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A REVIEW OF MULTIPHASE FLOW MODELING IN HORIZONTAL AND VERTICAL WELLS

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Abstract

The estimation of pressure drop for multiphase flow in wells is one of the most complex problems in oil field practice. Multiphase flow pressure profile is extremely difficult to analyze. Fortunately, the availability of the computer simulators in the petroleum industry has enhanced the investigation of the multiphase flow problem. In most cases in the petroleum industry, pressure histories of wells used for production analysis is not measured directly at bottom – hole condition, but is calculated from surface measurements by the use of Multiphase Flow Correlations. Five of the best vertical and horizontal correlations were chosen and evaluated in this study; the Hagedorn & Brown, Duns & Ros, Orkiszewski, Beggs & Brill, and Eaton methods. The accuracy of these correlations was determined against measured multiphase flow pressure drop data from 40 wells. A separate main program was written for each pressure loss prediction method, with fluid property correlations handled as subroutines. The programming steps were selected in order to minimize the inaccuracies of average physical prosperities and at the same time, to maintain a reasonably short computation time. Using the proposed computer model in this project, no two methods yielded identical results for a given set of flow conditions. One of the correlations 100% accurately predicted the pressure losses in the wells for both vertical and horizontal flow. Considering the percentage error, the Orkiszewski and Hagedorn & Brown models were superior to Duns and Roas in most flow regions for vertical wells. Beggs & Brill method also perform satisfactorily for horizontal wells in all flow regions, and should therefore be considered as the first choice in such wells, ahead of Eaton et al.

Keywords: *multiphase, models, correlations horizontal and vertical wells, programming*

Introduction

In the exploitation of a hydrocarbon reservoir, liquids and gases flow simultaneously (Ilozobhie and Egu, 2013). This flow of liquids and gases, which may be in any direction or pattern, is called Multiphase Flow. The liquids are oil and water, while the gases are a composition of hydrocarbon and non-hydrocarbon gases. Among the hydrocarbon gases are methane, ethane, propane butane, pentanes, and hexanes plus. Some of the non-hydrocarbon gases are CO_2, N_2 and H_2S (Hasan and Kabir, 2002). Wells normally produce a mixture of gas and liquids, regardless of whether they are classified as oil wells or gas wells. However, the technology to predict multiphase flow behaviour has improved dramatically in recent years (Rai and Singh, 1999). It is now possible to predict pressure drops; select tubing sizes, and calculate flow rates in wells, with acceptable engineering accuracy. Fluids entering the wellbore from the reservoir can range from an under saturated oil to a single-phase gas, free water can also accompany the fluids as a result of water coning, water flooding, or production of interstitial water. Although many of the wells drilled on land tend to be nearly vertical wells, wells drilled in offshore environments are normally horizontal or deviated.

The pressure in well decreases from the bottom to the top and Multiphase flow may occur in vertical and horizontal wells (Hasan and Kabir,1999 and Fancher and Brown, 2003). Many correlations have been presented on the subject, but finding a single correlation that can accurately predict pressure losses for multiphase flow the different cases and tubing has not been easy (Peottmann and Carpenter, 2002 and Ilozobhie et. al., 2019). The reason is because describing the different relationships between liquids and gases is not easy. The different physical properties of the fluids such as viscosity, density and interfacial tension change as a function of pressure and temperature. Besides, liquids and gases normally present different flow patterns when they flow together in tubing. In addition, slippage occurs making the prediction of total pressure losses more complex. Flow rates of gas, oil and water vary widely, as well as casing and tubing diameters. Well depth can range from a few feet more than 20, 000ft. Pressure can be as low as a few atmospheres or as high as 20,000psia, and temperatures can be above 400^0F or approach the freezing point of water (Sogarasi,, et. al 1999). Oil viscosities in wellbores can also range from less than 1cp to 10,000cp and above. The broad changes in flow patterns and variables encountered in producing wells have made the development of prediction models and correlations much more complex, as techniques and assumptions that are valid for some wells are totally invalid for others (Aziz et al, 1999).

