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Research Article

An Advanced Early-Stage Production Forecasting Model for Middle-High Rank Coal Development

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Reasonable production prediction of coalbed methane (CBM) is of great significance for improving the economic benefit of CBM reservoirs. Current prediction methods for CBM production focus on the later stages of development, with few studies on early production forecasting. The objective of this work is to provide a reliable new idea for the early production prediction of CBM through various analyses and demonstrations. First, the CBM development modes are classified according to the production characteristics of the Panhe demonstration block of Shaanxi Province, China. Second, an efficient and feasible early production prediction model is established based on the geological potential and development potential. Finally, using the proposed model, different modes' production characteristics and optimization strategies are analyzed. The research shows that the gas production profiles can be divided into two modes: single-peak mode (SPM) and multipeak mode (MPM). The peak production and average EUR of the SPM are 49.6% and 32.4% higher than those of the MPM, but the stable production period is only 0.2~1 year. In terms of the geological potential of CBM wells, the gas content, critical desorption pressure, and formation coefficient of the SPM are 6.7%, 13.3%, and 37.8% higher than those of the MPM, and the gas wells are mainly located in the high part of the coal seam (the average height difference is about 20 m). Besides, the concept of quasidesorption degree P_{dq} is innovatively introduced to characterize the development potential of gas well. The P_{dq} has an exponential relationship with CBM production, and the coefficient of the exponential term in SPM is approximately 22% larger than that in MPM. Moreover, the production of gas wells is greatly affected by the continuity of production. In the process of gas production, the influence of factors such as equipment shutdown should be minimized. To examine the applicability of the proposed method, the model is applied to an actual CBM well in Panhe, and the prediction accuracy is higher than 85%.

1. Introduction

CBM is a kind of unconventional natural gas occurring in coal seam in adsorbed state, and its methane content is concentrated at 90%~98%. It is a kind of new energy with high calorific value and low pollution and also an important force to replace conventional oil and gas energy and support the oil and gas revolution [1–3]. The global CBM resources buried below 2000 meters are about $240 \times 10^{12}\,m^3$, which is more than twice the proven reserves of conventional natural gas. The United States is the earliest and most successful country in the exploration and development of CBM, and the recoverable resources of coalbed methane are $21.19 \times 10^{12}\,m^3$. In China, according to the fourth round of national resource assessment in 2015, the total resources of CBM buried more than 2000 meters deep are about $30 \times 10^{12}\,m^3$, and the recoverable reserves are about $12.5 \times 10^{12}\,m^3$. From the perspective of coal rank distribution, CBM resources are distributed in high coal rank (the vitrinite reflectivity Ro ≥ 2%), medium coal rank (0.65% ≤ Ro ≤ 2%), and low coal rank (Ro < 0.65%), among which the proportion of high-middle rank coal is about 68% [4, 5]. The large-scale development of China's CBM began in 2004, which is still in the early development stage. According to the history of CBM, the development of CBM in China can be divided into three stages (Figure 1): exploration stage (1985-2004),

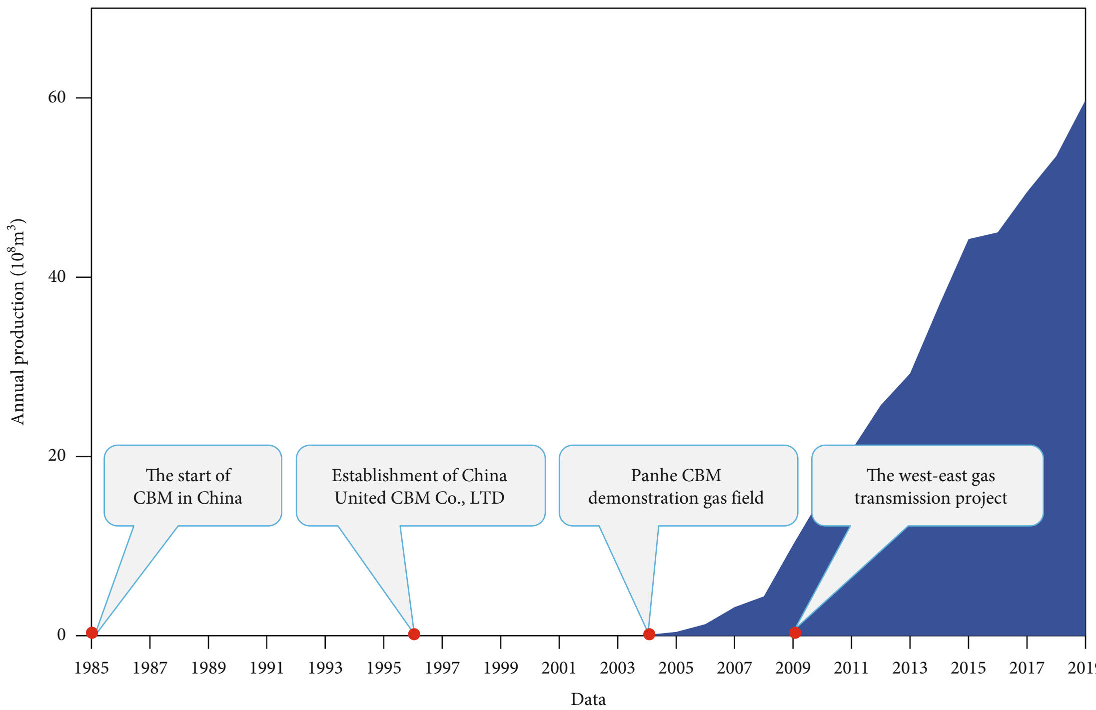


FIGURE 1: Development history of CBM in China.

breakthrough stage (2004-2009), and industrial development stage (2009–) [6–9].

