

Evaluation of infill well pattern based on the dynamic change of reservoirs during coalbed methane development

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Abstract With the deepening of coalbed methane (CBM) exploration and development, the problem of low gas production has gradually become one of the main factors restricting the development of the CBM industry in China. Reasonable well pattern deployment can improve the productivity of CBM wells and reduce the cost of production, while the reservoir changes of CBM wells play an important role for well pattern infilling. In this study, the dynamic characteristics of the average reservoir pressure (ARP), permeability, and drainage radius during the development process of CBM wells are systematically analyzed, and predicted the production changes of well groups before and after infilling wells in combination with the characteristics of reservoir changes. The results show that the high gas production wells have a larger pressure drop, long drainage radius, and a large increase in permeability. On the contrary, low gas production wells are characterized by small drainage radius, damaged permeability and difficult to recover. The productivity of infilled horizontal wells is predicted for two well groups with different productivity and reservoir dynamic characteristics. After infilling wells, the production of current wells has increased at different degrees. It is predicted that the average gas production of low gas production well group H1 and middle gas production well group H2 will increase 1.64 and 2.09 times respectively after 3000 days production simulation. In addition, the pressure interference between wells has increased significantly, and the overall gas production of the well group has greatly increased. Infill wells can achieve better development results in areas with superior CBM resources, recoverable reservoir permeability, and small drainage radius during the early production process. The research

results provide a reference for the later infill adjustment of CBM well patterns in the study area.

Keywords well pattern optimization, reservoir dynamic variation, infill well deployment, coalbed methane, Qinshui Basin

1 Introduction

In recent years, China has accelerated energy and natural gas transformation to “increase reserves and production”, of which coalbed methane (CBM) is an important component (Qin et al., 2018; Zou et al., 2019). China’s CBM industry is developing rapidly, but the problem of low single-well gas production has not been effectively addressed (Lau et al., 2017; Tao et al., 2019). Well pattern optimization and adjustment are key factors in CBM development engineering. A reasonable well pattern layout is conducive to expanding and superimposing pressure drop funnels between adjacent wells, forming reservoir pressure reduction over large areas, and improving the CBM desorption rate and the production of CBM wells (Bustin and Clarkson, 1998; Xuan et al., 2013; Feng and Liao, 2020; Ma, 2021; Zuo et al., 2022). The optimization of well spacing in low gas production areas can effectively improve CBM production (Meng et al., 2018).

At present, research on CBM well pattern optimization has mainly focused on well spacing, well pattern type, and well pattern orientation from the aspects of the geological conditions of the coal reservoirs (Zhang et al., 2020; Wątor et al., 2020; Wang et al., 2021), theoretical mathematical models (Keim et al., 2011), numerical simulation software technology (Liu et al., 2015; Liu et al., 2021), and well pattern economy (Zuber et al.,

1990). Liu et al. (2015) proposed that the orientation of the well pattern is related to the fracture direction through a detailed description of geological conditions. Generally, the long side of a rectangular well pattern is parallel to the fracture direction or the face cleat direction, and the combined deployment of U-shaped wells and vertical wells is most conducive to the high production of CBM wells. Zhao et al. (2016) analyzed the sensitivity of CBM reservoir parameters, proposed an optimized well pattern model combined with reservoir properties, surface conditions, and economy. Xu et al. (2017) established a mathematical model based on the concept of a balanced pressure drop, optimized the well spacing of fractured vertical wells, and verified the model through a numerical simulation.

Well pattern optimization and adjustment should be based on reservoir geological conditions, be guided by reservoir dynamic changes during the production process, and be aimed at reservoir collaborative depressurization (Li et al., 2018; Meng et al., 2018; Sun et al., 2018). Dynamic changes in the reservoir during the production process is the key factor affecting the well spacing. The change in the reservoir pressure directly affects methane desorption and production. Therefore, it is very important to find out the pressure propagation during the production process for the optimal deployment of a CBM well pattern (Connell et al., 2010; Tao et al., 2012; Zhao et al., 2014; Yan et al., 2019). There is no unified method and standard for the optimization of CBM well patterns, and its application is limited. Based on studying the pressure propagation law during the production process of single wells, some scholars have conducted theoretical and experimental research on pressure propagation under the production conditions of well groups (Liu et al., 2011; Jin et al., 2015; Lin and Shen, 2015), but they have not combined the propagation characteristics of the reservoir pressure with the productivity of CBM wells to demonstrate the advantages of large-scale well pattern development technology. Theoretical research on the pressure drop of single wells is relatively sound, and the mathematical theory involved in well group development is relatively complex. The dynamic change in the pressure of a well group can be effectively simulated by the numerical simulation method.

CBM has been developed commercially for more than ten years in the Shizhuangnan Block (SZB) of the Qinshui Basin, but there are a large number of low gas production wells and the overall productivity is poor in the block (Peng et al., 2017). Taking the CBM well in the SZB as the research object, this study calculates and analyzes the dynamic changes in permeability, average reservoir pressure (ARP), and drainage radius during the production process of CBM wells with different drainage and production characteristics. Based on the reservoir dynamic variation characteristics of CBM wells, an infill well pattern model for productivity prediction is established. This study looks at whether promote the

overall collaborative pressure drop by drilling new wells in the low gas production well area to achieve the increase of gas production of old wells. The results of this study can provide a theoretical basis for formulating a reasonable well pattern and spacing, help to scientifically and accurately predict development indicators, and achieve the efficient development of CBM wells.

2 Geological setting

The SZB is located in the south-eastern part of the Qinshui Basin in Shanxi Province. The overall structural form of the block is a monocline striking NNE, and there are many secondary small depressions inside. The Sitou fault, the largest fault in the study area, is a NW-trending normal fault, and it forms the north-west boundary of the study area (Fig. 1). A series of arc-shaped folds with nearly EW axes are present in the south-east (Qin et al., 2018; Li et al., 2020; Yan et al., 2020a; Yan et al., 2021).

The No. 3 coal seam and the No. 15 coal seam have been stably developed in the study area. These coal seams belong to the Carboniferous Permian Taiyuan Formation and the Lower Permian Shanxi Formation, respectively. The No. 3 coal seam is thick, stable, and continuously distributed across the area, and is the main production layer for CBM development. The thickness of the coal seam ranges from 3.8 to 9.4 m, with an average of 6.29 m. The burial depth of the coal seam is distributed from 496 to 1267 m, with an average of 720 m, and the northern part is deeper than the southern part (Yan et al., 2020b; Yang et al., 2020). The initial reservoir pressure ranges from 1.4 to 8.3 MPa, with an average of 3.38 MPa. The ratio of the critical desorption pressure and the initial reservoir pressure is between 0.3 and 0.7, belonging to the undersaturated reservoir type. The permeability is mainly distributed between 0.02 and 1.30 mD, but 90% of the permeability data are below 0.5 mD, with the overall permeability being low. The gas content ranges from 4.1 to 23.3 m³/t, with an average of 13.96 m³/t. The reservoir is highly heterogeneous (Zhang et al., 2016).