Statement of Problem

The petroleum industry is interested in accurately predicting the pressure losses for multiphase flow in wells. Accurate predictions of pressure losses in well insure correct selection of completion strings, prediction of flow rates, and the design of artificial lift installations. Finding the value of the pressure gradients for multiphase flow is not easy. The reason for this is that the simultaneous flow of gases and liquids involves slippage between the phases, depending on the regime and flow pattern. This slippage involves transfer of energy from gases to liquids and to the surroundings. The transfer of energy may be in the form of heat exchange, phase exchange, or acceleration. Multiphase flow is a complicated phenomenon which also 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. Since an analytical solution does not exist, therefore, the use of empirical multiphase flow correlations is necessary. Additionally, the PVT analysis from the fluids is not always available, the use of empirical correlations for the determination of these properties is also necessary.

Aim

To evaluate the important methods of predicting flow pressure profile in wells, using five most commonly used multiphase flow correlations methods, and also to discuss their limitations and ranges of applicability. The five methods are the correlations of Hagedorn and Brown, Duns and Ros, Orkiszewski, all for vertical wells, also Beggs and Brill and Eaton et al for horizontal wells.

Methodology

programming of methods

A separate main program was written for each pressure loss prediction method, with fluid properties and correlations handled as subroutines. Subroutines were written for calculating values of formation volume factor and solution gas oil ratio, oil and water viscosity, oil and water surface tension, gas viscosity and gas compressibility. Calculations were made for changes in well depth corresponding to assigned pressure changes starting with the measured wellhead pressure. When values of fluid properties representative of the average conditions in the tubing section were needed, the subroutines were entered with arithmetic average pressure and temperature. When temperature varied with depth, the calculation was by trial and error to match the given temperature gradient. The gravity of the free gas, and that of the gas dissolved in the oil phase at higher pressure were both set equal to the total produced gas gravity.

The values of pressure, temperature and other fluid conditions calculated for the exit of the first tubing section were used as inlet values for the next length. The calculation proceeded in this incremental manner until the total depth was reached. The pressure gradient was calculated by linear interpretation of the last two pressure/depth coordinates. It should be noted that for different methods, the calculations starting at the measured bottom-hole condition and ending at the tubing head would not necessarily give the same pressure drop.

The programming steps were selected in order to minimize the inaccuracies of averaged physical properties and at the same time, to maintain a reasonably short computation time. The pressure loss methods programmed required only a fraction of a second on the Intel dual core computer to calculate the pressure traverse. However, certain extensions were made in both vertical and horizontal correlations to cover extremes encountered in analyzing the well test data. When a dependent variable in a correlation was defined in only a certain range of the independent variable, the range of definition of the dependent variable was extended to include these extreme values of independent variable. For example, extrapolations were made in Hagedorn & Brown and Eaton et al correlations. Such extrapolations may not always be advisable but for this study, the extensions were necessary to reduce the handling of data and to simplify the presentation of results. The flow charts for each of the programmed multiphase flow correlations/pressure loss methods considered in this project are clearly presented below. For vertical wells, we have Hagedorn and Brown, Duns and Ros, and Orkiszewski correlations. For horizontal wells we have Beggs and Brill, and Eaton et al correlations (Brill and Briggs, 1998, Orkiszewski, 1997 and Duns and Ros, 1998).

