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Multiphase Production Oil Well System Analysis

Maria Stoicescu, Doru Stoianovici

Universitatea Petrol – Gaze din Ploieşti, Bd. Bucureşti 39, Ploieşti
e-mail: stoicescu.maria@yahoo.com; doru.stoianovici@yahoo.com

Abstract

The paper presents the change of inflow discharge in case of vertical multiphase production oil well using different correlations for vertical wellbore flow and flow line, such as: Hagedon & Brown, Orkijevski, Beggs & Brill, Xiao & Mechanistic, Mukherjee & Brill.

Key words: *vertical wellbore flow, flow line, correlations, producing well system*

Well System Analysis

The primary objective of the system analysis technique is to maximize well productivity by analyzing and optimizing the complete producing well system. The analysis can lead to increased profitability from oil and gas investments by improving completion design, increasing well productivity and increasing producing efficiency.

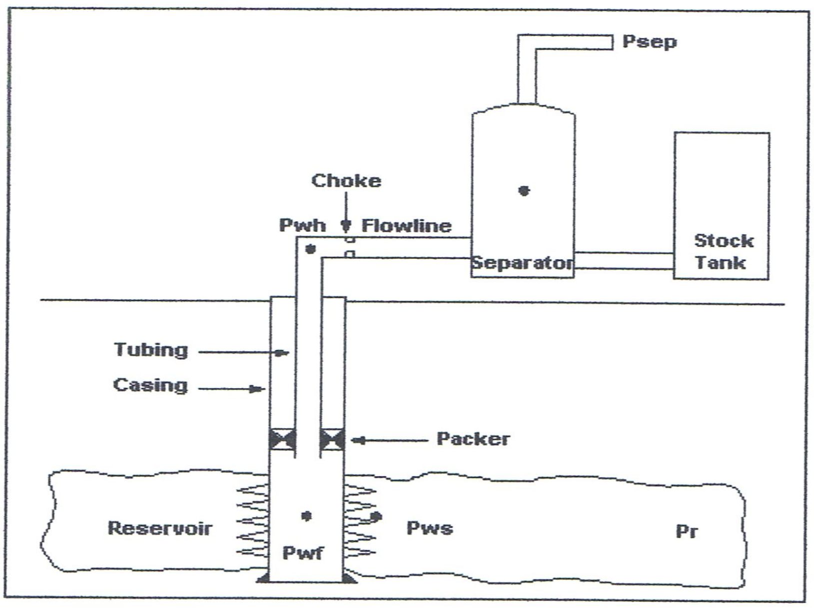

Fig.1. Producing System

System analysis is essentially a simulator of the producing well system. The system, illustrated in Figure 1, includes flow between the reservoir and the wellhead (separator if a flowline is included), and contains the following components:

- Flow through the reservoir to the sandface
- Flow through the completion
- Flow through the bottomhole restrictions
- Flow through the tubing
- Flow through the surface flowline restrictions
- Flow through the flowline into the separator

As system analysis simulates the entire system, it models each component within the system using equations or correlations to determine the pressure loss through the component as a function of flow rate. The total pressure loss through the system for a given flow rate is the summation of the pressure losses through all components.

Minimizing pressure loss in individual components within the system results in less overall pressure loss and increased flow rate from a well.

The total pressure loss is ultimately realized as the overall difference between average reservoir pressure, p_r, and the wellhead or separator pressure, p_{wh} or p_{sep}. The average reservoir pressure and wellhead or separator pressure constitute the endpoints of the system (inlet and outlet), and are the only pressures in the system that do not vary with flow rate.

System analysis analyzes the entire system by focusing on one point within the series of components. This point generally is referred to as a node, hence the term nodal analysis.

The final solution is independent of the location of the node. The vertical flow component of the well system is necessary for calculating the wellbore or tubing curve for the system analysis at several flow rates. It is also used to calculate the gradient curve for the gradient analysis at a defined flow rate. For a system analysis, the calculation of the vertical flow is dependent on the node position. If the node is at the bottom of the well, then the vertical flow component is the outflow curve of the well system. If the node is at the wellhead, then the vertical flow component is part of the inflow curve. In this case, the outflow curves are nothing more than constant pressure curves if there is no flowline considered in application.

