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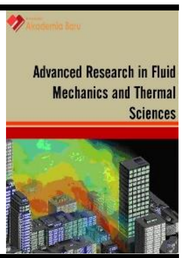

Effect of Flow Patterns on Two-Phase Flow Rate in Vertical Pipes

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ABSTRACT

During two-phase gas-liquid flow in pipelines, the fluids may take up different flow patterns. The exact nature of the flow pattern varies according to conduit size and geometry, fluids' properties, and each phase's velocity. When the conduit size and fluid properties are constant, then any changes in individual flow rates will result in changes to the flow regime. Predicting the flow patterns within a pipe is essential as it is a critical parameter that determines the pressure gradient and liquid holdup in the conduit. This paper presents the results in predicting the multiphase flow patterns and their effects on flow measurements in vertical pipes. The study was conducted on vertical upward multiphase flow using well and reservoir properties. OLGA dynamic simulator was used to predict flow pattern in a vertical pipeline for 35 oil wells using electrical submersible pumps (ESP) with external pipe diameters of 3.5 inch. The predicted oil flow rates of 35 ESP oil wells were compared with measured flow rates and a good agreement was observed. Indeed, the results indicated that the variation of the flow pattern had insignificant impact and it was insensitive to the accuracy of the flow rate values of the ESP oil wells where the average overall flow rates accuracy was lower than +/-10%. Additionally, simulation results demonstrated a promising model performance and showed the magnitude of possible variation between the oil rates measured with different methods.

Keywords:
Electrical Submersible pumps, Multiphase flow, flow pattern, slug flow, bubble flow, annular flow

1. Introduction

Field engineers and researchers alike have increasingly focused on the measurement of flow rates in multiphase situations and the identification of the flow regime present in production wells. New techniques in petroleum refining and production have added to recent interest in flow regimes [1]. Accurate prediction of the flow pattern, pressure drop and liquid holdup is imperative for the design of production systems and for the maintenance and operation of the downstream facilities. The variables that affect flow behavior include pipe diameter, liquid/gas flow rates, angle of inclination, and properties of the flowing materials [2]. Several researchers presented flow pattern maps based

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on their investigations using conventional ways to determine the flow regimes. However, these maps cannot be used with high confidence for all types of fluids and conditions that may be encountered in oil and gas field production systems. Therefore, there are many studies on the flow pattern in vertical and horizontal multiphase flows. Two research teams, [3-5], experimented with air–oil mixes within horizontal pipes with internal diameters of 50.8 mm. The oil viscosity of about 200 cp - 600 cp was manipulated through variations in temperature. Based on such experimentation, Gokcal [4] put forward new correlations for slug frequency and Taylor bubble. The correlation from Kora *et al.,* [3] centered on void fraction in slugs. Smith *et al.,* [6] used a larger horizontal pipe with an internal diameter of 69 mm and a length of 52 m, as well as oils with viscosities of 2 cp and 100 cp. As a result, Kora [3] and Gokcal [4] found larger slug flow regions than Smith; higher gas density was probably the cause for this discrepancy. Pan *et al.,* [7] used multiple ring type impedance sensors (non-intrusive type) for the identification of both upward air–water multiphase flow. They have identified bubbly, slug, annular and churn–turbulent flow regimes. Jeyachandra *et al.,* [8] proposed yet another correlation for the slug drift velocity as a function of pipe diameter and viscosity using same flow loop as the one used by Kora [3] and Gokcal [4]. Additional studies on high viscosity liquids can be found in several works [9-11]. It is important to note that experimental conditions do not reflect industrial high-pressure natural gas conditions because the experiments made use of low pressure nitrogen as their gas phase. Zubir and Zainon's [12] experiment showed that the flow pattern transition and void fraction performed as a function of the gas/liquid superficial velocity. Moreover, the flow pattern transition also strongly depended on the liquid viscosity [13]. Vieira *et al.,* [14] predicted various flow features using dual wire-mesh sensor and statistical analysis of the signals. Identification of flow regimes through visualization of the flow field was performed by some of the investigators. Simultaneous concurrent flows of gas and liquid through vertical tubes in the upward direction as well as through horizontal tubes are very common in industrial practice and have been studied most extensively [15]. Vertical up-flow presents four basic flow regimes, namely, bubbly, slug, churn, and annular. A large number of efforts have been made to identify the flow regimes during both gas-liquid up-flow and horizontal flow [16].

