DISSERTATION

GAS LIFT OPTIMIZATION OF BAYAN WELLS USING PROSPER

BY

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12052

SEPT 2012

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CERTIFICATION OF APPROVAL

Gas Lift Optimization Of Bayan Wells Using PROSPER

by

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A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
in partial fulfilment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

____

(Dr. Mohd Nur Fitri Ismail)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
September 2012

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.

MUHAMMAD AIZUDDIN B. MOHAMMAD ROSLAN

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ACKNOWLEDGEMENT

I would like to express our sincere gratitude and deep appreciation to the following people for their support, patience and guidance. Without them, this thesis would not have been made possible. It is to them that I owe my deepest gratitude.

- **Dr. Mohd Nur Fitri Ismail**, *FYP Supervisor* for his assistance, encouragement, guidance, constructive critism and excellent advice throughout this research project.
- **Ms Raja Rajeswary Suppiah**, *Co-Supervisor* for her assistance in acquiring the data, understanding of the oil field and guidance throughout this research project

Last but not least, I would also like to thank my family, friends, and Geosciences and Petroleum Engineering Department lecturers for their unwavering love, support and assistance throughout the thesis.

ABSTRACT

This project aims to study the complete mechanism of gas lift optimization and application to help increase the oil and gas production in BAYAN wells. The BAYAN wells have been producing for several years now and the production rate have been declining over time and in need of well stimulation and gas lift optimization is the best option. Gas lift optimization is the most common artificial lift method widely used in oil production. It will help to increase the production by increasing the effective density of the oil and increasing the pressure inside the reservoir. The total gas used for oil production is constrained by daily availability limits and limits on maximum injection volume into each well. The oil produced from each well is known to be a nonlinear function of the gas injected into it and varies between wells. The problem is to identify and inject the optimal amount of gas into each well to maximize the total amount of oil production from the reservoir on a daily basis. The problem has long been of practical interest to all major oil exploration companies as it has a potential of deriving large financial benefits. Thus, it is hoped that this project will increase the production rate of BAYAN wells.

INTRODUCTION

Background

As a reservoir produces, it naturally encounters pressure drop, solution gas reduction and water cut increase which can stop or reduce its production flow rate. Artificial lift methods including gas lift can resume or increase the production rate by adding some additional energy to the fluid in well. Gas lift is one of the most common artificial lift methods which are used widely in oil production process. The objective of installing gas lift in a completion is to increase the drawdown on the producing formation by injecting gas into the lower part of the oil column and consequently reducing the flowing gradient in the oil column. This cab increase flow rate or bring a dead well on production. Gas lift optimization is crucial to ensure maximum oil production within facility constraints. During the lift process, gas is injected into the tubing. Gas injection will lighten the fluid column along the tubing, so it will increase oil production. Normally oil production increases as gas injection increases. However, the gas injection has an optimum limit because too much gas injection will cause slippage, where gas phase moves faster than liquid, so that it reduces oil production.

Gas lift becomes critical to sustain production as oil fields mature. Increasing watercut and decreasing reservoir pressure eventually cause wells to cease natural flow. Subsequently, gas lift is required to kick off and sustain flow from these wells. Gas lift optimization requires a lot of effort, and faces many challenges in the process of implementation. However, the gain is significant, and always perceived as the most cost effective restoration method. Many parameters are involved in a successful gas lift operation. Gas lift optimization means specifying these parameters in such a way that the production and the operation’s net present value are maximized. If the parameters are not specified properly, the operations become impossible or at least uneconomical.

For this project, the field used is BAYAN field located offshore of Sarawak.

Problem Statement

Problem Identification:

- As the oil field mature, the productions from the field have been declining over the years. This is due to the fact that the pressure inside the reservoir is decreasing as the oil and gas produced from the well increases, thus reducing the flow of oil and gas from the well.

Significant of the Project:

- This project will help to investigate the best methods and process of gas lift to optimize BAYAN Field production. The optimization will have a return value acceptable with the cost needed to perform the gas lift.

Objectives and Scope of Study

I. To optimize the production of BAYAN field well by using gas lift optimization.

LITERATURE REVIEW

Gas Lift

In an oil producing-well, reservoir fluid consisting of oil and water and sometimes together with gas flows from reservoir through a tubing toward surface facilities. In case where the reservoir pressure is high enough, the reservoir fluid can flows up to the surface naturally. However as time increases, the reservoir depletes and the pressure decreases. If this happened, oil production decreases so that artificial lift methods, such as gas lift method need to apply.

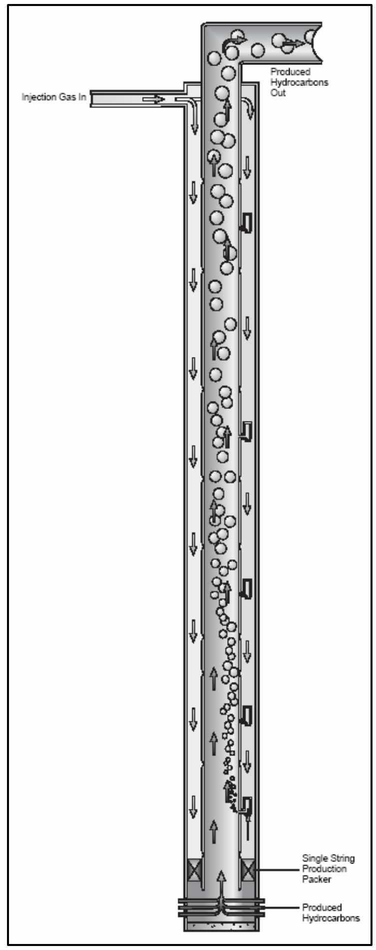


Figure 1 – Continues Gas Lift

Gas lift is the method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas to lift the well fluids. The primary consideration in the selection of a gas-lift system to lift a well, a group of wells, or an entire field is the availability and compression cost of gas. Continuous-flow gas lift is the only method of artificial lift that fully utilizes the energy in the formation gas production. Most wells are gas lifted by continuous flow, which can be considered an extension of natural flow by supplementing the formation gas with additional high pressure gas from an outside source. Gas is injected continuously into the production conduit at a maximum depth on the basis of the available injection gas pressure. The injection gas mixes with the produced well fluids and decreases the flowing pressure gradient of the mixture from the point of gas injection to the surface. The lower bowing pressure gradient reduces the flowing bottomhole pressure (BHFP) to establish the drawdown required for attaining a design production rate from the well. In a typical gas lift system, compressed gas is injected through gas lift mandrels and valves into the production string. The injected gas lowers the hydrostatic pressure in the production string to re-establish the required pressure differential between the reservoir and well bore, thus causing the formation fluids to flow to the surface.

Produce fluid and gas along with injected gas is then flown into separator. Produced oil is pumped to storage while injected gas and produced gas is returned to the suction side of the compressor. After the gas is recompressed, the rotation cycle is completed. Make up gas from another gas producing well is used for compressor start-up. The typical general gas lift system is shown on following figure.

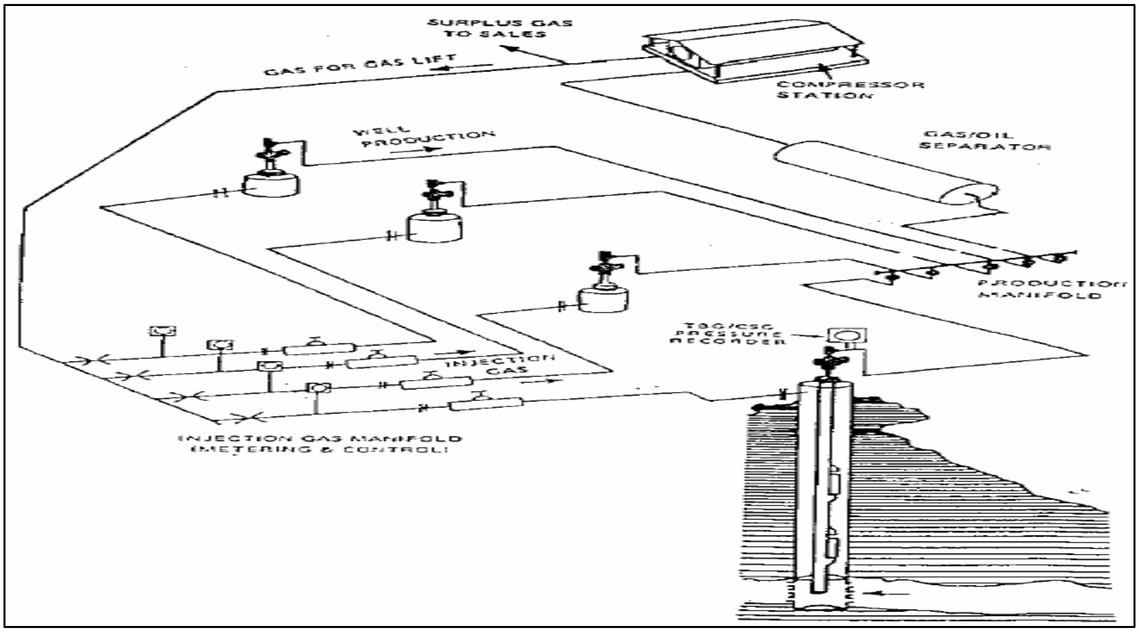


Figure 2 – General Gas Lift System

If sufficient drawdown in the bottomhole pressure (BHP) is not possible by continuous flow, intermittent gas lift operation may be used. Intermittent gas lift requires high instantaneous gas volumes to displace liquid slugs to the surface. The disadvantage of intermittent lift is an "on-off" need for high pressure gas, which presents a gas handling problem at the surface and surging in the BHFP that cannot be tolerated in many wells producing sand. Most high-pressure gas lift systems are designed to recirculate the lift gas. The low-pressure gas from the production separator is compressed and reinjected into the well to lift the fluids from the well. This closed loop is referred to as a closed rotative gas-lift system. Continuous-flow gas lift operations are preferable with a closed rotative system.

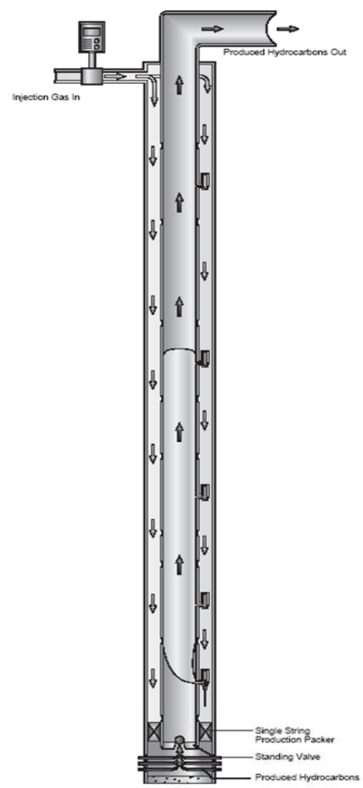


Figure 3 – Intermittent Gas Lift

Intermittent gas lift operations are particularly difficult to regulate and to operate efficiently in smaller closed rotative systems with limited gas storage capacities in the low- and high-pressure lines.

According to completion procedure, general gas lift classification has been shown in the figure below.

