Jurnal
Teknologi

Full Paper

# DETERMINATION OF THE BEST-FIT MULTIPHASE FLOW CORRELATION FOR HIGH WATER-CUT WELLS USING PROSPER

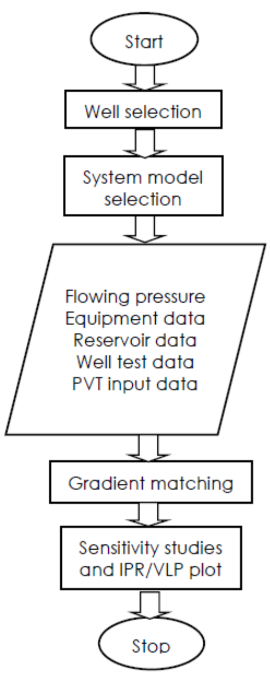
Issham Ismail*, Lim Teck Shern, Ariffin Samsuri, Muhamad Shafie Issham, Ling Hua Sid, Norhafizuddin Husein@Yusof, Natalie Vanessa Boyou, Zainal Zakaria

Department of Petroleum Engineering, Faculty of Chemical and Energy Engineering, Universiti Teknologi Malaysia, 81310 UTM Johor Bahru, Johor, Malaysia

**Article history**
Received
*27 August 2017*
Received in revised form
*21 November 2017*
Accepted
*15 January 2018*
Published online
*1 April 2018*

*Corresponding author
issham@utm.my

**Graphical abstract**




## Abstract

Pressure drop in a vertical or deviated borehole is mainly due to hydrostatic changes and friction when the produced fluids flow to the surface. When the oil is flowing upwards, the flowing pressure along the tubing string will drop and gas starts to liberate from the oil. Thus, multiphase flow forms in the tubing string. Hence, adequate modeling of vertical lift performance is required to predict the pressure drop and subsequently the wellbore pressure. The bottomhole pressure prediction was realized by using PROSPER, a program developed by Petroleum Experts. The data of oilwell X-01 with high water cut (i.e., 56%) in field X was used in this research work. The most accurate correlation was chosen from 12 selected built-in correlations to predict the pressure drop via gradient matching. A sensitivity analysis has been done to observe the parameters that affected the vertical lift performance of a high water cut well. These parameters were tubing diameter, gas-oil ratio, wellhead pressure, water cut, and tubing roughness. The results show that Dun and Ros original correlation appeared to be the best-fit correlation for well X-01. Results from sensitivity analysis indicated that reduction of wellhead pressure from 390 psi to 285.3 psi could increase liquid rate by 13.2%. An adjustment of wellhead pressure gave the most significant impact on the production rate of well X-01 as compared to other four parameters studied.

*Keywords*: High water-cut well, multiphase flow correlation, pressure drop, Prosper, vertical lift performance

## Abstrak

Kejatuhan tekanan di dalam lubang telaga tegak atau condong berpunca daripada perubahan hidrostatik dan geseran apabila mengalirnya bendalir ke permukaan. Dengan mengalirnya minyak mentah ke permukaan, tekanan aliran sepanjang rentetan tetiub akan berkurang dan gas mula terbebas daripada minyak terbabit. Sehubungan dengan itu, terbentuk aliran berbilang fasa di dalam rentetan tetiub. Berikutan itu, pemodelan prestasi angkat tegak secara berkesan diperlukan untuk meramal kejatuhan tekanan dan seterusnya tekanan dasar lubang. Ramalan tekanan dasar lubang boleh dilaksana menggunakan PROSPER, suatu program yang dibangunkan oleh *Petroleum Experts*. Data telaga minyak X-01 yang mempunyai potong air tinggi (iaitu 56%) di medan X telah digunakan dalam kajian ini. Sekaitan yang paling tepat dipilih daripada 12 sekaitan yang terbina dalam perisian terbabit bagi meramal kejatuhan tekanan menerusi pemadanan kecerunan. Analisis sensitiviti telah dilakukan untuk mencerap parameter-parameter yang mempengaruhi prestasi angkat tegak telaga yang mempunyai potong air tinggi. Parameter terbabit ialah diameter tetiub, nisbah gas-minyak, tekanan kepala telaga, potong air, dan kekasaran tetiub. Keputusan kajian menunjukkan bahawa sekaitan asal Dun and Ros memberikan padanan yang terbaik untuk telaga X-01. Hasil daripada analisis sensitiviti menunjukkan bahawa pengurangan tekanan kepala telaga dari 390 psi ke 285.3 psi boleh meningkatkan kadar pengeluaran bendalir telaga sebanyak 13.2%. Pelarasan tekanan kepala telaga memberikan kesan yang paling ketara terhadap kadar pengeluaran telaga X-01 berbanding empat parameter lain yang dikaji.

*Kata kunci*: Telaga berpotong air tinggi, sekaitan aliran berbilang fasa, kejatuhan tekanan, Prosper, prestasi angkat tegak



## 1.0 INTRODUCTION

Multiphase flow in tubing string is still receiving much attention in upstream petroleum industry as it remains as a black box problem over past few decades [1]. The multiphase flow studies which began in 1950's need a better understanding on the ways that hydrocarbon liquid, water and gas flowing from bottom hole to the surface [2,3] and even in the gathering lines [4,5,6] prior to reaching the onshore crude oil terminal as it can offer significant economic savings [7].

The flow behavior of multiphase flow is much complicated than single phase flow because it involves combination of several flow variables. Liquid and gas usually do not flow at the same velocity in tubing string. This is because for upward vertical flow the gas phase which is less dense and lower viscosity able to flow much faster than liquid phase. At the opposing side, liquid flows faster than gas when moving downwards due to gravity force and density differences. Even though multiphase flow is subjected to simple pipeline geometry, the calculations are still complex [2, 3]. Therefore, reliable prediction of two phase flow behaviour often requires a correlation which can be developed from several experiments. Every multiphase flow correlation has its limitations and only works well when subjected to a certain range of well conditions. Among the correlations are Poettmann and Carpenter [8], Duns and Ros [9], Fancher and Brown [10], Hagedorn and Brown [11], Orkiszewski [12], Govier and Aziz [13], Beggs and Brill [14], Mukherjee and Brill [15], and Hasan-Kabir [16].

