Screening Criteria to Adopt the Best Multiphase Flow Correlation

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Introduction

Multiphase flow in pipes is defined as concurrent movement of free gases and liquids in the pipes. Flow may be in any direction. The gas and liquid may exist as a homogeneous mixture, or the liquid may be in slugs with gas displacement (which is pushing behind slugs). The liquid and gas may flow parallel to each other, or other combinations of flow patterns may be present. The gas may be flowing with two liquids (normally oil and water), and the possibility exists that the two liquids may be emulsified. The prediction of pressure gradients occurring during the simultaneous flow of gas and liquid in pipes is necessary for the proper tubing size selection, design of artificial lift installations and many other production systems in the petroleum and chemical industries. Petroleum engineers encounter multiphase flow more frequently in well tubing and flowlines. The ability to accurately and analytically predict the pressure at any point in a flow string is essential in determining optimum production string dimensions and in the design of gas-lift and other kinds of production equipment installations. This information is invaluable for predicting bottomhole pressure in flowing wells.

As with any correlation, the correlations developed are often misused and applied to cases outside the range of the database from which it was developed. Even though the range of the correlation's application can be extrapolated, it must be used with caution. Hence, a decision has to be made as to which correlation should be used to suit the given set of well data. The importance of being able to assess the accuracy of calculating methods or previously developed correlations is demonstrated in this paper. In fact, their range of validation in the light of the variety of conditions is discussed. These set of tested ranges are used as tools for obtaining a criteria in order to determine the suitability of different correlations towards the given data. This paper is an extraction of work done in relation to the masters' thesis by Palisetti[1].

Literature Review

The existence of multiphase flow and the problems associated with it have been recognized since 1797. Numerous correlations and equations have been presented on the subject of multiphase vertical, inclined and horizontal flow in the literature. However, most of the significant contributions have been made since 1945. They have been presented separately under vertical, inclined, directional and horizontal flow categories. The empirical, semi-empirical & mechanistic models and equations developed so far have contributed significantly to the multiphase flow problems. The most important empirical model included those of Duns and Ros[2], Orkiszewski[3], Hagedorn and Brown[4, 5, 6], Beggs and Brill[7], Aziz, Govier and Fogarasi[8], and Mukherjee and Brill[9]. Earlier contributions included the published work by Poettmann and Carpenter[10], Baxendell and Thomas[11], Fancher and Brown[12], Cornish[13] and Hagedorn and Brown on viscous effects. The correlations of Duns and Ros, Orkiszewski, Hagedorn and Brown, and Beggs and Brill are general and may be used for all pipe sizes and for any fluid. Other correlations are limited to only one pipe size, and some are best for particular fluid properties such as liquid viscosity. The mechanistic models were presented by Ansari[14] et al. and Xiao[15] et al. and are quite comprehensive in nature and account for various directional pressure losses based on flow pattern mapping. Figures presented in Appendix 1.

Briefing on fluid physical properties: The heart of any multiphase flow correlation is the calculation of fluid properties such as fluid density, velocity, and viscosity. Also, many of the pressure drop methods require the values for surface tension to calculate correlating parameters. Fluids encountered in the production, injection and transportation phases of the petroleum and natural gas industries are normally water and hydrocarbons in the gaseous and/or liquid state. Although little emphasis is placed on fluid properties in this work, this section is included since prediction of these properties is an integral part of pressure loss calculations. Also, whenever any kind of laboratory data is available on fluid properties, it should always be used. Even if available at values of pressure and temperature not encountered in the wells or pipelines, laboratory data can be used to improve predicted values. Empirical correlations are available for predicting every fluid property of interest in multiphase flow operations. However, the limitations of each correlation should be kept in mind. The laboratory data is seldom available at flowing conditions and hence must be predicted with empirical correlations.

Previous Investigations: The accuracy of the methods for calculating pressure drops in vertical and horizontal flow has been investigated by Espanol[16], Vohra[17], Lawson[18], Takacs[19], Gregory[20], Rai[21] and probably many more. Furthermore, each author of a pressure drop calculation method has naturally given the results of calculations compared to measurements in the field in such a way as to tend to demonstrate the superiority of the method. The objectivity of these studies is not contested. The range of validation is limited to the data for the correlation in light of a variety of conditions and equipment having to do with the field. Published findings are often difficult to verify in the absence of important data concerning the geometry of wells, the temperature and especially the characterization of the fluids (composition and physical and thermodynamic properties of the phases as a function of pressure and temperature), which is a very important parameter for the calculations. Detailed data are required for accurate calculation. Yet the field data which makes up the databanks of oil companies and is generally considered as confidential information. Moreover, the use of inconsistent notation, units, and criteria for assessment also complicates interpretation of the results. It is therefore more difficult to make the conclusions clear and convincing for non-specialists.