In system analysis, with the node at the top perforation in the wellbore, the outflow segment is defined as the summation of the components between the node and the downstream endpoint of the system, usually the separator (with a flowline) or wellhead (no flowline). Because this discussion designates the node at a point within the wellbore directly adjacent to the top perforation of the completion or the top of the reservoir interval in an open hole completion, the outflow segment is comprised of the following components:

- Flow through wellbore downhole safety valves or restrictions
- Flow up the tubing
- Flow through surface valves, restrictions, or chokes
- Flow through the flowline

In most producing well systems, flow up the tubing constitutes the majority of pressure loss in the outflow segment, if not the entire system. In fact, in some oil wells more than 80 percent of the pressure loss in the entire system occurs in the tubing as fluids are moved vertically from downhole to the surface.

The flowline component is usually the second most predominant pressure loss component in the outflow segment followed by the valves, chokes and other restrictions. In general, pressure loss through restrictions is minimal unless an obvious undersizing or similar abnormality is present. In a typical oil or gas well, predicting the pressure loss through the tubing (and flowline) is complicated by the fact that more than one fluid phase generally exists in the producing stream. This multiphase behaviour causes a problem in determining the fluid characteristics necessary for the pressure drop calculation.

Oil Well Vertical Flow

The general pressure gradient equation for vertical flow can be summarized as:

$$\left(\frac{\mathrm{d}p}{\mathrm{d}z}\right)_{total} = \left(\frac{\mathrm{d}p}{\mathrm{d}z}\right)_{elev} + \left(\frac{\mathrm{d}p}{\mathrm{d}z}\right)_{accel} + \left(\frac{\mathrm{d}p}{\mathrm{d}z}\right)_{fric}$$

The elevation component is a function of average liquid density calculated using a liquid holdup value. Holdup is defined as the volumetric fraction of the liquid phase to the total flowing fluid. The friction component requires the determination of a two-phase friction factor. The acceleration component is significant only in cases of extremely high flow velocities, and is generally considered negligible.

Many correlations have been developed over the years to predict the relationship of the gradient components to vertical multiphase flow. Beggs and Brill have summarized these correlations in three main categories, each varying in complexity and technique.

- Category A: No slip effect or flow regime considered
- Category B: Slip considered, no flow regime considered
- Category C: Slip and flow regime considered

Slip is defined as the movement of the gas phase by the liquid phase when the two phases are flowing independently at different velocities. Flow regimes have been suggested to describe these different types of flow patterns that can exist in multiphase flow. These include bubble, slug, transition, and mist flow. There have been many multiphase flow correlations developed to date. Yet, all of the investigators maintain that no correlation has been found to be superior to all others for all flow conditions. Individual well test data and experience in an area can be used to obtain the correlation that will best fit each well's characteristics. In lieu of having data to validate a particular correlation type, the Hagedorn and Brown correlation is suggested as the initial correlation to use in oil wells and the Orkiszewski correlation for gas wells with GLR's above 9000 m^3/m^3. Use the Gray correlation for gas condensate wells. The following sections describe some of the more predominant correlations by category type.

Category A

Poettmann &Carpenter

Used field data to prepare a correlation that treated the multiphase flow as though it were a single, homogeneous phase. Assumed that the flow had a high degree of turbulence and that flow would be independent of viscosity effects. It can be used with confidence for the following conditions.

- Tubing sizes, 2, 2.5, and 3 inches.
- Viscosities less than 5 cP.
- GLR less than 267 m^3/m^3.
- Flow rates greater than 60 m^3/d

Baxendell &Thomas

There were used La Paz and Mara field (Venezuela) data to develop a revision of the Poettmann method to perform better at higher flow rates.

Fancher & Brown

There were used data generated from a 2440 m experimental well equipped with 2 3/8-in. plastic coated tubing to develop a revision to the Poettmann method to better match low rate, high GLR cases. Data used for:

- GLR less than 890 m^3/ m^3
- Flow rates less than 60 m^3/d
- Extended to 2 7/8 in. tubing

Category B

Hagedorn & Brown

This correlation was developed experimentally using a 458 m test well with 1-in., 1.25-in., and 1.5-in. tubing. The correlation is used extensively throughout the industry and is recommended for wells with minimal flow regime effects and generally with GLR < 1800 m^3/ m^3. The Griffith and Wallis correlation can be used for improved performance in bubble flow regimes.