Compared with conventional natural gas reservoirs, CBM is significantly different in terms of accumulation mechanism, occurrence state, seepage law, and its development mode. Theoretically, the output of CBM mainly includes three processes: the desorption of the coal seam surface, the diffusion of the decomposed coalbed methane to the endogenetic fracture, and the seepage through the endogenetic fracture [10–12]. Field practice shows that the production process of CBM is mainly divided into three stages: early drainage and pressure reduction, production rise stage, and production decline after the peak (Figure 2). This study primarily focuses on the production rise stage. CBM productivity is affected by many factors, including geology and development aspects [13, 14]. Geological factors include gas content, permeability, coal seam thickness, desorption pressure, reservoir position, and other factors, which are mainly used to describe the geological potential of the coalbed. The development factors include the continuity of equipment operation, extra auxiliary stimulation measures, and bottom-hole pressure. These factors are used to describe the release potential of the CBM. The influence of these factors needs to be considered when carrying out production forecasting [15–19].

The current CBM production prediction methods mainly include the decline analysis method, numerical simulation method, analogy method, and statistical method [20, 21]. The decline analysis method is mainly for the decline of Arps production [22]. This method is only suitable for gas production profiles of gas wells with obvious decline trends and cannot predict the initial production and peak production of gas wells. The numerical simulation methods use computer programs to solve approximate solutions of mathematical models. Ren [23] carried out productivity prediction and demonstration of stimulation measures by establishing a numerical model of coalbed methane. However, this method takes a long time for modeling and requires high accuracy and integrity of reservoir data. Moreover, when fitting historical gas production, the adjustment of parameters is limited by experience, and it has multiple solutions. In addition, many assumptions are made during the establishment of the numerical model, which also affects the accuracy of the results. The analogy method mainly compares the gas production profile data of adjacent wells or gas wells with similar geological parameters [24]. This method is limited by experience and has certain uncertainties. The statistical method mainly analyzes the mathematical law of data and establishes the corresponding model. This method has been widely used in recent years. Kang [25] analyzed the influence of factors such as reservoir thickness, physical properties, and pressure on productivity, divided CBM production modes into three categories, and used linear regression method to predict productivity. Zhang and Li [26] analyzed three statistical prediction methods, the Weibull model method, the generalized Weng model method, and the H-C-Z model method, and concluded that the Weibull model method has higher fitting accuracy. Kang et al. [27] established an early CBM production prediction method considering reservoir potential and quasidesorption degree and achieved good fitting results, but this method did not consider the influence of coal seam location on production performance. Sun et al. [28, 29] have shown through relevant studies that the gas-water two-phase flow phenomenon has an impact on CBM productivity. Affected by reservoir stress

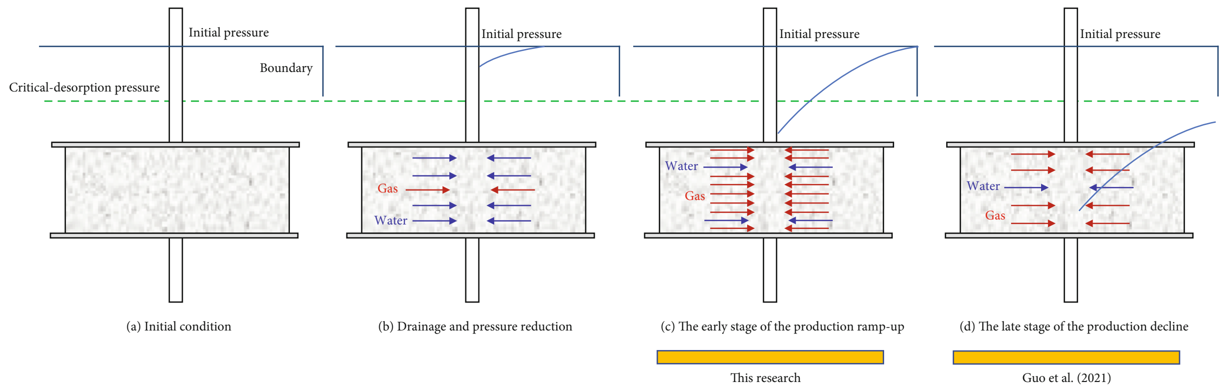


Figure 2: Sketch of the production process of CBM reservoirs.

and gas-water gravity, the water production in the lower part of the reservoir is larger and the gas well production is lower. Therefore, the influence of structural location on the production prediction cannot be ignored. Cao [30] used the grey relational analysis method to analyze the relationship between geological factors and production capacity and believed that factors such as gas content and coal structure had a greater impact on the average gas production. Li et al. [31] employed the Bayesian time matrix factorization (BTMF) method for time series analysis to achieve rolling prediction of dynamic data in the late stage of CBM production.

From the above analysis, we can draw the following conclusions: (1) There are few studies on early productivity prediction. Current productivity evaluation methods are mostly limited to the late stage of development, mainly aimed at the gas well with a declining trend. (2) The current research method also lacks the production mode classification, and the influence of geological, engineering, and other internal factors is not considered in the related mode. (3) The gas-water two-phase flow in the process of CBM flow has a great influence on gas productivity, and the water production at different depths of the same reservoir is different. In the common prediction model, the impact of depth differences on production capacity is not reflected. (4) Numerical simulation is widely used in production prediction, but to achieve the desired results, detailed models need to be established, which takes a long time, requires a lot of data to prepare, and is greatly affected by the experience of engineers in the process of model correction.