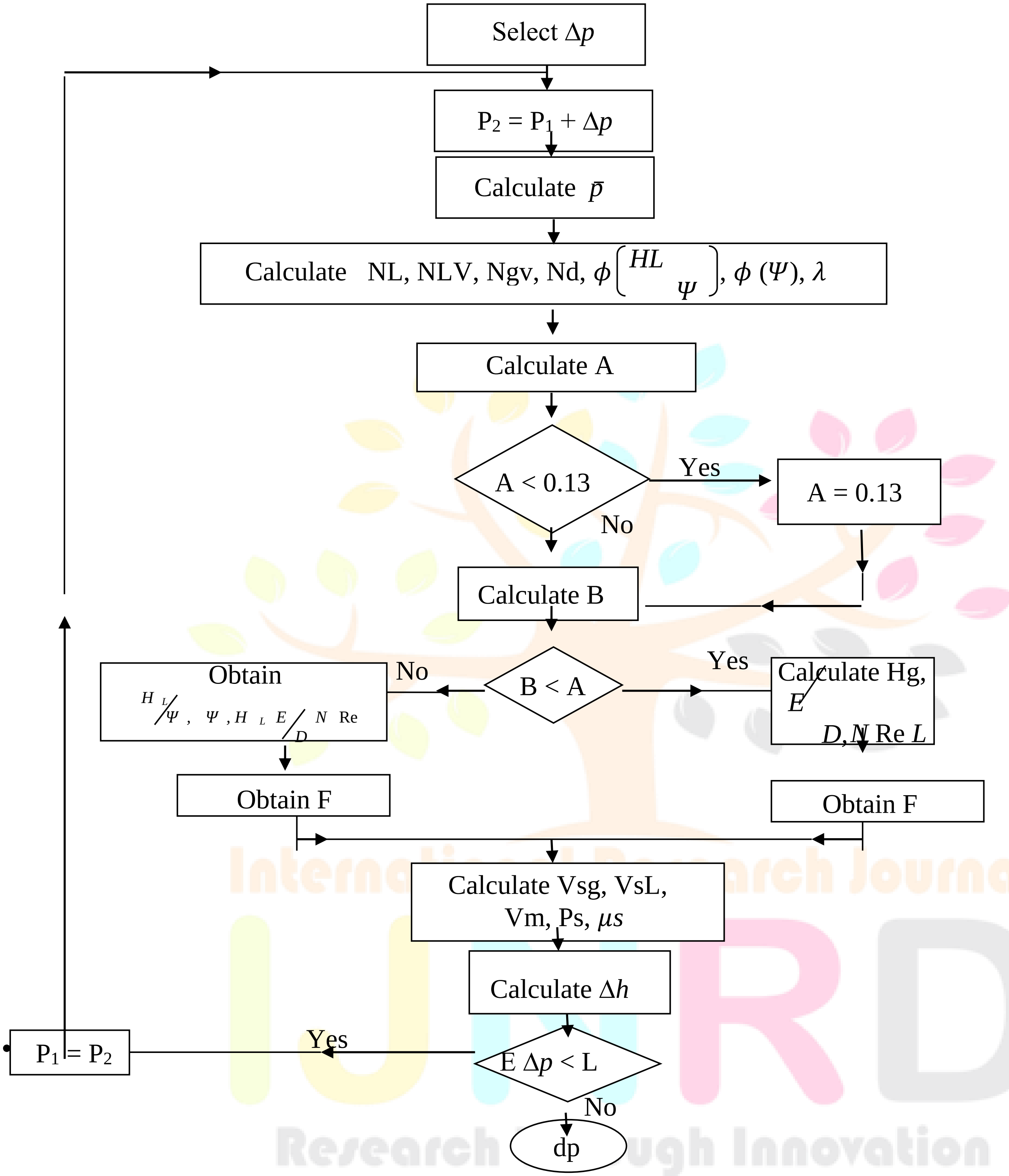

Fig. 1.0: Flow Chart for Hagedorn and Brown Correlation.