Flow pattern is one of the main factors to decide the quality of multiphase flow but its analysis is not as simple as laminar or turbulent in a single phase flow. The relative quantities between the two phases and topology of interfaces must also be explained. The types of flow pattern which can be found in tubing string are bubbly flow, slug flow, churn flow, annular flow, etc. [2]. The flow patterns become more complex in waxy crude as highlighted by Ismail *et al*. [5] and Piroozian *et al*. [17]. Each of the flow patterns is distinctive because of the relative magnitudes of forces such as surface tension and buoyancy force acting on fluid which also varies with flow rates, pipe diameter, and fluid properties of the phase. Therefore calculations of pressure gradient using any correlation require a lot of flow condition parameters such as fluid density, velocity, viscosity, etc. [2, 13].

The calculations for pressure losses in multiphase flow are very complicated due to phenomenon of gas/liquid slippage. Today, there are two main approaches — empirical and mechanistic — are used to predict the pressure losses in multiphase flow in pipes. The empirical approach correlates pressure losses empirically with all important parameters without explaining the cause of phenomenon whereas mechanistic approach analyses and explains the phenomenon with physics [18, 19]. In order to construct the model of a well production system, large amount of real data and calculations of multiphase flow are required [20]. As a result, many multiphase flow correlations for predicting liquid holdup and pressure gradient have been developed empirically over the years. Nevertheless, there is none of these multiphase flow correlations could work well across the all full range of production conditions and parameters such as tubing size, gas liquid ratio, presence of water cut, etc. In other words, there is no single correlation which can be applied satisfactorily to all types of flow regimes in the well. Therefore, different multiphase correlations may be used in different range of parameters to avoid huge errors mainly caused by PVT characteristics of the fluid [1,2].

The general equation of pressure gradient which is applicable to any fluid flowing in vertical or deviated well was derived using the basic energy balance equation. It was developed for two-phase flow by assuming that their flow regimes and properties are homogenous in a fixed volume of pipe. Equation (1) shows the total pressure gradient comprises three components; hydrostatic or elevation changes, friction, and acceleration [2].

$$(-\frac{\mathrm{dP}}{\mathrm{dZ}})_{total} = (\frac{dP}{dL})_{hydrostatic} + (\frac{dP}{dL})_{friction} + (\frac{dP}{dL})_{acceleration} \quad \text{Equ. (1)}$$

System analysis has been used for many years to analyse the performance of systems composed of multiple interacting components. Gilbert [21] was perhaps the first to introduce the approach to oil and gas wells but Mach, Proano, and Brown [22] popularized the concept, which was typically referred to as nodal analysis in the oil and gas industry. The objective of system analysis is to combine the various components of the production system for an individual well to estimate production rates and optimize the components' design of the production system [22, 23].

An in-depth understanding of the impacts of flow conditions on multiphase flow is crucial. Flow qualities of fluid in a vertical or deviated well will change accordingly depending on the traits of wells and fluid properties. Therefore, using the wrong correlation may consequently affect the prediction of vertical lift performance. Inaccuracy of vertical lift performance eventually will lead to wrong prediction of production rate (i.e., underestimated or overestimated).

Modeling of a production system in an appropriate way is essential in order to predict the optimum production rate of a well for certain production conditions. Over prediction of productivity index may lead to an error on the expected deliverability of the well. The PVT properties of the fluid flow such as gas-oil ratio, oil formation volume factor, and fluid viscosity in a tubing string must be accurately determined so that the correct fluid flow pattern in the particular tubing segment can be identified. A small change in PVT data may lead to large error in predicting the pressure gradient [2, 24].

One of the objectives of this research work was to determine the most suitable multiphase flow correlation(s) from the 12 selected correlations available in PROSPER for high water-cut well X-01 in field X — a well condition which requires serious well interventions due to excessive water produced with oil. The effects of varying the percentage of water cut, gas-oil ratio, wellhead pressure, tubing diameter, and tubing roughness were also studied for well X-01.

# 2.0 METHODOLOGY

## 2.1 Scope of Study

This research work was carried out based on several scope listed as follow:

(1) Utilized the PROSPER software which contains numerous multiphase flow correlations that are able to generate pressure gradients using data of well X-01. The results were then matched with measured pressure gradient of the well to determine the percentage of errors. Those correlations are listed in Table 1.

(2) Five parameters were investigated for their effects on vertical lift performance and subsequently the production rate. The five parameters selected were as follow:

(a) Tubing diameter
(b) Gas-oil ratio
(c) First node pressure/wellhead pressure
(d) Water cut
(e) Tubing roughness

**Table 1** Correlations in PROSPER [25]

| Correlation | Category | Slip effect | Flow regime |
|---|---|---|---|
| Duns & Ros original (DRo) | Empirical | Considered | Considered |
| Duns & Ros modified (DRm) | Empirical | Considered | Considered |
| Hagedorn & Brown (HB) | Empirical | Considered | None |
| Fancher & Brown (FB) | Empirical | None | None |
| Mukerjee Brill (MB) | Empirical | Considered | Considered |
| Orkiszewski (OKS) | Empirical | Considered | Considered |
| Beggs & Brill (BB) | Empirical | Considered | Considered |
| Petroleum Experts (PE) | Empirical | Considered | Considered |
| Petroleum Experts 2 (PE2) | Empirical | Considered | Considered |
| Petroleum Experts 3 (PE3) | Empirical | Considered | Considered |
| Petroleum Experts 4 (PE4) | Mechanistic | Considered | Considered |
| Petroleum Experts 5 (PE5) | Mechanistic | Considered | Considered |

## 2.2 PROSPER

PROSPER is a software specialized for modeling most types of well configurations. This software is used widely in oil and gas industry because of its capability to predict well performance, design, and optimization of a production system, etc. PROSPER can assist petroleum production engineers to estimate well performance at downhole condition accurately.