In this work, to address these issues, two main research works will be implemented: (1) Based on the production data of gas wells in Panhe, the development modes of gas wells are summarized, and the production potential from the aspects of geology and development is analyzed. (2) Comprehensively considering various factors related to CBM development, an early prediction model with strong feasibility and high precision is established. Furthermore, to demonstrate applicability and reliability, the proposed model is applied to a real well in Panhe. The novelty of this research is establishing an early prediction model by considering various factors, which provides an efficient path to evaluate production potential of CBM wells and helps to optimize the production strategies.

2. Overview of Panhe Demonstration Gas Field

The main CBM production areas in the Panhe gas field are located in the Qinshui and Ordos basins. The development target layers are mainly medium-high rank coal. Panhe is the first CBM demonstration project in China. The overall structure of Panhe is simple, with local secondary folds, alternating anticline arrangement, and few faults. The coal-bearing strata are the upper Carboniferous Taiyuan Formation and lower Permian Shanxi Formation, the average thickness of the coal seam is 13.4 m, and the reflectance of vitrinite (Ro) in the main coal seam ranges from 2.20% to 4.25%. The average reservoir pressure is 2.30 MPa, and the average pressure gradient is 0.435 MPa/100 m. The average Langmuir pressure is 2.78 MPa. The measured saturation is 125% on average, which has a high gas storage capacity. The coal seam is characterized by fractured structural coal with well-developed microfractures and good connectivity. Most of the fracture surfaces are filled with calcite. The average permeability is 0.66 mD, and the average porosity is 7.95% (Table 1).

The Panhe was put into production in 2004, and there are 236 gas wells in production, with $55.40 \times 10^8\ m^3$ of producing geological reserves. By October 2021, the cumulative production was $24.2 \times 10^8\ m^3$, the recovery degree was 43.7%, the peak gas production was $2.6 \times 10^8\ m^3$, and the annual production exceeded $2.0 \times 10^8\ m^3$ for 9 consecutive years. The scale of production capacity and economic benefits exceeded expectations, and a good development effect was achieved. This gas field is currently the most successfully developed CBM block with the best economic benefits in China.

3. Classification of Production Mode of Gas Wells

The gas wells in the Panhe have high output and good production benefits and are currently in the stage of the production ramp-up. Statistical analysis of gas wells shows that the production modes are mainly divided into two categories: single-peak mode (SPM) and multipeak mode (MPM). The parameter values at each stage of different production modes are counted, as shown in Table 2.

Table 1: Statistical table of main coal seam characteristics in Panhe demonstration gas field.

Layer	Name of coal seam	Depth of coal seam (m)	Vitrinite reflectivity (%)	Formation pressure (MPa)	Langmuir pressure (MPa)	Langmuir volume (m^3/t)	Permeability (mD)
Upper Carboniferous Taiyuan Formation	15#	330~775	3.5~4.25	1.85~4.09	1.99~3.32	29.5~55.2	0.33~0.82
Lower Permian Shanxi Formation	3#	256~540	2.2~3.99	1.40~3.34	1.69~2.25	44.2~50.6	0.70~4.4

Table 2: Statistical table of production characteristics of gas wells.

Types	The number of peaks	Peak production (10^4 m^3)	Gas production rising rate (%)	Stable production period (year)	Gas production declining rate (%)	Forecasted EUR (10^4 m)
SPM	1	0.7~1.3	58.0	0.2~1	23.4	1890
MPM	2~6	0.2-0.7	37.6	2~5	10.3	1283

The SPM (Figure 3) is mainly characterized by rapid production growth in the early stage (average annual rising rate of 58.0%), short stable production time (0.2~1.0 years), high peak production (peak value $0.7\sim1.3\times10^4$ m^3), and high output. After reaching the peak, the declining rate of gas production is 23.4%. The production profile of such gas wells has only one typical peak, and the cumulative gas production is higher than that of MPM gas wells. The predicted average EUR of SPM gas well is 1890×10^4 m^3.

The main features of the MPM (Figure 3) are that peak production occurs multiple times (2 to 6 times), and the stable production period is longer (usually 4 to 6 years). The MPM has a low peak production, with an average peak production rate of 0.5×10^4 m^3. And its declining rate and rising rate of gas production are annually 10.3% and 37.6%, respectively, which are smaller than SPM. The predicted average EUR of a single well of MPM is 1283×10^4 m^3, which is about 2/3 of the MPM.

For the MPM, it is found that the gas production potential of this kind of well is poor and the production is relatively low. Auxiliary measures are often taken to improve the production during the gas production process, so the number of peaks is mainly affected by engineering factors. Taking typical well PHX-01 as an example (Figure 4), the number of peaks in the production process is 6, 4 of which are generated by nozzle replacement and the other 2 peaks are affected by the booster.

4. Analysis of Gas Production Potential

In order to accurately evaluate and predict the production potential of gas wells, it is necessary to comprehensively consider the geological and engineering aspects to understand the differences between different production modes, so that the formulation of subsequent plans is more reasonable.

CBM production mainly includes three processes: desorption, diffusion, and seepage. Desorption is the inverse process of adsorption, which can be characterized by the Langmuir isotherm adsorption law, which is mainly affected by factors such as coal rock microstructure, microscopic composition, degree of coalification, and temperature. The diffusion process conforms to Fick's law, and the amount of diffusion is mainly affected by the diffusion coefficient, matrix-crack concentration gradient, matrix pore area, and diffusion time. The seepage process in the endogenetic fracture can be described by Darcy's law, which is mainly affected by factors such as viscosity, permeability, and pressure difference [32–34]. The development performance of CBM wells is affected by many factors, and the production characteristics of gas wells vary due to different production potentials. In order to quantitatively analyze the influence of different factors on the production potential, the influencing factors are divided into two categories according to the dynamic and static data: geological potential and development potential.