Increasingly sophisticated flow simulation models have been developed to meet the needs of operators as they open new frontiers. Computational fluid dynamic (CFD) models are important tools used for the analysis of complex multiphase flow phenomena and their impact on the operation and initial design of oil and gas fields. These models are vital for helping production engineers to understand and to predict the flow regime, pressure drop and liquid holdup at any flow conditions. A model was proposed where a special focus was given to gas compressibility and its effect on slug generation, dissipation, and growth [17]. Fagundes, Netto *et al.,* [18] took yet another approach. Their model contained a bubble shape calculation that involved conservation of mass as well as conservation of momentum for a bubble's body, tail, and nose and for a hydraulic jump at the rear of the bubble. Alternate approaches of modeling flow regime transition through CFD have also been proposed by few researchers [19]. Models that track slugs use empirical correlations for the modeling of specific slug characteristics. The commercial program OLGA is a prime example of such a model in action [20]. The approach favored by Zheng *et al.,* [21] employed slug tracking to predict growth, dissipation, and generation of each individual slug. Similarly, Barnea and Taitel [22] employed slug tracking that also analyzed slug length distribution. Nydal and Banerjee's [23] approach to slug tracking used an object-oriented Lagrangian method for dynamic gas–liquid slug flow where individual bubbles and slugs became discrete computational objects, tracked within linked lists. For several decades, research has focused on the dynamics of liquid-gas flows. These multiphase flows can be simulated in many ways, from continuum-based models requiring a considerable number of closure relationships [24] to direct model-free numerical simulations (DNS) [25].

This paper highlights the impact of the type of flow regimes in vertical pipes on the fluid flow measurements at the wellhead using an OLGA simulation model to simulate the actual well flow performance under the uncertainties of many well input data measurements. The OLGA multiphase simulation model was used to mimic the multiphase flow regime in a vertical pipe and also to validate the predicted oil flow rate with the measured oil flow rate of 35 ESP oil wells. The well model was built based on each well production operation conditions.

2. Methodology

The simulation was performed on 35 ESP oil wells from different oil fields (G, W, and D oil fields), located in North African region, to study the impact of the velocities of gas and liquid, and the water cuts on pressure gradients and flow patterns. The study was performed for wells having the following range properties; water cut (0% - 90%), viscosity (0.896 cp - 1.03 cp), API gravities (22.8°-58.6°), and gas oil ratio (300 scf/stb - 400 scf/stb). OLGA software is used for an initial estimation of an ESP well model to simulate the types of flow regimes existing in the vertical pipe riser.

2.1 Well Path Profile

The OLGA models employ GOR, liquid and gas production, water-cut percentage, and oil gravity, with the other parameters being obtained from the PVT data. The ESP pump operations condition was defined in OLGA based on each well completion data. Figure 1 shows the entire well path that was contained in input file data such as wellhead data, pump data, well casing strings data, tubing string data, and reservoir data. OLGA must be fed fluid property descriptions as a unique function of variations in pressure and temperature.

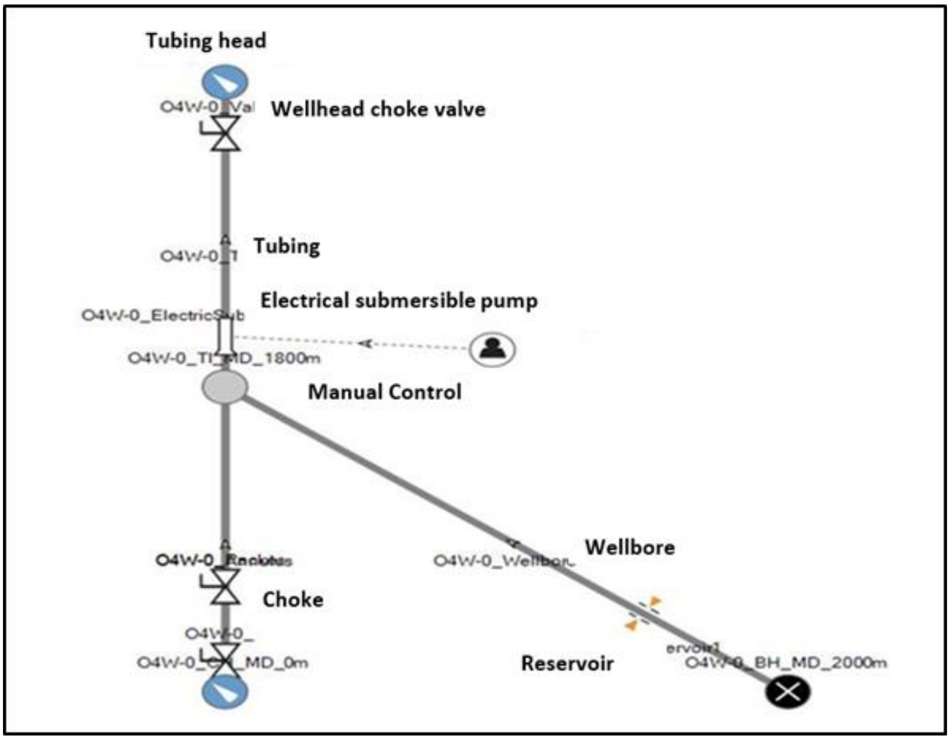

Fig. 1. OLGA well path profile

2.2 OLGA Mechanistic Model

Most multiphase flow predictions, including void fraction predictions, depend on correct flow regime identification. The methodology presented holds considerable promise for multiphase flow diagnostic and measurement applications. Gas-Liquid phases are introduced at their respective inlets. The superficial velocities of oil, gas, and water, corresponding to the given experimental conditions, were set as inlet conditions. The computation assumed an immiscible liquid pair and an unsteady flow. The time step used in the following computations is 0.001s. The main source of high volume error peaks is the change of phase velocity direction from one time step to the next and thus the volume flow and velocities may have opposite directions. The volume error is corrected by adding or subtracting fluid volume over several time steps (not by iteration). Therefore, the choice of a small time step of 0.001s will compute more accurate volume flow and velocities for each single phase flow.

