

# Optimization of wellbore multiphase pipe flow calculation model for low permeability sandstone gas reservoir in Ordos Basin

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**Abstract.** The study of wellbore vertical pipe flow is the basis of reasonable production allocation and wellbore size optimization. According to the characteristics of low water gas ratio in sandstone gas reservoir of a gas field in Ordos Basin, the bottom hole pressure of typical gas wells in this area is calculated by using various wellbore pipe flow models such as Hagedorn brown, beggs Brill, Mukherjee Brill, gray and Aziz; Based on the measured bottom hole pressure, the relative performance coefficient evaluation method is used to optimize the wellbore calculation method. The results show that for the sandstone gas reservoir with low water gas ratio in gas field a, the calculation results of Hagedorn Brown model are in good agreement with the test results, so it is appropriate to use the Hagedorn Brown model to calculate the vertical pipe flow characteristics.

**Keywords:** low permeability gas reservoir, pit shaft, Multiphase pipe flow, Relative coefficient of performance, Model optimization.

## 1. Introduction

A gas field is located in the Middle East of Ordos Basin, which is a typical low permeability lithologic gas reservoir. The structure of the gas field is simple. It is a wide and gentle slope of high NE and low SW with a slope of 3-10m / km. The main gas bearing horizons are Shan 2, Shan 1, Tai 2 and he 8. According to the sedimentary characteristics, the Shanxi formation, the main production layer, is adjacent to the combination of fluvial delta and shallow marine facies, and has the nature of marine delta. Reservoir porosity is mainly distributed in 4% - 10%, with an average of 6.36%; The logging permeability is 0.1 ~ 10md, with an average of 3.84md. The driving energy of gas reservoir is mainly driven by gas elasticity, with weak edge water locally. The gas field has been put into development since 2001, with 235 gas wells put into production, and the average daily gas production of single well is  $3.6\% \times 09m^3 / 10^4m^3$ , oil pressure 5.7mpa.

With the gradual reduction of wellhead pressure, gas field a has entered the middle and late stage of development as a whole, so it is urgent to implement development technical countermeasures such as pressurized production to maintain the continuous and stable production of gas field [1-3]. However, at present, the flow characteristics of gas wells are not clear, which brings great difficulties to the development and adjustment of gas fields. Literature research shows that domestic and foreign scholars have done a lot of theoretical and Experimental Research on wellbore flow characteristics, and established a number of calculation models. However, due to the limitation of experimental conditions, each model has different adaptability [4-16]. Therefore, the calculation model of wellbore multiphase flow suitable for low production and low gas water ratio of gas well in a gas field is optimized.

## 2. The calculation model of multiphase pipe flow in common wellbore

At present, the commonly used multiphase pipe flow calculation models in China are Hagedorn Brown model, beggs Brill model, Mukherjee Brill model, gray model, Aziz model and Orkiszewski model.

### 2.1. Hagedorn-Brown model

Hagedorn Brown (1965) obtained the Hagedorn Brown model for the three-phase flow of oil, gas and water in vertical wells by testing the mixture of oil, gas and water with viscosity of 10, 30, 35 and 110 MPa · s in small diameter test wells. The model does not need to distinguish the flow pattern, but considers various parameters such as pipe diameter, fluid properties and flow range. It is usually used in multiphase pipe flow calculation of vertical oil and gas wells. The pressure drop gradient equation is as follows A subsection. The paragraph text follows on from the subsection heading but should not be in italic. When receiving the paper, we assume that the corresponding authors grant us the copyright to use the paper for the book or journal in question. Should authors use tables or figures from other Publications, they must ask the corresponding publishers to grant them the right to publish this material in their paper.

$$10^6 \frac{\Delta p}{\Delta H} = \rho_m g + \frac{f_m q_L^2 M_t^2}{9.21 \times 10^9 \rho_m d^5} + \frac{\rho_m V_m^2}{2 \Delta H} \quad (1)$$

Where:  $\Delta H$  is the depth increment of vertical pipe, m;  $\Delta P$  is the pressure increment of vertical pipe, MPa;  $\rho_m$  is the density of gas-liquid mixture, kg/m<sup>3</sup>;  $G$  is the acceleration of gravity, M/S<sup>2</sup>;  $F_M$  is the two-phase friction coefficient, dimensionless;  $Q_L$  is the daily liquid production on the ground, m<sup>3</sup> / d;  $V_M$  is the velocity of gas-liquid mixture, M/s;  $M_T$  is the total mass of liquid associated gas and liquid produced underground standard conditions, kg/m<sup>3</sup>;  $D$  is the pipe diameter, M.