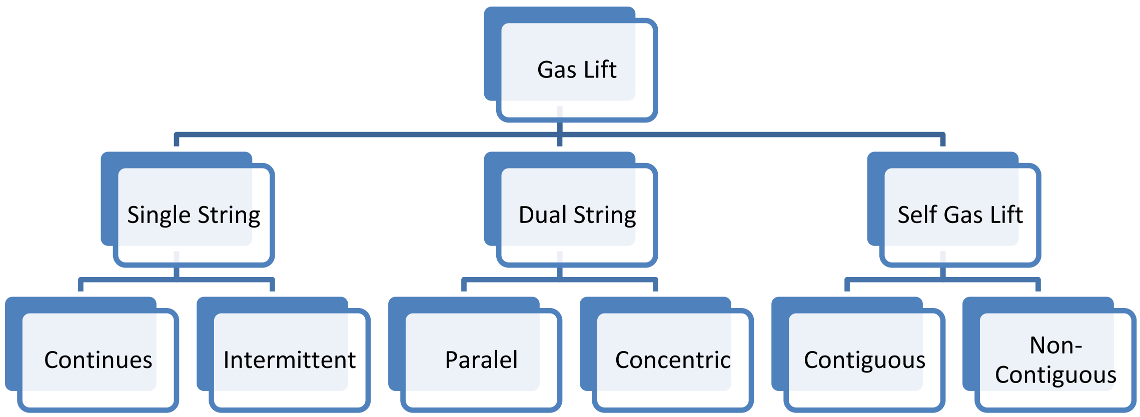


Figure 4 – General Gas Lift Completion Classification

Gas lift optimization is key factor to enhance the production performance in a maturing environment, where natural production depletes rapidly. During initial stage of gas lift operation, the focus is to kick off dead wells; less attention is put in optimization effort. The initial oil production buildup is substantial as dead wells resumed production. With the increasing numbers of gas lift wells online, gas lift optimization efforts become critical to maximize oil production within system constraints. Pressure of a production system is carefully preset to meet specific delivery requirement. In certain circumstances, production system pressure may be reduced, which translates to less surface backpressure to wells. With lower backpressure, a well can produce at higher drawdown, hence higher flow rate.

$$q = Productivity\ Index\ \times drawdown$$

The gas allocation optimization problem is a complicated long time problem of interest. Liquid production rate for each well is nonlinear function of gas injection rate, but unfortunately it is not known explicitly. In existing approaches, the optimization problem has been solved in three steps of procedure. In first step, a set of data relating gas injection to oil production from each well are collected. The data may be obtained from field data or numerical simulation data. In second step, a regression or interpolation method is applied to estimate the nonlinear function which relates gas injection to liquid production.

However, a thorough evaluation is necessary before commitment is made as they are certain setbacks, e.g. lower compressor discharge pressure, lower sales gas volume etc. Also, not all wells will respond to the lower backpressure. A low Gas-Oil ratio (GOR) well is more likely to respond to the lower system pressure whereas for a high GOR well, choke is normally installed to control drawdown. In this case, the backpressure exerted on the well is the high tubing head pressure upstream to the choke due to restricted flow across the choke. Reduction in production system pressure downstream to the choke has no impact to the well

In most cases, oil is produced using gas lift system from an oil field which consists of a group of gas lift wells such as BAYAN Field. The most common optimization problem faced in multi gas lift wells system is maximization of total oil production. Let the total gas available for injection N gas lift wells are given by $Q_{gav.}$ How much gas should be injected to each well to maximize total oil production? Since

$$q_0 = (1 - WC)q_l$$

Then the problem can be written as a constrained maximization

$$maxQ_0 = \sum_{k=1}^{N} (1 - WC_k)\varphi_k(qg_k)$$

Subject to

$$\sum_{k=1}^{N} qg_k \leq Qg_{av}$$

In case where the gas available for injection Qgav is large enough, then for each k = 1, 2,…,N, gas injection qgk is chosen such that maximizing liquid production 'k(qgk). Gas available for injection Qgav is usually very limited and should be shared in optimal form for each well.

Advantages and Limitations of Gas Lift

The flexibility of gas lift in terms of production rates and depth of lift cannot be matched by other methods of artificial lift if adequate injection-gas pressure and volume are available. Gas lift is one of the most forgiving forms of artificial lift, since a poorly designed installation will normally gas lift some fluid. Many efficient gas lift installations with wireline-retrievable gas lift valve mandrels are designed with minimal well information for locating the mandrel depths on initial well completion. Highly deviated wells that produce sand and have a high formation gas/liquid ratio are excellent candidates for gas lift when artificial lift is needed. Many gas lift installations are designed to increase the daily production from flowing wells. No other method is as ideally suited for through-flowline (TFL) ocean floor completions as a gas lift system.

Maximum production is possible by gas lift from a well with small casing and high deliverability. Wireline-retrievable gas lift valves can be replaced without killing a well or pulling the tubing. The gas lift valve is a simple device with few moving parts and sand-laden well fluids do not have to pass through the valve to be lifted. The individual well in-hole equipment is relatively inexpensive. The surface equipment for injection gas control is simple and requires little maintenance and practically no space for installation. The reported overall reliability and operating costs for a gas lift system are lower than for other methods of lift. Maximum liquid production is achieved by availing gas lift system. The performance comparison of different artificial lift method has been shown in figure below.

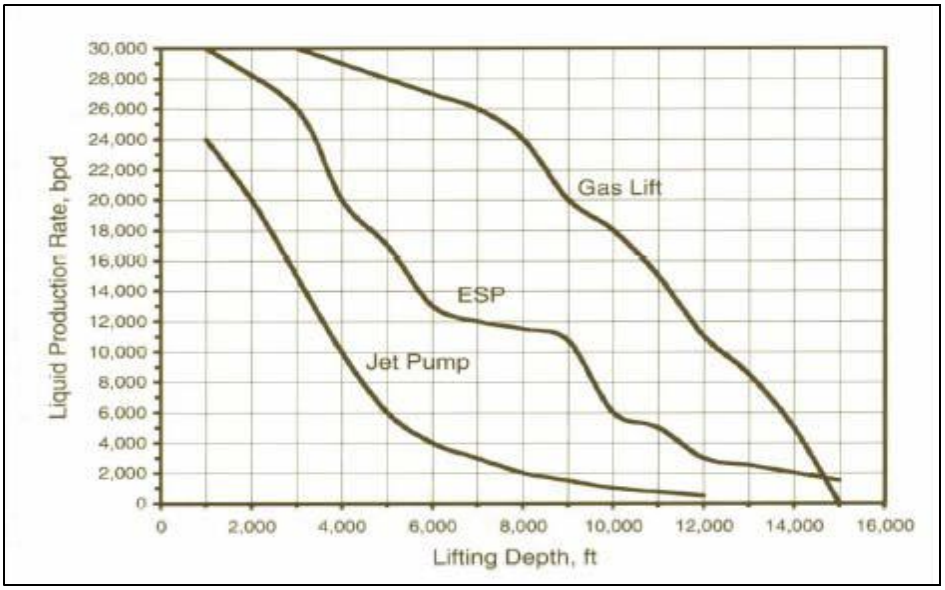


Figure 5 – Gas Lift, ESP and Jet Pump Performance Curve

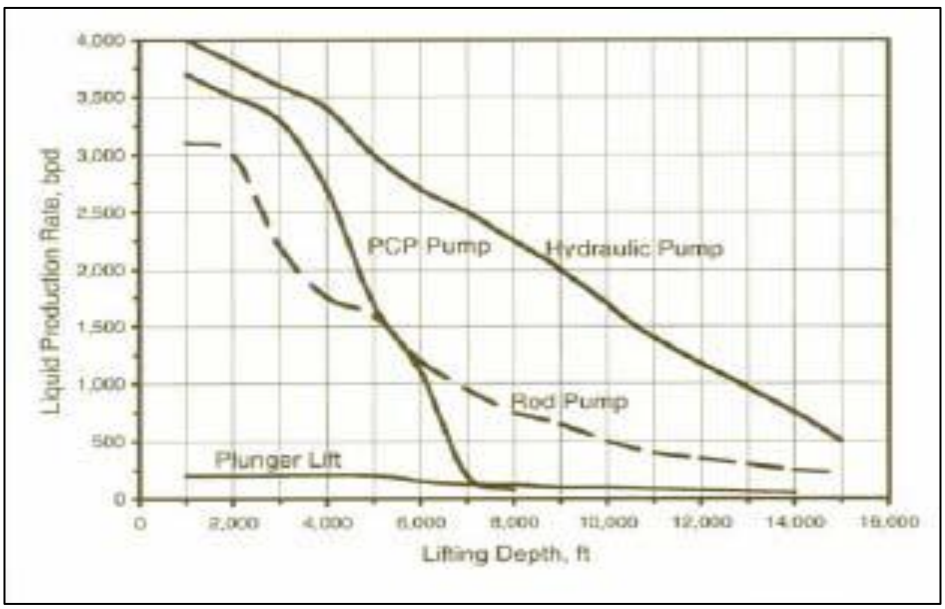


Figure 6 – Hydraulic Pump, PCP Pump, Rod Pump and Plunger lift Performance Curve.

The primary limitations for gas lift operations are the lack of formation gas or of an outside source of gas, wide well spacing, and available space for compressors on offshore platforms. Generally, gas lift is not applicable to single-well installations and widely spaced wells that are not suited for a centrally located power system. Gas lift can intensify the problems associated with production of a viscous crude, a super-saturated brine, or an emulsion. Old casing, sour gas, and long, small-ID flowlines can rule out pas lift operations. Wet gas without dehydration will reduce the reliability of gas lift operations.

Inflow Performance

The Inflow Performance Relationship (IPR) describes pressure drawdown as a function of production rate, where drawdown is defined as the difference between static and flowing bottom hole pressure (FBHP). The simplest approach to describe the inflow performance of oil wells is the use of the productivity index (PI) concept. It was developed using the following assumptions:

- Flow is radial around the well
- A single-phase liquid is flowing
- Permeability distribution in the formation is homogeneous
- The formation is fully saturated with the given liquid.

The flow through a porous media is given by the Darcy equation:

$$\frac{q}{A} = \frac{k}{\mu}\frac{dp}{dl}$$

Using the assumptions above it can be written as

$$q = \frac{0.00708kh}{\mu\beta ln\left(\frac{r_e}{r_w}\right)}\left(p_r - p_{wf}\right)$$

Where: q = liquid rate, STB/d

k = effective permeability, mD

h = pay thickness, ft

μ = liquid viscosity, cP

B = liquid volume factor, bbl/STB

re = drainage radius of well, ft

rw = radius of wellbore, ft

pR = average reservoir pressure

pwf = flowing bottomhole pressure

Most parameters on the right hand side are constant, which permits collecting them into a single coefficient called PI:

$$q = PI(p_r - p_{wf})$$

This gives us:

$$PI = \frac{q}{(p_r - p_{wf})}$$

This equation states that liquid inflow into a well is directly proportional to the pressure drawdown. It will plot as a straight line on a pressure vs. rate diagram. The use of the PI concept is quite straightforward. If the average reservoir pressure and the PI are known, use of equation above gives the flow rate for any FBHP. The well's PI can either be calculated from reservoir parameters, or measured by taking flow rates at various FBHPs.

This works well for a single phase flow, but when producing a multiphase reservoir the curve will not plot as a straight line. As the oil approaches the well bore and the pressure drops below bubble point, gas comes out of solution. Thus, the free gas saturation in the vicinity of the oil steadily increases, which implies that the relative permeability to gas steadily increases at the expense of the relative permeability of oil. The greater the drawdown, the bigger this effect would be. Since the PI depends on the effective oil permeability, it is expected that it will decrease. Figure below shows the IPR curve for this condition.