The control volume was the basis for the equations' integration and the conservation of parameters (velocity and pressure) was attained by solving the continuity and momentum equation set. The simulation models within the dynamic multiphase flow simulator include continuity equations for the three fluid phases: a gas phase; a liquid phase consisting of oil, condensate or water; and a liquid droplet phase consisting of hydrocarbon liquid-oil or condensate dispersed in water. These continuity equations are coupled through interfacial friction, interfacial mass transfer and dispersions such as oil in water. OLGA offers the advantage of flexibility in the choice of schemes for discretization of each individual governing equation. Once the equations were discretized, it was possible to solve them, using the boundary and initial conditions, with a segregated solution method in order to arrive at a numerical solution.

Prediction of the Gas-Liquid flow behavior in a vertical pipe is performed with the Eulerian model. With this method, the model contains two continuous, inter-penetrating media that represent the two present phases. The continuous phase is considered to be the first and the dispersed phase is considered to be the second. The volume fractions represent the quantities of the first and second phases, with both being linked within the momentum equation. Then all the equations mentioned below are solved in OLGA multiphase simulation model.

This simulation solves three separate continuity equations for gas, liquid droplets, and liquid bulk, coupled through interfacial mass transfer.

Conservation of liquid phase is given by Eq. (1):

$$\frac{\partial}{\partial t}(\mathrm{V_L}\rho_\mathrm{L}) = \frac{1}{A}\frac{\partial}{\partial z}(\mathrm{A\,V_L}\rho_\mathrm{L}v_\mathrm{L}) - M_\mathrm{g}\frac{\mathrm{v_L}}{\mathrm{v_L+v_D}} - M_e + M_d + G_l \tag{1}$$

Conservation of the liquid droplets is given by Eq. (2):

$$\frac{\partial}{\partial t}(\mathrm{V_L}\rho_\mathrm{L}) = \frac{1}{A}\frac{\partial}{\partial z}(\mathrm{A\,V_D}\rho_\mathrm{L}v_\mathrm{D}) - M_\mathrm{g}\frac{\mathrm{v_D}}{\mathrm{v_L+v_D}} + M_l - M_d + G_D \tag{2}$$

Conservation of the gas phase is given by Eq. (3):

$$\frac{\partial}{\partial t}(\mathrm{V_g}\rho_\mathrm{g}) = \frac{1}{A}\frac{\partial}{\partial z}(\mathrm{A\,V_g}\rho_\mathrm{g}v_\mathrm{g}) + M_\mathrm{g} + G_\mathrm{g} \tag{3}$$

where V_L, V_D, and Vg are the volume factions for the liquid-film, liquid droplet, and gas respectively, v is velocity, p is pressure, A is pipe cross-sectional area, and ρ is density. M_g is Mass-transfer rate between the phases, M_e, M_d are the entrainment and deposition rates, and G_f is possible mass source of phase f. Subscripts g, L, i, and D indicate gas, liquid, interface, and droplets, respectively. An incompressible liquid and a compressible gas are assumed. The gas obeys the ideal-gas equation. To simplify the equations, an isothermal flow is assumed.

Momentum is conserved across three fields, which yields separate 1D equations for momentum, corresponding to the gas, liquid droplets, and liquid bulk.

For the liquid droplets,

$$\frac{\partial}{\partial t}(\mathrm{V_D}\rho_L v_D) = -V_D\left(\frac{\partial p}{\partial z}\right) - \frac{1}{A}\frac{\partial}{\partial z}(A\,\mathrm{V_D}\rho_L v_D^2) + V_\mathrm{D}\rho_L \mathrm{g}\cos\theta - M_\mathrm{g}\frac{\mathrm{v_D}}{\mathrm{v_L}+\mathrm{v_D}}v_a + M_e v_i - M_d v_D + F_D{}' \quad (4)$$

For the gas phase,

$$\frac{\partial}{\partial t}(\mathrm{V_g}\rho_g v_g) = V_g\left(\frac{\partial}{\partial z}\right) - \frac{1}{A}\frac{\partial}{\partial z}(A\,\mathrm{V_g}\rho_g v_g^2) - \lambda_\mathrm{g}\frac{1}{2}\rho_\mathrm{g}|v_g|v_\mathrm{g}\times\frac{S_\mathrm{g}}{4A} - \lambda_\mathrm{i}\frac{1}{2}\rho_\mathrm{g}|v_r|v_r\frac{S_\mathrm{i}}{4A} + \mathrm{V_g}\rho_\mathrm{g}\mathrm{g}\cos\theta + \mathrm{M_g}\,v_a - \mathrm{F_D} \quad (5)$$

