CHAPTER II

LITERATURE REVIEW

In this chapter, some of the published multiphase flow correlations, publication of some new multiphase flow models, extension or modification of some published multiphase flow correlations and models, and evaluation, analyzing of some published multiphase flow correlations and models have been reviewed as follows.

In 1952, a semi-empirical method developed from an energy balance was proposed by Poettmann and Carpenter[10]. Their correlation is based on actual pressure measurements from field wells. Accurate predictions from this correlation are limited to high flow rates and low gas-liquid ratios. In their correlation, the gas-liquid ratio and the viscosity were omitted. The viscosity was justifiably omitted since their data was in the highly turbulent flow region for both phases, and most wells fall in this category. The gas-liquid ratio was incorporated to some extent in the gas-density term.

In 1954, Gilbert[11] presented numerous pressure gradient curves obtained from field data for various flow rate and gas-liquid ratios for the determination of optimum flow strings. However, no method was presented for predicting pressure gradients except by comparison to these curves.

Baxendell *et al.*[12] proposed a method based on Poettmann and Carpenter's procedure for high-rate flowing wells in 1961. Their method involved establishing a new energy-loss-factor correlation to cover high flow rate and, also, some adaptation of the method to permit mechanized calculation using punch-card machines.

The concept of "two-phase friction factor" and "two-phase Reynolds' number function" was developed and successfully applied to correlate horizontal multiphase flow by Bertuzzi, Tek and Poettmann[13]. Two new correlations by Tek and Chan[14] have been presented on simultaneous flow of liquid and gas through vertical pipe. The extension of the concept of two-phase Reynolds' number function developed for horizontal flow to vertical multiphase flow systems and application of the results to actual engineering problems were reviewed by Tek[15] in 1961.

In 1963, Fancher *et al.*[7] utilized an experimental field well to conduct flowing pressure gradient tests under conditions of continuous, multiphase flow through 2⅜" O.D tubing. From these test data, an accurate pressure traverse has been constructed for various flow rates and for various gas-liquid ratios. A comparison of these tests to Poettmann and Carpenter's correlation indicates that deviations occur for certain ranges of flow rates and gas-liquid ratios. Numerous curves were presented to illustrate the comparison of this correlation with the field data.

An analytical study of the flow of fluids through small vertical conduits was performed by Gaither *et al.*[16] in 1963. Experimental data were obtained for single-phase gas and liquid flow as well as for two-phase flow of water-gas mixtures. Useful relationships for annular flow as well as comparison with classic annular flow concepts were discussed and compared with experimental results. A new correlation for two-phase water-gas flow has been developed based on the experimental data.

In 1963, Duns and Ros[4] published the results of an experimental study of vertical two-phase flow. The experiment was based on some 4,000 runs and 20,000 data points. This correlation was conducted in a laboratory facility at low pressure using air, oil, and water. This correlation was used in 10 m test section and pipe diameters ranged from 3.2 to 8.02 cm. This correlation was measured by radioactive tracers for liquid holdup and observed by transparent test section for flow pattern. Correlations were developed for slip velocity (from which the holdup can be calculated) and friction factor for three distinct flow patterns (bubble flow pattern, slug flow pattern, and mist flow pattern). This correlation performed better mist flow than most others.

In 1964, Hagedorn and Brown[6] published the effect of liquid viscosity on two-phase flowing pressure gradient. Continuous, two-phase flow tests have been conducted during which four liquids of widely differing viscosities were produced by means of air-lift through 1¼" tubing in a 1,500 feet experimental well. From these data, accurate pressure-depth traverses have been constructed for a wide range of test conditions. From these tests, it is concluded that viscous effects are negligible for liquid viscosities less than 12 cp but must be taken into account when the liquid viscosity is greater than this value. Fancher and Brown has developed a correlation based on the method proposed by Poettmann and Carpenter for 1¼" tubing which accounts for the effects of liquid viscosity when these effects are important.

In 1965, Hagedorn and Brown[17] used in a 1,500 feet experimental well to study the pressure gradients occurring during continuous, vertical, two-phase flow through 1", 1¼"and 1½"nominal size tubing. These tests were conducted for widely varying liquid flow rates, gas-liquid ratios, and liquid viscosities. From these data, an accurate pressure-depth traverse was constructed for each of the three tubing sizes. Correlations have been developed for accurate prediction of flowing pressure gradients for a wide variety of tubing sizes, flow conditions, and liquid properties. Also, the developed correlations satisfy the necessary condition that they reduce to the relationships appropriate for single-phase flow when the flow rate of either the gas or the liquid phase becomes zero.