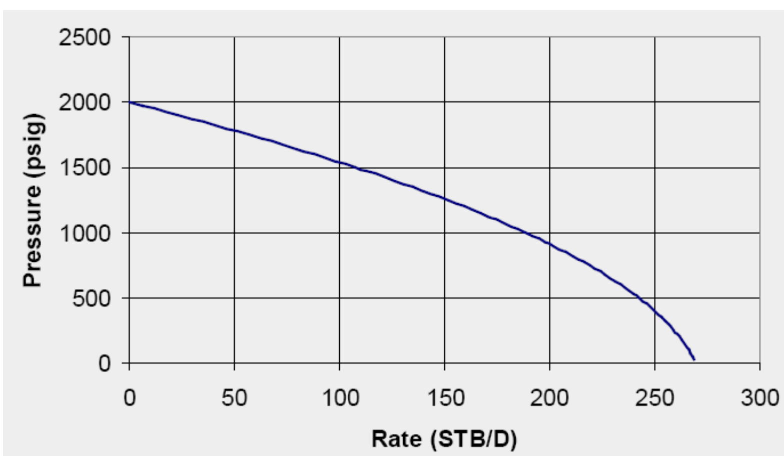


Figure 7 – IPR Curve

Vogel used a numerical reservoir simulator to study the inflow of wells depleting solution gas drive reservoirs. He considered cases below bubble point and varied parameters like draw downs, fluid and rock properties. Vogel found that the calculated IPR curves exhibited the same general shape, which is given by the dimensionless equation:

$$\frac{q}{q_{max}} = 1 - 0.2\frac{p_{wf}}{2} - 0.8\left(\frac{p_{wf}}{p_r}\right)^2$$

The equation is generally accepted for other drive mechanisms as well, and is found to give reliable results for almost any well with a bottom hole pressure below bubble point of the oil. There are a number of other models designed for special cases e.g. horizontal wells, transient flow, fractured wells, non-Darcy pressure loss, high rates etc.

Outflow Performance

The well's outflow performance, or Vertical Lift Performance (VLP), describes the bottomhole pressure as a function of flow rates. According to Golan and Whitson the outflow performance is dependent on different factors; liquid rate, fluid type (gas-to- liquid ratio, water cut), fluid properties and tubing size. Gabor divides the total pressure drop in a well into a hydrostatic component, friction component and an acceleration component:

<u>Hydrostatic component</u> represents the change in potential energy due to gravitational force acting on the mixture:

$$\left(\frac{dp}{dl}\right)_h = \rho g \sin \beta$$

Where: ρ = density of fluid

β = pipe inclination angle, measured from horizontal

g = gravity constant

Friction component stands for the irreversible pressure losses occurring in the pipe due to fluid friction on the pipe inner wall:

$$\left(\frac{dp}{dl}\right)_f = \frac{1}{d} f \frac{1}{2} \rho v^2$$

Where: f = friction factor

d = pipe inside diameter

v = fluid velocity

The type of flow is determined from the Reynolds number:

$$Re = \frac{\rho v d}{\mu}$$

Where: μ = fluid viscosity

The boundary between flows regimes are:

Re ≤ 2000:	Laminar flow
2000 < Re ≤ 4000:	Transition between laminar and turbulent flow
4000 < Re:	Turbulent flow

Acceleration component represents the kinetic energy changes of the flowing mixture and is proportional to the changes in flow velocity. The term is often negligible:

$$\left(\frac{dp}{dl}\right)_a = -\rho v \frac{dv}{dl}$$

Multiphase Flow

Oil wells normally produce a mixture of fluids and gases to the surface while phase conditions usually change along the path. At higher pressures, especially at the well bottom, flow may be single phase. But going up in the well the continuous decrease of pressure causes dissolved gas to gradually escape from the flowing liquid, resulting in multiphase flow. Gas injection into a well is also an example of multiphase flow. In single phase flow we discriminate between laminar and turbulent flow. In two phase flow we discriminate in addition between flow regimes that are characteristic for the time and space distribution of gas and liquid flow. In horizontal flow we discriminate between the flow regimes:

- Stratified flow
- Slug flow
- Dispersed bubble flow
- Annular flow

These are shown in figure below. At low velocities the gas and liquid are separated as in stratified flow. At high velocities gas and liquid become mixed. Slug flow is an example of a flow regime in between, representing both separation and mixing. Slug flow is consequently referred to as an intermittent flow regime.

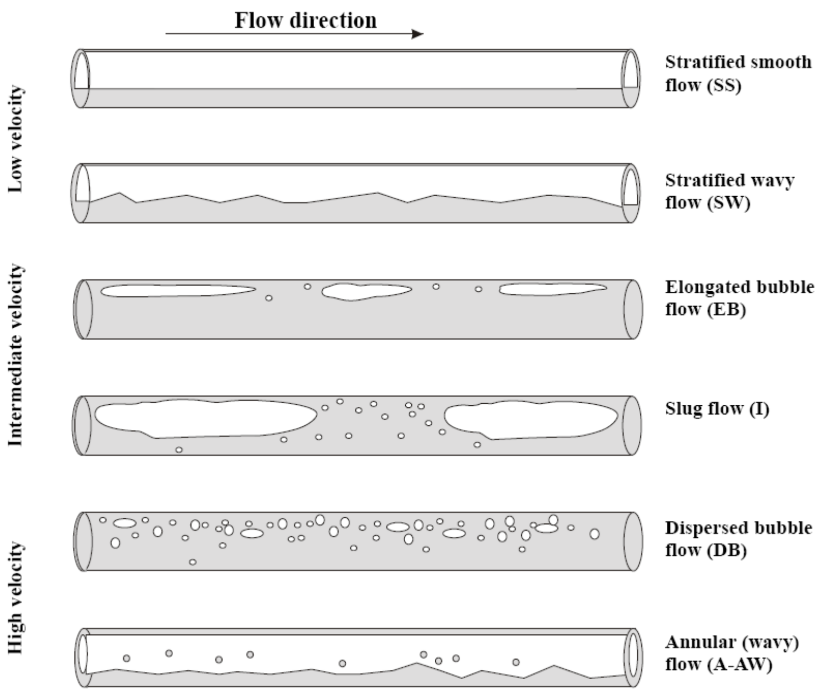


Figure 8 – Flow regimes in horizontal flow

In vertical flow we discriminate between the flow regimes

- Slug flow
- Churn flow
- Dispersed bubble flow
- Annular flow

Figure below illustrates the flow regimes in vertical flow. The same comments that apply to horizontal flow are valid in vertical flow. The big difference is that in vertical (concurrent upward) flow it is not possible to obtain stratified flow. The equivalent flow regime at identical flow rates of gas and liquid is slug flow with very slow bullet shaped Taylor bubbles.

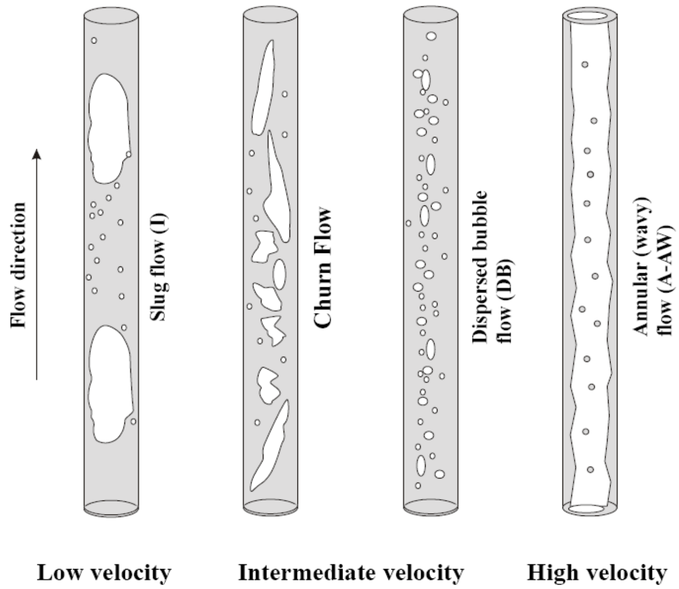


Figure 9 – Flow regimes in vertical flow

BAYAN Oil Field

Bayan oil field is located offshore of Sarawak. It is one of Malaysia's longest serving oil field. It consists of 3 parts name 'West Bayan', 'North West Bayan' and 'North Bayan'.

METHODOLOGY

PROSPER

PROSPER is a PROduction and System PERformance analysis software. It assists the production or reservoir engineer to predict tubing and pipeline hydraulics and temperature with accuracy and speed. Prosper's powerful sensitivity calculation features enable existing design to be optimized. It helps petroleum producers to maximize their production earnings by providing the means of critically analyzing the performance of each producing well.

Preparation of Well Model in Prosper

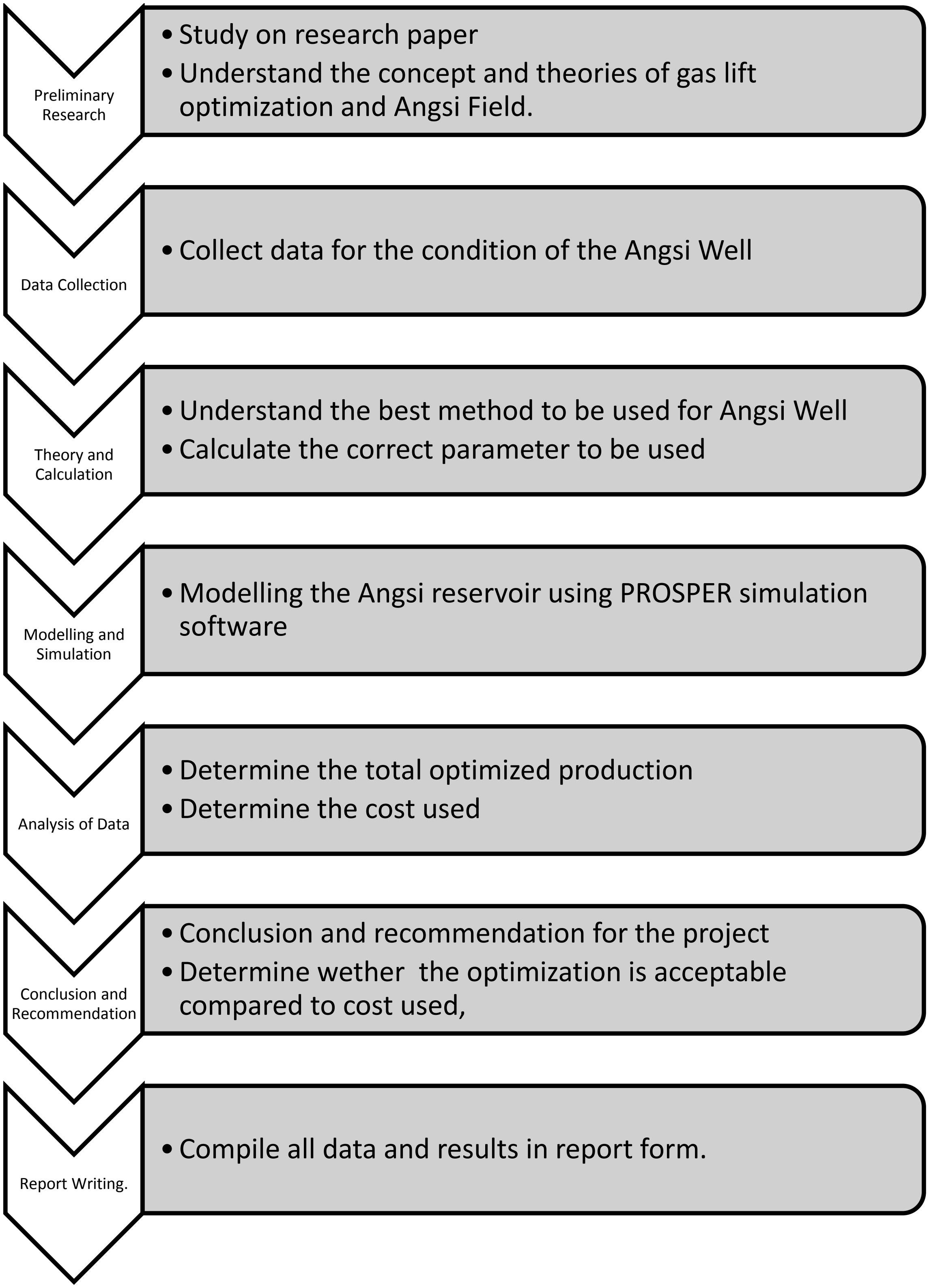
The well models in this work had been prepared by Prosper program. Prosper makes model for each component of the producing well system separately which contributes to overall performance, and then allows to verify each model subsystem by performance matching. In this way, the program ensures that the calculation is as accurate as possible. Once the system model has been tuned to real data, Prosper is confidently used to model the well in different scenarios and to make forward predictions of reservoir pressure based on surface production data.