Category C

Orkiszewski

This correlation was developed using work from both Duns & Ros and Hagedorn & Brown. It was used Griffith and Wallis method for bubble flow, a new method for slug flow, and Duns and Ross for transition and mist flow. The Triggia liquid distribution coefficient can be used if desired when the mixture velocity is greater than 3 m/sec. It was developed to eliminate pressure discontinuities.

Duns & Ros

This correlation uses the result of laboratory work where liquid holdup and flow regime were observed. A flow pattern map was utilized to determine the slip velocity (and consequently liquid holdup) and friction factor. This correlation is recommended for wells where high gas-liquid ratios and flow velocities have induced flow regime behavior.

Aziz, et al.

They presented new correlations for bubble and slug flow. Duns & Ross were used for transition and mist flow. Also the flow regime map was revised.

Beggs & Brill

This correlation was developed experimentally using 1-in. and 1.5-in. pipe, inclined at several angles. Correlations were made to account for inclined flow. The correlation is recommended for deviated wells or horizontal flow. You can use the Palmer correlation to correct for liquid holdup effects. Note that the Palmer correlation is unsuitable for single phase flow and should be used with caution.

Mukherjee & Brill

This correlation was developed experimentally using 1.5-in. steel pipe inclined at several angles. It included downhill flow as a flow regime. It is recommended for inclined or horizontal flow.

MONA

Correlation requires three flow coefficients to model vertical flow from actual data to account for phase slippage. Coeff. 1 is the relative velocity of the liquid phase. Coeff. 2 represents the additional velocity of the gas phase over the liquid phase such that the gas velocity is (Coeff. 1 X liquid velocity) + Coeff. 2. Coeff. 3 is a two-phase friction factor. Use 1.0 by default. For nominal results, set Coeff. 1 to 1.2, Coeff. 2 to 1.43 and Coeff. 3 to 1.00 for nominal results and change the Coeff. 1 as needed to adjust the liquid holdup. For homogeneous flow with no slip, set Coeff. 1 to 1.0, Coeff. 2 to 0.0 and Coeff. 3 to 1. For vertical slug flow, set Coeff. 1 to 1.2, Coeff.2 to 0.35, and Coeff. 3 to 1.0.

MONA Modified

Correlation requires two flow coefficients to model vertical flow from actual data. Set Coeff. 1 to 1.0 and Coeff. 2 to 0.0 for nominal results and change the Coeff. 1 as needed to adjust the liquid holdup. Coeff. 2 is normally not changed. The Modified MONA omits Coeff. 3 because of the friction factor being calculated using the Moody factor with either the laminar flow or the Colebrook equations. If the flow is laminar, it uses the Blasius friction factor for the first guess in the Colebrook equation and therefore does not need Coeff. 3.

Sylvester & Yao Mechanistic

Mechanistic and empirical combination model for predicting pressure traverses for two-phase flow using flow pattern prediction and a set of independent mechanistic models. It can be used for vertical and inclined flow.

Ansari Mechanistic

It consists of a comprehensive model to predict flow behaviour for upward two-phase flow composed of a model for predicting the flow patterns and independent models for predicting holdup and pressure drop dependent on the flow pattern. The model was compared to a 1,712 well data bank and found to match better than any of the other empirical or mechanistic models. Uses bubble flow, slug flow, and annular flow models. In vertical multiphase flow calculations, the pipe is divided into small increments based either on a set length or pressure amount. The pressure loss in each increment is determined in a trial-and-error process using average pressure and temperature values to calculate fluid properties. The iterative procedure is necessary as flow regime and subsequent fluid and flow properties change continually through the pipe. As a result, computer solution is almost mandatory; however, curves have been prepared and published to aid hand calculations. The pressure loss calculated over the entire pipe interval is related in part to the size and number of increments chosen. Each of the correlations listed relates to certain wells and well conditions. The determination of the best-suited correlation for a particular well is accomplished by first using the preliminary guidelines listed earlier, followed by testing and comparison to actual field results.

Oil Well Horizontal Flow

The following correlations are available for determining pressure losses in pipelines for oil wells. Some are for a single phase while others are for two-phase flow.