4.1. Geological Potential. Geological potential refers to the potential of the coal reservoir itself. According to the characteristics of the coal seam, the geological potential is analyzed from three aspects: gas content, formation coefficient, and relative depth of the coal seam.

4.1.1. Gas Content. Gas content (C_g) refers to the gas volume per unit volume of the coal reservoir. Generally speaking, the higher the C_g of the reservoir, the greater the gas supply potential of the coal seam. C_g is a decisive factor of gas production capacity, which determines the absolute upper limit of peak gas production and stable production capacity of gas wells. When other conditions are similar, the higher the C_g, the higher the peak production, and vice versa. The C_g of No. 3 coal in Panhe is smaller in the northeast and east of the working area, and the corresponding peak daily gas production per well is obviously lower than that in other areas.

Figure 5 shows the difference in peak production under the similar structure of 3# coal in Panhe. The analysis shows that, in general, the peak production of gas wells and C_g show a positive correlation trend, and the C_g and peak production of the SPM are better than those of the MPM.

4.1.2. Formation Coefficient. The formation coefficient is defined as the product of formation thickness H and permeability K. After drainage and depressurization of the coal

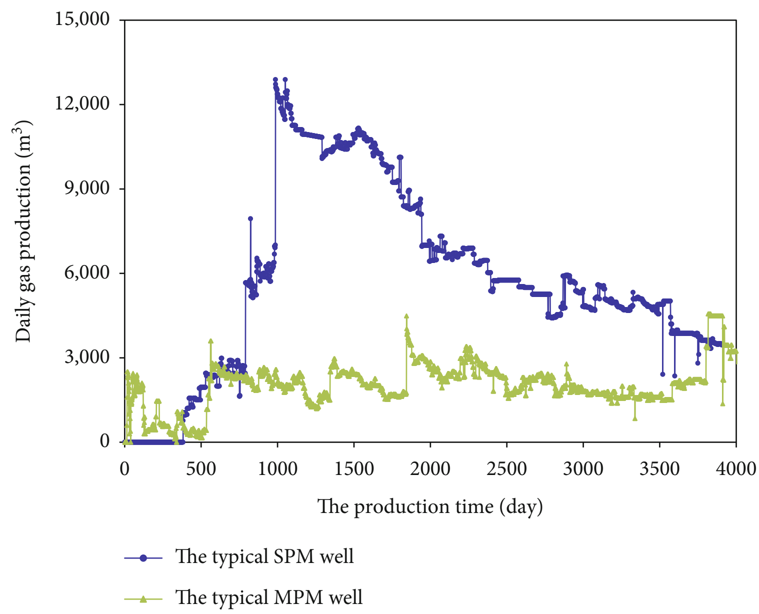


FIGURE 3: The typical gas well production profile of SPM and MPM.

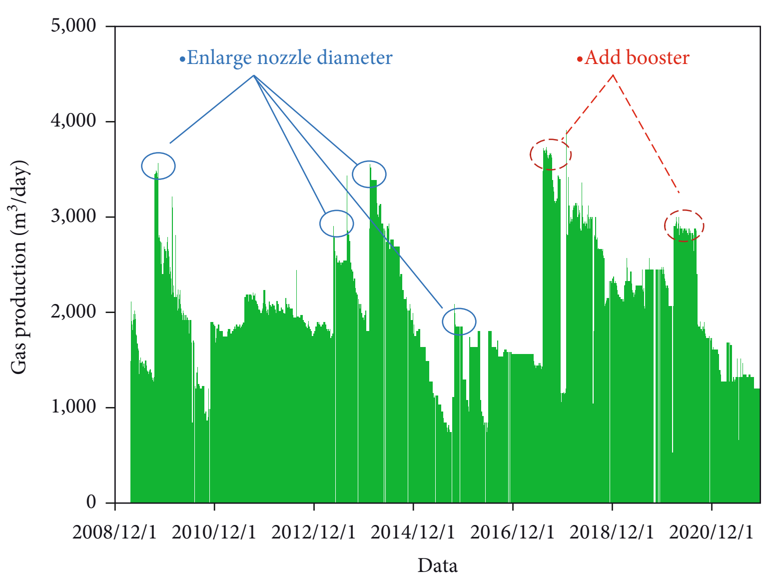


FIGURE 4: Production dynamic analysis of the typical MPM well PHX-01.

reservoir, the pressure drop areas continue to expand, and the gas supply area gradually increases. During this process, the fluid viscosity μ, porosity $\varnothing$, and compressibility coefficient Ct are basically unchanged. Under the same pressure difference, the swept volume is affected by the reservoir thickness H and permeability K in the area where the gas well is located [35]. The larger the reservoir permeability K and thickness H, the larger the swept area, and the gas well is more likely to have high and stable production.

In order to quantitatively characterize the influence of reservoir thickness and permeability on gas wells, the relationship between the formation coefficient and peak production of gas wells in Panhe is statistically analyzed, as shown in Figure 6. In the same block, when other conditions are approximately the same, there is a certain correlation between the peak production and the formation coefficient. The production of gas wells increases with the increase of the formation coefficient, and the formation coefficient of SPM is significantly higher than that of MPM.

