الاستهلال:

قال تعالى:

(وَقُلِ اعْمَلُوا فَسَيَرَى اللَّهُ عَمَلَكُمْ وَرَسُولُهُ وَالْمُؤْمِنُونَ) [التوبة:105]

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Abstract

In this study, since the estimation of the pressure drop in vertical wells is quite important for several practical applications, a comparative study of pressure drop models and correlations has been done by using a commercial software. When calculating multiphase pressure drops in oil wells, there are several models available to do this. Each correlation was developed for a specific set of conditions which makes the applicability of any correlation outside the respective set of flow conditions questionable. In addition, models can have different complexities and, consequently, different calculation accuracies. The objective of the present study is to investigate the expected accuracies of three models. Two wells have been selected which are producing from different reservoirs having oil with similar API. In order to evaluate each correlation or model, the values of both measured and predicted pressure drop were analysed. It has been found also that the smallest errors were obtained by Beggs and Brill model despite the fact that the average absolute error is high for this particular case. Therefore, Beggs and Brill model outperformed Duns & Ross and Orkiszewski for the two wells studied under the specified conditions. It is recommended to perform this study amongst pressure drop correlations and models at early stages of production. Also, it is recommended to investigate as many wells as possible producing from the same reservoir and perform sensitivity analysis on some possible influential factors.

التجريد

في هذه الدراسة و بما أن تقدير حسابات انخفاض الضغط في الابار الرأسية ذو أهمية كبيرة تم إجراء دراسة مقارنة بين النماذج المستخدمة لحسابات انخفاض الضغط باستخدام أحد البرامج الحاسوبية. عند إجراء حسابات انخفاض الضغط هناك عدة نماذج متوفرة. كل من تلك النماذج والصيغ رياضية تم تطويرها تحت ظروف محددة مما يجعل تطبيقها خارج نطاق هذه الظروف غير دقيق. بالاضافة الى ان هذه النماذج معقدة و بالتالي تعطي نتائج ذات دقة مختلفة . الهدف من هذه الدراسه التحقق من دقة حسابات انخفاض الضغط لثلاثة نماذج. تم اختيار بئرين من مكمنين مختلفين ينتجان نفس نوع الزيت. لتقييم النماذج تم تحليل قيم انخفاض الضغط المقاسة و المتوقعة. وجد ان طريقة Beggs &Brill تعطي اقل خطأ متبوعه ببقية النماذج. نوصي بتطوير هذه الدراسة باستخدام اكبر عدد ممكن من الابار من نفس المكمن .

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Chapter One

1 Introduction

Estimation of the pressure drop in vertical wells is quite important for cost effective design of well completions, production optimization and surface facilities. However, due to the complexity of multiphase flow several approaches have been used to understand and analysis the multiphase flow.

In the petroleum industry a common occurrence is steady state simultaneous. Oil wells normally produce a mixture of liquids and gases to the surface and phase conditions usually change along the flow path. At the well bottom pressure the single-phase appears but going higher up in the well as pressure decrease gas dissolves gradually evolve from the flowing liquid resulting in multiphase. In addition to gas, gas well can produce condensed liquids and/or formation water. These are some of the reasons why multiphase flow in wells is a frequently occurring and important phenomenon.

Single-phase flow is a less complex than multiphase flow. Single-phase flow problems are well defined and most often have analytical solutions developed over the years. The calculation of pressure drop along the pipe is the most important task then can be solved with a high degree of calculation accuracy. The multi-phase makes conditions difficult to predict due to several reasons. Friction losses, for example, are more difficult to describe since more than one phase is in contact with the pipe wall. In addition, due to the great difference in densities of the liquid and gas phases, slippage losses arise and contribute to the total pressure drop. Both of these losses vary with the spatial arrangement of the flowing phases (conventionally called flow patterns) in the pipe, etc.

According to (Takacs 2001), "*no multiphase pressure drop calculation model can achieve the same accuracy for all the possible conditions encountered in practice". He* also stated that *"There is no "over-all best" method, and all efforts to find it are deemed to fail. Nevertheless, production engineers, in order to increase the accuracy and reliability of their designs and analyses, need to use the model giving the least calculation error for the conditions of the problem at hand".*

1.1 Objectives

The objectives of this study are:

- Understanding the different flow regimes and the associated models.
- Understanding the mechanistic and empirical methods and the usage of each.
- Sensitivity analysis on factors affecting the selection
- Development of a methodology for comparative study of pressure drop models and correlations by using a commercial software.

1.2 Proposed deliverables

Thought this project, it has been proposed that the following items should be delivered at different stages.

1. Background on flow patterns, maps, mechanistic models and empirical correlations.
2. Literature review on comparative and evaluation studies of pressure drop prediction methods
3. Collection of field data from different wells for the study and sorting them.
4. Running simulations using WellFlo showing the effect of different selected influential parameters.
5. Error analysis and sensitivity analysis for all wells.

Chapter Two

2 Literature Review and Background

For good engineering data accurate prediction of the pressure drop to be encountered during the multiphase is desired which depend on the reliability of pressure drop data and experimental flow apparatus for correlation data gathering represent the inherent problems of obtaining a general multiphase flow model. During multiphase flow in vertical tubing at least four distinct regimes of flow are identifiable.

Multiphase flow is very common in many industrial processes and applications. Oil and gas industry is one of the fields which have motivated intensive studies on multiphase flow. In particular, studying the behavior of one of the flow patterns that causes critical challenges which is slug flow. For instance, slug flow causes irregularity in production and generates high dynamic load and vibration that can damage the piping system and surface equipment such as separators.

In general, gas and liquid flowing in a channel tend to be distributed in different specific configurations. These specific distributions of the interface between fluids are called flow regimes or flow patterns. A lot of work has been done in defining these patterns for different fluids, pipe geometries, and orientations. In the subsequent sections, there flow patterns will be explained in terms of their main characteristics and the method used to identify them. Then more details will be given about slug flow and some of the experimental and computational fluid dynamics studies made to investigate this flow pattern.

The expression of ‘multi-phase flow’ is used to describe the simultaneous of more than one fluid. The importance of multiphase flow is tubing performance relationship and designing oil well equipment and optimizing well production conditions beside gas lift design. Oil wells usually produce a mixture of fluids and gases to the surface. Sometimes the flow situation change during the course of run of. At high pressure in the bottom hole, flow is one phase but by going upward with the continuing decline in pressure appear the gas dissolved gradually arising from the flow of fluid causing multiphase flow. Also gas well produce condensate or liquid in addition to gas causing two-phase flow.

Multiphase flow is so complicated is that several different flow regimes can exist vertically in a flowing well, as pressure drops and as gas evolves from solution. The possible various flow regimes in vertical tubes are shown in Figure 2-1.

We can understand how each of these flow regimes develops if we high enough to keep all the gas in solution (liquid flow). As the assume that the oil produced into the wellbore is at a pressure oil moves up the tubing and pressure decreases, gas bubbles begin to form as a discontinuous phase dispersed within the oil (bubble flow). As the fluid moves up the tubing the larger bubbles slip through the oil at a higher velocity, growing larger and expanding across the tubing diameter (plug or slug flow). As pressure is decreased further, the gas expands to break through the oil slugs and forms a continuous gas phase with the oil distributed as a film or annulus on the tubing wall and as droplets in the gas (annular flow). As the pressure decreases and the velocity increases still further, the annular oil becomes completely atomized as droplets within the gas phase (mist flow). Often two or three but not all of these flow regimes may occur within a single flowing well.

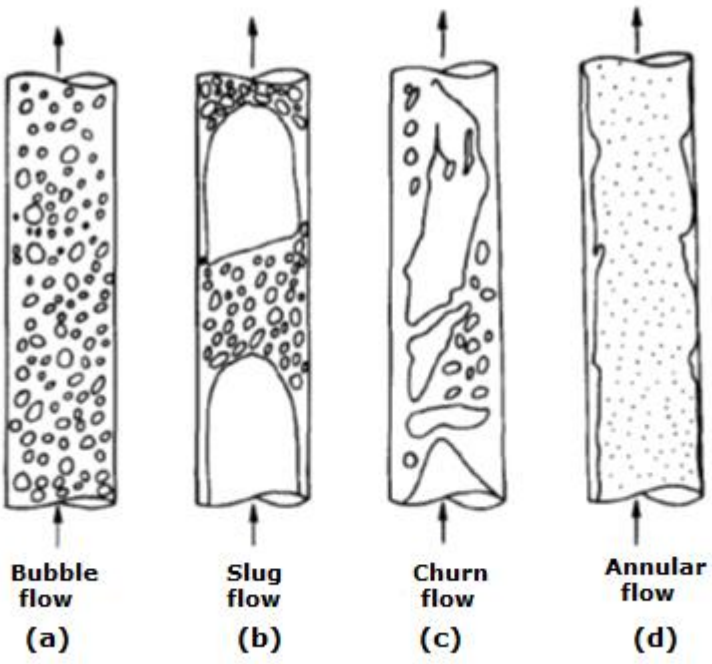

Figure 2-1: Flow patterns in vertical flow:(a) bubble flow, (b) slug flow, (c) churn flow and (d) annular flow(Taitel, Bornea et al. 1980)

In horizontal tubes, flow patterns and flow regimes are similar to those in vertical but the distribution is influenced by gravity. At high mass flow rates , bubbly flow occurs and when liquid and gas velocity decrease , gas go to the top and liquid to the bottom forming stratified flow. Stratified wavy form when velocity increasing and then wavy formed on the in the interface. Stratified waves in stratified wavy became large and wash the top of the tube when gas velocity increase forming plug and slug flow. At large gas flow rate liquid forms a continuous annular film around the perimeter of the tube similar to that in vertical but thicker at the bottom than the top. At very high gas velocity all liquid entrained as small droplets in the continuous gas phase forming mist flow and it is similar to that in vertical as shown in Figure 2-2.