3 Materials and methodology

3.1 Reservoir dynamic calculation model

The dynamic change of the coal reservoir during the process of CBM development can be studied by using the material balance method (Yee et al., 1993; Salmachi et al., 2014; Zhao et al., 2018). The pressure drop funnel is regarded as a cylinder with the wellbore as the central axis; with the discharge of the water in the coal seam and the continuous desorption of CBM, the pressure drop funnel expands. According to the research of Yan et al. (2020), the equivalent drainage radius during the production process can be calculated by using the principle of

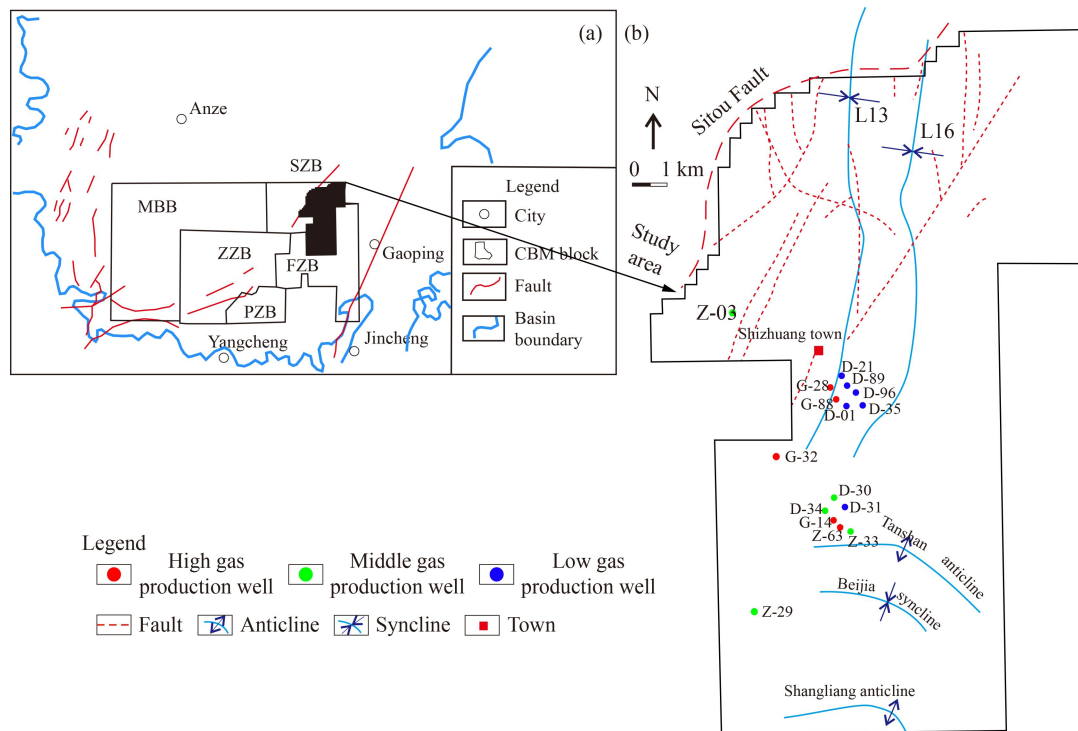


Fig. 1 Location of the sampling and study area. (a) The study area in the southern Qinshui Basin. (b) Diagram of the structural outline and location of wells in the study area (Modified from Zhang et al., 2015).

formation water conservation (Tao et al., 2014). According to the volume conservation principle of formation water, the cumulative water production of coalbed methane wells is the difference between the water volume in the reservoir and the remaining water volume in the reservoir under the original conditions plus the water volume increased due to elastic expansion (Yan et al., 2020b):

$$Ah\varphi S_w = Ah\varphi_i S_{wi} + Ah\varphi_i S_{wi} C_w (P_i - P) - W_p B_w. \quad (1)$$

Equation (1) can be converted into

$$A = \frac{W_p B_w}{h\varphi_i S_{wi} [1 + C_w (P_i - P)] - h\varphi S_w}, \quad (2)$$

$$r = \sqrt{\frac{A}{\pi}}. \quad (3)$$

According to the formula of the equivalent drainage area (A) in the process of CBM development, combined with the principle of volume conservation, the average reservoir pressure (ARP), which refers to the average value of the reservoir pressure within the drainage radius, can be calculated by Eq. (4) (Yan et al., 2020b):

$$\frac{G_p}{W_p B_w} = \frac{\frac{\rho V_L P_i (P_i P_L - P_L P)}{(P_i + P_L)(P_i P_L + P_i P)} + \frac{\varphi_i (1 - S_{wi})}{B_{gi}} - \frac{\varphi (1 - S_w)}{B_g}}{\varphi_i S_{wi} [1 + C_w (P_i - P)] - \varphi S_w}. \quad (4)$$

In the above formula, the gas volume and water volume

are converted to the subsurface condition. Here, A is the equivalent drainage area, m^2 ; W_p is the cumulative water volume, $10^{-8} m^3$; B_w is the water formation volume coefficient, dimensionless; h is the coal seam thickness, m ; φ_i is the initial porosity, dimensionless; S_{wi} is the initial water saturation, dimensionless; C_w is the compressibility coefficient of the formation water, dimensionless; P_i is the initial reservoir pressure, MPa ; P is the reservoir pressure, MPa ; φ is the porosity, dimensionless; S_w is the irreducible water saturation, dimensionless; G_p is the cumulative gas production under the surface state, $10^{-8} m^3$; ρ is the coal density, g/cm^3 ; V_L is the Langmuir volume, m^3 ; P_L is the Langmuir pressure, MPa ; B_{gi} is the gas volume coefficient under the initial pressure, dimensionless; B_g is the gas volume coefficient, dimensionless; r is the equivalent drainage radius, m .

For unsaturated coal reservoirs, the dynamic changes in the reservoir permeability during the complete drainage process include the dynamic changes in the single-phase water flow stage and the CBM desorption stage. The permeability in the single-phase flow stage (k_1) during CBM production is only affected by the effective stress, while the permeability in the gas-water two-phase flow stage (k_2) is comprehensively affected by the effective stress, the matrix shrinkage, and the gas slippage. Since gas slippage has little effect on permeability (Zhou et al., 2015), it is ignored in this study. The two-stage mathematical model of permeability change can be obtained by introducing the calculated reservoir pressure into the permeability model (Lai et al., 2013; Chen et al., 2015;

Yan et al., 2020b):

$$k_1 = k_i e^{-C_f \left(\frac{1+\nu}{1-\nu} \right) (P_i - P)}, \quad (5)$$

$$k_2 = k_{cd} e^{-C_f \left(\frac{1+\nu}{1-\nu} \right) (P_{cd} - P)} + k_{cd} \left[\frac{\pi S_v \rho^3}{162} \frac{(R(P_{cd})^3 - R(P)^3 + \varphi_i)}{\varphi_i} \right]^3 - k_{cd}, \quad (6)$$

where k_1 is the dynamic permeability of the single-phase flow stage, mD; k_2 is the dynamic permeability of the gas-water two-phase flow, mD; k_i is the initial permeability, mD; ν is the Poisson's ratio of the coal seam, dimensionless; k_{cd} is the corresponding reservoir permeability when the pressure reaches the critical desorption pressure, mD; P_{cd} is the critical desorption pressure, MPa; P_g is the pressure distribution in the desorption zone, MPa; S_v is the specific surface area, m²/kg; $R(P)$ is defined as the equivalent matrix particle radius, which is equal to the sum of the matrix radius and the adsorption layer thickness, m; C_f is the formation compressibility coefficient, MPa⁻¹.