Use of Multiphase Flow Pressure Loss Calculations

The application of multiphase flow correlations to predict the pressure loss in tubings is extremely important to the petroleum industry. Some of the uses are design of slim-hole completions, artificial lift installation design, gathering and separation system design, sizing of surface flow lines, sizing of transmission lines, sizing of gas lines, tubing design in deviated wells, surface design for inclined flow, heat exchanger design, condensate line design and many others.

Summary of Historical Development

Author	Date	Type of work	Pipe size	Fluids	Comments
Poettmann & Carpenter	1952	Semi-empirical method using field data	2", 2.5"	Oil, water, gas	a) GLR < 1500 scf/bbl b) Rates > 350 bbl
Baxendell & Thomas	1961	Field data by Poettmann & Carpenter method	2.5", 3.5", 4"	Oil, gas	Used Lake Maracaibo field data with Poettmann & Carpenter correlation for higher rates
Duns & Ros	1961	Laboratory experimental data	All	All	Correlation for all ranges of flow
Fancher & Brown	1963	Field experimental	2"	Gas, water	Extended correlation of Poettmann & Carpenter for low flow rates and high GLR
Dukler[22] (horizontal)	1964	Laboratory and field data	All	All	For all ranges of G/L's and rates and only for horizontal flow

Hagedorn & Brown	1965	1500 feet experimental well	1" , 1.25", 1.5"	Oil, water, gas (air)	Flow through small conduits
Orkiszewski	1967	Review of all methods plus own correlation	All	Oil, water, gas	Utilized work of Ros and Griffith & Wallis to prepare own general correlation to predict pressure losses for all ranges of flow
Aziz, Govier & Fogarasi	1972	Laboratory and field data	All	All	Presented correlations developed mechanistically and tested against field data
Beggs & Brill	1973	Laboratory data	1", 1.5"	Air, water	Generalized correlation to handle all ranges of multiphase flow for any pipe angle
Mukherjee & Brill	1983	Experimental well using 1.5" steel pipe at various inclinations	1.5"	Air, water	Generalized correlation to handle all ranges of multiphase flow for any pipe angle

Categories of Flow Correlations

Correlation	Dependence on flow pattern	Basis for flow patterns	Slippage and friction losses treated separately
Poettmann & Carpenter	No	Slug	No
Baxendell & Thomas	No	Slug	No
Fancher & Brown	No	Slug	No
Hagedorn & Brown	No	Slug	No
Hagedorn & Brown revised	Yes	Bubble, slug, transition, mist	Yes
Duns & Ros	Yes	Bubble, slug, transition, mist	Yes
Beggs & Brill	Yes	Bubble, slug, transition, mist	Yes
Orkiszewski	Yes	Bubble, slug, transition, mist	Yes
Aziz et al.	Yes	Bubble, slug, transition, mist	Yes
Mukherjee & Brill	Yes	Bubble, slug, transition, mist	Yes

Well Databank

The databank used for the comparison is the result of sorting done on a databank of several hundred tests on oil wells compiled by Tulsa University Fluid Flow Projects (TUFFP). The databank covers a fairly wide range of parameters. All of the data is comprised of either oil-gas or oil-water-gas or water-gas phases. The flowrates and gas/liquid ratios are very low, medium or high. The tubing sizes selected for the analysis are 2 inches nominal and 2.5 inches nominal. This databank contains data for wells with light, medium and heavy crudes. The measured bottomhole pressure is assumed to be correct for all the calculation purposes. This databank consists of data for vertical flow only. The testing was limited to only vertical flow because of the lack of data for the inclined and horizontal flow.

Certain factors such as experimental uncertainties, particularly concerning the flowrates, gauge reading or the composition of the phases should be checked carefully when considering the accuracy of the measured data.