4.1.3. Relative Depth of Coal Seam. The productivity of a gas well is affected by the relative depth of the coal seam. The overall geological features of the Panhe are anticlines and synclines that are alternately arranged in the near north-south trend, and the relatively high part is 150 m higher than the low part. The production situation of Panhe shows that

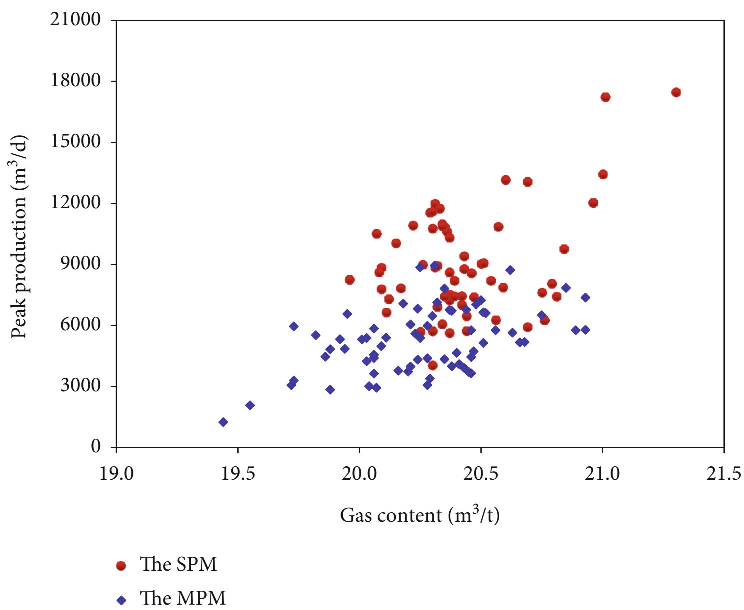


FIGURE 5: Relationship between C_g and peak production.

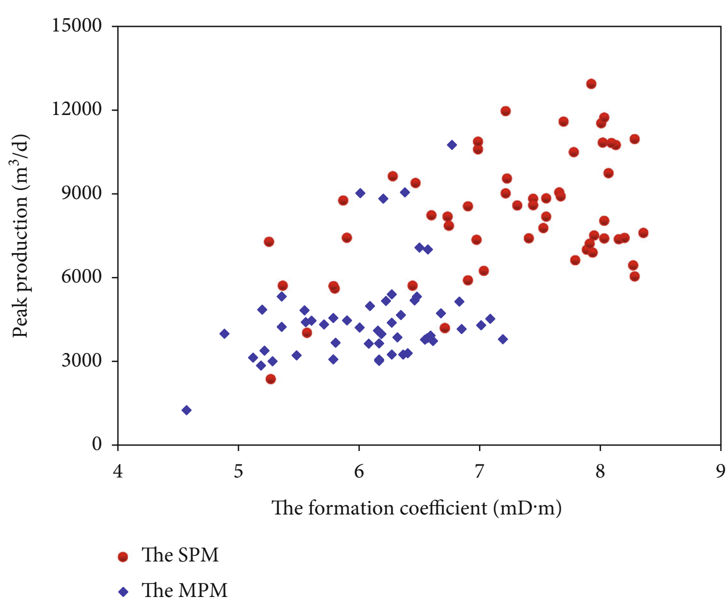


FIGURE 6: Relationship between formation coefficient and peak production.

there is a significant positive correlation between the relative depth of the coal seam and the production of gas wells; that is, the production of gas wells in the higher part is larger than wells in the lower part (Figure 7). The relationship between the water production of gas wells and the relative depth of coal seam is also obvious. The liquid production rate of the wells perforating below 170 m can reach up to 20 m^3/d, while the rate of the wells perforating above 170 m is generally 2~5 m^3/d.

The SPM is mostly located in the higher part of the coal seam. From the perspective of geological origin, the high part is generally tensile stress environment, and its permeability is larger. In addition, due to its higher position, the adjacent low-position CBM gradually migrates to the high position after pressure relief. In contrast, the water in the coal seam is more inclined to converge to the low position. Under multiple factors, the gas wells in the high position have higher productivity than those in the low position (Figure 8).

Field production data show that the impact of relative depth on gas well production is mainly concentrated in the early production stage. The wells in the lower part of the coal seam are greatly affected by water production, so the gas production rises slowly, and the time to reach the peak is long.