In 1967, Orkiszewski[8] published the method that is an extension of the work done by Griffith and Wallis and was found to be superior than five other published methods. The precision of the method was verified when its predicted values were compared against 148 measured pressure drops. The unique features of this method over most others are that liquid holdup is derived from observed phenomena, the pressure gradient is related to the geometrical distribution of the liquid and gas phase (flow regimes), and the method provides a good analogy of what happens inside the pipe.

Gas-liquid flow in inclined pipes was investigated to determine the effect of pipe inclination angle on liquid holdup and pressure loss by Beggs and Brill[9] in 1973. A correlation has been developed to predict liquid holdup and pressure gradients occurring in two-phase, air-water flow in 1" and 1.5" smooth, circular pipes at any angle of inclination. In this method, corrections for liquid holdup and friction factor were developed for predicting pressure gradients for two-phase flow in pipes at all angles for many flow conditions.

In 1974, a model for predicting pressure distribution in two-phase flow through vertical, inclined, or curved pipes combining the best available correlations for predicting pressure gradients for each flow regime was presented by Gould *et al* [18]. Their work involves a computerized method designed and developed first to determine the flow regime likely to prevail at a given point in the pipe, then to use the best correlation available in the literature to predict the density, friction, and acceleration gradients for that particular flow regime before iterating to the next pipelength increment. This method has been evaluated statistically against literature data and directly against field data from directionally drilled offshore wells.

In 1974, the accuracy of several pressure loss prediction methods in terms of flow variables familiar to the practicing engineer was reported by Lawson *et al.*[19]. The correlations included in this study are those of Poettmann and Carpenter, Baxendell and Thomas, Duns and Ros, Fancher and Brown, Hagedorn and Brown, and Orkiszewski. Each of these correlations was proposed specifically for predicting pressure losses in vertical oil well tubing for the upward flow of multiphase well fluids. These methods were tested against 726 well tests from field and experimental wells. A statistical analysis was made to find the most acceptable method for different ranges of flow variables and also the method having the best over-all performance for predicting the measured pressure losses.

Chierici *et al.*[20] presented a combination of mass-transfer flow regime methods for predicting two-phase pressure gradients in oil wells with low to medium GOR in 1974. The same basic approach as Orkiszewski's has been adopted in their work. A new relationship has been developed for the slug-forth flow regime to improve the accuracy of the calculated local thermodynamic parameters.

Vohra *et al.*[21] extended the work of Lawson *et al.*[10] to evaluate three new correlations in 1974. These three new correlations are Beggs and Brill, Aziz *et al.*, and Chierici *et al.* correlations. Data from 726 tests, embracing broad ranges of flow rate, pipe size, API gravity, gas-liquid ratio, and water/oil ratio were used in their evaluation. They concluded that no single correlation consistently performed best in every range.

In 1975, Browne[22] used the Monte Carlo simulation technique to evaluate the effect of errors on the rate available from a well connected to a flow network. He determined measures of accuracy and precision of published techniques that are used for predicting pressure losses in two-phase flow, and these predictions are compared with measured values.

Cornish[23] presented a method for calculating the pressure drop in a vertical well flowing oil and gas in 1976. This method was designed primarily for flow rates in excess of 5,000 B/D in large diameter tubing, casing, or casing annuli and relies heavily on the use of PVT data.

In 1984, Asheim[24] proposed a new model that has been formulated and implemented in a computer program called MONA. The model has two unique features. The first involves a parametric description of holdup and wall friction. The holdup and wall friction are described by three independent parameters that are related to hydrodynamic and can be estimated a priori for a given flow situation. The other unique feature involves optimal-flow-data matching. Where flow data exist, the program can be run in data matching mode. The program then finds the values of the three flow parameters that minimize computation errors.

Prediction of pressure drops in tubing for high-water-cut gas well was presented by Reinicke *et al.*[25] in 1987. Experimental data were evaluated and compared with the calculations from over 15 different pressure prediction schemes. Then, they proposed for modification of some methods that resulted in significantly improved predictions.

Kabir *et al.*[26] presented a physical model for predicting flow pattern, void fraction, and pressure drop during multiphase flow in vertical wells in 1986. First, they analyzed the hydrodynamic conditions giving rise to various flow patterns. The method for predicting void fraction and pressure drop was then developed. In the development of the equations for pressure gradient, the contribution of the static head, frictional loss, and kinetic energy loss were examined. Laboratory data from various sources show excellent agreement with the model.

In 1987, Ral *et al.*[27] proposed a composite model for pressure-drop calculation. Then, a comparison was made between this composite model and nine existing proposed methods with 323 sets of field measured data. The proposed model was studied for applicability in different ranges of liquid flow rate, GOR, API gravity, and water cut.

A comprehensive model was formulated to predict the flow behavior for upward two-phase flow by Ansari *et al.*[28] in 1990. This model was composed of a model for flow-pattern prediction and a set of independent mechanistic models for predicting such flow characteristics as holdup and pressure drop in bubble, slug, and annular flow. Then, this model was evaluated by using a data bank made up of 1,712 well cases covering a wide variety of field data. Model performance was also compared with six commonly used empirical correlations and the Hasan-Kabir mechanistic model.