Prosper's Approach and Systems Analysis

Prosper's approach is to first construct a robust PVT model for the reservoir fluid. The PVT model is constructed by entering laboratory PVT data and adjusting the correlation model until it fits the measured data for improving the accuracy of forward prediction. Well potential and producing pressure losses are both dependent on fluid (PVT) properties. The accuracy of system analysis calculation is therefore dependent on the accuracy of the fluid properties model.

In the VLP matching phase, Prosper divides the total pressure loss into friction and gravity components and uses a non-linear regression technique to separately optimize the value of each component. Not only does the matching process result in a more accurate model, it also highlights the inconsistencies in the PVT model or in equipment description.

When sufficient accurate field data is available, robust PVT, IPR and VLP models are prepared by performance matching. Each model component is separately validated; therefore dependency on the components of the model can be eliminated.
The following flow chart gives an outline of the calculation steps required to carry out a system analysis using Prosper and the thesis work had been performed according to this procedure.


Preliminary Research
• Study on research paper
• Understand the concept and theories of gas lift optimization and Angsi Field.
Data Collection
• Collect data for the condition of the Angsi Well
Theory and Calculation
• Understand the best method to be used for Angsi Well
• Calculate the correct parameter to be used
Modelling and Simulation
• Modelling the Angsi reservoir using PROSPER simulation software
Analysis of Data
• Determine the total optimized production
• Determine the cost used
Conclusion and Recommendation
• Conclusion and recommendation for the project
• Determine wether the optimization is acceptable compared to cost used,
Report Writing.
• Compile all data and results in report form.

Week	Objectives
	FYP I
5	Completion of preliminary research work
6	Submission of extended proposal
9	Completion of proposal defence
12	Confirmation on lab material and equipment for conducting experiment
13	Submission of Interim draft report
14	Submission of Interim report
	FYP II
5	Finalized the experiment procedure
6	Conducting experiment
7	Result analysis and discussion
8	Submission of progress report
9	Preparation for Pre-SEDEX
11	Pre-SEDEX
12	Submission of draft report
13	Submission of technical paper and dissertation
14	Oral presentation
15	Submission of project dissertation

Table 1 – Gantt chart

Result, Calculation & Discussion

Well model set up of this FYP work had been approached systematically by working from left to right through the main screen of Prosper. The main screen is divided into following order:

- Options Summery
- PVT Data
- Equipment Data
- Gas Lift Data (for gas lift well)
- IPR Data
- Calculation Summary

This order reflects the recommended workflow to follow to set up the well model. The first five sections are input data screen and the last section mentions all the calculation and design features. Calculation menus are activated only when the necessary input data has been entered.

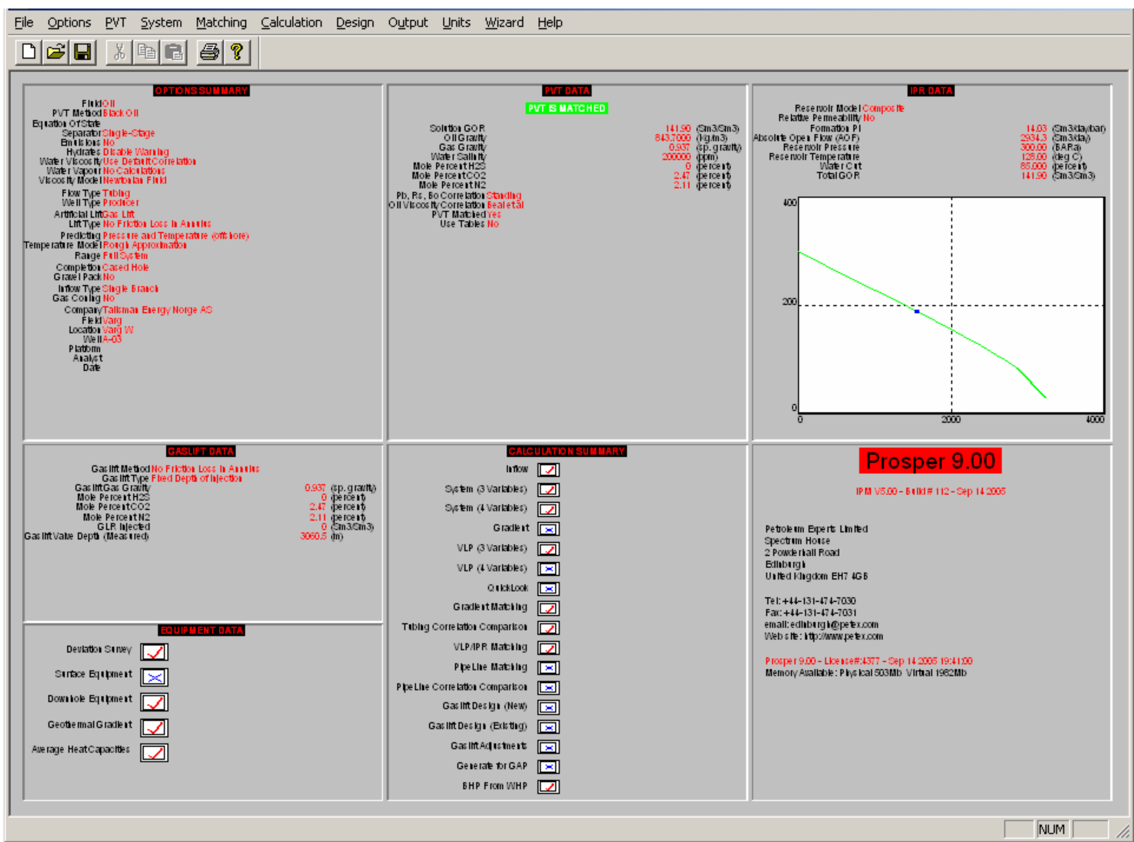


Figure10 – Menus and options in Prosper Main Screen

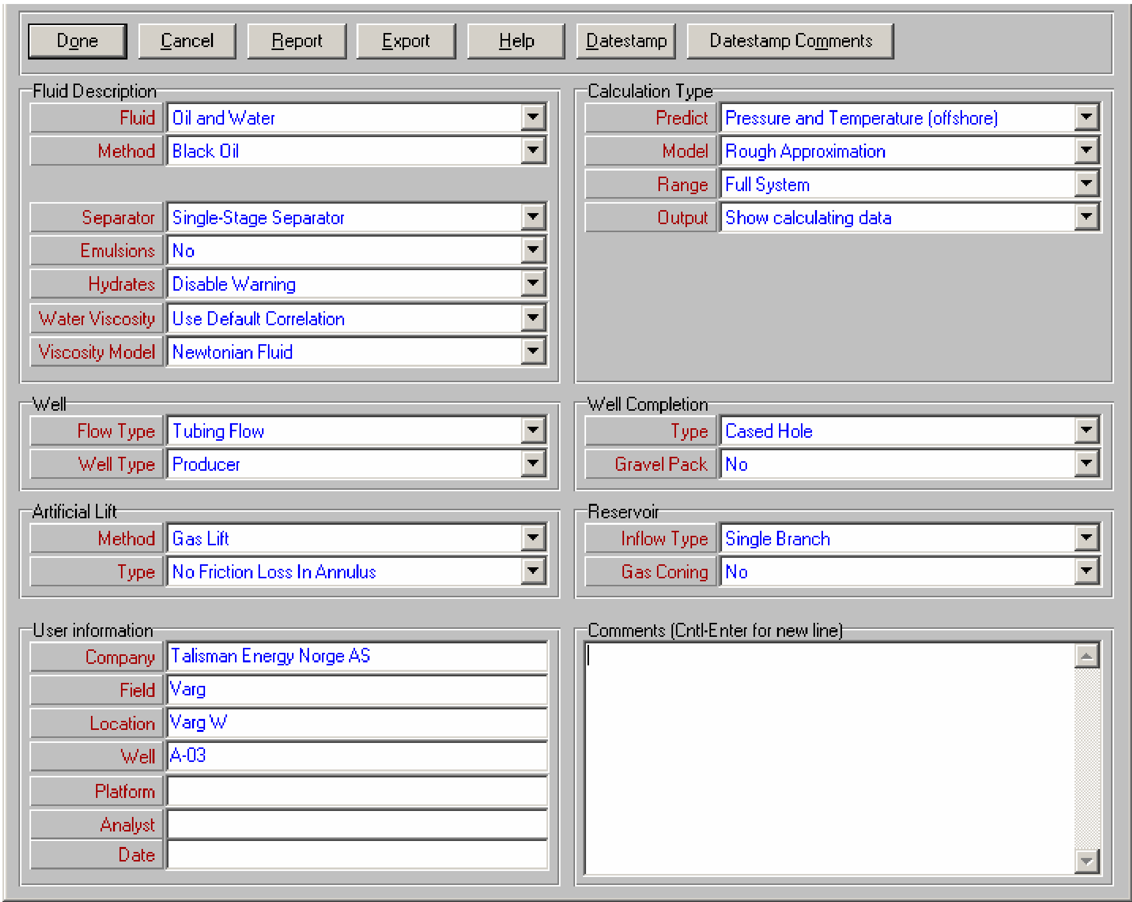


Figure 11 – System Summary

To predict pressure and temperature changes from the reservoir along the well bore and flow line tubular, it is necessary to accurately predict fluid properties as a function of pressure and temperature. Full set of PVT data had been entered to describe the fluid properties properly and enable the program to calculate them. Necessary PVT data had been adopted from the report.