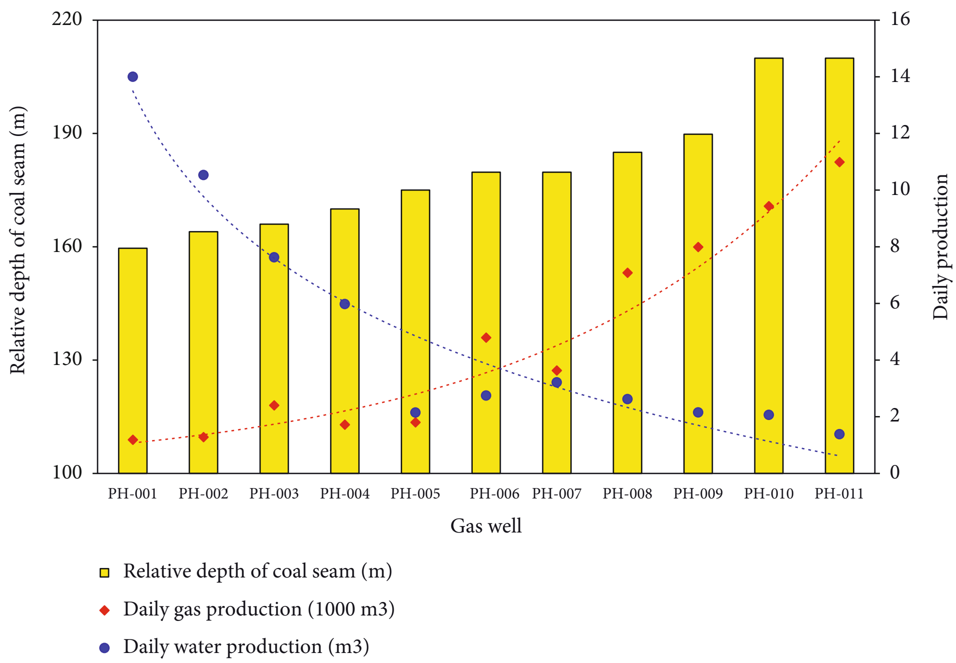
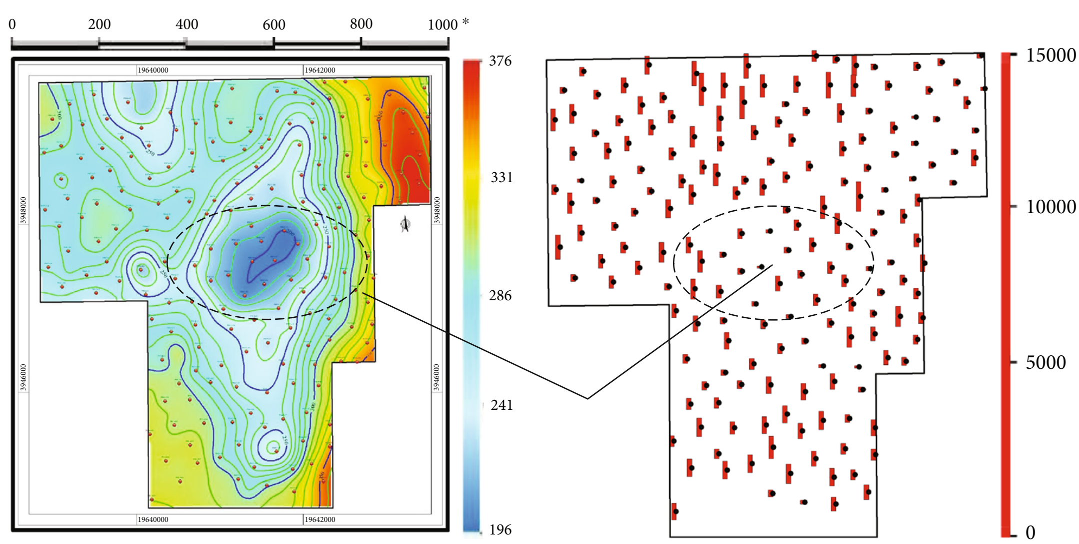


Figure 7: Relationship between gas well production and relative depth of coal seam.



(a) (b)

Figure 8: (a) The relative depth of 3# coal beam. (b) The corresponding daily gas production of wells at early stage.

4.1.4. Comprehensive Evaluation of Geological Potential. The geological parameters corresponding to the two types of production modes are counted, as shown in Figure 9. For the two production modes, the gas content, critical desorption pressure, and formation coefficient of the SPM are 6.7%, 13.3%, and 37.9% higher than those of the MPM, respectively, and the coal seam depth of the SPM is 20 m higher on average than that of the MPM. The peak yield and average EUR of the SPM are 49.6% and 32.4% higher than those of the MPM. Due to the good production performance of SPM, the productivity-maintained capacity is affected after the peak is reached. The average stable production period of SPM (1 year) is shorter than that of MPM (4 years), and its declining rate in the later stage is also larger.

The above analysis shows that the geological potential is comprehensively affected by factors such as gas content, formation coefficient, and relative depth. The geological potential evaluation model P_g is defined here.

$$P_g = C_g \bullet \frac{KH}{\sqrt{D}} \quad (1)$$

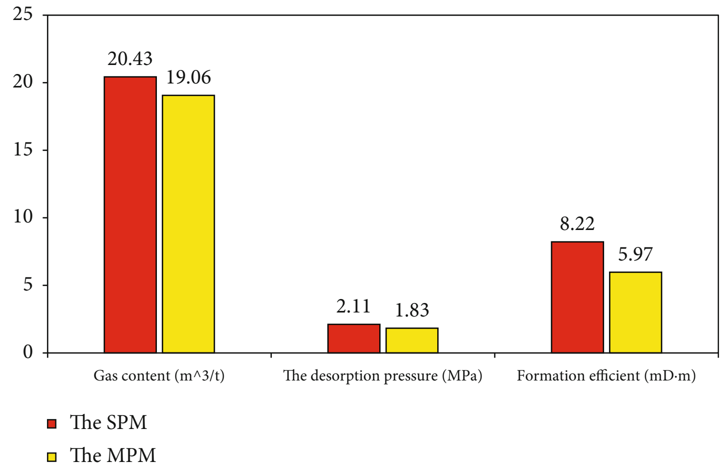


Figure 9: Comparison of gas production potential of two production modes.

where C_g is the gas content (m^3/t), KH is the formation coefficient (mD•m), and D is the relative depth of coal seam (m).

The relationship between peak production and geological potential of typical wells in the Panhe is analyzed (Figure 10). In general, the peak production of gas wells rises with the increase of geological potential, and the geological potential of SPM is better than that of MPM.

4.2. Development Potential. The influence of development potential is analyzed from the two aspects of quasidesorption degree P_{dq} and continuity of gas well production. This parameter mainly characterizes the release degree of geological potential.