PROSPER is designed to allow building of reliable well models. The well models are able to address every aspect related to the production system such as reservoir inflow performance (IPR), pressure-volume-temperature (PVT), vertical lift performance (VLP) correlations, and calculations of pipeline and tubing pressure losses. Once the production system has been tuned to field data, PROSPER is able to model the well with different cases, determine the best-fit correlation for the well, and subsequently predict production rates. In addition, it also allows petroleum production engineers to design artificial lift system when required and monitor the well performance.

## 2.3 Schematic Flow Chart

The flow chart in Figure 1 indicates the procedures of accomplishing the process of gradient matching and sensitivity analysis study. It shows the steps to input the required reservoir and well data, flowing pressure survey data, etc. in PROSPER.

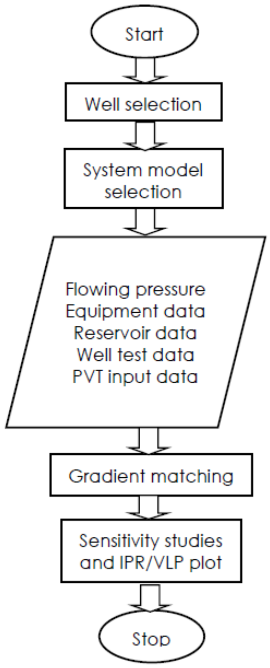



**Figure 1** A flow chart to do gradient matching using PROSPER

## 2.4 Data Description

This simulation work involved the use of field data from field X. The oil well, X-01, stopped producing due to high water cut (approximately 56%) and also high gas-oil ratio of produced fluid although gas lift was implemented to increase oil recovery. In fact, this research work was intended to solve the problems related to vertical lift performance of well X-01. The well test data of well X-01 was used to model production rate curves at varying conditions using the available specific multiphase correlations in PROSPER and subsequently suggesting the ways for production optimization. The reservoir data and well descriptions for well X-01 are given in Table 2 while Table 3 shows the flowing gradient survey data for well X-01.

**Table 2** Reservoir data and well data for well X-01

| **Reservoir data** | |
|---|---|
| Reservoir pressure, psi | 2060 |
| Reservoir temperature, ˚F | 240 |
| Water cut, % | 56 |
| Permeability, md | 200 |
| Skin | 10 |
| Wellbore radius, inch | 9-5/8" – 7" |
| Total GOR, scf/STB | 440 |
| **Well data** | |
| Liquid rate, bbl/day | 2000 |
| Productivity index, bbl/psi/day | 4.2 |
| Wellhead pressure, psi | 390 |

**Table 3** Flowing gradient survey for well X-01

| Description | Depth (m) MDDF | Depth (m) MDTHF | Upper pressure (psia) | Bottom pressure (psia) | Difference |
|---|---|---|---|---|---|
| Lub THP | 0 | 0 | 455.183 | 452.561 | 2.622 |
| 1st Grad Stop | 200 | 177 | 536.749 | 535.47 | 1.279 |
| 2nd Grad Stop | 400 | 377 | 593.139 | 593.479 | 0.340 |
| 3rd Grad Stop | 600 | 577 | 687.177 | 686.812 | 0.365 |
| 4th Grad Stop | 800 | 777 | 759.906 | 759.168 | 0.738 |
| 5th Grad Stop | 842 | 819 | 747.72 | 748.421 | 0.701 |
| 6th Grad Stop | 1000 | 977 | 768.958 | 769.361 | 0.403 |
| 7th Grad Stop | 1200 | 1177 | 841.727 | 842.05 | 0.323 |
| 8th Grad Stop | 1400 | 1377 | 875.802 | 876.521 | 0.719 |
| 9th Grad Stop | 1600 | 1577 | 893.024 | 893.686 | 0.662 |
| 10th Grad Stop | 1800 | 1777 | 932.149 | 932.612 | 0.463 |
| 11th Grad Stop | 2010 | 1987 | 967.938 | 968.99 | 1.052 |
| 12th Grad Stop | 2200 | 2177 | 1030.198 | 1032.005 | 1.807 |
| 13th Grad Stop | 2400 | 2377 | 1114.542 | 1116.573 | 2.031 |
| 14th Grad Stop | 2600 | 2577 | 1190.165 | 1192.419 | 2.254 |
| 15th Grad Stop | 2800 | 2777 | 1247.137 | 1249.309 | 2.172 |
| 16th Grad Stop | 3000 | 2977 | 1311.609 | 1314.061 | 2.452 |
| 17th Grad Stop | 3200 | 3177 | 1398.321 | 1400.646 | 2.325 |
| 18th Grad Stop | 3400 | 3377 | 1460.208 | 1462.911 | 2.703 |
| 19th Grad Stop | 3567 | 3544 | 1523.764 | 1526.194 | 2.430 |
| 20th Grad Stop | 3600 | 3577 | 1519.983 | 1522.474 | 2.491 |
| 21st Grad Stop | 4000 | 3977 | 1671.075 | 1673.351 | 2.276 |
| 22nd Grad Stop | 4200 | 4177 | 1744.88 | 1747.09 | 2.210 |
| 23rd Grad Stop | 4400 | 4377 | 1813.645 | 1815.798 | 2.153 |
| 24th Grad Stop | 4572 | 4549 | 1872.005 | 1873.932 | 1.927 |
| 25th Grad Stop | 4600 | 4577 | 1884.05 | 1886.062 | 2.012 |
| Set depth | 4643 | 4620 | 1896.56 | 1898.486 | 1.926 |
| Lub THP | 0 | 0 | 458.45 | 456.107 | 2.343 |

*Note*: MDDF: measured depth from derrick floor; MDTHF: measured depth from tubing head flange

After determining the best-fit multiphase flow correlation for the said well, it was then used to assist in the sensitivity studies. The five parameters and their ranges for the study are given in Table 4.