Eq. (4) and Eq. (5) were used to generate a momentum equation, where the gas/droplet drag terms, $\mathrm{F_D}$, cancel out,

$$\frac{\partial}{\partial t}(\mathrm{V_g}\rho_g v_g + \mathrm{V_D}\rho_L v_D) = -(V_g + V_D)\left(\frac{\partial p}{\partial z}\right) - \frac{1}{A}\frac{\partial}{\partial z}(A\,\mathrm{V_g}\rho_\mathrm{g} v_g^2 + A\,\mathrm{V_D}\rho_L v_D^2) - \lambda_\mathrm{g}\frac{1}{2}\rho_\mathrm{g}|v_g|v_\mathrm{g}\frac{S_\mathrm{g}}{4A} - \lambda_\mathrm{i}\frac{1}{2}\rho_\mathrm{g}|v_r|v_r\frac{S_\mathrm{i}}{4A} + (\mathrm{V_g}\rho_\mathrm{g} + V_\mathrm{D}\rho_L)\,\mathrm{g}\cos\theta + M_g\frac{\mathrm{v_L}}{\mathrm{v_L}+\mathrm{v_D}}v_a + M_e v_i - M_d v_D \quad (6)$$

For the liquid at the wall,

$$\frac{\partial}{\partial t}(\mathrm{V_L}\rho_L v_L) = -V_L\left(\frac{\partial p}{\partial z}\right) - \frac{1}{A}\frac{\partial}{\partial z}(A\,\mathrm{V_L}\rho_L v_L^2) - \lambda_\mathrm{L}\frac{1}{2}\rho_\mathrm{L}|v_L|v_\mathrm{L}\frac{S_\mathrm{L}}{4A} + \lambda_\mathrm{i}\frac{1}{2}\rho_\mathrm{g}|v_r|v_r\frac{S_\mathrm{i}}{4A} + \mathrm{V_L}\rho_\mathrm{L}\,\mathrm{g}\cos\theta - M_g\frac{\mathrm{v_L}}{\mathrm{v_L}+\mathrm{v_D}}v_a - M_e v_i + M_d v_D - V_L d(\rho_\mathrm{L} - \rho_\mathrm{g})\mathrm{g}\frac{\partial V_L}{\partial z}\sin\theta \quad (7)$$

where Θ is pipe inclination with the vertical and S_g, S_L, and S_i are wetted perimeters of the gas, liquid, and interface, respectively.

The above equations are applicable to all flow regimes. However, some of these terms are not needed to represent certain flow regimes. For example, in slug flow, also known as dispersed bubble flow, there is no need for droplet terms.

Simulations were run under steady-state conditions, assuming that any condition in which produced fluids were flowing in a fairly uniform and uninterrupted manner through the wellbore and vertical pipe. A number of transient simulations were also run to determine how the production stream would react to dynamic situations that included startup, shutdown, and initial well ramp up.

The entire equations are grouped in subsets according to the characteristics or properties of the equations. The subsets are solved in stages, one stage followed by the next at the same time step. The stages are coupled together explicitly at the time step. The equations are solved numerically using iterative techniques. Figure 2 shows the flow chart of the solving multiphase flow models using OLGA simulation model.