An older adiabatic flow patterns maps for vertical and horizontal flows in tubes used to predict the local flow patterns in tube. It’s a diagram that display the transition boundaries between the flow patterns. All maps based on mass velocity and properties of the fluid.

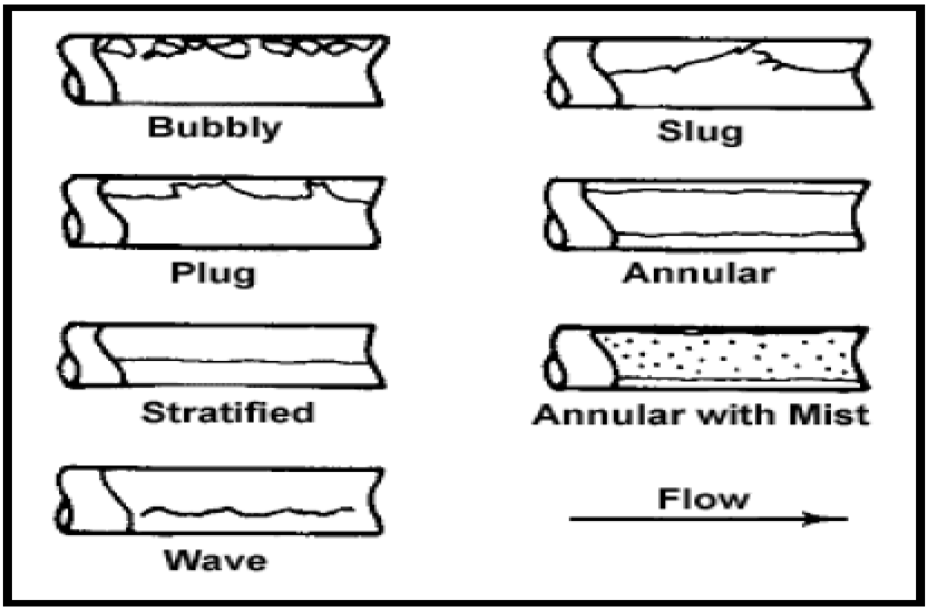

Figure 2-2: Flow patterns in horizontal pipes

2.1.1 Flow patterns

When liquid and gas flow upwardly as a mixture in vertical channels, they tend to distribute in various flow patterns. Each pattern is describing the axial or radial distribution of gas and liquid. Due to the fact that usually the flow is chaotic, there are some difficulties in describing those phase distributions (Taitel, Bornea et al. 1980).

In 1970, Hewitt and Hall-Taylor designated four basic patterns of upward vertical flow. These patterns are: bubble, slug, churn and annular flow as shown in Figure 2-1. Each flow regime is briefly outlined below:

Bubble Flow: At low gas flow rates, the gas phase is approximately uniformly dispersed as discrete bubbles in the liquid phase continuum as shown in Figure 2-1(a).

Slug Flow: At flow rates of gas higher than that in bubble flow, some of the bubbles would have nearly similar cross sectional area as that of the pipe. Therefore, the majority of gas is located as big bubbles having a bullet shape. These bubbles with a diameter approximately the same as that of the pipe are referred to as Taylor bubbles or slugs as shown in Figure 2-1(b). They flow along the pipe detached by liquid plugs that might or might not encompass a spreading of small gas bubbles. In addition, between the Taylor bubbles and the wall of the pipe, liquid moves downward having the shape of a thin film. "At relatively low rates, in which the gas/liquid boundaries are distinct, this flow regime has been termed by other authors as plug flow, or piston flow. Whereas, at higher rates, in which the boundaries are less clear referred to as slug flow" ,Taitel et al.(Taitel, Bornea et al. 1980).

Churn Flow: As the gas flow rate increases in a flow of the form of slug regime, it leads to a full damage of slug flow characteristic with subsequent oscillation. So, churn flow and slug flow are to some extent alike. It is, nevertheless, much more disordered and frothy where the shape of Taylor bubbles is deformed [see Figure 2-1(c)]. Also, the high concentration of gas in the slug triggers a destruction of the liquid continuity flowing in the slugs between consecutive Taylor bubbles. Consequently, liquid slug falls and accumulates to form a bridge which is then picked up by the gas. Therefore, this irregular direction of liquid movement is the main characteristic of churn flow.

Annular Flow: When gas flow rates become very high, the flow becomes annular. This flow pattern is described by the fact that the gas phase is continuous along the middle of the channel or pipe as shown in Figure 2-1(d). As far as liquid flow is concerned in this pattern, liquid moves upwardly in the form of thin wavy films and as entrained drops in the gas flowing in the middle.

2.1.2 Vertical lift performance

Just as there is a drop in pressure within the formation during production, there is also a drop in pressure within the tubing from the bottom of the well to the surface, during vertical flow. The pressure loss in the tubing for any given set of flowing conditions is a difficult value to predict because it is dependent on many factors, which are not always known or constant. A list of these factors appears (below) .

Factors effecting vertical flow pressure drop :

- Tubing size
- Flow rate
- Gas-liquid ratio
- Water-oil ratio
- Fluid densities
- Fluid viscosities
- Slippage
- Temperature gradient

The estimation of the pressure drop in vertical wells is quite important for cost effective design of well completions, production optimization and surface facilities However, because of the complexity of the vertical flow regimes, correlations have been developed to predict pressure losses in the tubing for a wide variety of vertical flow conditions. These correlations have been published and incorporated into various software packages. For any given flow rate, tubing configuration, and production fluid characteristics, the pressure drop in the tubing from the bottom of the hole to the surface may be estimated using these correlations.

2.1.3 Classification of Pressure Drop Prediction Models

Multiphase flow is a very complicated phenomenon which depends on many variables such as fluid properties, flow pattern, flow rate, GOR, water-cut, and pipe diameter. Because of such complexity, a complete analytical solution does not exist. Several empirical correlations have been developed for prediction of pressure drop. Each correlation was developed for a specific set of conditions. This made the applicability of any correlation outside the respective set of flow conditions questionable.

Group I:

Under this group, slip between phases in not considered in the models as both phases are assumed to travel at the same velocity. Flow patterns are not distinguished, general formulas are given for mixture density and friction factor determination. Pressure losses are described by a single energy loss factor.

Group II.

Flowing density calculations include the effects of slippage. No flow patterns are distinguished.

Group III.

Flow patterns are considered and calculation of mixture density and friction factor varies with the flow pattern. Flowing mixture density calculations include the effects of slippage.

2.1.4 Empirical correlations

The empirical correlations are formed by establishing a mathematical relation based on experiment data. Early empirical correlation treated the multiphase flow problem as the flow of a homogeneous mixture of liquid and gas. This approach completely disregarded the well-known observation that the gas phase, due to its lower density, overtakes the liquid phase resulting in "slippage" between the phases. Slippage increases the flowing density of the mixture. Later, the evolution of the empirical models brought about the appearance of empirical liquid holdup correlations to account for the slippage between the phases. More advanced models tried to include also the effects of the different spatial arrangements of the two phases, called "flow patterns".

- **Hagedorn-Brown II**

Hagedron & Brown correlation is one of the most common correlations used in the industry. Hagedron & Brown correlation developed using an experimental study of pressure gradients occurring during continuous two-phase flow in small diameter vertical conduits, 1500 ft. vertical wellbore and considering 5 different fluids types in the experiment which is water and four types of oil. This correlation involves only dimensionless groups of variables and it can be applied over a much wider range of conditions compared to other correlations.

The conclusions made by Hagerdon and Brown are:

1) Liquid viscosity has an effect on the pressure losses occurring in two-phase flow and in particular for liquid viscosities greater than 12 CP.

2) A more reliable holdup factor may be defined for experimental studies with long tubes than for short tubes.

3) It did not appear necessary to separate two-phase flow into the various flow patterns to provide sufficient accuracy for engineering purposes.

4) The change in kinetic energy can account for an appreciable percentage of the total pressure losses, particularly at the wellhead where low tubing pressures are encountered.

5) The correlation is general and may be applied over a wide range of conditions.

- **Duns-Ros**

This empirical correlation is resulted from laboratory experiments with some modification and adjustments in the correlation by using 5 actual field data. Duns & Ros correlation is in terms of a dimensionless gas velocity number, diameter number, liquid velocity number and a dimensionless mathematical expression. The acceleration gradient is neglected in the methods. Although this method is developed to calculate the pressure drop with dry oil/gas mixtures, it can also be used with wet oil/gas mixtures in some cases.