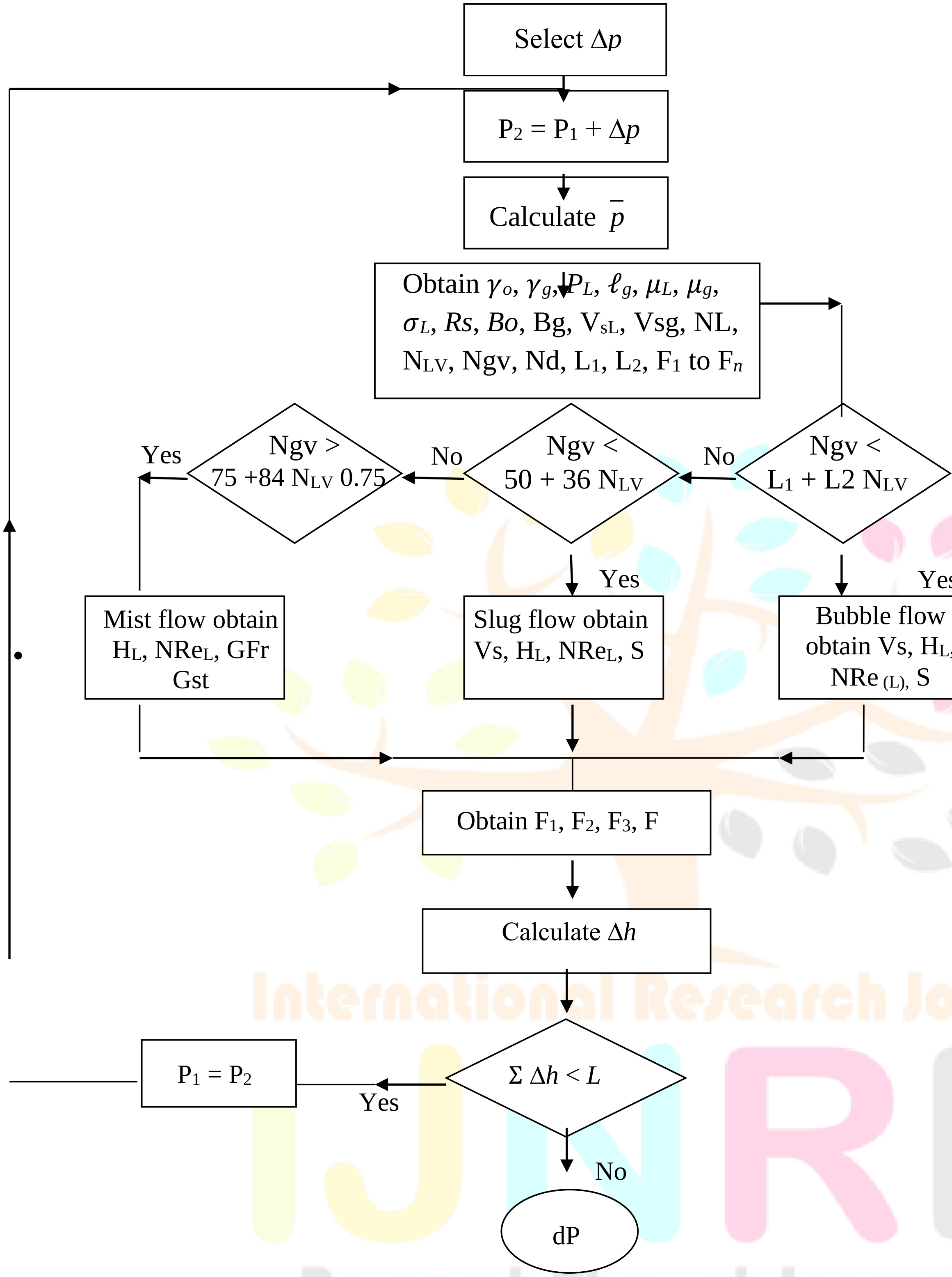

Fig. 2.0: Flow Chart for Duns and Ros Correlation.