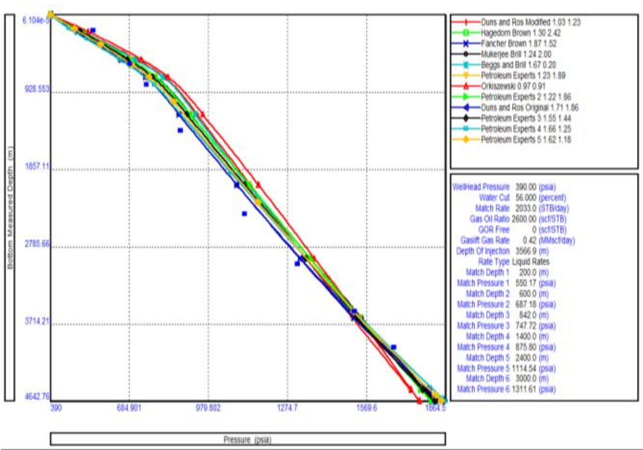
**Table 4** Ranges of parameters in sensitivity studies

| Parameter | Ranges |
|---|---|
| Tubing diameter (in) | 2.69 – 2.90 |
| Gas-oil ratio (scf/STB) | 2600 – 5000 |
| Wellhead pressure (psi) | 285.3 – 565.3 |
| Water cut (%) | 0 – 56 |
| Tubing roughness (in) | 0.0006 – 0.004 |

## 3.0 RESULTS AND DISCUSSION

### 3.1 Gradient Matching

Matching multiphase flow correlation is the first imperative step for quality control of a production model. Figure 2 shows Duns and Ros original (DRo) gives the best matching with the measured flowing pressure survey data (blue solid squares) compared to the other 11 built-in correlations. On the contrary, Orkiszweski (OKS) correlation gives the least accurate result in predicting the pressure drop for the tubing string.




***Note***: *The measured flowing pressure data are in the form of blue solid squares*

**Figure 2** Gradient matching using 12 different multiphase flow correlations while measured data are in blue solid squares

The pressure gradient predicted by DRo correlation provides a good match over the 10 measured data points. However, OKS correlation tends to over predict the pressure loss from depth of 600 m (1969 ft) to 3567 m (11 703 ft) and under predict pressure drop from 4000 m (13 123 ft) to 4643 m (15 233 ft).

Similarly, Table 5 indicates that the consistency and accuracy in calculating the gravity term and friction term of pressure drop for each correlation and their standard deviation. After entering the required data, PROSPER calculates the PVT properties mentioned above and compares them with the field values which have been introduced in order for the software to proceed to the matching process. PROSPER performs a nonlinear regression prior to allowing us to determine the best-fit correlation. The non-linear regression technique applies a multiplier (Parameter 1) and a shift (Parameter 2) to all correlations [25]. If PROSPER has to adjust parameter 1 (which is the multiplier for gravity term) by more than 10%, it indicates that there is an inconsistency between fluid density predicted by PVT (black oil) model and field data. On the other hand, Parameter 2 (the multiplier for the friction term) needs a large correction. It is likely that there are problems existing in the equipment input measured data. As the effect of a shift in the friction component on the overall pressure loss is less than gravity term, a larger range in the value of Parameter 2 is expected. Referring to Table 5, the standard deviations of all 12 correlations are ranging from 41.9167 to 97.9616. Duns and Ros Original correlation has the lowest standard deviation. Conversely, Orkiszewski correlation has the highest standard deviation which means it deviates significantly from measured data and eventually gives the highest percentage error.

In the pressure gradient matching, only 10 different measured pressures are allowed to match with the calculated pressure gradient. However, there were 27 measured flowing pressures at different depths that provided by an international oil company. At the early phase of trial run, random selection of 10 measured pressures affected the selection of best-fit correlation. Therefore, the result was dependent on the 10 best selected match points.

**Table 5** Standard deviation for each correlation

| Correlation | Parameter 1 | Parameter 2 | Standard deviation |
|---|---|---|---|
| DRo | 1.71293 | 1.8644 | 41.9167 |
| DRm | 1.02685 | 1.2367 | 87.3681 |
| HB | 1.30197 | 2.41958 | 66.0059 |
| FB | 1.87459 | 1.521 | 45.1633 |
| MB | 1.24387 | 1.99736 | 64.9073 |
| OKS | 0.97047 | 0.90923 | 97.616 |
| BB | 1.67321 | 0.2 | 69.8896 |
| PE | 1.23203 | 1.89116 | 68.478 |
| PE2 | 1.21799 | 1.86175 | 68.0707 |
| PE3 | 1.54917 | 1.44095 | 58.7143 |
| PE4 | 1.65602 | 1.24742 | 46.8699 |
| PE5 | 1.62241 | 1.1771 | 49.6284 |

### 3.2 Calculation of Pressure Losses in Well X-01

Table 6 implies the total values of differences between pressure calculated from multiphase flow correlations and the 10 measured flowing pressure match points. Again Orkiszewski correlation contributes a total pressure difference of 863 psi which indicates that the correlation is the least accurate when matching with the 10 measured pressure survey data. On the other hand, Duns and

Ros original correlation has the lowest variation in predicting the pressure gradient with difference in total pressure amounted to only 345 psi.

**Table 6** Difference between calculated pressure and measured pressure at each match point

| Measured data point | Difference between measured data and predicted pressure (psi) 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Total dP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Duns & Ros Original | -63 | -2 | 35 | 51 | 75 | 44 | 0 | -15 | -30 | -30 | 345 |
| Duns & Ros Modified | -41 | 62 | 107 | 116 | 114 | 60 | 0 | -54 | -111 | -117 | 782 |
| Hagedorn & Brown | -47 | 28 | 65 | 86 | 107 | 65 | 0 | -31 | -77 | -81 | 587 |
| Fancher & Brown | -62 | -4 | 31 | 47 | 67 | 34 | 0 | -33 | -52 | -53 | 383 |
| Mukerjee & Brill | -48 | 31 | 71 | 90 | 110 | 70 | 0 | -20 | -64 | -67 | 571 |
| Beggs & Brill | -44 | 55 | 102 | 108 | 110 | 66 | 0 | -22 | -56 | -60 | 623 |
| Orkiszweski | -25 | 70 | 112 | 128 | 130 | 73 | 0 | -57 | -130 | -138 | 863 |
| Petroleum Experts | -46 | 29 | 66 | 88 | 108 | 66 | 0 | -34 | -85 | -89 | 611 |
| Petroleum Experts 2 | -46 | 30 | 67 | 88 | 107 | 65 | 0 | -37 | -84 | -88 | 612 |
| Petroleum Experts 3 | -49 | 20 | 55 | 74 | 91 | 51 | 0 | -38 | -72 | -74 | 524 |
| Petroleum Experts 4 | -70 | -3 | 38 | 62 | 93 | 63 | 0 | -1 | -20 | -21 | 371 |
| Petroleum Experts 5 | -57 | 7 | 45 | 66 | 90 | 56 | 0 | -16 | -42 | -43 | 422 |