Analysis of Results

The tests performed in the field, often under difficult environmental conditions, include a set of data measured by industrial sensors with an uncertainty that is generally around 1-3%. Each parameter has a varying degree of sensitivity for the results of each computing method. Thus, the maximum error by taking into consideration the experimental uncertainties of pressure, temperature and flowrate conditions, on density, viscosity and other properties and on diameter, length and slope and roughness of the tubing can be considered as ±10% at best.

The analysis is limited to 2 inches nominal and 2.5 inches nominal sizes because of their extensive use in the field. The earlier single energy loss correlations such as Poettmann and Carpenter, Baxendell and Thomas, and Fancher and Brown were evaluated and are not recommended because of their non-dependence on flow patterns. Baxendell and Thomas correlation can still be used to obtain good results for high rate packed tubing strings. Furthermore, since most of the pressure-drop correlations were developed during the times when Standing's[23] fluid property correlation was the only thing available, it was mostly used in our analysis and evaluation of the pressure drop correlations.

The analysis of the results is discussed for various correlations based on the size of the tubing, rate and gas/liquid ratios. The results are presented in tabular as well as graphical form. The analysis is presented in such a way so as to recommend the validity of the various multiphase flow correlations. A percentage error ranging from 0 to ±10 was considered valid. The analysis is based on tubing size, flowrate and gas/liquid ratio. Various graphs and were presented for this purpose such as:

1. Range validation and Rate versus Correlations:
    a. 2.0 inches nominal tubing size (Appendix 2);
    b. 2.5 inches nominal tubing size (Appendix 3).
2. Performance evaluation table and chart (Appendix 4).

The amount of error in the tubing pressure drop calculations can be assessed in relation to the result sought after; i.e., the pressure at the wellhead (PWH) or at the bottomhole (PBH), depending on the chosen calculation, or can be based on the total pressure drop. Several authors have based on their results on bottomhole pressure:

$$\text{Error (psia)} = PBH_{measured} - PBH_{calculated},$$
$$\text{Error\%} = (\text{Error} / PBH_{measured}) * 100.$$

With this definition of errors, results always appear to be better than the one calculated on the basis of the total pressure gradient in the well, especially for high wellhead pressures. Since the purpose of the methods is to calculate the pressure gradient, it is clear that they must be tested on the total pressure drop and not on the bottomhole pressure, which gives:

$$DP_{calculated} = PBH_{calculated} - PWH_{calculated},$$

$DP_{measured}$ = $PBH_{measured}$ - $PWH_{measured}$,
Error (psi) = $DP_{measured} - DP_{calculated}$,
Absolute Error = | Error (psi) |,
Error% = $(DP_{measured} - DP_{calculated}) / DP_{measured}$.

In this way, all the errors made under different conditions encountered throughout the entire well are taken into consideration.

Conclusions and Recommendations

The main characteristics of the different multiphase flow correlations were studied. Due to the lack of field data for inclined flow and horizontal flow, these pressure drop calculations were not presented. The vertical flow field data was obtained from TUFFP and other sources as described above. The analysis of the results for various tubing ranges give a clear picture that no single order of rank can be stated concerning the accuracy of the correlations examined. Therefore, before planning the production of any given field, it is always best to select the most accurate pressure drop calculation model on the basis of comparison with control measurements such as pressure, rate, gas/liquid ratio, and fluid properties. The limited field data was a factor behind the further testing and validation of the above mentioned concept

Even if the most applicable correlation is selected, it frequently occurs that the differences between the measured and calculated values are significant. The main reasons of this phenomenon are the following:

1. possible measurement errors;
2. paraffin or scale deposits in the tubing string;
3. unknown pipe wall roughness;
4. tubing not being fully vertical;
5. the non-newtonian flow behavior of the oil;
6. changes in the flow parameters of the non-newtonian oils in the course of cooling;
7. the super-saturating of the liquid with gas.