3.2 Typical wells

Based on the production time, average daily gas and water production, and the peak value of the production curve of the CBM wells in the study area, the CBM wells are divided into three categories and five sub-categories as follows: high gas production wells (average daily gas production > 1000 m³/d), medium gas production wells (average daily gas production is between 500 and 1000 m³/d), and low gas production wells (average daily gas production < 500 m³/d). And the average daily gas

production is defined as ratio of the total gas production and the valid gas production days (i.e., the normal production days or total production days plus the shut down days). The dynamic changes of the reservoir in different production well types vary during the production process. A typical well with a continuous drainage process and long production time is selected for each type of typical well in the study area (Fig. 1(b)). The typical high gas production wells include well G-88 and well G-32, the typical medium gas production wells include well Z-29 and well Z-03, and the typical low gas production wells include well D-01. Based on geological and production data (Table 1), the corresponding dynamic changes in the reservoir are calculated using the dynamic change model of the reservoir pressure and permeability, and then the dynamic change laws of the different types of CBM wells are analyzed.

3.3 Evaluation method of the infill effect

This study relies on the Comet 3 numerical simulation software to evaluate the infilling effect of CBM wells. Comet 3 is an unconventional natural gas development platform used to simulate multidimensional, multicomponent gas, gas-water two-phase, and multiple pore structures. Based on the dual pore structure model of coal reservoirs constructed under an idealized condition of the fractured medium and according to the changes of the bottom hole flow pressure and drainage system during the production process, this software simulates the desorption, diffusion, seepage, migration, and other processes of the CBM in the reservoir through built-in control equations; the software also accurately inverts the geological parameters of the coal reservoir and then carries out historical fitting and prediction of the CBM productivity (Li et al., 2012). Comet 3 software has the

Table 1 Geological and characteristic drainage parameters of typical wells

Types of CBM wells		Typical high gas production wells		Typical medium gas production wells		Typical low gas production wells
		G-88	G-32	Z-29	Z-03	D-01
Geological parameters	Initial reservoir pressure (MPa)	4.8	3.5	3.1	4.0	3.2
	Langmuir volume (m ³ /t)	35.7	32	36.8	36.1	32.9
	Langmuir pressure (MPa)	1.8	2.8	2.4	1.6	3.1
	porosity (%)	0.01	0.015	0.03	0.02	0.05
	Initial permeability (mD)	0.80	1.00	0.56	0.29	0.14
Drainage and production parameters	Average daily gas production (m ³ /d)	1398	1215	535	573	385
	Average daily water production (m ³ /d)	0.40	0.32	1.53	0.95	4.76
	Cumulative production time (d)	3636	3369	2309	2943	2341
	Start gas production time (d)	74	94	40	46	37
	Time to peak gas production (d)	336	914	1452	1361	/
	Maximum gas production (m ³ /d)	2356	2688	1210	1050	840
	Maximum water production (m ³ /d)	8.5	4.8	6.3	7.2	7.9

following basic assumptions when it is used: 1) constant reservoir temperature; 2) the flow of gas and water in the fracture system can be described by Darcy's law and relative permeability; 3) in the finite difference grid model, the coal matrix is isotropic, but the size and adsorption time of different matrix can be different; 4) at any time, the diffusion process of fluid from coal matrix to fracture system is pseudo steady-state.

First, a dual-porosity, single permeability, gas and water two phase, single component, sorption model is selected. Secondly, a three-dimensional geological model is established based on coal thickness, gas content, initial permeability, fracture permeability, methane adsorption (Langmuir volume and Langmuir pressure), gas water relative permeability, and other parameters (Fig. 2). The Comet 3 software optimizes the conversion between the maximum water production rate and the bottom hole pressure control, which is conducive to the management of well group operation constraints. The infill well group is selected based on the dynamic changes of the reservoir and the actual drainage and production conditions of the production wells.

The differences in the reservoir pressure, gas content, gas and water production before and after the infilling of vertical well groups during CBM production are compared and the infilling effect is evaluated using the numerical simulation method. The specific numerical simulation and encryption effects are discussed in Section 4.3.

4 Results and Discussion

4.1 Dynamic changes of the reservoir in the CBM wells

4.1.1 Dynamic characteristics of the coal reservoir in the high gas production wells

Based on the characteristics of the gas and water production, the high gas production wells are divided into type 1 and type 2. The time to reach high gas production for the type 1 and type 2 wells are less than 500 d and more than 500 d, respectively. After that, they maintain a high and stable production for a long time. These two types of wells produce low amounts of water during the production process, and the water production curve shows a single peak. Specifically, the water production is high before reaching high gas production, and the water production is close to zero in the later stage. The production parameters of the CBM wells are shown in Table 2.

The peak times of the gas production of the typical high gas production wells, i.e., G-88 (type 1 well) and G-32 (type 2 well) are 247 days and 854 days, respectively (Figs. 3(a) and 3(b)). The ARP drop of well G-88 and well G-32 is 118.23 kPa/100d and 75.4 kPa/100d during the production process, respectively. The effective drainage radius of the two wells is 180 m and 122 m, respectively (Figs. 3(c) and 3(d)).

Water production is closely related to the change of the

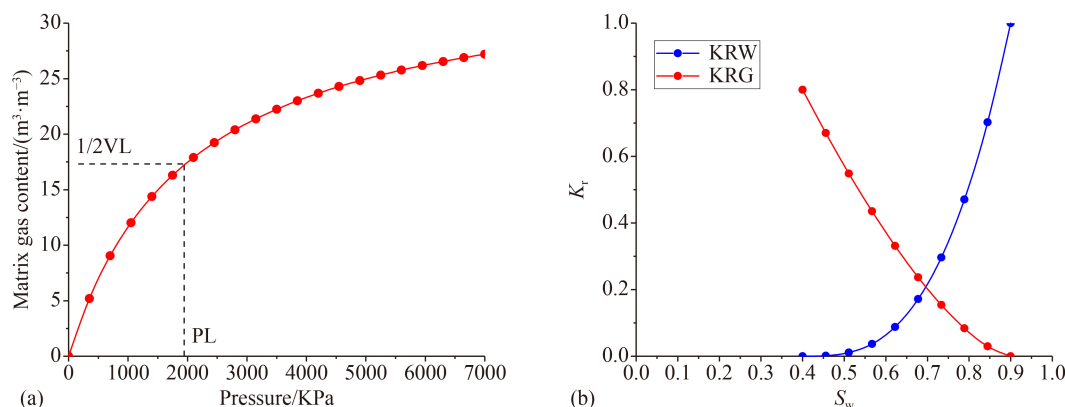


Fig. 2 Models for infill well numerical simulation. (a) Methane gas storage capacity. (b) Relative permeability model of gas and water. S_w : fracture water saturation (fraction), KRG: fracture relative permeability to gas (fraction), KRW: fracture relative permeability to water (fraction).

