A STUDY OF PRODUCTION OPTIMIZATION USING PROSPER

by

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ABSTRACT

The production optimization of oil and gas wells using computerized well model has become a successful technique contributing towards the better efficiency and higher production of many wells.

Well modeling using PROSPER, one of components of the Integrated Production Modeling (IPM) was implemented in Field X which is located in Peninsular Malaysia. The model carries all the properties of the well with detailed description of the reservoir and vertical lift performance.

The process includes four phases. First phase was building well model by using PVT, IPR, surface and equipment data. Second phase was constructing well matching based on the monthly well test data. This helps to ensure that the model is well calibrated and constructed. Third phase was performing well analysis based on the well matching results. Well analysis can be performed by evaluating each components of the producing well. Often this procedure will identify possible problems occurred in the production components which restricting flow and causing the well to produce in a manner that the maximum potential rate not achieved.

Overall, this production optimization technique permits engineer to come out with some modifications and suggestions which is expected to increase the production.

ACKNOWLEDGEMENTS

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ABBREVIATIONS

IPM	Integrated Production Modelling
IPR	Inflow Performance Relationship
PVT	Pressure volume temperature
VLP	Vertical Lift Performance
MBAL	Material balance
PETEX	Petroleum Expert
MPFM	Multiphase flow meter
ESP	Electric submersible pump

TPR	Tubing performance relationship
GOR	Gas oil ratio
PE	Petroleum experts
E&P	Exploration and production
GLR	Gas lift ratio
BHP	Bottomhole pressure
OPR	Operating performance relationship
TIDC	Tapered Internal Diameter Tubing Completion
OD	Outside diameter
ID	Internal diameter
FBHP	Flowing bottomhole pressure
WHP	Wellhead pressure
WC	Water cut
STB/D	Stock tank barrel per day
API	American Petroleum Institute
THP	Tubing head pressure
MMSCFD	Million standard cubic feet per day
PI	Productivity Index

NOMENCLATURES

Pr	Reservoir pressure
Bo	Oil formation volume factor
Bg	Gas formation volume factor
Bw	Water formation volume factor
Cp	Centipoise
Rb/stb	Reservoir barrel per stock tank barrel

CHAPTER 1: INTRODUCTION

1.1 BACKGROUND OF STUDY

There are many oil and gas wells around the world that have not been optimized to achieve an objective rate in efficient manner. In fact, many may have been routinely completed in a manner such that their maximum potential rate cannot be achieved.

The production optimization of oil and gas wells using well models has contributed to improved completion techniques, better efficiency and higher production with many wells. One of the most important aspects of well analysis is to offer recognitions of those wells that can produce at rates higher than the current rate.

This project is about the production optimization of a field, which is located in the southern region of Malay basin (Field- X). Three oil producers wells involved in this project.

By introducing the concept of the Integrated Production Modeling IPM, three well models have been constructed by using PROSPER. Well modeling using PROSPER is the bridge between the reservoir and surface model. The model carries all the properties of the well with detailed description of the reservoir and vertical lift performance.

Ensuring that the model is well calibrated is essential to study the real behavior of the well. After constructed well model, the well matching process can be performed by using the well test data. The well analysis is then conducted at each components of the production system to determine if it is producing at the lower rate as compared to its maximum potential rate. A basic requirement for well analysis is to be able to define the current well inflow performance relationship (IPR). Accurate well test data must be obtained and proper IPR model applied for successful analysis.

By the end of this project, a few recommendations and suggestions are put forward in order to optimize the field production in the near future.

Figure 1: Project phases

1.2 PROBLEM STATEMENT

Nowadays, many oil and gas wells may be producing at rates which appear to be optimum but actually contains unnecessary restrictions to flow. These wells can be analyzed using modeling techniques to evaluate all components of producing well systems. Often this procedure will identify possible modifications in the well which if made will result in larger flow rates. All components starting at the static reservoir pressure and ending at the separator are evaluated if present.

This may include inflow performance, flow across the completion, flow up the tubing string including any down hole restrictions, flow across the surface choke if applicable, safety valves, flow through horizontal flow lines and into the separation facilities.

By performing well analysis using well model, each components of the well system can be determined if it is restricting the flow rates unnecessarily when compare to the flow capacity of other system components.

This optimization technique permits quick recognition by the operator's management and engineering staff of ways and means to increase production rates. Overall, optimization techniques can serve as an excellent tool to verify that a problem exists and indicate that additional testing is in order.

1.3 OBJECTIVES

The objective of production optimization method is to find out any component of the well that is restricting the rate below its maximum potential rate. It thus provides an opportunity for the engineer to propose possible recommendation and modification to the well which could improve the production later on. However, it may also be find out that the incorrect data is the cause of the predicted higher rate.

1.4 SCOPE OF STUDY

This project is about constructing well model using simulation followed with some analysis. Basically, this project consists of few phases which include:

Stage 1: Build up well model

Stage 2: Perform well matching

Stage 3: Simulate base case scenario

Stage 3: Well analysis

Stage 4: Recommendation and modification

1.5 RELEVANCY OF THE PROJECT

This production optimization is very relevant to the needs of oil and gas industry organization. From this project, the well performance at the Field X can be observed and analyzed based on the proper well model. From the well analysis, engineer will be able to identify if there is any problems occurred in the components of the production system which cause it to flow below its maximum potential. From there, the engineer staff as well as the operator’s management can find ways and means to increase production rate. For example, assume that a well is producing 400 bbl/D of oil. However, by applying a well modeling analysis, it shows that this well capable to produce up to 600bbl/D. This difference may attribute to many factors. By performing well analysis using the model, some well components may be identified as restricting flow below its optimum rate. This provides an opportunity for the engineer to come out with few recommendation and modification to optimize the well.

From this production optimization technique, it can extend reservoir life as well as increase the rates. This in return can increase the revenue of the country and contribute towards a higher profit to the oil and gas companies.

1.6 FEASIBILITY OF THE PROJECT WITHIN THE SCOPE AND TIME FRAME

For the final year project, it is divided into two parts; final year project 1 (FYP 1) and final year project II (FYP 2). For the FYP 1, the project is about the documentation of the project. While, for the FYP 2, the project is more towards the development of the project using simulation and followed with some analysis. For the project process during the FYP 2, the author need to divide the task wisely as the time provided to conduct the project is only about 3 months. For this project, the four phases involved can be considered not so time- consuming. The only problem faced by the author is the difficulties to obtain the required data to do well model as well as well matching. As a whole, this project is successfully accomplished within the given time frame.

CHAPTER 2: LITERATURE REVIEW

2.1 INTEGRATED PRODUCTION MODELLING- PROSPER

Based on the Integrated Petroleum Handbook published by the Petroleum Experts Limited, PROSPER is a well performance, design and optimization program which is part of the Integrated Production Modeling Toolkit (IPM).

Some of its applications include:

- Design and optimize well completions including multi lateral, multilayer, and horizontal wells
- Design and optimize tubing and pipeline sizes
- Design, diagnose and optimize Gas lifted, Hydraulic pumps and ESP wells.
- Generate lift curves for use in simulators
- Calculate pressure losses in wells, flow lines and across chokes
- Predict flowing temperatures in wells and pipelines
- Monitor well performance to rapidly identify wells requiring remedial action
- Calculate total skin and determine breakdown (damage, deviation or partial penetration)
- Unique black oil model for retrograde condensate fluids, accounting for liquid dropout in the wellbore
- Allocate production between wells

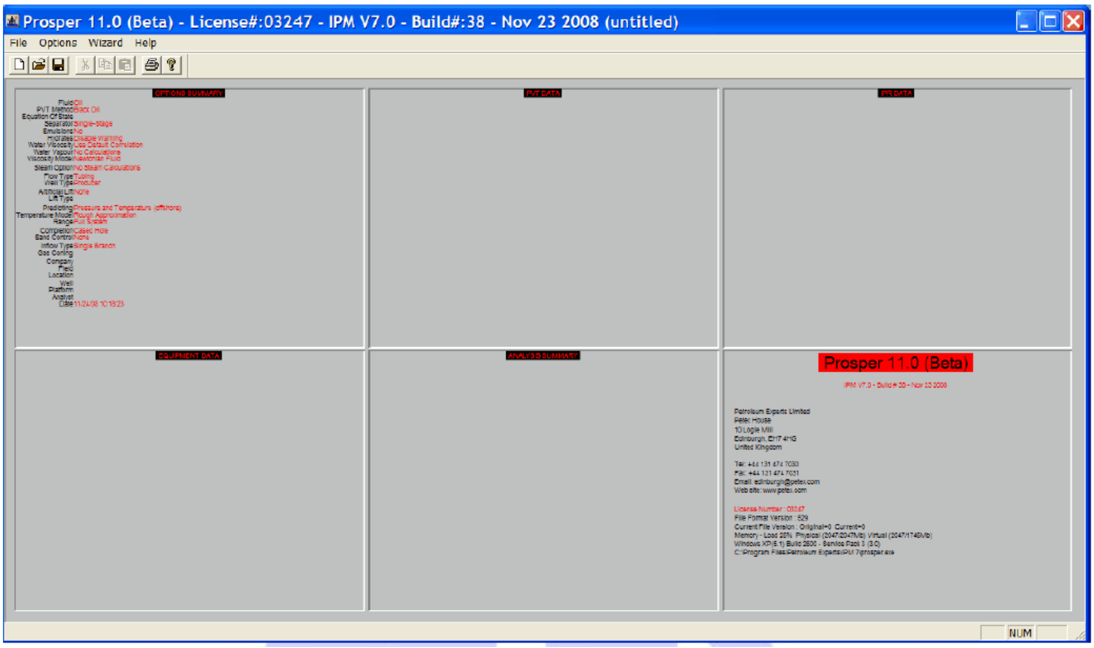

Figure 2: PROSPER main menu option

2.2 TO DEVELOP THE OPTIMUM FIELD DEVELOPMENT PLAN FOR CONDENSATE WELLS USING INTEGRATED PRODUCTION MODELLING (IPM)

In this paper, Shoaib Memon and Asif Zameer (2012) discussed that IPM is an approach for modeling an entire asset from reservoir to the final delivery point. The components of IPM model which include fluid model, well model, reservoir model and facility model give an understanding on how:

- One end of the delivery chain affects the other: Psep v Pres.
- Constituting components design and operation interact with each other: facilities constraints, pipeline bottlenecks, well potential, etc
- It defines design and operating criteria for a given field, not just for today but also for the future.

To start modeling, PVT properties of the reservoir fluid need to be generated using PVTP software. At initial, every fluid model will not behave as the actual one and thus, it need to be matched with the lab data. This is to ensure that the model does not divert away and behave as closely as it can as a real reservoir fluid.

After PVT model, wellbore model is then developed using Prosper software. It is a basic tools used to enhance production of a well when reservoir pressure start to decline. Some of the evaluations can be done by analyzing the Inflow performance curve (IPR) and Vertical Lift performance (VLP).

Reservoir modeling can be used to understand the behavior of current reservoir by using Petroleum Experts MBAL. From this model, the future prediction of the reservoir also can be performed apart from determining its depletion. The reliability and accuracy of the developed model depends upon the pressure and production points during the production history.

2.3 INTEGRATED PRODUCTION SYSTEM MODELLING OF THE BAHRAIN FIELD

In this paper, Vijay Pothapragada, Hamza Al Kooheji, Said Al Hajri and Ibrahim Siyabi (2012) discussed about the optimization in the Bahrain Field using Integrated Production Model (IPM). An IPM involves a proactive, creative process of searching, identifying and realizing opportunities to improve performance and results in oil and gas field.

IPM is an advanced way to evaluate the production performance of the entire production system. By constructing oil production system model, the users can perform:

Surveillance: To assess if measurements taken in the field agree with expectations.

Design and optimization: To be able to perform gas lift design optimization and optimum gas lift gas allocation.

Field Management: the Bahrain Field currently has gas handling capacity constraints. The model is used for optimizing field production through choke size optimization and gas lift optimization while honoring gas capacity constraints.

Field development: The model is used for design and optimization activities such as optimum locations for new well connections to the field network and existing system or facilities debottlenecking.

Apart from that, the authors discussed a typical methodology involves when constructing model which includes:

- Data preparation and quality check
- Load new production data to VLP/IPR screen
- Match VLP and IPR
- Calculate expected lift point for gas lift wells
- Prepare VLP table data range
- Match flow line pressure drop in surface model
- Data management

Figure below shows the workflow process logic for the model update automation.

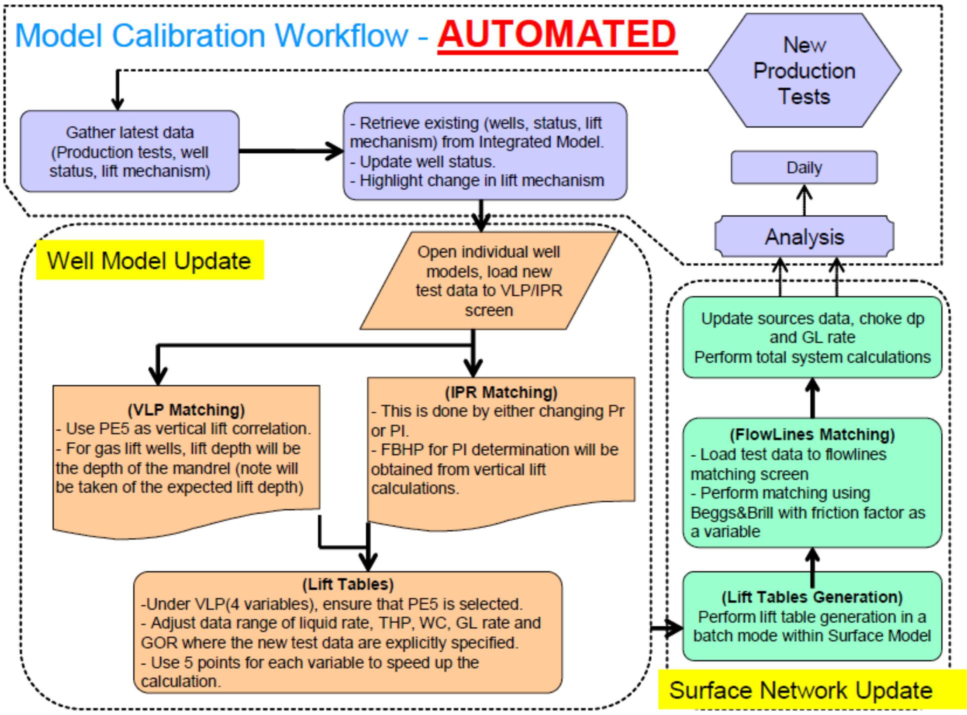

Figure 3: Model update automation workflow

2.4 WELL PRODUCTIVITY

According to the journal published by the department of petroleum engineering from Heriot-Watt University, the productivity of the system is dependent on the pressure loss which occurs in several areas of the flow system namely:

- The reservoir
- The wellbore
- The tubing string
- The choke
- The flow line
- The separator

Under natural flowing conditions the reservoir pressure must provide all the energy to operate the system i.e. the pressure drop in the system.

$$P_R = \Delta P_{SYSTEM} + P_{SEP}$$

where;

P_R = reservoir pressure

ΔP_{SYSTEM} = total system pressure drop

P_{SEP} = separator pressure

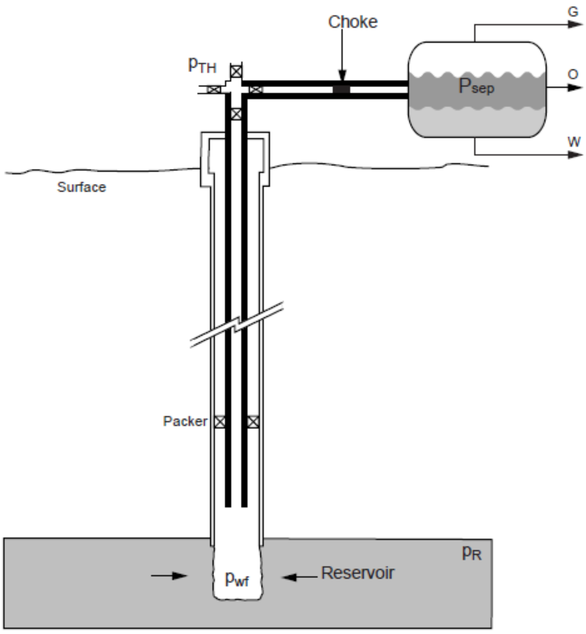

Figure 4: The production system

The production drop which occurs across the reservoir, Pres is defined as the inflow performance relationship or IPR. The pressure drop and cause the flow in the tubing and wellbore is that which cause the lifting of fluid from the reservoir to the surface and is known as the vertical lift performance or VLP, or the tubing performance relationship, TPR.

$$\text{i.e. for natural flow } R = \Delta P_{RES} + \Delta P_{TBG} + P_{TH}$$

Where;

P_{TH} = Tubing head pressure

The pressure drop across the reservoir, the tubing and choke are rate dependent and these relationships therefore define the means by which we can optimize the production of fluid from the reservoir.

2.5 VLP CORRELATION APPLICATION IN PROSPER

Based on the Integrated Petroleum Expert handbook, a few Vertical lift performances (VLP) correlations and its applications have been presented.

VLP correlation applications

Fancher Brown is a no-slip hold-up correlation that is provided for use as a quality control. It gives the lowest possible value of VLP since it neglects gas/liquid slip it should always predict a pressure, which is less than the measured value. Even if it gives a good match to the measured down hole pressures, Fancher Brown should not be used for quantitative work. Measured data falling to the left of the Fancher Brown on the correlation comparison plots indicates a problem with fluid density (i.e. PVT) or field pressure data. This is thus essentially for quality control purposes.

For oil wells, **Hagedorn and Brown** perform well for slug flow at moderate to high production rates but well loading is poorly predicted. Hagedorn Brown should not be used for condensates and whenever mist flow is the main flow regime. Hagedorn Brown under predicts VLP at low rates and should not be used for predicting minimum stable rates.

Duns and Roses Modified usually performs well in mist flow cases and should be used in high GOR oil and condensate wells. It tends to over-predict VLP in oil wells. Despite this, the minimum stable rate indicated by the minimum of the VLP curve is often a good estimate.

Duns and Roses Original is the original published method, without the enhancements applied in the primary Duns and Roses correlation. The primary Duns and Roses correlation in PROSPER has been enhanced and optimized for used with condensates.

Petroleum Experts correlation combines the best features of the existing correlations

Petroleum Experts 2 includes the feature of the PE correlation plus original work on predicting low rate VLPs and well stability
Orkiszewski correlation often gives a good match to the measured data. However, its formulation includes a discontinuity in its calculation method. The discontinuity can cause instability during the pressure matching process; therefore we do not encourage its use.

Beggs and Brills is primarily a pipeline correlation. It generally over-predicts pressure drops in vertical and deviated wells.

Gray correlation gives good results in gas wells for condensate ratios up to 50bbl/MMscf and high produced water ratios. Gray contains its own internal PVT model which over-rides PROSPER normal PVT calculations.

2.6 PRODUCTION OPTIMIZATION OF A MATURE OFFSHORE ASSET

In this paper, G. Bates, D. Bagoo, D.G. de la Calle, A.Finol, R.Nazarov, C.Rivas, M. Hernandes & C.Bunraj (2012) have presented that an objective of gas lift optimization is to achieve the following:

- To produce at a stable rate i.e. the following parameters such as casing and tubing pressures, water cut and well head temperature are all stable
- To produce the same oil rate with less gas injection
- To maximize the production considering the costs of the gas compression and produced water handling. In many cases, the optimum injection point may not be the same as the economical injection point, simply because the marginal production gain is not economically justify by the increase of gas injection.

2.7 APPLICATION OF IPM MODELLING FOR PRODUCTION SURVEILLANCE, ALLOCATION AND OPTIMIZATION

In this paper, Herbert Orioha, Chris Gruba, Gabriel Muoneke and Ifeanyi Ezuka (2012) discussed that:

IPM modelling challenges were to:

- History match several years of field production and pressure data
- Accurately allocate multizone production from multi-reservoir sands including some inter reservoir communication
- Optimize gas lift within the framework of the existing gas lift mandrel design
- Determine viability of compressor upgrade, enabling increased gas lift volumes resulting in increased production rate from the reservoir

Objective reporting/reviewing:

- Maximize oil production by continuous well optimization
- Quarterly update of simulation & IPM models

Actions:

Requirement to achieve the strategies include:

- Update the current operations performance
- Optimize wellhead chokes on all wells using drawdown targets and field well tests
- Minimize idle well capacity

Key performance indicator/ targets:

- Maintain financial discipline
- Actively monitor and report weekly well rates, choke settings and target drawdown against plan
- Generate data for and support production forecast on a monthly basis
- Reconcile production variances at end of month relative to predicted values

2.8 RECENT ADVANCES AND PRACTICAL APPLICATIONS OF INTEGRATED PRODUCTION MODELLING AT JACK ASSET IN DEEPWATER GULF OF MEXICO

In this paper, Umut Ozdogan, James F.Keating, Mark Knobles, Adwait Chawathe and Doruk Seren (2008) have presented a five step workflow to build an integrated production model. Some of them include:

Step 1: Framing: Framing is the step when entire project teams define the problem and provides the key technical assumptions that can affect the decision being considered.

Step 2: Modeling: In this step, all of the technical parameters from the framing step are input to the respective models and software.

Step 3: Static Quality Check (Reservoir to separator): This is when engineer quality checks the rock, fluid, and the mechanical design input in each model (subsurface, wellbore, surface network and others if any) and compares against the available data (well log, core, flow back test, fluid samples, seismic and others)

Step 4: Initialization (Link Surface Network to Subsurface Model): The well in the subsurface model are linked to their pairs in surface facility model

Step 5: Dynamic Quality Check: The full system is run for the whole prediction period. Convergence problems if observed are fixed. If an anomaly is detected, a modeling step might be revisited.

Step 6: Forecasting: IPM can be used for major economic decisions in two main forms which are for 1) integrated use and 2) modular use.

Integrated use: Whole IPM is run to forecast for full-field predictions

Modular use: Certain module of IPM is extracted and used to support a relatively smaller scale decision.

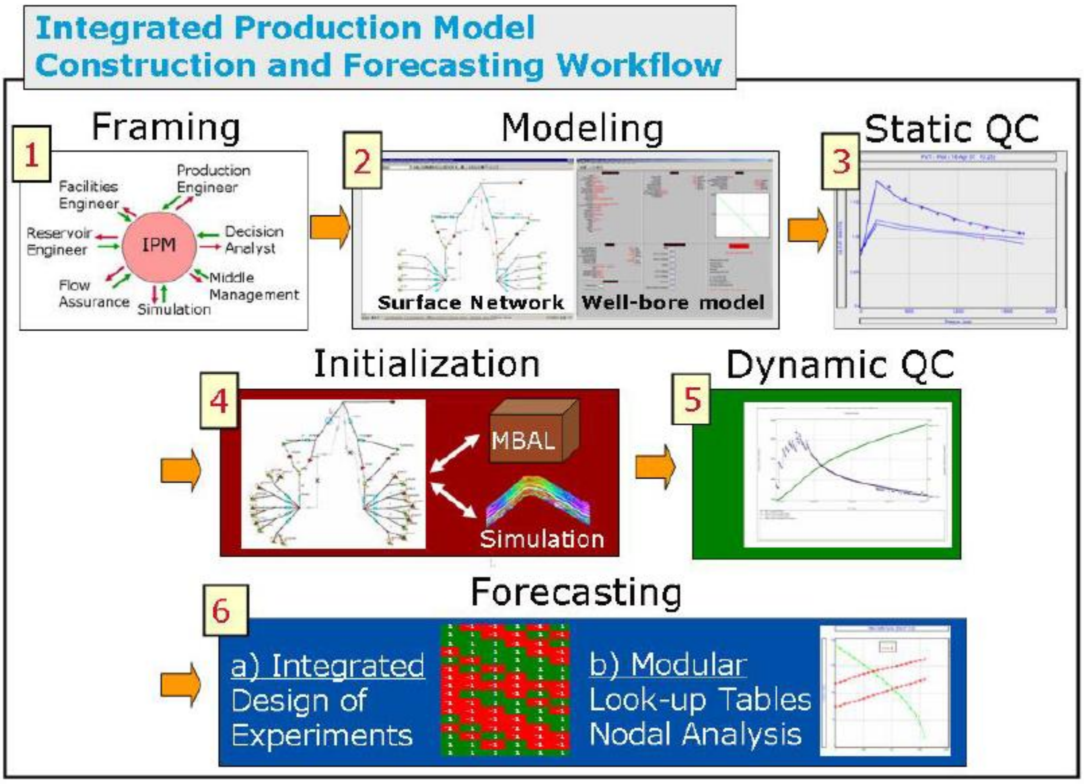

Figure 5: Integrated Production Model construction and Forecasting Workflow

2.9 IMPROVING OPERATIONS USING MODEL BASED DECISION SUPPORT

In this paper, F. Verre, A. Casarotti, A.Palma & G.Viadana (2011) stated that the optimization must be able to find solutions that maximize the output of the production system in accordance with all the constraints of the entire system. In line with this, an optimization program needs to be analyzed using the entire asset and few operating variables that can maximize a production rate can be proposed to the operator.

The authors also further discussed on a few typical degrees of freedom which involved in E&P asset optimization process. Some of them include of:

- Choke valve setting (wellhead pressure or choke opening)
- Well routings (in low, medium or high pressure manifolds)
- High, medium and low pressure separators pressures
- Pumps and compressors flows or speeds

- Stabilization and dehydration columns pressures, temperatures, reflux flows (or ratios)
- Slug-catcher and oil header pressures
- Gas lift rates

Practical optimization techniques have three basic requirements:

1) The method should find the true global optimum
2) The convergence should be fast
3) The number of control parameters should be limited so that it will be easy to set

In addition, the authors discussed on the tests which were carried on by using three kinds of optimization; two ordinary optimizations using commercial available tools and third optimization performed by the Generic Algorithm tool developed by Production Department.

- Optimization conducted on gathering system by imposing outgoing maximum flow rate. This model is able to maximize an objective function, for example liquid flow rate, gas flow rate, gas lift rate or revenue. The main process variables are not modified, e.g.; the pressure of separator is a fixed data and cannot be optimized
- Optimization conducted on gathering system by imposing outgoing maximum flow rate and minimum FBHP (Flowing Bottom Hole Pressure) per each well.
- Optimization conducted using the Genetic Algorithm tool.

2.10 INTEGRATED PRODUCTION MODELLING: ADVANCED BUT, NOT ALWAYS BETTER

According to the C. Correa (2010), IPM can integrate as many or as few independent models as required to perform the defined tasks which include:

- Reservoir Dynamic model
- Nodal Well Models
- Wellpad or Manifold model
- Transport & Processing Facilities Model

Meanwhile, commercial software RESOLVE was used as the base ground platform. Among many other intersecting features, RESOLVE allows linking different platforms while performing prediction and optimization processes at all involved levels. The full set of applications consists of:

- RESOLVE
- ECLIPSE (and MBAL)
- PROSPER
- GAP
- HYSYS

The author also stated that the core of the logic relies on GAP (surface network model). The standard procedure applied for each time step could be summarized as:

- Reservoir data is passed to GAP using well inflow performance tables
- Surface network is then solved and optimized based on the GAP objective function
- Separator fluids (rates, PVT data) pass to the process model, which is then solved
- Optimization result are passed back to the simulation models using any of flowing rates, bottom hole flowing pressure or tubing head pressure
- If global optimization is introduced in RESOLVE, it will iterate on points 2 and 3, trying to solve the system against the overall objective function before passing back any data to the simulator models.

Each application in IPM was requested to perform the following tasks:

- ECLIPSE is requested to perform model solves at each time step under the rates or pressures passed by GAP
- PROSPER does not perform explicit runs (much slower) at each time step and pre-tabulated VLPs, (according to the expected range of operation) are built into GAP and ECLIPSE models for quick interpolation.
- GAP perform individual surface model solves and is also requested to optimize some key operation variable (evenly distribute production among wells to maximize wellhead pressure)
- HYSYS is basically requested to perform individual time step solves, but by using internal “set” and/or adjust capabilities; it is also forced to perform

some optimization tasks not visible to other applications (equally distribute compression power between stages, maintain constant MV pressure..)

- RESOLVE act as the global integrator, performing the time step running, prediction tasks and globally optimizing defined target functions.

2.11 USING INTEGRATED PRODUCTION MODELLING (IPM) AS AN OPTIMIZATION TOOL FOR FIELD DEVELOPMENT PLANNING AND MANAGEMENT

In this paper,E. A. AGEH, A. ADEGOKE & O.J.UZOH. (2010) discussed some of the benefits and challenges of deploying IPM for field development optimization using the PETEX GAP production modeling tool coupled with an in-house reservoir simulator, MoRes. GAP-MoRes Integrated production model (IPM) can be used to help:

- Explicit modeling of water injection network
- The GAP/Prosper imbedding which allowed seamless integration of the well models generated by Production Engineers into the network model
- Imbedded fluid blending functionality in GAP
- Smart well modeling functionality
- Ease of use of the GAP model building interface
- Ease of obtaining support from PETEX when needed

Meanwhile, for the subsea engineering purpose, an independent model of the production system was built using UNISIM and PIPESIM. UNISIM and PIPESIM inputs and results can be compared with those from IPM model. This is done to assure alignment and model consistency, thus improving the confidence level of the predictive capability of the IPM (GAP-MoRes model).