Figure 3 shows that these flow correlations actually give relatively comparable total pressure drop. There is just a small variation between them. Nevertheless, different multiphase flow correlations predict different flow regimes. Thus, hydrostatic term and frictional term may vary among the correlations and significantly affect the total pressure loss in a vertical well. Hydrostatic term solely has contributed 61% to 83% of the total pressure loss among the correlations except for Mukerjee and Brill, Beggs and Brill, and Duns and Ros Original correlations. These correlations vary with others probably due to the assumptions of different flow regimes and frictional term.

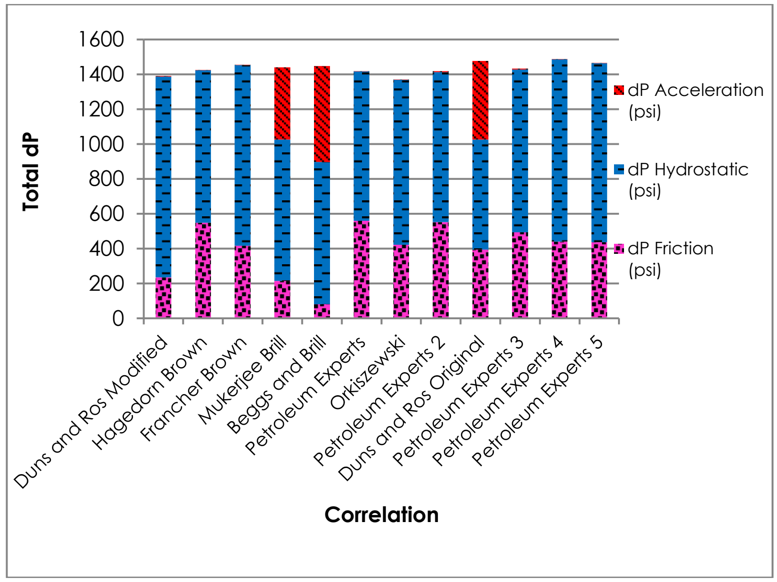



**Figure 3** Sum of three components (hydrostatic, frictional, and acceleration) in pressure drop (psi) from 12 multiphase correlations for deviated well X-01

Acceleration term is usually significant in a horizontal or deviated well and negligible when predicting the pressure gradient in a vertical well. This term can be found only in Mukerjee and Brill, Beggs and Brill, and Duns and Ros Original. The simulation results also show that the frictional term of Mukerjee and Brill, Beggs and Brill, and Duns and Ros Original correlations contributes a significant pressure loss, ranging from 29% to 38% of total pressure drop from bottomhole to the tubing head. This might be caused by the basis or assumptions used in developing the correlations and also the deviation of well X-01. Besides that, Beggs and Brill correlation is a pipeline correlation that usually used for deviated or horizontal well.

## 3.3 Sensitivity Analysis

Before starting the sensitivity analysis, IPR/VLP matching is required in order to tune the wellbore multiphase flow correlation to fit with bottomhole flowing pressure (real condition) using the well test data. This allows us to check the consistency of VLP. PROSPER is able to calculate the VLP for a range of flow rates and pressure values at the sandface for each of the active test points that have been entered into the VLP Matching segment. IPR may or may not need to adjust to match the measured data, depending on the percentage difference in calculated liquid rate and bottomhole pressure with the measured data

### 3.3.1 Effect of Tubing Diameter

Figure 4 shows the intersection of IPR and VLP curves using various tubing sizes. The tubing diameter used was uniform from tubing head until the end of tubing string.

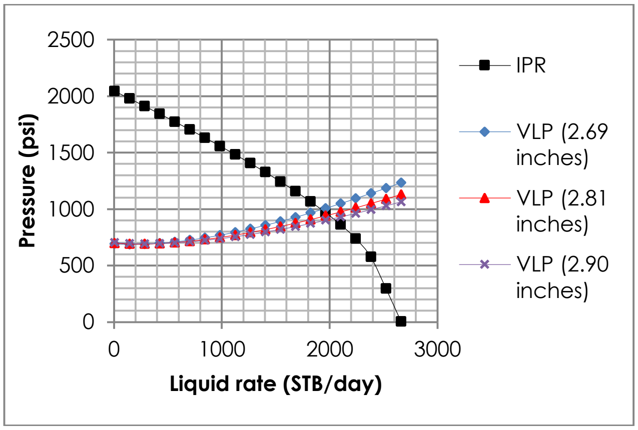



**Figure 4** Liquid production rates for various tubing diameters of well X-01

Table 7 shows that increasing tubing diameter at constant wellhead pressure will increase the optimum production rate. Tubing diameters of 2.69 in., 2.81 in., and 2.90 in. give optimum liquid rates of 1938 STB/day, 2000 STB/day, and 2039 STB/day respectively. The percentage changes of those optimum liquid rates based on measured liquid rate are –3.1%, 0%, and 2.0% respectively.

An inference that can be made is that the use of smaller tubing size has reduced the flow area and consequently it increases the resistance to flow. This will restrict the production rate and subsequently reduces the amount of fluid that can be produced. Conversely, larger tubing size will cause excessive downhole liquid loading during lifting besides economic impact may reach beyond the available cost [26].

A sensitivity analysis study for tubing size should be carried out prior to the production phase. This is to ensure the optimum tubing size can be determined in order to support the expected rates of production of oil and gas. Production optimization allows the lowest energy requirement for lifting and prolongs the flowing time.

