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PRODUCTION OPTIMIZATION BY NODAL ANALYSIS

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Production Optimization by Nodal Analysis.

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CRETIFICATION OF APPROVAL

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A project dissertation submitted to the

Petroleum Engineering Programme

Univiersiti Teknology PETRONAS

in partial fulfilment of the requirement for the

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(PETROLEUM)

Approved by,

____

Dr. Mahbubur Rahman

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2015

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 acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

RAMI ALI ALI ALTAM

ABSTRACT

As gas field development is a costly business, it is important to ensure that each component in the production system (from the dwonhole completion all the way to the separator) is functioning to its best utilization. The goal of field optimization is to establish the ranges of operating parameters that will ensure then and help achieving the operator's objective, such as maximizing the production rate of the entire field. This rate is sustainable for the conditions established by the system components (tubing, pipeline, choke, etc.), reservoir pressure, and separator pressure. Nodal Analysis provides a sound method to aid the decision making process for optimization. This project presents the results of a study conducted on the 'X' gas field which is producing with two wells. First step was optimizing tubing size for each well. Then a field wide network model was constructed to include the wells and surface facilities. Predictive simulation was run at the network, considering three cases. There are: i) base case, ii) installing surface compressor, iii) drilling a new well. The comparative analysis shows that case 3 is the optimum production strategy for the 'X' gas field which provide an increment by around 14% in gas recovery, compared to the base case.

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NOMENCLATURE & SYMBOLS

ΔP_T	=	Total pressure (psi)
P_r	=	Reservoir average pressure (psi)
P_{wfs}	=	Sand face pressure (psi)
P_{wf}	=	Bottomhole pressure (psi)
P_{wh}	=	Wellhead pressure (psi)
P_{sep}	=	Separator pressure (psi)
ΔP	=	Drawdown pressure (psi)
J	=	Productivity index (STB/day/psi)
Qo	=	Oil flow rate (STB/day)
Ko	=	Permeability (md)
h	=	Thickness (ft)
uo	=	Oil viscosity (cp)
Bo	=	Oil formation volume factor (bbl/STB)
re	=	External radius (ft)
rw	=	Wellbore radius (ft)
s	=	Skin effect

ABBREVIATIONS

BBLD	Barrel Oil Per Day
CGR	Condensate Gas Ratio
GAP	General Allocation Package
IPM	Integrated Production Modeling
IPR	Inflow Performance Relation
MBAL	Material Balance
MMSCFD	Million Standard Cubic Feet Per Day
STB	Stock Tank Barrel
TPR	Tubing Performance Relation
VLP	Vertical Lift Performance
WGR	Water Gas Ratio

CHAPTER 1

PROJECT BACKGROUND

1.1 Background

Transportation or movement of the fluids needs energy so it can withstand and overcome the friction losses in the system as well as to move oil or gas to the surface. The movement of the fluids will go through the reservoir then the piping system and finally flow into the separator for liquid and gas separation process. The production system can be either simple system with less pressure losses or it can be quite complicated with all the components in which pressure losses occur [1-4].

Figure 1 shows several pressure losses that may occur in the system from the reservoir to the separator.

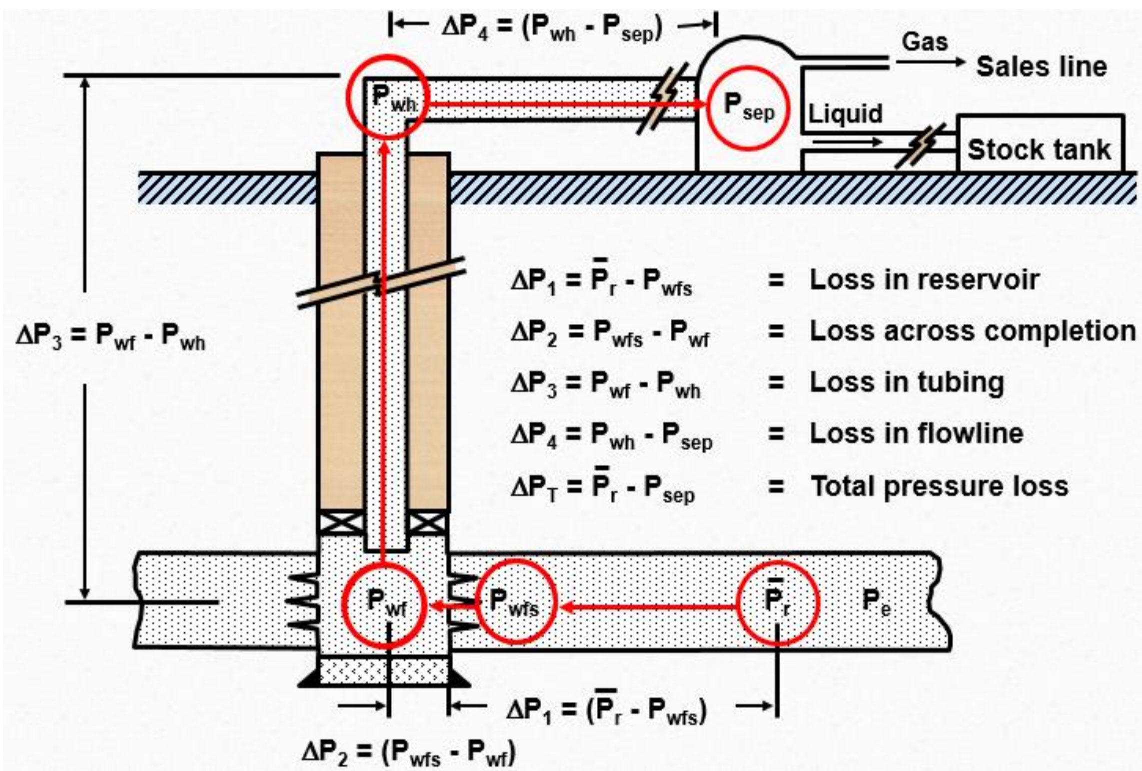


Figure 1: System Description and Pressure Losses [5]

The decline in pressure is the sum of the pressure drops for the individual components in the production system. The pressure drop is dependent on the interaction between the various components in the system due to the compressible nature of the fluids produced in oil and gas operations. This happens because that the pressure drop in a particular component is dependent on the flow rate and the average pressure through the component [6].

Therefore, an integrated approach is required for the final design of a production system, since the system cannot be divided into a piping component or a reservoir component and controlled independently. The pressure drop in the system depends on the amount of fluid flowing through the system, and the amount of gas and oil produced from the reservoir to the surface depends on the total pressure drop in the production system. Accordingly, the whole production system must be analyzed as a unit or system [7].

If the separator represents the end of the production system as shown in Figure 1, the difference between the average reservoir pressure and the separator pressure is the total pressure drop in the system.

$$\Delta P_T = P_r - P_{sep} \qquad \text{(Eq. l)}$$

This total pressure drop is composed of the individual pressure drops as the reservoir fluid flowing to the surface. These pressure drops happen as the fluid flows from the reservoir and through well completion, up the tubing, the wellhead equipment and choke, and then through the surface flow lines into the separator. So, the total pressure drop of Eq. l can be represented by Eq.2

$$\Delta P_T = P_1 + P_2 + P_3 + P_4 \qquad \text{(Eq.2)}$$

However, these individual pressure drops can be even divided into additional pressure drops for subsurface safety valves, restrictions, tubing accessories, etc.

Systems analysis is based on the concept of continuity. There is a particular production rate and pressure at any given point in the production system. If a change is made in any point of the system, this will result in a change in the production rate and pressure at that same point [8].

As oil and gas demand increases dramatically, oil and gas industries are required to come up with effective and economic ways in order to maximize the production.

Therefore, for a producing well, we need to carry out operations to improve the productivity, Flow through a complicated system, like production system must be broken down into several components for analysis [9].

Nodal analysis has been selected to accomplish the required task, where nodal analysis is a system analysis approach which can be used to improve a production system such as an oil or gas well. In order to achieve the most desirable rate with highest economical return every component in a well of a producing system should be analyzed separately and then as a group [10].

Integration of all components is an important part for total system optimization. Where computer aided approach is generally adopted. By using three components software of the Integrated Production Modeling (IPM) suite that can apply nodal analysis methodology to generate the Inflow Performance Relation (IPR) and Vertical Lift Performance (VLP) curves as shown in Figure 2 [11].

The intersection point between the IPR and VLP curves is called the solution node where:

- The flow into the node is the same as the flow out of the node.
- There is only one pressure exists at the node.

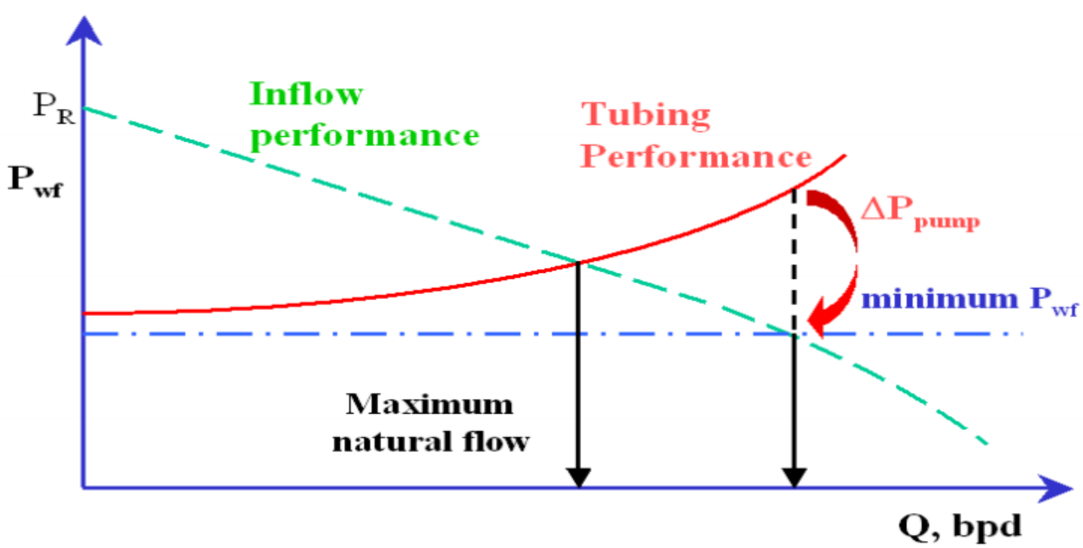


Figure 2: Inflow and tubing performance relationships

After the solution node is selected, the node pressure can be estimated by developing the pressure relationships for the inflow and outflow sections of the system. The inflow section pressure drop is determined from Eq.3, while the pressure in the outflow section is determined from Eq.4.

$$P_r - \Delta P_{upstream} = P_{node} \qquad \text{(Eq.3)}$$

$$P_{sep} + \Delta P_{downstream} = P_{node} \qquad \text{(Eq.4)}$$

Figure 2 known as a system graph where the effect of altering any component of the system can be estimated by recalculating the new characteristics node pressure for the system. The inflow curve will change if there is any change in an upstream component of the system while the outflow curve will remain the same. However, if there is a change in the downstream component, then the outflow curve will change while the inflow curve will remain the same. Both the outflow and inflow curves will be shifted if there is a change in any of the fixed pressures in the system, which can happen when evaluating the effects of reservoir depletion or wellhead pressures or considering different separator conditions [12].

1.2 Problem Statement

The production of the hydrocarbons is often restricted by reservoir conditions, fluid handling capacity of facilities, deliverability of the pipeline system, economic and safety considerations, or all these considerations combined in petroleum fields. Devising ideal operating approaches to accomplish certain operational objectives is the task of field operators. These goals are different from field to another and with time. Typically anyone may perhaps wish to increase the daily oil rates or at least reduce production expenses [13].