Table 2 Calculation results of reservoir dynamic changes of typical wells

Types of CBM drainage wells	High gas production wells		Medium gas production wells		Low gas production wells
	G-88	G-32	Z-29	Z-03	D-01
Pressure drop amplitude (%)	89.58	62.85	64.00	43.25	33.75
Drainage radius (m)	181	125	111	105	97
Permeability change rate (k/ki)	3.00	3.40	0.92	0.96	0.90
Average pressure drop rate (KPa/100d)	118.2	75.4	125.0	73.7	46.2

ARP and the drainage radius. Before reaching high gas production, a large amount of coal seam water is discharged, resulting in the rapid reduction of the reservoir pressure and the rapid expansion of the drainage radius. The average water production of well G-32 is relatively high and the declining rate of the reservoir pressure is slow. Figure 3(d) shows that after reaching high gas production, further expansion of the drainage radius almost stops close to the well control boundary, the ARP drop increases, a large amount of CBM within the well control range is desorbed, and this enables the well to reach peak gas production.

Before gas production reaching the peak, gas production is low but the water production is relatively large. The permeability curves of the two wells show a rising trend in the entire production process, with the increasing speed from slow to fast. This is because the “positive effect” caused by matrix shrinkage in the early stage is greater than the “negative effect” caused by effective stress, resulting in a slow increase in permeability. With the decrease of water production, the effective stress effect decreases gradually; but with the increase of methane desorption, the matrix shrinkage effect is more significant, and the permeability increases faster (Mazumder et al., 2012; Chen et al., 2015).

During the entire production process, the increase in the amplitude of the permeability and the decrease in the amplitude of the ARP shows a process from slow to fast,

and the drainage radius tends to be stable after rapidly expanding to the well control boundary.

4.1.2 Dynamic characteristics of the coal reservoir in the medium gas production wells

There are also two types of medium gas production wells. The daily gas production of the type 1 medium gas production wells reaches high production during the production process, but the time of high and stable production is short; the water production is relatively stable, and there is a “stable platform” for the water production curve before high gas production (Fig. 4(a)). The type 2 medium gas production wells fail to achieve high production. The water production curve shows a multi-peak shape or the water production is stable and high in the production cycle (Fig. 4(b)).

The ARP drop of well Z-29, which is a type 1 medium gas production well is 125 kPa/100 d; during the production process, the effective drainage radius reaches up to 111 m, and the permeability curve presents three stages of “decrease - stability - increase”. The reservoir change of well Z-29 can be divided into four stages: single-phase water stage, stage before high gas production, high gas production stage, and gas production decline stage (Fig. 4(c)).

In the single-phase water stage, the ARP and permeability decrease rapidly. This is because before gas

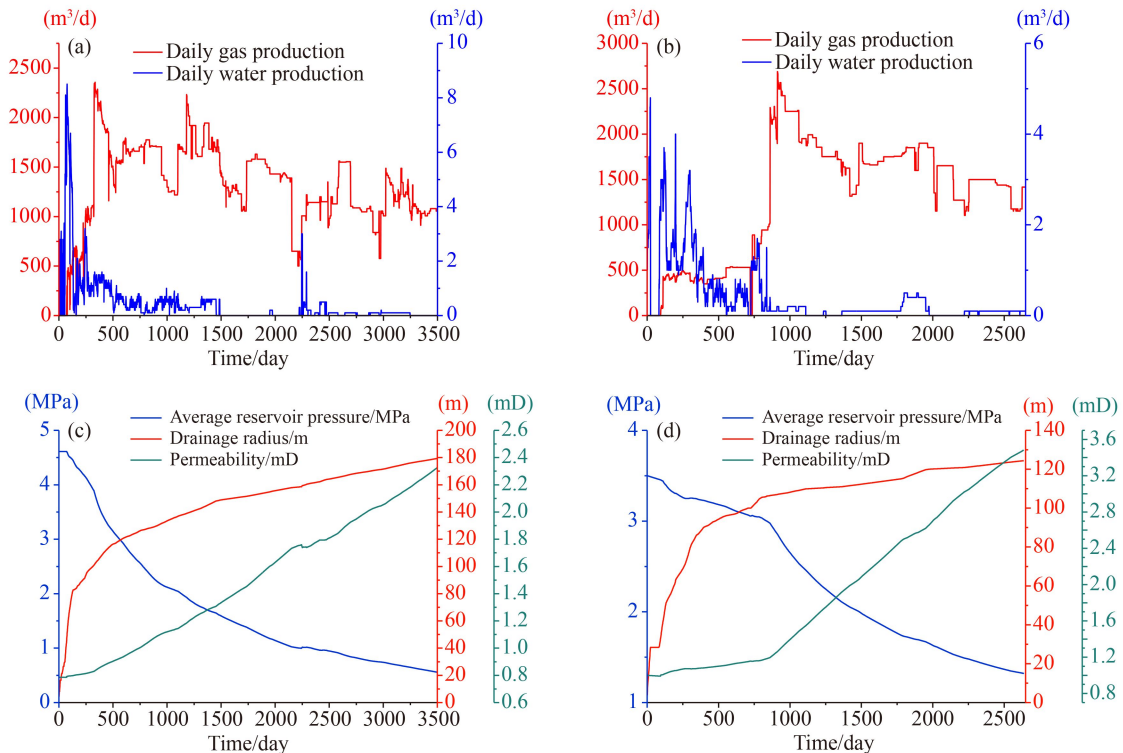


Fig. 3 Drainage production and reservoir performance curve of the typical high gas production wells. (a) and (b) Production curves of Well G-88 and Well G-32, respectively. (c) and (d) Reservoir performance curve of Well G-88 and Well G-32, respectively.