### 2.2. Beggs-Brill model

Beggs and Brill (1973) set up the beggs Brill model based on the experiment of changing the inclination angle in short and small diameter pipes with water and air as the flow medium. The model takes into account the differences of separated flow, intermittent flow and dispersed flow, and can be used to calculate gas-liquid two-phase flow in horizontal, vertical and arbitrarily inclined pipes. The pressure drop gradient formula is as follows:

$$\frac{\Delta p}{\Delta H} = \frac{g \rho_m \sin \theta + f_m \rho_m v_m^2 / (2d)}{1 - \rho_m v_m v_{sg} / p} \quad (2)$$

### 2.3. Mukherjee-Brill model

Based on the research work of beggs and Brill (1973), Mukherjee and Brill (1985) improved the experimental conditions, studied the flow pattern of two-phase flow in inclined pipe, and put forward more suitable flow pattern criterion of two-phase flow in inclined pipe (including horizontal pipe) and convenient empirical formula of liquid holdup and friction coefficient. The pressure drop gradient equation of Mukherjee Brill model is as follows:

$$\frac{dp}{dH} = - \frac{\rho_m g \sin \theta + f_m \rho_m V_m^2 / (2d)}{1 - \rho_m v_m v_{sg} / p} \quad (3)$$

### 2.4. Gray model

Gray (1987) established a vertical pipe flow model based on the data of 108 condensate wells. The pressure drop gradient equation is as follows

$$\frac{dp}{dz} = f\rho_m v_m^2 / (2d) + g\rho_m - \rho_m^2 V_m^2 \frac{d}{dz} \left( \frac{1}{\rho_m} \right) \quad (4)$$

Among:

$$\rho_m = \rho_L H_L + \rho_g (1 - H_L) \quad (5)$$

$$H_L = \frac{\exp\{-2.314[N_v(1+205/N_D)]^B\}}{R+1} \quad (6)$$

$$B = 0.0814 \left[ 1 - 0.0554 \ln \left( 1 + \frac{730R}{R+1} \right) \right] \quad (7)$$

$$N_v = \frac{\rho_m^2 V_{sm}^2}{q\tau(\rho_L - \rho_g)} \quad (8)$$

$$N_D = \frac{g(\rho_L - \rho_g)d^2}{\sigma} \quad (9)$$

$$R = \frac{v_{so} + v_{sw}}{v_{sg}} \quad (10)$$

### 2.5. Aziz model

Aziz (1992) put forward the calculation model of wellbore pressure drop

$$\phi(p_{wf}) = 0.03415\gamma_g H - (p_{wf} - p_{tf}) \sum_{i=0}^{i=M} a_i I_i \quad (11)$$

Given the PTF, the Newton iteration method is used to solve the PWF

$$p_{wf}^{(n+1)} = p_{wf}^{(n)} - \frac{\phi(p_{wf}^{(n)})}{\phi'(p_{wf}^{(n)})} \quad (12)$$

$$\phi'(p_{wf}^{(n)}) = - \frac{\frac{p_{wf}^{(n)}}{T_{wf} Z_{wf}^{(n)}}}{\left( \frac{p_{wf}^{(n)}}{T_{wf} Z_{wf}^{(n)}} \right)^{(2)} + \frac{1.324 \times 10^{-18} f q_{sc}^{(2)}}{d^5}} \quad (13)$$

Where:  $\gamma_g$  is the relative density of gas phase, 1; H is the depth, m;  $P_{wf}$  is bottom hole pressure, MPa;  $P_{tf}$  is wellhead pressure, MPa;  $T_{wf}$  is bottom hole temperature, K;  $Z_{wf}$  is the deviation coefficient of corresponding gas under bottom hole pressure, 1; f is the friction coefficient, 1;  $Q_{sc}$  is the gas flow rate, m<sup>3</sup>/d.