To achieve the set objective, such as maximizing field production rate, individual components of the entire production system must be tuned or designed and operated such that their interaction is just right to yield the overall result as desired. Thin required total system approach, which cannot be done by any simple method. Nodal analysis is a method which taken the whole system and optimize it. Thus, the aim of the project is to investigate ways to achieve increased production from a field by nodal analysis.

1.3 Objectives

The objectives for this project can be summarized as follows:-

- Optimize tubing size for each well.
- Create a field wide network model to combine wells and surface facilities.
- Study the effects of changing surface conditions such as separators pressures.
- Study the important of installing surface compressors.
- Study the important of adding additional wells.
- Make recommendation for development strategy.

1.4 Scope of Study

The scope of this project is to simulate and study the well performance for total production system optimization and forecasting studies. Therefore, a software package like the Integrated Production Modeling (IPM) suite is the best computer aided approach to accomplish that task where IPM suite applies Nodal Analysis methodology to generate the Inflow Performance Relation (IPR) and Vertical Lift Performance (VLP) and integrate the wells and reservoirs respectively along with surface facilities such as, inline chokes, pipelines and separators. Different scenarios such as changing tubing size, wellhead pressure separator pressure, etc. will be investigated to select the most suitable measures for the field under study.

CHAPTER 2

LITERATURE REVIEW

The early 1950s is the beginning of the upstream oil industry optimization techniques applications and have been growing stronger since then. Applications have been reported for recovery processes, history matching, planning, drilling, well placement and operation, facility design and operation.

One of these techniques is the mathematical programming that was born in the later 1940s [14]. Where a mathematical programming has been developed into a mature field with great diversification and deep specialization. Mathematical programming encompasses subfields such as nonlinear programming, integer programming, linear programming, and combinatorial optimization.

Optimization techniques have been applied to almost all aspects of the oil and gas industries. In this research, our focus will be on the uses of optimization techniques in production system operations and design, rate allocation, and reservoir management and development.

Camargo et al. [15] simulated a gas lift-based oil production technique which is based on Nodal Analysis, applied to well head level, where the production data were available. The model was obtained to calculate the pressure drop and production flow rate relationship for all the components of the completion system. Therefore, the oil or gas flow produced by the well can be determined easily. The author observed that stabilizing the well flow will allow Nodal Analysis to improve the gas lifted wells performance.

Traditionally, optimization of production system design and operation in a petroleum field was implemented by nodal analysis together with trial and error [1]. For example, a particular variable is diverse to see which value of this variable gives the optimum objective function value, by holding all other parameters fixed.

A ‘gas lift nodal analysis model – economical optimization approach’ comprehensive experimental study was conducted by Al-Lawati [16]. The author concluded that the higher rates achieved by increasing the lifting pressure from 700 psi to 1178 psi and enabled moving the lifting operating orifice deeper, resulting in increasing of the production rate from 170 BOPD to 323 BOPD.

Haq et al. [17] conducted a study on production optimization of Saldanadi gas field by Nodal Analysis method, the study was carried out for separator pressure varied from 500 psi to 1000 psi. The author found that lowering the separator pressure to 500 psi lead to a maximum rate of 5.00 MMSCFD in well # 1.

A successful experience in a production well optimization in a southern Iranian oil field was done by Shadizadeh et al. [18]. The author described a process, to develop Choke Performance Curves, Tubing Performance Curves and Inflow Performance Curves for well No. 305b. He addressed that increasing the choke size will result in improving production, and lead to an optimal reduction in bottom hole flowing pressure and wellhead pressure. Using 9/16 in. choke size instead of 7/16 in. and 7in. OD tubing size instead of 9 5/8 in., the wellhead pressure between 700 psi to 1180 psi in well No. 305b. The results show that the production rate can be increased from 2000 BOPD to 3150 BOPD.

The objective of production optimization methods is to find out that component of the well which is restricting the rate below the maximum possible [19], where well inflow performance relationship (IPR) and tubing performance relationship (TPR) are the basic requirements for well analysis. That was the basis of the ‘production optimization of an oil reservoir’ study that was conducted by Ayoub et al. [20]. In the study, two wells of an oil reservoir were analyzed to determine optimum tubing and choke sizes for production optimization, where nodal analysis technique was used to analyze tubing and choke sizes for these two wells. As well as, the effects of skin damage change on IPR curve and well deliverability were examined.

The author has observed the following:

- The proper tubing and choke bean sizes for well A are 4.276" and 40/64" respectively, where the flow rate increases from 3000 STB/d to 4800 STB/d.
- If the reservoir pressure decreased to 4771 psia, and all other parameters are held constant, well A cannot produce with the casing 8.535" on natural depletion. However, it can produce until the reservoir pressure decreased to below 4691 psia, if it is completed with the tubing size 4.274".
- The proper tubing and choke bean sizes for well B are 2.99" and 32/64" respectively, where the flow rate increases from 1000 STB/d to 1900 STB/d.
- If the reservoir pressure decreased to 4164 psia, and all other parameters are held constant, well B cannot produce with the casing 8.535" on natural depletion. However, it can produce until the reservoir pressure decreased to below 3964 psia, if it is completed with the tubing size 2.99".
- If the skin damage decreases, inflow performance curves will be improved considerably and the flow rates do increase. Therefore, these wells need a cleanup program and stimulation to remove the damage.

CHAPTER 3

METHODOLOGY

Methodology is the process undertaken in order to achieve the objectives of this study that are listed in section 1.3. This section aims to cover the project activities along with the work flow, Gantt chart, and milestones effectively.

3.1 Procedure

The following steps should be taken to accomplish the objectives.

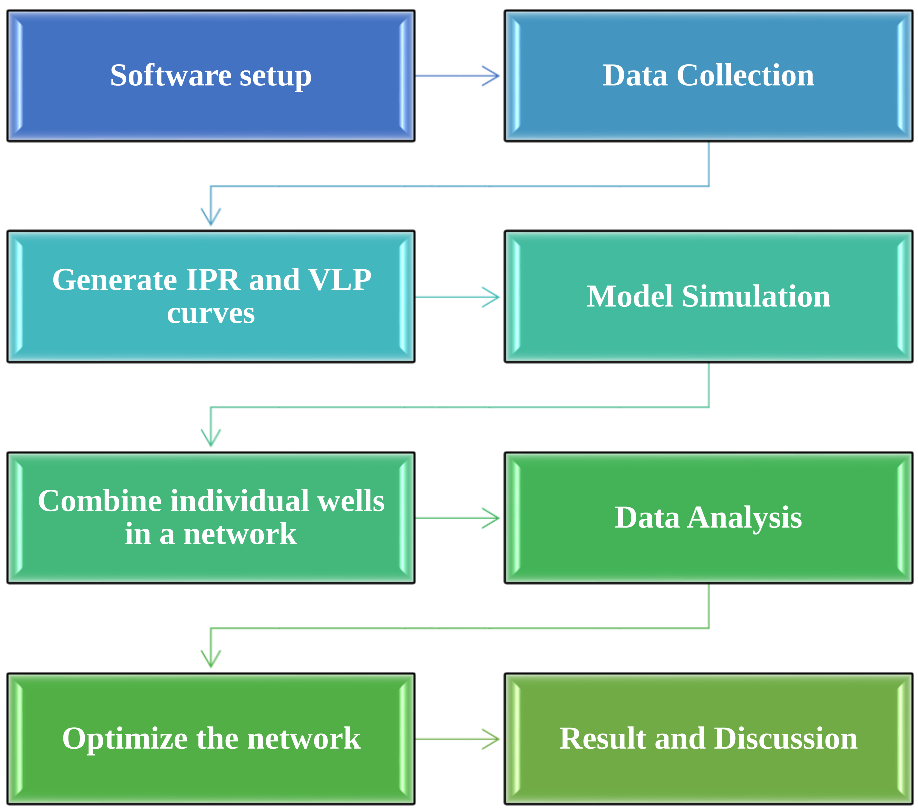


Figure 3: Project Procedure

3.2 Project Flowchart

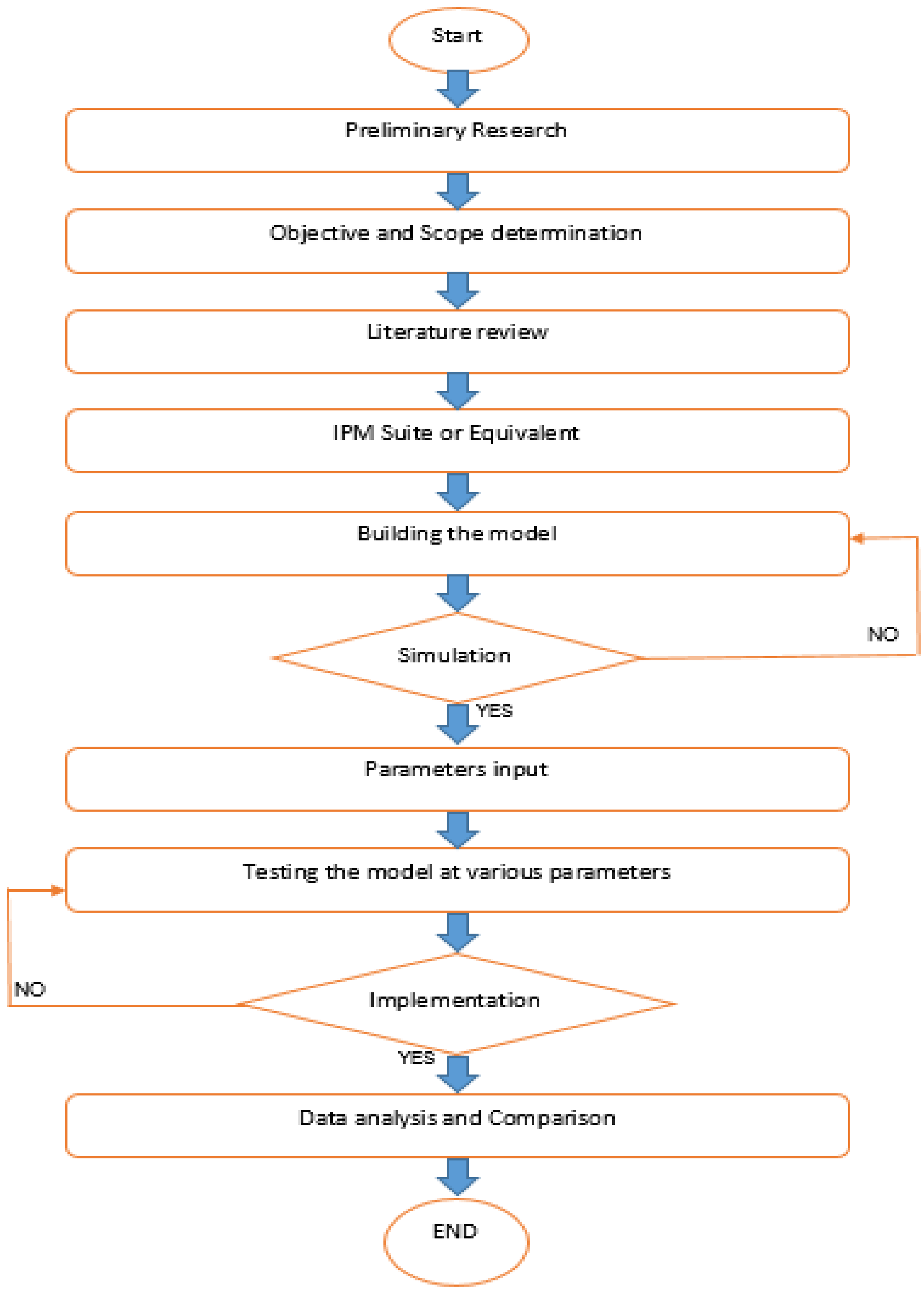


Figure 4: Project flowchart

3.3 Project Activities

Table 1: Project Activities

ACTIVITY	DESCRIPTION
Preliminary Research	Finding previous research in similar field of study. Understanding and gathering information of the topic.
Objective and scope determination	Determining the boundaries of the study based on the determined objectives.
Literature review	Comprehensive study of the previous finding and the methodology used.
IPM suite or equivalent	Installing the Software and understanding the process.
Building the model	Develop the model consist of IPR and TPR curves for the pressure drop vs the flow rate.
Parameters input Simulation	Study the well performance before and after the solution node.
Testing model under various parameters	Study the model and the well performance under the influence of various parameters such as separator pressure variations, changing tubing size, etc.
Data analysis and Comparison	Computing the result and compare with experimental results of different study.