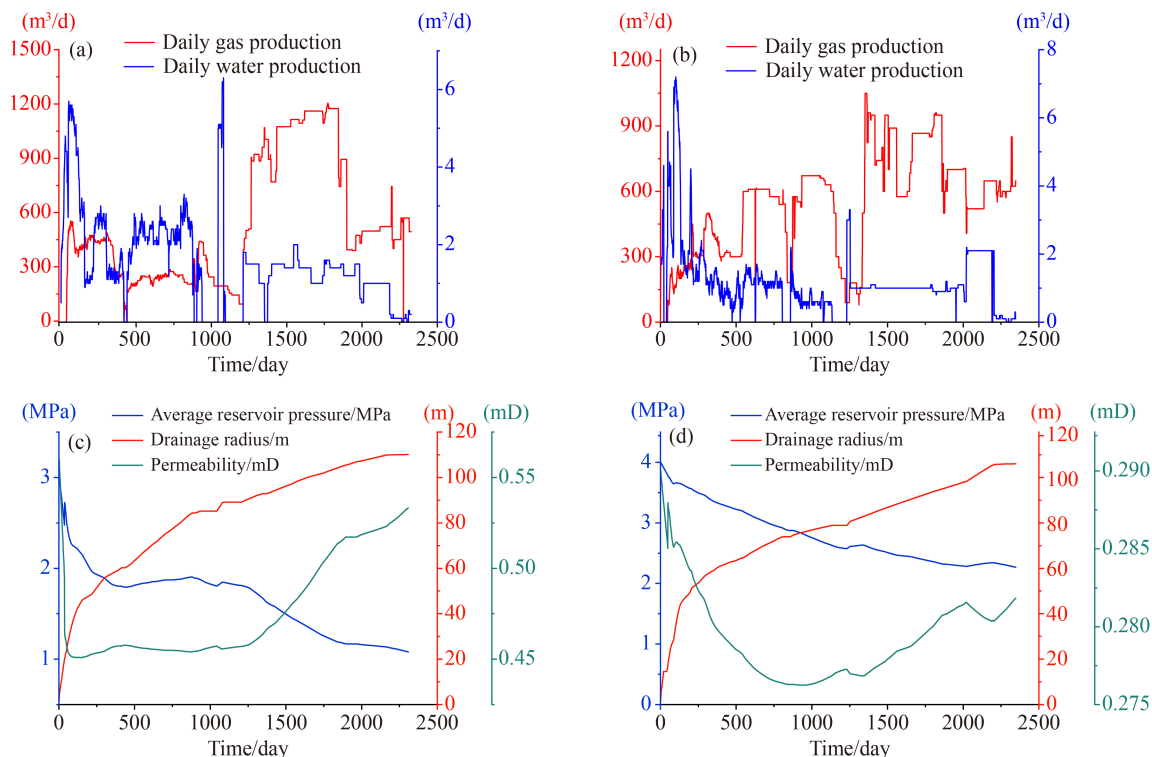


Fig. 4 Drainage production and reservoir performance curve of typical medium gas production wells. (a) and (b) Production curves of Well Z-29 and Well Z-03, respectively. (c) and (d) Reservoir performance curve of Well Z-29 and Well Z-03, respectively.

production, the coal reservoir near the wellbore is subject to fracturing transformation, and the permeability is much greater than that in other parts. The drainage radius is near the wellbore, and a large amount of water production leads to the rapid decline of the ARP within the drainage radius. At the same time, the single-phase water leads to an increase in the reservoir's effective stress and a decrease in permeability under the influence of the effective stress effect. In the stage before high gas production, the drainage radius is mainly expanded. The expansion of the drainage radius leads to the ARP being stable for a certain period of time. At this time, the gas gradually begins to desorb, the matrix shrinkage effect gradually plays a role, and the permeability remains relatively stable. In the high gas production stage, as the drainage radius gradually approaches the well control boundary and forms an effective inter-well pressure interference, the ARP decreases steadily, a large amount of methane is desorbed, and the gas production increases and maintains a high level. The matrix shrinkage effect produced by gas desorption has a greater recovery effect on the reservoir permeability than the damaging effect of the effective stress, and the reservoir permeability increases gradually. In the gas production decline stage, the drainage radius hardly expands and the variation range of the ARP and permeability is small. The analysis shows that the sudden decline of gas production in the later stage of production may be caused by unstable drainage and production, and, therefore, stable drainage

and production are very important for the high production of CBM wells.

The extended distance of well Z-03, which is a type 2 medium gas production well, is similar to that of the type 1 well, Z-29, but the ARP drop range is only 43.25%. The permeability curve shows a “rebound” shape of first decreasing and then increasing (Fig. 4(d)). At about 850 days, the positive effect caused by matrix shrinkage is balanced with the negative effect caused by the effective stress, and the permeability reaches the rebound point and finally returns to 96.2% of the initial value. This may be due to the low initial permeability and the difficulty of rapidly draining the coal seam water. This kind of well has poor reservoir conditions and difficult reconstruction characteristics. The equivalent drainage radius takes a long time to reach the maximum well control boundary.

4.1.3 Dynamic characteristics of the coal reservoir in the low gas production wells

The maximum gas production of the low gas production wells during the production process is less than 1000 m³/d, the gas production curve has volatility, and the overall water production is high. The water production curve shows a multi-peak shape or is stable with high water production (Fig. 5(a)).

The pressure drop amplitude of the low gas production well, D-01, is only 33.75%, the expansion distance of the drainage radius is within 100 m, and the reservoir

permeability is stable at a low value after 200 days (Fig. 5(b)). There are two possible reasons for this phenomenon. On the one hand, the engineering and drainage factors lead to the blockage of pores and fractures, and the reservoir permeability is too low, and, therefore, the drainage radius is small, the pressure can't spread, and the methane can't be desorbed; this results in the permeability remaining at a low level. On the other hand, it may be that the fractures communicate with the aquifer, and the water in the aquifer flows to the wellbore, resulting in the failure of the drainage radius to expand to the far end and causing the ARP to be keep at a high level. Water lock occurs in the reservoir, and, therefore, the matrix shrinkage effect is not obvious and the permeability cannot be restored.

Overall, the development effect is better in CBM wells with a large decline of the ARP, long drainage radius, and the recovery of the permeability is better. Areas with a small expansion distance of the drainage radius and a low decline range of the ARP are potential areas for the future exploitation of CBM.

Based on the above, areas with good geological resources, simple geological structure, and low gas production of the surrounding wells should be selected and engineering measures such as infill well patterns should be implemented to improve the productivity of the CBM wells. After the well pattern is densified, the well spacing is reduced, which can make the adjacent wells cause inter-well interference earlier, and effectively improve the pressure drop range of the production wells to improve the productivity of the wells.

4.2 Current well spacing

The development time of the CBM wells in the SZB is long and the number of wells is large, but low gas production wells account for a high proportion of the total wells. At present, vertical and directional wells have been mainly deployed in the study area, while horizontal wells have been deployed less. The well spacing of 1008 wells

was counted and recorded in the SZB; the well spacing is mostly distributed in the range of 250 m to 350 m, accounting for about 66% of the total number of wells. However, the number of wells with well spacings less than 300 m accounts for 39%, and there are only 87 wells with a well spacing less than 250 m, accounting for 9% of the total number of wells (Fig. 6).