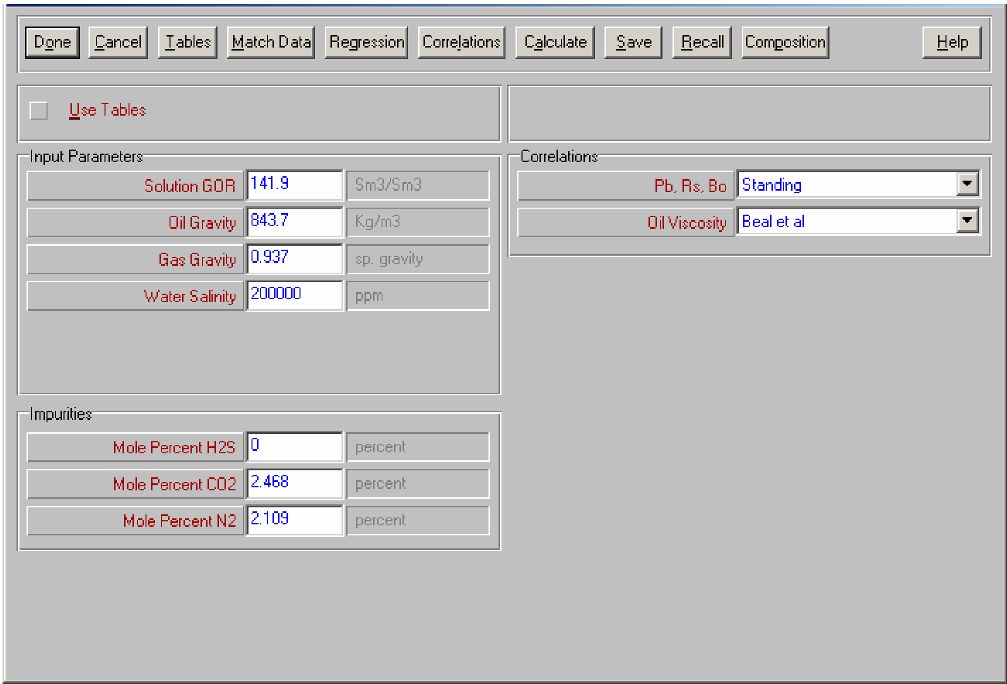


Figure 12 – PVT Input Data

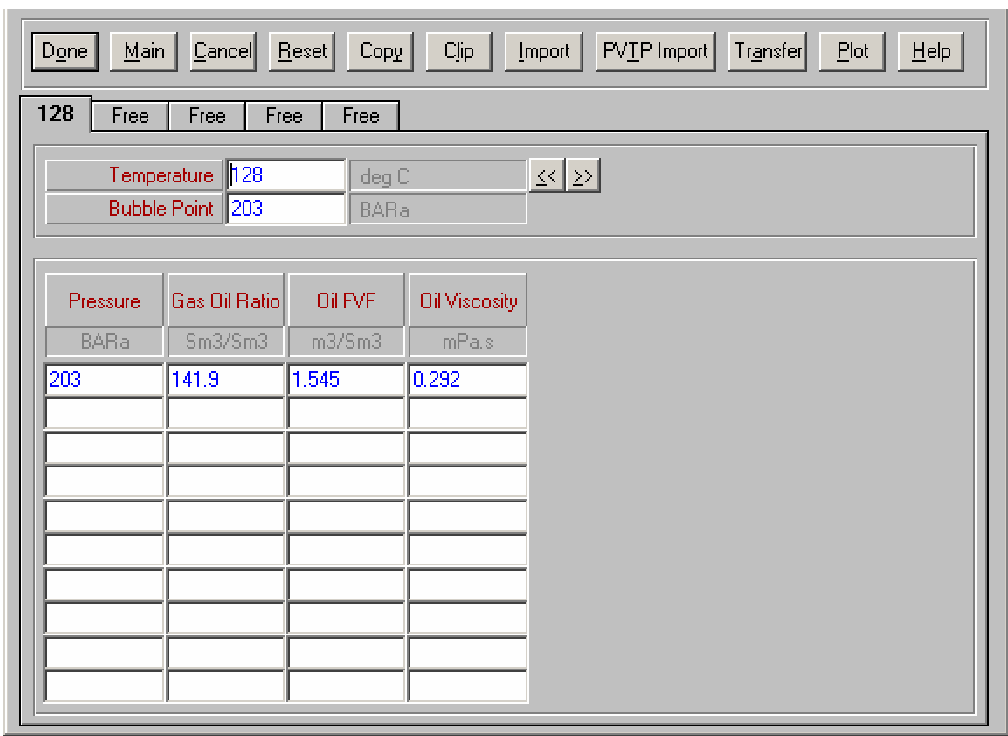


Figure 13 – PVT Input Data

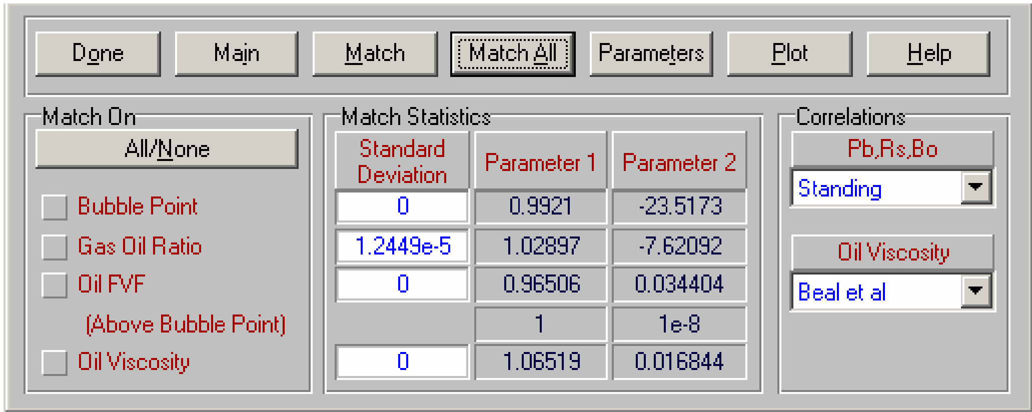


Figure 14 - Regression Screen

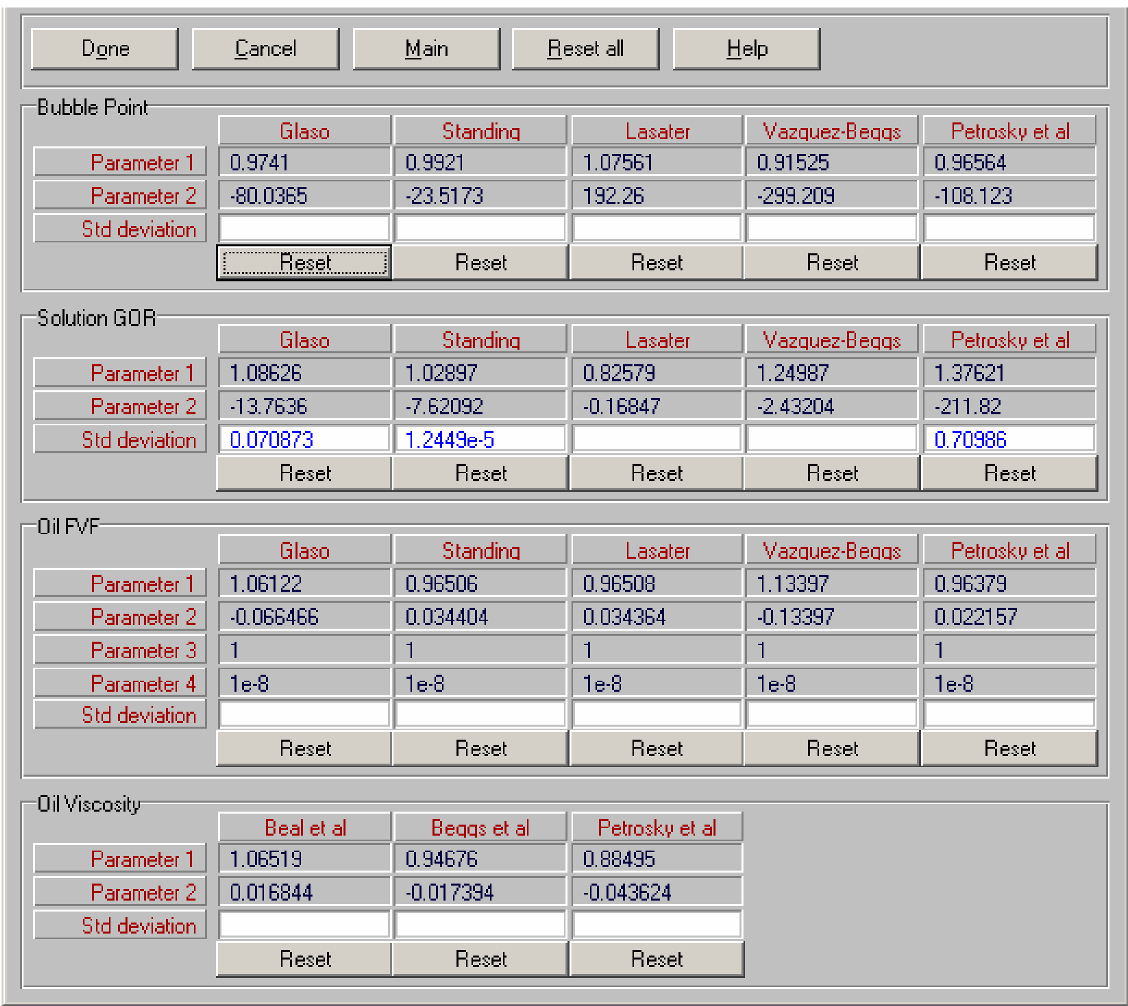


Figure 15 – Correlation Parameters Screen

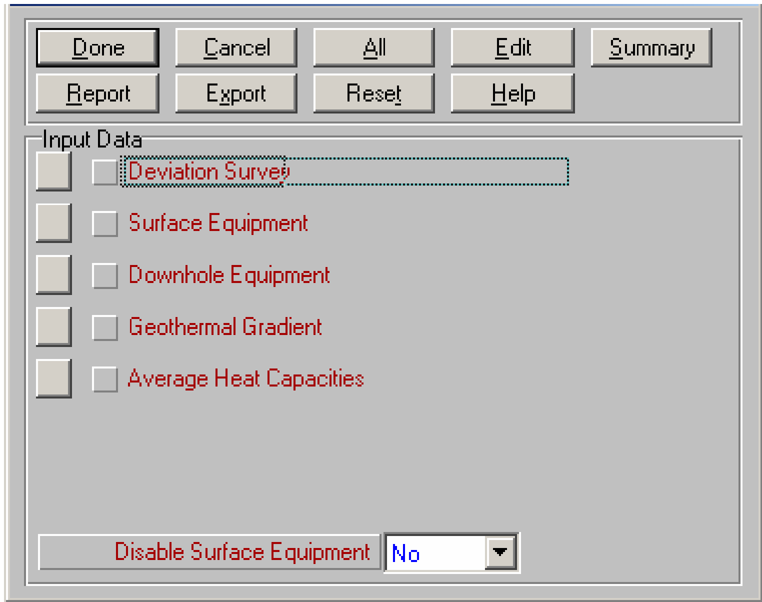
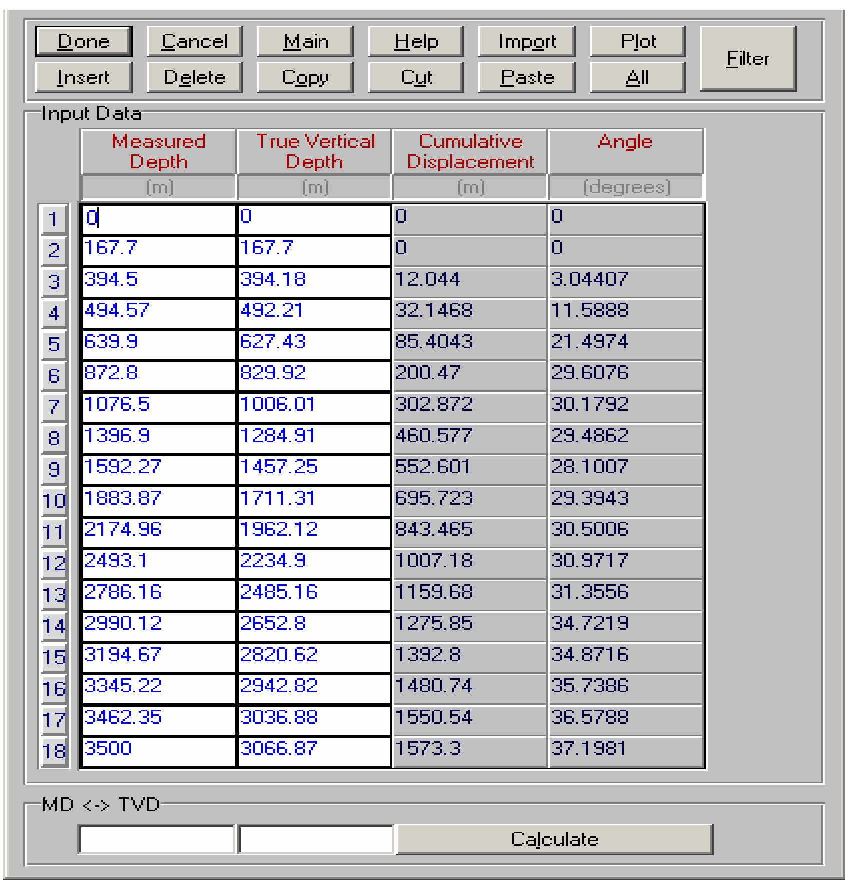
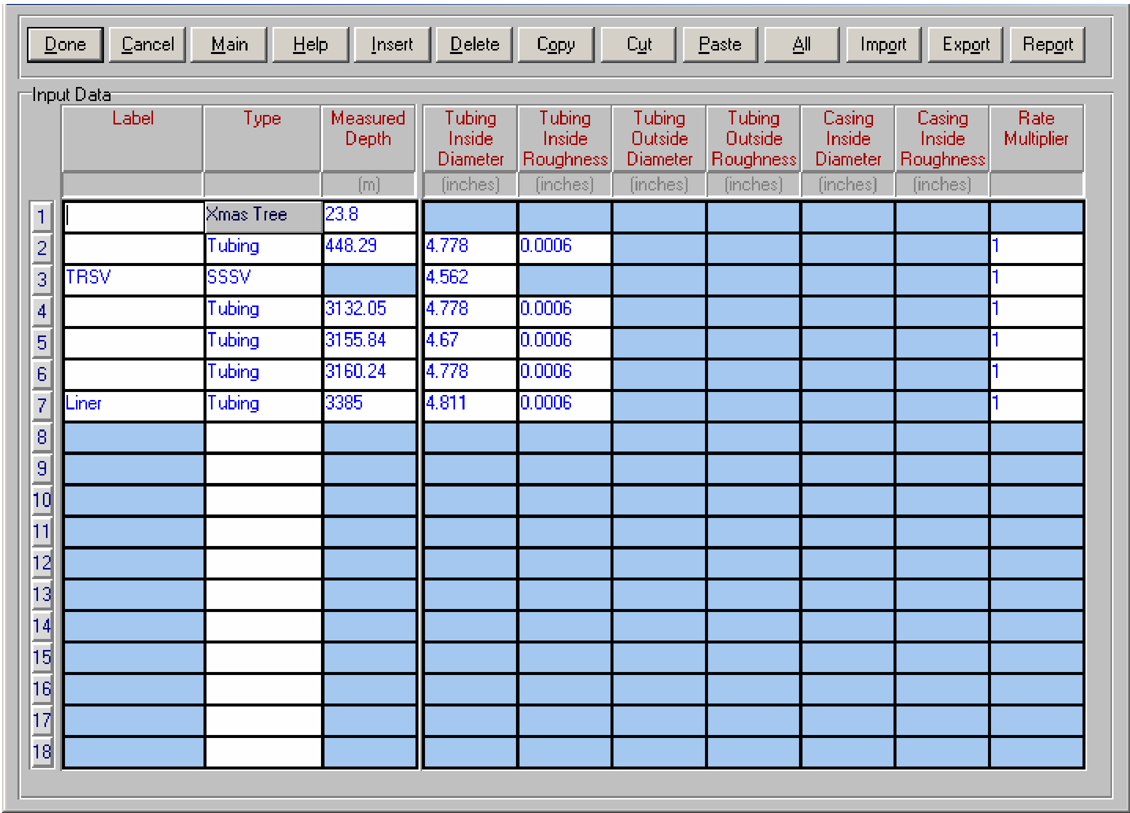


Figure 16 – Equipment Input Data



	Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Angle (degrees)
1	0	0	0	0
2	167.7	167.7	0	0
3	394.5	394.18	12.044	3.04407
4	494.57	492.21	32.1468	11.5888
5	639.9	627.43	85.4043	21.4974
6	872.8	829.92	200.47	29.6076
7	1076.5	1006.01	302.872	30.1792
8	1396.9	1284.91	460.577	29.4862
9	1592.27	1457.25	552.601	28.1007
10	1883.87	1711.31	695.723	29.3943
11	2174.96	1962.12	843.465	30.5006
12	2493.1	2234.9	1007.18	30.9717
13	2786.16	2485.16	1159.68	31.3556
14	2990.12	2652.8	1275.85	34.7219
15	3194.67	2820.62	1392.8	34.8716
16	3345.22	2942.82	1480.74	35.7386
17	3462.35	3036.88	1550.54	36.5788
18	3500	3066.87	1573.3	37.1981

Figure 17 – Deviation survey data



	Label	Type	Measured Depth (m)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	23.8							
2		Tubing	448.29	4.778	0.0006					1
3	TRSV	SSSV		4.562						1
4		Tubing	3132.05	4.778	0.0006					1