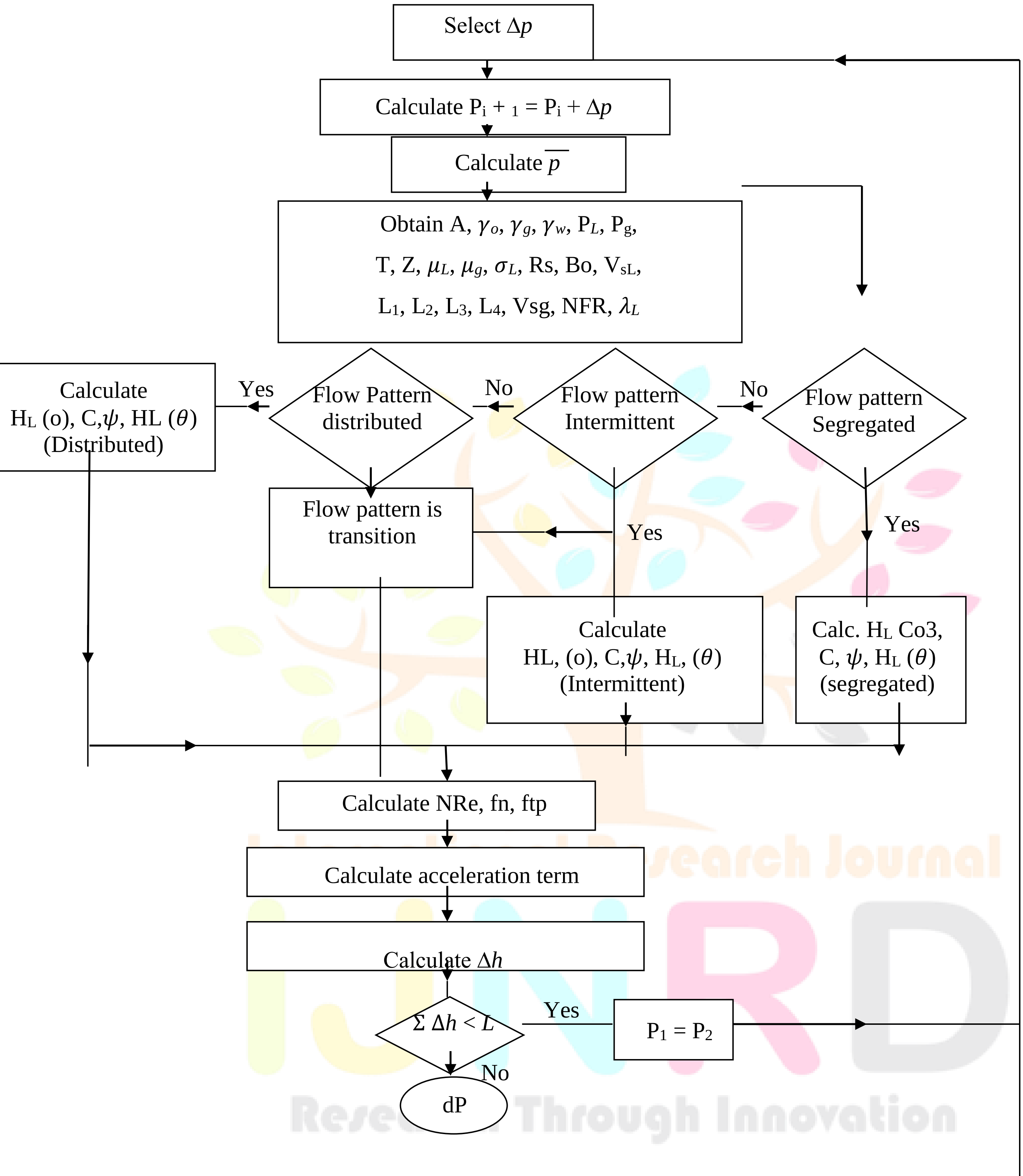

Fig. 3.0: Flow Chart for Beggs and Brill Correlation..