The drainage radius of the different types of CBM wells was calculated, and the results show that the drainage radius of most of the CBM wells is less than 150 m, and that of some low gas production CBM wells is below 100 m. In this case, the well spacing of 300 m is not enough to cause a pressure disturbance between adjacent wells. Comparing the current well spacing with that from the calculation of drainage radius, it is considered that the current well spacing is too large, and it makes it difficult for collaborative depressurization to form between adjacent wells; therefore, it is not conducive to the optimal production of CBM. A proper infill well deployment within the current well pattern is conducive to improving the productivity of wells in the study area.

4.3 Productivity prediction of infill wells

4.3.1 Selection principle of the infill well group

The initial reservoir permeability is low in the SZB, and most of the well spacing in the early well pattern deployment is too large. Therefore, deploying infill wells is one of the best measures to increase production. However, previous studies have shown that using a vertical infill well pattern has problems of a limited pressure relief area and difficulties in causing large-area inter-well interference (Sun et al., 2019). Considering the strong advantages of horizontal wells, this study proposes to deploy horizontal infill wells in the existing vertical well group. This can reduce the well spacing and also achieve a staggered connection series and the collaborative depressurization of the vertical and horizontal wells,

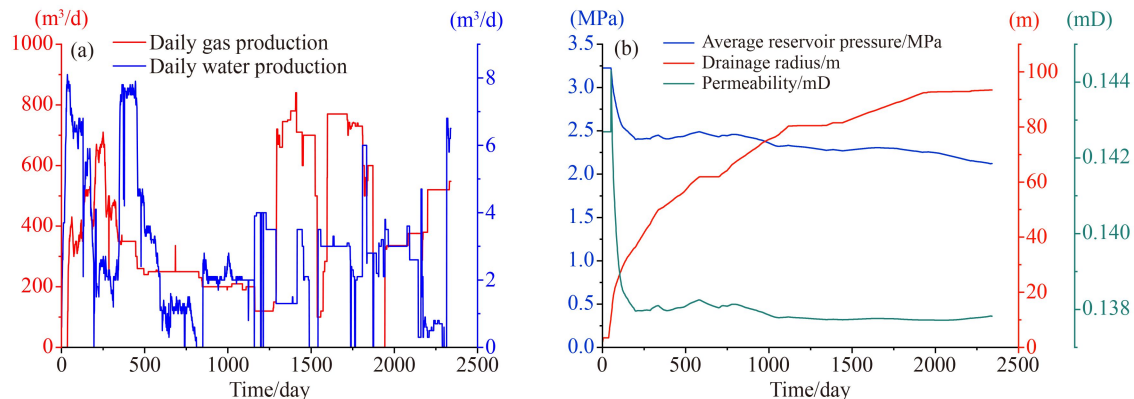


Fig. 5 Drainage production and reservoir performance curve of typical low gas production well D-01. (a) Production curves. (b) Reservoir performance curve.

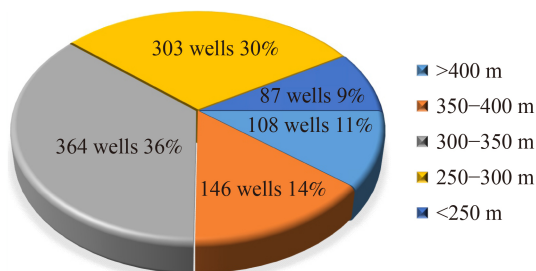


Fig. 6 Statistics of the current well spacing in study area.

and improve the utilization of resources.

To further clarify the geological applicability of horizontal infill well technology in the SZB and comprehensively consider the economic benefits and geological conditions, the selection of horizontal infill wells in the study area should follow the following principles: 1) the current wells have large spacing and small drainage radius, and, therefore, the gas production does not meet the expectation; 2) abundant resource conditions: high gas content, located in high potential areas; 3) high-quality reservoir conditions: far away from faults, small dip angle of the coal seam, and simple coal structure. Deployment principles of horizontal wells: 1) the orientation of the horizontal section should be perpendicular to the fracturing fracture of the vertical well; 2) the horizontal section should be about 800 m long and the horizontal section or fracturing fracture should be within 100 m from the vertical well.

4.3.2 Numerical simulation of the infill wells

According to the well layout principles, two vertical well groups in the SZB were selected for infilling. The cumulative production time of each well in the two well groups is approximately 3000 days. The well spacing in each well group is between 300 m and 400 m, and the geological conditions of each well in the well group are

similar. The H1 well group includes five low gas production wells (D-21, D-89, D-96, D-35, and D-01) and two high gas production wells (G-28 and G-88). Different from the H1 well group, the H2 well group includes two high gas production wells (G-14 and Z-63), three medium gas production wells (D-30, D-34, and Z-33), and one low gas production well (D-31) (Fig. 7).

In the H1 well group, the existence of the high gas production wells indicates that the resources at the H1 well group are abundant, and, therefore, the low gas production is not caused by geological factors. The average daily gas production of the high gas production wells, G-28 and G-88, is 1253.5 m³/d, the drainage radius is 150 m and 181 m, respectively, the permeability increases gradually with the progress of production, and the ARP is below 1 MPa (Figs. 8(f) and 8(g)). However, in the five low gas production wells, the average daily gas production is 231.6 m³/d; the reservoir dynamic change curve of each well shows that the ARP drop rate is only 10.31%, the permeability curves show a decreasing shape, the permeability change rate is between 89% and 0.99%, and the expansion distance of the drainage radius is within 150 m (except for well D-96) (Figs. 8(a)–8(e)).

The reservoir pressure drop diagram after the vertical well of the H1 well group was put into operation shows that the reservoir pressure at the intermediate infill well is still about 3 MPa, the pressure relief range of the production wells is limited, and the utilization rate of the resources is low, resulting in low gas production of the single wells. Excessive well spacing makes it difficult to achieve effective pressure interference between the adjacent wells, and the amount of resources produced by a single well is limited.

