 Well C after Using ESP

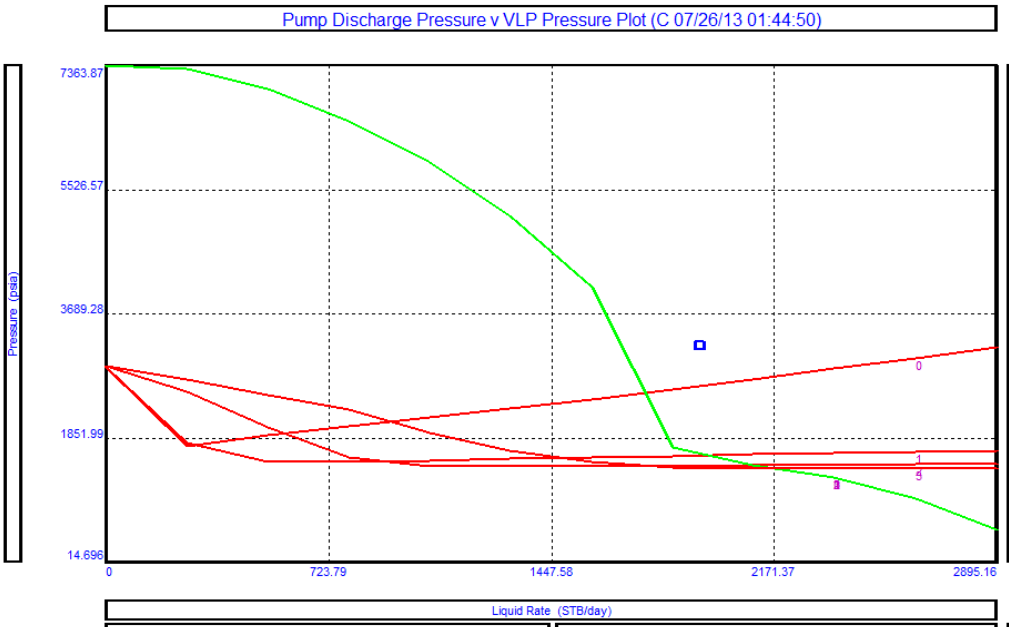


Figure 60: Pump Discharge Pressure/ VLP for changing Tubing Size after using ESP

Tubing Size ID (in)	Oil rate (stb/day)
2	1752.9
4	1958.7
6	2110.4
8	2175

Table 65: Oil Rate at Various Tubing Internal Diameter Size after using ESP

4.3.10.2.4 Overview

It is observed that by changing various sizes of tubing internal diameter (ID), the oil rates increment obtained are small and not too much significant. Thus, it is not recommended to change the tubing size in this well.

4.3.10.3 Changing Artificial Lift Method Parameter

4.3.10.3.1 Changing Gas Injection Rate Gas Lift

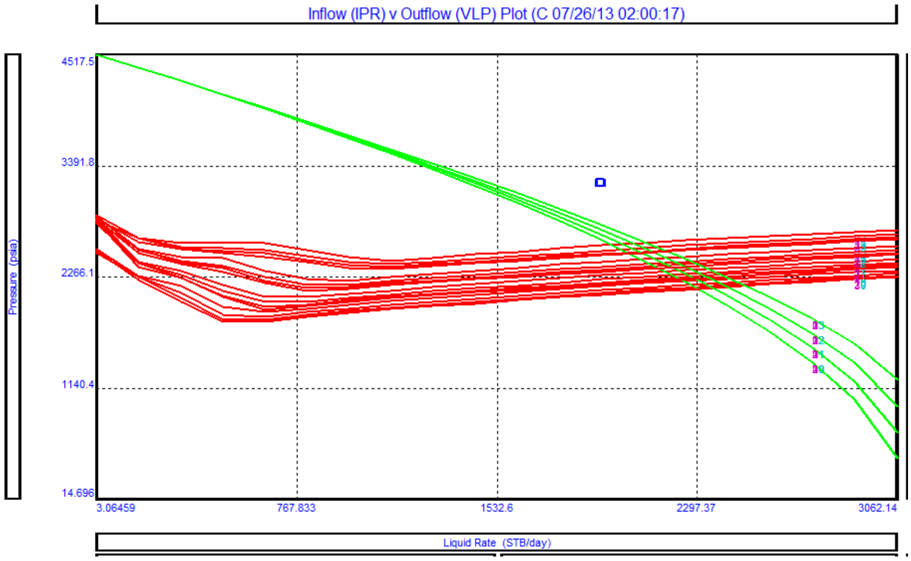


Figure 61: IPR VS VLP for changing Gas Lift Rate

Gas Injection (MMscf/day)	**Water Cut (%)**			
	20	33	46	60
	Oil Rate (stb/d)			
4	1800.6	1484.4	1163.6	842.6
6	1819.9	1504.3	1182.2	858.8
8	1832.5	1516.7	1194.4	869.2
10	1840.8	1524.9	1202.3	875.1

Table 66: Oil Rate with various Gas Injection Rates

It is observed that increase in gas injection rate gas lift will result increase in oil rate production.

4.3.10.3.2 Changing Pump Operating Frequency ESP

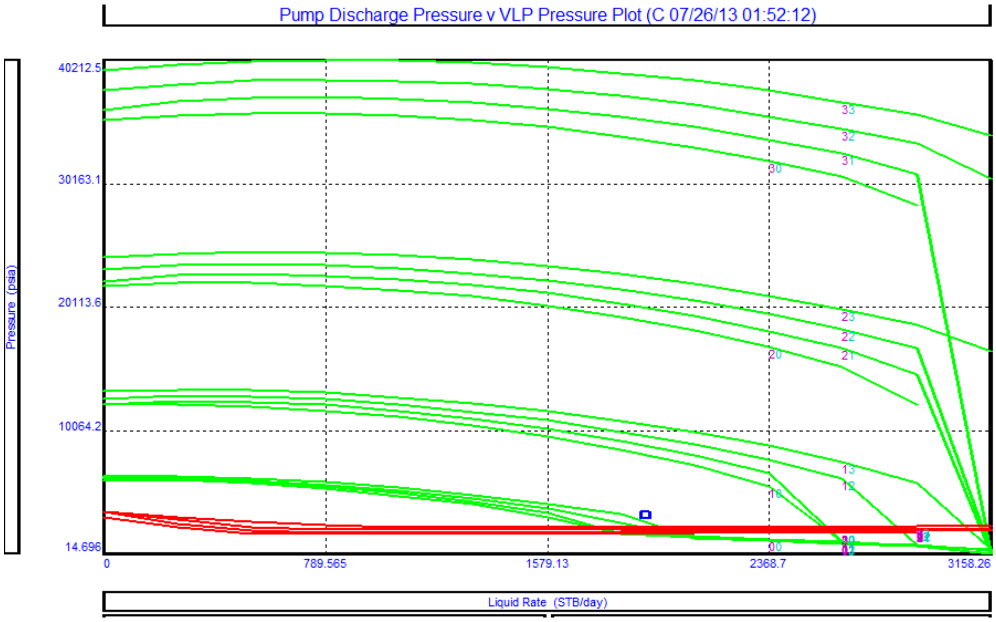


Figure 62: Pump Discharged Pressure/VLP for changing Pump Operating Frequency

Pump Operating Frequency	**Water Cut (%)**			
	20	33	46	60
	Oil Rate (stb/d)			
50	1468.3	1208.4	1044.5	790.5
83	2070.5	1726.9	1510	1226.4
116	2347.7	2083.3	1669.1	1457.5
150	2379.6	2095	1773	1678.3

Table 67: Oil Rate with Various Pump Injection Rates

It is observed that increase in pumps operating frequency ESP will result increase in oil rate production.

4.3.11 Well D

Well D was completed in 1982 as an oil producer. POSPER software is used to predict the well performance. Fluid data (PVT), reservoir data (IPR) and down hole equipment description (VLP) are provided. The following is the system summary for oil well D:

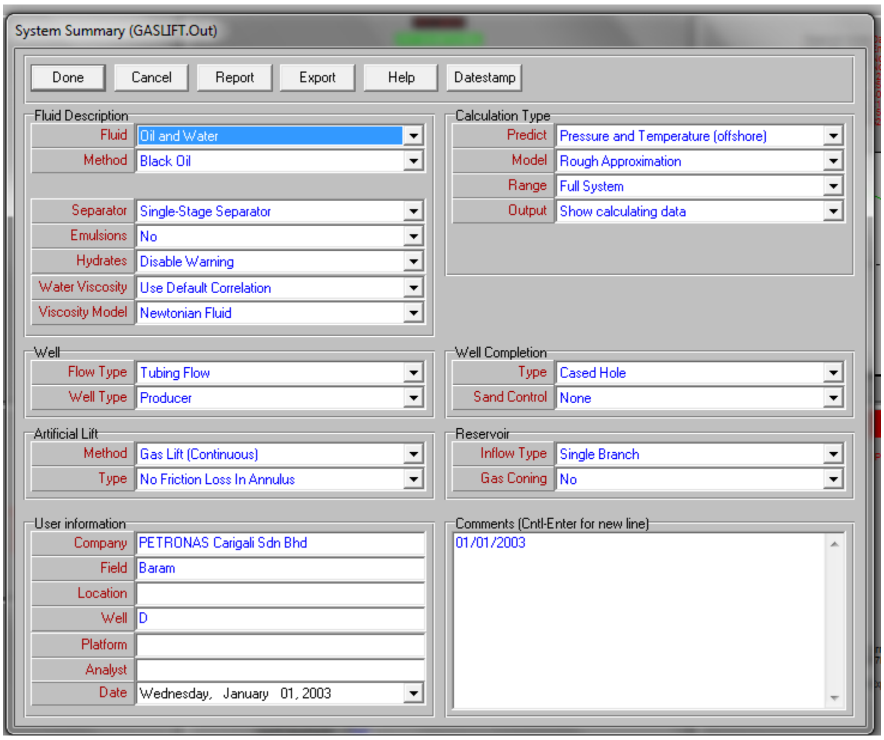


Figure 63: System Summary

4.3.11.1 Input Technical Data

4. PVT Lab Data and Well Test Data

Parameter	Value
Solution GOR	820 scf/stb
Oil Gravity	34 API
Gas Gravity	0.833
Water Salinity	150000 ppm
Impurities (CO2, N2, H2S)	None
Bubble Point Pressure	3256 psia
Temperature	210 deg F

Table 68: PVT Input Data

Pressure (psia)	Gas Oil Ratio (scf/stb)	Oil FVF (rb/stb)	Oil viscosity (centipoises)
3256	820	1.491	0.435

Table 69: PVT Lab Data

Parameter	Value
Tubing Head Pressure	250 psia
Tubing Head Temperature	134 deg F
Water Cut	15 %
Liquid Rate	9500 stb/d
Gauge Depth Measured	11000 feet
Gauge Pressure	2750 psia
Reservoir Pressure	4000 psia
GOR	820 scf/stb

Table 70: Well Test Data

5. VLP Input Data

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

Table 71: Deviation Survey

Equipment Type	Measured Depth (ft)	Internal Diameter (in)	Roughness (in)	Rate Multiplier
Xmas Tree (Well Head)	0	N/A	N/A	N/A
Tubing	1000	3.958	0.0006	1
SSSV	N/A	3	N/A	1

Tubing	11000	3.958	0.0006	1
Casing	11400	6	0.0006	1

Table 72: Downhole Equipment

Measured Depth (ft)	**Static Temperature (deg F)**
0	45
11400	210

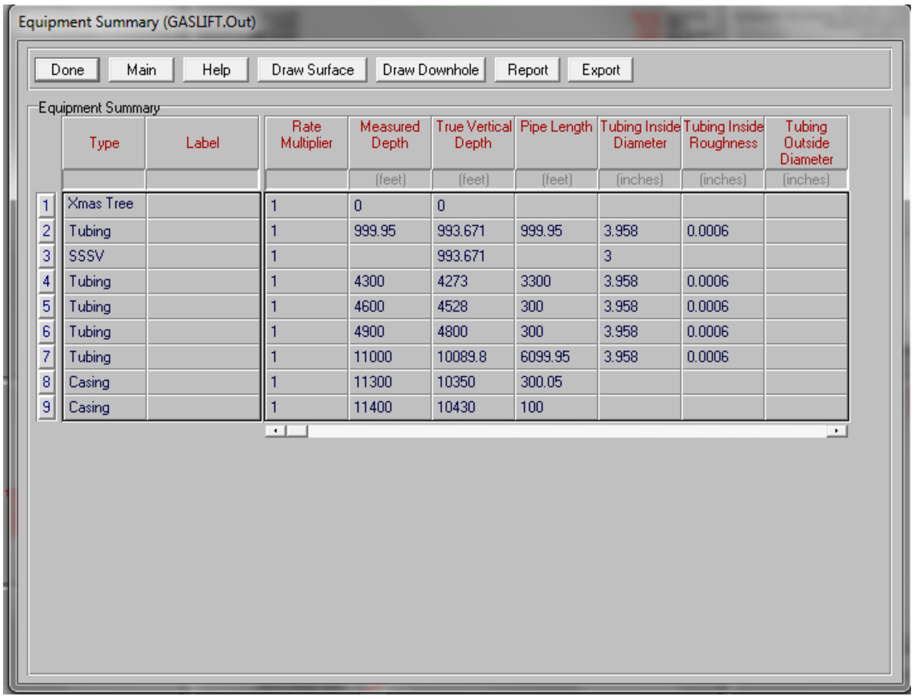
Table 73: Geothermal Gradient

6. IPR Input Data

IPR Model	Darcy
Reservoir Pressure	4000 psia
Reservoir Temperature	210 deg F
Water Cut	80%
Total GOR	820 scf/stb
Compaction Permeability Reduction Model	No
Relative Permeability	No
Reservoir Permeability	50 md
Reservoir Thickness	200feet
Drainage Area	500 acres
Dietz shape factor	31.6
Wellbore radius	0.354 inches
Mechanical Skin	4

Table 74: IPR Input Data

To summarize, the following figure are the system summary of the input data for well D:



Equipment Summary (GASLIFT.Out)

Done | Main | Help | Draw Surface | Draw Downhole | Report | Export

Equipment Summary

	Type	Label	Rate Multiplier	Measured Depth	True Vertical Depth	Pipe Length	Tubing Inside Diameter	Tubing Inside Roughness	Tubing Outside Diameter
				(feet)	(feet)	(feet)	(inches)	(inches)	(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			
9	Casing		1	11400	10430	100			

Figure 64: Equipment Summary

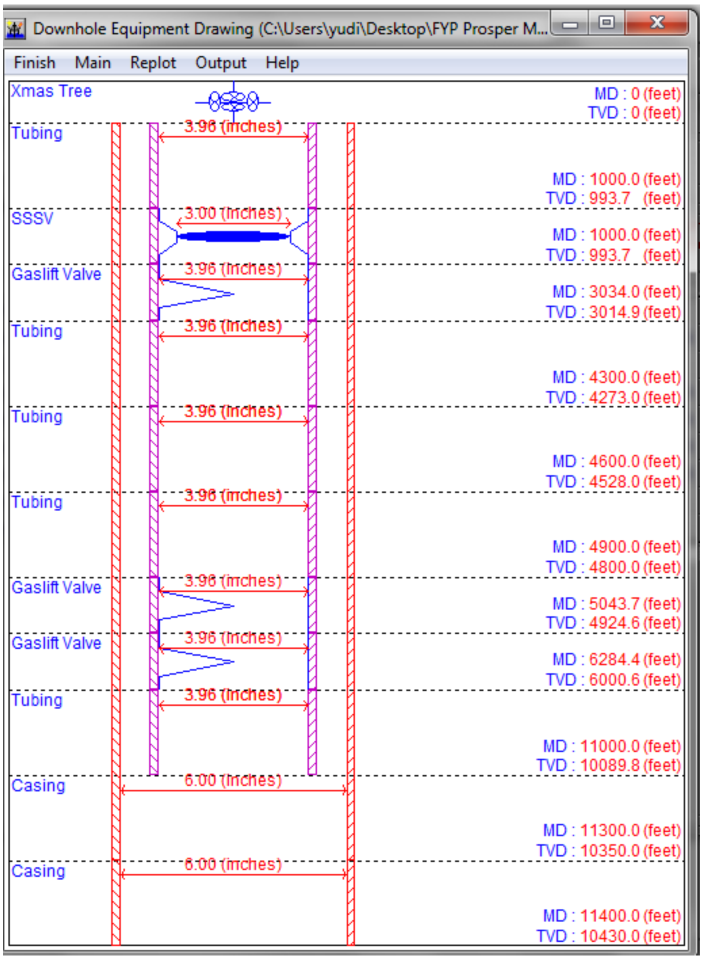


Figure 65: Downhole Equipment

Inflow Type Single Branch
Completion Cased Hole
Sand Control None
Gas Coning No

Reservoir Model Darcy

M&G Skin Model Enter Skin By Hand
Compaction Permeability Reduction Model No
Relative Permeability No
Formation PI 12.60 (STB/day/psi)
Absolute Open Flow (AOF) 21827.2 (STB/day)
Reservoir Pressure 4000.00 (psig)
Reservoir Temperature 210.00 (deg F)
Water Cut 15.000 (percent)
Total GOR 820.00 (scf/STB)
Reservoir Permeability 50.00 (md)
Reservoir Thickness 200.0 (feet)
Drainage Area 500.0 (acres)
Dietz Shape Factor 31.6
Wellbore Radius 0.354 (feet)
Skin 4

Figure 66: IPR Summary

4.3.11.2 Generate the IPR Curve

A well's inflow performance relationship defines its production potential. In this well D, the IPR is expressed as the following figure:

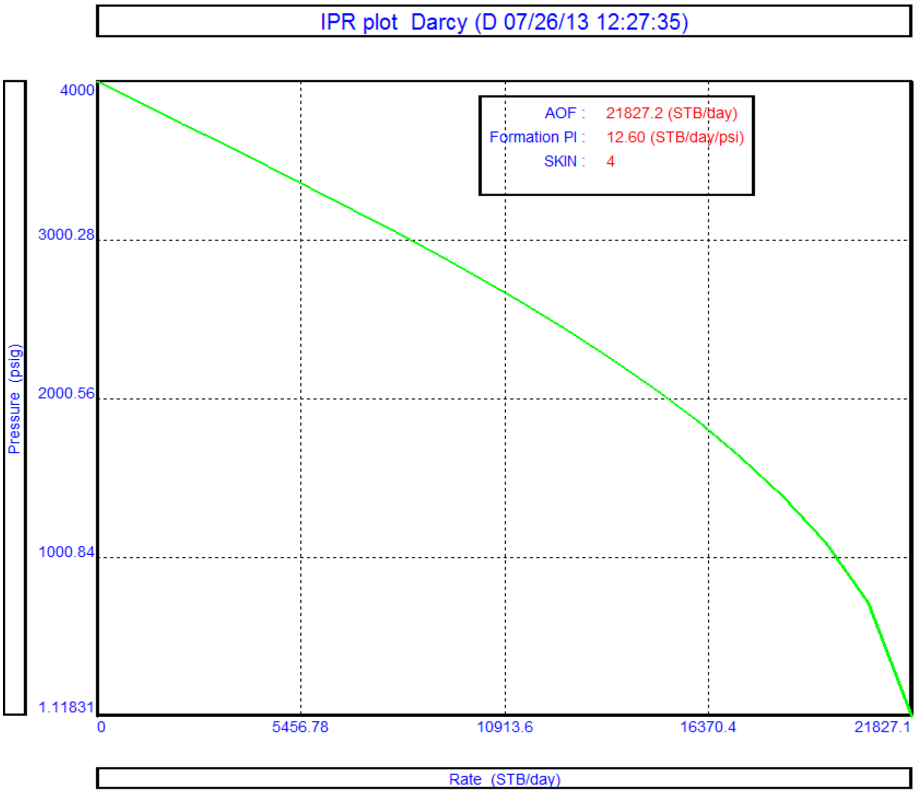


Figure 67: IPR Plot

In this example of well D, it can be observed that the Absolute Open Flow potential (AOF) is around 21827.2 stb/day. This AOF indicates that the maximum production rate is achieved when the bottomhole pressure approaches zero.

In addition, the productivity index in this well D is computed as 12.60 stb/day/psi. This production index indicates the ratio of production rate in well D to its drawdown pressure.

Apart from that, it is observed that the mechanical skin is shown as 4. This positive skin denotes as any phenomenon that causes a distortion of the flow lines from the perfectly normal to the flow direction or a restriction to flow. The causes of positive skin is normally mechanical causes (partial completion, inadequate number of perforations), phase changes (reduction of relative permeability of the desired fluid), turbulence and damage to the natural reservoir permeability

4.3.11.3 Perform PVT Matching

In this example of well D, the PVT matching can be summarized as figures below:

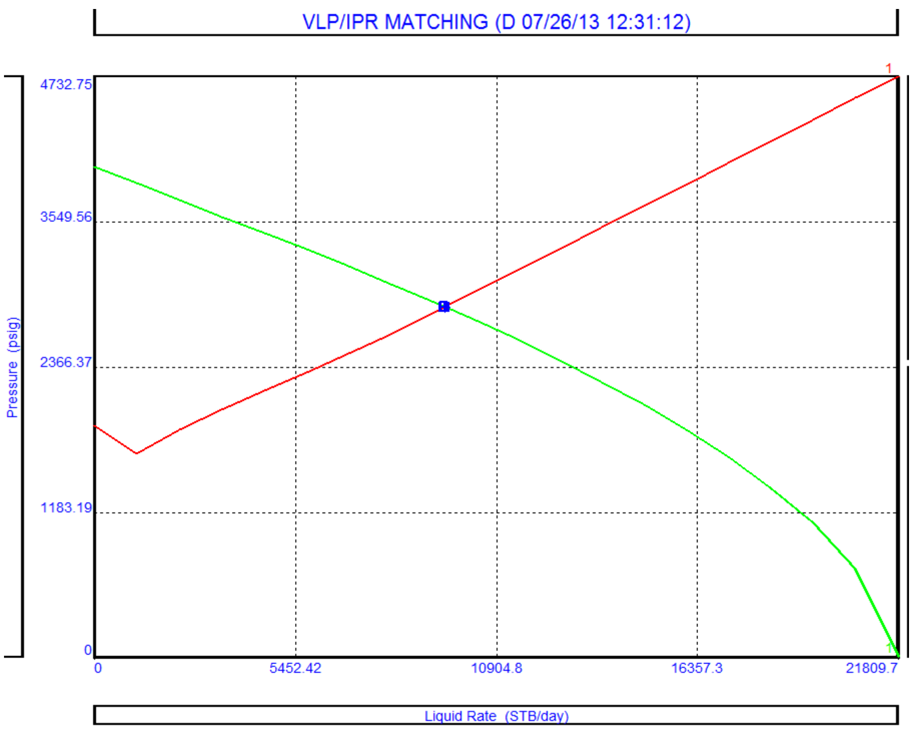


Figure 68: VLP/PVT Matching

	LIQUID RATE (STB/day)			BOTTOM HOLE PRESSURE (psig)		
	Measured	Calculated	% Difference	Measured	Calculated	% Difference
1	9500.0	9517.7	0.18664	2852.74	2855.46	0.09532

Figure 69: VLP/PVT Matching Correlation

As per shown in the figure above, there are only 0.18664% difference between measured liquid rate and simulated liquid rate whereas for bottom hole pressure, the difference is only 0.09532%. This percentage is less than 1%, thus the percentage difference is considered small and acceptable. Therefore, the well model is validated and eligible for further analysis.

4.3.12 Simulate Base Case Forecast under Various Operating Conditions

In this example of well D, the maximum economic water cut is set to be maximum 90% in a range of reservoir pressure between 4000 psia - 7000 psia. In the oil production as the time goes by, the water cut is increasing meanwhile the reservoir pressure is declining. The oil rate targeted is set to be produced at its economic rate (1500 stb/d) and any oil rate below than that will not be further considered or investigated.

To summarize, the following table are the oil rates obtained from this base case analysis:

Parameter	Range
Reservoir Pressure (psia)	4000, 5000, 6000, 7000
Water Cut (%)	60, 70, 80, 90

4.3.12.1 *Well D before Using Gas Lift and* ESP

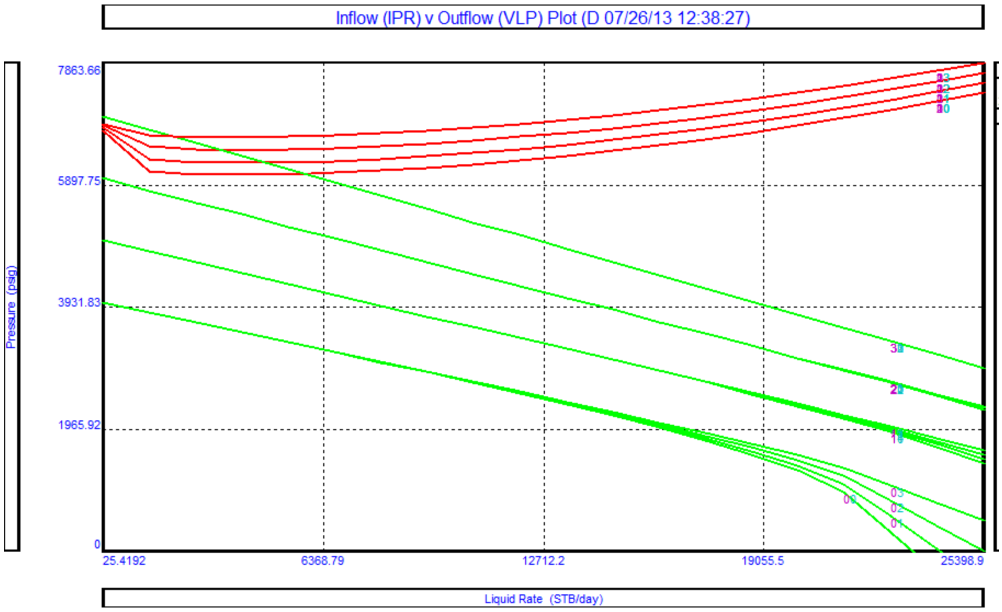


Figure 70: IPR VS VLP before using Gas Lift and ESP

Reservoir Pressure (psia)	Water Cut (%)			
	60	70	80	90
	Oil Rate (stb/d)			
7000	2327.6	1409.6	685.7	200.5
6000	0	0	0	0
5000	0	0	0	0
4000	0	0	0	

Table 75: Oil Rates Produced before Using Gas Lift and ESP

4.3.12.2 Well D after Using Gas Lift

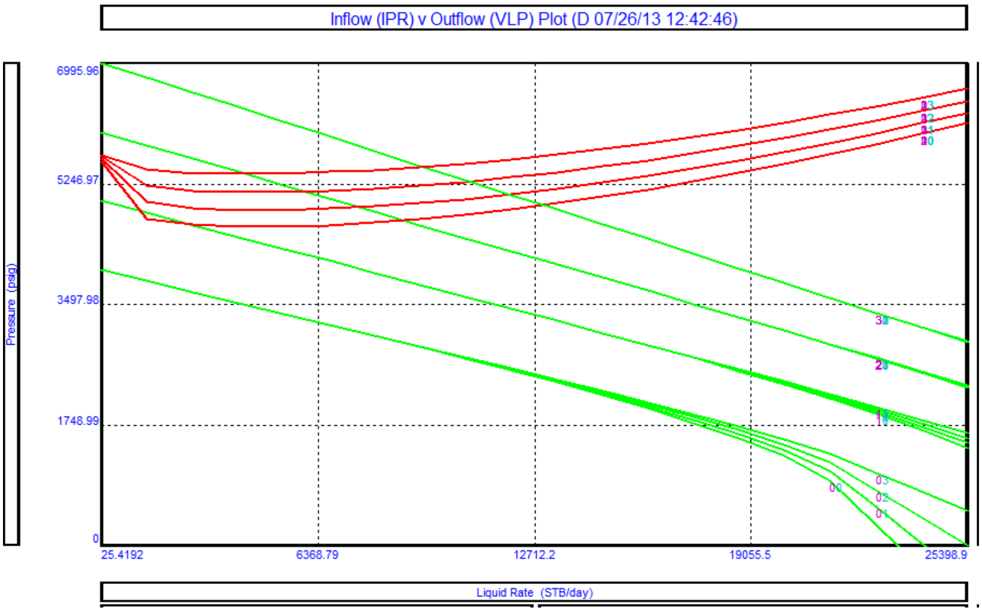


Figure 71: IPR VS VLP after Using Gas Lift

Reservoir Pressure (psia)	Water Cut (%)			
	60	70	80	90
	Oil Rate (stb/d)			
7000	4188.0	3596.9	2146.4	947.5
6000	3571.2	2282.7	1207.7	424.1
5000	1060.7	0	0	0
4000	0	0	0	0