Duns and Ros developed four dimensionless groups which were used extensively in their correlations:

$$N_{gv} = V_{sg}(\frac{\rho_l}{g\sigma})^{1/4} \quad \textbf{(2.1)}$$

$$N_{lv} = V_{sl}(\frac{\rho_l}{g\sigma})^{1/4} \quad \textbf{(2.2)}$$

$$N_d = d(\frac{\rho_l g}{\sigma})^{1/2} \quad \textbf{(2.3)}$$

$$N_l = \mu_l(\frac{g}{\rho_l \sigma^3})^{1/4} \quad \textbf{(2.4)}$$

Where:

N_{gv}=gas velocity number

N_{lv}=liquid velocity number

N_d=diameter number

N_l=liquid viscosity number

V_{sg}=superficial gas velocity (ft/sec)

V_{sl}=superficial liquid velocity (ft/sec)

ρ_l=liquid density (Ib_m/ft^3)

μ_l=liquid viscosity (cp)

d=pipe inside diameter (ft)

g=acceleration due to gravity (ft/sec^2)

σ=gas-liquid surface tension (dynes/cm)

- **Orkiszewski**

This correlation had developed an equation for two-phase pressure drops in flowing and gas-lift production wells over a wide range of well conditions with range of precision about 10%. The method is an extension of the work done by Griffith and Wallis (1961). The correlation is valid for several flow regimes such as; bubble flow, slug flow, transition flow and annular-mist flow. Orkiszewski proved his assumptions by comparing the measured pressure drop results of 184 wells to the calculated ones. The parameters considered in his equation for the pressure drop are the effect by the energy lost by friction, the change in potential energy and the change in kinetic energy. The results obtained by these methods are still applicable for wide range of well conditions (e.g. heavy oil). But, there are some well conditions that have not been evaluated (e.g., flow in the casing annulus and in the mist flow regime).

$$\Delta P_k = \frac{1}{144}\left|\frac{\rho_l + \tau_f}{1 - w_t q_g / 4637 {A_p}^2 \bar{P}}\right|_k \Delta h_k \qquad \textbf{(2.5)}$$

$$\tau_f = \frac{f \rho_l V_l}{2 g_c d_{hy}} = \left(\frac{dP}{dh}\right)_f \qquad \textbf{(2.6)}$$

Where:

ΔP= pressure drop, psi

Δh= depth change, ft

τ_f= friction losses gradient, psi/ft

ρ_l=liquid viscosity, Ib/cu ft

w_t= total mass flow rate, cu ft/sec

q_g=gas volumetric flow rate, cu t/sec

A_p= pipe area, sq ft

$\bar{P}$= average pressure, Pisa

f= friction factor

V_l= liquid velocity, ft/sec

g_c= conversion of unit parameter (=32.2)

d_{hy}= hydraulic diameter, ft

- **Beggs-Brill**

The Beggs and Brill method was developed to predict the pressure drop for horizontal, inclined and diameter were used. The parameters used are gas flow rate, Liquid flow rate, pipe diameter, inclination angel, liquid holdup, pressure gradient and horizontal flow regime. This correlation has been developed so it can be used to predict the liquid holdup and pressure drop.

$$\frac{dP}{dz} = \frac{\left(\frac{dP}{dz}\right)_{el} + \left(\frac{dP}{dz}\right)_f}{1 - E_k} \quad \textbf{(2.7)}$$

$$E_k = \frac{\rho_s v_m v_{sg}}{g_c P} \quad \textbf{(2.8)}$$

$$\left(\frac{dP}{dz}\right)_{el} = \frac{g}{g_c}\rho_s \quad \textbf{(2.9)}$$

$$\rho_s = \rho_l H_l + \rho_g H_g \quad \textbf{(2.10)}$$

$$\left(\frac{dP}{dz}\right)_f = \frac{f_{tD}\rho_n {V_m}^2}{2g_c} \quad \textbf{(2.11)}$$

$$\rho_n = \rho_l \lambda_l + \rho_g \lambda_g \quad \textbf{(2.12)}$$

$$f_{tD} = f_n \frac{f_{tD}}{f_n} \quad \textbf{(2.13)}$$

$$f_n = 1/[2\log(N_{Re}/4.5223\log N_{Re} - 3.8215)]^2 \quad \textbf{(2.14)}$$

$$N_{Re} = \frac{\rho_n V_m d}{\mu_n} \quad \textbf{(2.15)}$$

$$\mu_n = \mu_l\lambda_l + \mu_g\lambda_g \quad \textbf{(2.16)}$$

Where:

$\left(\frac{dP}{dz}\right)$= total pressure gradient, psi/ft

$\left(\frac{dp}{dz}\right)_{el}$ = pressure gradient due to elevation, psi/ft

$\left(\frac{dp}{dz}\right)_f$ = pressure gradient due to friction, psi/ft

E_k=kinetic energy parameter

ρ_g, ρ_l= gas and liquid densities

H_g, H_l= gas and liquid holdup

f_n= no-slip friction factor

N_{Re}= Reynolds number

λ_g, λ_l= gas and liquid no-slip holdup

μ_g, μ_l=gas and liquid viscosities, cp

- **Mukherjee-Brill**

Mukherjee & Brill Proposed a correlation for Pressure loss, Holdup and flow map. Their correlation was developed following a study of pressure drop behavior in two-phase inclined flow. However, it can also be applied to vertical flow. Prior knowledge of the liquid holdup is needed to compute the pressure drop using Mukherjee & Brill (1985) correlation. The results obtained from their experiments were verified with Prudhoe Bay and North Sea data.

It also takes into account the several flow regimes in the multiphase flow. Therefore, Beggs & Bril (1973) correlation is the most widely used and reliable one by the industry. In their experiment, they used 90 ft. long acrylic pipes data. Fluids used were air and water and 584 tests were conducted. Gas rate, liquid rate and average system pressure was varied. Pipes of 1 and 1.5 inch

2.1.5 Mechanistic Models

The continuous efforts of researchers and practicing engineers to improve the accuracy of pressure drop predictions have indicated that empirical calculation methods, by their nature, can never cover all parameter ranges that may exist in field operations. Fundamental hydraulic researches, as well as adaptation of the achievements of the abundant literature sources in chemical engineering and nuclear industries have gradually shifted the emphasis from empirical experimentation to a more comprehensive analysis of the multiphase flow problem. This is the reason why the modeling approach is exclusively utilized in the current research of multiphase flow behavior. Investigators adopting this approach model the basic physics of the multiphase mixture’s flow and develop appropriate fundamental relationships between the basic parameters. At the same time, they try to eliminate empirical correlations in order to widen the ranges of applicability.

Mechanistic models or known also as semi-empirical correlations deal with the physical phenomena of the multiphase flow. These types of models are developed by utilizing mathematical modelling approach. A fundamental hypothesis in this type of models is the existence of different flow configurations or flow regimes, including stratified flow, slug flow, annular flow, bubble flow, churn flow and dispersed bubble flow. The first objective of this approach is thus, to predict the existing flow pattern for a given system. Even if most of the current presented mechanistic models have been developed under certain conditions which limit their ability to be used in different range of data, these models are expected to be more reliable and general because they incorporate the mechanisms and the flow important parameters (Gomez et al. 2000).

- **Aziz et al. Model (1972)**

Aziz, Govier and Fogarasi (1972) have proposed a simple mechanistically based scheme for pressure drop calculation in wells producing oil and gas. The scheme was based on the identification of the flow pattern map. The mechanical energy equation was presented in the relationship between the pressure gradient, the flow rate, the fluid properties and the geometry of the flow duct. While the model proposed new equations for bubble and slug flow patterns, it recommended the old Dun &Ros equations for annular mist pattern. The new prediction method incorporates an empirical estimation of the distribution of the liquid phase between that flowing as a film on the wall and that entrained in the gas core. It employs separate momentum equations for the gas-liquid mixture in the core and for the total contents of the pipe. The model has presented 44 value of predicted pressure drop with absolute error almost equal to that for Orkiszewski correlation. However, the uncertainties and lack of some filed data made it difficult to develop a fully mechanistically, reliable based computation method.

- **Ansari et al. Model (1994)**

This mechanistic model is developed for upward two-phase flow in wellbores. This model was developed as part of the Tulsa University Fluid Flow Projects (TUFFP) research program. The model predicted the existence of four flow patterns which are; bubble flow, slug flow, churn flow and annular flow. The model was evaluated by using the TUFFP well databank that is composed of 1775 well cases, with 371 of them from Prudhoe Bay data. Ansari et al (1994) claimed that the overall performance of the comprehensive model is superior to all other methods considered with an exception of Hagedorn & Brown empirical correlation due to extensive data used in its development and modifications made to the correlation.

- **Chokshi et al. (1996) Model**

They developed a mechanistic model that considers three flow patterns: bubble, slug and annular flow, and used drift flux modeling approach for bubble to slug transition. Measured data were gathered from 324 tests for widely varying flow rates. Pressure drop predictions of the model were compared to eight correlations/mechanistic models using measured data and Independent data bank of 1712 data sets.

2.1.6 Comparative and evaluation studies of pressure drop prediction methods

A recent comparative study by (Yahaya and Gahtani 2010) conducted on a number of empirical correlation and mechanistic models for predicting pressure drop and other fluid flow characteristics during multiphase flow in vertical well bore. Using 414 real field data points covering pipe sizes of 2.375 in. to 7.0 in. oil flow rate of 280B/D to 23,200B/D. water cut up 95%, gas-oil ratio up 927SCF/STB from the Middle East, the correlations and models are used to predict pressure drop in vertical multiphase flow for several wells. The predict performance is then compared with actual measured well pressure drop data. Based on the results from the analysis, mechanistic model of Ansari et al. out-perform all the conventional empirical correlations in the study for vertical multiphase flow for the Middle East region.

(Espanol, Holmes et al. 1969)chose and evaluated three of the best correlations; the Hagedron and Brown, Duns and Ros, and Orkiszewski methods. The accuracy of these new correlations was determined against multiphase flow pressure drop data from 44 wells. The best solution which was both general and gave satisfactory accuracy for all possible ranges of well conditions was determined. The method of Orkiszewski was found to be most accurate for engineering design usage and was the only correlations which could evaluate a three phase flow condition when water is simultaneously being produced with the gas-oil mixture. The Orkiszewski method had to be tested against more data for wells of lower API gravity oil and with a wider range of WOR. 0rkiszewski has also shown his method to give better results than either the Duns and Ros or Hagedorn and Brown method. However, special communication with both Ros and Hagedorn has indicated that their method is more accurate in certain ranges of flow. This study by

(Espanol, Holmes et al. 1969) therefore points up the fact that the comparison of these three methods should be continued with additional well data to establish their accuracy in all ranges of flow.

(Hasan 1986) used standard oilfield correlations for estimating PVT properties of oil and gas , computation on test data gathered from some 115 oil wells , involving all the two-phase flow regimes, indicates that the proposed model performs better than the other models considered: Aziz et al. Orkiszewski, Duns and rose, Beggs and Brill, Hagedorn and Brown, and Chierici et al. Calculations also reveal that bubbly and slug flow are the dominate flow mechanism in most cases, while churn an annular flow are associated with high flow rate wells. Hydrostatic head contributes to the most of the pressure drop (90%+) when the flow is essentially restricted to the bubbly and slug flow.