Xiao Mechanistic

Comprehensive mechanistic model developed for gas-liquid two-phase flow in horizontal and near horizontal pipelines. The model first detects the existing flow pattern, predicts the flow characteristics (liquid holdup and pressure drop) for stratified, intermittent, annular, or dispersed bubble flow patterns.

Beggs, Brill, & Minami

It represents a modification of the original Beggs & Brill correlation for horizontal flow only.

Dukler

It is a simple horizontal flow correlation that does not require determination of flow patterns. It includes effects for single and two-phase flow in horizontal flow only.

MONA

Correlation requires three flow coefficients to model vertical flow from actual data to account for phase slippage. Coeff. 1 is the relative velocity of the liquid phase. Coeff. 2 represents the additional velocity of the gas phase over the liquid phase such that the gas velocity is (Coeff. 1 X liquid velocity) + Coeff. 2. Coeff. 3 is a two-phase friction factor. Use 1.0 by default. For nominal results, set Coeff. 1 to 1.2, Coeff. 2 to 1.43 and Coeff. 3 to 1.00 for nominal results and change the Coeff 1 as needed to adjust the liquid holdup. For homogeneous flow with no slip, set Coeff. 1 to 1.0, Coeff. 2 to 0.0 and Coeff. 3 to 1. For vertical slug flow, set Coeff. 1 to 1.2, Coeff. 2 to 0.35 and Coeff. 3 to 1.0.

Mukherjee & Brill

It was experimentally developed using 1.5-in. steel pipe inclined at several angles. It includes downhill flow as a flow regime and it is recommended for inclined or horizontal flow.

Beggs & Brill

This correlation was experimentally developed using 1-in. and 1.5-in. pipe, inclined at several angles. Correlations were made to account for inclined flow. The correlation is recommended for deviated wells or horizontal flow. The Palmer correlation can be used to correct liquid holdup effects. Note that the Palmer correlation is unsuitable for single phase flow and should be used with caution.

Application

Oil Well Data

Fluid		**Resv – Vogel/Harrison (1968)**	
Water Cut	20%	Resv BHP	13790 kPa
Oil Grav	0.850 g/cc	Resv Temp	93.3 °C
SG Gas	0.650	Standing FE	1.000
GLR	44.53 mc(g)/mc(l)	Vogel Rate	159 m^3/d
SG Water	1.070	Vogel Pres	6996 kPa

Compl – Open Perf		**Tbg – Orkiszewski (1967)**	
Perf Intrvl	6.1 m	Perf Top	1676.4 m
Perf Density	13.1 SPM	Csg ID	161.7 mm
Perf Dia	6.35 mm	Tbg ID	62.0 mm
Perf Len	508.0 mm	Sep Press	6.0 bar
Horz Perm	20.0 mD	Pipe ID	77.93 mm
KcKf	1.000	Pipe Length	5000 m

Table 1. Elevation survey

Elevation Survey														
Distance [km]	0.05	0.1	0.15	0.2	0.35	0.5	0.7	1	1.5	2	2.5	3	4	5
Angle [Deg]	-5	0	1	1	-10	-5	8	0	2	0	1	-1	1	1

Well Performance Analysis

Table 2. Inflow & outflow data

Inflow Data - Orkizewski			Outflow Data - Case 1		Case 2	Case 3	Case 4
Liquid Rate, mc/d	Pressure, kPa		Liquid Rate, mc/d	Wellhead Pressure, kPa			
	Sandface	Wellhead	0.8	1150	1338	1125	796
18.3	13105	892	4.6	1032	1334	1054	764
36.5	12421	1057	6.9	1004	1328	1037	746
54.8	11736	1208	9.5	982	1322	1025	726
72.7	11052	1350	12.7	967	740	1019	705
89.6	10367	1311	16.5	958	674	1016	686
105.5	9683	1202	21.4	947	671	1017	669
120.5	8999	1061	28.3	941	672	1026	654
134.6	8314	878	40.2	948	678	1054	644
147.7	7630	686	72.3	1056	1201	1216	636
159.9	6945	492	107.1	1293	1151	1528	633
171.1	6261	218	147.3	1598	1064	1813	632
175.9	5941	101	187.5	1921	966	2035	631
			227.7	2255	892	2310	630
			267.8	2596	835	2580	630