Table 76: Oil Rates Produced after Using Gas Lift

4.3.12.3 *Well D after Using* ESP

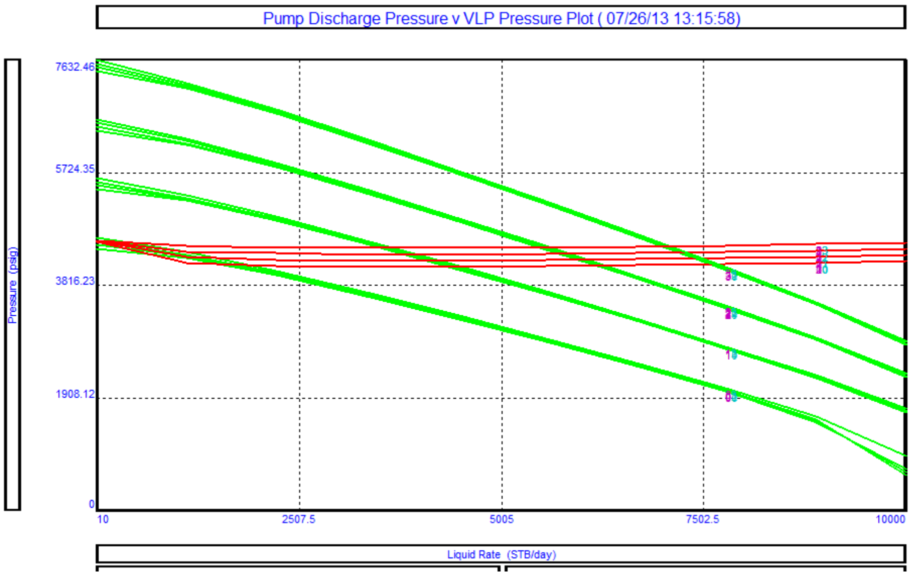


Figure 72: Pump Discharge Pressure VS VLP Pressure Plot

Reservoir Pressure (psia)	**Water Cut (%)**			
	60	70	80	90
	Oil Rate (stb/d)			
7000	3951.5	2897.2	1878.6	906.9
6000	3586.5	2605.9	1668.0	792.9
5000	3080.5	2201.1	1381.9	640.2
4000	2383.5	1654.1	994.8	436.4

Table 77: Oil Rates Produced after Using ESP

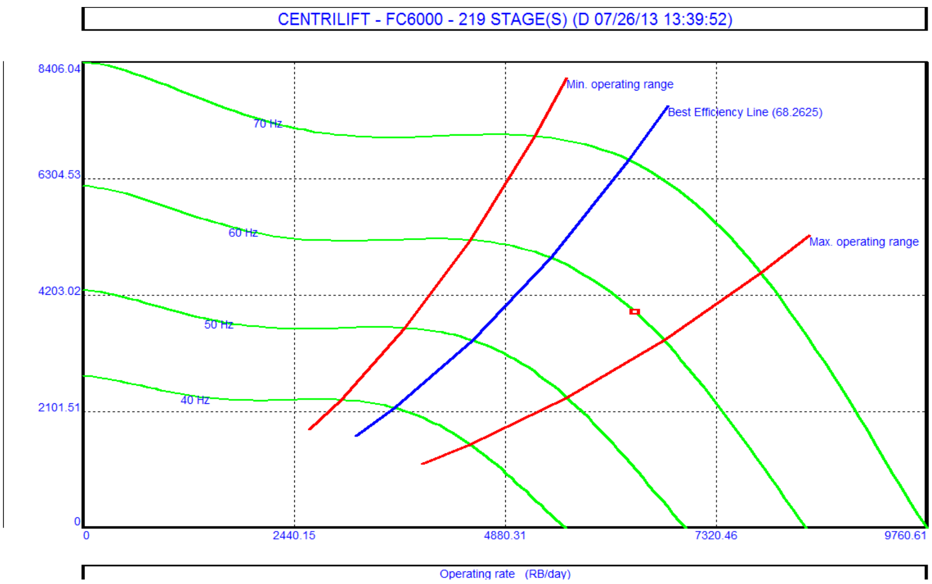


Figure 73: Pump Performance Curve

Pump performance curve describes the relation between flow rate and head for the actual pump. In this well D, the best efficiency line for pump performance curve is calculated as 68.2625.

4.3.12.4 Overview

To summarize, the following table provides detailed information for each base case scenario:

Scenario	Minimum Economic Production Rate Produced	Maximum Economic Production Rate Produced
Without gas lift and ESP	200.5 stb/d at 7000 psia with 90 %WC	2327.6 stb/d at 7000 psia with 60 %WC
With Gas Lift	1060.7 stb/d at 5000 psia with 60 %WC	4188.0 stb/d at 7000 psia with 60 %WC
With ESP	436.4 stb/d at 4000 psia with 90% WC	3951.5 stb/d at 7000 psia with 60% WC

Table 78: Economic Base Case Condition

4.3.13 Evaluate Various Development Options to Optimize Oil Production

To summarize, the operating rates produced by each analysis are provided in the following table.

Parameter	Range
Wellhead Pressure (psia)	500, 1000, 1500, 2000
Tubing Diameter (in)	2, 3.3, 4.6, 6
Water Cut (%)	60, 70, 80, 90
Gas Lift gas Injection Rate (MMscf/day)	2, 3, 4, 5
Pump Operating Frequency (Hertz)	60, 65, 70, 75

Table 79: Range of Parameter Base Scenario

4.3.13.1 Changing Wellhead Pressure (WHP)

4.3.13.1.1 Well D before Using Gas Lift and ESP

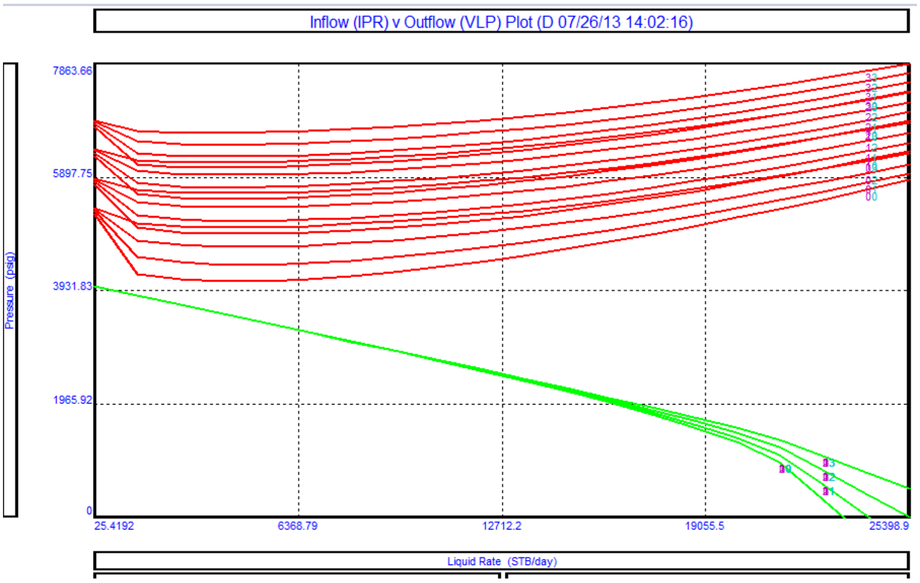


Figure 74: IPR VS VLP for Changing WHP before Using Gas Lift and ESP

WHP (psia)	**Water Cut (%)**			
	60	70	80	90
	Oil Rate (stb/d)			
2000	0	0	0	0
1500	0	0	0	0
1000	0	0	0	0
500	0	0	0	0

Table 80: Oil Rates at different WHP before Using Gas Lift and ESP

4.3.13.2 Well D after using Gas Lift

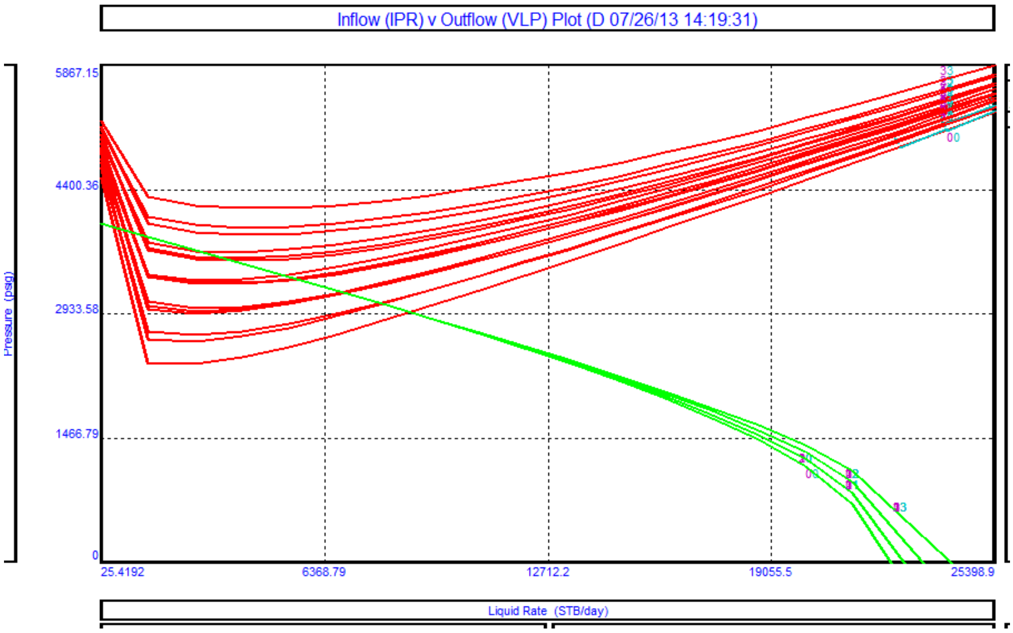


Figure 75: IPR VS VLP for Changing WHP after Using Gas Lift

WHP (psia)	**Water Cut (%)**			
	60	70	80	90
	Oil Rate (stb/d)			
2000	3335.6	1843.0	0	0
1500	4138.9	2798.3	1362.9	0
1000	4776.2	3475.0	2193.9	828.8
500	5286.3	4004.3	2756.9	1543.6

Table 81: Oil Rates at different WHP after Using Gas Lift

4.3.13.2.1 Well D after Using ESP

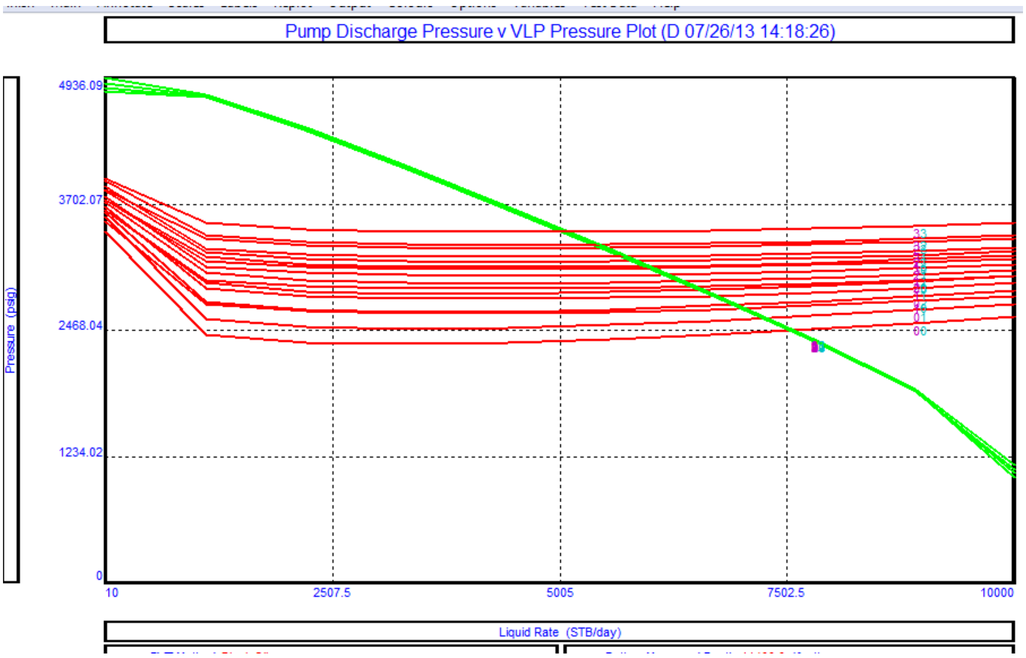


Figure 76: Pump Discharge Pressure VS VLP for Changing WHP after Using ESP

WHP (psia)	**Water Cut (%)**			
	60	70	80	90
	Oil Rate (stb/d)			
2000	4180.5	3419.9	2706.3	2045.2
1500	4512.8	3691.7	2922.8	2210.7
1000	4893.4	4016.8	3176.8	2398.5
500	5276.4	4355.4	3473.4	2636.4

Table 82: Oil Rates at different WHP after Using Gas Lift

4.3.13.3 Overview

As per shown in the figures and tables above, it is observed that by changing wellhead pressure from 500 to 2000 psia, the operating rates produced become higher. However, when the water cut is increasing to maximum 90%, the oil rates obtained are decreasing.