(Al-muraikhi 1996) studied the comprehensive evaluation of existing correlations and modifications of some correlations to determined and recommend the best correlations or correlations for various field conditions. More than 400 field data sets covering tubing sizes from 2 to 7 in, oil rates up to 23200 B/D, water cut up to 95%, and gas/oil ratio (GOR) up to 927 scf/STB were used in this study. Considering all data combined, the Beggs and Brill correlation provided the best pressure predictions. However, the Hagedorn and Brown correlation was better for water cuts above 80%, while the Hasan and Kabir model was better for total liquid rates above 20,000 B/D .The Aziz correlations was significantly improved when the Orkiszewski flow-pattern transition criteria were used classify the calculation models used for calculation of multiphase vertical pressure drops in oil wells. He analyzed the causes of calculation error and deviation of calculated and measured pressure drops to stem from different sources that can have different importance from case to case. He describes the petroleum engineer's proper attitude towards vertical pressure drop correlation. A recent study has been performed for the old correlations and models to evaluate and assess the current empirical correlations, mechanistic model and artificial neural networks for pressure drop estimation in multiphase flow in vertical wells by comparing the most common methods in this area. The parameters affecting the pressure drop are very important for the pressure calculation Therefore, it will also be taken into account in the evaluation (Musaab M. Ahmed 2011) A study was conducted by (Espanol, Holmes et al. 1969) to evaluate the best existing models for the prediction of pressure drop during multiphase flow and to determine which, if any, is most applicable for use in petroleum engineering practice.

Chapter Three

3 Methodology Employed in this Study

One of the objectives of this project is to employ a methodology for comparative study of pressure drop models and correlations by using a commercial software.

3.1 Description of the problem

When calculating multiphase pressure drops in oil wells, there are several models available to do this. These models can have different complexities and, consequently, different calculation accuracies. The aims of the present study are to investigate the expected accuracies of three models under study which will be shown later.

The importance of the study stems from the fact that no multiphase pressure drop calculation model can result in the same accuracy for all the possible conditions faced in practice. As there is no "over-all best" model, we need to apply the model which results in the least calculation error for the conditions of the problem under study.

3.2 Field and wells data description and analysis

For the present study, two wells have been selected which are producing from the different reservoirs. The produced oil have the same API. However, the gas oil ratio GOR is a bit different. They difference can be noticed in the amount of produced water represented as the water cut which is 20% and 80% for Well#1 and Well#2, respectively.

Pressure surveying data were obtained for the two wells five years before the current production date as shown in Table A 1 in the Appendix A.

The reservoir and fluid data are shown in Table 3-1 and wells data are shown in Table 3-2.

Table 3-1: Reservoir and fluid data

Reservoir Data		
	Well#1	**Well#2**
Pressure	2000 psi	2600 psi
Wellbore radius	0.46 ft	0.4583 ft
Temperature	183.6 F	84.2 F
IPR model	Straight line	Straight line
Drainage area shape	Circular	Circular
Fluid parameters		
	Well#1	**Well#2**
Oil API gravity	31	31
Gas gravity	0.6	0.7
Water gravity	1	1
PVT method	Black oil	Black oil
GOR	2000 scf/stb	1750 scf/stb
Water cut	0.2	0.8

Table 3-2: Wells data

	Well#1	**Well#2**
Kelly Bushing (KB)	571.139 m	558.7m
Ground Level (GL)	564.939 m	549.5m
KB- GL	6.2m	9.2m
FloatCollar	2805.09 m	2374.78mkB
Surface Casing	339.7 mm × 183.64m	339.7mm×204.3mkB
IntermediateCasing	———	244.5mm×1754.45mkB
Linear production casing	139.7 mm × 2843.23m	———
production casing	244.5mm×1845.27m	1397×1629.63-2398.4mkB
TD	2,848.0 m KB	2,400 m kB
Max Deviation(deg)@Depth(m)	1.00 degree@ 1837mKB	2.05 degree@2047mkB

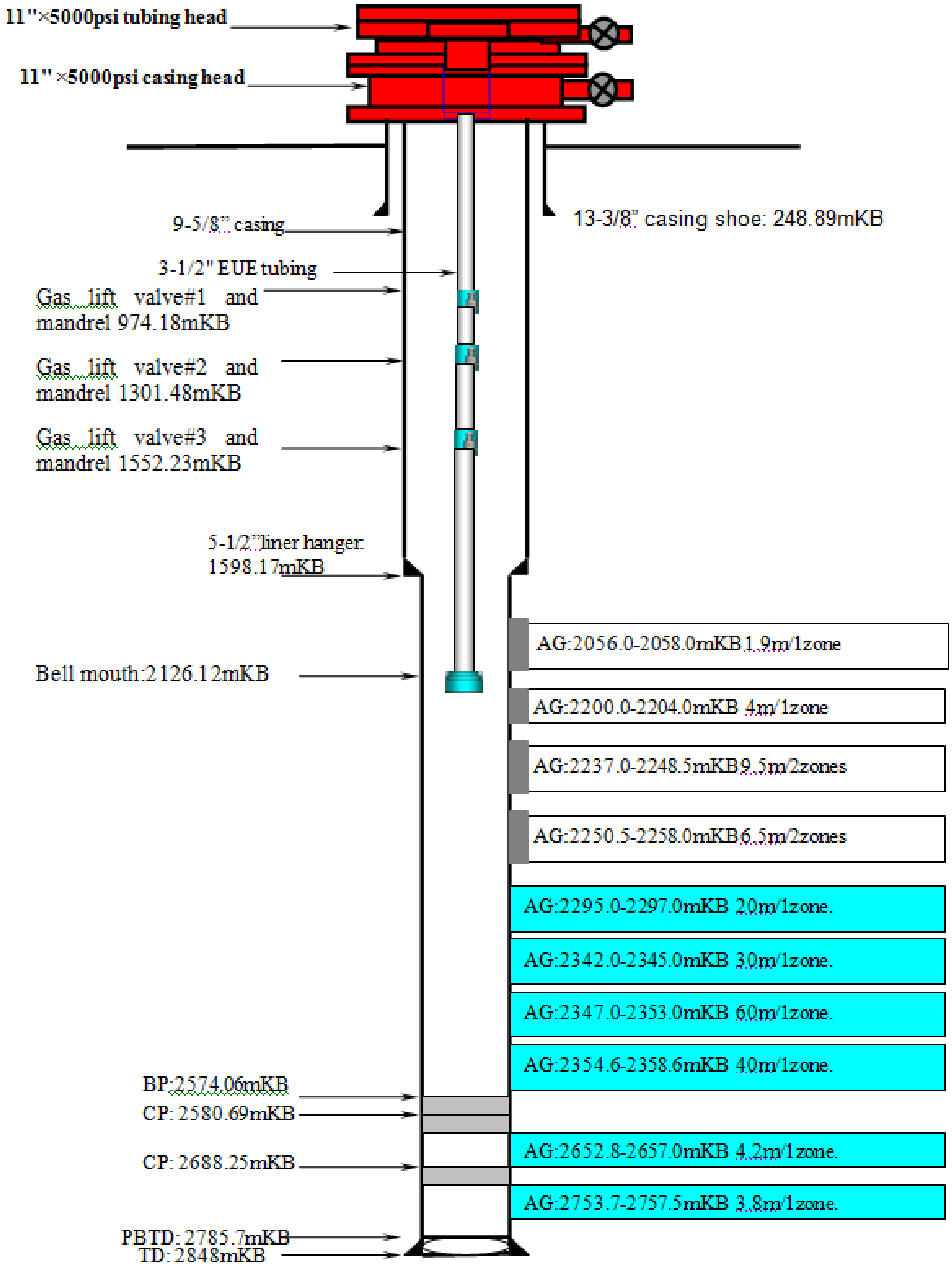

Figure 3-1: Schematic for Well#1

3.3 Building the Model using WellFlo

A reliable and accurate prediction of pressure drop during multiphase, it will help defining the completion for new wills or identifying the wells that need to be artificially lifted, and at the field level the question is what the type of empirical correlation should be applied. For predicting the suitable multiphase flow correlation for a Sudanese field a set of data points will be used and compared to actual field results in order to determine which correlation is the suitable for known field. WELLFLO software will be used to tuning the survey data and test the vertical empirical correlations. The steps of the WellFlo are show in Appendix B.

WellFlo is a Nodal Analysis program designed to analyze the behavior of petroleum fluids in wells. This behavior is modeled in terms of the pressure and temperature of the fluids, as a function of flow rate and fluid properties. The program takes descriptions of the reservoir, the well completion (i.e. the hardware within the well), and the surface hardware (i.e. pipelines etc.), combined with fluid properties data. The program then performs calculations to determine the pressure and temperature of the fluids.