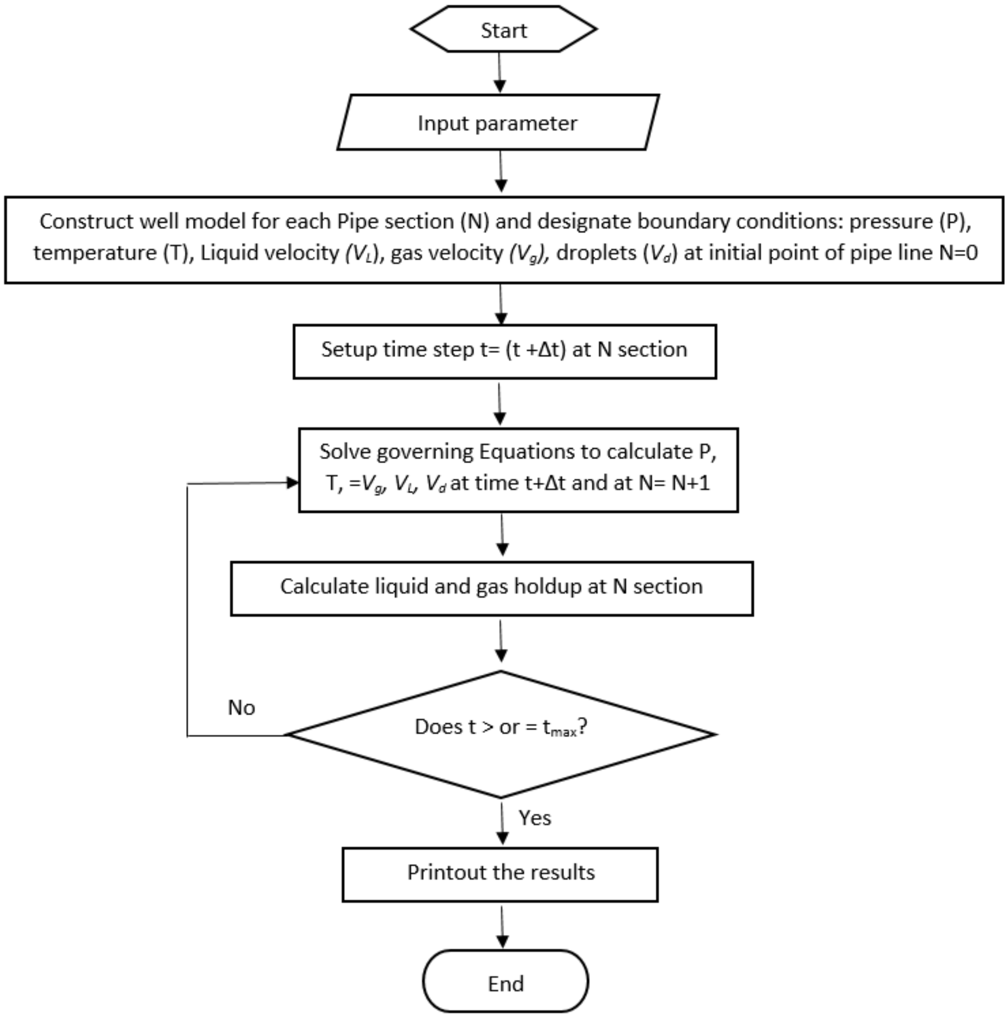

Fig. 2. Flowchart of solving multiphase flow models using OLGA simulation model

3. Results

3.1 Predicted Flow Regimes

In order to mimic the multiphase flow regime in vertical pipe and also to validate the predicted oil flow rate with the measured oil flow rate of the ESP oil wells, simulation model has been carried out for 35 ESP oil wells. The well models were built based on each well production operations conditions. The models were validated by an OLGA-generated flow regime profile plot, as seen in Figure 3. The figure shows a bubble flow regime at the inlet (4) that changed to a slug flow regime as the fluid travelled along the vertical pipe riser (3), and then changed to annular flow (2) at the top of the pipe close to the wellhead. This finding agrees with Bratland [26] who stated that stratified flow is impossible in vertical pipes due to the impossibility of liquid or gas phase to flow in the lower part of the pipe. However, low flow rates in vertical pipes will provide a bubbly flow of which buoyancy is the driving force. In addition to slug flow, dispersed bubble flow and annular flow, churn flow is a usual flow regime in vertical pipe flow.

Since OLGA only has 4 flow patterns: annular flow, slug flow, stratified flow and bubble flow, it is assumed that OLGA identifies both slug flow and churn flow as slug flow.

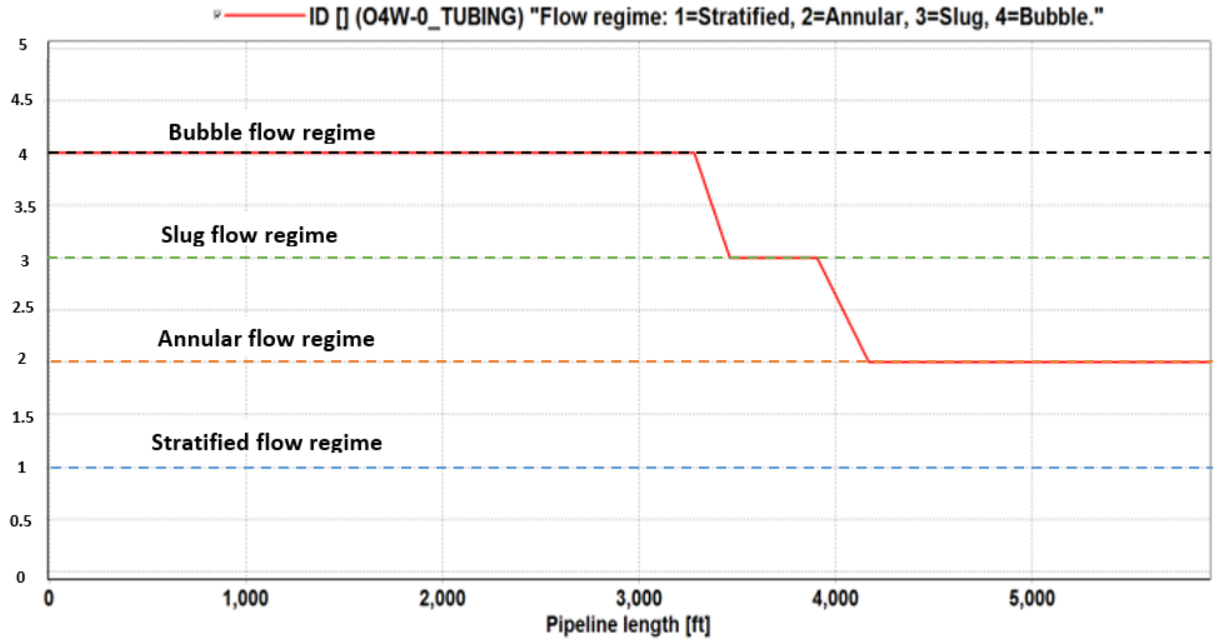

Fig. 3. Example of flow regimes observed in all wells (bubble (4), slug (3) and annular (2))