3.4 Gantt Chart

Table 2: Gantt chart Final Year Project 1

Week / Activity	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Project proposing and selection														
Preliminary research objective and scope determination														
Literature review														
Extended proposal submission						*								
Studies continue, building the model														
Presenting “Proposal defense”									*					
IPM suit software simulation														
FYP1 Draft Report Submission													*	
FYP1 interim report Submission														*

*** Key milestone**

Table 3: Gantt chart Final Year Project 2

Week Activity	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Model Testing														
Data Collection & analyzing results														
Submission of progress report								*						
Model testing under various parameters														
Analyzing results														
Pre-SEDX presentation										*				
Recommendation for further studies														
Draft Report Submission													*	
Final Report Submission														*
VIVA														*

*** Key milestone**

3.5 Project Key Milestones

The project rotates about three key milestones:

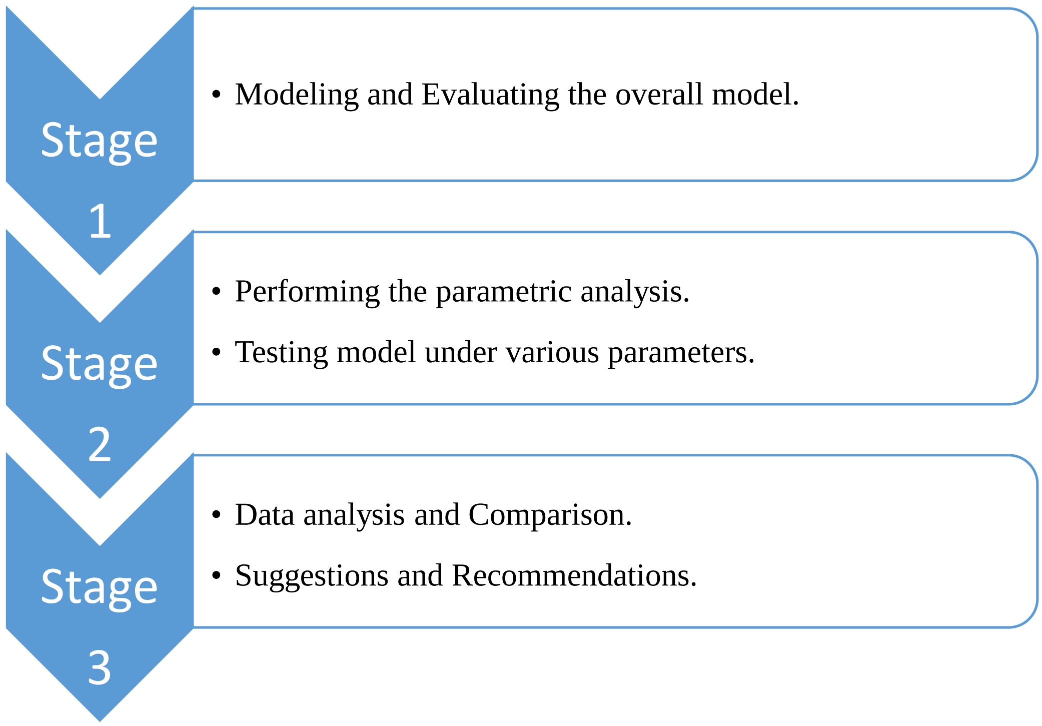


Figure 5: Key Milestones

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Productivity Index

The productivity index is the commonly used measure of the ability of the well to produce. It also the ratio of the total liquid flow rate to the pressure drawdown. The inflow performance relationship (IPR) is known as the functional relationship between the bottom hole flowing pressure and the production rate [14]. Eq. 5 displays the productivity index (J) for a water-free oil production

$$J = \frac{Q_o}{P_r - P_{wf}} = \frac{Q_o}{\Delta P} \qquad \text{(Eq.5)}$$

4.2 Case Studies

This study considered the following three production cases:

i. Base Case.
ii. Installing surface compressor.
iii. Adding a new well.

4.3 Reservoir Behavior

The 'X' gas field has two distinct reservoir layer, and the fluid samples and composition analysis shown that the 'X' field is mainly composed of roughly 99.4% of methane and no hydrocarbon components heavier than C3 are observed. Only a trace amount of nitrogen is observed. The reservoir gas is classified as dry gas and is suitable for sales after minimal (H2O) dew point processing. A phase envelope for the filed is shown in figure 6 indicates that in the plant separator condition at pressure of 1000 psig, it is clearly assumed that the fluid is purely dry gas.

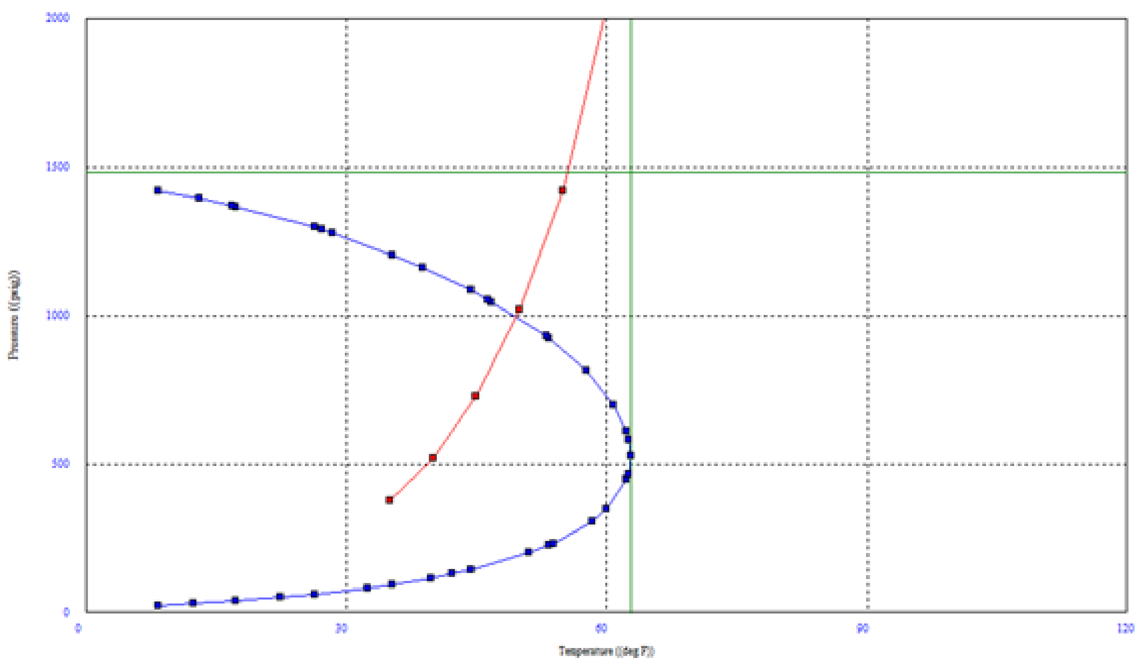


Figure 6: Phase Diagram of the 'X' Gas Field

3.4 Individual Well Modeling by PROSPER

3.4.1 Inflow Performance Relationship

The data obtained from the deliverability test were used as input data for the generation of IPR curve as shown in the following Figure 7 and Figure 8. At the time of constructing of IPR curve, it was important to keep in mind that, the reservoir pressure that was used must be the pressure value at the time when the deliverability test was conducted.

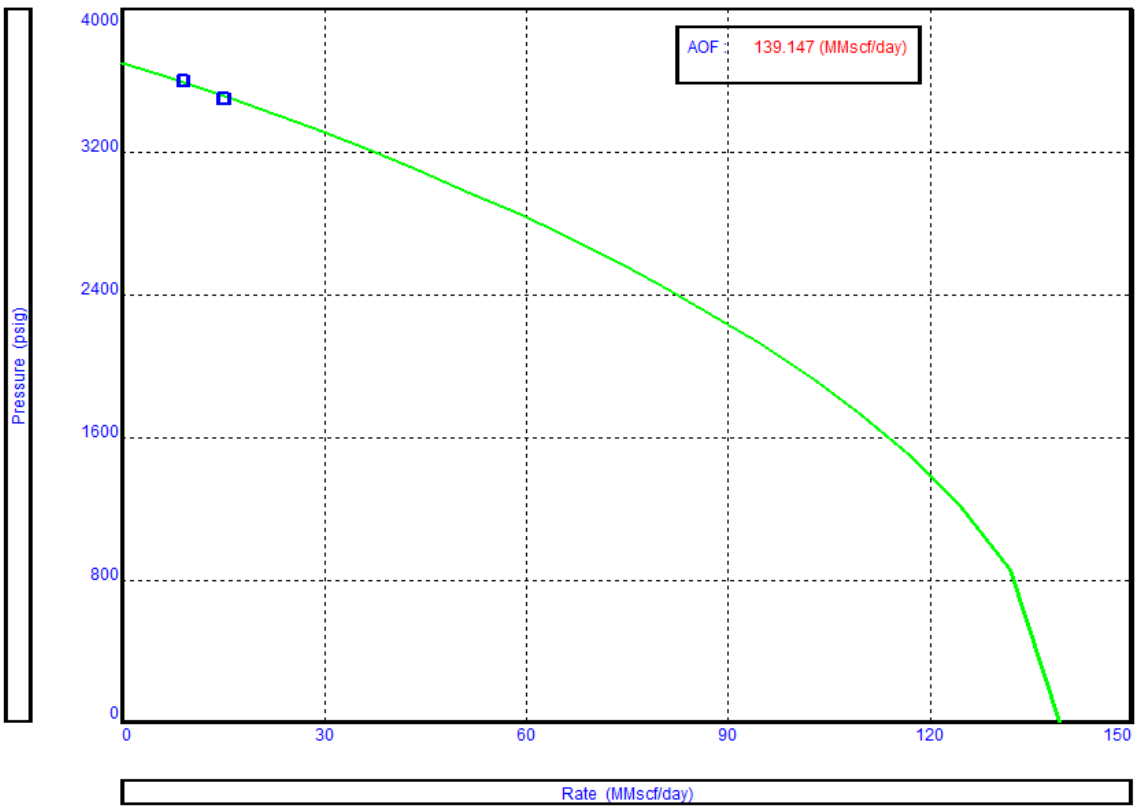


Figure 7: Inflow Performance Relationship Curve of well X-1

From the IPR curve, it is observed that Absolute Open Flow potential (AOF) is around 139.147 MMSCFD for well X-1.