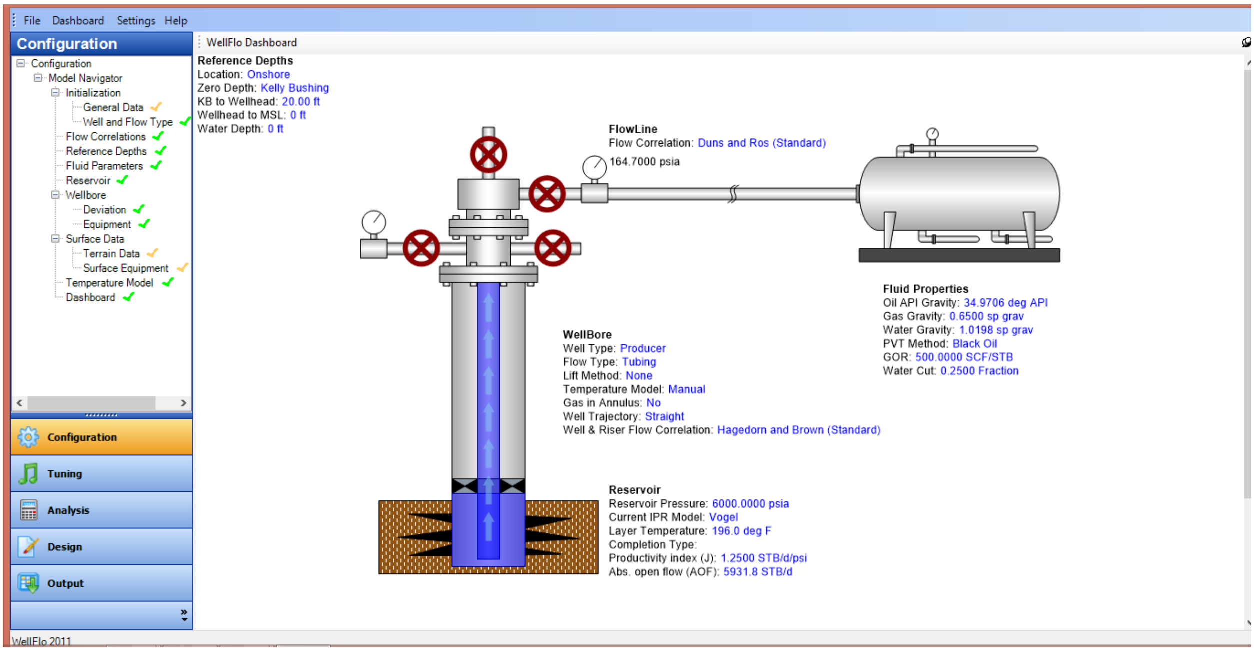

Figure 3-2: WellFlo window

Different modes of operation can be employed to either solve for flow rate given controlling pressures (typically deliverability calculations), or solving for pressure drops given measured flow rates (typically diagnostic calculations).

Deliverability Applications

- Calculating the Flow Potential (or Deliverability) of a Well
- Designing the Completion of a Well
- Modeling the Sensitivity of a Well Design to Different Factors That May Affect it in the Longer Term

Diagnostic Applications

This alternative mode of calculation is simpler: this is where the flow rate is known and the pressure at one point is required, given the pressure at another point. This is useful for the following reasons:

- **Comparing measured and calculated data**
- **Monitoring work**,
- **Design work** where it is required to calculate the pressure drop in a system

3.4 Models and Correlations Applied

In this study, three empirical correlations were evaluated. The correlations are: Duns & Ros, Beggs & Brill and Orkiszewsk. Those three models were selected for this study according to the previous studies form the literature which showed that those model give the best prediction results (Musaab M. Ahmed 2011) (Takacs 2001).

3.5 Evaluation Process

The common obstacle for using a pressure drop method if it's an empirical correlation, a mechanistic model or an artificial neural network model that most of these models are applicable for specific range of data and conditions for predicting the pressured drop accurately. However, in some cases, it may work well also in some actual filed data with acceptable prediction error.

To analyze and compare the effectiveness of each correlation or model, the values of both measured and predicted pressure drop are recorded. All the selected correlations and models are evaluated using actual filed data where the predicted pressure drop is compared to the measured one. The analysis is conducted via statistical and graphical error analysis.

Chapter Four

4 Results and Discussions

In this section, the results of the simulation using WellFlo for Well#1 and Well#2 will be shown. The predicted pressure drop profile using the three applied models under study which are Duns & Ros, Orkiszewski and Beggs & Brill will be shown. Then, statistical Error analysis has been used to check the accuracy of the models. The statistical parameters used in this study are average absolute error and the standard deviation of error.

The following figures show the survey pressure profile versus the predicted pressure drop simulated using the empirical models applied in this study. Figure 4-1, Figure 4-2 and Figure 4-3 are for Well#1 showing Duns & Ros, Orkiszewski and Beggs &Brill, respectively. Then, the three models' results were plotted against the survey to illustrate the differences between them as shown in Figure 4-4.