4.2.1. Quasidesorption Degree P_{dq}. In the actual production process, coalbed methane desorption begins when the formation pressure is lower than the critical desorption pressure. As the pressure decreases, the degree of desorption continues to increase, and the gas production gradually increases, reaching a peak and entering a stable or declining stage. In order to quantitatively characterize the desorption degree, the coefficient P_d is defined, which represents the ratio of the difference between the critical desorption pressure P_{cd} of the coal seam and the average formation pressure P_f to the critical desorption pressure P_{cd} within the swept area of the gas well.

$$P_d = \frac{P_{cd} - P_f}{P_{cd}}, \tag{2}$$

where P_d is the coefficient of desorption degree, P_{cd} is the critical desorption pressure of the coal reservoir within the swept area (MPa), and P_f is the average formation pressure near the well bottom (MPa).

Since it is difficult to obtain the average formation pressure near the well bottom, from the perspective of data availability, bottom-hole flow pressure P_{wf} is considered to replace the P_f, and the P_{wf} can be measured by instrumentation or calculated mathematically. When the well produces stably, the average formation pressure decreases with the decrease of the bottom-hole pressure. Here, the pseudodesorption degree is used to represent the desorption potential P_{dq}, and its expression is

$$P_{dq} = \frac{P_{cd} - P_{wf}}{P_{cd}}, \tag{3}$$

where P_{wf} is the bottom-hole flow pressure.

The relationship between gas production (the stable gas production corresponding to different bottom-hole pressures in the early stage of development) and the degree of pseudodesorption is statistically analyzed, as shown in Figure 11. It can be seen that the higher the degree of desorption, the higher the gas production, and the two meet the exponential relationship. Since the coefficient of SPM (4.4341) is significantly higher than that of MPM (3.2272), the desorption capacity of SPM is larger and the production is higher, which is in line with the actual statistical results.

4.2.2. Continuity of Gas Well Production. The production of CBM wells is greatly affected by the continuity of production, and the discontinuity of production will lead to the water lock in the coal seam, which will lead to poor seepage flow and the difficulty of drainage and pressure reduction in the wellbore. In addition, the interruption of production will also lead to the blockage of pulverized coal in the seepage channel and the accumulation in the wellbore, which will further lead to the poor production effect.

Statistics show that gas production in Panhe is inversely proportional to the number of shutdowns and downtime. The fewer the number of shutdowns, the shorter the overall downtime, the higher the gas production, and the greater the release potential of productivity. The main factors affecting the continuity of production include mechanical failure, stoppage of pulverized coal, and power outage.

5. Dynamic Prediction Model for Early Production of Gas Wells

From the above analysis, the productivity of gas wells is comprehensively affected by factors such as gas content,

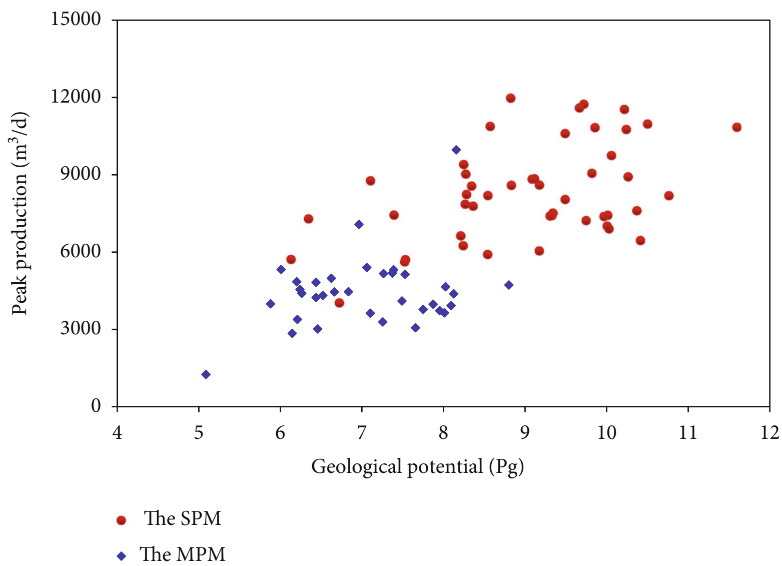


FIGURE 10: Relationship between peak production and geological potential.

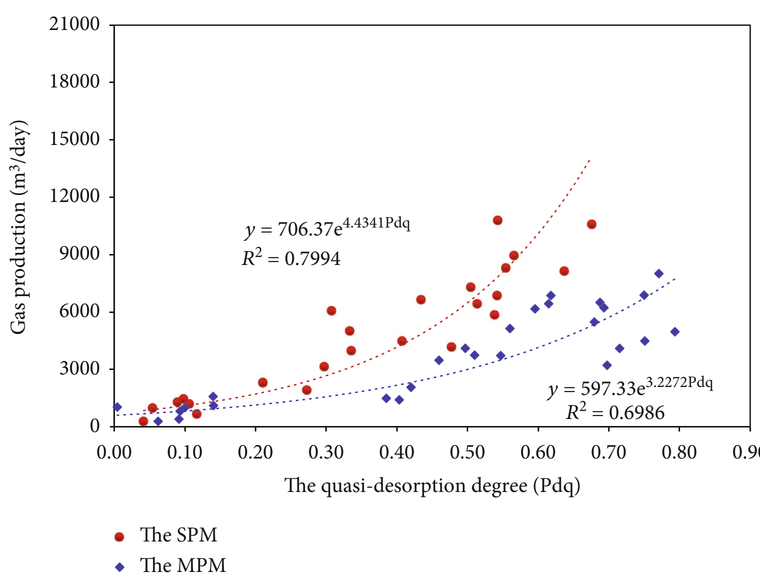


FIGURE 11: The relationship between gas production and quasidesorption degree.

formation coefficient, the relative depth of coal seam, and the coefficient of quasidesorption degree. Therefore, when carrying out the early production prediction of gas wells, it is necessary to establish a comprehensive evaluation model considering both geology and development potential. Here, the expressions of early gas production Q, geological potential P_g, and quasidesorption degree P_{dq} of SPM and MPM are established by using the multiple regression method.

$$q = \alpha_0 + f_1(P_g) + f_2(P_{dq}), \tag{4}$$

where α_0 is the coefficient.