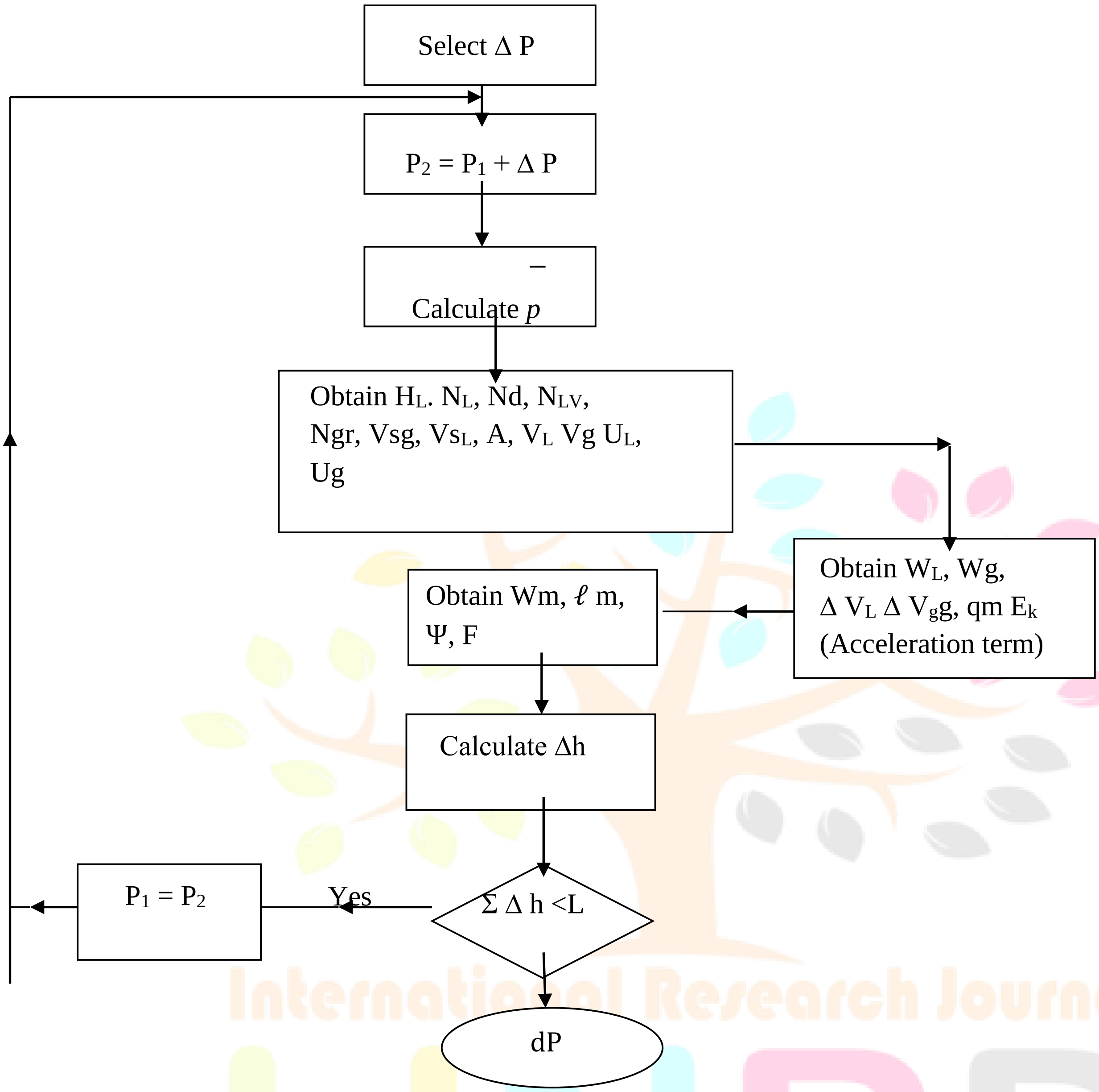

Fig. 4.0: Flow Chart for Eaton Et Al Correlation.

Validation of Programming

Because of the intricacy of some of the correlations and the complexities of the programming involved, pressure losses calculated by the computer program for each pressure-loss prediction method were compared with calculated pressure losses available from another source for the same well test data. Close agreement between the calculated pressure losses from this study and the independent calculation indicates that the programming was done correctly.

Field Data Presentation, Results, and Analysis

A total of forty well are considered in this study, twenty of them being vertical wells, and twenty horizontal wells. The proposed computer program was used to compute the pressure drop in each well, as well as, to evaluate the considered correlation results against actual field – measured data. This evaluation was also based on statistic parameters of percentage error of each correlation result. Tables 1.0 and 2.0 present the data ranges used for both vertical and horizontal wells respectively. The wells were grouped to study the effect of gas – liquid ration on pressure drop prediction. Considering this effect, the performances of the five most commonly used prediction methods – Hagedorn & Brown, Duns & Ros, and Orkiszewski for vertical wells, Beggs & Brill and Eaton for horizontal wells were also analyzed for different flow regions.

Table 1.0: Minimum, Maximum, and Average values of Vertical wells data

VARIABLES	MINIMUM	MAXIMUM	AVERAGE
Well Heads Pressure (Psia)	480	1400	580
Well Tubing Diameter (ft)	0.5	0.5	0.5
Well Depth (ft)	7500	10500	
Tubing Roughness factor	0.00012	0.00012	0.00012
Surface Temperature	100	180	130
Oil gravity °API	28	34	30.55
Oil flow rate SCF/d	7200	10500	7990
Gas liquid ratio SCF/STB	280	5150	1000
Viscosity of Oil C_p	0.97	3.9	3.46
Viscosity of Gas C_p	0. 016	0.17	0.134

Table 2.0: Minimum, Maximum, and Average value of Horizontal wells data

VARIABLES	MINIMUM	MAXIMUM	AVERAGE
Well Heads Pressure (Psia)	500	1700	604
Well Tubing Diameter (ft)	0.5	0.5	0.5
Well Depth (ft)	8000	11000	9280
Tubing Roughness factor	0.00012	0.00012	0.00012
Surface Temperature	100	180	126.25
Oil gravity °API	26	35	30.55
Oil flow rate SCF/d	7140	10000	7919

Gas liquid ratio SCF/STB	250	5150	1000
Viscosity of Oil C_p	1	3.9	3.46
Viscosity of Gas C_p	0. 057	0.17	0.135