Figure 4 shows the type of flow regimes observed in the vertical pipe of the ESP oil wells where the majority of the wells demonstrated bubble and slug flow regime in the vertical pipe. About 5 wells show only bubble, slug, and annular flow regime. The flow map was an attempt to answer if it is possible to determine the type of flow regime from available flow data and determine the flow regime type with certain accuracy. The flow map indicates the most likely flow regime for each well parameters such as transport properties of gas and liquid (density difference, viscosity, related to the Reynolds number, and surface tension), geometry scales and pipe roughness, mass, and volume fractions in pipes and velocity ratio between phases. Besides, the map identified the existence of either two flow regimes or three flow regimes for each single ESP well flow model, where most of the well flow conditions are similar. Therefore, the accuracy to mimic the actual flow regime in the vertical pipe is still uncertain, despite the predicted flow rates of all ESP wells are close to the measured one.

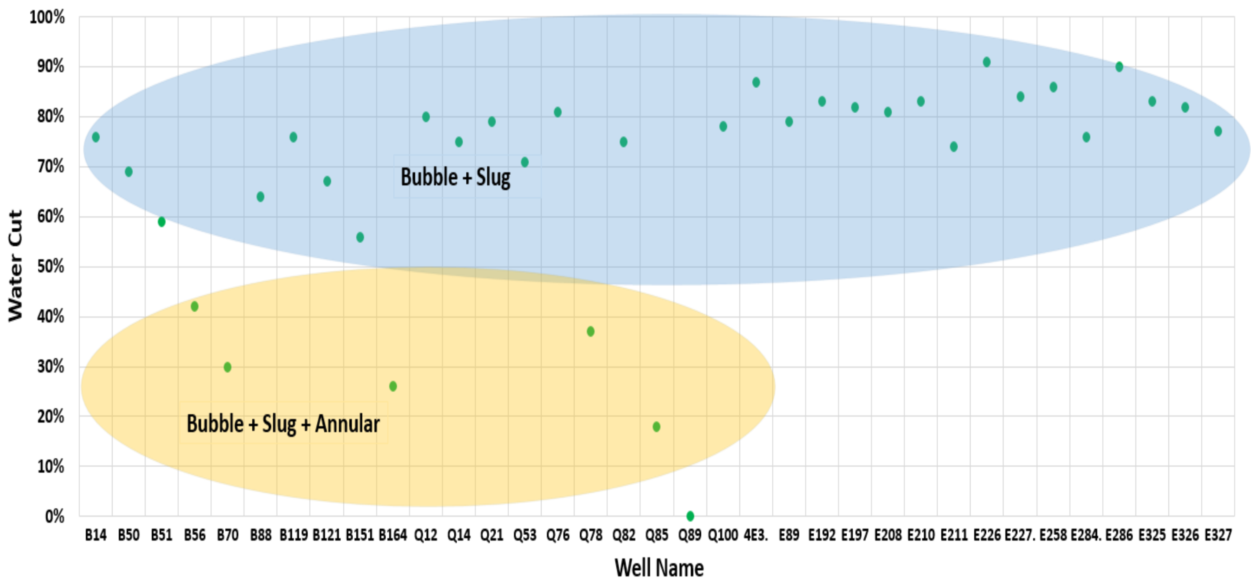

Fig. 4. Types of flow regime observed in the vertical pipe of ESP oil wells

3.2 Predicted Oil Flow Rate

Table 1 shows all the ESP oil wells and types of flow regime observed in the vertical riser pipe, and the percentages of flow rate accuracies between the calculated oil rate values and measured values for the 35 ESP oil wells. The flow rate of each ESP oil well was measured using a test separators process.

For the purpose of conveniently observing how close the OLGA predicted and the test separator measured flow rates, the results listed in the Table 1 are shown in Figures 5 and 6. The results showed a good agreement between the measured and predicted oil flow rates as shown in Figure 5. Indeed, the plotted data points are very close to the 45° straight line, drawn on the cross plot of these values, pointing to the good accuracy of the OLGA predicted oil flow rates. The latter displayed small average relative error values of ± 10%, with a high R- square value (R^2) of 99.6%, indicating that the process is satisfactory for describing the data.