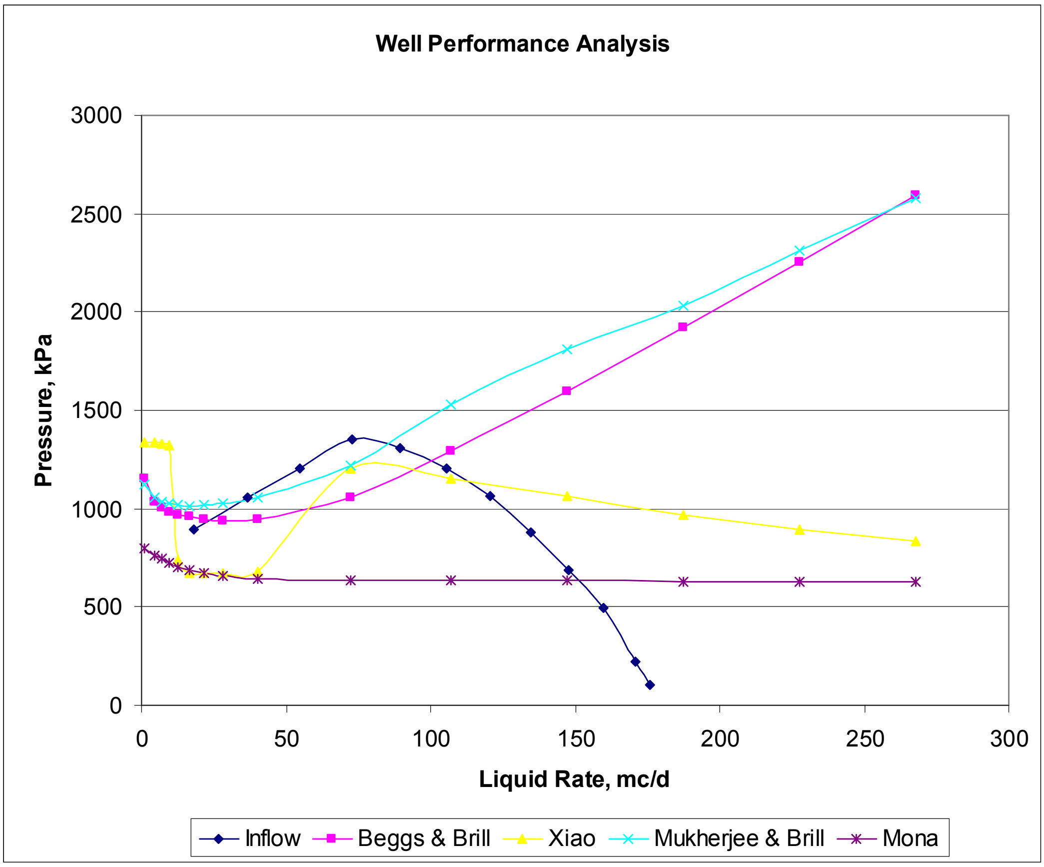

Fig.2. Well Performance Analysis

Solution Points

Table 3. Solution points

	Flow Rates [mc/d]	Pressures [kPa]	Completion Pressure Drop [kPa]
Case 1: Beggs & Brill	99.6	1241	324
Case 2: Xiao	112.1	1140	373
Case 3: Mukherjee & Brill	84.2	1323	267
Case 4: Mona	151.1	267	547

Conclusions

1. This paper presents a summary of calculus methods for pressure losses in reservoir – well – separator system, based on empirical correlations and models developed in years by researchers, pointed both their positive items and limitations.
2. For the presented case study, four correlations were used, i.e.: Beggs & Brill; Xiao Mechanistic; Mukherjee & Brill; Mona.
3. The results indicate that "Beggs & Brill" and "Mukherjee" correlations lead to similar values. The best case, i.e., maxim flow rate and minim drop pressure, corresponds to Mona correlation. Hence, this presents a bigger drop pressure at completion level, the total drop pressure remains smaller than in other cases.

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Analiza curgerii multifazice
în sistemul strat – sondă – linie de amestec

Rezumat

În această lucrare este simulată funcţionarea unei sonde de petrol utilizând diferite corelaţii(Beggs & Brill, Orkiszewski, Hagedon & Brown, Poettman & Carpenter, MONA ş.a.) pentru curgerea multifazică în sondă şi în linia de amestec sondă - separator.