4.3.13.4 Changing Tubing Size

4.3.13.4.1 Well D before Using Gas Lift and ESP

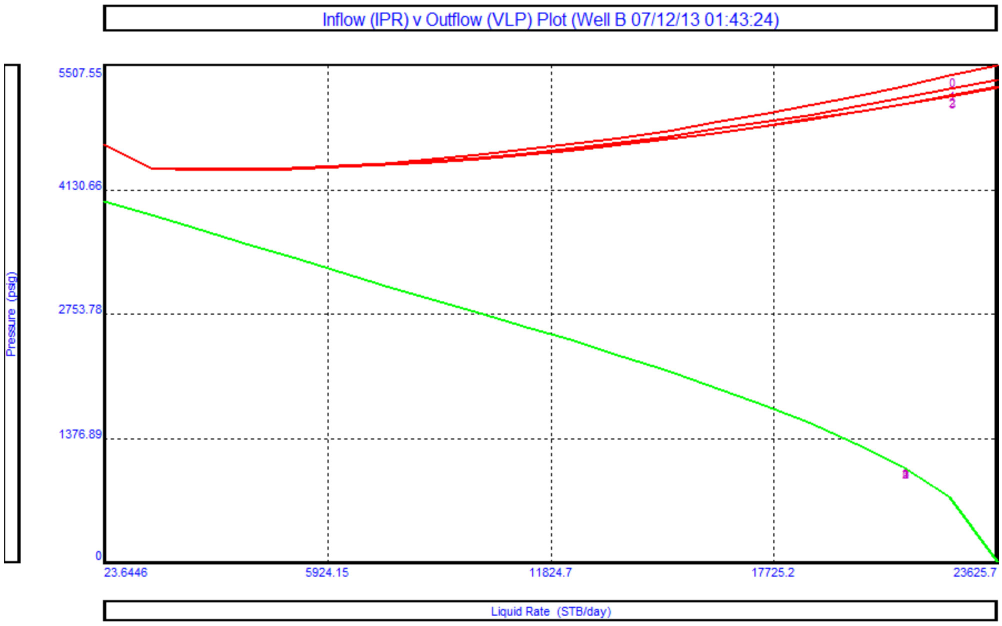


Figure 77: IPR VS VLP for Changing tubing Size before Using Gas Lift and ESP

Tubing Size ID (in)	Oil rate (stb/day)
2	0
3.3	0
4.6	0
6	0

Table 83: Oil Rate at Various Tubing Internal Diameter Sizes before Using Gas Lift and ESP

4.3.13.5 Well D after Using Gas Lift

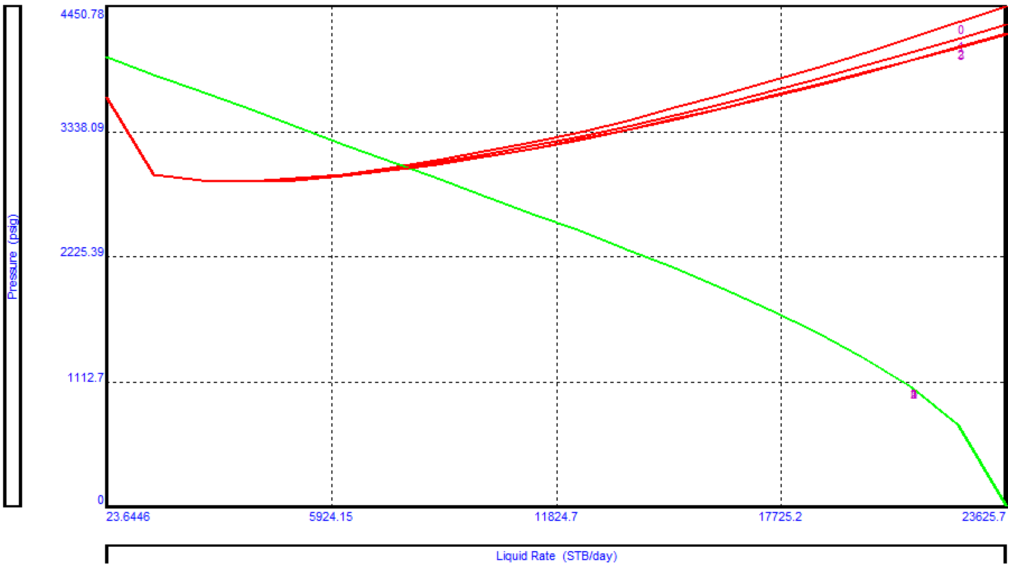


Figure 78: IPR VS VLP for Changing tubing Size after Using Gas Lift

Tubing Size ID (in)	Oil rate (stb/day)
2	2434.2
3.3	2518.5
4.6	2563.7
6	2571.4

Table 84: Oil Rate at Various Tubing Internal Diameter Sizes after Using Gas Lift

4.3.13.6 Well D after using ESP

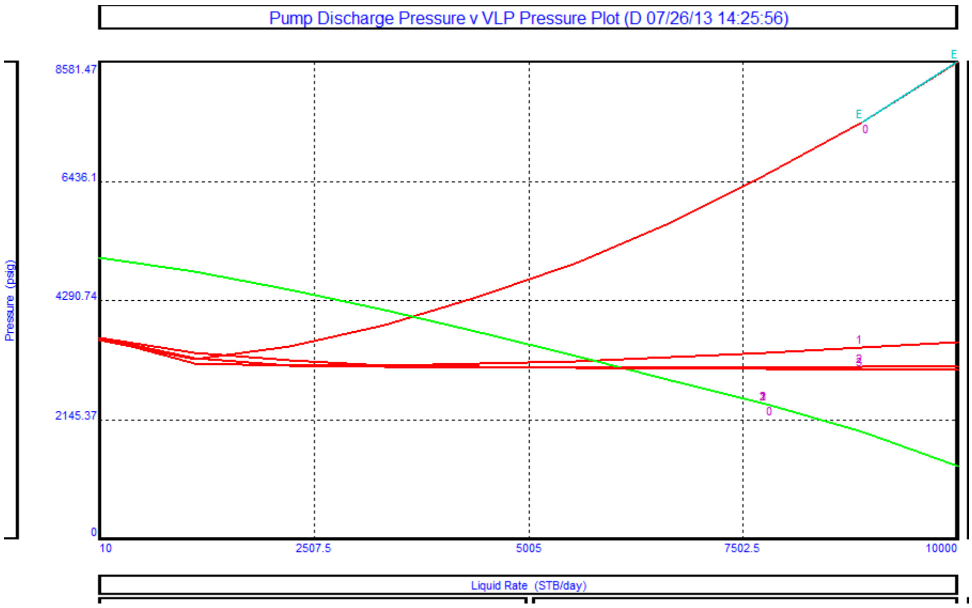


Figure 79: Pump Discharge Pressure VS VLP Pressure after using ESP

Tubing Size ID (in)	Oil rate (stb/day)
2	2032.3
3.3	2150.0
4.6	2224.8
6	2228.3

Table 85: Oil Rate at Various Tubing Internal Diameter Sizes after Using ESP

4.3.13.7 Overview

It is observed that by changing various sizes of tubing internal diameter (ID), the oil rates increment obtained are small and not too much significant. Thus, it is not recommended to change the tubing size in this well.

4.3.13.8 Changing Artificial Lift Method Parameter

4.3.13.8.1 Changing Gas Injection Rate Gas Lift

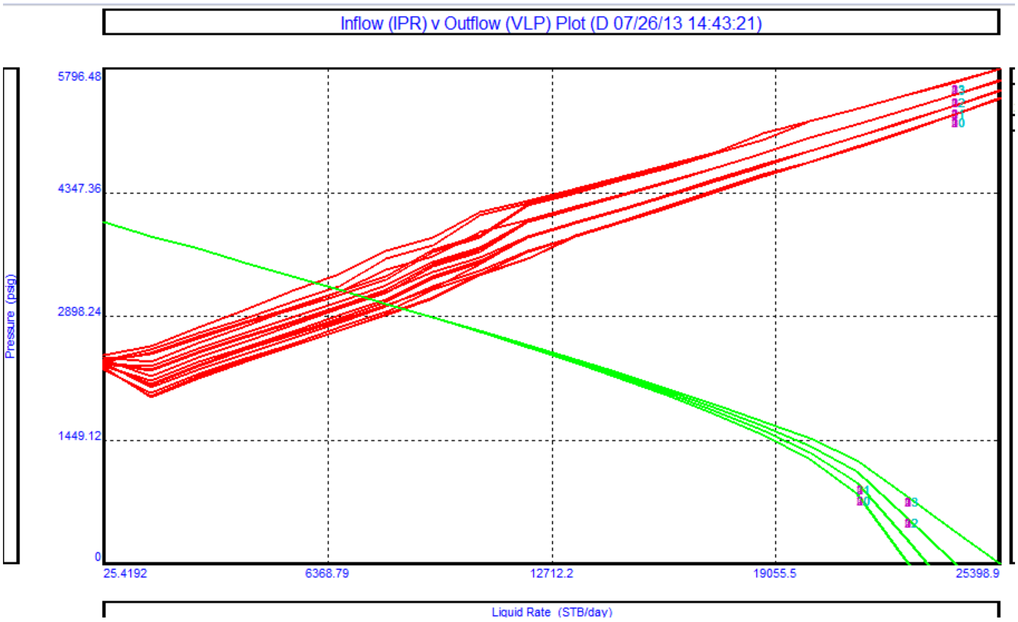


Figure 80: IPR VS VLP for Changing Gas Lift Rate

Gas Injection (MMscf/day)	Water Cut (%)			
	60	70	80	90
	Oil Rate (stb/d)			
2	4078.3	3018.5	2038.4	1202.9
3	4161.5	3134.9	2166.5	1306.4
4	4243.0	3197.8	2232.3	1363.6
5	4271.5	3235.2	2266.2	1393.1

Table 86: Oil Rate with Various Gas Injection Rates

It is observed that increase in gas injection rate gas lift will result increase in oil rate production.

4.3.13.8.2 Changing Pump Operating Frequency ESP

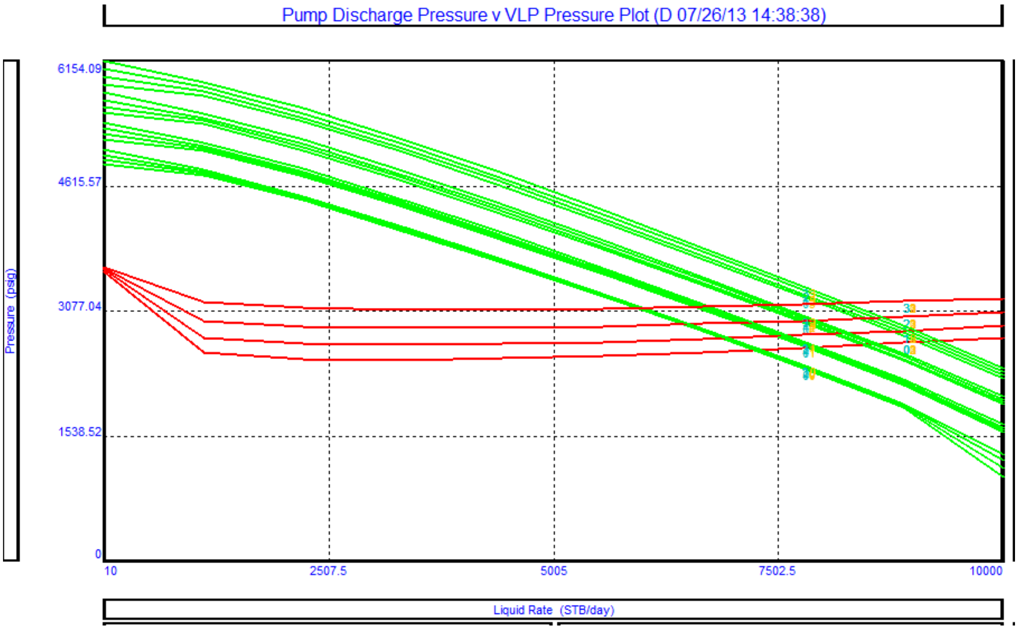


Figure 81: Pump Discharged Pressure/VLP for changing Pump Operating Frequency

Pump Operating Frequency	**Water Cut (%)**			
	60	70	80	90
	Oil Rate (stb/d)			
60	3617.3	2758.0	1948.1	1202.8
65	3913.4	3008.3	2149.8	1349.8
70	4213.5	3266.4	2359.4	1499.0
75	4526.0	3535.6	2572.1	1651.2

Table 87: Oil Rate with Various Pump Injection Rates

It is observed that increase in pumps operating frequency ESP will result increase in oil rate production.