Table 1
Flow pattern and flow rate accuracy of 35 ESP wells

Well	Type of Flow Pattern			Measured Oil Rate (STB/D)	Calculated Oil Rate (STB/D)	Accuracy
B14	Bubble			921	920	-0.1%
B50	Bubble			1160	1177	1.5%
B51	Bubble			1916	1926	0.5%
B56	Bubble	slug		352	394	11.9%
B70	Bubble	slug		552	547	-0.9%
B88	Bubble	slug		316	318	0.6%
B119	Bubble	slug		382	387	1.3%
B121	Bubble	slug		1133	1141	0.7%
B151	Bubble	slug		1017	1025	0.8%
B164	Bubble	slug		790	797	0.9%
Q12	Bubble	slug		689	689	0.0%
Q14	Bubble	slug		311	296	-4.8%
Q21	Bubble	slug		199	206	3.5%
Q53	Bubble	slug		263	262	-0.4%
Q76	Bubble	slug		312	311	-0.3%
Q78	Bubble	slug	Annular	560	560	0.0%
Q82	Bubble	slug		725	727	0.3%
Q85	Bubble	slug	Annular	540	540	0.0%
Q89	Bubble	slug	Annular	450	461	2.4%
Q100	Bubble	slug		590	581	-1.5%
4E3.	Bubble	slug		396	424	7.1%
E89	Bubble	slug		924	908	-1.7%
E192	Bubble	slug		348	374	7.5%
E197	Bubble	slug		604	691	14.4%
E208	Bubble	slug		892	816	-8.5%
E210	Bubble	slug		404	495	22.5%
E211	Bubble	slug		319	312	-2.2%
E226	Bubble	slug		248	259	4.4%
E227.	Bubble	slug		532	514	-3.4%
E258	Bubble	slug		368	376	2.2%
E284.	Bubble	slug		616	706	14.6%
E286	Bubble	slug		284	288	1.4%
E325	Bubble	slug		380	398	4.7%
E326	Bubble	slug		228	213	-6.6%
E327	Bubble	slug		477	511	7.1%

Generally, OLGA software simulated the type of flow pattern in a vertical pipe to optimize the accuracy of the well flow rate values at different flow regime. The relation between the accuracy of flow rate value and type of flow regimes in the well riser pipe was investigated. Figure 6 shows the accuracy of predicted oil flow rate values versus the measured values for each ESP oil well. The overall well flow rate average accuracy showed lower than +/-10%. It means an average relative error band of ±10%, the 89% of total number of the ESP oil wells, have been correctly predicted the oil flow rate. This study demonstrated that the effect of the flow regime in the vertical pipe has minor impact on the well flow rate measurements of the ESP oil wells.