Conclusions

1. Data for each well was run several times with various fluid property correlations because different fluid property calculations changed the percentage of error for certain multiphase flow correlations. Hence, different combinations of fluid properties were tried to obtain the optimum results. The lowest error results were reported with the fluid property correlations used.
2. Empirical methods such as those dealt with-in this work were developed by making use of the well production data. They show that it is necessary to base correlations on the real world phenomena. This makes it possible to take controlling parameters into consideration.
3. The computing was done in the reverse direction to that of flow (i.e. from welhead to the bottomhole) so as to obtain the greatest number of pressure and temperature convergences the computing. Many of the correlations in particular Orkiszewski, have a high rate of failure in convergence, particularly for high GOR crude, when calculated in the direction of flow. However, more accurate pressure drops can be predicted in the direction of flow.
4. The results were presented according to the range of flowrates, tubing sizes and gas/liquid ratios. Due to the lack of data sampling, analysis done using various graphs proved to be insufficient to enable the results to be considered fully significant. Additional test data would further validate the results. The range of validation for each multiphase flow correlation was decided by the combination of results analyzed and conclusions shared by other authors.
5. The sensitivity of the fluid property correlations was observed.
6. The results of tests on the category with the highest flowrates are more accurate, which can be explained by their less two-phase nature (note: the fact that at high rates more gas is in solution and there is only slug flow which makes them behave as a single phase fluid).

Recommendations

The following recommendations are suggested based on literature review and current work by the author:

1. A reasonable range of error to be considered a good fit for a given correlation is 0 to ±10. Errors in that magnitude should be considered normal and any flow correlation performing in that range should be accepted.
2. Palmer hold-up correction in the Beggs and Brill method is unsuitable for the single-phase flow and thus should be used with care and caution.
3. Duns and Ros correlation can be used with confidence for packed tubing strings.
4. Hagedorn and Brown correlation can be used for high rate packed tubing strings. It under-predicts pressure drop values for low rates and high gas/liquid ratios.
5. The various fluid property correlations should be tried in order to obtain better match for the well conditions. This is because the multiphase flow authors used different fluid property correlations.
6. More and varied field data should be used to test the correlations in order to obtain better criteria.
7. Most of the authors prefer to use flow rates as the basis for comparing various correlations. Since gas/liquid ratio also plays an important role along with flow rates, it should not be neglected.
8. Finally, two or three good methods should be tried before reaching any conclusions regarding the accuracy of the correlations.
9. Since gas/liquid ratios play an important role in the composition of multiphase fluid, future work should be concentrated on the analysis based on the ratio of flowrates versus gas/liquid ratio.