For the H2 well group, except for well D-31, the average daily gas production of each well is 800.20 m³/d, and the permeability changes are increased or restored. However, the ARP drop amplitude of the five medium and high gas production wells is 58.13%, which is not a

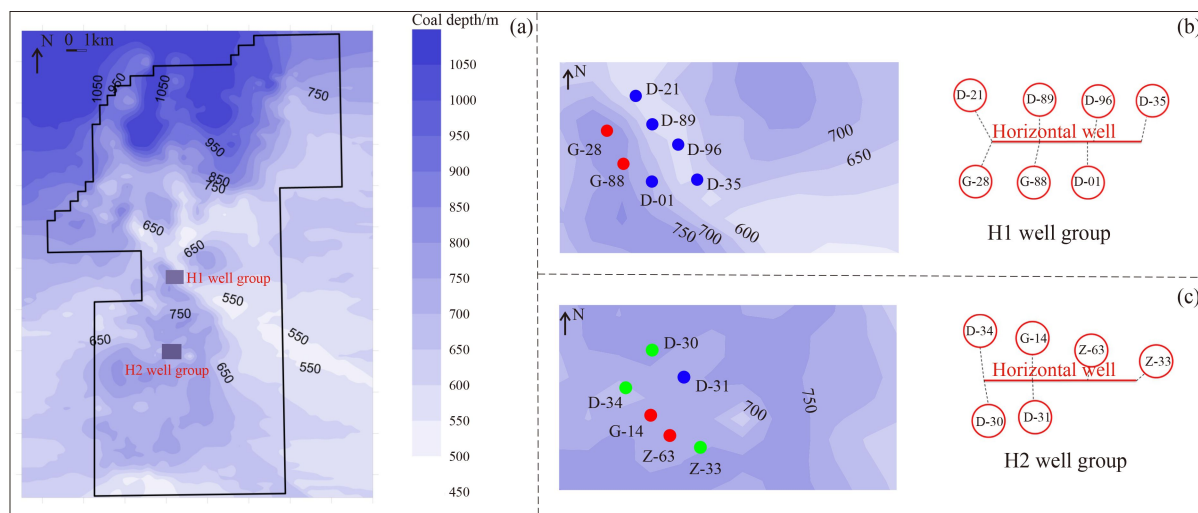


Fig. 7 Location of two well group and infill horizontal wells schematic diagram.

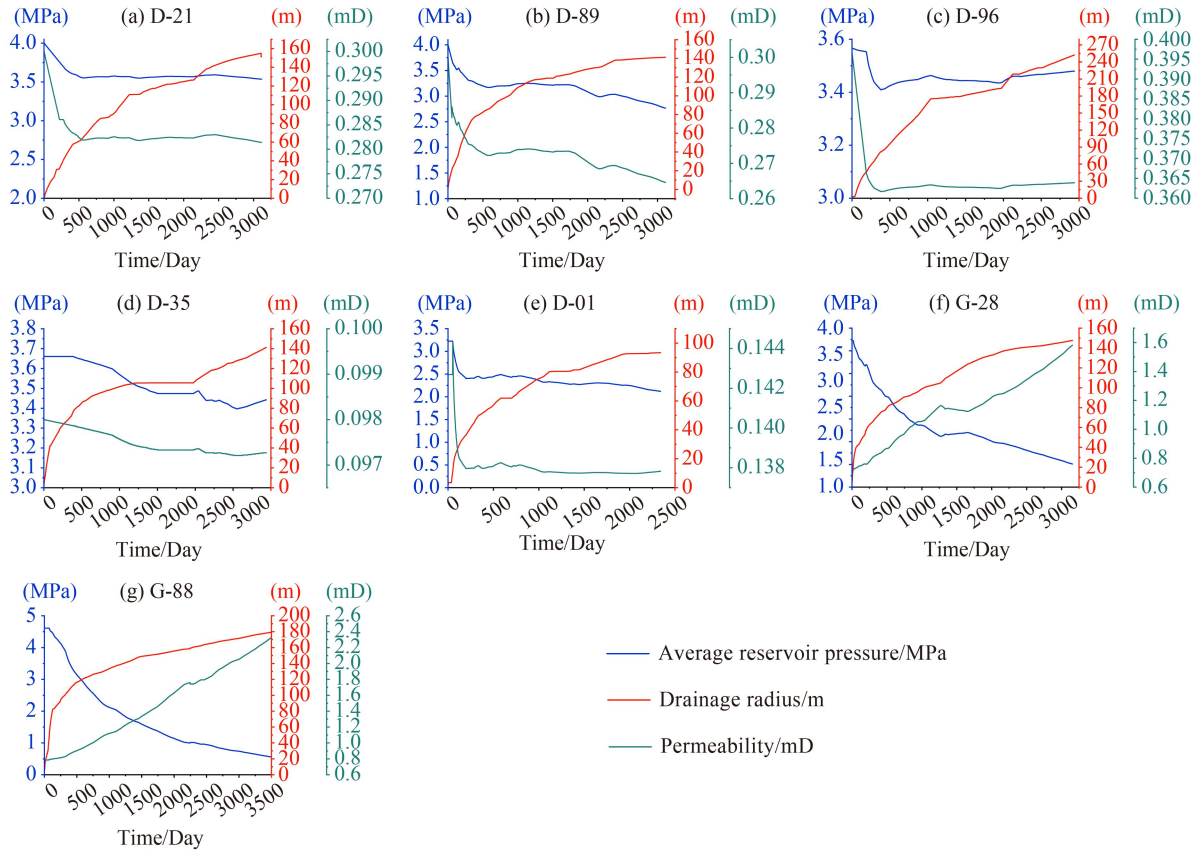


Fig. 8 H1 well group reservoir dynamic change curve during the production process.

sufficient pressure drop (Fig. 9). In addition, the drainage radius of the five wells is less than 140 m, which indicates that the well group productivity is still excellent without the formation of inter-well interference. At this time, if infill wells are deployed, the well group productivity in the favorable area will be greatly increased. The permeability of the low gas production well, D-31, decreases continuously, the ARP decreases by only 13%, and the drainage and production radius reaches 180 m (Fig. 9(f)). The production situation shows that the low gas production and the high water production, which may be caused by the well being located in the low part of the structure, the interference between wells D-31 and D-30 is caused by the convergence of the surrounding coal seams' water.

The productivity history of the stable production vertical wells in the well group was fitted using the numerical simulation software to correct the basic geological parameters (Table 3), simulate the coupling relationship between the horizontal wells and the adjacent wells, and predict the productivity potential of the well group after infilling. The horizontal well adopts the bottom hole pressure stably produced in the block, and the vertical well steadily depressurizes to the abandonment pressure of 0.2 MPa based on the original bottom hole pressure drop.

4.3.3 Effect of the infill wells

The prediction results show that after the horizontal wells are added to the well group, the maximum daily gas production and average daily gas production of each well in the well group increase to varying degrees due to the synergistic depressurization effect of the surrounding vertical wells. In the H1 well group, the maximum daily production of the single horizontal well is 8100 m³/d, and the average daily gas production is 5625 m³/d. The gas production of the 5 low production vertical wells increased from 216 m³/d to 666 m³/d, which is an increase of 3.08 times. The average daily production of the vertical wells of the H1 well group increased by 1.64 times (Fig. 10(a)).

It is predicted that the average daily gas production of the horizontal wells in the H2 well group is 5424 m³/d, the gas production of the surrounding old wells all reach high production, and the maximum gas production of the vertical wells reaches 2702 m³/d. After infilling, the average daily production of the well group increases by 2.09 times (Fig. 10(b)).