2.12 VERTICAL LIFT MODELS SUBSTANTIATED BY STATFJORD FIELD DATA

In this paper, Marthe Gilje Fossmark, Kari Nordaas Kulkarni, Havard Thomassen Lauritsen, Statoil & Svein M. Skjaeveland (2012) agreed that the accuracy of the flow correlations seems to be dependent on the flowing GLR. The flow correlations tend to over predict the pressure loss at high GLR and under predict the pressure loss at low GLR. Petroleum Expert 3 and Hagedorn Brown tend to be most accurate at high GLR's while Petroleum Expert tends to be most accurate at low GLR's for pure prediction.

2.13 BEST PRACTICES AND LESSONS LEARNED IN THE CONSTRUCTION AND MAINTENANCE OF A COMPLEX GAS ASSET INTEGRATED PRODUCTION MODEL (IPM)

According to the C. Amudo, M.S. Walters, D.I. O'Reilly, M.D. Clough, J.P.Beinke & R.S.T. Sawaris (2011) defined PROSPER as a modeling toolkit that can handles well performance, design and optimization. It is designed to allow the construction of reliable and consistent well models. It also has capability to incorporate each aspect of the wellbore modeling including fluid characterization (PVT), reservoir inflow performance (IPR) and pressure losses along tubing and flow lines (VLP). However, there are still some challenges in using PROSPER especially when modeling big bore or high rate wells that are capable of producing in excess of 300 MMscf/d. Some of the problems include:

- A lack of well test data because of some limitations appeared in the size of the test separators which available on the platforms.
- Location of the permanent down hole gauges almost 1200m above the perforations resulting in extrapolation error in Bottom hole pressure (BHP).
- Possibility of the VLP-predicted BHP to be higher than the reservoir pressure which result in a non physical situation.
- An apparent lack of transparency in ensuring consistency in the well models between the different software (PROSPER, MBAL and GAP).

2.14 REAL TIME PRODUCTION OPTIMIZATION IN THE OKUME COMPLEX FIELD, OFFSHORE EQUATORIAL GUINEA

According to the Wole Omole, Luigi Saputelli, Janvier Lissanon, Obiageli Nnaji, Fabio Gonzalez, Georgie Wachel, Kim Boles, Edicson Leon, Bimal Parekh, Nicholas Nguema, Jesus Borges and Pieris Hadjipieris (2011), the production optimization requires the updated reservoir model (analytical or numerical) that are fed with previous well rate estimation and also volume allocation.

Apart from that, the authors discussed that the consistency among different well rate estimation methods will depend on the validity of their parameters and the evolution of reservoir parameters. For example, if the GOR increase, then the fluid density decreases, causing the BHP to decrease (causing in the increase of IPR rate), the pressure drop across the tubing to decrease (causing VLP rates to decrease) and the pressure drop across the choke to increase (causing choke rate to increase). On the other hand, an increase in water cut will increase the density in the tubing, which will increase the BHP and the pressure drop across the tubing. This will eventually cause an increase in the VLP rate and a decrease in the IPR rate.

2.15 PRODUCTION OPTIMIZATION BY REAL-TIME MODELLING AND ALARMING: THE SENDJI FIELD CASE

According to the Jacques Danquigny, Renaud Daian, Marc Tison & Ronald Herrera (2007), the optimization of field production is not obtained by the optimization of each individual producer well. It implies the integration of the whole production chain, from reservoir, near wellbore, wellbore, production network up to the process facilities and export constraints.

2.16 A NEW NODAL ANALYSIS TECHNIQUE HELPS IMPROVE WELL COMPLETION AND ECONOMIC PERFORMANCE OF MATURED OIL FIELDS

In this paper, M. Rafiqul Awal and Lloyd R. Heinze (2009) discussed that a new concept of using Tapered Internal Diameter Tubing Completion (TIDC) has become successful in optimizing production rate. As defined by Schlumberger, TIDC is a tapered production string with larger OD tubing sections in the upper wellbore area which can optimize the hydraulic performance of the string. TIDC offers more profitability as compared to the conventional tubing size.

Conventional Tubing Size optimization procedure for maximizing fluid flow rate:
The routine procedure includes the following steps:

1) Perform nodal analysis for a given well using all or a few of the tubing sizes available
2) Plot a graph of fluid flow rate vs tubing size (ID), and select the tubing size, d-optimum that corresponds to the highest fluid flow rate
3) If d-optimum is not a standard tubing size, select the nearest standard size, which could be either greater or smaller than d-optimum.

In this paper, the authors are further discussed on the nodal analysis procedures done on TIDC by using commercial software, PERFORM. In order to illustrate the use of TIDC, the Vogel & Harrison and Beggs and Brill correlations are used.

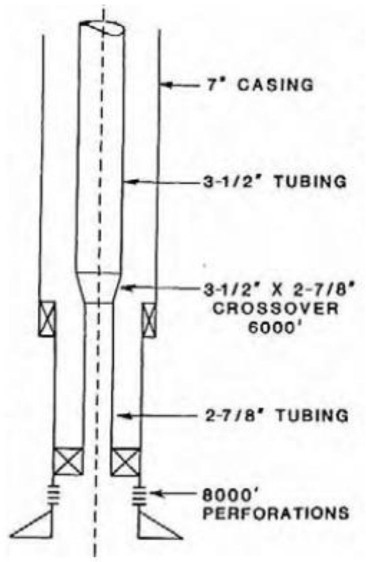

Figure 6: Typical example of TIDC

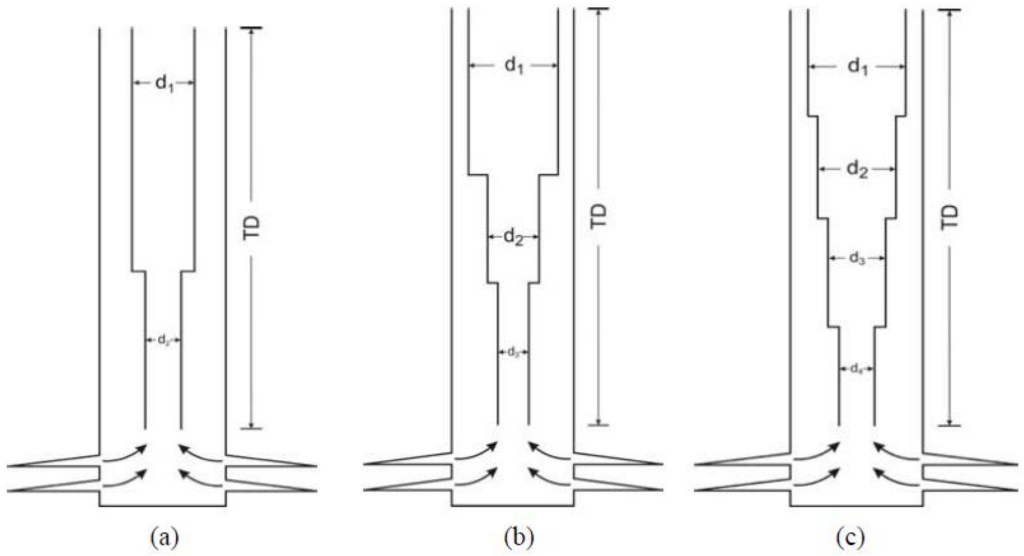

Figure 7: Three realizations of TIDC in order to optimize the fluid dynamics a) Duplex b) Triplex c) Quad

2.17 WORKFLOW FOR INTEGRATED MODELLING OF GAS WELLS IN THE NORTHERN COOPER BASIN

According to the Tejaswi Shrestha, Suzanne Hunt, Paul Lyford & Hemanta Sarma (2008), the surface network can be modeled using GAP and the MBAL and PROSPER tools are used to model the reservoir and well respectively.

Below demonstrated on how production system is modeled.

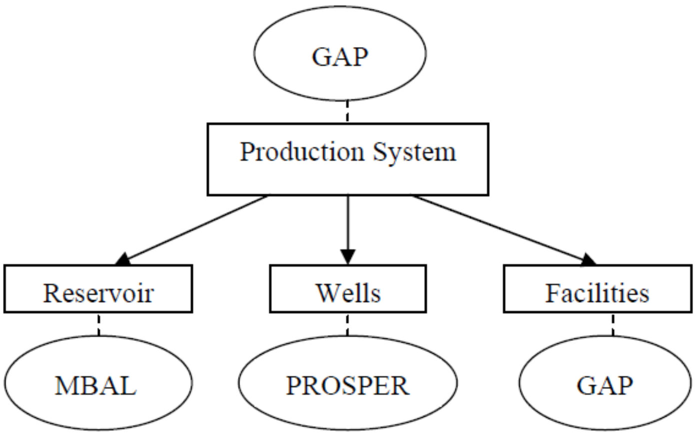

Figure 8: Modeling of production system

2.18 PRODUCTION OPTIMIZATION AND FORECASTING

In this paper, Mohammad Sohrab Hossain (2008) explained that the production optimization means a balance between production rate and demand. Production optimization includes a good understanding about production systems & reservoir fluid.

Optimization procedures:

1. Identify the components in the system
2. Select one component to be optimized
3. Select the node location that will best emphasize the effect of change
4. Develop expression for inflow and outflow
5. Calculate pressure drop versus rate for all components
6. Determine the effect of changing the characteristics of the selecting component
7. Repeat the procedure for each component
8. Optimize the production system

Production forecasting:

For future time

1. Construct future time IPR- Standing or Fetkovitch Method
2. For gas well construct IPR by Jones, Blunt and Glaze method
3. Select the respective component
4. Use Nodal analysis
5. Analyze future performance of a production system

2.19 IMPLEMENTATION OF A TOTAL SYSTEM PRODUCTION- OPTIMIZATION MODEL IN A COMPLEX GAS LIFTED OFFSHORE OPERATION

According to the Manickam S.Nadar, Tim S. Schneider, Kathy L.Jackson, Calum J.N. Mckie and Javad Hamid (2008), an implementation of a full-field optimization software package has resulted in operating cost-reductions and production gains. The network model used can modeled the complex production networks accurately and has been history matched across the operating range.

In addition, an accurate well model tuning is essential across the full operating range. Well models must be updated frequently to describe its actual behavior. During the execution of the project, the true value of the project does not lie in a single time implementation of the model optimization results. Thus, the field optimization has to be in progress and ongoing process. Overall, in order to sustain the optimization benefits, the field network model should be updated on a regular basis and optimization runs performed and implemented in the field.

Apart from that, the authors agreed that the detailed modeling of all components may not be necessary to achieve the optimization objectives. A study performed which has resulted that the development of two field models with a single-node link rather than one large model has reduced run-time requirements by 50%.

2.20 PRODUCTION OPTIMIZATION OF SALDANADI GAS LIFTED BY NODAL ANALYSIS

In this paper, M.B.Haq, E.Gomes and M. Tamim (2008) discussed that the success of a nodal analysis method, depends on the use of appropriate correlation and equations while analyzing inflow performance relationship (IPR) and outflow performance relationship (VLP).

The authors are further discussed on the methods involved when conducting the nodal analysis:

1st: Solution node is selected. This node usually corresponds to a component or point in the system. It is the most convenient for specific sensitivity calculations.

2nd: Appropriate correlation and equations are assigned to each component for analyzing IPR and OPR.

3rd: Pressures are calculated at the selected node for each part of the system (one part always starts from the reservoir pressure and the other part from the separator pressure) for several flow rates.

4th: Calculate results (pressure and rates) are used to generate a plot to of node pressure vs flow rate

5th: A plot of node pressure versus flow rate will produce two curves of Inflow or Outflow. The overall production performance of the system is determined from the intercept of the inflow and the outflow performance curves.

The effect of change in any components can be analyzed by recalculating the node pressure versus flow rate using the new characteristics of the component that was changed. If a change was made in the upstream component, the outflow curve will remain unchanged. However, if either curve is changed, the intersection will be shifted and a new flow capacity and node pressure will be established. The curves will also be shifted if either of the fixed pressure is changed, which may occur with depletion or a change in separation conditions.

CHAPTER 3: METHODOLOGY

3.1 PROJECT ACTIVITIES

1. ***Define research problem*** - For this project, the problem has been identified as how to evaluate and optimize the well production using PROSPER

2. ***Review concepts and theories/ Review previous research findings*** - Critical analysis on the literature is conducted to have a better understanding on the research area and to review for any optimization done previously using simulation.

3. ***Gather project requirements/Data Gathering*** – To gather data and information on the requirements using different methods of data collections.

4. ***Simulation*** **-** The simulation is then performed by using PROSPER. Few phases had been conducted in order to monitor the performance as well as optimize the well production. Phase one is the build up model using lab data. For this task, three well models have been constructed which consists of three oil producers well. Phase two is well matching based on the well test data. Phase three is simulating base case by using various operating conditions and followed with the well analysis. After that, the recommendations are put forward in order to optimize the well production in the near future.

5. Project flow

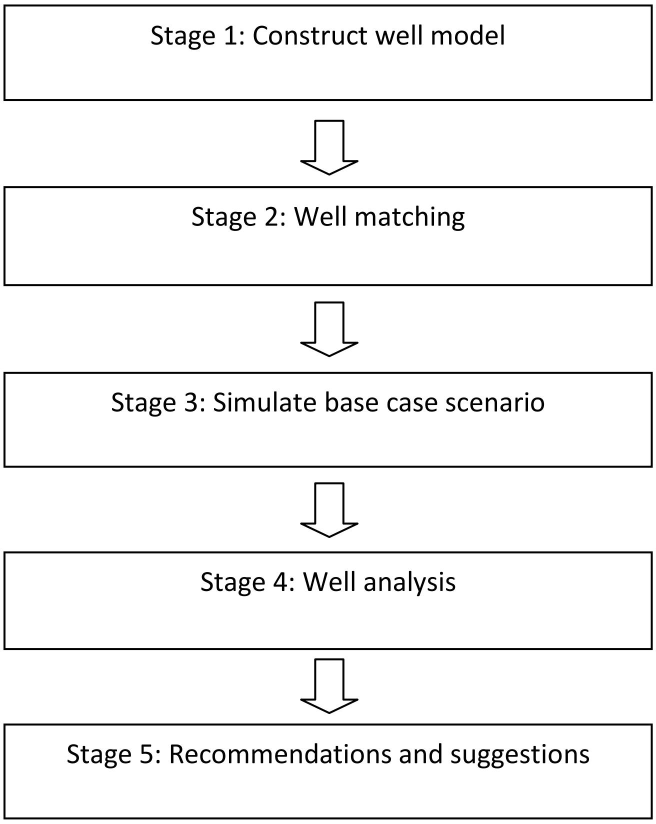

Figure 9: Project flow

Stage 1: Construct well model

Input data which consists of PVT, IPR, Trajectory and surface & equipment data

Stage 2: Well matching

Performed well matching based on the well test data for three wells.