In 1993, Pucknell *et al.*[29] published their paper to evaluate two of the recently published "mechanistic" models, one by Ansari, the other by Hasan and Kabir. Then, the performance of these methods was compared against traditional correlations in three ways. No single traditional correlation method gave good results in both oil and gas wells. In fact, most of the traditional methods which worked reasonably in oil wells, but gave very poor predictions for gas wells. Hasan and Kabir mechanistic method was generally found to be no better than the traditional correlation methods. However, Ansari's mechanistic model gave consistently reasonable performance. Although it did not give the most accurate results in every field, it gave reasonable results across the complete range of fields studied.

Barrufet *et al.*[30] proposed a numerical simulator to predict the bottomhole flowing pressure (BHFP) in multiphase systems, where oil/gas or oil/water/gas are flowing together in 1995. To improve the accuracy of the prediction, they coupled the Beggs and Brill procedure for pressure drop calculations to a thermodynamic equation-of-state (EOS). The Peng-Robinson EOS was used to predict the thermodynamic phase separations along the tube and the fluid phase properties.

Chokshi *et al.*[31] presented an extensive experimental investigation to measure pressure drop in a test well. Measured data was gathered from 324 tests for widely varying flow rates. The tests were conducted on a air-water system in a 3½" diameter, 1,348 feet long, vertical test section. Pressure drop predictions of the new model were compared to eight correlation/mechanistic models using measured data and an independent data bank of 1,712 data sets. It was found that the new model performs better than the other methods yielding the smallest average error and the least scatter.

A comprehensive evaluation of existing correlations and modifications of some correlations to determine and recommend the best correlations for various high production rates and large tubulars conditions was reported by Aggour *et al.*[32] in 1996. In this paper, it was found that Beggs and Brill correlation provided the best pressure predictions. However, Hagedorn and Brown correlation was better for water cuts above 80%, while Hasan and Kabir model was better for total liquid rates above 20,000 B/D. Aziz correlation was significantly improved when Orkiszewski flow-pattern transition criteria were used.

In 1999, Gomez *et al.*[33] presented a unified mechanistic model for the prediction of flow pattern, liquid holdup, and pressure drop in wellbores and pipelines. The model is based on two-phase flow physical phenomena, incorporating recent developments in this area. It consists of a unified flow pattern prediction model and unified individual models for stratified, slug, bubble, annular, and dispersed bubble flow, applicable to the entire range of inclination angles, from horizontal (0°) to upward vertical flow (90°).

Takacs[34] proposed a classification of the calculation models commonly used for the calculation of multiphase vertical pressure drops in oil wells in 2001. Then, the main parameters of the experimental data used to develop the different empirical correlations were also presented. An analysis and classification of many possible causes of calculation error was expressed in this paper. Deviation of calculated and measured pressure drop was shown to stem from different sources.

In 2001, Guo[1] presented three analytical models for underbalance drilling hydraulic calculation. These three models cover multiphase flow of commonly used drilling fluids in three categories: (1) air, gas, mist, and unstable foam, (2) stable foam, and (3) aerated liquid. Then, these models were compared with field measurements. It was indicated that these analytical models are accurate enough for UBD design.

An analytical model for gas-water-coal particle flow in coalbed-methane (CBM) production wells was presented by Guo[2] in 2001. In this model, liquid holdup effects were considered by applying a tuning factor to friction factor. The tuning factor was defined as a function of gas-liquid ratio (GLR) and vertical depth. The model was calibrated with measurements from a full size physical well model. This calibrated analytical model was used for predicting performance of CBM wells during gas-lift dewatering operations and proven to be accurate for upward flow of CBM gas and water in a 2⅞" tubing.

In 2001, Guo[3] also presented a paper describing that a mechanistic model originally developed for modeling gas, water, oil, and solid particle four-phase flow in borehole drilling can be employed for establishing IPR for oil wells when bottom hole pressure measurements are not available. Two cases with field measurements were presented to show the application of the model.

In the literature review of this study, it can be seen that most of the reviewed correlations and models have been used to predict the pressure drop or bottomhole flowing pressure for multiphase flow wells. It is necessary to evaluate or analyze the multiphase flow correlations or new multiphase flow models with field data after they were published. In the review of Guo's four-phase flow model, it was evaluated with three field data (one from CBM gas-lift dewatering operation and two from establishing IPR of high and low GOR two-phase oil wells). However, it is needed to evaluate for various well conditions. Therefore, this model is used to investigate the applicability in two-phase and three-phase flow wells for various conditions. Then, modifications are made to improve for its accuracy.