5		Tubing	3155.84	4.67	0.0006					1
6		Tubing	3160.24	4.778	0.0006					1
7	Liner	Tubing	3385	4.811	0.0006					1
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										

Figure 18 – Downhole Equipment data

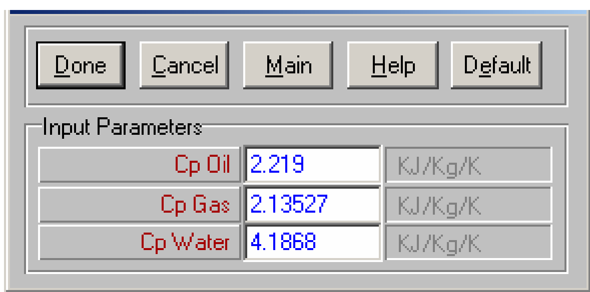


Figure 19 – Average Heat Capacities

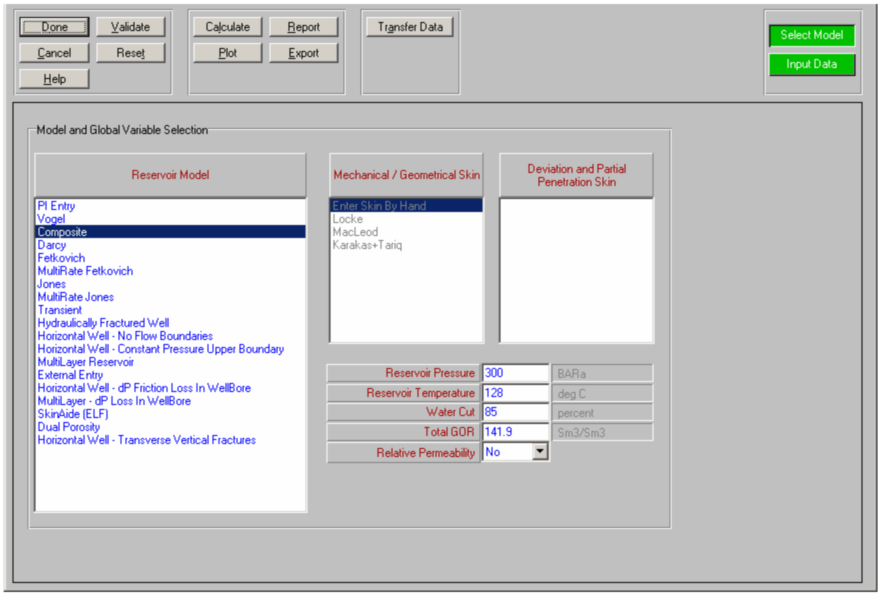


Figure 20 – IPR Model Selection

For matching Bubble point pressure, Solution GOR and Oil FVF; Prosper uses following traditional Black oil correlations: Glaso, Standing, Lesater, Vazquez-Beggs and Petrosky.

For matching Oil Viscosity; Prosper uses Beal at el, Beggs at el and Petroskey at el. Carefully inspecting the correlation parameters in Prosper, the following correlations had been identified for the best overall fit for the matched PVT:

- Pb, Rs and Bo ----------------Standing
- Oil viscosity ------------------Beal at el

After selecting the best fit correlations, PVT input data had been matched with measured data and Prosper was showing PVT is MATCHED in input screen.

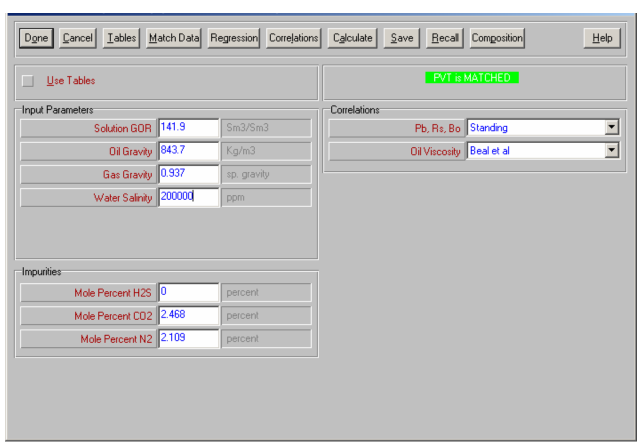


Figure 21 – Matched PVT

PVT Plot

A PVT plot with GOR versus Pressure had been drawn to check the consistency with the match data. From the plot diagram, it had been observed that the Black oil model had been properly matched with the PVT match data.