4.3.14 Well E

Well E was completed in 1976 as an oil producer. POSPER software is used to predict the well performance. Fluid data (PVT), reservoir data (IPR) and down hole equipment description (VLP) are provided. The following is the system summary for oil well E:

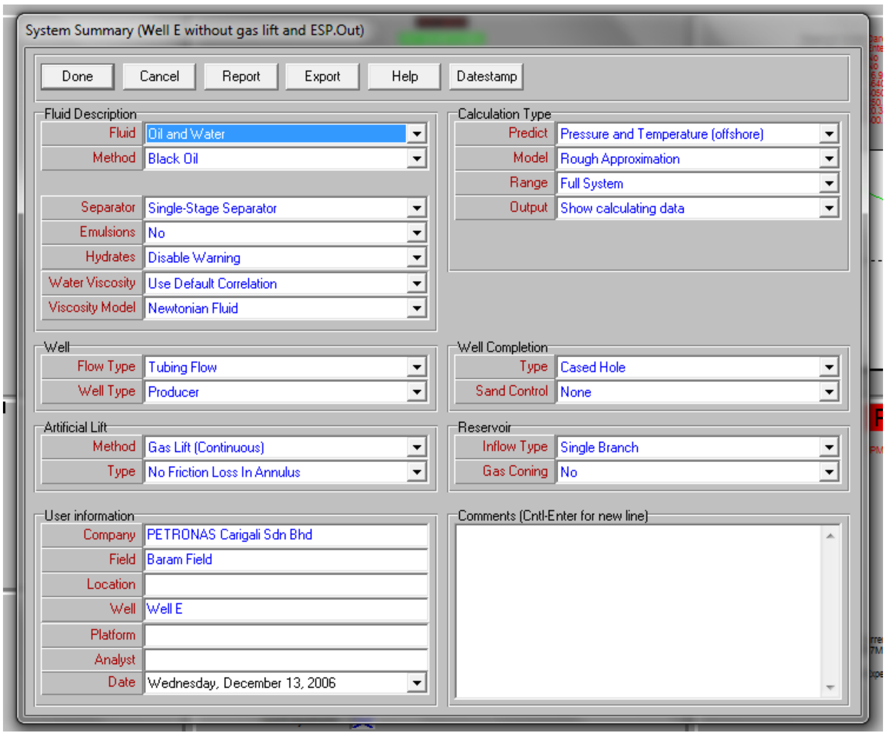


Figure 82: System Summary

4.3.14.1 Input Technical Data

7. PVT Lab Data and Well Test Data

Parameter	Value
Solution GOR	500 scf/stb
Oil Gravity	39 API
Gas Gravity	0.798
Water Salinity	100000 ppm
Impurities (CO2, N2, H2S)	None
Bubble Point Pressure	3256 psia
Temperature	210 deg F

Table 88: PVT Input Data

Pressure (psia)	Gas Oil Ratio (scf/stb)	Oil FVF (rb/stb)	Oil viscosity (centipoises)
2200	500	1.32	0.4

Table 89: PVT Lab Data

Parameter	Value
Tubing Head Pressure	264 psia
Tubing Head Temperature	132.8 deg F
Water Cut	5 %
Liquid Rate	6161 stb/d
Gauge Depth Measured	14800 feet
Gauge Pressure	3382 psia
Reservoir Pressure	2600 psia
GOR	500 scf/stb

Table 90: Well Test Data

8. VLP Input Data

Measured Depth (ft)	True Vertical Depth (ft)
0	0
1000	1000
2500	2405
6500	5322
15200	11500

Table 91: Deviation Survey

Equipment Type	Measured Depth (ft)	Internal Diameter (in)	Roughness (in)	Rate Multiplier
Xmas Tree (Well Head)	0	N/A	N/A	N/A
Tubing	14500	3.96	0.0006	1
Casing	15200	6	0.0006	1

Table 92: Downhole Equipment

Measured Depth (ft)	Static Temperature (deg F)
0	50
15200	250

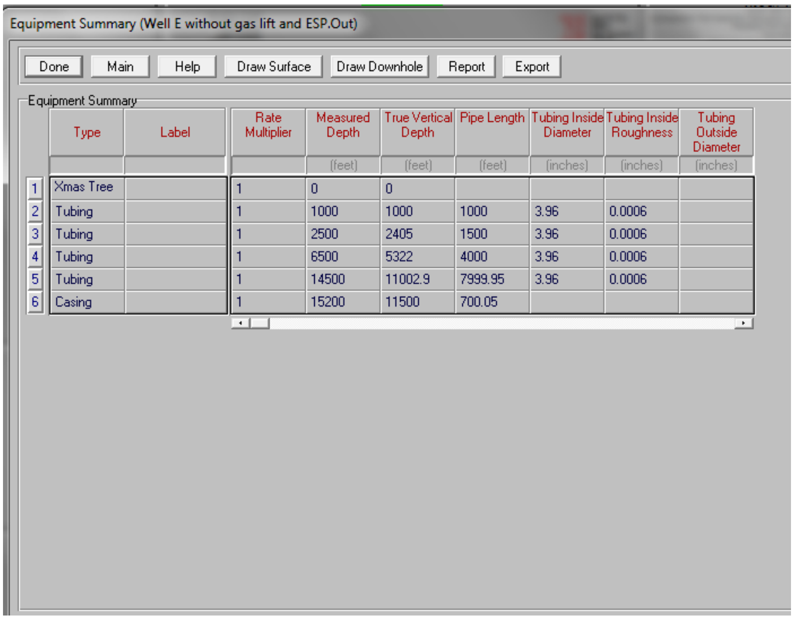
Table 93: Geothermal Gradient

9. IPR Input Data

IPR Model	Darcy
Reservoir Pressure	2600 psia
Reservoir Temperature	250 deg F
Water Cut	5%
Total GOR	500 scf/stb
Compaction Permeability Reduction Model	No
Relative Permeability	No
Reservoir Permeability	100 md
Reservoir Thickness	100feet
Drainage Area	100 acres
Dietz shape factor	31.6
Wellbore radius	0.354 inches
Mechanical Skin	0

Table 94: IPR Input Data

To summarize, the following figure are the system summary of the input data for well E:



Equipment Summary (Well E without gas lift and ESP.Out)

Done | Main | Help | Draw Surface | Draw Downhole | Report | Export

Equipment Summary

	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)
1	Xmas Tree		1	0	0				
2	Tubing		1	1000	1000	1000	3.96	0.0006	
3	Tubing		1	2500	2405	1500	3.96	0.0006	
4	Tubing		1	6500	5322	4000	3.96	0.0006	
5	Tubing		1	14500	11002.9	7999.95	3.96	0.0006	
6	Casing		1	15200	11500	700.05			

Figure 83: Equipment Summary

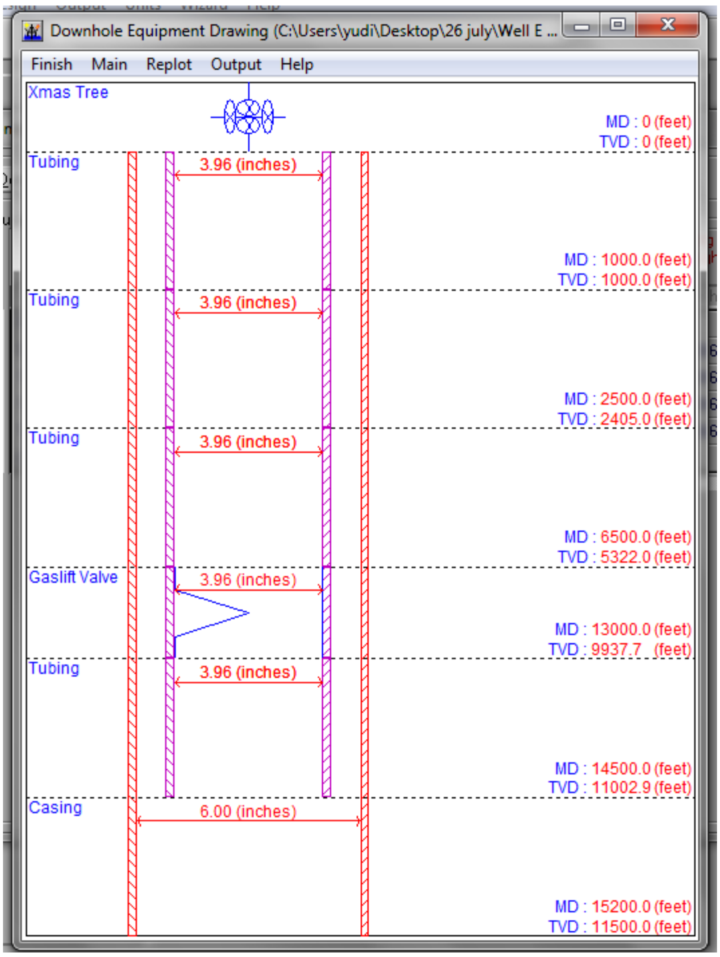


Figure 84: Downhole Equipment

Inflow Type	Single Branch
Completion	Cased Hole
Sand Control	None
Gas Coning	No
Reservoir Model	Darcy
M&G Skin Model	Enter Skin By Hand
Compaction Permeability Reduction Model	No
Relative Permeability	No
Formation PI	17.67 (STB/day/psi)
Absolute Open Flow (AOF)	28771.9 (STB/day)
Reservoir Pressure	2600.00 (psig)
Reservoir Temperature	250.00 (deg F)
Water Cut	5.000 (percent)
Total GOR	500.00 (scf/STB)
Reservoir Permeability	100.00 (md)
Reservoir Thickness	100.0 (feet)
Drainage Area	100.0 (acres)
Dietz Shape Factor	31.6
Wellbore Radius	0.354 (feet)
Skin	0

Figure 85: IPR Summary

4.3.14.2 Generate the IPR Curve

A well's inflow performance relationship defines its production potential. In this well E, the IPR is expressed as the following figure:

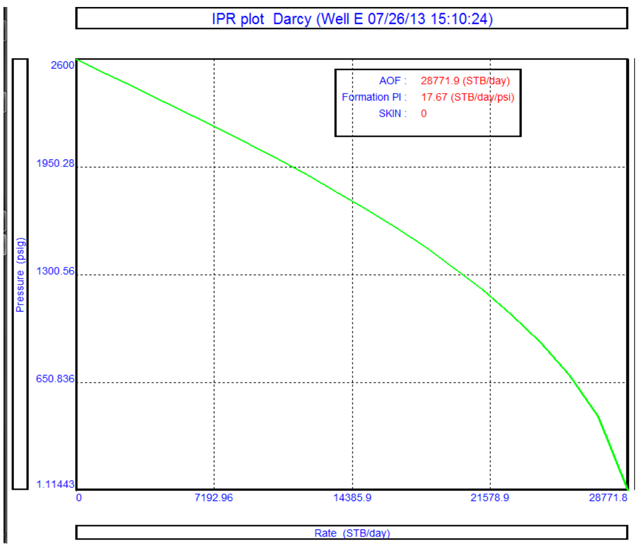


Figure 86: IPR Plot

In this example of well E, it can be observed that the Absolute Open Flow potential (AOF) is around 28771.9 stb/day. This AOF indicates that the maximum production rate is achieved when the bottomhole pressure approaches zero.

In addition, the productivity index in this well E is computed as 17.67 stb/day/psi. This production index indicates the ratio of production rate in well E to its drawdown pressure. Apart from that, it is observed that the mechanical skin is shown as 0.

4.3.14.3 Perform PVT Matching

In this example of well E, the PVT matching can be summarized as figures below:

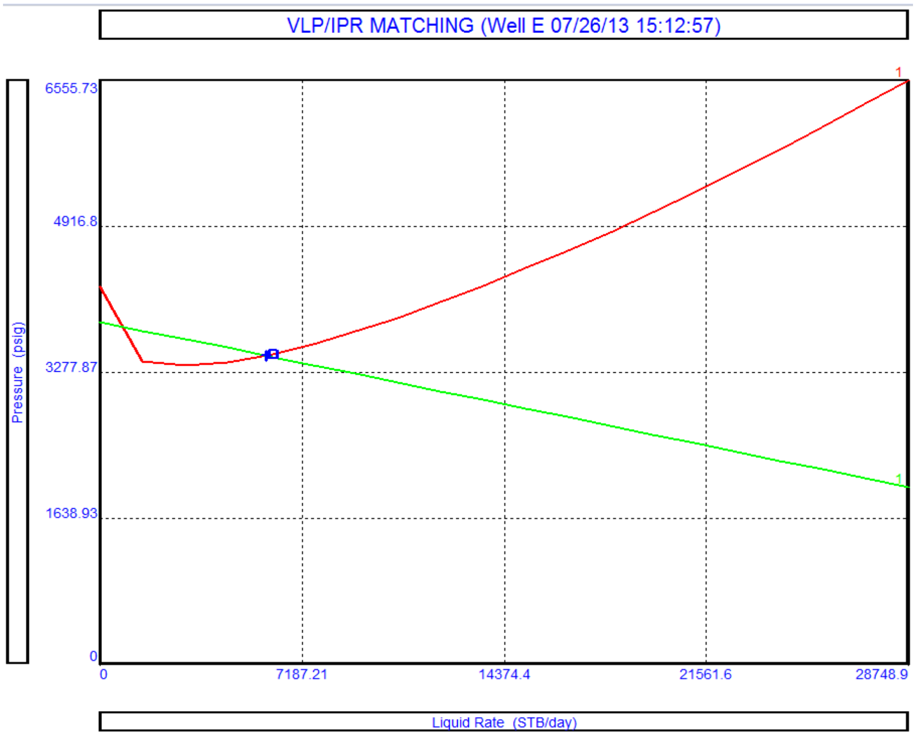


Figure 87: VLP/PVT Matching

LIQUID RATE (STB/day)			
	Measured	Calculated	% Difference
1	6161.0	5923.6	-3.85

BOTTOM HOLE PRESSURE (psig)			
	Measured	Calculated	% Difference
1	3476.16	3462.75	-0.38587

Figure 88: VLP/PVT Matching Correlation

As per shown in the figure above, there are -3.85% difference between measured liquid rate and simulated liquid rate whereas for bottom hole pressure, the difference is only -0.38587%. This percentage is considered small and acceptable. Therefore, the well model is validated and eligible for further analysis.

4.3.15 Simulate Base Case Forecast under Various Operating Conditions

In this example of well E, the maximum economic water cut is set to be maximum 30% in a range of reservoir pressure between 2000 psia - 5000 psia. In the oil production as the time goes by, the water cut is increasing meanwhile the reservoir pressure is declining. The oil rate targeted is set to be produced at its economic rate (1500 stb/d) and any oil rate below than that will not be further considered or investigated.