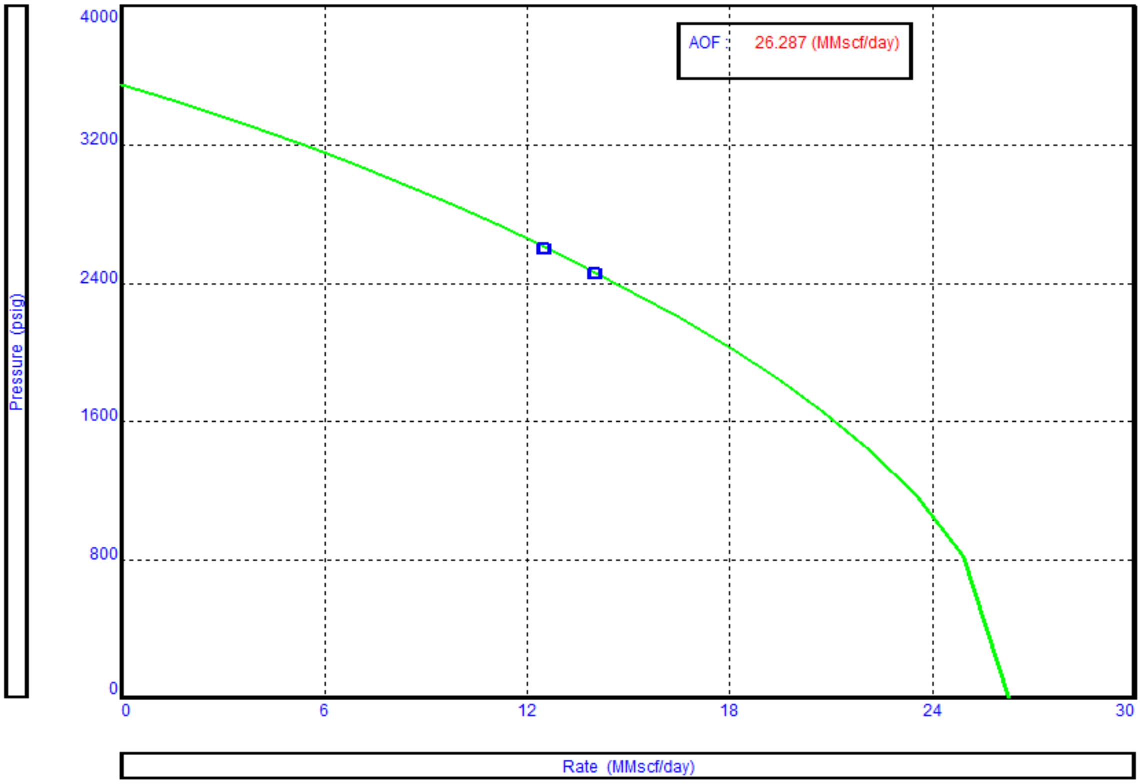


Figure 8: Inflow Performance Relationship Curve of well X-2

From the IPR curve, it is observed that Absolute Open Flow potential (AOF) is around 26.287 MMSCFD for well X-2.

3.4.2 Completion Data

The deviation survey, geothermal gradient data, down-hole equipment and tubing-casing sizes data were used as input in this section. The down-hole equipment data for well X-1 and well X-2 are shown in Figure 9 and Figure 10.

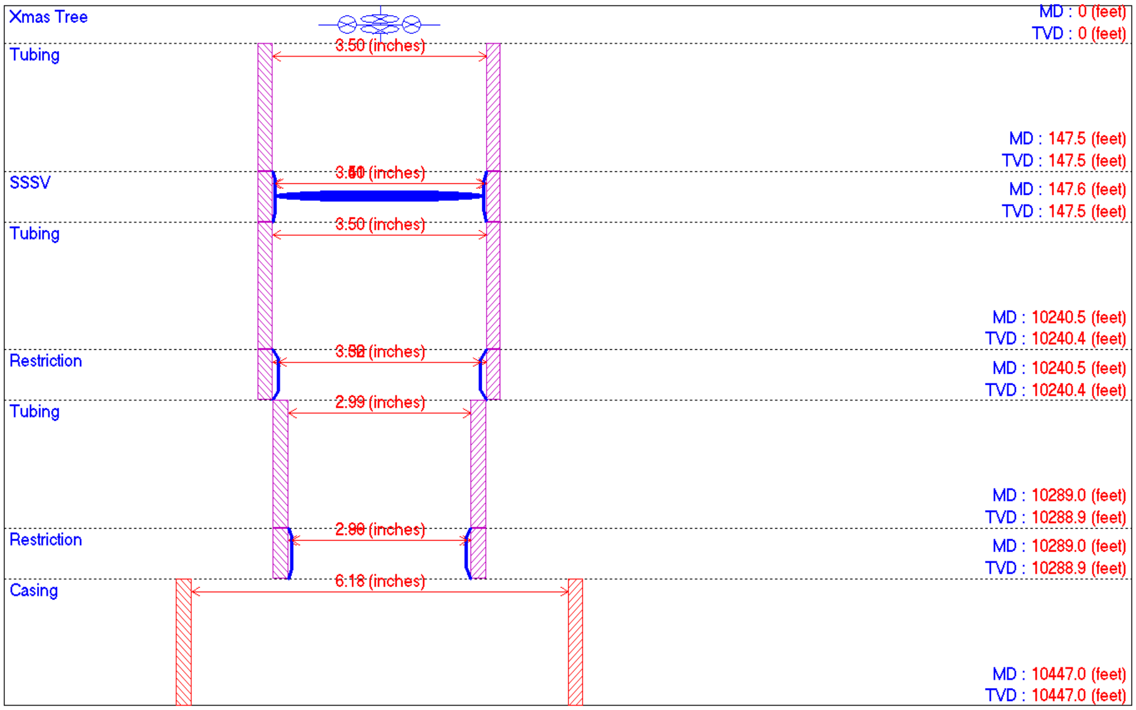


Figure 9: Downhole equipment of well X-1

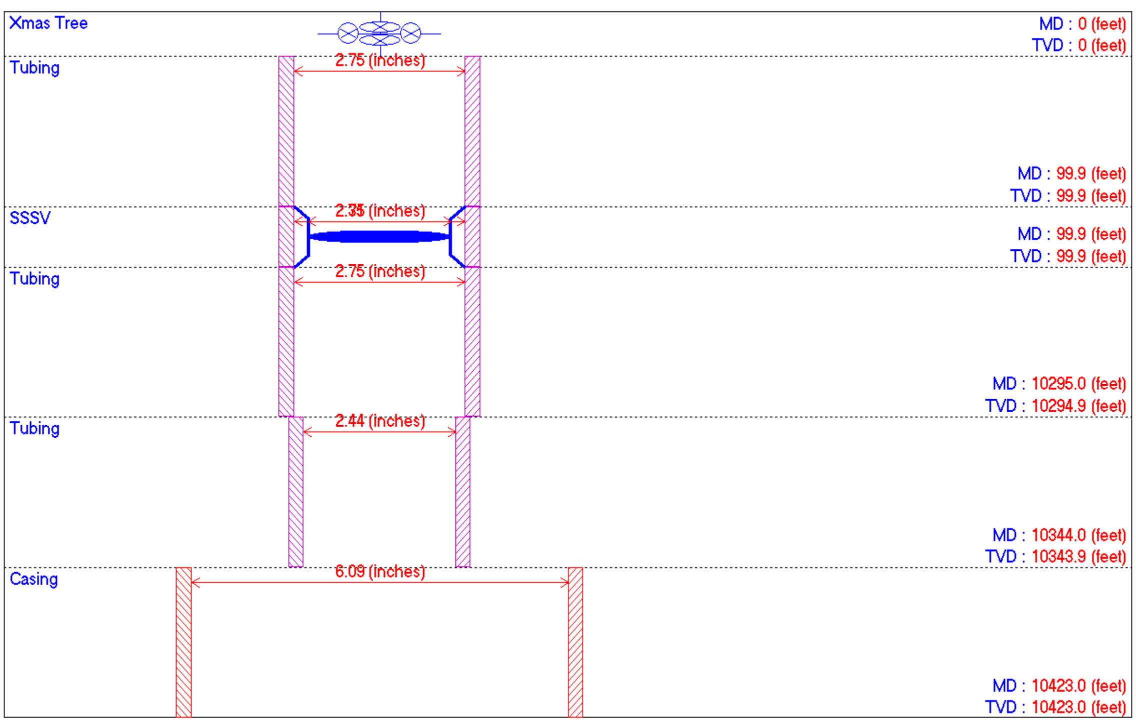


Figure 10: Downhole equipment of well X-2

3.4.2 Matching Well Model

i. VLP/IPR Match

In developing the VLP for a well model, the IPR/VLP matching option are used to match the well model with a standard test data to validate the model. After the flow correlation for the VLP was selected, it was matched to the flowing gradient survey. The IPR was tuned by adjusting the reservoir pressure so that the intersection of the VLP and IPR curve fit the well test measurement Error between the calculated and measured data is shown on the right hand side of the plot. If the test points are not consistent with the IPR model, the IPR can be adjusted until a match is obtained.

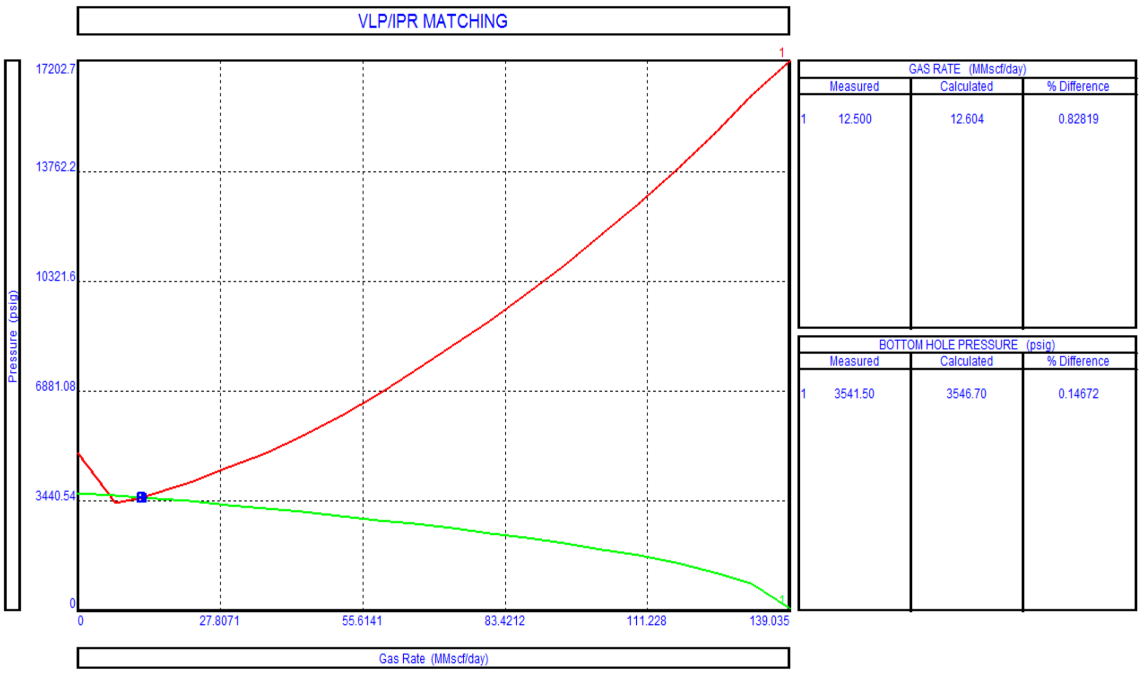


Figure 11: VLP/IPR matching for well X-1

In Figure 11 it is observed that there are only 0.82819% difference between measured and calculated gas rate where as for the bottom hole pressure, the difference is only 0.14672%.