Stage 4: Simulate base case scenario

Simulate base case scenario by using various operating conditions.

Stage 3: Well analysis

For this stage, the well analysis is conducted by evaluating various development options to optimize oil production. In this part, user has selected various conditions for the optimization by:

i. Reducing the wellhead pressure
ii. Changing tubing size
iii. Increasing the gas lift injection rates

Stage 4: Recommendation and modification

Last but not least, few recommendations have been proposed in order to enhance and optimize the well production in the near future.

3.2 PROJECT PROCEDURES

1) Determine which components in the system can be changed.
2) Select one component to be optimized.
3) Select the node location that will best emphasize the effect of change in the selected component.
4) Develop the expressions for the inflow and outflow.
5) Obtained the required data to calculate pressure drop versus rate for all the components.
6) Determine the effect of changing characteristics of the selected component by plotting inflow versus outflow and reading the intersections.
7) Repeat the procedure for each component that is to be optimized.

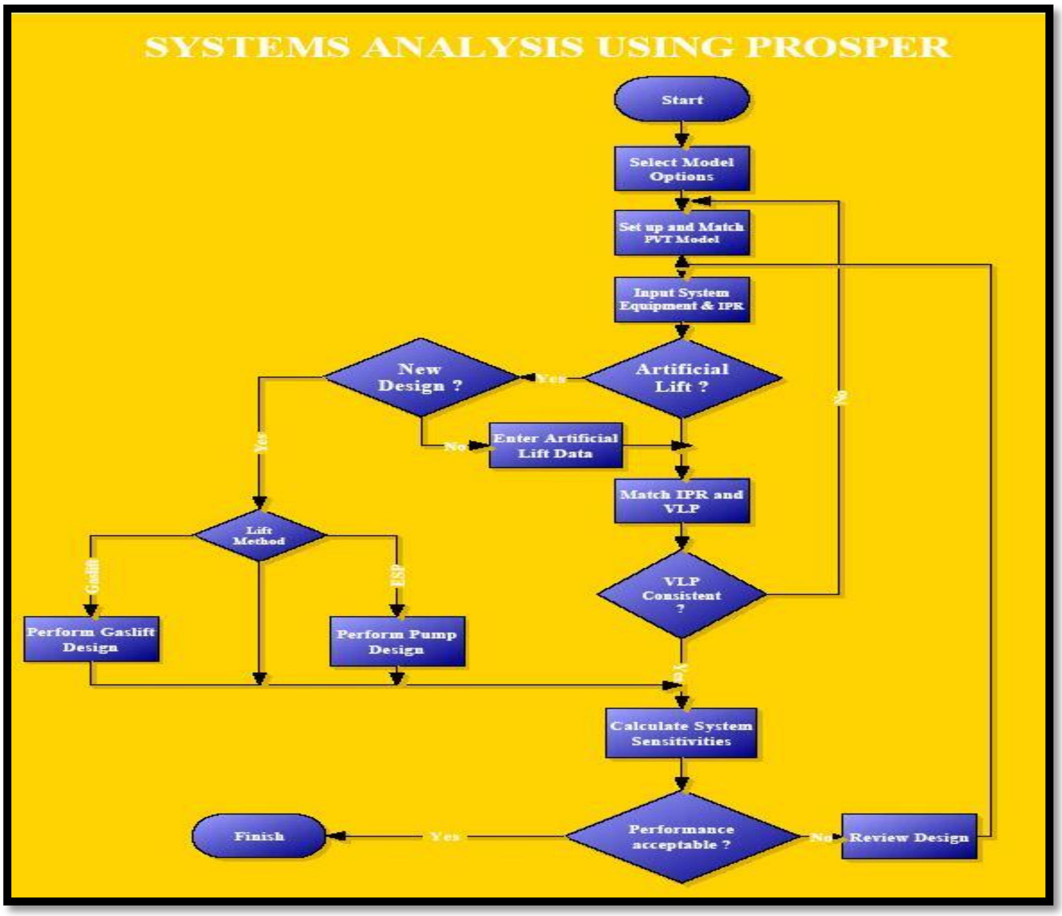

Figure 10: System analysis using PROSPER

3.3 GANTT CHART

See appendices A (Gantt chart)

3.4 TOOLS

Some tools required for this project consists of:

- Integrated Production Modeling 7.5 (IPM) software – PROSPER
- Lab data which include reservoir, drilling and equipment data
- Well test data

CHAPTER 4: RESULT AND DISCUSSION

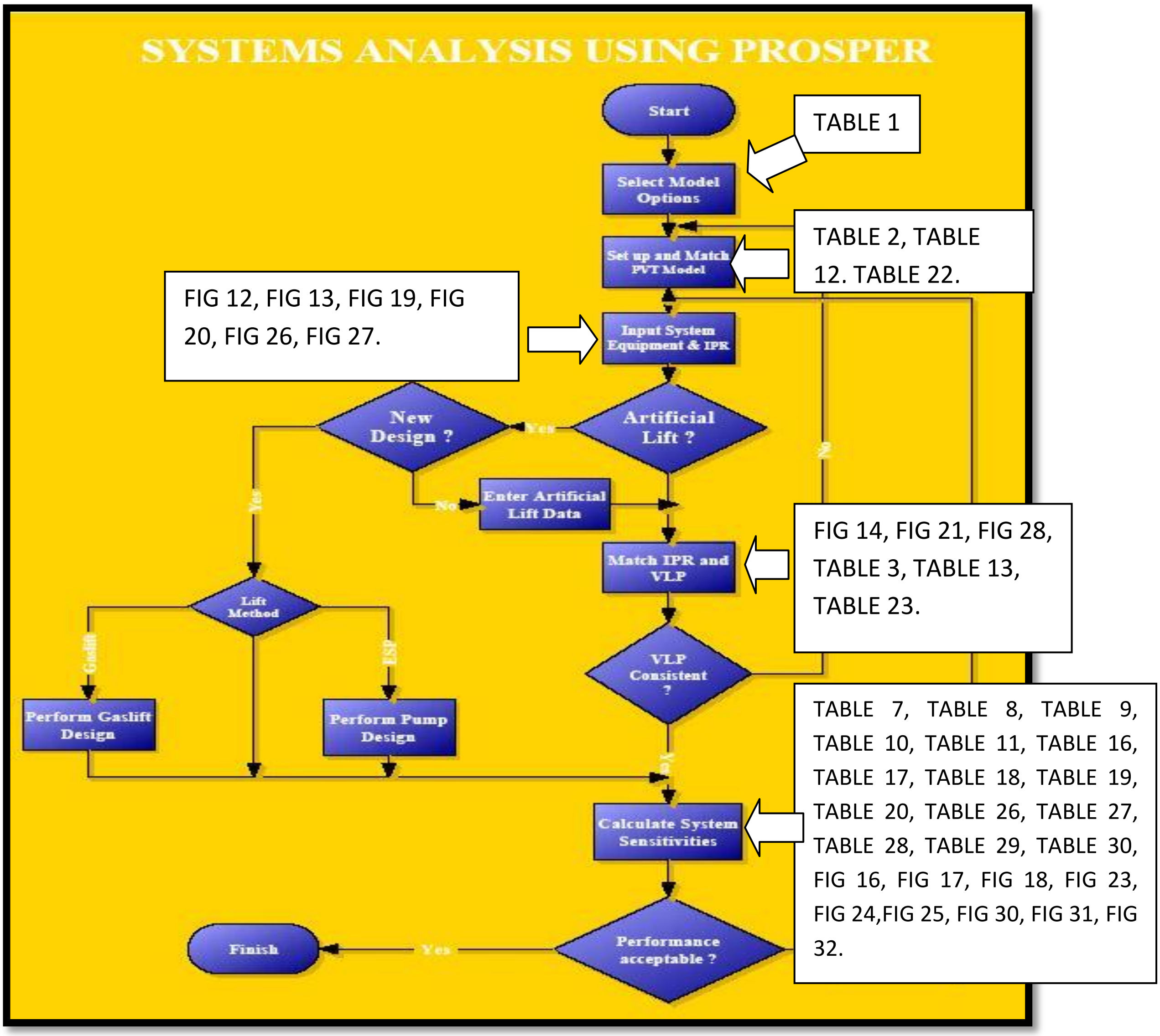

Figure 11: Flow diagram for data entry

Three oil producer wells were used in this optimization study. All of the wells used in this case study will be designated as Well X 1, Well X 2 and Well X 3.

The Field X was reached its peak production in 1997. Since then, oil production has decreased rapidly due to an increase in water content as well as decline of reservoir pressure.

An economic limit of 1000 STB oil/ day was premised for Well X 1, Well X 2 and Well X 3. Any well which is producing at rate lower than that is considered as not economical.

Fluid	Oil & water
PVT method	Black oil
Separator	Single-stage separator
Flow type	Tubing flow
Emulsion	No
Well type	Producer
Lift method	None
Predicting	Pressure only
Completion	Cased hole
Gravel pack	No

Table 1: Data entry in PROSPER

4.1 Well X1

4.1.1 Develop well model

Reservoir temperature	239 deg F
Oil API Gravity	40
Gas relative density	0.766
GOR	400
Pb	2335 psia
Bo	1.388 rb/stb
Oil viscosity	0.379 cp
Bg	1.388 rb/ Msf
Gas viscosity	0.017 cp
Bw	1.047 rb/stb
Gas Z Factor	3.35E-06 (1/psia)
Water Salinity	9708 ppm
Water viscosity	0.255433 cp
P initial (psia)	2325
P current (psia)	1600

THP (psig)	400
WC (%)	0

Table 2: PVT data for well X1

In order to develop well model, few sections of the PROSPER have to filled, which includes IPR, PVT as well as equipment data. **Figure 12, Figure 19** and **Figure 26** summarize the IPR plots which can be obtained from these three well models. These IPR plot can predict the performance of the wells by providing the value of Absolute Open Flow (AOF), Productivity Index (PI) as well as skin.

Figure 13, Figure 20 and **Figure 27** below describe the downhole systems which are also can be obtained from the three well models.