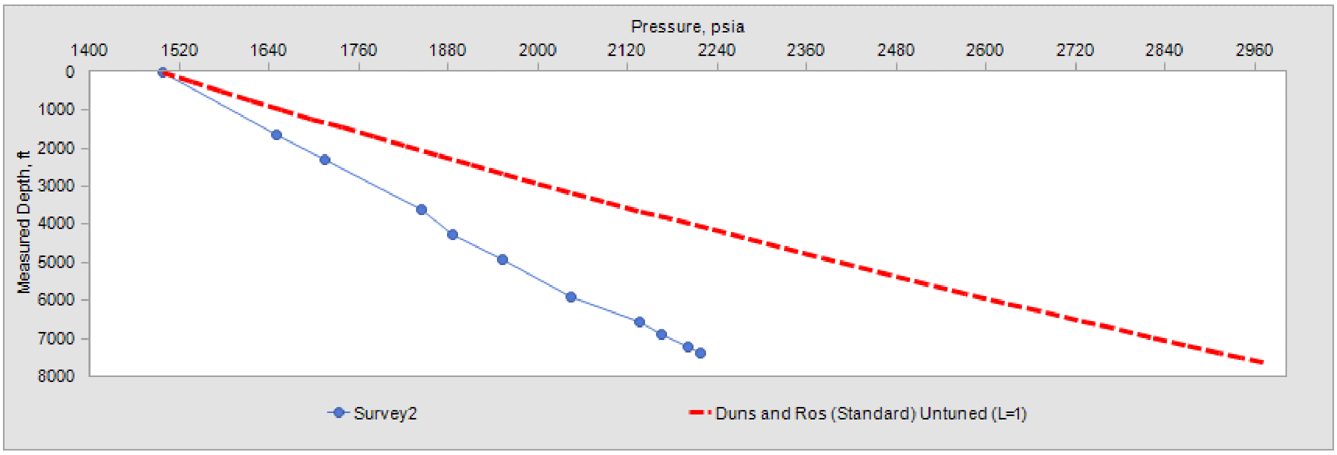

Figure 4-1: Survey profile vs predicted using Duns & Ros for Well#1

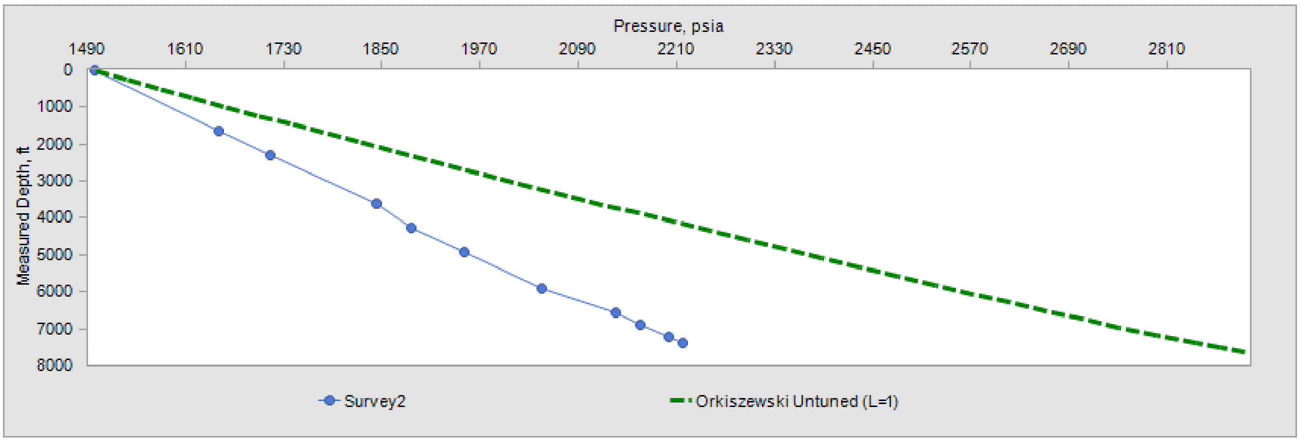

Figure 4-2: Survey profile vs predicted using Orkiszewski for Well#1

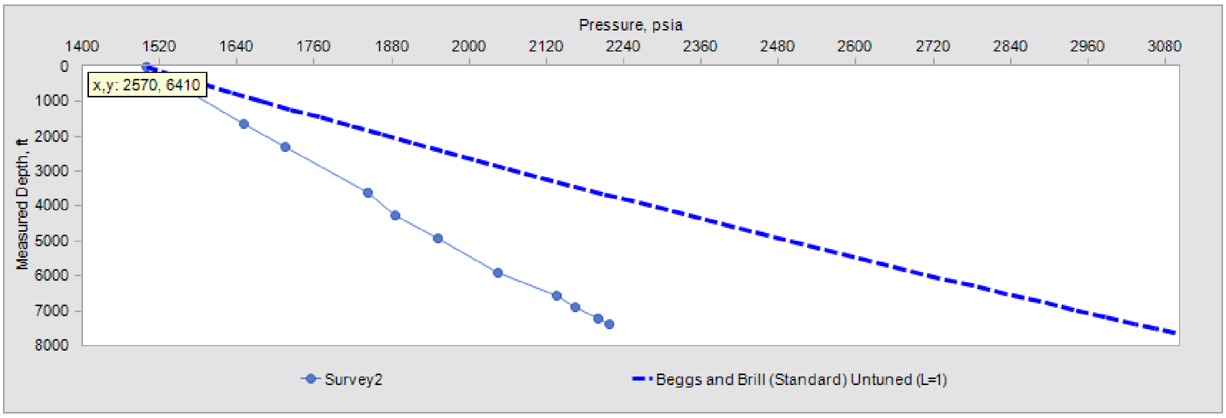

Figure 4-3: Survey profile vs predicted using Beggs & Bril for Well#1

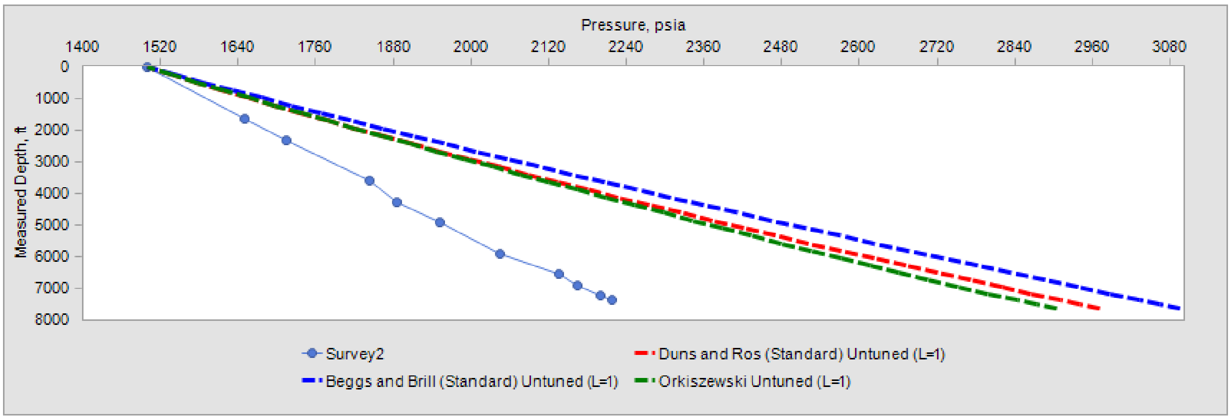

Figure 4-4: Survey profile vs predicted using three models for Well#1

For Well#2, the following figures were obtained for each model separately then the three models' profiles were plotted on one figure for comparison purposes.

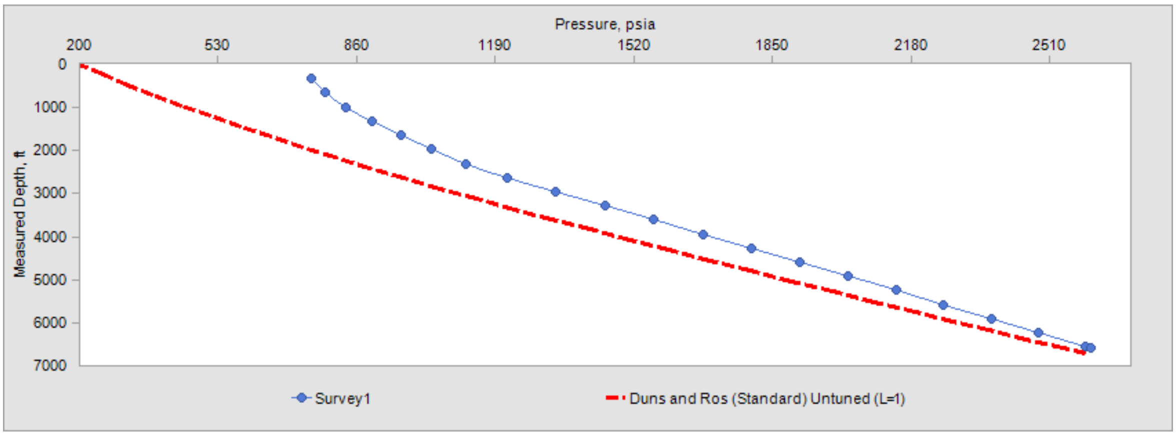

Figure 4-5: Survey profile vs predicted using Duns & Ros for Well#2

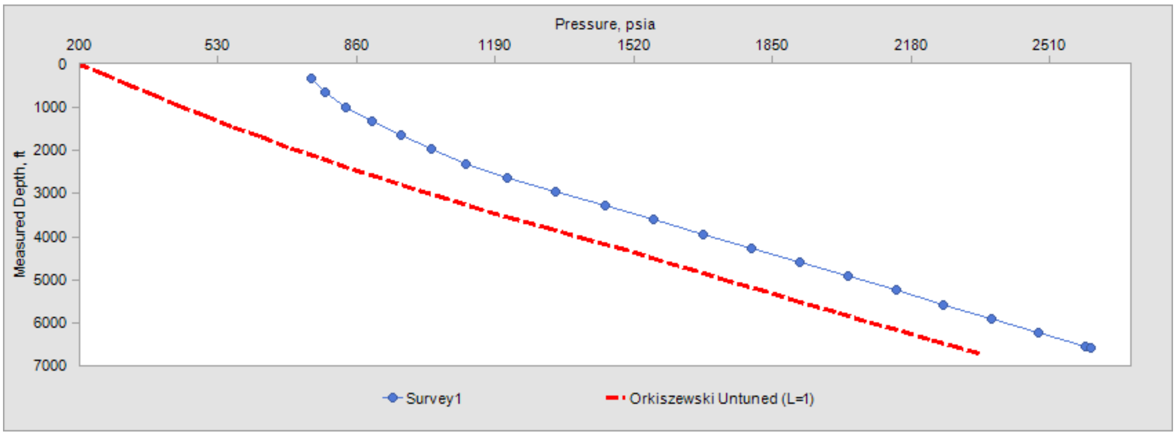

Figure 4-6: Survey profile vs predicted using Orkiszewski for Well#2

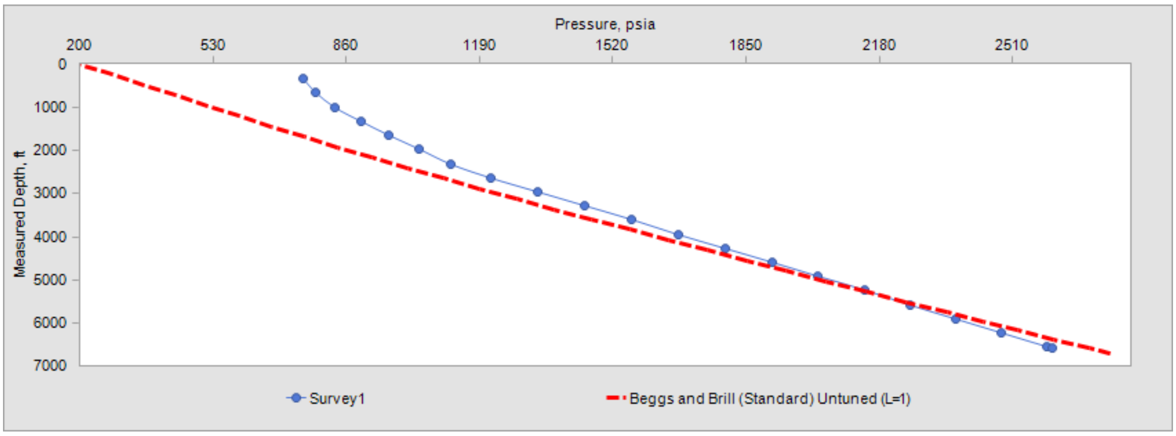

Figure 4-7: Survey profile vs predicted using Beggs & Brill for Well#2

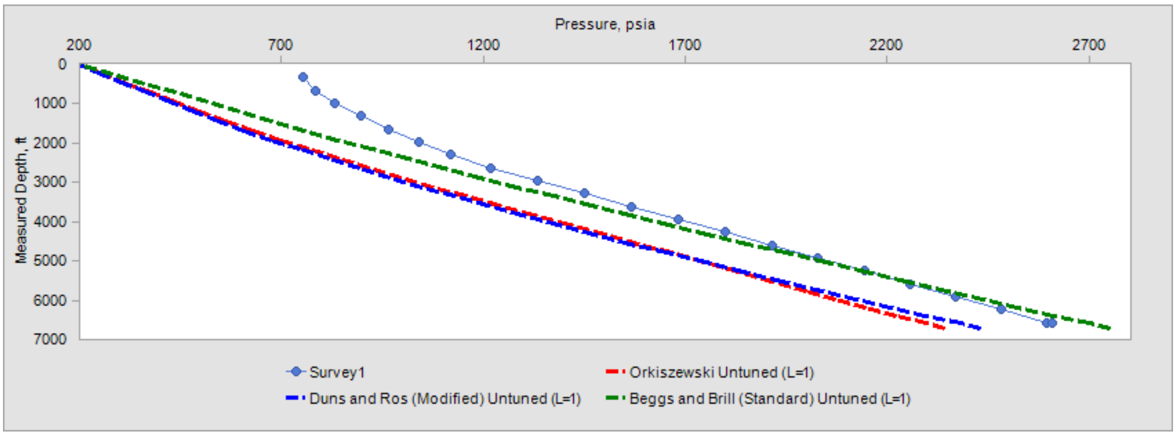

Figure 4-8: Survey profile vs predicted using three models for Well#2

It can be seen from Well#1 figures and Well#2 figures that there is a clear big difference between the predicted pressure drop profile and the pressure survey for Well#1 in comparison with the figures of Well#2. This difference could be due to the water cut value which is 20% for Well#1 and around 80% for Well#2.

From Figure 4-4, it is clear that there is a small difference between Orkiszewski and Duns&Ros predicted profile, although, both showed huge difference from the measured survey data. Comparatively, Orkiszewski seems to give better results in this well under the given conditions. On the other hand, from Figure 4-8, it is found that Beggs &Brill model gave better results, comparatively.

Another key observation from Figure 4-4 is models' predicted results showed bigger deviation from the survey data as we move from the bottom of the well up to the top where all model nearly overlaid with each other and getting closer to the survey profile. In contrast, from Figure 4-8 is can be seen that opposite trend is obtained where the predictions increase deviation as we go up.

In order to have a quantitative comparison, an error analysis was performed as will be shown in the next subsection.