**Table 7** Percentage change in production with changes in tubing diameter

| Tubing inside diameter (inches) | Optimum liquid rate (STB/day) | Percentage change in production rate (%) |
|---|---|---|
| 2.69 | 1938 | –3.1 |
| 2.81 | 2000 | 0.0 |
| 2.90 | 2039 | 2.0 |

### 3.3.2 Effect of Gas-Oil Ratio

The gas-oil ratio (GOR) used in the sensitivity study were 2600 scf/STB, 4000 scf/STB, and 5000 scf/STB while other parameters were kept constant. Based on the well test data provided by the international oil company, the GOR of produced well fluid from well X-01 increased gradually (2079 scf/STB to 2600 scf/STB) from the time it was released to production again. The gas rate for gas lift operation was also increased two-fold in order to enhance the production rate (liquid rate). Hence, a deduction that can be made is increasing the injected gas rate will produce higher GOR oil. Detailed explanation on GOR has been given by Brown [2, 3].

Theoretically, application of gas injection reduces the density of flowing well fluid which also reduces the required drawdown to push the liquid mixture upwards. Nonetheless, Figure 5 and Table 8 show that the liquid production rate decreasing with increasing in GOR of produced fluid. Producing oil with GOR of 2600 scf/STB, 4000 scf/STB, and 5000 scf/STB would result in liquid production rate of 2038 STB/day (1.9% increment based on measured flow rate), 2014 STB/day (0.7%), and 1995 STB/day (–0.3%) respectively.

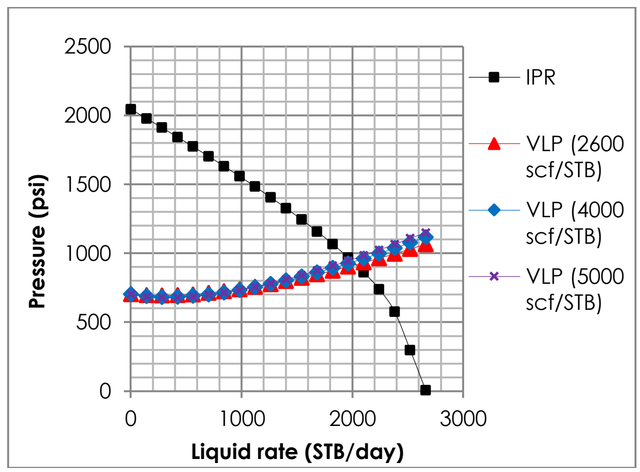



**Figure 5** Liquid production rates for various gas-oil ratios of well X-01

Although the effect of GOR on VLP is not significant as shown in Figure 5, there is still reduction of production rate when increasing GOR. The percentage change is highlighted in Table 8. This is probably due to the insufficient drawdown to provide the upward force to push the well fluid to the surface. As the fraction of gas increasing in a constant oil rate, the frictional term will overtake the hydrostatic term and plays a major role in pressure loss along the tubing string. Pressure maintenance or water injection can be done in order to build up the reservoir pressure and attain optimum drawdown. However, economic evaluation will always be the first consideration to decide whether the well should be abandoned or continued for production.

**Table 8** Percentage change in production with changes in gas-oil ratio

| Gas-oil ratio (scf/ STB) | Liquid rate (STB/day) | Percentage change in production rate (%) |
|---|---|---|
| 2600 | 2038 | 1.9 |
| 4000 | 2014 | 0.7 |
| 5000 | 1995 | –0.3 |

### 3.3.3 Effect of First Node Pressure (Wellhead Pressure)

A sensitivity analysis was done on flowing wellhead pressure (WHP) in order to analyze the effect of wellhead pressure on production rate. Figure 6 shows the IPR/VLP curves for four different wellhead pressures of 285.3 psig, 385.3 psig, 485.3 psig and 565.3 psig. Table 9 shows that when wellhead pressures are increased from 285.30 psig to 565.30 psig with the same production string, the liquid production rate has reduced from 2263 STB/ day to 2038 STB/day. It also highlights the percentage change in production at those WHPs.

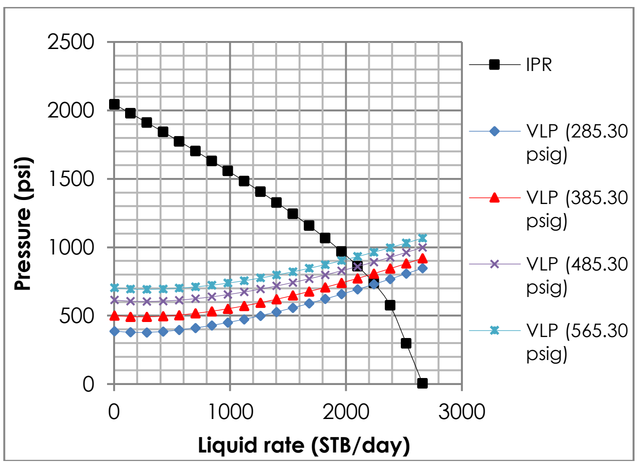



**Figure 6** Effects of various first node or wellhead pressures on liquid production rates for well X-01

WHP can be adjusted by different ways such as changing the choke size, surface pressure, and flowline. It is essential to determine the minimum WHP in order to maintain the flow from wellhead to separator. When WHP is reduced, higher liquid rate can be produced. Therefore, higher wellhead tubing pressure is required in case the production rate is too high and to maintain the optimum production rate. However, the choice of minimum WHP is dependent on the tubing size, alteration of reservoir condition, and type of well completion [3].

**Table 9** Percentage change in production rates with changes in first node pressure (wellhead pressure)

| First node pressure (psig) | Liquid rate (STB/day) | Percentage change in production rate (%) |
|---|---|---|
| 285.30 | 2263 | 13.2 |
| 385.30 | 2195 | 9.8 |
| 485.30 | 2115 | 5.8 |
| 565.30 | 2038 | 1.9 |

### *3.3.4 Effect of Water Cut*

Referring to IPR/VLP plot in Figure 7, increment in water cut (WC) has a little impact on vertical lift performance or outflow curve. High water production rate will increase the hydrostatic pressure loss. Consequently higher drawdown or reservoir energy is needed to lift the reservoir fluid to the surface. Nonetheless, the IPR curve is also affected by increasing the water cut.