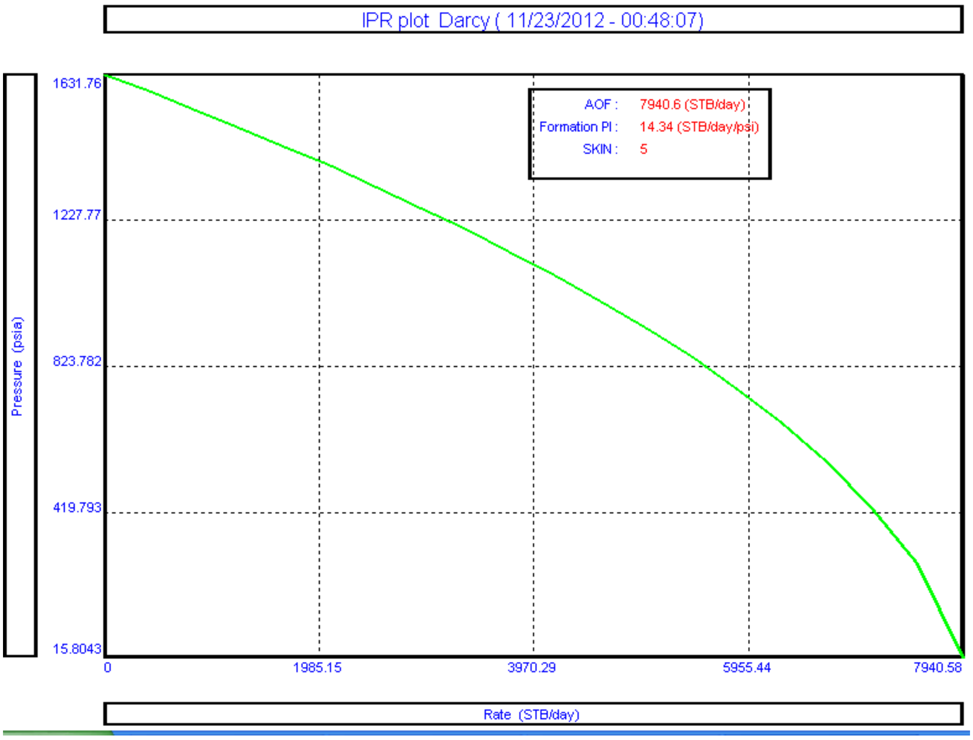

Figure 12: IPR for well X1

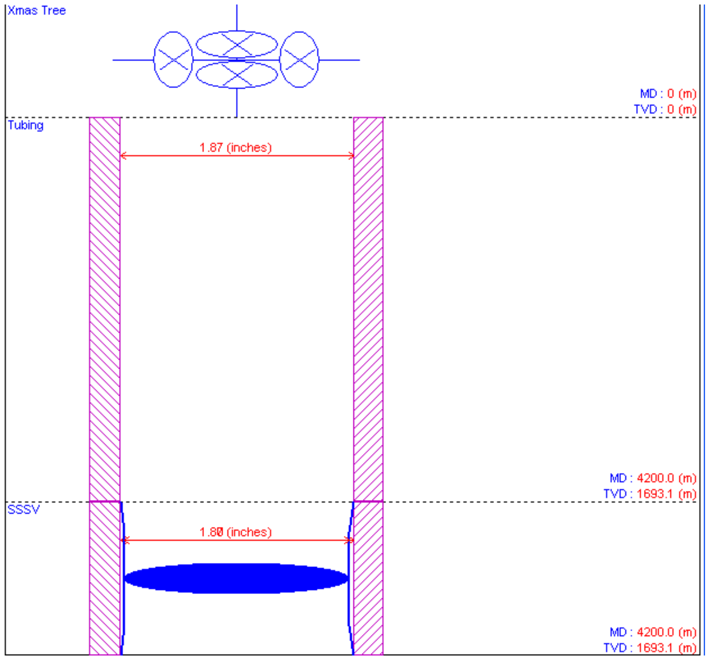

Figure 13: Downhole system for well X

4.1.2 Perform well matching

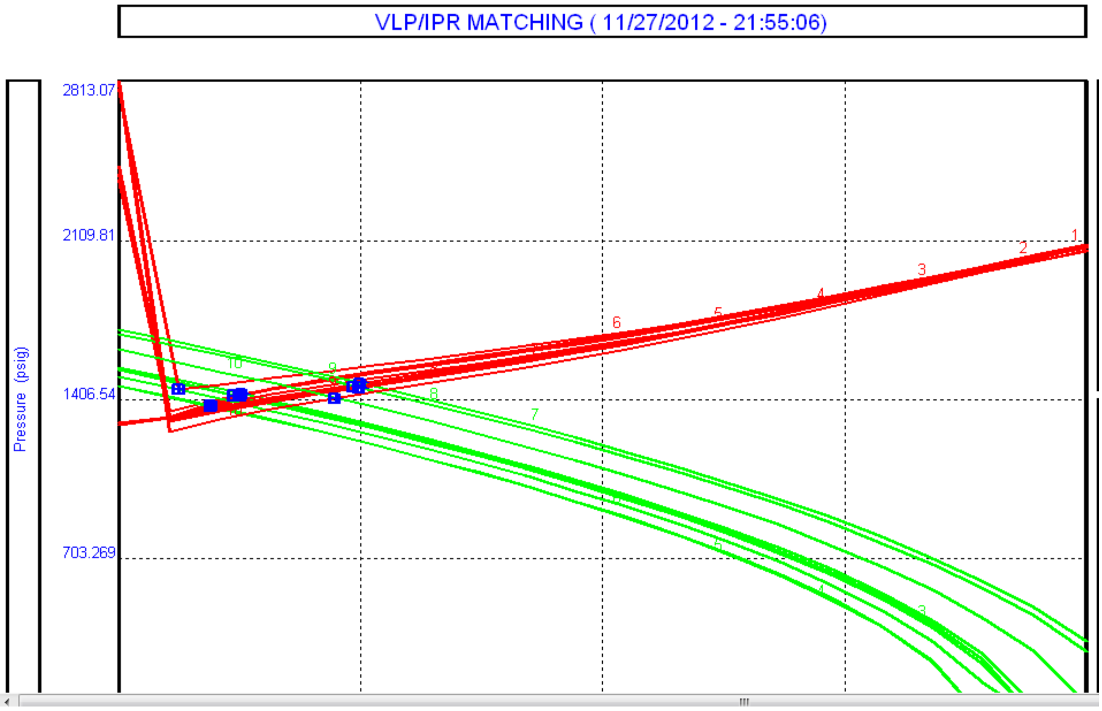

Figure 14: VLP/IPR matching for well X1

The next step involved in this technique is performing well matching based on the well test data from each well. As can be seen from the **Table 3, Table 13** and **Table 23**, the percentage differences for the measured and calculated values are small. This indicated that the previous well models are validated and thus they can be used for further analysis. If the percentage differences obtained are large, this means that some input data as PVT, IPR and VLP data are incorrect.

Oil rate (STB/d)		
Measured	**Calculated**	**% difference**
929.5	936.9	0.78822%
984.3	996.3	1.22
999.1	1013.2	1.41
747.2	746.1	-0.1466
753.7	758	0.56249
486.8	488.3	0.31543
1940.5	1965.8	1.31
1940.7	1968.8	1.45
1894.6	1928.1	1.77
1747.9	1765.7	1.02

Table 3: Match data for well X1

4.1.3 Simulate base case forecast under various operating conditions

To start optimization, user has to simulate the base case scenario for the Well X1 by using different ranges of reservoir pressures and water cut. From this base case analysis, the maximum economic water cut is 10% as the well is no longer capable to produce at its economic rate (1000 stb/d) as reservoir pressure starts to decline. **Table 5** summarizes the oil rates obtained from this base case analysis.

Parameter	Range
Reservoir pressure	1600,1400,1200,1000 (psia)
Water cut	0,5,10 (%)

Table 4: Reservoir pressure and water cut ranges for well X1

Reservoir pressure (psig)	Water cut (%)		
	0	5	**10**
	Oil rate (STB/d) at different water cut (%)		
1600	1358.6	1239.6	**1131.6**
1400	900.7	826.5	**756.4**
1200	498.1	454.9	**413.7**
1000	197.9	183.5	**169.7**

Table 5: Oil rates at given parameter ranges for well X1

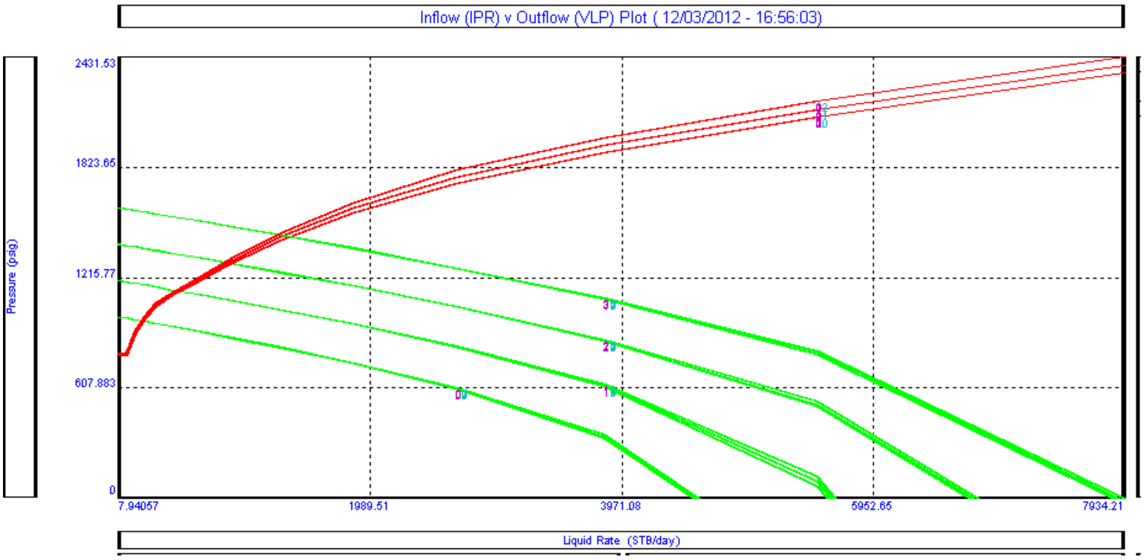

Figure 15: IPR/VLP for base case

Scenario	Maximum economic water cut (%)	Production rate at 0% water cut
Base case	10	1358.6 (STB/D)

Table 6: Economic base case conditions for well X1

4.1.4 Evaluate various development options to optimize oil production

Further analysis is then performed by evaluating various development options in order to optimize the oil production. In this analysis, optimization had been performed by changing the value of wellhead pressure, using different tubing sizes as well as increasing the gas lift injection rates. The operating rates produced by each analysis are summarized in the **Table 7, Table 9** and **Table 10** below.

1. Changing WHP

Wellhead pressure (psig)	Water cut (%)				
	10	20	30	**40**	50
	Oil rate (STB/d) at different water cut (%)				
400	1307.5	1072.5	867.2	**688.5**	531.1
350	1520.3	1252.8	1011.8	**797.1**	612.4
300	1756.2	1443.7	1170.5	**925.7**	709.5
250	2023	1668.9	1345.5	**1062.8**	816.8
200	2298.4	1908.1	1549.6	**1224.3**	934

Table 7: Oil rate at various WHP & WC for well X1

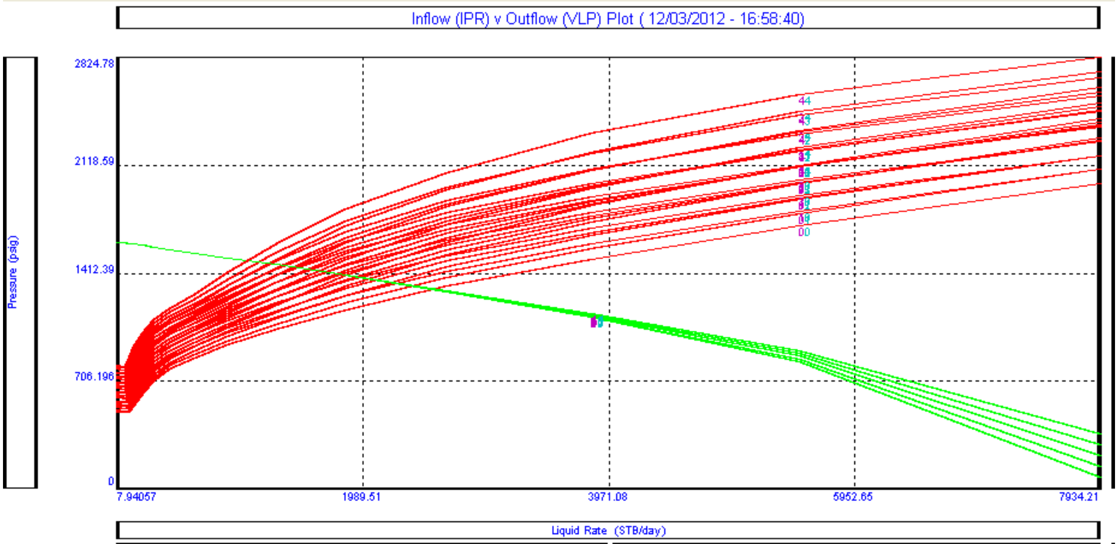

Figure 16: IPR/VLP for changing WHP Well 1

Scenario	Maximum economic water cut	Production rate at 10% water cut
Lowering Christmas tree pressure	40 %	2298.4 STB/D

Table 8: Oil rate at economic water cut for well X1

By changing the wellhead pressure from 400 to 200 psig, the operating rates produced become higher. However, when the water cut is increasing to 40%, the oil rates obtained are already reached 1000 stb/d and no longer economical as the water cut is keep increasing. Thus, it can be concluded that Well X1 can produce economically until 40% of water cut by changing the wellhead pressure from 400 to 200 psig. **Table 7** shows that at the WHP of 200 psig, this well can produce up until 2298.4 stb/d which is 43.11% higher than the rate produced at the WHP of 400psig @ 10% water cut.

2. Changing tubing size

Tubing Size ID (in)	Oil rate (STB/d)
2.441	1151.2
2.992	1402.9
4.09	1683.5
4.892	1753.8

Table 9: Oil rate at various tubing internal diameter sizes for well X1

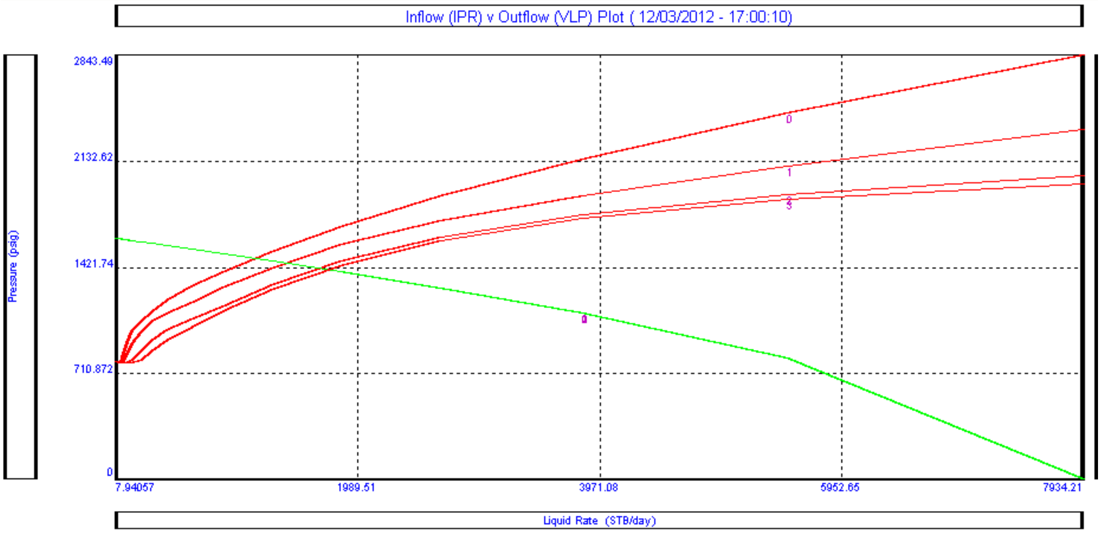

Figure 17: IPR/VLP for changing tubing size at Well 1

Second analysis is then performed by using various sizes of tubing internal diameter (ID). From the **Table 9**, the oil rates increment obtained by using different sizes of tubing are small. Thus, it is not recommended to change the tubing size in this well.

3. Gas lift (artificial lift method)

Gas injection (MMscf/d)	Water cut (%)				
	10	20	30	**40**	50
	Oil rate (STB/d) at different water cut (%)				
1	1164.8	962.8	781.8	**620.5**	477.2
2	1564.6	1314.2	1082.4	**870**	677.1
3	1723.3	1459.1	1213.8	**984**	771.1
4	1807.7	1534.8	1279.1	**1044.2**	824.7

Table 10: Oil rate with various gas injection rates for well X1

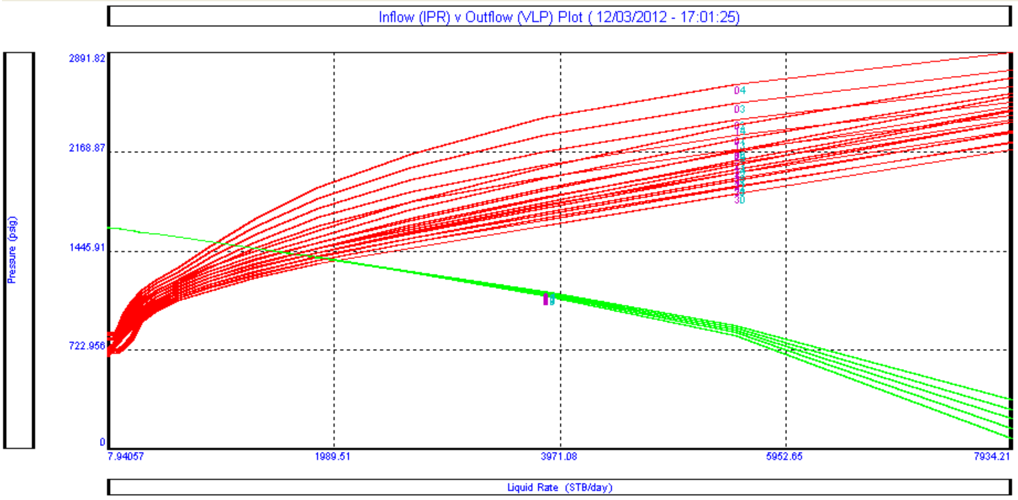

Figure 18: IPR/VLP for changing gas lift rate at Well 1

Third analysis is performed by increasing the gas lift injection rates from 1 to 4 MMscf/d. From **Table 10**, the operating rates produced at 40% water cut are already reached the economic limit with the production rates of 620stb/d to 1040 stb/d.

Scenario	Maximum economic water cut	Production rate at 10% water cut
Optimised gas lift	40%	1164.8

Table 11: Economic oil with optimized gas lift for well X1

Result analysis Well X1

1) Lowering Christmas tree pressure to 200 psig is recommended because the well's life can be extended to 40% water cut.
2) Changing tubing size is not recommended as it does not produce fruitful increment in oil production rate.
3) The gas lift method is economical as it can produces up to a maximum economic water cut of 40% with gas injection rate of 1-4 MMscf/d and producing oil rates of 600 to 1040 STB/d.