4.1 Error calculations:

The error analysis calculations have been performed using the following equations in order to give an idea of the performance of the three models. The calculations are shown below in Table 4-1.

$$d = \frac{\sum_{i=1}^{N} di}{N} \tag{4.1}$$

$$\sigma = \sum_{i=1}^{N} \sqrt{\frac{(di - d)^2}{N - 1}} \tag{4.2}$$

$$d_a = \frac{\sum_{i=1}^{N} |di|}{N} \tag{4.3}$$

Where:

$$d_i = \frac{\Delta P_{calc} - \Delta P_{meas}}{\Delta P_{meas}} \times 100$$

d=average error

σ=standard deviation

d_a=average absolute error

N=total number of cases considered

ΔP_{calc}=calculated pressure drop, psia

ΔP_{meas}=measured pressure drop for same condition, psia

As discussed earlier in the qualitative comparison, that models' prediction for Well#1 have much higher difference compared with that for Well#2. In order to quantify those differences, we can look at the numerical values for the error analysis. From Table 4-1, considering the average absolute error, it is obvious that this error is higher for Well#1 for all models as opposed to Well#2. For example, Duns and Ros gave 37.12% error for predicting pressure profile of Well#1. Whereas, nearly half of that percentage were obtained for Well#2 which is 16.7%. The same applies for the two models for the two wells.

Although the average absolute error can be considered as high for this particular case study, the smallest errors were found by Beggs and Brill giving about 32.3% for Well#1 and around 14.2% for Well#2. Therefore, Beggs and Brill model outperformed Duns & Ross and Orkiszewski for the two wells studied under the specified conditions.

It is worth mentioning that the reliability and accuracy of the measured data used are extremely important as they can significantly change models' pressure drop calculations (Takacs 2001).

Table 4-1 : Error Analysis calculations for Well#1 and Well#2

Calculation Models		**Well#1**	**Well#2**
Duns and Ros	Average error	-35.705	-13.207
	Standard deviation	28.59679	19.00206
	Average absolute error	37.1203	16.6741
Orkiszewski	Average error	-32.592	-19.532
	Standard deviation	27.81983	16.34423
	Average absolute error	34.3111	19.6328
Beggs and Brill	Average error	-24.469	-6.082
	Standard deviation	32.23982	18.16048
	Average absolute error	32.2547	14.2199

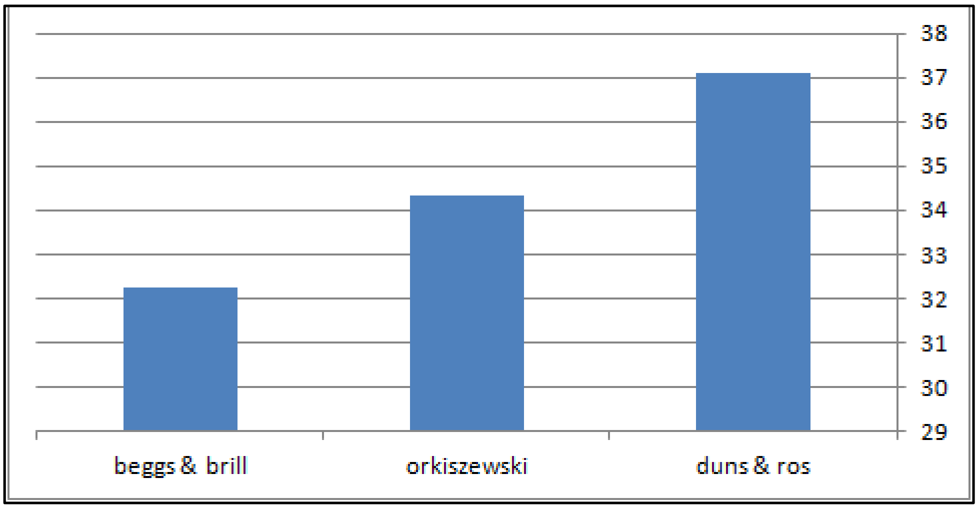

Figure 4-9 Average absolute error for Well#1

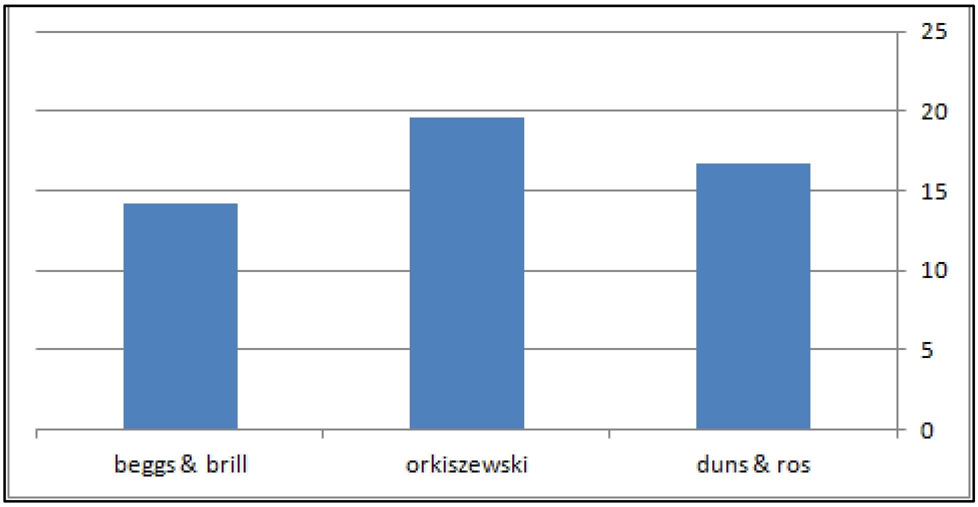

Figure 4-10: Average absolute error for Well#2

Chapter Five

5 Conclusions and Recommendations

The aim of the present study is to investigate the expected accuracies of three models as there is no multiphase pressure drop calculation model which can result in the same accuracy for all the possible conditions. For practical purposes, we need to apply the model which results in the least calculation error.

Steady state simulations for two wells using a commercial software have been conducted. It has been found that there is a clear big difference between the predicted pressure drop profile and the pressure survey for Well#1 in comparison with that for Well#2. This difference is possibly due to the huge water cut difference which is 20% for Well#1 and 80% for Well#2. It has been found also that the smallest errors were obtained by Beggs and Brill model despite the fact that the average absolute error is high for this particular case. Therefore, Beggs and Brill model outperformed Duns & Ross and Orkiszewski for the two wells studied under the specified conditions.

From the study, it is recommended to perform a comparative study amongst pressure drop correlations and models at an early stage of production and to ensure the dates of the survey data at hand. This comparative study will help selecting the optimum model for the specific filed under study or development based on the least error gained.

For further studies, we recommend the following:

- Uses as many wells as possible to enhance the study and hence the calculations
- Using survey data obtained within the same period as the production data.
- Applying the study for wells producing from the same reservoir.
- Perform a sensitivity analysis to determine the effect of some influential parameters, e.g., water cut.

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Appendix A

Table A 1: Pressure survey data for the two wells

Well#1		Well#2	
Pressure, psia	MD, ft	Pressure, psia	MD, ft
2207.93	7381.89	2607.09	6594.49
2190.96	7207.91	2595.45	6561.68
2173.99	7033.92	2483.91	6233.6
2157.02	6859.94	2370.98	5905.51
2140.05	6685.95	2257.37	5577.43
2123.08	6511.97	2143.51	5249.34
2106.11	6337.99	2029.15	4921.26
2089.14	6164.00	1914.37	4593.18
2072.18	5990.02	1799.48	4265.09
2055.21	5816.03	1683.98	3937.01
2038.24	5642.05	1568.21	3608.92
2021.27	5468.07	1451.64	3280.84
2004.30	5294.08	1334.86	2952.76
1987.33	5120.10	1217.36	2624.67
1970.36	4946.11	1118.51	2296.59
1953.39	4772.13	1038.84	1968.5
1936.42	4598.15	965.5	1640.42
1919.45	4424.16	896.43	1312.34
1902.49	4250.18	833.49	984.25
1885.52	4076.20	785.32	656.17
1868.55	3902.21	752.71	328.08
1851.58	3728.23		

1834.61	3554.24		
1817.64	3380.26		
1800.67	3206.28		
1783.70	3032.29		
1766.73	2858.31		
1749.76	2684.32		
1732.79	2510.34		
1715.83	2336.36		
1698.86	2162.37		
1681.89	1988.39		
1664.92	1814.40		
1647.95	1640.42		