Tables 3.0 and 4.0 present the calculated results from each method as compared to the measured pressure drops, and also depict the deviation of each correlation from the actual pressure drop measured. To determine the accuracy of each flow correlation, the percentage error of each method was calculated. The absolute percentage error as shown in figures 1.0 and 2.0 was calculated using the equation below as;

Absolute % Error = [(*Measured Δp - predicted Δp)/ Measured Δp*] x100%

TABLE 3.0: Measured and Predicted Pressure drops for Vertical wells

Well No	Measured ΔP	Hagedorn & Brown	Duns & Ros	Orkiszewski	% Error I	% Error II	% Error III
1	1913	1731	1813	2000	9.5	5.2	-4.5
2	1970	2080	2100	1870	-5.5	-6.6	5.1
3	2635	2453	2400	2521	6.9	8.9	4.3
4	1685	1570	1816	1599	6.8	-7.7	5.1
5	1847	1657	1694	1900	10.2	8.2	-2.8
6	2292	2004	2036	2120	12.5	-8.6	7.5
7	2240	2440	1415	2192	-8.9	9.1	2.1
8	1250	1157	2790	1150	7.4	-13.2	8
9	3274	3047	1950	3199	6.9	14.7	2.2
10	2350	2405	1370	2210	-2.3	-17.8	5.9
11	2432	2241	1405	2350	7.8	19.8	3.3
12	1118	1003	2506	1009	10.2	-22.5	9.7
13	1857	1750	1711	1765	5.7	24.3	4.9
14	3260	3011	2506	3150	7.6	23.1	3.3
15	2439	2500	1711	2331	-2.5	29.8	4.5
16	2550	2290	1862	2650	10.2	26.9	-3.9
17	1450	1605	1013	1320	-10.6	30.1	8.9
18	1173	1095	1773	1119	6.6	-51.1	4.6
19	3428	3682	2670	3500	-7.4	22.11	-2.1
20	1781	1631	1023	1820	8.4	42.5	-2.2

Table 4.0: Measured and Predicted Pressure drops for Horizontal wells

Well No	Measured ΔP	Hagedorn & Brown	Duns & Ros	% Error I	% Error II
1	2425	2500	2605	- 3.1	- 7.4
2	2350	2260	2160	3.8	8.1
3	3500	3430	3150	2	10
4	4317	4200	4001	2.7	7.3
5	2720	2810	2405	-3.3	11.5
6	4508	4608	4185	-2.2	7.1
7	3044	3111	3357	-2.2	-10.2
8	4440	4290	3959	3.3	10.8

9	2982	2790	3255	6.4	-9.1
10	3872	3995	3472	-3.1	10.3
11	4317	4423	4717	-2.4	-9.2
12	2887	2698	3050	6.5	-5.6
13	2785	2659	3108	4.5	-11.5
14	3950	4005	3473	-1.3	12.0
15	3690	3495	3995	5.2	-8.2
16	4200	4335	4651	-3.2	-10.7
17	3928	3884	3498	1.1	10.9
18	2835	2899	3200	-2.2	-12.8
19	4376	4478	4005	-2.3	8.4
20	2980	2861	2680	3.9	10.1

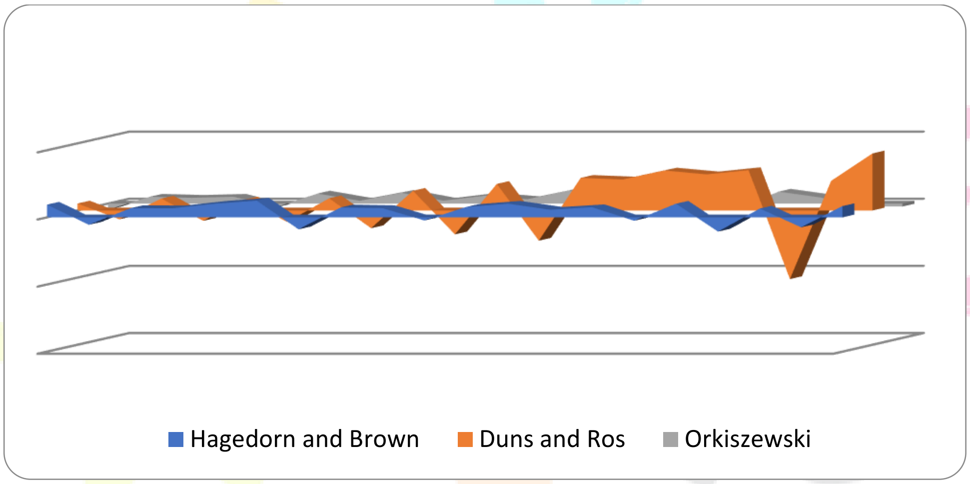

Fig. 1.0: Percentage errors of measured pressures of Hagedorn and Brown, Duns and Ros and Orkiszewskis correlations in vertical wells.