4.2 Well X2

4.2.1 Develop well model

Reservoir temperature	239 deg F
Oil API Gravity	40
Gas relative density	7.791 lb/ft3
GOR	440 scf/ STB
Pb	2335 psia
Bo	1.388 rb/STB
Oil viscosity	0.379 cp
Bg	1.337 rb/Mscf
Gas viscosity	0.019 cp
Bw	0.255 cp
Gas Z Factor	3.35E-06 (1/psia)
Water Salinity	9708 ppm
Water viscosity	0.379 cp
P initial (psia)	2319
P current (psia)	1900
THP (psig)	700
WC (%)	0

Table 12: PVT data for well X2

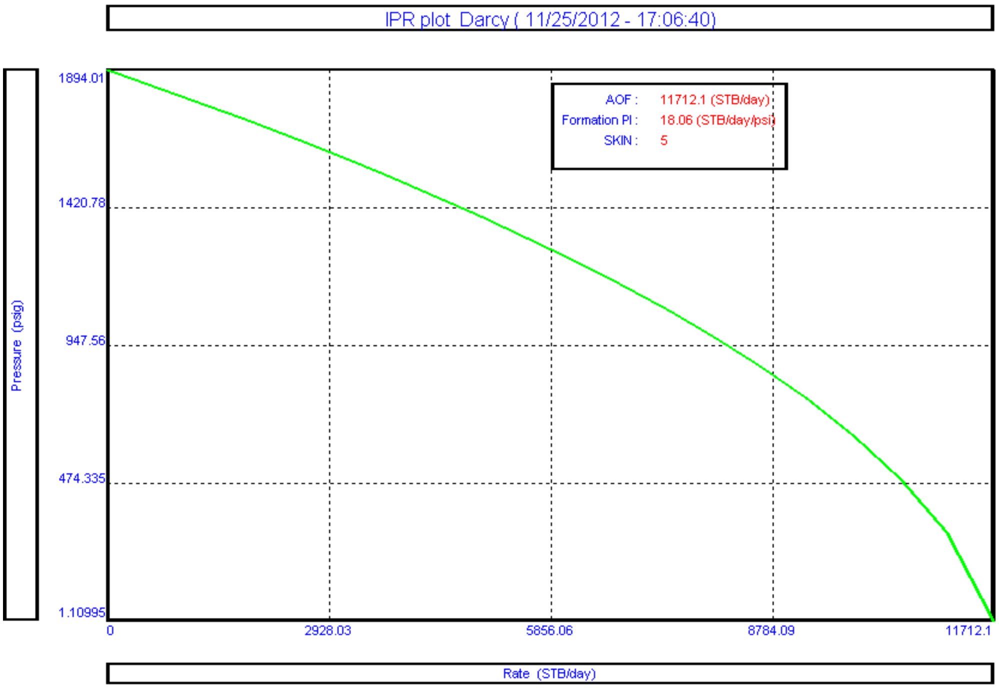

Figure 19: IPR for well X2

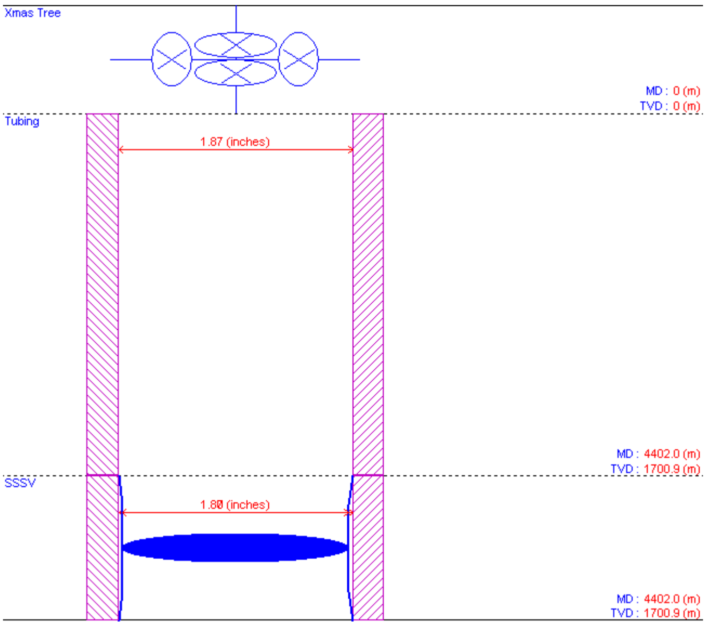

Figure 20: Downhole equipment for well X2

4.2.2 Perform well matching

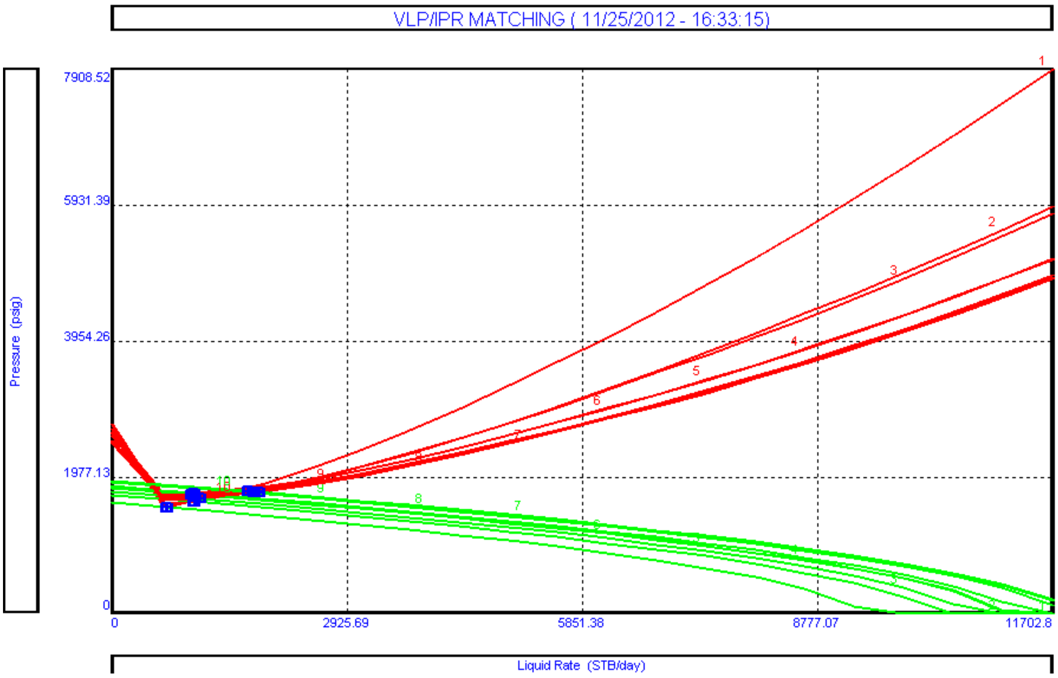

Figure 21: VLP-IPR MATCHING FOR WELL X2

Oil rate (STB/d)		
Measured	**Calculated**	**% difference**
681.1	683.6	0.3668
1022.8	1025.9	0.31171
1093.7	1091.6	-0.19157
1011	1018.8	0.76779
987.1	988.1	0.10504
983.9	981.7	-0.2223
1814.7	1806.7	-0.44182
1766.6	1770.1	0.19679
1691	1694.5	0.202
1762.1	1762	-0.0035331

Table 13: Match data for well X2

4.2.3 Simulate base case forecast under various operating conditions

To start optimization, user has to simulate the base case scenario for the Well X2 by using different ranges of reservoir pressures and water cut. From this base case analysis, the maximum economic water cut is 15% as the well is no longer capable to produce at its economic rate (1000 stb/d) as reservoir pressure starts to decline. **Table 15** summarizes the oil rates obtained from this base case analysis.

Parameter	Range
Reservoir pressure	1900, 1700, 1500 (psia)
Water cut	0, 5, 10, 15 (%)

Table 14: Reservoir pressure and water cut ranges for well X2

Reservoir pressure (psig)	Water cut (%)			
	0	5	10	**15**
	Oil rate (STB/d) at different water cut (%)			
1900	2477.1	2290.5	2107	**1926.1**
1700	1891.2	1738.2	1586.9	**1439.7**
1500	1318.8	1198.5	1083.6	**974**

Table 15: Oil rates at given parameter ranges for well X2

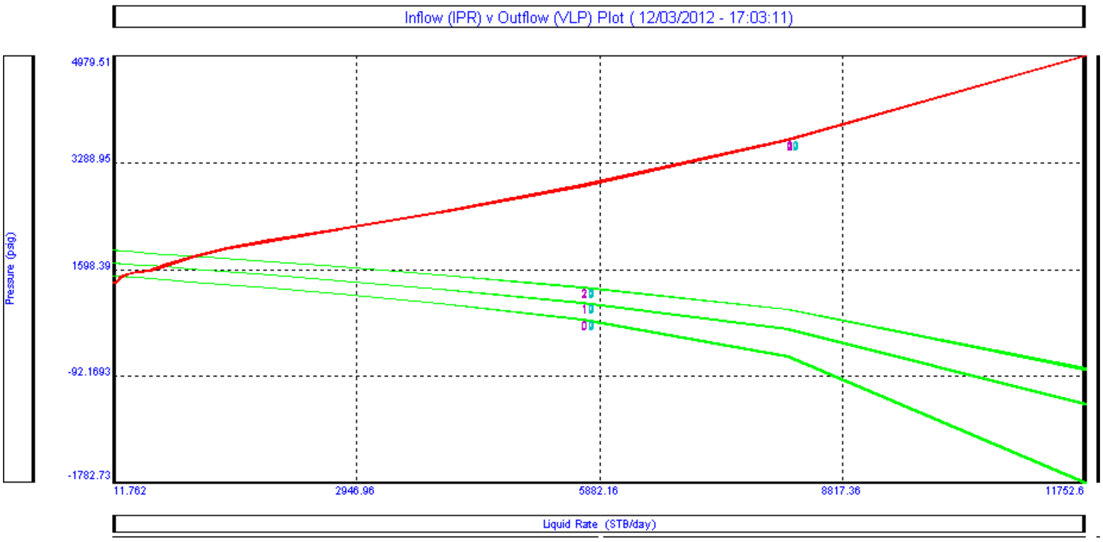

Figure 22: IPR/VLP for base case at Well X2

Scenario	Maximum economic water cut (%)	Production rate at 0% water cut
Base case	15	2477.1 (STB/D)

Table 16: Economic base case conditions for well X2

4.2.4 Evaluate various development options to optimize oil production

The operating rates produced by each analysis are summarized in the **Table 17, Table 19** and **Table 20** below.

1. Changing WHP

Wellhead pressure (psig)	Water cut (%)				
	15	30	40	**60**	70
	Oil rate (STB/d) at different water cut (%)				
700	733.3	507.2	379.6	**186.2**	119.6
500	1498.2	1062.4	805.7	**415.1**	286.1
300	1062.4	1731.3	1379.8	**753.7**	501
100	2921.4	2306.6	1905	**1135.6**	786.3

Table 17: Oil rate at various WHP & WC for well X2

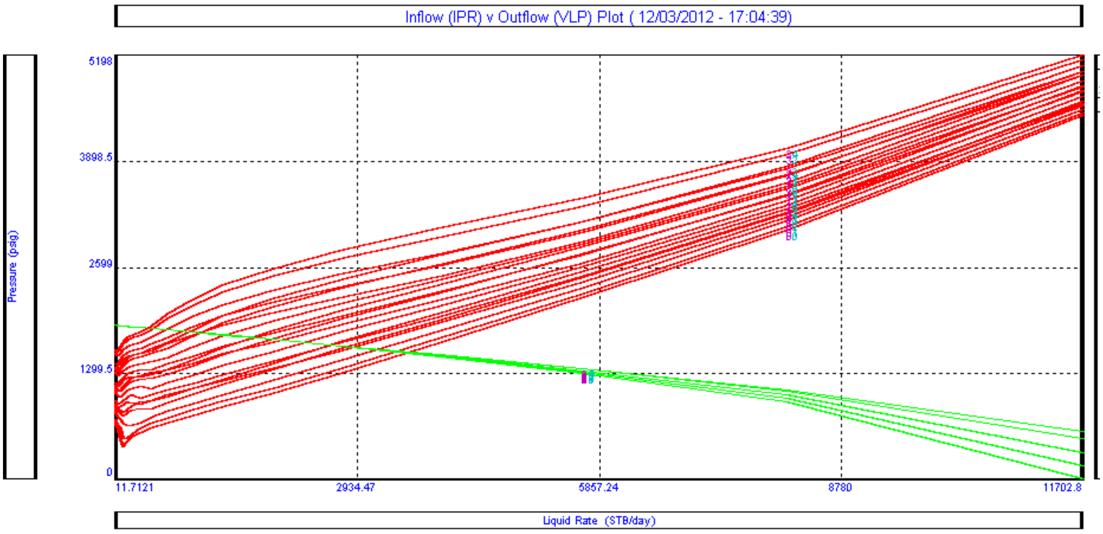

Figure 23: IPR/VLP for changing wellhead pressure at Well X2

Scenario	Maximum economic water cut	Production rate at 15% water cut
Lowering Christmas tree pressure	60 %	2921.4 STB/D

Table 18: Oil rate at economic water cut for well X2

By changing the wellhead pressure from 700 to 100 psig, the operating rate produced becomes higher. However, when the water cut is increasing to 60%, the oil rates obtained are already reached 1000 stb/d and no longer economical as the water cut is keep increasing. Thus, it can be concluded that Well X2 can produce economically until 60% of water cut by changing the wellhead pressure from 700 to 100 psig. **Table 17** shows that at the WHP of 100 psig, this well can produce up until 2921.4 Stb/d which is 74.9 % higher than the rate produced at the WHP of 700psig @ 15% water cut.