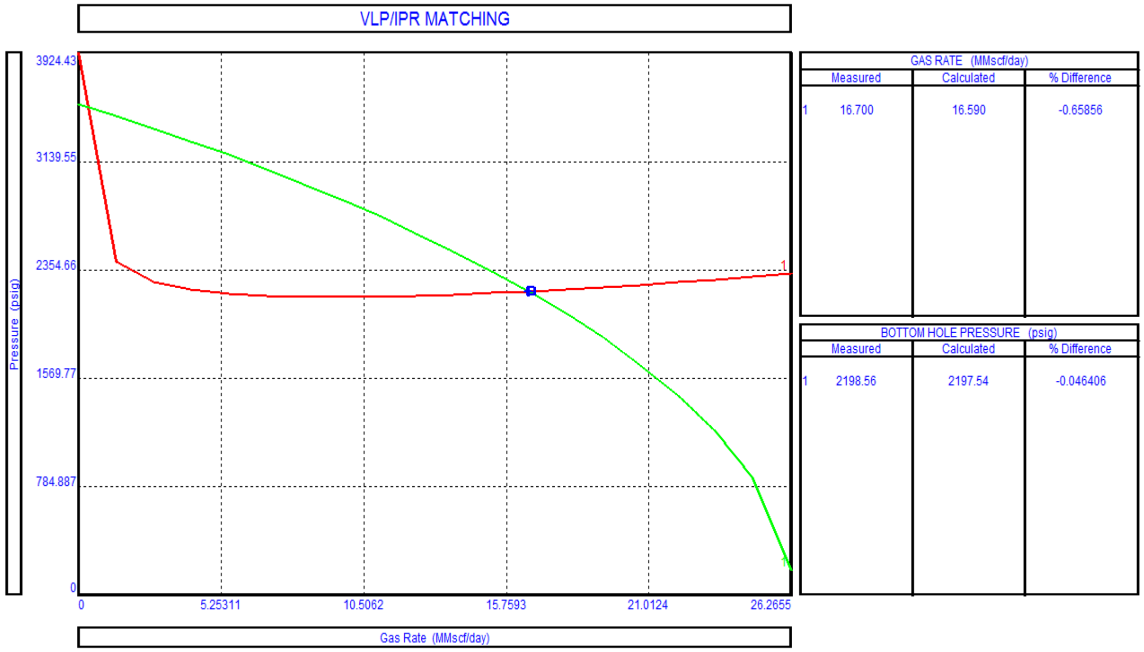


Figure 12: VLP/IPR matching for well X-2

In Figure 12 it is observed that there are only 0.65858% difference between measured and calculated gas rate where as for the bottom hole pressure, the difference is only 0.046406%.

ii. Gradient Matching

The Dynamic gradient test data was entered in the gradient matching option in order to compare the Vertical Lift Curve correlations with the test points obtained at various depths of the well, as shown in the Figure 13 and Figure 14. This was accomplished as an alternative technique of quality checking for the correlations used.

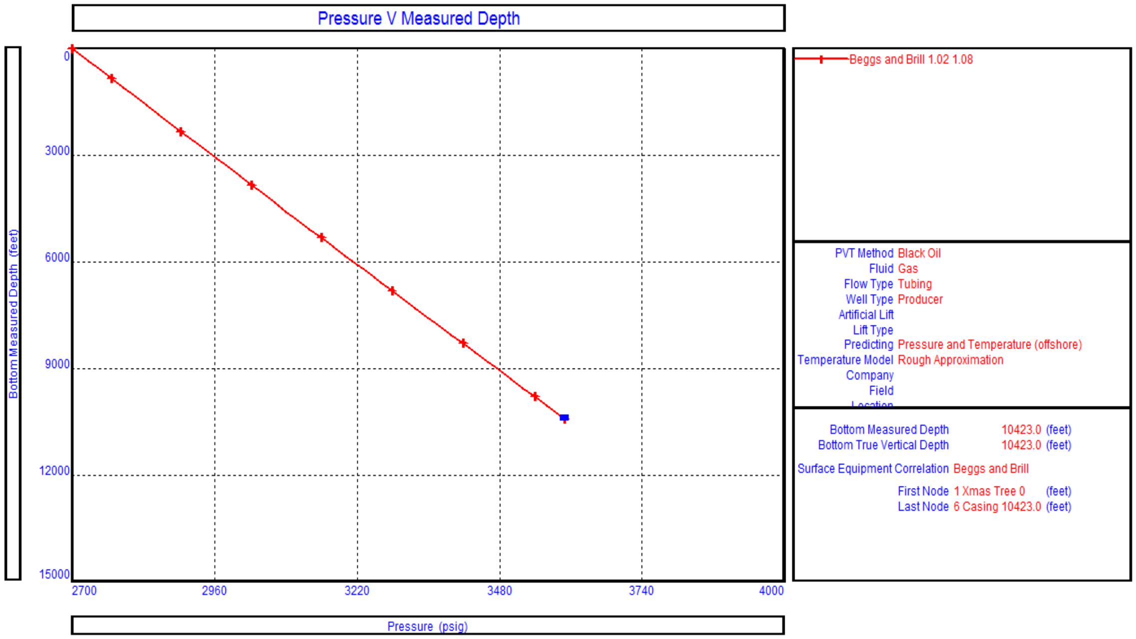


Figure 13: Besting Tubing correlation comparison for well X-1

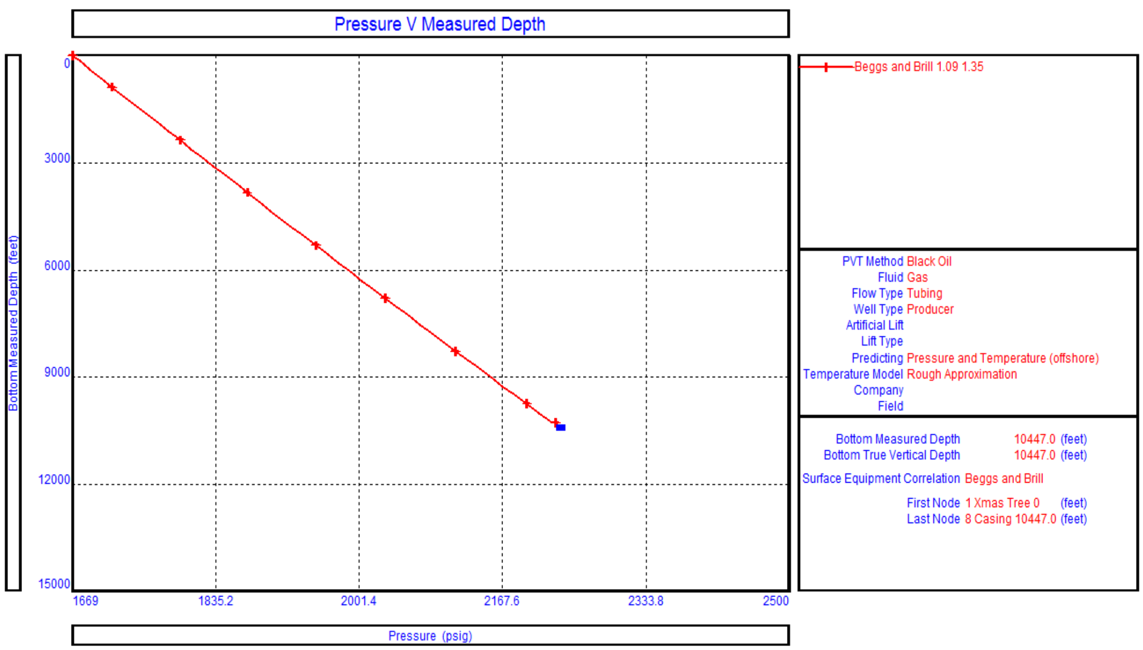


Figure 14: Besting Tubing correlation comparison for well X-2

Matching the given test point for all correlation for both wells X-1 and X-2, in the appendix1

3.4.3 System Calculation

The well model was finally analyzed using the variables such as reservoir pressure, first node pressure/well head pressure and tubing size. PROSPER had calculated the solution point using Nodal analysis as shown in the Figure 15 and Figure 16.

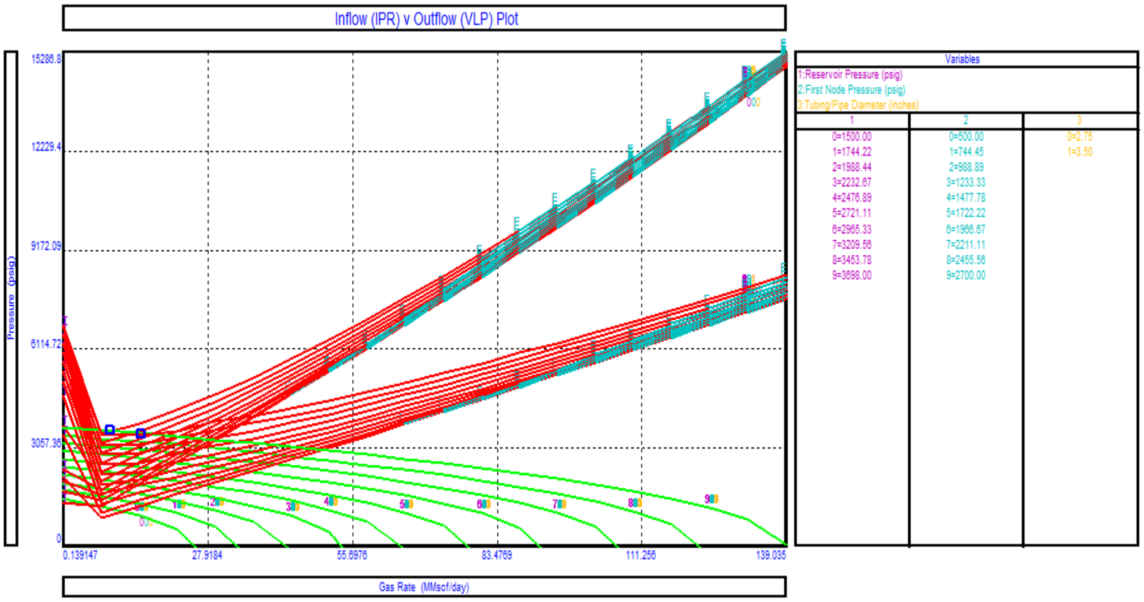


Figure 15: Nodal Analysis of well X-1

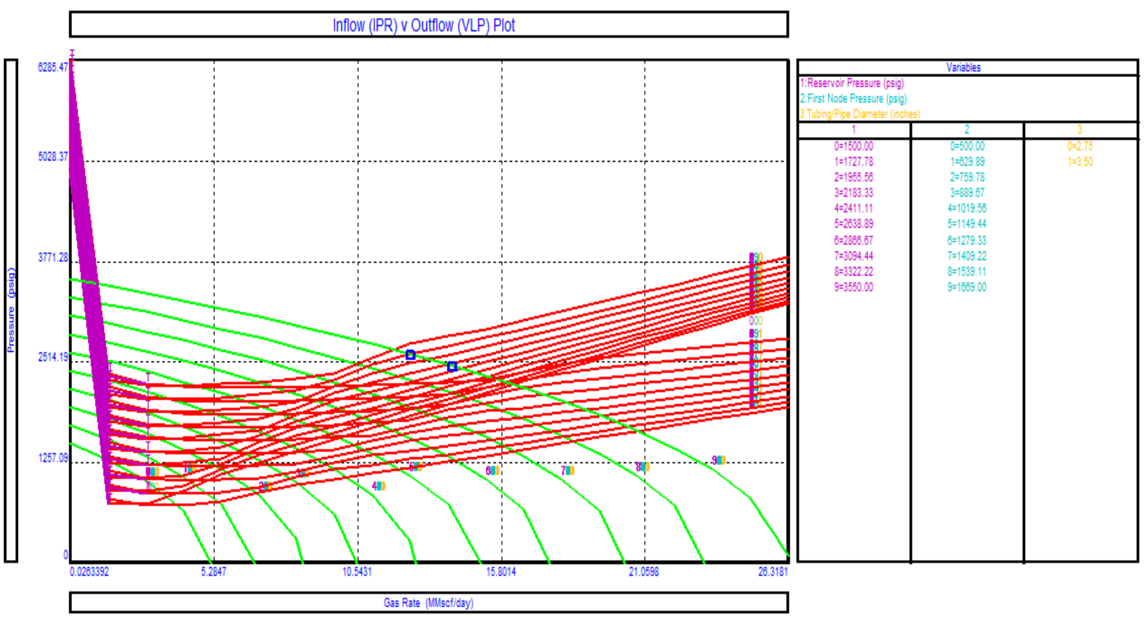


Figure 16: Nodal Analysis of well X-2

The prediction is run for different reservoir pressure with both 2.75 inches and 3.5 inches tubing size at wellhead pressure of 500 psig for both wells X-1 and X-2.