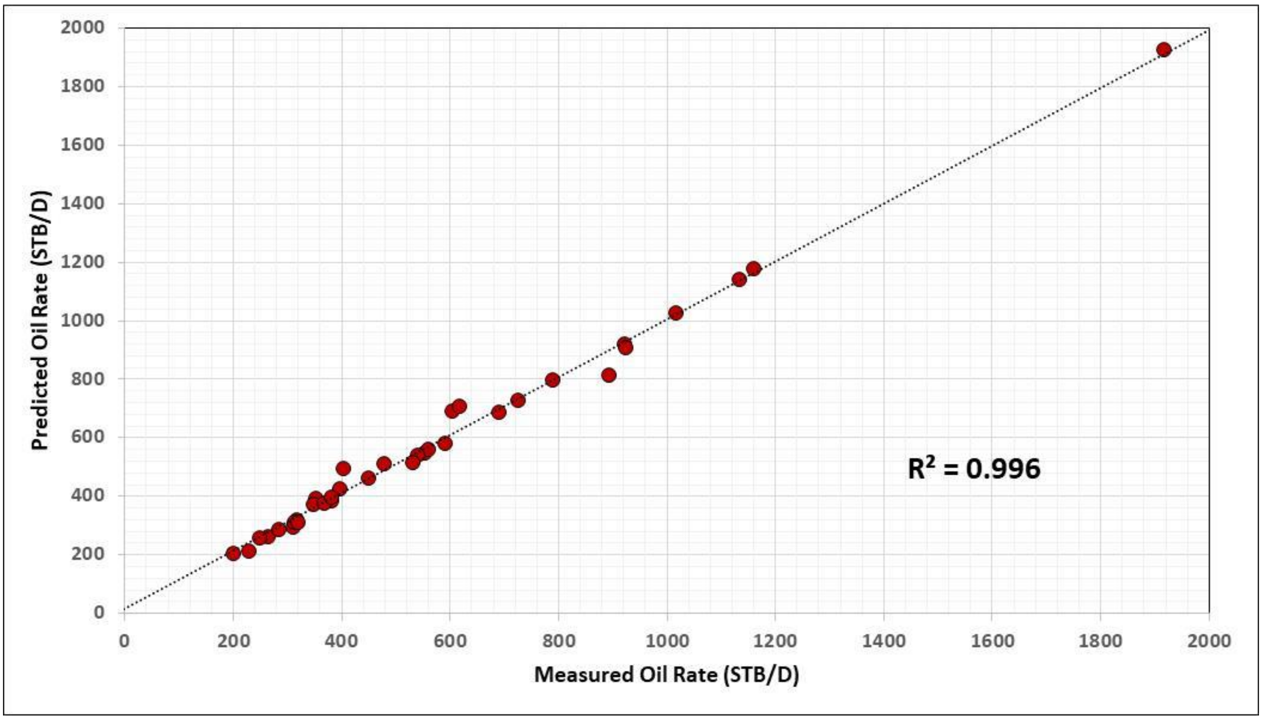

Fig. 5. Comparison between predicted and measured oil flow rates

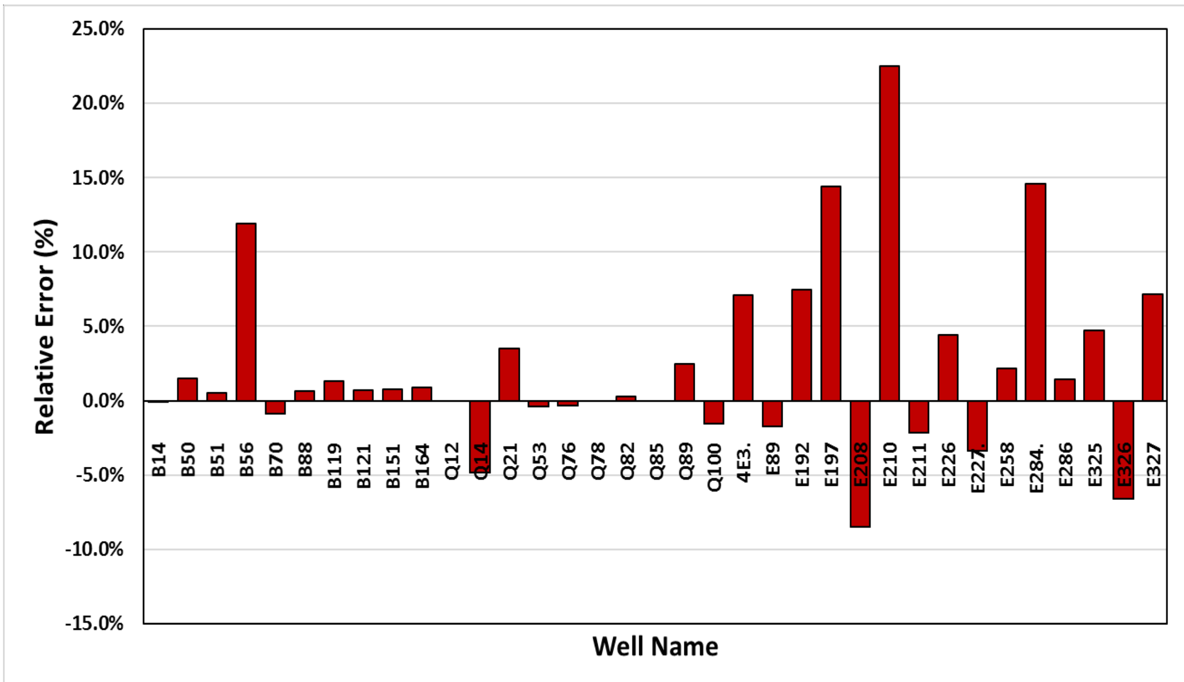

Fig. 6. Accuracy of calculated and measured oil flow rates

3.3 Discussion

To predict and analyze the flow patterns, the mechanism that causes the change of flow pattern must be understood and established. Multiphase flow patterns are very sensitive to pipe parameters, such as pipe orientation and diameter. The flow patterns that were observed were highly dependent on liquid velocities, gas velocities, and water fraction. Three flow patterns were observed: bubble, slug, and annular flow. These flow types demonstrate that the flow pattern will change as the water cut gradually changes from oil-dominated to water-dominated or from water-dominated to oil-dominated. Flow regimes significantly affect fluid distribution that in turn significantly affects the pressure gradient within the tube. These flow regimes progress proportionately to the increased gas flow rate for each ESP oil well.

The flow regime categorized the flow into either bubble flow, slug flow, or annular flow and the different flow regimes will occur due to different compositions of gas and liquid as well as the change in their velocities. Among the 35 ESP oil wells, the existence of bubble flow was predicted for 3 oil wells. Another 3 wells exhibited bubble-slug-annular flow while the remaining 29 wells were predicted to have bubble-slug flow.

According to Bendiksen *et al.,* [27], the flow regimes in OLGA are treated with separate flow regime maps as functions of void fractions and mass flow only. The approach of determining flow regimes are treated as an integrated part of the two-fluid system, where the correct flow regime, as a function of the average flow parameters, is required for flow regime prediction. Two basic flow regime classes are applied, namely distributed and separated where the first contributes to bubble and slug flow and the latter includes annular flow. The transition between distributed and separated flow regimes is based on the assumption of continuous average void fraction which means the flow regime yielding when the minimum gas velocity is chosen.

4. Conclusions

In this paper, OLGA simulation model was presented with emphasis on the particular multiphase flow model applied and the flow regime description. The results indicated that the variation of the flow pattern has an insignificant impact on the accuracy of the flow rate values of the ESP oil wells. Indeed, a comparison of the predicted flow rates with the measured oil flow rates of the 35 ESP oil wells showed that the average overall flow rate accuracy is lower than +/-10%. The cross plot of both values demonstrated a positive correlation of the actual oil rate values when compared with the predicted values.

The computational model and results discussed in this study demonstrated a promising model performance and its usefulness in explaining the implications that local flow patterns have on the measured oil flow rate and extending the applications of CFD models for simulating the flow regime in the vertical pipe of the ESP oil wells.

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