2. Changing tubing size

Tubing Size ID (in)	Oil rate (STB/d)
2.441	829.2
2.992	1038.7
4.09	1077.3
4.892	983.7

Table 19: Oil rate at various tubing internal diameter sizes for well X2

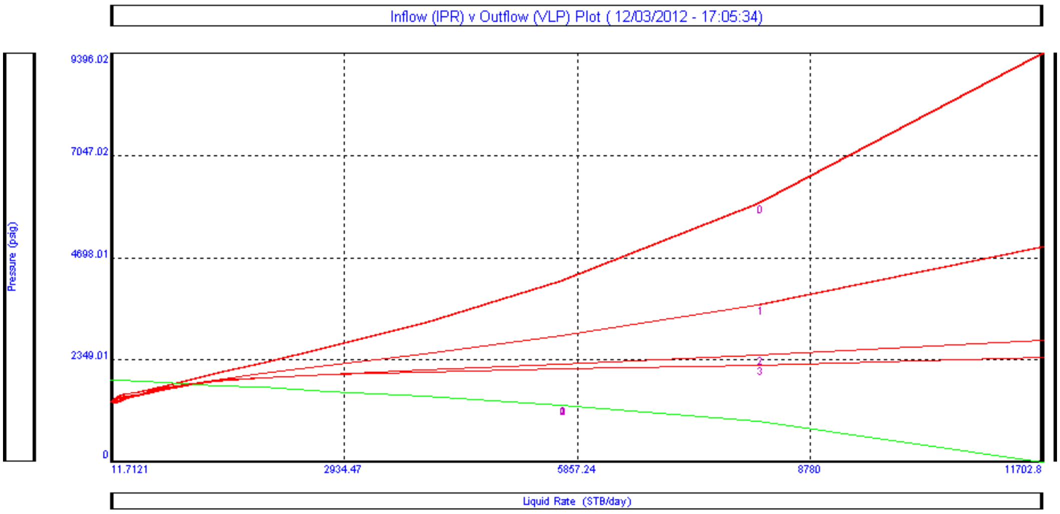

Figure 24: IPR/VLP for changing tubing size at Well X2

Second analysis is then performed by using various sizes of tubing internal diameter (ID). From the **Table 19,** the oil rates increment obtained by using different sizes of tubing are small. Thus, it is not recommended to change the tubing size in this well.

3. Gas lift (artificial lift method)

Gas injection (MMscf/d)	Water cut (%)			
	15	20	40	**50**
	Oil rate (STB/d) at different water cut (%)			
1	2078.7	1913.1	1292.1	**1007**
2	2127.3	1968	1360.9	**1077.6**
3	2091.7	1937.5	1349	**1073.2**
4	2037.4	1889.1	1319.5	**1052.1**

Table 20: Oil rate with various gas injection rates for well X2

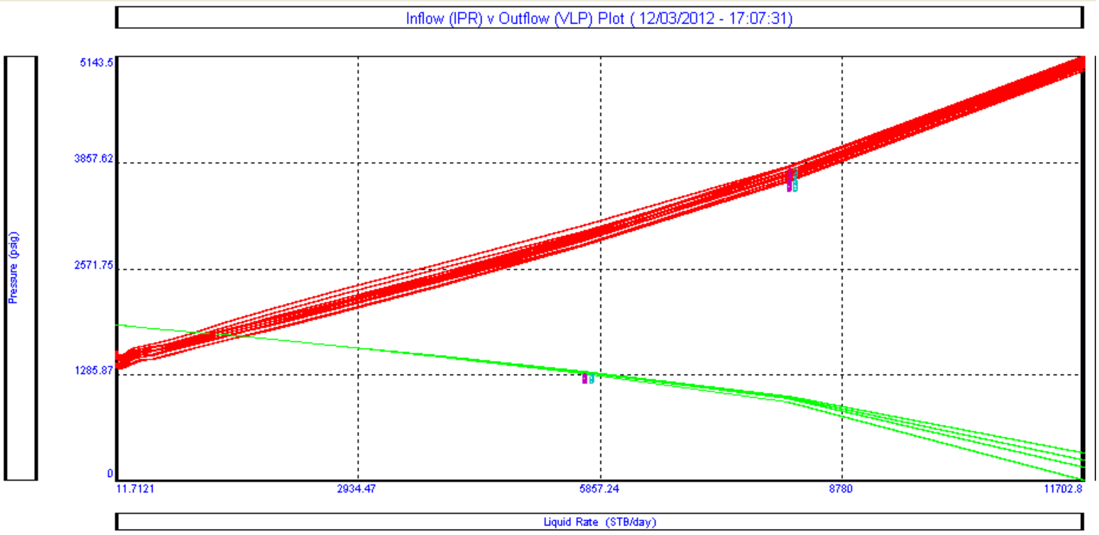

Figure 25: IPR/VLP for changing gas injection rate at Well X2

Third analysis is performed by increasing the gas lift injection rates from 1 to 4 MMscf/d. From **Table 20**, the operating rates produced at 50% water cut are already reached the economic limit with the production rates of 1000stb/d to 1050 stb/d.

Scenario	Maximum economic water cut	Production rate at 15% water cut
Optimised gas lift	50%	2078.7

Table 21: Economic oil rate with optimized gas lift for well X2

Result analysis Well X2

1. Lowering Christmas tree pressure to 100 psig is recommended because the well's life can be extended to 60% water cut.
2. Changing tubing size is not recommended as it does not produce fruitful increment in oil production rate.
3. The gas lift method is economical as it can produces up to a maximum economic water cut of 50% with gas injection rate of 1-4 MMscf/d and producing oil rates of 1000 to 1050 STB/d.

4.3 Well X3

4.3.1 Develop well model

Reservoir temperature	235 deg F
Oil API Gravity	38
Gas relative density	8.04 lb/ft3
GOR	500 scf/ STB
Pb	2335 psia
Bo	1.377388 rb/STB
Oil viscosity	0.379 cp
Bg	1.3887 rb/Mscf
Gas viscosity	0.019 cp
Bw	0.255 cp
Gas Z Factor	3.35E-06 (1/psia)
Water Salinity	9710 ppm
Water viscosity	0.379 cp
P initial (psia)	2334
P current (psia)	2000
THP (psig)	300
WC (%)	0

Table 22: PVT data for well X3

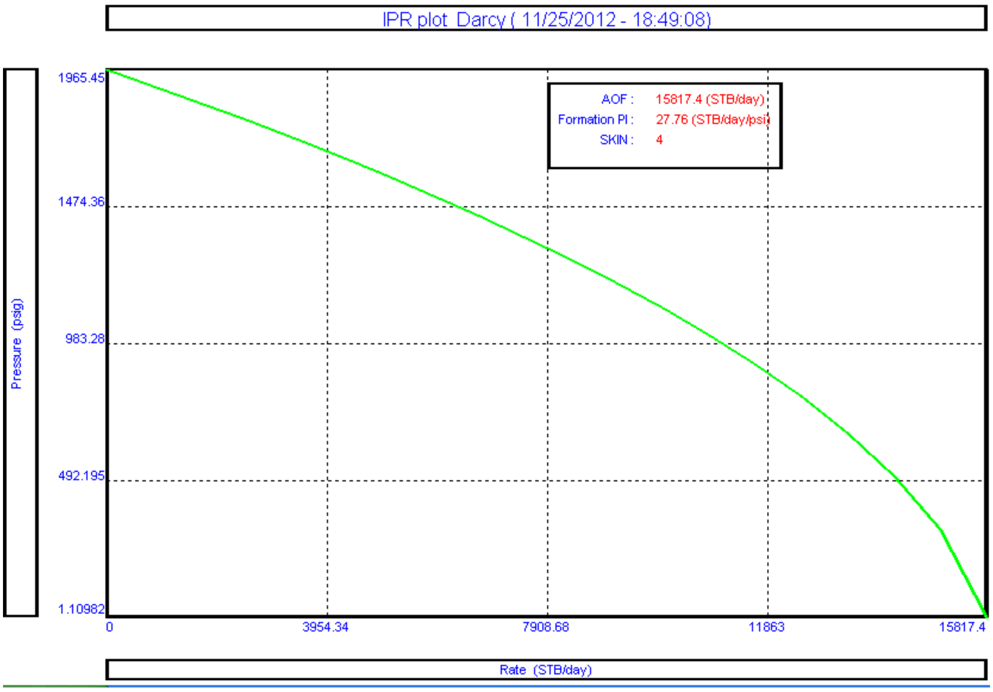

Figure 26: IPR for well X3

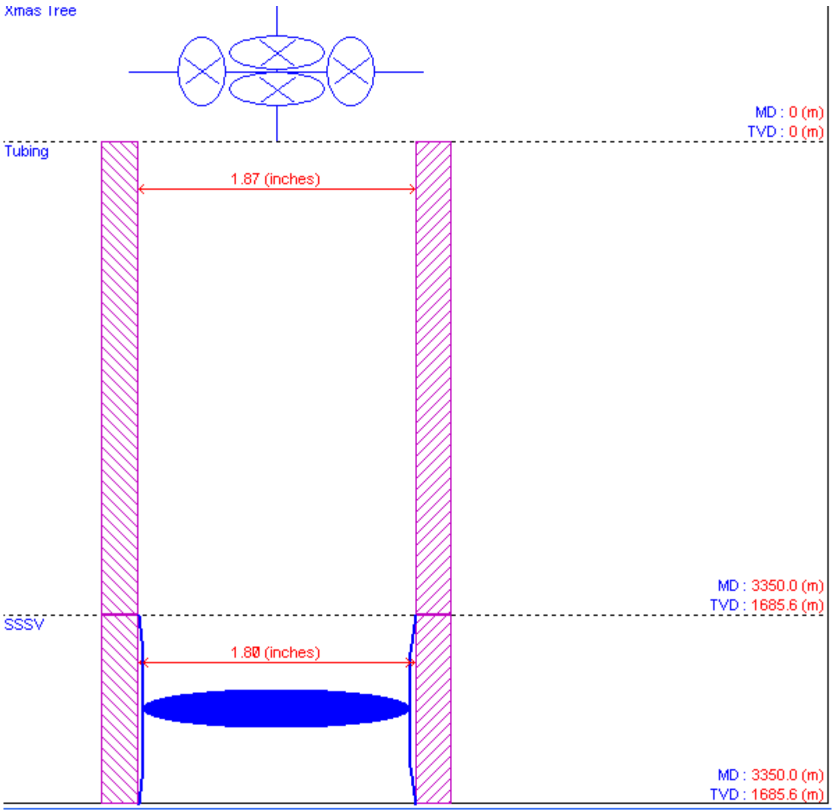

Figure 27: Downhole equipment for well X3

4.3.2 Perform well matching

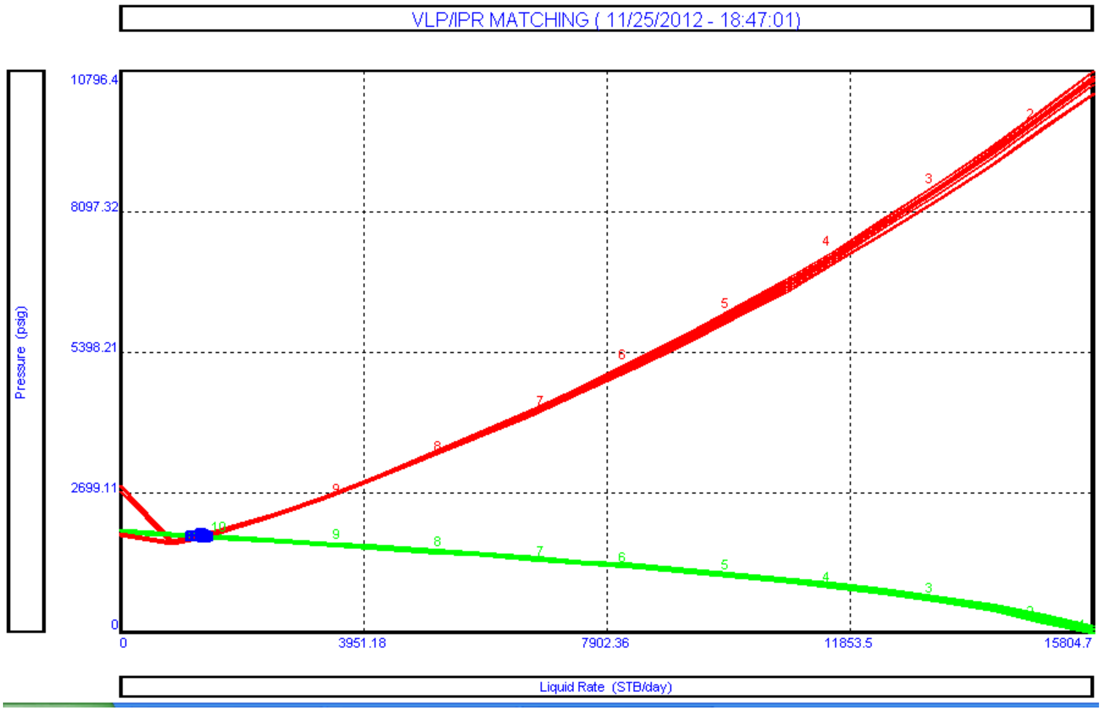

Figure 28: VLP-IPR MATCHING FOR WELL X3

Oil rate (STB/d)		
Measured	**Calculated**	**% difference**
1159	1149.1	-0.85329
1317.7	1315	-0.20258
1339.9	1340	0.0054298
1355.7	1358.9	0.23202
1314.9	1316.6	0.12355
1354.5	1353.9	-0.043341
1356.7	1355.5	-0.093394
1313.3	1315.2	0.14579
1361	1361.6	0.043834
1398.6	1398.9	0.018198

Table 23: Match data for well X3

4.3.3 Simulate base case forecast under various operating conditions

To start optimization, user has to simulate the base case scenario for the Well X3 by using different ranges of reservoir pressures and water cut. From this base case analysis, the maximum economic water cut is 25% as the well is no longer capable to produce at its economic rate (1000 stb/d) as reservoir pressure starts to decline. **Table 25** summarizes the oil rates obtained from this base case analysis.