Figure 7 shows IPR curves at the initial reservoir pressure of 2060 psi. Four different values of water cut, 0%, 10%, 20%, and 56% were used to study their effects on well performance. The liquid rates for the four different water cuts are given in Table 10: 1836 STB/day for 0% WC, 1865 STB/day for 10% WC, 1898 STB/day for 20% WC, and 2038 STB/day for 56% WC. Their respective percentage changes in production rates are also given in Table 10.

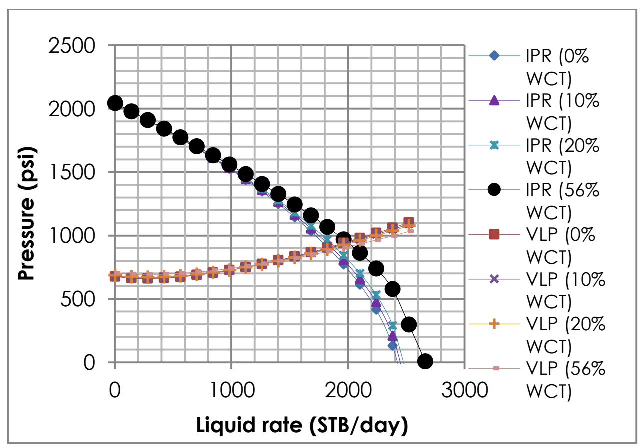



**Figure 7** Effect of various water cuts on liquid production rates for well X-01

**Table 10** Changing in AOF and percentage change in production with changes in water cut

| Water cut (%) | AOF (STB/day) | Liquid rate (STB/day) | Percentage change in production rate (%) |
|---|---|---|---|
| 0 | 2420 | 1836 | –8.2 |
| 10 | 2444 | 1865 | –6.8 |
| 20 | 2473 | 1898 | –5.1 |
| 56 | 2663 | 2038 | 1.9 |

*Note*: AOF: absolute open flow

### 3.3.5 Effect of Tubing Roughness

In the equipment data input, we took the value of tubing roughness for the production string as 0.0006 in [27]. Three different tubing roughness values were considered for the sensitivity study, namely 0.0006 in., 0.0015 in., and 0.0040 in. to study their effects on well performance. The simulation results from PROSPER are shown in Figure 8 and Table 11.

Table 11 shows that tubing roughness of 0.0006 in., 0.0015 in., and 0.0040 in. give production rate of 2038 STB/day, 2025 STB/day, and 2002 STB/day respectively. Also included in the table is the percentage change in production rate for each of the cases. An increment in tubing roughness reduces the liquid rate. Generally, tubing roughness affects vertical lift performance of a well. When tubing roughness is increased, it increases the frictional loss in the tubing string. Eventually, a higher bottomhole pressure is required to produce the required flow rate.

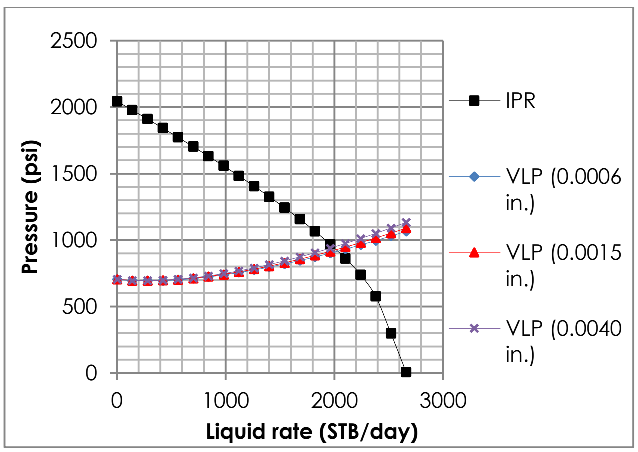



**Figure 8** Effects of tubing roughness on liquid production rates of well X-01

**Table 11** Percentage change in production rate with changes in tubing roughness

| Tubing roughness (inch) | Liquid rate (STB/day) | Percentage change in production rate (%) |
|---|---|---|
| 0.0006 | 2038 | 2.0 |
| 0.0015 | 2025 | 1.3 |
| 0.0040 | 2002 | 0.1 |

## 4.0 CONCLUSIONS

Based on the analysis done, the following conclusions have been framed out accordingly:

(1) Dun and Ros original correlation appears to be the best-fit multiphase correlation for high water-cut well X-01 with standard deviation of 41.9167. However, Orkiszweski correlation gives the least accurate result in predicting the pressure drop for the well.

(2) The effect of changing the tubing diameter is significant on the well performance. Reduction of tubing diameter from 2.90 in. to 2.69 in. can reduce 5.1% of the initial production rate.

(3) Increment in GOR from 2600 scf/STB to 5000 scf/STB reduces production rate by 1.9%. Therefore, gas lift operation is unable to enhance production rate further due to increase in frictional pressure loss inside the tubing string.

(4) Reduction of wellhead pressure from 390 psi to 285.3 psi has increased liquid production rate by 13.2%.

(5) Increment of water cut affects both IPR and VLP curves. From 0 to 56% of water cut, it increases the AOF of IPR curves from 2420 STB/day to 2663 STB/day and enhances the production rate from 1836 STB/day to 2038 STB/day. However, the water influx also increases gradually.

(6) Increase in tubing roughness requires higher bottomhole pressure to produce the required liquid rate.

(7) The bottomhole pressure is found to be insufficient to lift the reservoir fluid to the surface and high water cut is the main reason for well X-01 to stop production. Although reduction of WHP can increase production rate significantly but the drawdown is too low to lift the fluid up to the surface.

## Acknowledgement

The authors wish to extend their highest gratitude to the international oil company for providing the field data required for this study. They also express their sincere thanks to Universiti Teknologi Malaysia for funding the study via RUG (vote 14H83).