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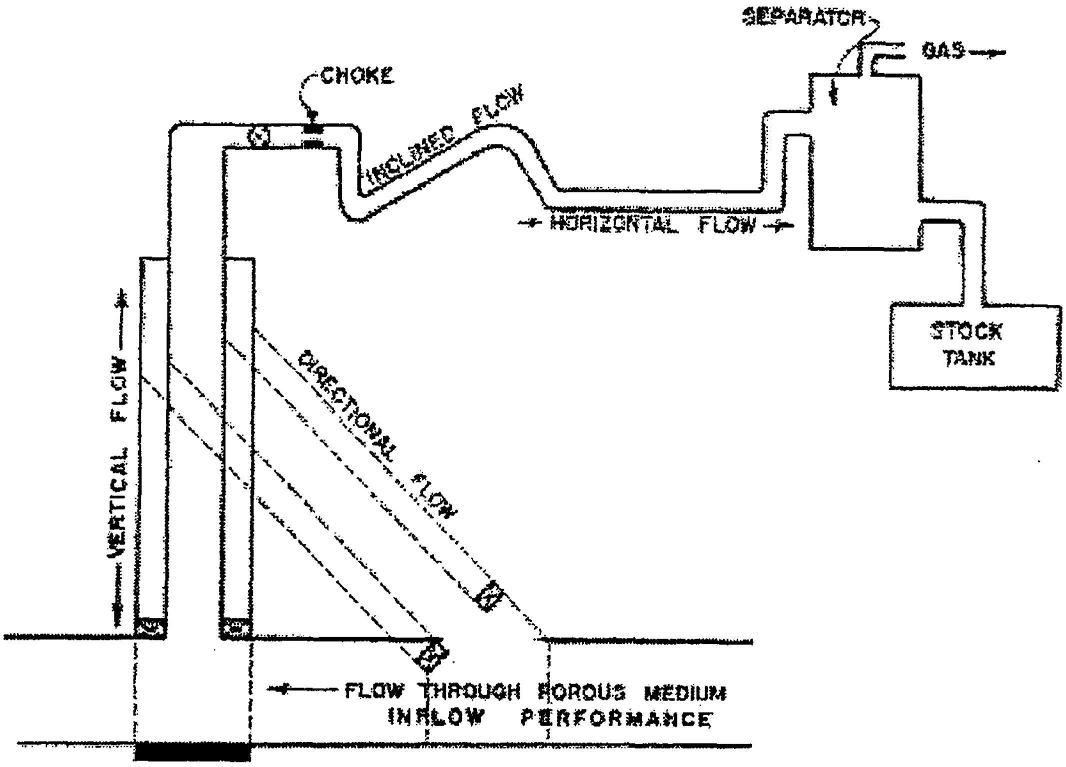
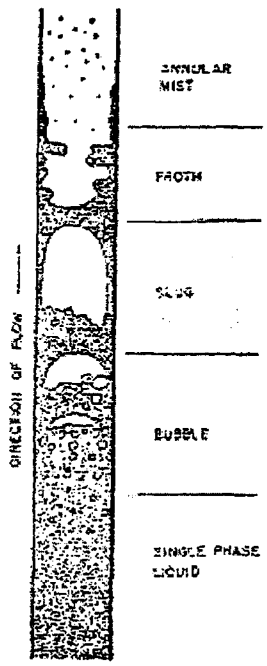
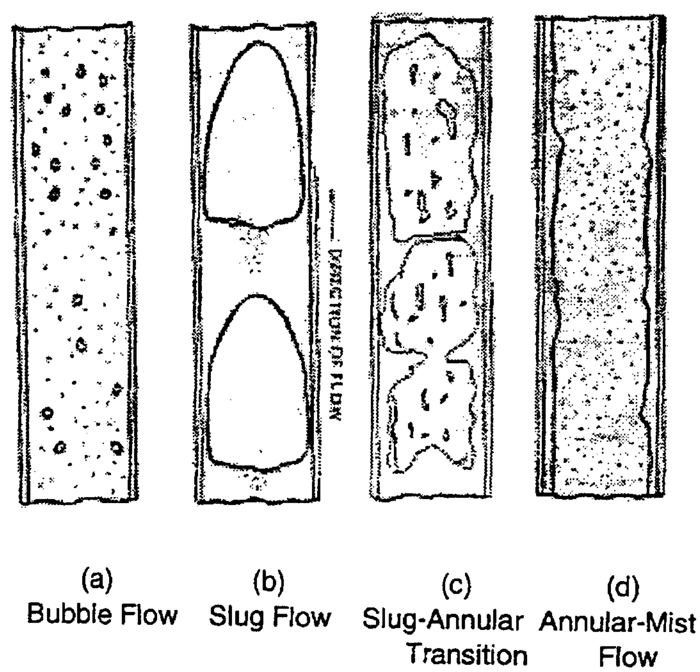


Overall Production System



Typical Flow Pattern for Vertical Flow
Gas-Liquid Mixtures



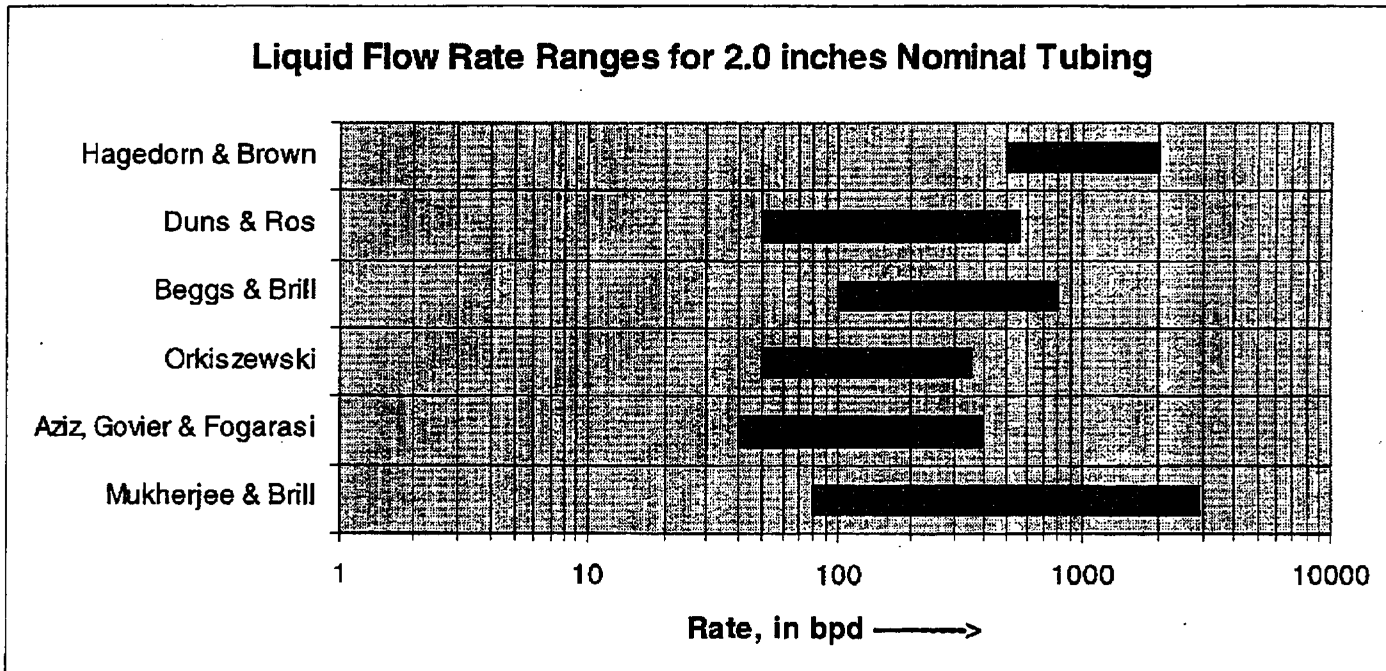
Ideal Flow Regimes Illustrated by Orkiszewski