Appendix B

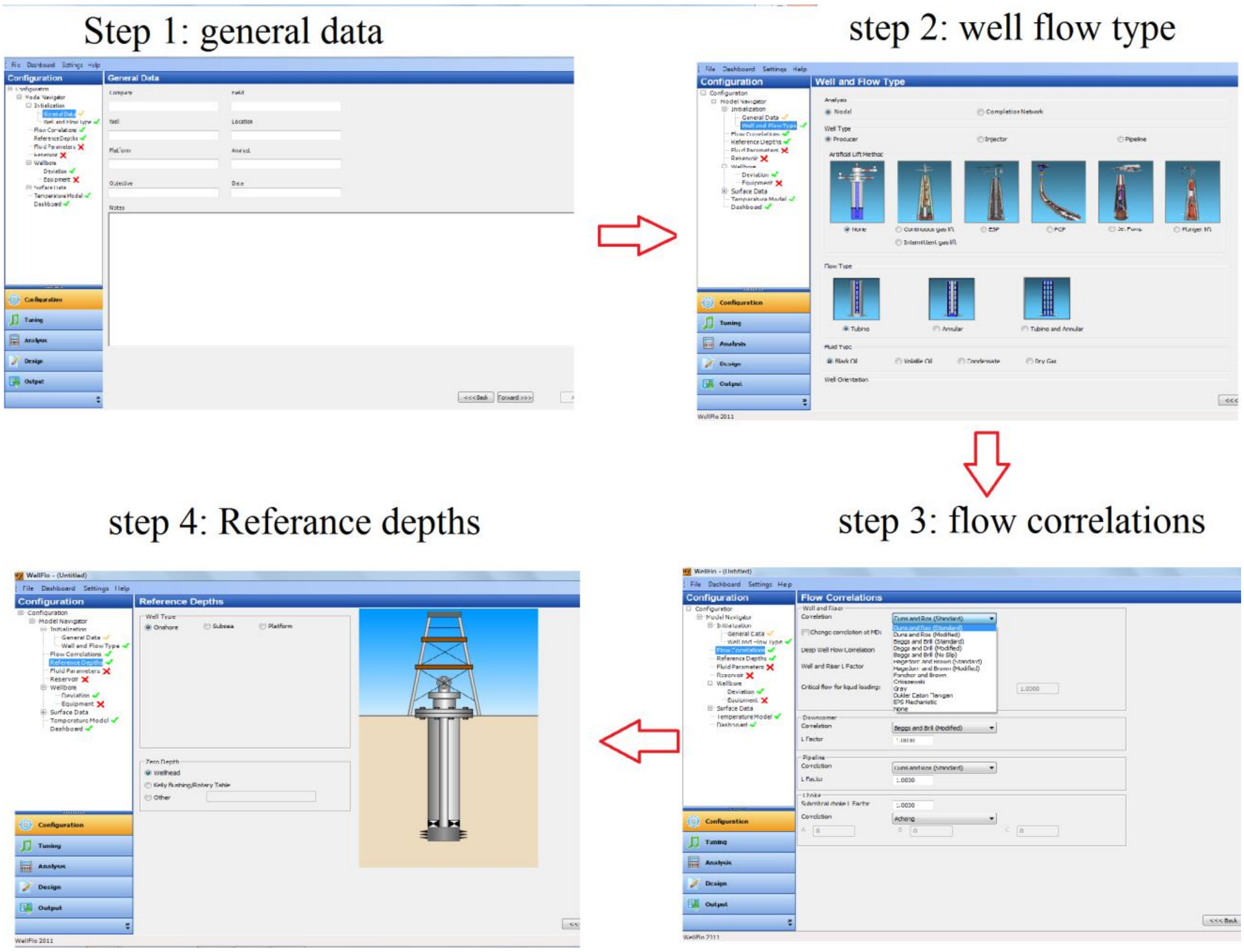
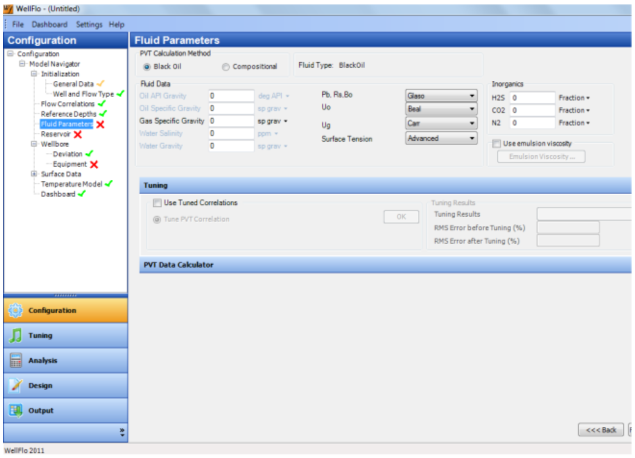
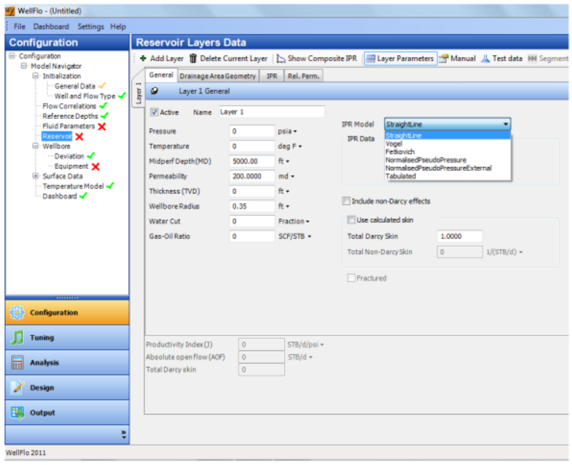


Figure B- 1

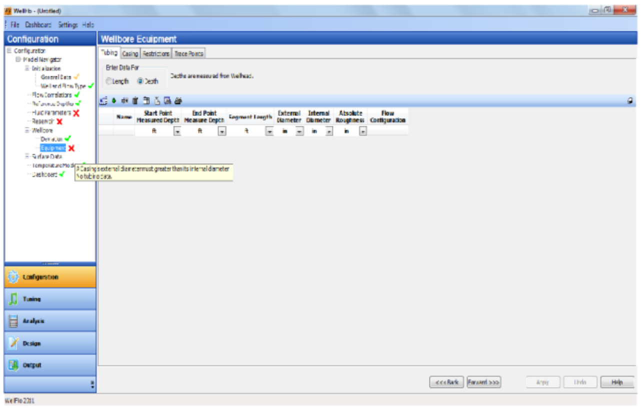
step 5:fluid parameters



step 6: Reservoir data



step 8: wellbore equipment data



step 7:wellbor deviation

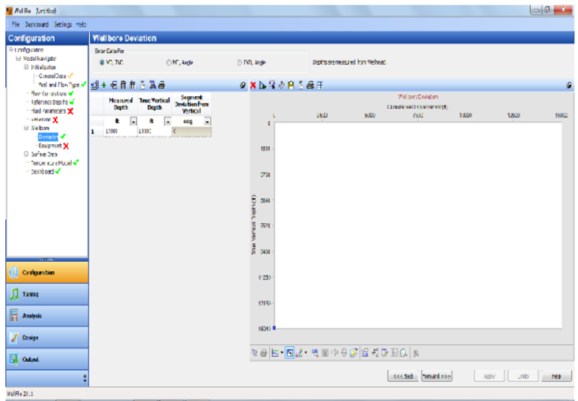


Figure B- 2

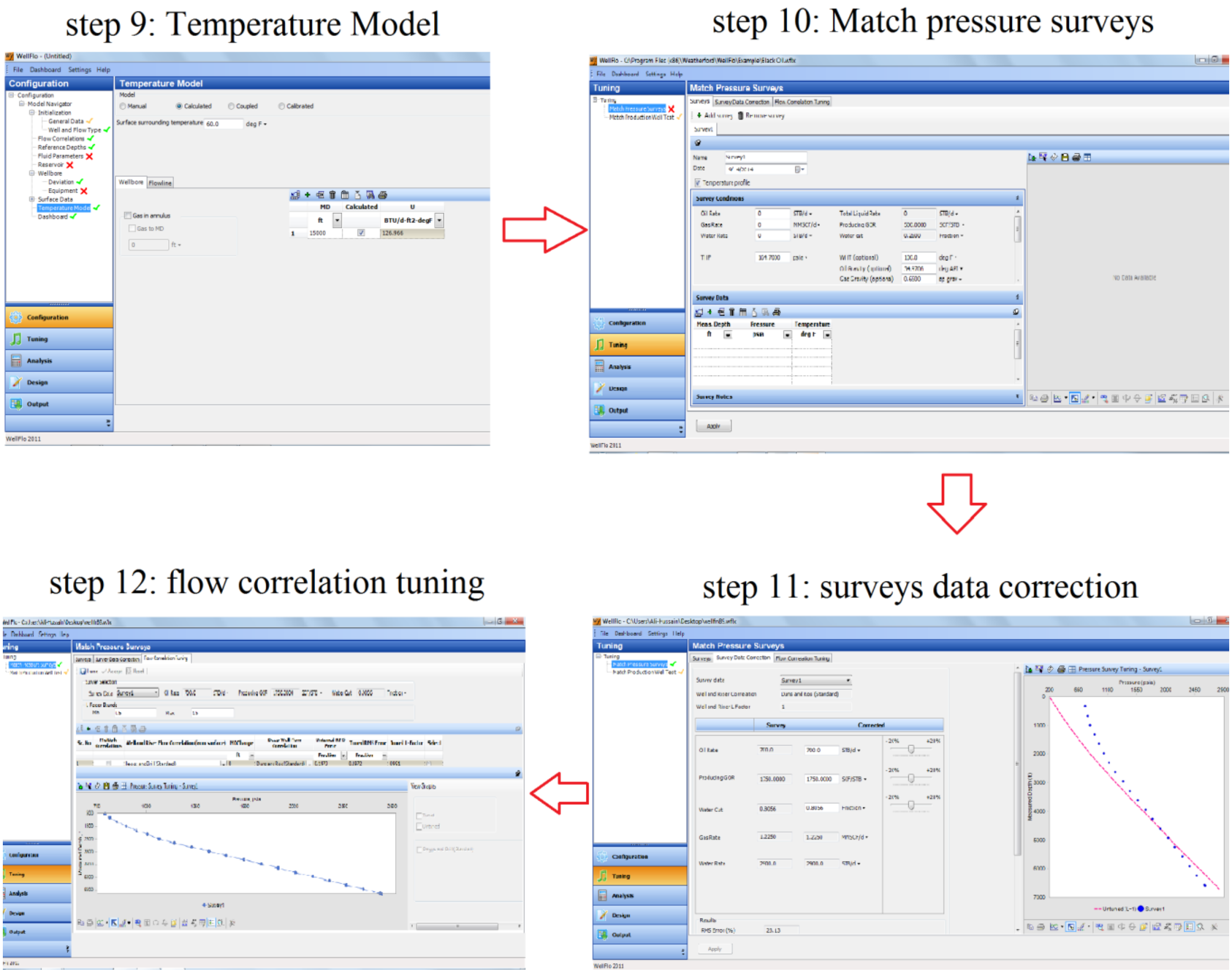

step 9: Temperature Model
step 10: Match pressure surveys
step 11: surveys data correction
step 12: flow correlation tuning

Figure B- 3