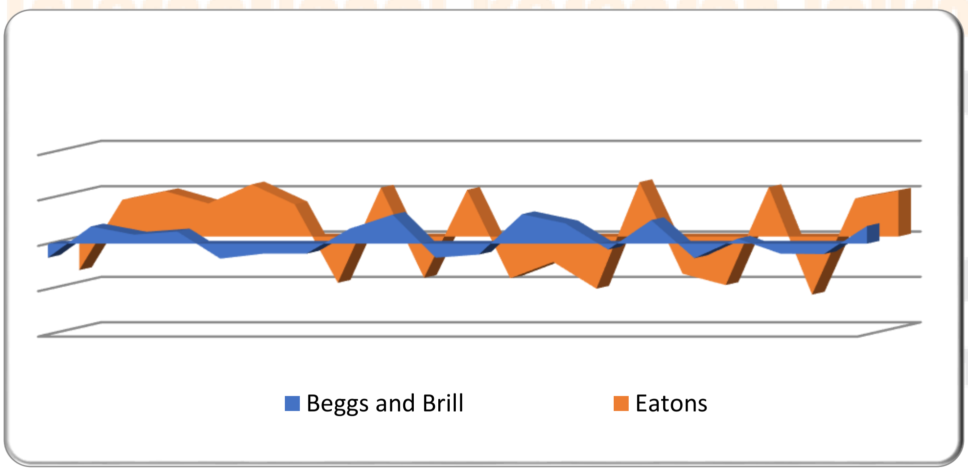

Fig. 2.0: Percentage errors of measured pressures of Beggs and Brill and Eatons correlations in horizontal wells.

Conclusion

A comparison study such as this depends a great deal on the quality and range of basic well data. Different well data may result in different conclusions as to the method having the best over-all performance. Inaccuracies of fluid physical property correlation for predicting volumes and statistical results are inherent with Darcy flows. Each pressure loss prediction method, which combines a pressure loss correlation and fluid physical property correlations, must ne considered as a unit when tested against measured losses.

None of the correlations 100% accurately predicted the pressure losses in the wells for both vertical and horizontal flow. In general, The Orkiszewski and Hagedorn & Brown model are found to perform satisfactorily for vertical wells in all flow regions, and should therefore be considered equally as the first choice in such wells. As shown earlier, the Duns & Ros correlation performed poorly with percentage errors ≥ 20% for wells with very high gas liquid ration (≥ 5000), and should be avoided for such cases.

For horizontal wells, the Beggs and Brills method performed satisfactorily for all regions and is applicable for well with high and low gas-liquid ration. It is currently the best choice available for horizontal and deviated wells. However, with the application of appropriate corrections, the method can also be utilized for vertical wells as the last choice. The performance of Eaton method was average for all flow regions.

Recommendation

Finally, it should be noted that the performance of the multiphase flow models may not always be affected entirely by the particular flow variable against which the performance of these trend is indicated. In most cases, the performance of these models may be dependent on a combination of several of these flow variables considered. Therefore, keeping these limitations in mind, the above discussion could be used as a guide to eliminate or select a particular correlation in the absence of other relevant information.

Nomenclature

A_p = Cross-sectional area of tubing
d = Tubing Diameter
D = depth
d_{hy} = hydraulic tubing diameter (4xAt/Wetted perimeter)
f = moody friction factor
g = acceleration of gravity
g_c = Conversion constant (32.2)
G = dimensionless pressure gradient
GLR = gas – liquid ratio
GOR = gas – oil ratio
H = elevation
H_L = Liquid hold up factor
M = total mass of oil, water and gas associated with one barrel of liquid flowing into and out flow string
N = Reynolds Number
P = Pressure
q_g =Volumetric gas flow rate
q_L = Liquid production rate
q_o = Oil rate
V = Volume
V = fluid velocity
w_L = Liquid mass flow

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