Graphs have been included in the Appendix2.

Table 4: Calculation results for well X-1

Reservoir Pressure (psig)	Tubing Diameter (inch)	Gas Rate (MMSCFD)
3500	2.75	27.271
	3.5	46.110
3000	2.75	22.036
	3.5	36.857
2500	2.75	17.022
	3.5	27.986
2000	2.75	12.195
	3.5	19.579
1500	2.75	7.636
	3.5	11.601

Table 5: Calculation results for well X-2

Reservoir Pressure (psig)	Tubing Diameter (inch)	Gas Rate (MMSCFD)
3500	2.75	15.872
	3.5	20.311
3000	2.75	12.302
	3.5	15.384
2500	2.75	8.984
	3.5	10.939
200	2.75	5.979
	3.5	7.095
1500	2.75	3.544
	3.5	3.979

Based on the results in table 4 and table 5, it is clear that the recommended tubing size is 3.5 inches for both wells X-1 and X-2.

4.5 Results from MPAL

4.5.1 History Matching

i. Recognition of Water Drive

Cole plot as shown in Figure 17 is applied to determine the missing reservoir and aquifer properties. The characteristic of Cole plot is almost a horizontal straight line. The Figure 17 shows that there is no external energy supporting the reservoir.

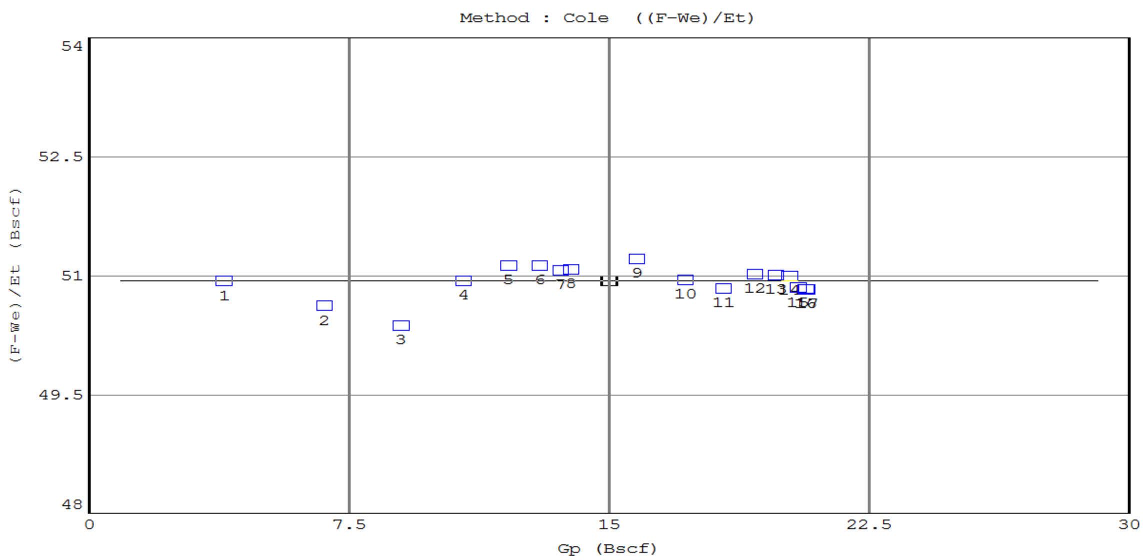


Figure 17: Cole plot without aquifer

ii. Reservoir Pressure Matching

A simulation of production was run to check the validity of the results obtained by analytical and graphical method. The technique was used in MBAL by calculating the average reservoir pressure, production history, reservoir/aquifer model parameters and then compared with the reservoir pressures obtained in the history as shown in the following Figure 18.

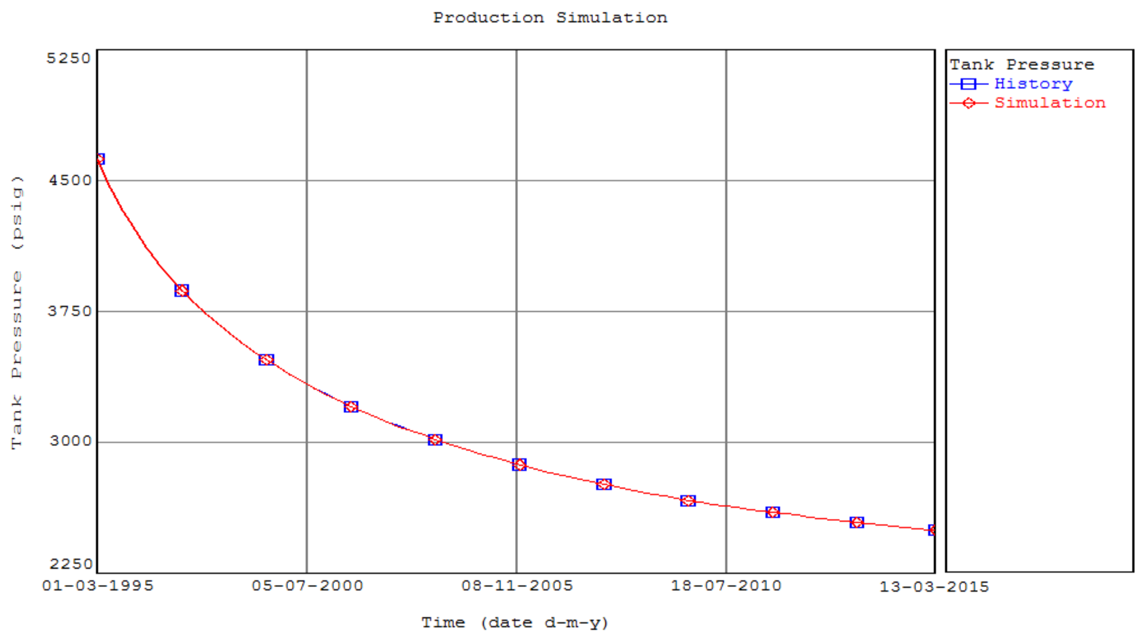


Figure18: History matching using the Reservoir/Aquifer Model and cumulative production data.

4.5.2 Reservoir's source of energy

The important finding from MBAL was to identify Rock Compaction as the supplementary drive mechanism for the reservoir along with the primary water drive & Gas-Cap expansion drive mechanism. The energy plot derived from MBAL in Figure 19 shows the relative contribution of the main source of energy in the reservoir and aquifer system. The Blue color represent the relative energy supplied by Compaction drive mechanism while Red color represent the relative energy supplied by Depletion drive mechanism.

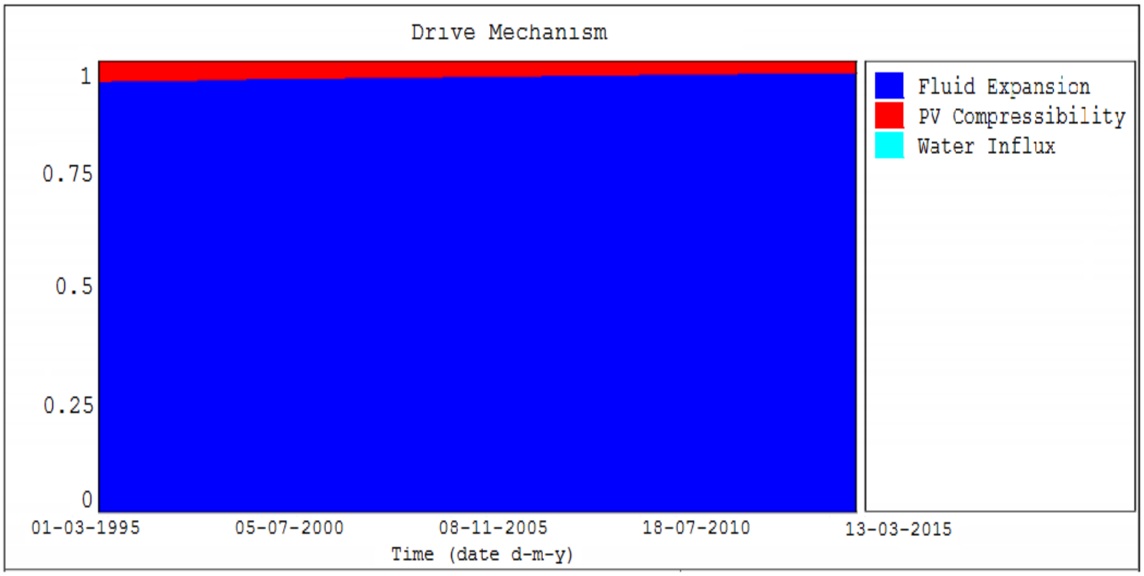


Figure 19: Energy plot showing relative contribution of drive mechanism.

It is clear from the plot that, initially fluid expansion was the main source of energy for the reservoir providing 95% of the total energy. Rock compaction provided 5% of the energy. It is clear also that there is no effective contribution of the water drive in the reservoir.

4.6 Results from GAP

4.6.1 Model Preparation

This step included defining the system, drawing schematic of the system and generating well VLP and IPR from PROSPER files for a wide range of operating conditions.