To summarize, the following table are the oil rates obtained from this base case analysis:

Parameter	Range
Reservoir Pressure (psia)	2000, 3000, 4000, 5000
Water Cut (%)	0, 10, 20, 30

4.3.15.1 Well E before Using Gas Lift and ESP

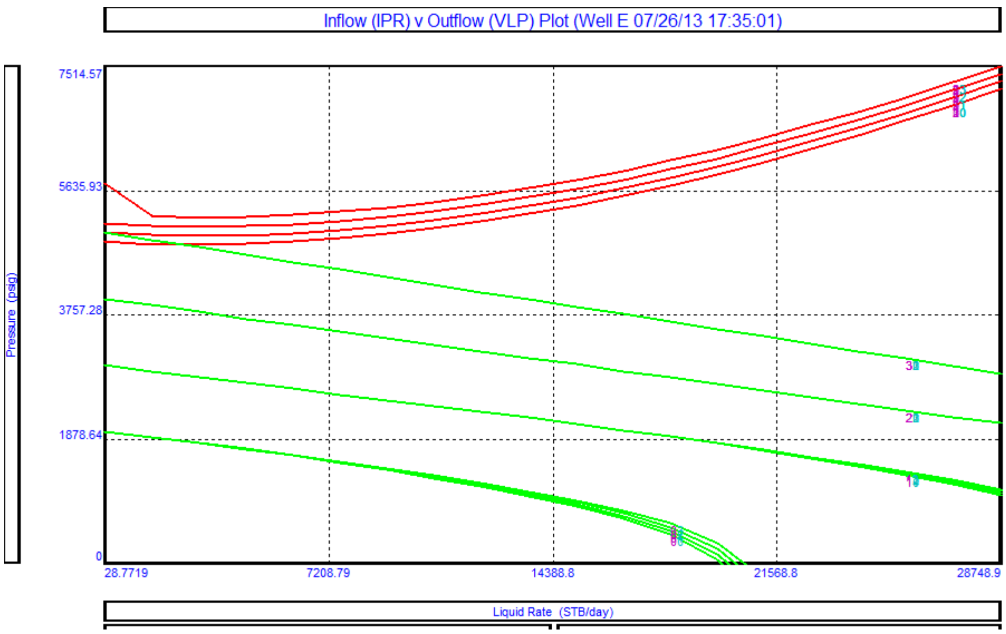


Figure 89: IPR VS VLP before using Gas Lift and ESP

Reservoir Pressure (psia)	Water Cut (%)			
	0	10	20	30
	Oil Rate (stb/d)			
5000	2405.6	0	0	0
4000	0	0	0	0
3000	0	0	0	0
2000	0	0	0	0

Table 95: Oil Rates Produced before Using Gas Lift and ESP

4.3.15.2 Well E after Using Gas Lift

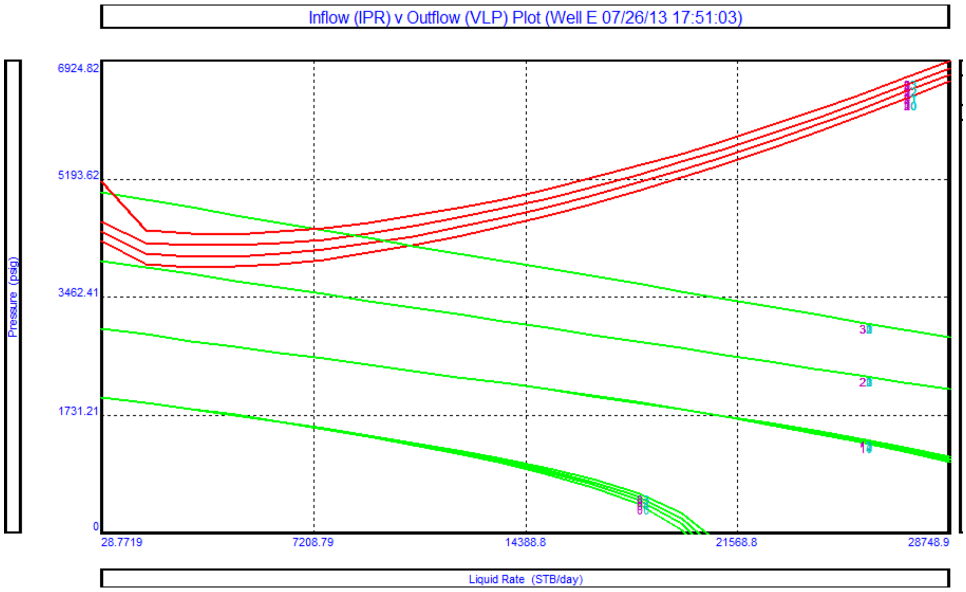


Figure 90: IPR VS VLP after Using Gas Lift

Reservoir Pressure (psia)	Water Cut (%)			
	0	10	20	30
	Oil Rate (stb/d)			
5000	10584.9	8700.2	6877.8	5103.8
4000	0	0	0	0
3000	0	0	0	0
2000	0	0	0	0

Table 96: Oil Rates Produced after Using Gas Lift

4.3.15.3 Well E after Using ESP

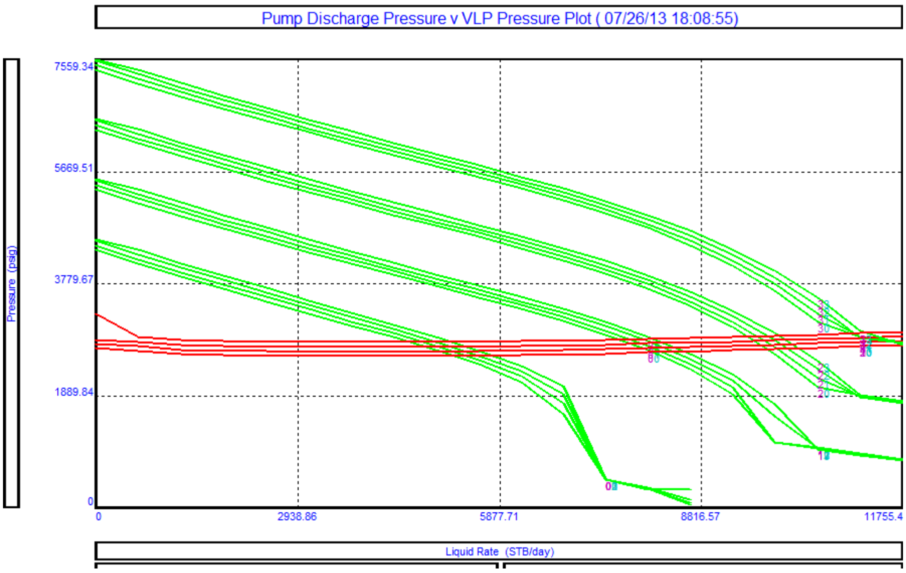


Figure 91: Pump Discharge Pressure VS VLP Pressure Plot

Reservoir Pressure (psia)	**Water Cut (%)**			
	0	10	20	30
	Oil Rate (stb/d)			
5000	10399.5	9876.4	8908.1	7864.2
4000	9801.4	8874.1	7931.0	6969.6
3000	8121.9	7316.8	6506.3	5689.0
2000	5215.6	4684.2	4152.1	3616.8

Table 97: Oil Rates Produced after Using ESP

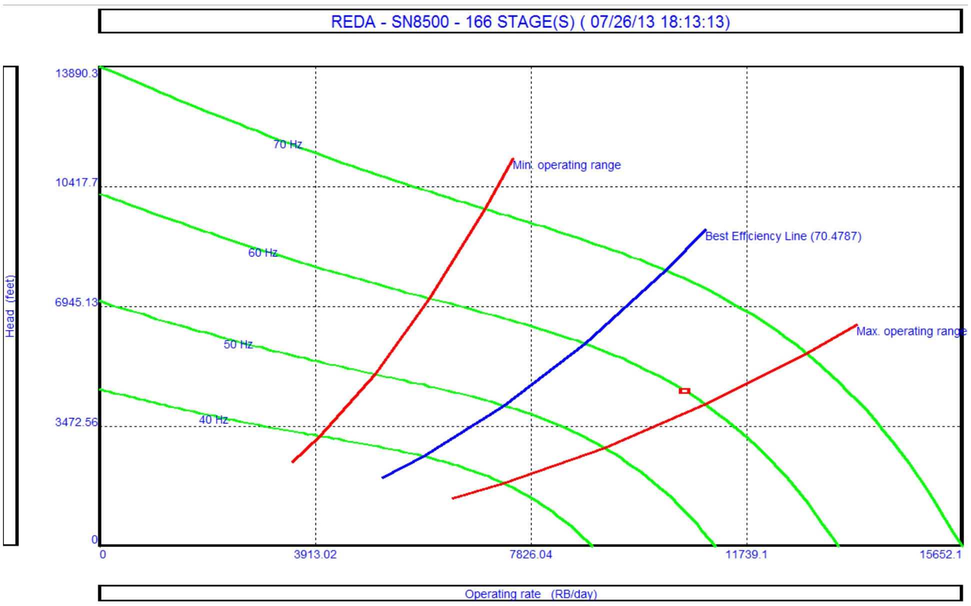


Figure 92: Pump Performance Curve

Pump performance curve describes the relation between flow rate and head for the actual pump. In this well E, the best efficiency line for pump performance curve is calculated as 70.4787.

4.3.15.4 Overview

To summarize, the following table provides detailed information for each base case scenario:

Scenario	Minimum Economic Production Rate Produced	Maximum Economic Production Rate Produced
Without gas lift and ESP	-	2405.6 stb/d at 5000 psia with 0 %WC
With Gas Lift	5103.8 stb/d at 5000 psia with 30 %WC	10584.9 stb/d at 5000 psia with 0 %WC
With ESP	3616.8 stb/d at 2000 psia with 30% WC	10399.5 stb/d at 5000 psia with 0% WC

Table 98: Economic Base Case Condition

4.3.16 Evaluate Various Development Options to Optimize Oil Production

To summarize, the operating rates produced by each analysis are provided in the following table.

Parameter	Range
Wellhead Pressure (psia)	400, 800, 1200, 1600
Tubing Diameter (in)	6, 6.7, 7, 7.3, 8
Water Cut (%)	0, 10, 20, 30
Gas Lift gas Injection Rate (MMscf/day)	2, 4, 6, 8
Pump Operating Frequency (Hertz)	40, 50, 60, 70

Table 99: Range of Parameter Base Scenario

4.3.16.1 Changing Wellhead Pressure (WHP)

4.3.16.1.1 Well E before Using Gas Lift and ESP

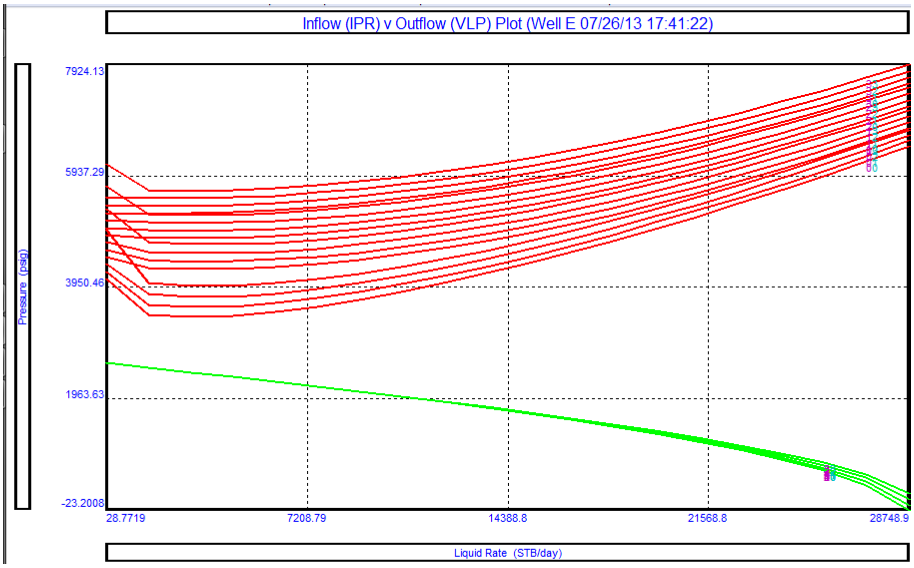


Figure 93: IPR VS VLP for Changing WHP before Using Gas Lift and ESP

WHP (psia)	Water Cut (%)			
	0	10	20	30
	Oil Rate (stb/d)			
1600	0	0	0	0
1200	0	0	0	0
800	0	0	0	0

400	0	0	0	0

Table 100: Oil Rates at different WHP before Using Gas Lift and ESP

4.3.16.2 Well E after using Gas Lift

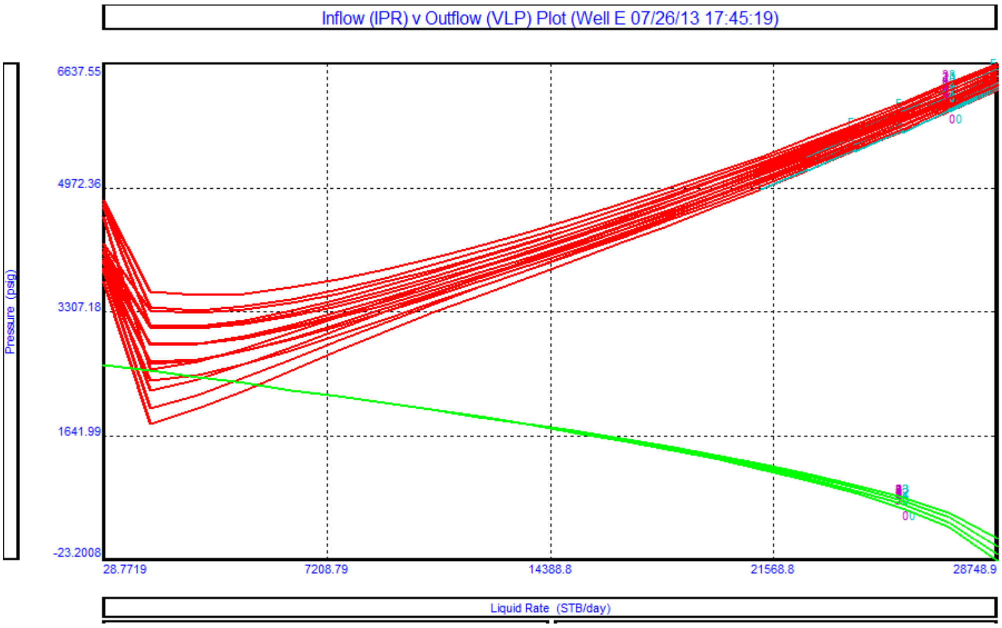


Figure 94: IPR VS VLP for Changing WHP after Using Gas Lift

WHP (psia)	**Water Cut (%)**			
	0	10	20	30
	Oil Rate (stb/d)			
1600	0	0	0	0
1200	0	0	0	0
800	2789.2	0	0	0
400	4950.2	3770	2557.7	0