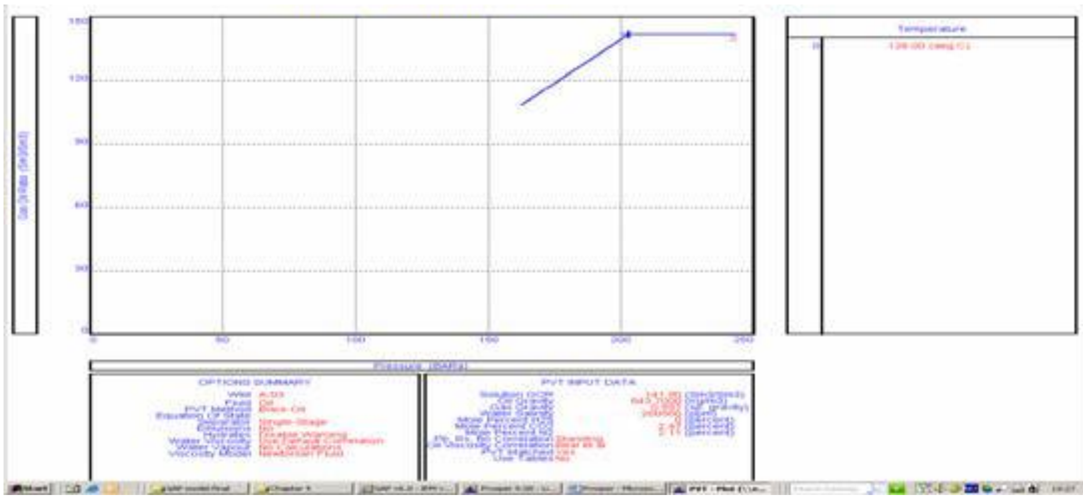


Figure 22 – PVT Plot

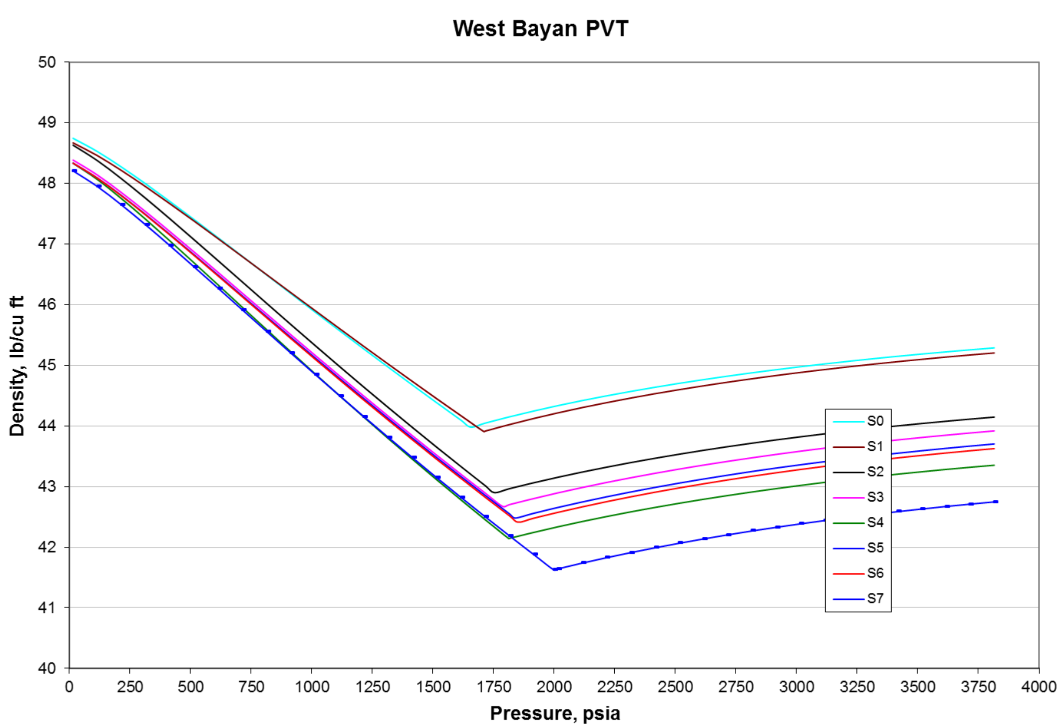


Figure 23 – Density graph

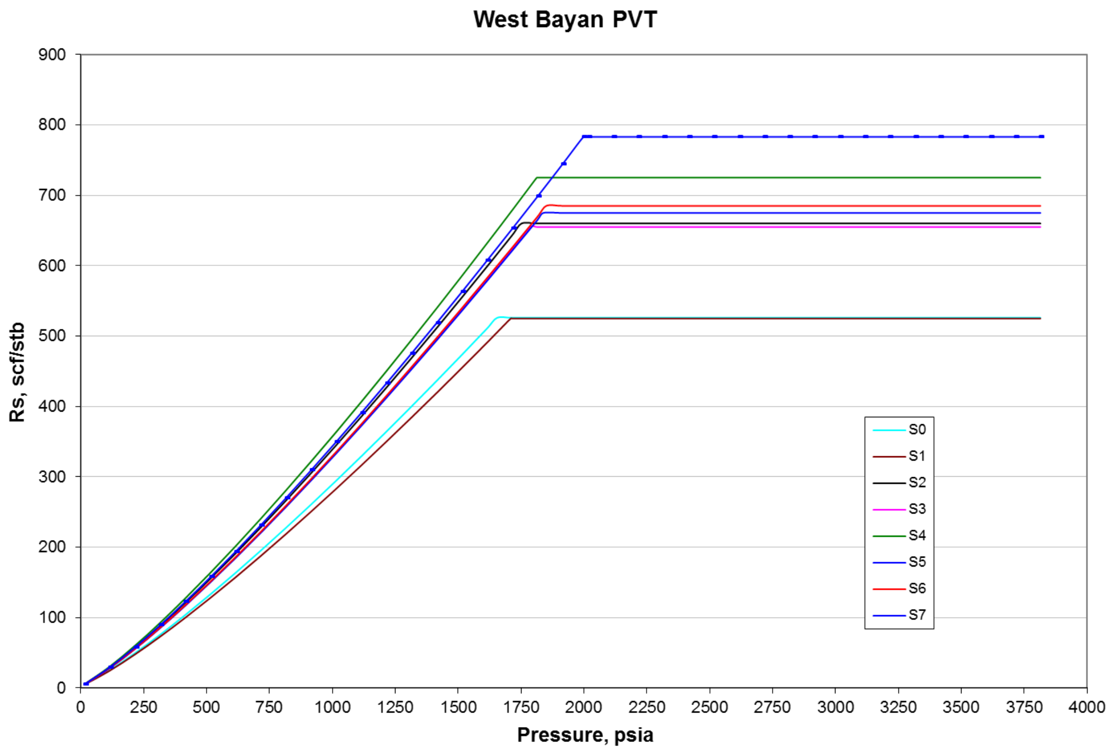


Figure 24 – Gas Liquid Ratio graph

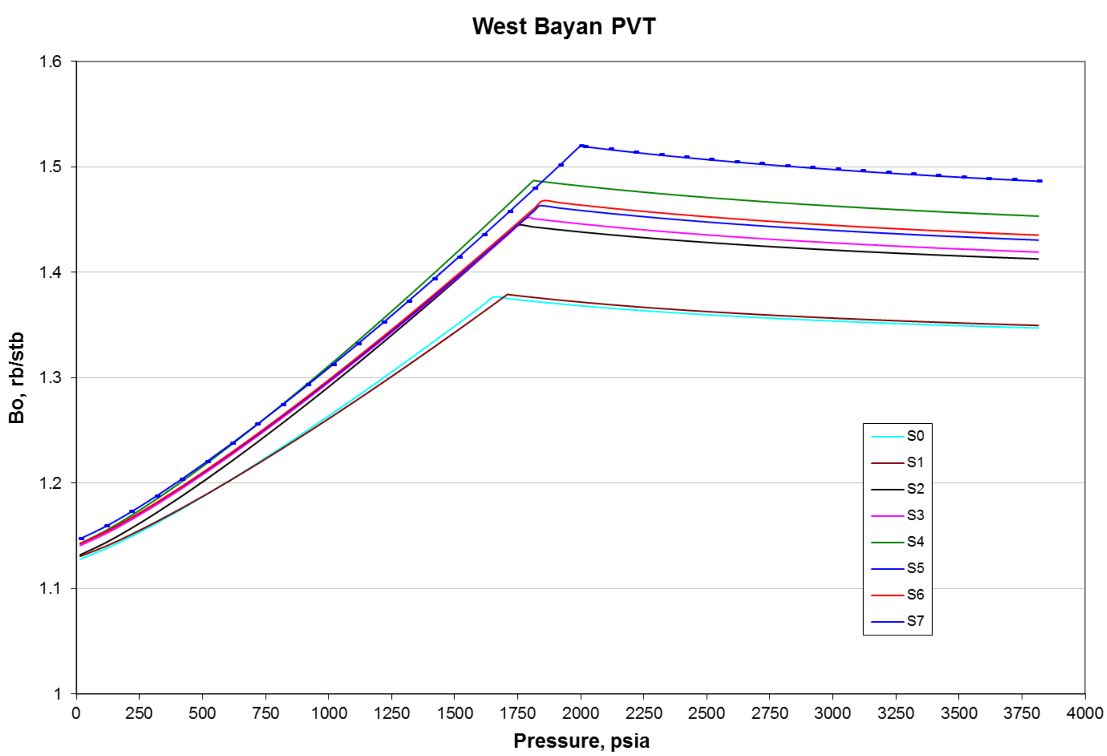


Figure 25 – Formation Volume Factor

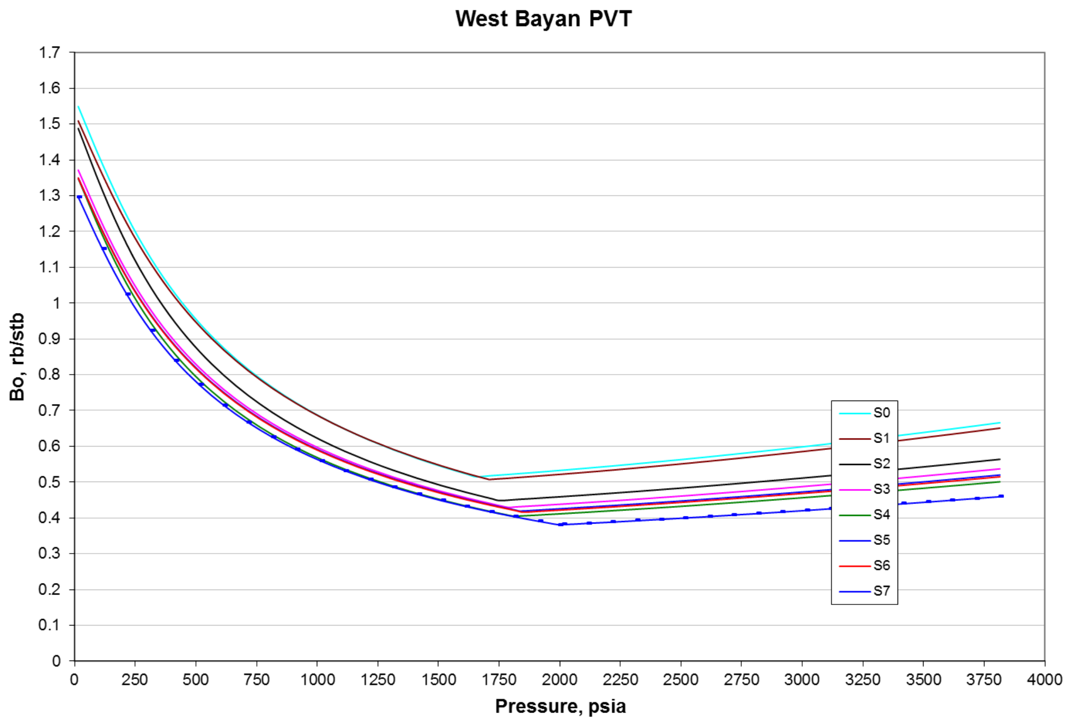


Figure 26 – Viscosity graph

Based on the data obtained from the field, the summary STOIIP, EUR and recovery factor for each well have been tabulated.