The geological potential and quasidesorption degree of typical wells in both SPM and MPM are counted, and the established dynamic prediction model is used for parameter fitting (Figure 12). The fitting errors of the two models are both less than 15%, indicating that the prediction model has high accuracy and reasonable prediction results. The expression of gas production q in this gas field is

$$q = \frac{249.6KHC_g}{\sqrt{D}} + 643.3e^{4.235P_{dq}} - 1876(\text{SPM}), \tag{5}$$

$$q = \frac{242.7KHC_g}{\sqrt{D}} + 629.4e^{3.317P_{dq}} - 1542(\text{MPM}). \tag{6}$$

Based on the research results, when carrying out early production capacity prediction of a new well, the dynamic

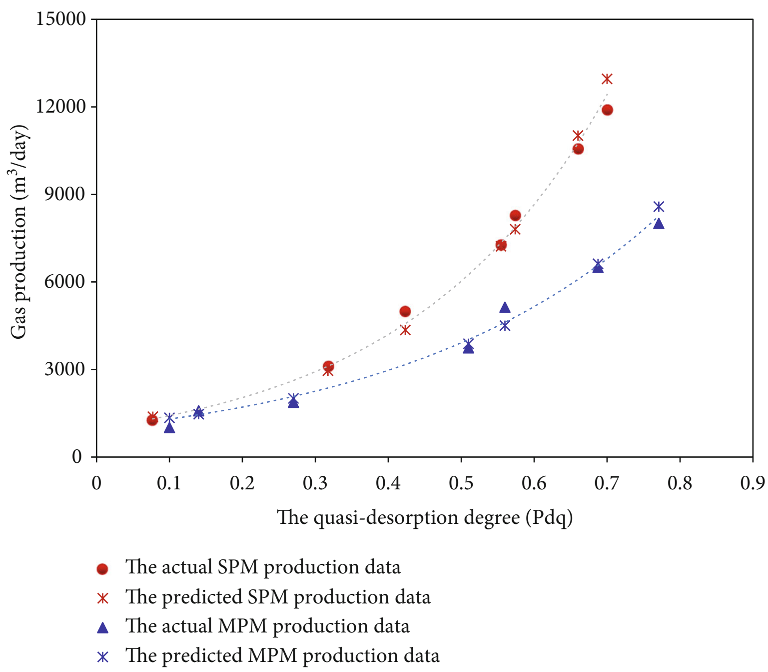


Figure 12: Comparison of actual gas production and predicted gas production.

production prediction model can be established by first analyzing the geological potential of this gas well and then fitting the actual data in the early stage. When the bottom-hole pressure tends to 0, that is, the degree of quasidesorption P_{dq} approaches 1, and the gas production obtained is the peak production of the gas well.

Considering the statistical data and prediction model results in Figure 9, the early productivity and later production mode of gas wells can be determined. For potential MPM gas wells, corresponding measures should be made in advance to accurately evaluate the development benefits and then optimize the development plan.

Although formulas (5) and (6) theoretically establish the relationship between gas production and P_{dp}, the wellbore dynamic fluid level should be slowly lowered in the process of reducing bottom-hole pressure, so as to prevent the damage to the reservoir caused by excessive pressure change. In the calculation of the desorption degree, P_{wf} is finally selected due to the huge acquisition difficulty of P_f, but it can be seen from Figure 11 that this parameter can also meet the prediction requirements.

6. Conclusion

(1) There are two main types of CBM gas production modes in Panhe: SPM and MPM. The SPM has high gas production potential, and the number of peaks MPM is mainly affected by the continuity of the gas well

(2) CBM production is comprehensively affected by gas content, formation coefficient, the relative depth of coal seam, degree of quasidesorption, and continuity of production, among which the degree of quasidesorption is more sensitive to production with the exponential relationship

(3) The continuity of a gas well affects its production. Due to mechanical failure, pulverized coal clogging, power outage, and so on, it is easy for water lock to occur in gas wells and increase seepage resistance, which leads to poor drainage effect. Therefore, the continuity of gas well production should be ensured as much as possible

(4) Based on the dynamic production prediction model, the development potential of gas wells can be reasonably evaluated, the late production mode can be judged, the development benefit of gas wells can be evaluated, and the development plan can be optimized

Nomenclature

CBM: Coalbed methane
SPM: Single-peak mode
MPM: Multipeak mode
EUR: Estimated ultimate recovery
P_g: Geological potential evaluation model (dimensionless)
C_g: Gas content (m^3/t)
KH: Formation coefficient (mD•m)
D: The relative depth of coal seam (m)
P_d: The coefficient of desorption degree (dimensionless)
P_{cd}: The critical desorption pressure of the coal reservoir within the swept area (MPa)
P_f: The average formation pressure near the well bottom (MPa)

P_{dq}: The pseudodesorption degree (dimensionless)
α_0: The coefficient of equation (dimensionless)
q: The daily production of CBM (m^3/d).

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare no conflict of interest.

Authors' Contributions

Zhiwang Yuan and Yancheng Liu were responsible for the conceptualization. Zhiwang Yuan was responsible for the methodology. Zhiwang Yuan and Hao Wu were responsible for the validation. Zhiwang Yuan was responsible for the writing—original draft preparation. Zhiwang Yuan, Hao Wu, Yifan Zhang, Yufei Gao, and Xu Zhang were responsible for the writing—review and editing.

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