Table 101: Oil Rates at different WHP after Using Gas Lift

4.3.16.2.1 Well E after Using ESP

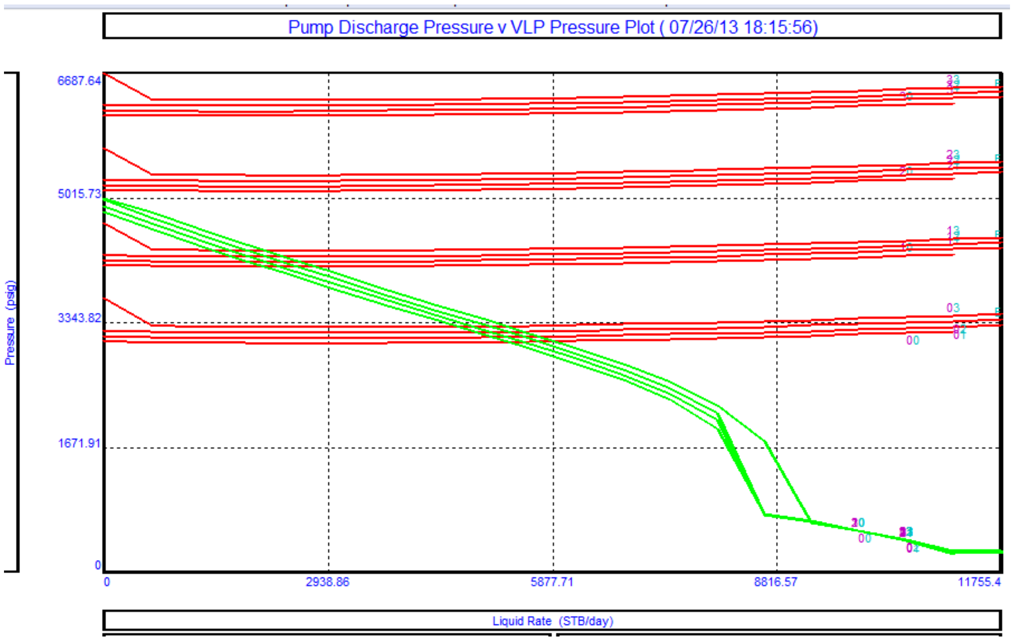


Figure 95: Pump Discharge Pressure VS VLP for Changing WHP after Using ESP

WHP (psia)	**Water Cut (%)**			
	0	10	20	30
	Oil Rate (stb/d)			
1600	0	0	0	0
1200	0	0	0	0
800	2104.4	1910.6	1713.7	1500.7
400	5307.5	4770.1	4233.6	3693.1

Table 102: Oil Rates at different WHP after Using Gas Lift

4.3.16.3 Overview

As per shown in the figures and tables above, it is observed that by changing wellhead pressure from 1600 to 400 psia, the operating rates produced become higher. However, when the water cut is increasing to maximum 90%, the oil rates obtained are decreasing.

4.3.16.4 Changing Tubing Size

4.3.16.4.1 Well E before Using Gas Lift and ESP

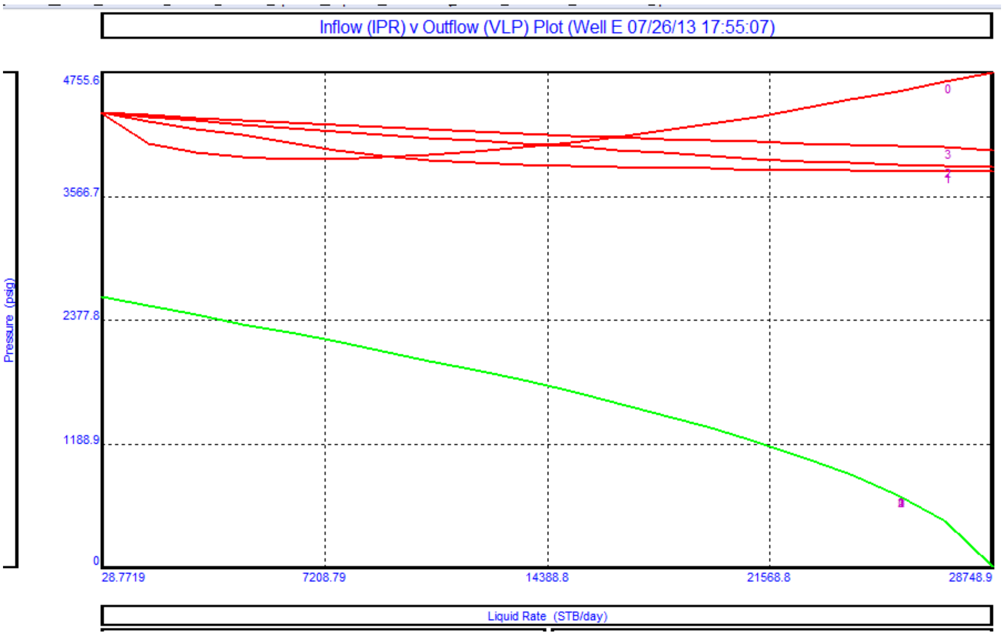


Figure 96: IPR VS VLP for Changing tubing Size before Using Gas Lift and ESP

Tubing Size ID (in)	Oil rate (stb/day)
6	0
6.7	0
7.3	0
8	0

Table 103: Oil Rate at Various Tubing Internal Diameter Sizes before Using Gas Lift and ESP

4.3.16.5 Well E after Using Gas Lift

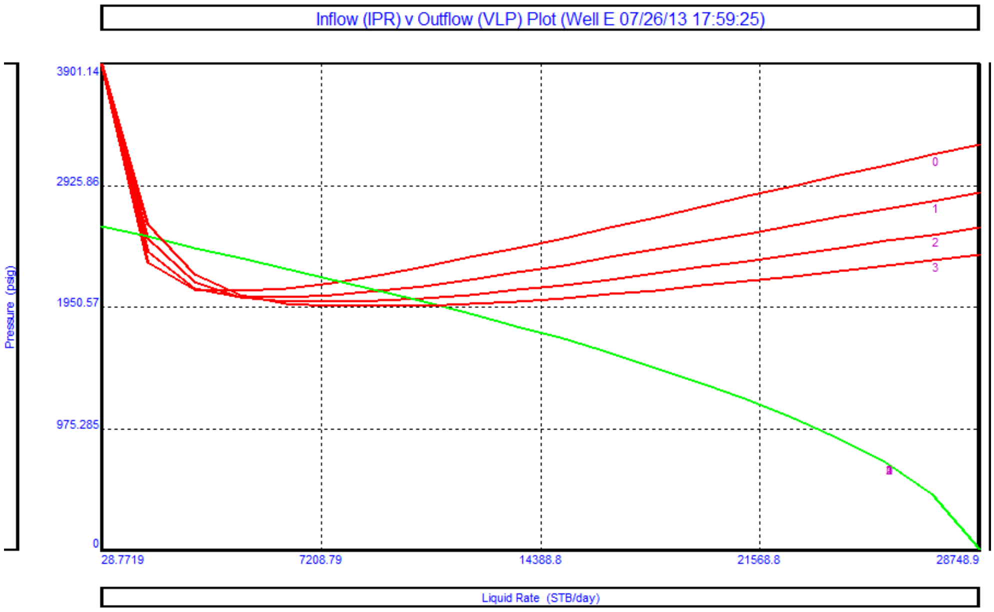


Figure 97: IPR VS VLP for Changing tubing Size after Using Gas Lift

Tubing Size ID (in)	Oil rate (stb/day)
6	8464.0
6.7	8693.3
7.3	8677.6
8	8697.9

Table 104: Oil Rate at Various Tubing Internal Diameter Sizes after Using Gas Lift

4.3.16.6 Well E after using ESP

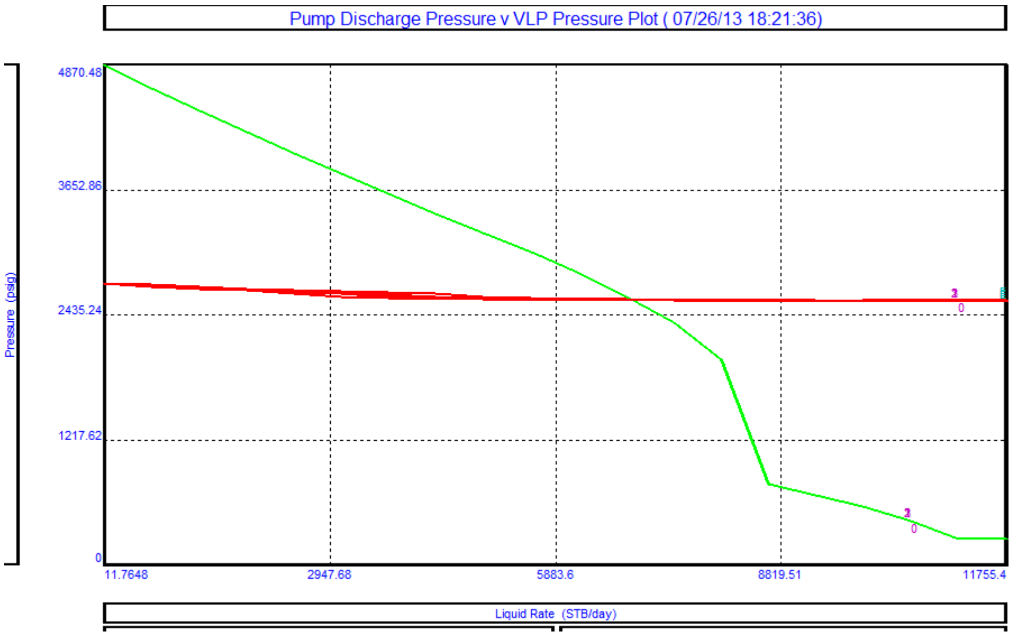


Figure 98: Pump Discharge Pressure VS VLP Pressure after using ESP

Tubing Size ID (in)	Oil rate (stb/day)
6	6477.0
6.7	6489.5
7.3	6498.1
8	6503.7

Table 105: Oil Rate at Various Tubing Internal Diameter Sizes after Using ESP

4.3.16.7 Overview

It is observed that by changing various sizes of tubing internal diameter (ID), the oil rates increment obtained are small and not too much significant. Thus, it is not recommended to change the tubing size in this well.

4.3.16.8 Changing Artificial Lift Method Parameter

4.3.16.8.1 Changing Gas Injection Rate Gas Lift

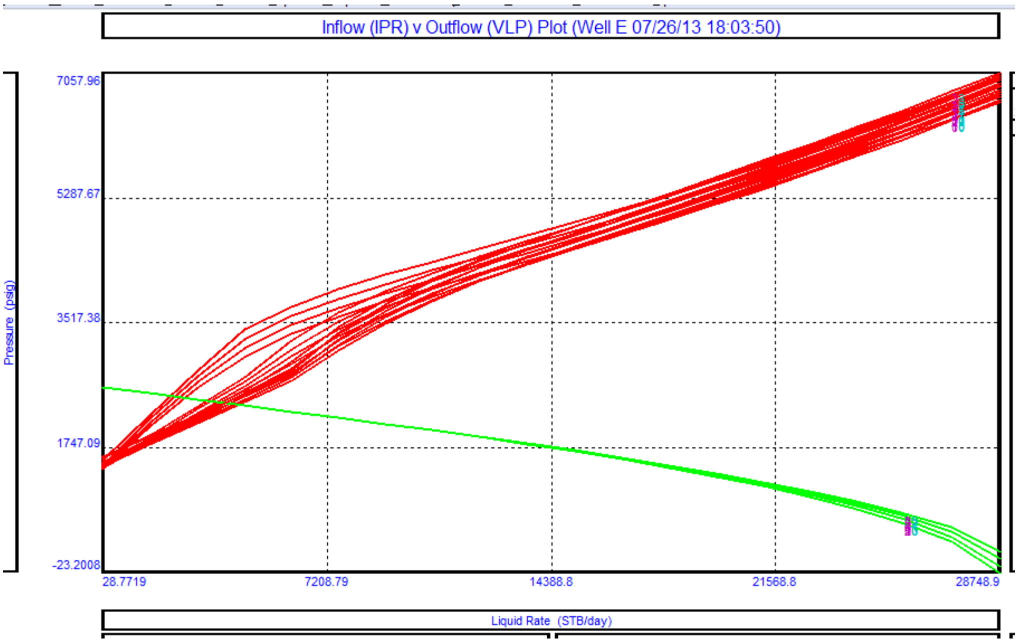


Figure 99: IPR VS VLP for Changing Gas Lift Rate

Gas Injection (MMscf/day)	Water Cut (%)			
	0	10	20	30
	Oil Rate (stb/d)			
2	2653.4	2242.8	1868.9	1528.6
4	3828.3	3292.6	2793.4	2327.3
6	4270.3	3702.6	3165.7	2658.4
8	4382.4	3810.7	3267.4	2749.9

Table 106: Oil Rate with Various Gas Injection Rates

It is observed that increase in gas injection rate gas lift will result increase in oil rate production.