Performance Evaluation Tables and Graphs

Appendix 2

Range of Validity for 2.0 inches Nominal Tubing

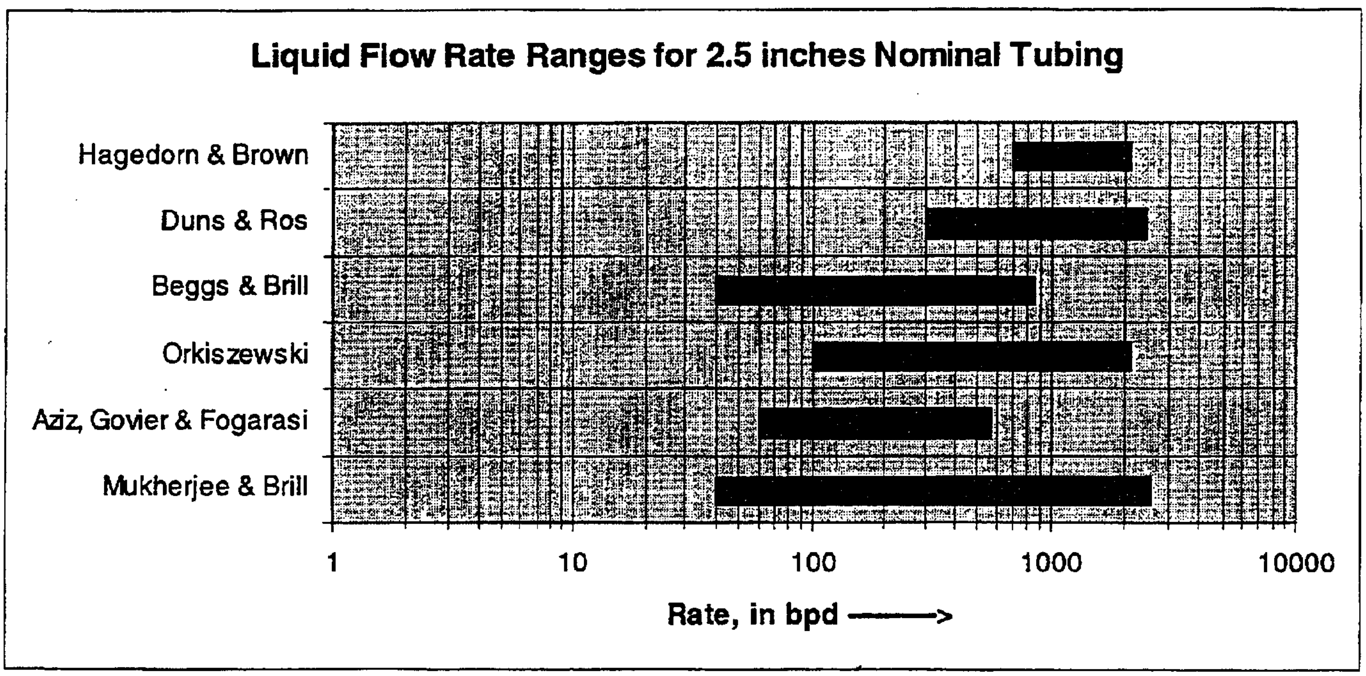
Correlation	Flow rate, in bpd	Gas/Liquid Ratio, in scf/bbl	Observation
Hagedorn & Brown	Rates > 550	GLR < 500	Good for high rates and low GLR Under-predicts pressure for low rates and high GLR
Duns & Ros	Rates < 600	GLR > 700	Can be used for low rates with medium-high GLR Very good for packed tubings
Beggs & Brill	Rates < 600	GLR < 700	Good for most ranges of rates and GLR especially low rates with medium GLR
Orkiszewski	Rates < 300	GLR > 700	Can be used for low rates and medium-high GLR
Aziz, Govier & Fogarasi	Low rates < 350	High GLR > 1000	Good for low rates and high GLR
Mukherjee & Brill	All ranges	All ranges	Very good for all ranges of rates and GLR