## References

[1] Ismail, I. 1990. Optimization of Tubing Size Selection in a Mature Offshore Field. *Thesis*. Imperial College of London.

[2] Brown, K. E. 1984. *The Technology of Artificial Lift Methods*. Vol. 4, Tulsa: PennWell.

[3] Brown, K. E. 1990. *Petroleum Production Technology of Lifting Methods*. Vol. 4. Beijing: Petroleum Industry Press.

[4] Ismail, A. S. I., Ismail, I., Zoveidavianpoor, M., Mohsin, R., Piroozian, A., Misnan, M. S. & Sariman, M. Z. 2015. Review of Oil–water through Pipes. *Flow Measurement and Instrumentation*. 45: 357-374.

[5] Ismail, A. S. I., Ismail, I., Zoveidavianpoor, M., Mohsin, R., Piroozian, A., Misnan, M. S. & Sariman, M.Z. 2015. Experimental Investigation of Oil–water Two-phase Flow in Horizontal Pipes: Pressure Losses, Liquid Holdup and Flow Patterns. *Journal of Petroleum Science and Engineering*. 127: 409-420.

[6] Piroozian, A., Hemmati, M., Ismail, I., Manan, M.A., Rashidi, M. M. & Mohsin, R. 2017. An Experimental Study of Flow Patterns pertinent to Waxy Crude Oil-water Two-phase Flows. *Chemical Engineering Science*. 164(2017): 313-332.

[7] Bai, Y. and Bai, Q. 2005. *Subsea Pipelines and Risers*. 2nd ed. Amsterdam: Elsevier Science.

[8] Poettmann, F. H. and Carpenter, P. G. 1952. Multiphase Flow of Gas, Oil and Water through Vertical Flow Strings. Drill. and Prod. Pract. Dallas: American Petroleum Institute.

[9] Duns Jr., H. and Ros, N. C. J. 1963. Vertical Flow of Gas and Liquid Mixtures in Wells. *Proc. 6th World Petroleum Congress*. Section II-Paper 22-PD6, Frankfurt. 451-465.

[10] Fancher, G. H. Jr. and Brown, K. E. 1963. Prediction of Pressure Gradients for Multiphase Flow in Tubing. *SPE Journal*. March: 59-69.

[11] Hagedorn, A. R. and Brown, K. E. 1965. Experimental Study of Pressure Gradients Occuring during Continuous Two-phase Flow in Small Diameter Vertical Conduits. *Journal of Petroleum Technlogy*. April: 475-484.

[12] Orkiszewski, J. 1967. Predicting Two-phase Pressure Drops in Vertical Pipe. *Journal of Petroleum Technology*. 19(6): 829-838.

[13] Govier, G. W. and Aziz, K. 1972. *The Flow of Complex Mixtures in Pipes.* London: Von Van Nostrand Reinhold.

[14] Beggs, H. D. and Brill, J. P. 1973. A Study of Two Phase Flow in Inclined Pipes. *Journal of Petroleum Technology*. May: 607-617.

[15] Mukherjee, H., and Brill, J. P. 1985. Pressure Drop Correlation for Inclined Two-Phase Flow. *Journal of Energy Resources Technology*. 107: 549-554.

[16] Hasan, A. R. and Kabir, C. S. 1992. Gas Void Fraction in Two-phase Up-flow in Vertical and Inclined Annuli. *Int. J. Multiphase Flow*. 18(2): 279-293.

[17] Piroozian, A., Hemmati, M., Ismail, I., Manan, M. A., Bayat, A. E., and Mohsin, R. 2016. Effect of Emulsified Water on the Wax Appearance Temperature of Water-in-Waxy-Crude-Oil Emulsions. *Thermochimica Acta*. 637: 132-142.

[18] Pucknell, J. K., Manson, J. N. E., and Vervest, E. G. 1993. An Evaluation of Recent Mechanistic Models of Multiphase Flow for Predicting Pressure Drops in Oil and Gas Wells. Presented at *Offshore European Conference*, Aberdeen, September 7-10.

[19] Yahaya, A. U. and Gahtani, A. A. 2010. A Comparative Study between Empirical Correlations and Mechanistic Models of Vertical Multiphase Flow. Presented at the *2010 SPE/DGS Annual Technical Symposium and Exhibition*, Al-Khobar, Saudi Arabia, April 4-7.

[20] Fossmark, M. G., Kulkarni, K. N., and Lauritsen, H. T. 2012. Vertical Lift Models Substantiated by Stajford Field Data. Presented at *EAGE Annual Conference & Exhibition* incorporating SPE Europec held in Copenhagen, Denmark, June 4-7.

[21] Gilbert, W. E. 1954. *Flowing and Gas Lift Well Performance*. Drill. and Prod. Pract. Dallas: American Petroleum Institute.

[22] Mach, J., Proano, E., and Brown, K. E. 1979. A Nodal Approach for Applying Systems Analysis to the Flowing and Artificial Lift Oil or Gas Well. *SPE 8025*.

[23] Beggs, H. D. 2003. *Production Optimization Using Nodal Analysis*. 2nd edition, Tulsa: OGCI & Petroskill.

[24] Wu, R. & Rosenegger L. 2000. Comparison of PVT Properties from Equation of State Analysis and PVT Correlations for Reservoir Studies. Presented at *50th Annual Technical Meeting* in Calgary, Alberta, June 14-18.

[25] Fevang, Ø, Fossmark, M. G., Kulkarni, K. N., Lauritsen, H. T. and Skjaeveland, S. M. 2012. Vertical Lift Models Substantiated by Statfjord Field Data. SPE 154803. Presentated at the *EAGE Annual Conference & Exhibition*, Copenhagen, Denmark, June 4-7.

[26] Abu, T. 2007. Optimization of Gas Lift System in Varg Field. Thesis. Faculty of Science and Technology, Unversitetet Stavanger, Stavanger, Norway.

[27] Munson, B. R., Young, D. F. and Okiishi, T. H. 2002. *Fundamentals of Fluid Mechanics*. 4th ed. Hoboken, New Jersey: John Wiley and Sons.