SUMMARY STOIIP - MMSTB

	BLOCKS	S0	S1	S2	S3	S4	S5	S6	S7	TOTAL
W BAYAN	1	-	14.5	22.9	14.4	49.1	5.0	2.1	18.5	126.50
	2 A	-	1.2	1.0	1.2	7.1	0.7	-	1.2	12.20
	2 B	35.2	3.1	8.1	1.2	1.4	0.4	-	0.1	49.40
	4	1.9	5.3	9.3	15.2	22.3	1.4	-	7.3	62.61
	5 E	-	0.2	2.0	2.8	-	0.6	0.3	0.2	6.15
	SUB TOTAL	**37.1**	**24.2**	**43.3**	**34.6**	**79.9**	**8.1**	**2.4**	**27.3**	**256.86**
NW BAYAN	3	11.3	3.9	6.5	23.1	-	-	-	-	44.76
	5 W12	18.7	-	10.5	39.0	-	-	-	-	68.19
	5 W34	4.0	1.3	2.4	3.6	-	-	-	-	11.30
	5 W5	1.9	-	2.9	1.7	-	-	-	-	6.54
	NWB	2.6	5.5	1.8	4.9	-	-	-	-	14.83
	SUB TOTAL	**38.4**	**10.7**	**24.2**	**72.3**	**-**	**-**	**-**	**-**	**145.62**
N BAYAN	1	-	-	-	-	-	-	-	3.6	3.61
	2 A	-	-	-	-	-	-	-	0.1	0.10
	2 B/C	-	-	-	-	-	-	-	13.9	13.89
	2 D	-	-	-	-	-	-	-	1.8	1.80
	2 E/F	-	-	-	-	-	-	-	5.5	5.53
	3	-	-	-	-	-	-	-	1.3	1.31
	8 A	-	-	-	-	-	-	-	1.9	1.90
	NBA	-	-	-	1.4	2.4	-	-	-	3.87
	SUB TOTAL	**-**	**-**	**-**	**1.44**	**2.43**	**-**	**-**	**28.14**	**32.01**
	TOTAL	**75.51**	**34.96**	**67.45**	**108.37**	**82.33**	**8.07**	**2.40**	**55.40**	**434.49**

SUMMARY EUR (MMSTB)

	BLOCKS	S0	S1	S2	S3	S4	S5	S6	S7	TOTAL
W BAYAN	1	-	0.0	7.1	8.9	24.0	1.2	-	9.0	50.19
	2 A	-	0.0	0.0	-	2.1	0.3	-	0.1	2.63
	2 B	10.5	0.0	0.3	0.0	-	-	-	-	10.79
	4	0.4	0.1	0.7	13.4	14.1	0.0	-	0.7	29.38
	5 E	-	-	-	-	-	-	-	-	-
	SUB TOTAL	**10.9**	**0.1**	**8.1**	**22.2**	**40.3**	**1.6**	**-**	**9.8**	**92.99**
NW BAYAN	3	-	0.1	3.4	4.6	-	-	-	-	8.07
	5 W12	3.7	-	1.1	9.4	-	-	-	-	14.24
	5 W34	-	-	0.2	0.0	-	-	-	-	0.25
	5 W5	-	-	-	-	-	-	-	-	-
	NWB	-	1.2	-	0.0	-	-	-	-	1.22
	SUB TOTAL	**3.7**	**1.3**	**4.6**	**14.1**	**-**	**-**	**-**	**-**	**23.78**
N BAYAN	1	-	-	-	-	-	-	-	0.5	0.50
	2 A	-	-	-	-	-	-	-	-	-
	2 B/C	-	-	-	-	-	-	-	2.9	2.86
	2 D	-	-	-	-	-	-	-	0.5	0.49
	2 E/F	-	-	-	-	-	-	-	3.2	3.22
	3	-	-	-	-	-	-	-	-	-
	8 A	-	-	-	-	-	-	-	-	-
	NBA	-	-	-	-	-	-	-	-	-
	SUB TOTAL	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7.07**	**7.07**
	TOTAL	**14.59**	**1.41**	**12.78**	**36.34**	**40.26**	**1.56**	**-**	**16.89**	**123.84**

Recovery Factor

	BLOCKS	S0	S1	S2	S3	S4	S5	S6	S7	TOTAL
W BAYAN	1		0%	31%	62%	49%	24%	0%	49%	40%
	2 A		0%	3%	0%	30%	49%		12%	22%
	2 B	30%	0%	4%	0%	0%	0%		0%	22%
	4	20%	1%	8%	88%	63%	1%		9%	47%
	5 E		0%	0%	0%		0%	0%	0%	0%
	SUB TOTAL									
										0%
NW BAYAN	3	0%	3%	52%	20%					18%
	5 W12	20%		10%	24%					21%
	5 W34	0%	0%	8%	1%					2%
	5 W5	0%		0%	0%					0%
	NWB	0%	22%	0%	0%					8%
	SUB TOTAL									
										0%
N BAYAN	1								14%	14%
	2 A								0%	0%
	2 B/C								21%	21%
	2 D								27%	27%
	2 E/F								58%	58%
	3								0%	0%
	8 A								0%	0%
	NBA				0%	0%				0%
	SUB TOTAL	**19.33%**	**4.05%**	**18.95%**	**33.54%**	**48.90%**	**19.35%**	**0.00%**	**30.48%**	**28.50%**

>65%
60%>RF>40%
40%>RF>20%
RF<20%

After the simulation is completed, the results are tabulated in a table form based on the recovery factor table.

Expected Recovery after Gas Lift Optimization

	BLOCKS	S0	S1	S2	S3	S4	S5	S6	S7	TOTAL
W BAYAN	1		0%	2%	6%	3%	1%	0%	4%	16%
	2 A		0%	0%	0%	2%	2%		1%	5%
	2 B	3%	0%	0%	0%	0%	0%		0%	3%
	4	3%	0%	0%	8%	5%	0%		0%	16%
	5 E		0%	0%	0%		0%	0%	0%	0%
	SUB TOTAL									
										0%
NW BAYAN	3	0%	0%	5%	1%					6%
	5 W12	2%		1%	1%					4%
	5 W34	0%	0%	8%	0%					8%
	5 W5	0%		0%	0%					0%
	NWB	0%	1%	0%	0%					1%
	SUB TOTAL									
										0%
N BAYAN	1								1%	1%
	2 A								0%	0%
	2 B/C								2%	2%
	2 D								2%	2%
	2 E/F								3%	3%
	3								0%	0%
	8 A								0%	0%
	NBA				0%	0%				0%
	SUB TOTAL	8.00%	1.00%	16.00%	16.00%	10.00%	3.00%	0.00%	13.00%	

RF>10%	
10%>RF>0%	
RF<0%	

Discussion

This feature in Prosper enables to adjust the multiphase flow correlations to match the flowing bottomhole pressure. Prosper uses a non-linear regression to tune the VLP correlations to best match the measured data. This is done by calculating a pressure traverse using a correlation and determining the error between measured and calculated pressures. The gravity and friction terms of the pressure loss equations are then adjusted and the process is repeated until the measured and calculated results agree within 1 psi or 50 iterations have been completed.

Parameter 1 (Gravity term): This is the multiplier for the gravity term in the pressure drop correlation. Provided that the PVT has been correctly matched, the greatest source of uncertainty in the VLP calculation for oil wells is usually the holdup correlations. Prosper attempts to make a gravity component match by adjusting the holdup correlation. If a match is not obtained with a parameter 1 more than 5% away from the value 1, the density is adjusted. For single phase applications, no hold up correction is possible. So any significant deviation from 1.0 for parameter 1 indicates a PVT problem. If Prosper has to adjust parameter 1 by more than +-10%, there is probably an inconsistency between the fluid density predicted by the PVT model and the field data.

Parameter 2 (Friction term): This is the multiplier for the friction term in the pressure drop correlation. If parameter 2 requires a large correction, it is likely that there is an error in equipment description or the flow rates are incorrect. As the effect of a shift in the friction component on the overall pressure loss is less than for the gravity term, a larger range in the value of parameter 2 is expected. If Prosper has to adjust the parameter 2 by more than +-10%, there is probably an error in the value of roughness entered of the equipment.

In this work, once the matching process was completed, the match parameters had shown alongside each of the correlations that had been matched. Parameter 1 and 2 were found very much close to unity with PE-2 correlation for current well test data of all wells

Correlations Comparison and Selecting the Best-fit Correlation

Correlation comparison is the fundamental step in the quality check of the model. This option allows pressure gradient plots to be generated with different correlations to be compared with measured gradient survey data. The comparison enables to understand if the measurements make sense, i.e. violate or not the principle of physics and to select the flow correlation that best fits the experimental measurements.
Two most important correlations had been primarily considered for rough quality check. Those are Fancher Brown (FB) and Duns and Ros Modified (DRM) correlations.

Fancher Brown: The gradient correlation to the left is the Fancher Brown correlation which provides the minimum pressure losses. It is a no slip hold-up correlation that gives the lowest possible value of VLP. Since it neglects gas/liquid slips, it always predict a pressure which is less than the measured value. Thus, measured data falling to the left of Fancher Brown on the correlation comparison plot indicates that there is a problem with fluid density or with field pressure data.

Duns and Ros Modified: The gradient correlation to the extreme right is the Duns and Ros Modified correlation which provides the maximum pressure losses. This correlation usually performs better in mist flow cases and should be used in condensate wells. It tends to over predict VLP in oil wells. Thus, measured data falling to the right of Duns and Ros Modified on the correlation comparison plot indicates that the measured data points are not consistent.

Some other relevant correlations that had been compared are mentioned below:

Hagedorn Brown: This correlation performs well for slug flow at moderate to high production rates. It should not be used for condensate 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.

Petroleum Experts: This correlation combines the best features of exiting correlations. It uses the Gould et al flow map and the Hagedorn Brown correlation in slug flow and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist result is used.

Petroleum Expert 2: This correlation includes the features of Petroleum Experts correlation with original work on predicting low rate VLP and well stability.

Petroleum Expert 3: This correlation includes the features of Petroleum Experts 2 correlation with original work for viscous, volatile and foamy oils.

Petroleum Experts 4: The correlation is an advanced mechanistic model for any angled wells, suitable for any fluid (including retrograde condensate).

Beggs and Brill: This is primarily a pipe line correlation. It generally over predicts pressure drops in vertical and deviated wells.

Hydro 3P (internal): This correlation is a mechanistic model and considers three phase flow.

CONCLUSION

The objective of the project is to study the best way to perform gas lift optimization in order to increase the production rate of BAYAN wells. From the research and simulation that will be done using PROSPER, it is hoped that a better understanding of the gas lift optimization will help to achieve the objective. Hence, it is expected that the result will be increase in production rate in BAYAN wells.

NOMENCLATURE

q = Production rate, STB/day

q_o = Oil production rate, STB/day

q_l = Liquid production rate, STB/day

WC = Water cut

G = Gravitational acceleration ft/s^2

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