Appendix 3

Range of Validity for 2.5 inches Nominal Tubing

Correlation	Flow rate, in bpd	Gas/Liquid Ratio, in scf/bbl	Observation
Hagedorn & Brown	Rates > 700	GLR < 600	Good for high rates and low GLR Under-predicts pressure for low rates and high GLR
Duns & Ros	All ranges	All ranges	Best for all ranges Very good for packed tubings
Beggs & Brill	Rates < 800	GLR < 600	Good for most ranges of rates and GLR, especially low rates with medium GLR
GLR < 500 & > 1500	All ranges	All ranges	Can be used for low rates and high GLR
Aziz, Govier & Fogarasi	Low rates < 300	High GLR < 1100	Good for low rates and low-medium GLR
Mukherjee & Brill	All ranges	All ranges	Very good for all ranges of rates and GLR

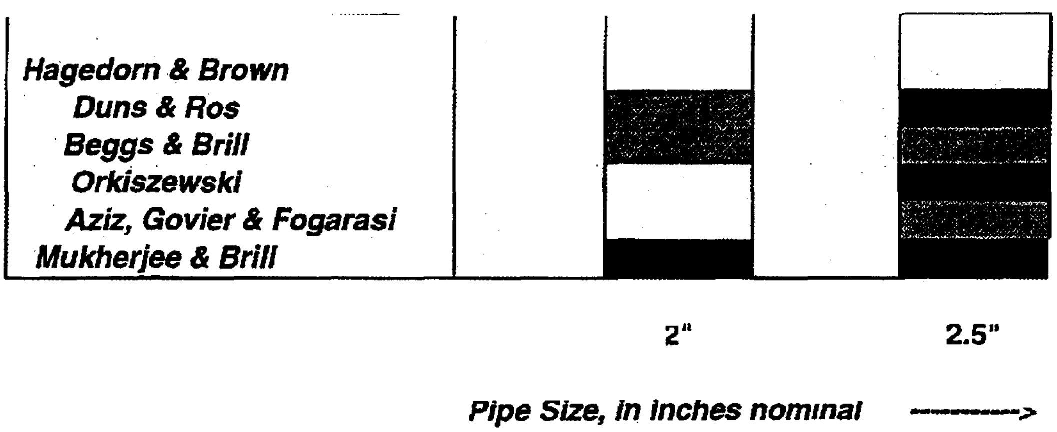


Appendix 4

Overall Performance Evaluation

Tubing size, I.D nominal	Correlation	Comments
2 inches	Duns & Ros	Good for packed tubing string
	Beggs & Brill	Good for rates less than 600 bpd
	Mukherjee & Brill	Best for all ranges
2.5 inches	Duns & Ros	Best for all ranges Good for packed tubing string
	Beggs & Brill	Good for less than 800 bpd
	Orkiszewski	Best for all ranges
	Aziz, Govier & Fogarasi	Good for rates less than 300 bpd
	Mukherjee & Brill	Best for all ranges

PERFORMANCE EVALUATION INDICATOR CHART



INDEX — *Indicates that the correlation can be used with confidence*

Indicates that the correlation can be used but with caution