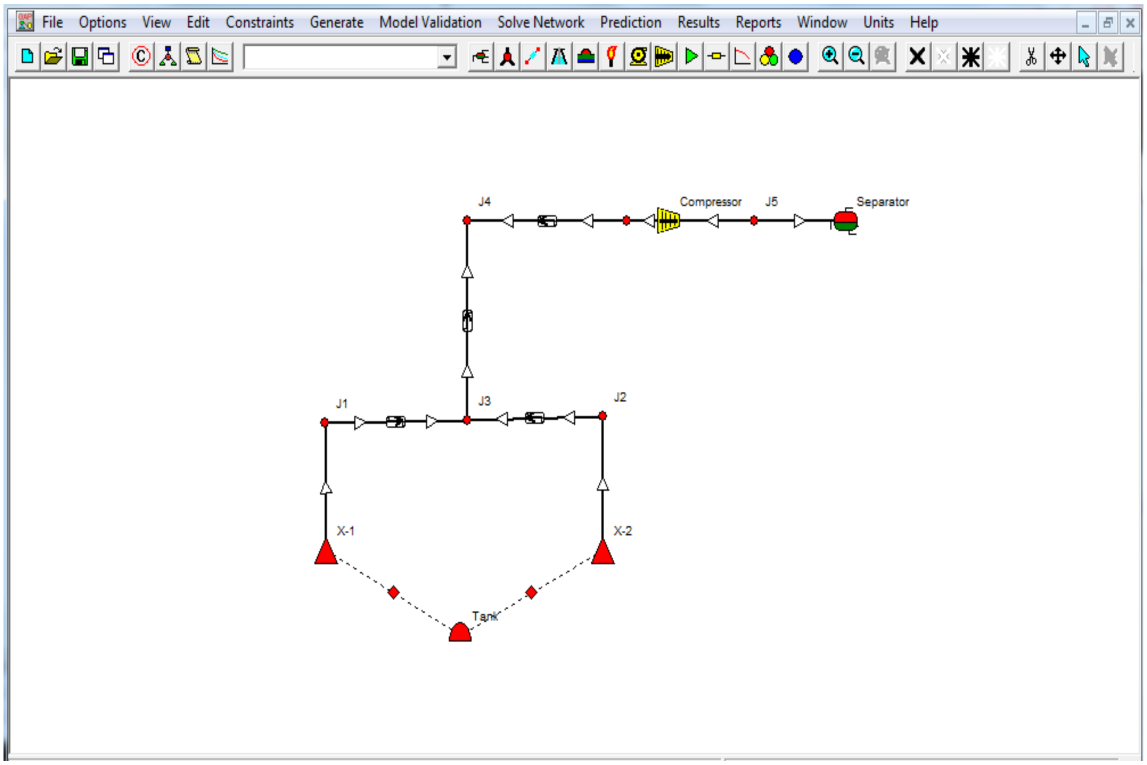


Figure 20: Schematic of the system (Reservoir, Separators, Pipeline etc.)
and Network Model

4.6.2 GAP Prediction Cases

The results are discussed here in the light of an important plot namely ‘Reservoir pressure & Gas recovery factor vs. Time’.

The production strategies investigated can be classified as:

i. Case 1: Base Case.

In this case, the ‘X’ gas field producing with two wells, well X-1 and well X-2 with tubing sizes of 3.5” and 2.75” respectively. The current total separator capacity of 60 MMSCFD and constant individual separator pressure (700 psig) had been maintained until the end of prediction period (year 2035). Keeping the separator pressure unchanged had eventually maintained a minimum allowable back pressure at corresponding wellheads of the wells.

From Figure 21 the following prediction results can be summarized:

- Abandonment pressure is found to be 1800 psig in January 2035 at a gas rate of 3.82 MMSCFD.
- Gas recovery factor is 57.76%.

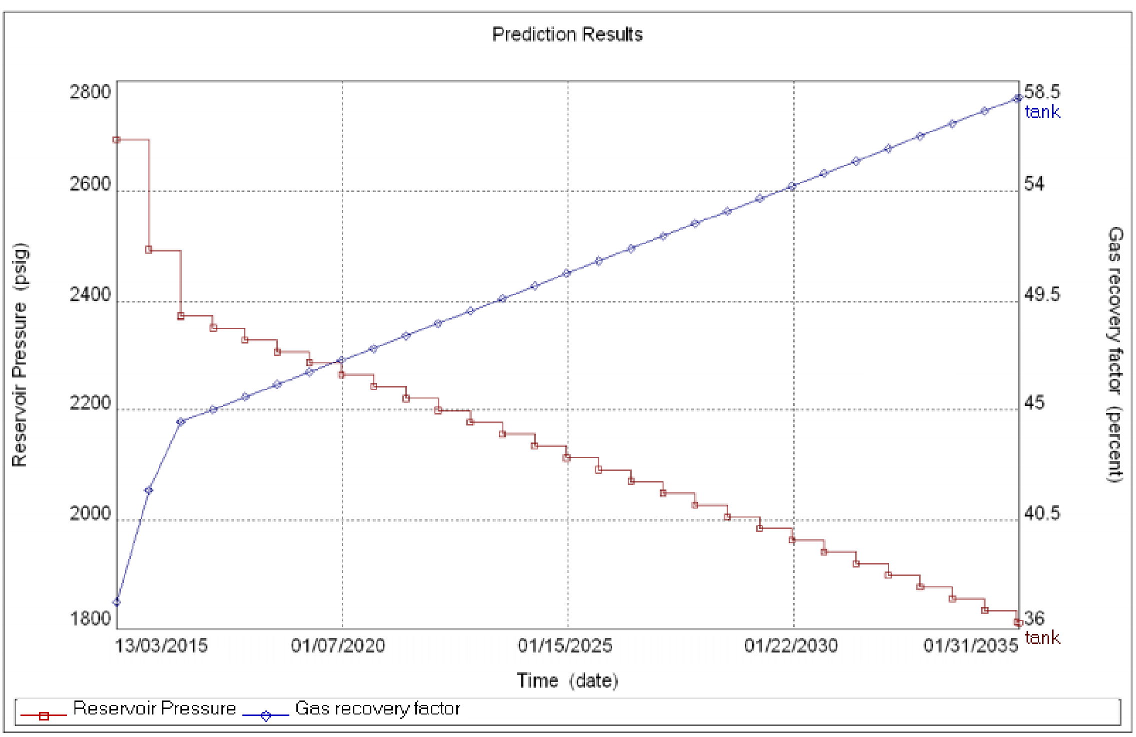


Figure 21: Reservoir pressure & Gas recovery rate vs Time, case 1

ii. Case 2: Installing surface compressor.

In this case, the pressure at the separator had been set constant at 700 psig but hypothetical compressors of fixed pressure drop and constant efficiency had been installed before the separator. This had ensured that the minimum allowable back pressure at the corresponding wellheads is been reduced to 500 psig.

From Figure 22 the following prediction results can be summarized:

- Abandonment pressure is found to be 1380 psig in January 2035 at a gas rate of 6.5 MMSCFD.
- Gas recovery factor is 67.25%.

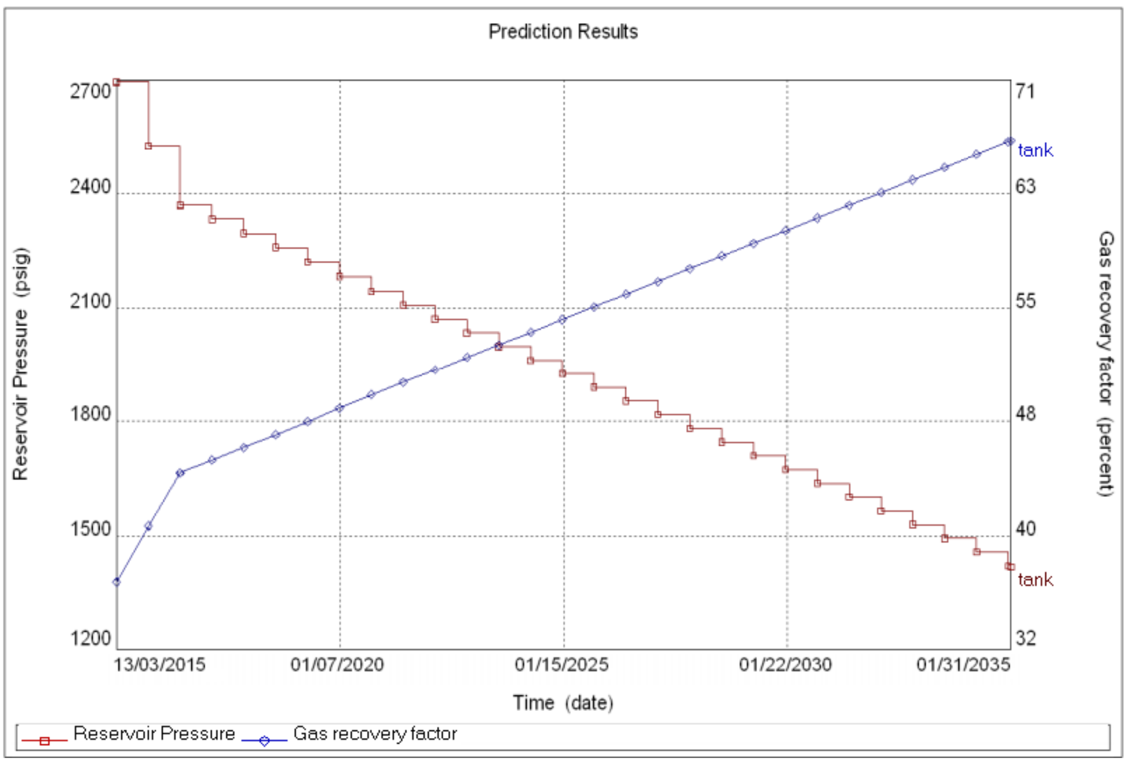


Figure 22: Reservoir pressure & Gas recovery rate vs Time, case 2

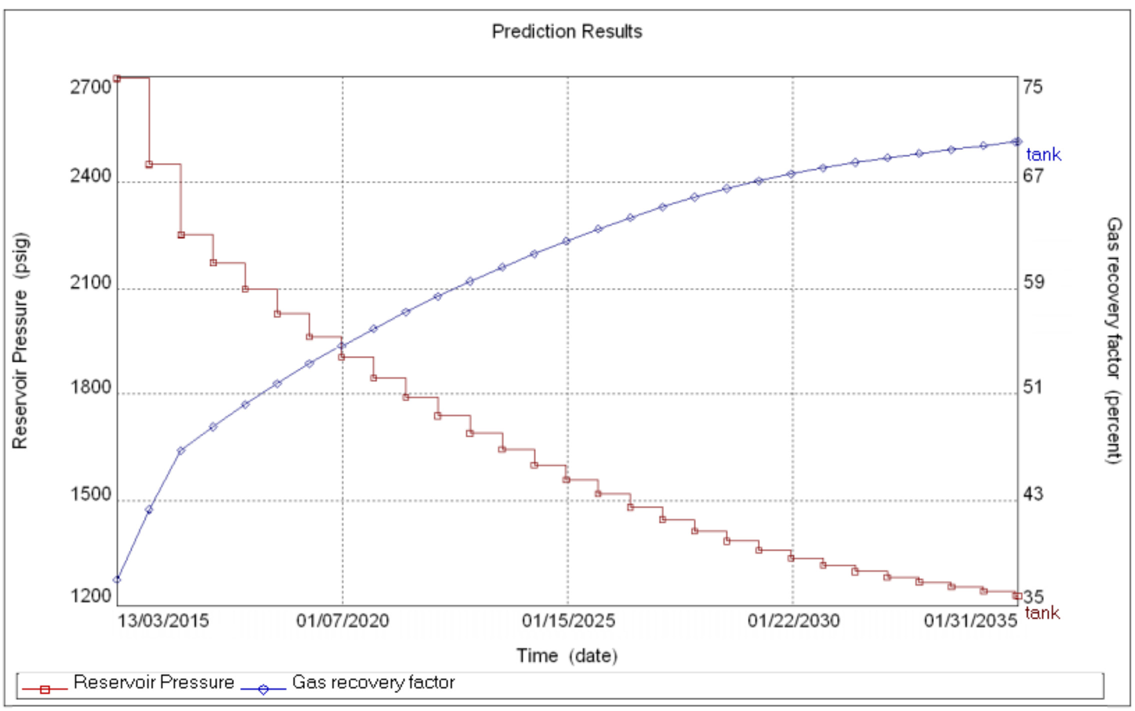
iii. Case 3: Adding a new well.