4.3.16.8.2 Changing Pump Operating Frequency ESP

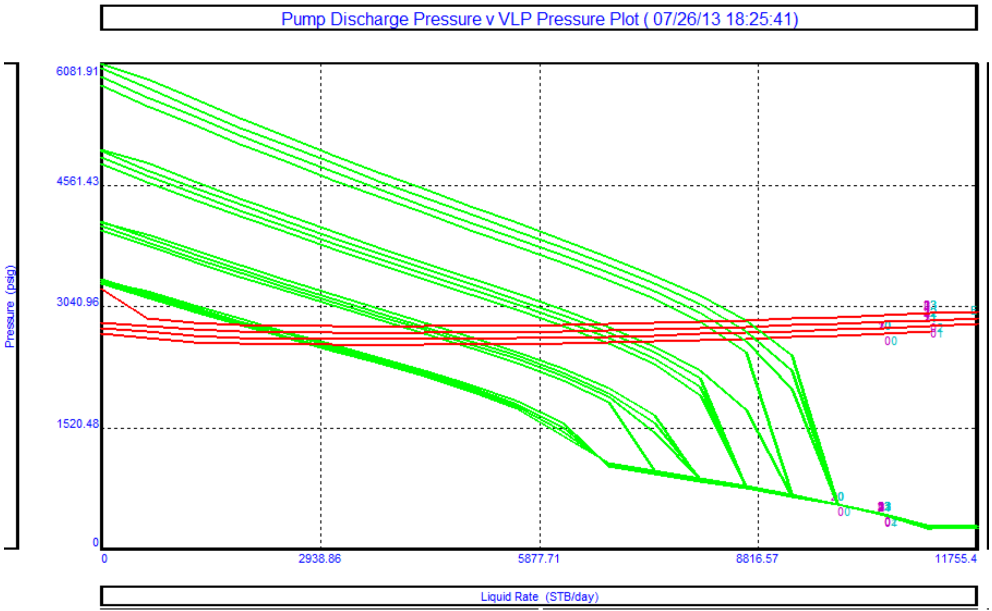


Figure 100: Pump Discharged Pressure/VLP for changing Pump Operating Frequency

Pump Operating Frequency	**Water Cut (%)**			
	0	10	20	30
	Oil Rate (stb/d)			
40	2806.3	2345.7	1917.8	1510.8
50	4848.4	4262.3	3692.2	3134.9
60	6782.5	6088.7	5394.4	4697.1
70	8413.6	7640.9	6854.3	6053.6

Table 107: Oil Rate with Various Pump Injection Rates

It is observed that increase in pumps operating frequency ESP will result increase in oil rate production.

4.4 Discussion

Throughout the simulation modeling that has been conducted for 5 wells; well A, well B, well C, well D and well E, it is observed that:

1. The oil production of the wells is decreasing over the time due to natural decline as a result of decrease in reservoir pressure and increase in water cut. The artificial lift such as gas lift and ESP is then required to lift large volume of fluid.
2. Five wells with different set of reservoir and well characteristics are being analyzed in order to achieve the objective of this project which is to compare gas lift and ESP performance for oil well production optimization;
   f. Well A: high reservoir pressure (4520 psia), high GOR (924.6 scf/stb) and no water cut (0%),
   g. Well B: moderate reservoir pressure (3015 psia), low GOR (400 scf/stb) and high water cut (80%)
   h. Well C: moderate reservoir pressure (3275 psia), moderate GOR (704.6 scf/stb) and moderate water cut (25%)
   i. Well D: high reservoir pressure (4000 psia), high GOR (820 scf/stb) and high water cut (80%)
   j. Well E: low reservoir pressure (2600 psia), low GOR (500 scf/stb) and low water cut (5%)
3. A various of sensitivity analysis is performed to achieve the objective of this project which is to study and analyze the behavior of oil well to improve ultimate oil recovery;
   a. Changing wellhead pressure
   b. Changing tubing diameter size
   c. Changing artificial lift method parameter; gas lift gas injection rate and pump operating frequency pump.
4. Looking at the overall performance of all five wells that are being analyzed, it can be concluded that gas lift is more economical than ESP, particularly in term of giving higher volume of oil production. However, ESP can further lift large volume of oil when gas lift is no

longer able to, such as in the condition when water cut increases and reservoir pressure decreases.

a. Well A

Reservoir Pressure (psig)	Before Using Gas Lift and ESP			After Using Gas Lift			After Using ESP		
	Water Cut (%)			Water Cut (%)			Water Cut (%)		
	0	15	20	0	15	20	0	15	20
	Oil Rate (stb/d)			Oil Rate (stb/d)			Oil Rate (stb/d)		
4500	0	0	0	2366.9	1990.5	1859.3	2291.8	1844.6	1704.8
2500	0	0	0	644.7	0	0	910.5	801.2	757.0
1000	0	0	0	0	0	0	0	0	0

b. Well B

Reservoir Pressure (psia)	Before Using Gas Lift and ESP				After Using Gas Lift				After Using ESP			
	Water Cut (%)				Water Cut (%)				Water Cut (%)			
	30	36	43	50	30	36	43	50	30	36	43	50
	Oil Rate (stb/d)				Oil Rate (stb/d)				Oil Rate (stb/d)			
5000	2906.7	2424.0	1893.4	1419.4	9132.8	8157.5	7042.4	5958.0	10319.7	9414.8	8362.8	7309.4
4500	0	0	0	0	7440.2	6569.1	5582.0	4634.1	9594.2	8732.3	7733.9	6738.1
4000	0	0	0	0	5577.5	4811.7	3948.3	3143.2	8689.2	7900	6972.3	6050.6
3500	0	0	0	0	3417.9	2726.1	1965.6	1257.4	7591.3	6869.8	6038.4	5216.2

c. Well C

Reservoir Pressure (psia)	Before Using Gas Lift and ESP			After Using Gas Lift			After Using ESP		
	Water Cut (%)			**Water Cut (%)**			**Water Cut (%)**		
	20	32	45	20	32	45	20	32	45
	Oil Rate (stb/d)			**Oil Rate (stb/d)**			**Oil Rate (stb/d)**		
4750	109.5	0	0	1811.1	1457.1	1057.1	1780.2	1549.4	1266.2
3625	0	0	0	910.9	617.8	0	1205.6	1022.9	933.2
2500	0	0	0	0	0	0	714.2	611.5	495.7

d. Well D

Reservoir Pressure (psia)	**Before Using Gas Lift and ESP**				**After Using Gas Lift**				**After Using ESP**			
	Water Cut (%)				Water Cut (%)				Water Cut (%)			
	60	70	80	90	60	70	80	90	60	70	80	90
	Oil Rate (stb/d)				Oil Rate (stb/d)				Oil Rate (stb/d)			
7000	2327.6	1409.6	685.7	200.5	4188.0	3596.9	2146.4	947.5	3951.5	2897.2	1878.6	906.9
6000	0	0	0	0	3571.2	2282.7	1207.7	424.1	3586.5	2605.9	1668.0	792.9
5000	0	0	0	0	1060.7	0	0	0	3080.5	2201.1	1381.9	640.2
4000	0	0	0	0	0	0	0	0	2383.5	1654.1	994.8	436.4

e. Well E

Reservoir Pressure (psia)	Before Using Gas Lift and ESP				After Using Gas Lift				After Using ESP			
	Water Cut (%)				Water Cut (%)				Water Cut (%)			
	0	10	20	30	0	10	20	30	0	10	20	30
	Oil Rate (stb/d)				Oil Rate (stb/d)				Oil Rate (stb/d)			
5000	2405.6	0	0	0	10484.9	8700.2	6877.8	5103.8	10399.5	9876.4	8908.1	7864.2
4000	0	0	0	0	0	0	0	0	9801.4	8874.1	7931.0	6969.6
3000	0	0	0	0	0	0	0	0	8121.9	7316.8	6506.3	5689.0
2000	0	0	0	0	0	0	0	0	5215.6	4684.2	4152.1	3616.8

5. Changing wellhead pressure is then performed to run sensitivity analysis. From the result obtained, it shows that reduction in wellhead pressure causes the drawdown to increase. As a result, decrease in wellhead pressure will increase oil production.
6. Adjusting the tubing size is also required to perform sensitivity analysis in this study. The effect of increasing the tubing size is to give a higher node pressure for a given flow rate because the pressure drop in the tubing is decreased. However, from the result obtained, changing tubing size is not recommended as it does not produce fruitful increment in oil production rate.
7. Changing gas injection rate and operating frequency pump in gas lift and ESP is also performed to run sensitivity analysis on artificial lift parameter.
8. The purpose of injecting gas into the tubing is to decrease the density of the flowing gas-liquid mixture and therefore decrease the required flowing bottomhole pressure. From the result obtained, increase in gas injection rate gas lift will result increase in oil rate production.
9. Upon installation of ESP, critical parameters such as pump speed or electric pump operating frequency (Hz) is set to optimize pump performance under the reservoir conditions that exist at the time. Result shown that increase in pumps operating frequency ESP will result increase in oil rate production.
10. Although ESP tends to be more expensive, ESP offer a potential flow rate superior to gas lift. In addition, ESP systems also offer superior performance in gaseous and water cut environment. However, these systems become far less efficient as the well goes deeper.
11. The well depth determines how much surface energy is needed to move fluids to surface and may place limits on gas lift and ESP.
12. In designing gas lift and ESP, the availability of electricity or natural gas governs the type of artificial lift selected, whether gas lift or ESP.
13. Well Inflow Performance Relationship (IPR) defines its production potential.
14. Flow rates are governed by wellhead pressure. And lowering wellhead pressure is recommended because the well's life can be extended to

certain water cut.

15. Gas lift can operate over a wide range of producing conditions and it can be applied to any well configuration (deviated, horizontal and dual completion).
16. Gas lift operating cost is generally low compared to ESP and also a direct function of fuel costs and system reliability or integrity.
17. In gas lift, a total system design approach is essential while in ESP it is less important.
18. Gas lift is recommended for full range of gas oil ratio.
19. ESP is recommended for gas oil ratio less than 500scf/stb. For range 500-200scf/stb, the achievable pump rate will be limited by the amount of gas breaking out of solution in the area of the pump. Greater than 2000scf/stb, *FBHP* will need to stay above the bubble point pressure to avoid gas cavitations in the pump.
20. Gas lift is recommended for all bubble points. This is because gas lift is not dependent on the bubble point pressure hence is suitable for any range.
21. ESP is not recommended for high bubble point as this will limit the maximum drawdown in the well due to the detrimental effects of free gas in the pump.
22. In reservoir characteristic with high sand control environment, ESP shall not be used as it will damage the pump.
23. ESP is more recommended for situation with full range of water cut.
24. High water cut reduce efficiency in gas lift.
25. Looking at the overall condition, gas lift system efficiency is about 10-30% meanwhile ESP is about 35-60%.
26. Some of factors that affect selection of gas lift and ESP are:

    - Producing characteristics (IPR performance)
    - Fluid properties (oil viscosities, oil volume factor with little influence from water viscosity, gas viscosity, water solubility and surface tension properties).
    - Hole characteristics (depth)
    - Reservoir characteristics (depletion drive reservoir, water drive

reservoir and gas cap expansion drive)

- Long range recovery plan (primary recovery, secondary recovery and tertiary recovery)
- Surface facilities (size, length and terrain)
- Location

27. Both gas lift and ESP are excellent artificial lift method to increase oil production.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

Selecting the most economical artificial lift method is very crucial for long term profitability of oil producing wells. Therefore, the main goal of this project is mainly to conduct a comparative study between gas lift and ESP as a function of an artificial lift method which is widely used in the exploration and production of oil and gas industry. In addition, this project's mission is to address an optimized oil well production by using gas lift and ESP method.

The term of optimization is applied as an optimum distribution of gas or pump pressure to a number of wells based on the premise of maximizing oil production or operating cash income. [22]

In assistance with PROSPER software, the optimization of gas lift can be further explained with respect to its main characteristic performance like IPR (Inflow Performance Relationship). IPR is a functional relationship between the flowing bottom-hole pressure (pwf) and the flow rate (q). This flow rate is at which fluid will flow towards the wellbore and depends on the viscosity of the fluid, the permeability of the rock, and the driving force. With the help of IPR curve obtained from PROSPER software, it will help this project to monitor well performance and predicts the simulation and artificial lift sensitivities variables of a number of well. Other than that, it can assist to measure life and productivity of reservoir.

In short, the proposed simulation using well model by PROSPER software does follow the objectives and scopes of study defined. The activities that have been conducted that include research and mostly application of theories into practices are relevant to the objectives specified.

5.2 Recommendation to Future Work

The simulation study on gas lift and ESP by using PROSPER has already reached to the final stage. Up to this point, there are already five wells that have been examined and analyzed with different set of well and reservoir characteristics. A complete analysis to fit the objective of this study and also the conclusion has been drawn and completely been accomplished. However, it is strongly recommended to use more accurate well data. The reliability of data is very important toward the success of this project. An overestimate of productivity will result in low equipment efficiency as a result it is a direct loss of profit. Following that, this project can also be further extended by integrating few models into one system. For this project, the production optimization is only conducted by using well model using PROSPER. In order to improve this technique, a reservoir model using MBAL as well as surface model using GAP can be integrated with the well model. Thus, continuation of the optimization can be broadly done from the surface until its subsurface system.

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APPENDICES

APPENDIX A

GANTT-CHART

No	Project Activities	Week	1,2	3,4	5,6	7,8	9,10	11,12	13,14	15,16	17,18	19,20	21,22	23,24	25,26	27,28
1	Planning		14 weeks													
	a. Information gathering															
	- Project familiarization															
	- Literature review															
	- General understanding of enhance oil recovery															
	- Focus study on gas lift and ESP															
	b. Obtain the real plant data															
	- Request a real plant data to company															
	- Literature reaserch plant data															
	c.Project Engagement with Supervisor															
	- Review on the extended proposal															
	d.Request PROSPER Software															
	- Obtain approval to use computer laboratory															
2	Simulation Study								8 weeks							
	a. PROSPER sotware familiarization															
	b. Apply prosper in application for gas lift and ESP															
	c. Model gas lift well and ESP well															
	d. Verify the simulation model with real plant data															
	e. Perform sensitivity simulation															
3	Analysis											6 weeks				
	a. Define parameters															
	b. Generate finding															
	c. Analyse behaviour of oil wells to improve ultimate oil recovery															
	d. Develop comparative study for gas lift and ESP optimization															
4	Review													4 weeks		
	a. Presenting simulation results and findings															
	b. Discussion & Recommendation of the Study															
5	Documentation															2 weeks
	a. Produce dissertation draft report															
	b. Produce Finalised dissertation report															

= Objective 1 shall achieve within week 15-16 = Objective 2 shall achieve within week 19-20 = Objective 3 shall achieve within week 23-24