Parameter	Range
Reservoir pressure	2200, 2000, 1500 (psia)
Water cut	0, 25, 30 (%)

Table 24: Reservoir pressure and water cut ranges for well X3

Reservoir pressure (psig)	Water cut (%)		
	0	**25**	30
	Oil rate (STB/d) at different water cut (%)		
2200	1753.4	**1017.5**	899
2000	1357.7	**781.8**	693.3
1500	669.9	**427**	382.1

Table 25: Oil rates at given parameter ranges for well X3

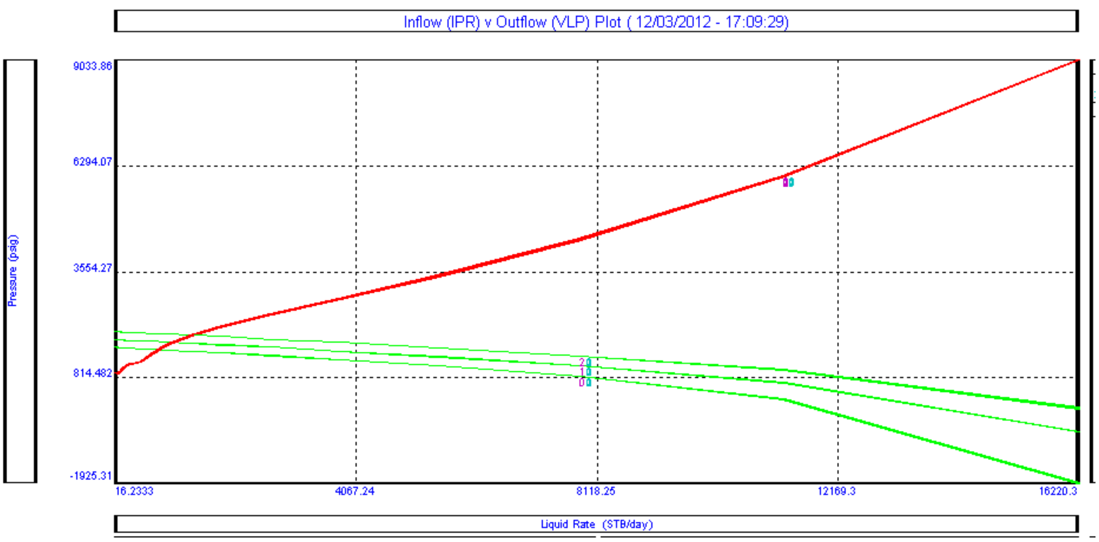

Figure 29: IPR/VLP for base case at Well X3

Scenario	Maximum economic water cut (%)	Production rate at 0% water cut
Base case	25	1753.4 (STB/D)

Table 26: Economic base case conditions for well X3

4.3.4 Evaluate various development options to optimize oil production

1. Changing WHP

The operating rates produced by each analysis are summarized in the **Table 27, Table 29** and **Table 30** below.

Wellhead pressure (psig)	Water cut (%)		
	25	**40**	60
	Oil rate (STB/d) at different water cut (%)		
300	1017.5	**678.2**	348.2
200	1413.1	**985.8**	530.1
100	1748.1	**1255.5**	718.8

Table 27: Oil rate at various WHP & WC for well X3

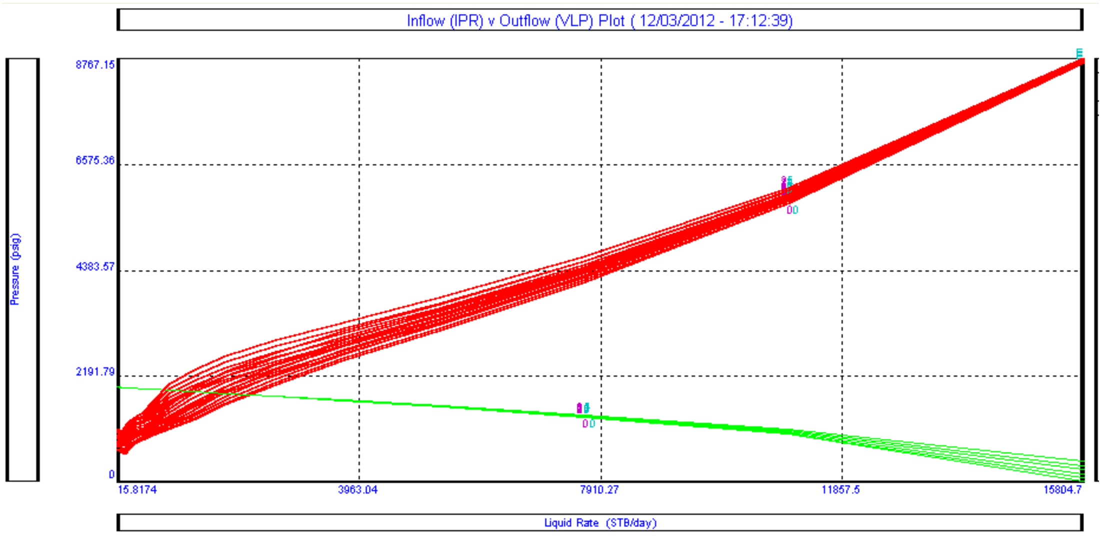

Figure 30: IPR/VLP for changing wellhead pressure at Well X3

By changing the wellhead pressure from 300 to 100 psig, the operating rate produced becomes higher. However, when the water cut is increasing to 40%, the oil rates obtained are already reached 1000 stb/d and no longer economical as the water cut is keep increasing. Thus, it can be concluded that Well X3 can produce economically until 40% of water cut by changing the wellhead pressure from 300 to 100 psig. **Table 27** shows that at the WHP of 300 psig, this well can produce up until 1748.1 Stb/d which is 42% higher than the rate produced at the WHP of 100psig @ 25% water cut.

Scenario	Maximum economic water cut	Production rate at 25% water cut
Lowering Christmas tree pressure	40 %	1748.1 STB/D

Table 28: Oil rate at economic water cut for well X3

2. Changing tubing size

Tubing Size ID (in)	Oil rate (STB/d)
2.441	1019.1
2.992	1753.4
4.09	3438.1
4.892	4541.2

Table 29: Oil rate at various tubing internal diameter sizes for well X3

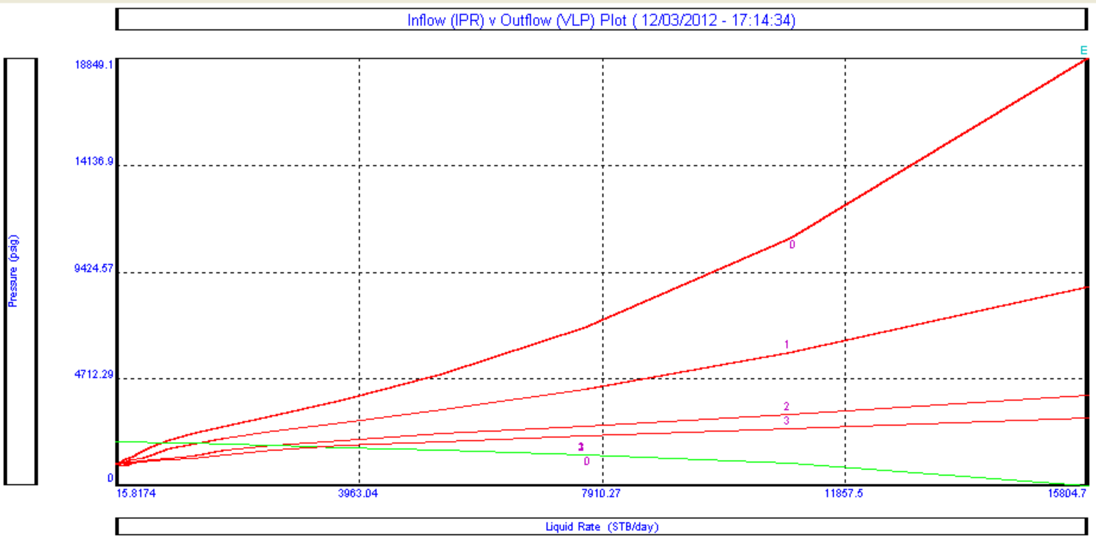

Figure 31: IPR/VLP for changing tubing size at Well X3

Second analysis is then performed by using various sizes of tubing internal diameter (ID). From the **Table 29**, the oil rates increment obtained by using different sizes of tubing are quite high. Changing tubing size is recommended for the optimization.

3. Gas lift (artificial lift method)

Gas injection (MMscf/d)	Water cut (%)		
	25	**27**	29
	Oil rate (STB/d) at different water cut (%)		
1	1017.5	**970.2**	922.5
2	1077.7	**1032.5**	988.4
3	1071.1	**1028.1**	984.5

Table 30: Oil rate with various gas injection rates for well X3

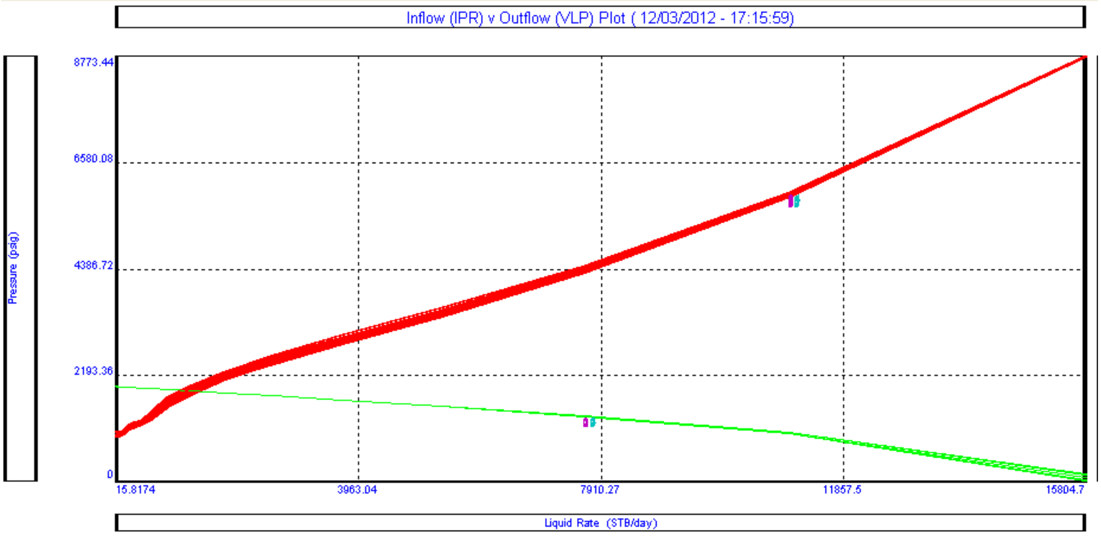

Figure 32: IPR/VLP for changing gas lift rate at Well X3

Third analysis is performed by increasing the gas lift injection rates from 1 to 3 MMscf/d. From **Table 30,** the operating rates produced at 27% water cut are already reached the economic limit with the production rates of 900stb/d to 1030 stb/d.

Scenario	Maximum economic water cut	Production rate at 25% water cut
Optimised gas lift	27%	1071.1

Table 31: Economic oil rate with optimized gas lift for well X3

Result analysis Well X3

1) Lowering Christmas tree pressure to 100 psig is recommended because the well's life can be extended to 40% water cut.
2) Changing tubing size is recommended as it does produce fruitful increment in oil production rate.
3) The gas lift method is not economical as it only can produces up to a maximum economic water cut of 27% with gas injection rate of 1-3 MMscf/d and producing oil rates of 970 to 1028 STB/d.

CHAPTER 5: CONCLUSION AND RECOMMENDATION

5.1 RELEVANCY TO THE OBJECTIVES

As stated previously, this report is written to provide documentation for optimizing the productivity in Field X by using production optimization technique. This technique is performed by using well model from Integrated Production Modelling IPM- PROSPER. Three models have been constructed which consists of three oil producers well. From this simulation, proper well models successfully built by integrating an accurate well test data. These well models then can be used to demonstrate the real behaviour of the well. After performing analysis on these three well models, the author has an opportunity to identify problems occurred in the production system which cause it to flow below its maximum rate. Further action can be taken by proposing few recommendation and modification to these well in order to optimize its production in the future. Thus, this technique can prolong the reservoir and field life by optimizing each of the individual wells.

In short, the proposed simulation using well model does follow the objectives and scopes 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 SUGGESTED FUTURE WORK FOR EXPANSION AND RECOMMENDATIONS

For this simulation test, it is recommended to use an accurate well test data in order to obtain a proper well model. This is essential to demonstrate a real behaviour of the well and thus an analysis can be performed successfully.

In addition, 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. From this technique, the optimization can be broadly done from the surface until its subsurface system.

Last but not least, the proper selection of the equipments should be used especially when obtaining the well test data in order to get a better repeatability and reproducibility of the results. The failure of the equipment such as multiphase flow meter (MPFM) in the platform is often contributed towards the inaccuracy of the well test results.

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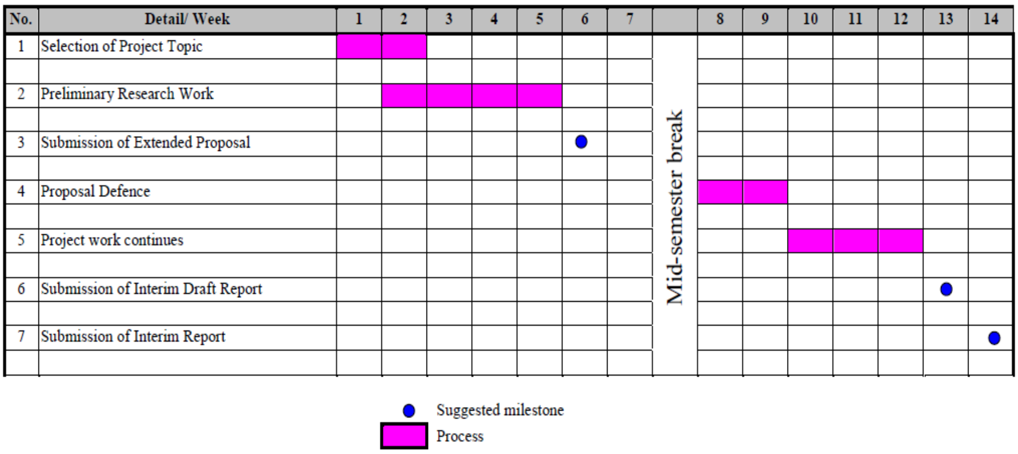
APPENDICES

GANTT CHART FOR FYP 1 & 2

Timelines for FYP 1



Timelines for FYP 2

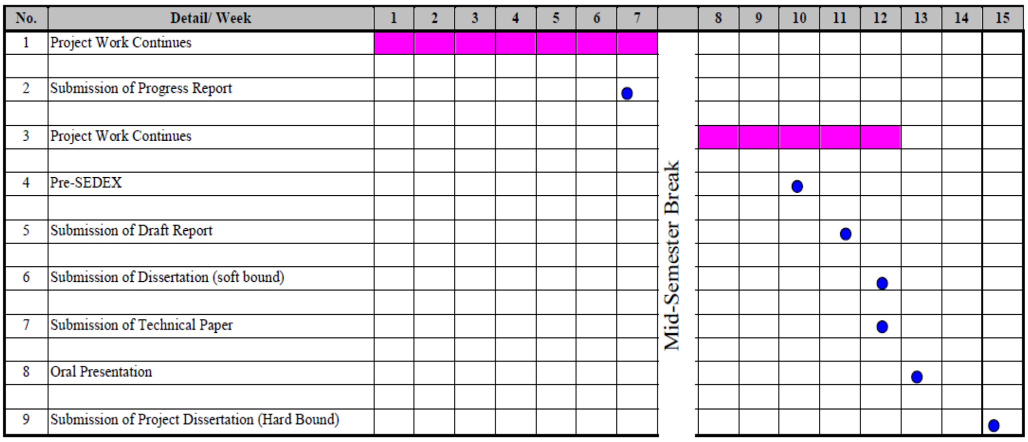


Figure 33: Gantt chart for FYP 1 & FYP 2