In this case, a new well has been drilled which is well X-3 with tubing size of 3.5” and 15 MMSCFD gas production rate.

Well X-3 is unloading to the same separator of well X-1 and well X-2, since the handling capacity of the separator which is 60 MMSCFD is more than the amount produced by the three wells which is 45 MMSCFD.

From Figure 23 the following prediction results can be summarized:

- Abandonment pressure is found to be 1250 psig in January 2035 at a gas rate of 2.27 MMSCFD.
- Gas recovery factor is 71.8%.



*10*Figure 23: Reservoir pressure & Gas recovery rate vs Time, case 3

The gas recovery factor has been increased by around 14% for any decision making process, which is close to maximum recovery that is mostly desirable for a gas reservoir.

4.6.3 Comparative analysis between the three cases

Table 6: Comparative analysis of Case 1, 2 and 3

Production Strategy	Abandonment Pressure (psig)	Abandonment rate (MMSCFD)	Gas recovery factor (%)
Case 1 Base Case	1800	3.82	57.76
Case 2 Installing a compressor	1380	6.5	67.25
Case 3 Adding a new well	1250	2.27	71.8

Based on table 6, it is clear that the case 3 is the best case scenario for the 'X' gas field.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

After critical evaluation of the 'X' field from the available field data given, it was observed that:

- The gas field is depletion type, no external support is evident.
- For individual well modelling by nodal analysis, as flow rate and reservoir pressure decline, 2.75" tubing size becomes less beneficial compare to 3.5" tubing size, thus, is recommended to use 3.5" tubing size.
- The duration of plateau for the gas rate can be further improved by reducing the minimum allowable backpressure at wellhead by use of compressor.
- Drilling a new well will significantly increase around 14% of gas recovery factor as well as maintain longer and sustainable production rate.

Therefore, case 3 (adding a new well) is the recommended optimized production strategy for the 'X' gas field.
This recommendation, however, is made only based on a technical point of view, and does not consider the economic feasibility of the strategy.

5.2 Recommendation

- In order to achieve maximum gas recovery, more wells are recommended to be drilled in the reservoir.
- Continuous monitoring and updating of well performance and the production prediction should be accomplished in an organized way in the future.

CHAPTER 6

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APPENDEX

Appendix1

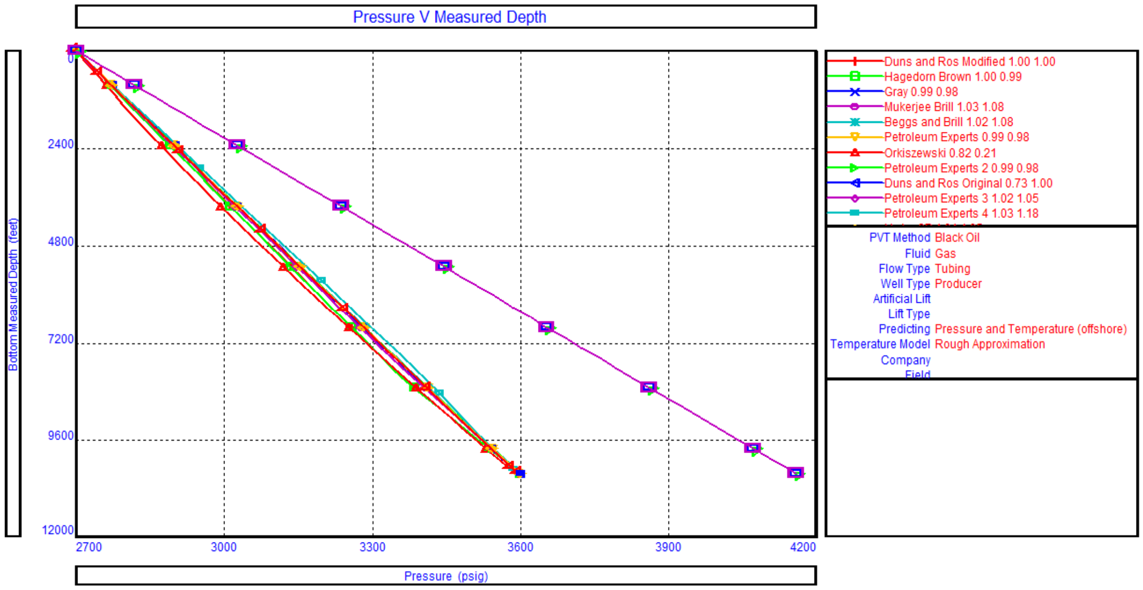

Figure 24: Pressure vs. Measured Depth for different flow correlation for well X-1

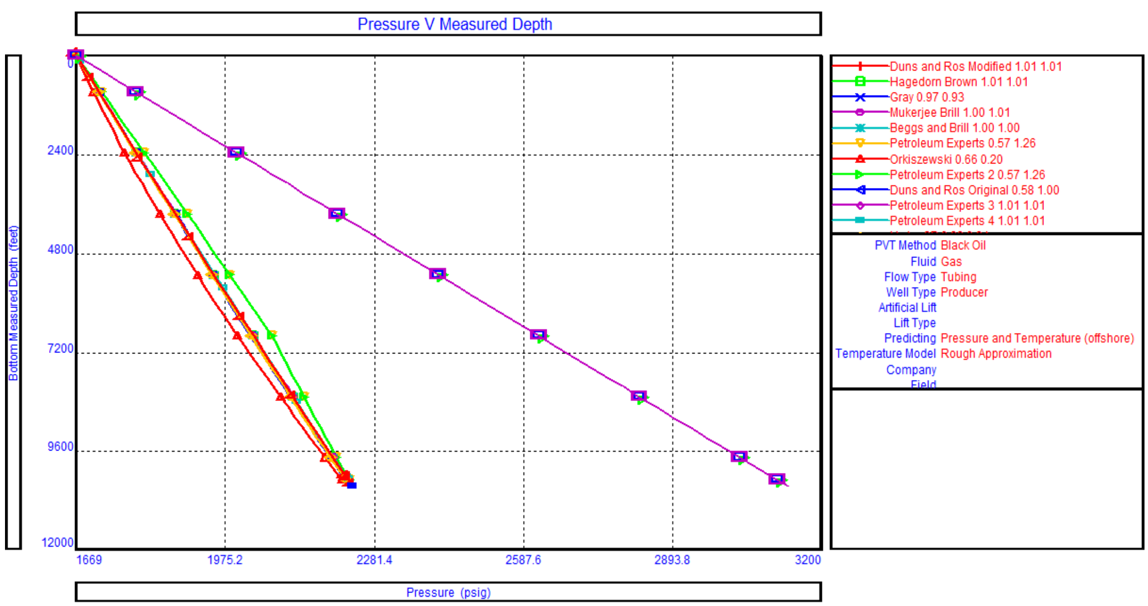

Figure 25: Pressure vs. Measured Depth for different flow correlation for well X-2

Appendix2

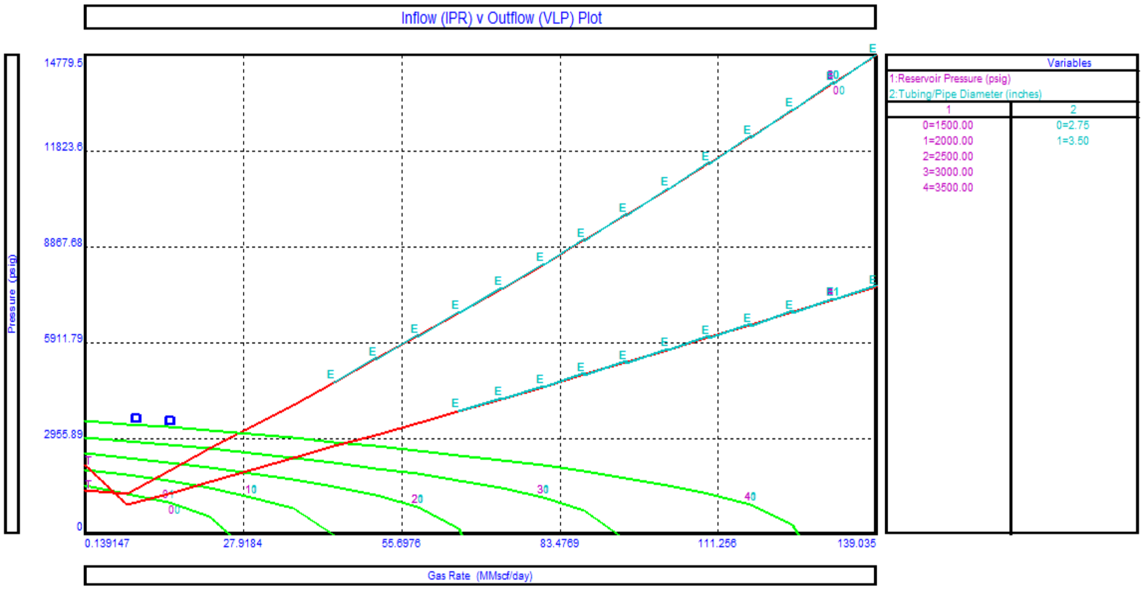

Figure 26: Nodal Analysis of well X-1 @WHP = 500 psig

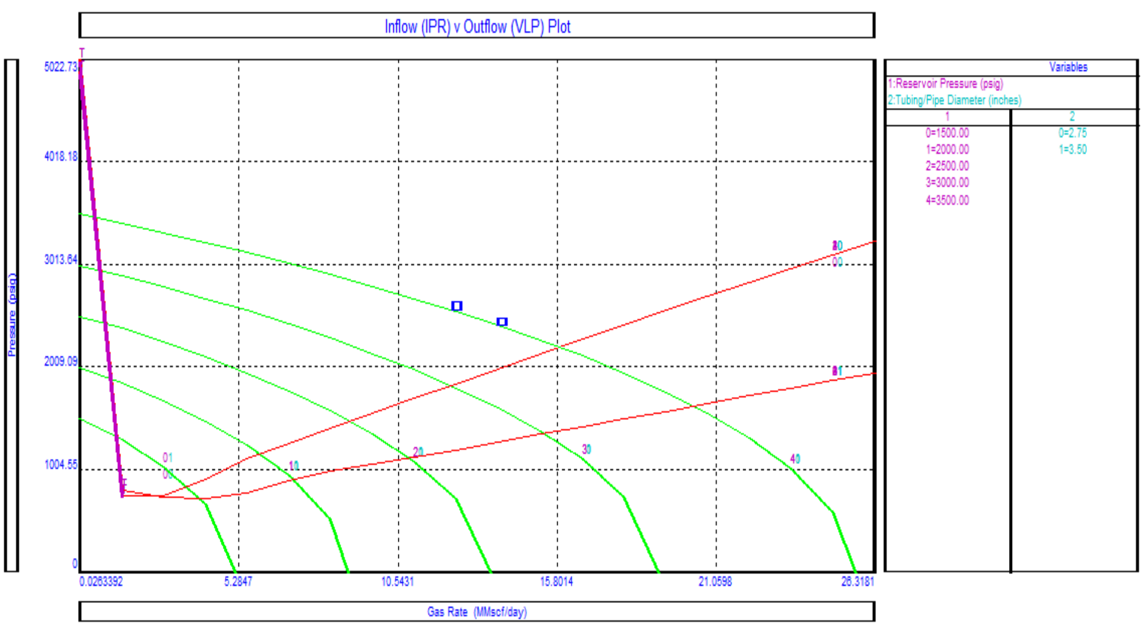

Figure 27: Nodal Analysis of well X-2 @WHP = 500 psig