### 2.6. Orkiszewski model

Orkiszewski (1967) used 148 wells to compare and analyze several gas-liquid two-phase flow models. Combining the best relationship with his research on the slug flow, a vertical multiphase pipe flow correlation formula which combines Griffith bubble flow and slug flow with Rose's annular fog flow and transition flow algorithm is proposed, which is usually suitable for the calculation of the multi-phase flow of vertical oil wells.

## 3. Optimization of wellbore pipe flow model

### 3.1. model calculation

According to the basic data of wellbore pipe flow analysis and measured data of typical gas wells (Table I), the bottom hole pressure of typical gas wells in a gas field is calculated by using Hagedorn Brown model, gray model, beggs Brill model, Mukherjee Brill model, Aziz model and Orkiszewski model. The calculation results are shown in Table I.

**Table 1.** Statistical table of basic data for wellbore vertical pipe flow characteristics analysis of typical gas wells in gas field a

Well number	Inner diameter of tubing /Mm	Medium deep gas reservoir /m	Daily gas production /(104m <sup>3</sup> /d)	Daily water production /(m <sup>3</sup> /d)	oil pressure /(MPa)	Measured bottom hole flowing pressure /(MPa)
Y20	62	2754.0	3.6004	0.69	5.54	6.90
Y44-18	62	2721.5	9.3653	1.84	5.58	7.19
Y30-0	62	3096.9	5.4822	1.08	6.54	8.33
Y43-2a	62	2895.9	8.6034	0.82	7.54	9.53

**Table 2.** Bottom Hole Pressure Calculated by Multiphase Flow Model of Typical Gas Wells in Gas Field A

Point	Measured bottom hole flowing pressure/MPa	Bottom hole pressure calculated by different wellbore multiphase pipe flow models/MPa					
		Hagedorn-Brown	Mukherjee-Brill	Gray	Beggs-Brill	Orkiszewski	Aziz
1	6.90	6.96	7.28	7.47	7.61	8.57	8.34
2	7.19	7.36	7.08	7.54	7.15	8.74	8.87
3	8.33	8.65	7.73	8.71	8.19	9.73	9.39
4	9.53	9.68	9.25	9.94	9.14	10.61	10.38
5	9.43	9.57	9.03	9.82	10.15	10.24	10.74
6	8.95	9.25	8.66	9.31	9.47	9.61	10.65

### 3.2. model adaptability evaluation

Some well parameters could not be collected for various reasons, so how to fill in missing values in the data set is much important for data analysis. The missing value imputation method is using the existing data to obtain reasonable imputation values. Which can construct a complete data set. Among them, the common missing value filling methods include k-nearest neighbor methods and K-mean filling methods.

### 3.2.1. k-nearest neighbor methods

Using the average value of the nearest K neighbor samples on the incomplete attribute to fill in the missing value. And how to measure the distance between samples is the key problem when obtaining neighbor samples. Common distance measures include Euclidean distance and so on.

Suppose that the training dataset D now has m samples, each corresponding to a category Y, and each sample has N features, then the training dataset D can be expressed as:

$$D = \{(x_1, y_1), (x_2, y_2), \dots, (x_m, y_m)\} \quad (14)$$

$$x_i = (x_i^{(1)}, x_i^{(2)}, \dots, x_i^{(n)}) \quad (15)$$

Where:  $x_i$  is the eigenvector of the sample,  $y_m$  is the category corresponding to the sample.

The Euclidean distance is the most common representation of the distance between two points, which meanings the distance between Euclidean space. The Euclidean distance between two points in three dimensions is:

$$d_{12} = \sqrt{(x_1 - x_2)^2 + (y_1 - y_2)^2 + (z_1 - z_2)^2} \quad (16)$$

And the Euclidean distance between two points in n-dimensional space is:

$$d_{12} = \sqrt{\sum_{k=1}^n (x_{1k} - x_{2k})^2} \quad (17)$$

### 3.2.2. K-means imputation method

Clustering based filling methods usually use clustering algorithms to divide the samples in the data set into different clusters, and fill the missing values of incomplete samples with reference to the cluster center and the complete samples within the class. The specific algorithm steps are as follows:

First, if k cluster centroid points are randomly selected, then k clusters exist:

$$\mu_1, \mu_2, \mu_3, \dots, \mu_k \in R^n$$

Second, for each  $x^{(i)}$ , we must calculate the distance between each centroid point, then  $x^{(i)}$  belongs to its nearest cluster.

$$\mu_j = \frac{\sum_{i=1}^n 1\{c^{(i)} = j\} x^{(i)}}{\sum_{i=1}^n 1\{c^{(i)} = j\}} \quad (18)$$

We use these methods to fill the missing wellbore data. Considering the large number of calculation models and samples, the relative performance factor (RPF) is used to comprehensively evaluate the adaptability of several calculation methods in order to accurately optimize the wellbore pipe flow model. RPF reflects the comprehensive relative performance differences of a group of pipe flow relations, the minimum value of which is 0, only when the absolute values of each error of pipe flow relations are the minimum, it is 0; The maximum value is 3, only when the absolute value of each error is maximum, it is 3; The closer the RPF is to 0, the better the relativity of the calculation method is, and the closer the RPF is to 3, the worse the performance is. The formula of RPF is as follows:

$$RPF = \sum_{i=1}^3 \frac{|E_i| - |E_i|_{\min}}{|E_i|_{\max} - |E_i|_{\min}} \quad (19)$$

Where:  $|E_i|_{\min}$  is the minimum absolute error value of the i-th term in the comparison equations;  $|E_i|_{\max}$  is the maximum absolute error value of the i-th term in the various comparison relations.

E1 is the average relative error of the pressure, which represents the overall deviation between the predicted results of the pipe flow model and the measured results

$$E_1 = \frac{1}{n} \sum_{i=1}^n \frac{p_{ci} - p_{ti}}{p_{ti}} \quad (20)$$

E2 is the absolute average relative error of the pressure, which represents the average error between the predicted results of the pipe flow model and the measured results

$$E_2 = \frac{1}{n} \sum_{i=1}^n \left| \frac{p_{ci} - p_{ti}}{p_{ti}} \right| \quad (21)$$

E3 is the pressure standard error, which indicates the dispersion degree between the predicted results and the measured results

$$E_3 = \sqrt{\frac{1}{n-1} \sum_{i=1}^n \left( \frac{p_{ci} - p_{ti}}{p_{ti}} - E_1 \right)^2} \quad (22)$$

According to the calculation method of relative coefficient of performance, the RPF values of six pipe flow calculation models are calculated, and the results are shown in Table III

**Table 3.** Calculation Results of Relative Coefficient of Performance of Wellbore Multiphase Flow Model

Parameter value	Calculation results of relative coefficient of performance for different wellbore multiphase pipe flow models					
	<i>Hagedorn-Brown</i>	<i>Mukherjee-Brill</i>	<i>Gray</i>	<i>Beggs-Brill</i>	<i>Orkiszewski</i>	<i>Aziz</i>
$E_1$	0.0216	0.0154	0.0550	0.0099	0.1847	0.1647
$E_2$	0.0216	0.0429	0.0550	0.0415	0.1847	0.1647
$E_3$	0.0128	0.0528	0.0186	0.0637	0.0566	0.0678
RPF	0.0223	0.2966	0.1893	0.3493	0.9321	0.9208

It can be seen from table III that the relative coefficient of performance (RPF) of Hagedorn Brown model is the smallest, which indicates that the model has good adaptability to a gas field; The relative coefficient of performance (RPF) of Hagedorn Brown model and Aziz model is large, which indicates that the model has poor adaptability to a gas field. Therefore, Hagedorn Brown model should be used to calculate the pipe flow pressure characteristics of gas well in gas field a.

#### 4. Conclusions

According to the characteristics of various pipe flow models, the relative coefficient of performance evaluation method should be used to evaluate the adaptability of each model. The method takes into

account the overall deviation, average error and discrete degree between the calculation results and the test results, and the reliability of the evaluation results is high.

For the low water content gas reservoir in a gas field, the relative coefficient of performance (RFP) of Hagedorn Brown model is the smallest, so this model should be selected to calculate the pipe flow characteristics of gas wells.

For different gas fields and different sandstone gas reservoirs with low water gas ratio, different wellbore pipe flow models can also be used to calculate the bottom hole pressure of typical gas wells, and then the relative performance coefficient evaluation method can be used to optimize the wellbore calculation method References.

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