Then, the changes of each well in the H1 well group before and after infilling were analyzed. The drainage radius of the two high gas production wells, G-28 and G-88, in front of the infill wells is 170 m and 180 m, respectively, but the well spacing between the two wells

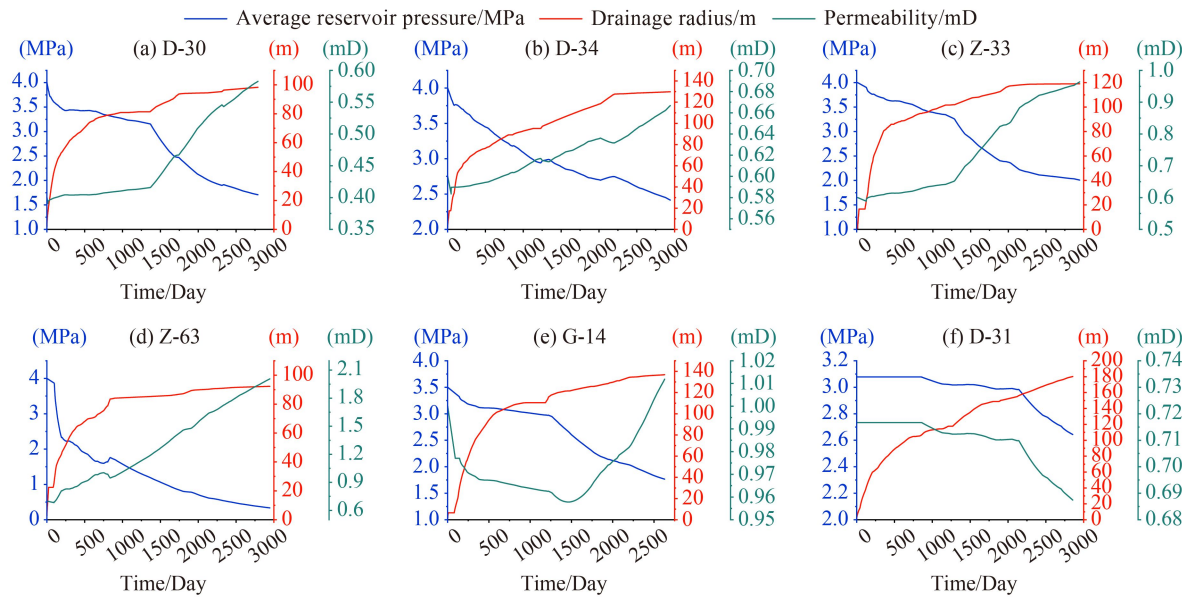


Fig. 9 H2 well group's reservoir's dynamic change curve during the production process.

Table 3 Numerical simulation parameters of the well group

Parameter category	parameters	H1 well group fitting value	H2 well group fitting value
History fitting parameters	Buried depth (m)	775	658
	permeability (mD)	0.2	0.5
	Reservoir pressure (MPa)	4	4
	Langmuir volume (m ³ /t)	31	35
	Coal thickness (m)	6	6
	Fracture porosity (%)	6%	1.5%
	Langmuir pressure (MPa)	2.5	2.5
	Gas content (m ³ /t)	17	21
	skin factor (/)	−1	−1.5
	Reservoir temperature (°C)	26	24
Horizontal well parameters	Length of horizontal section (m)	800	
	Number of fracturing fractures (/)	4	
	Fracture conductivity (μm ² ·cm)	60	
	Half length of fracturing fracture (m)	100	
Numerical simulation settings	Abandonment pressure (MPa)	0.2	
	Simulation time (d)	3000	

is 300 m, indicating that inter-well pressure interference was formed between the two wells. After infilling the horizontal wells, the two wells further formed a pressure interference with the surrounding vertical wells (D-01) and horizontal wells, forming a large-area regional pressure drop change, which enabled high and stable production (Fig. 11(a)). The gas production of the five low gas production wells in the well group reached the medium gas production level after infilling; the maximum daily gas production reached 748 m³/d, and the average daily gas production of a single well increased by 6.9 times. It is worth noting that the drainage radius of well

D-96 as calculated by the model reaches 270 m; based on the analysis of the productivity and dynamic change curve of the reservoir, the well has high water production and low gas production. Because the drainage radius in the model is calculated based on the drainage and production parameters such as cumulative water and gas production, with the expansion of the drainage radius, the ARP shows an ascending pattern; this means that with the high water production of the CBM well, the formation continues to supplement water to the wellbore, and, therefore, this indicates that the well can communicate with the aquifer. Overall, before infilling, the reservoir

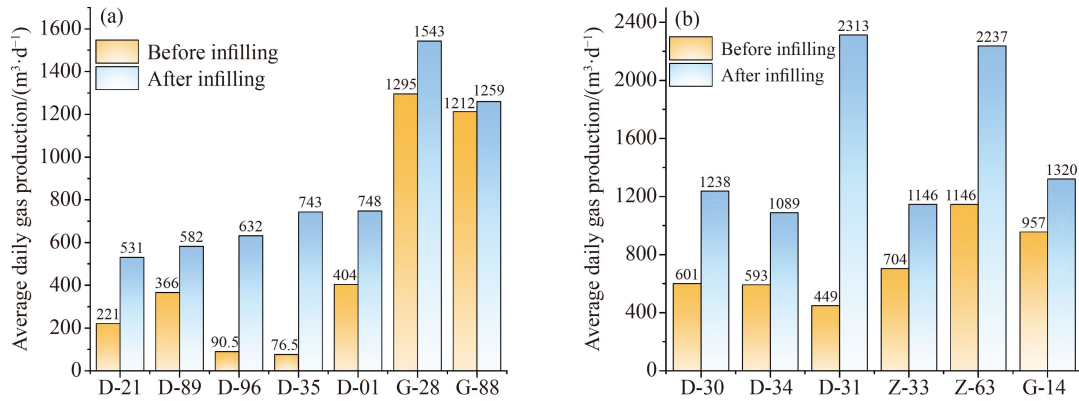


Fig. 10 Comparison of average daily gas production of each single well before and after infilling. (a) H1 well group. (b) H2 well group.

pressure propagation of each low gas production well does not interfere with that from the other low gas production wells, and each well is discharged and produced independently. One year after the horizontal well is infilled, there is inter-well interference. The horizontal well and the modified well achieved a significant pressure drop in about three years of production, and the production of each vertical well was increased (Fig. 11(a)).

In the H2 well group, before infilling, pressure interference had formed between some adjacent wells, and some wells reached high production; after the horizontal well was put into operation, the degree of inter-well interference was high and the pressure drop effect was obvious (Fig. 11(b)). It is worth noting that well D-31 changed from a low gas production one to a high production one, thereby showing that the development of the new well significantly stimulated the efficient development of the old well; the stimulation effect was significantly improved after infilling.

Specifically, although the gas production increased after the densification of the two well groups, there were also some differences. It is considered that the main reasons affecting the infilling effect are as follows.

1) Differentiated geological conditions. The average gas content of the H1 well group and the H2 well group is 18 m³/t and 20.5 m³/t, respectively. The vertical well of the H1 well group has a large coal seam burial depth, low initial permeability, and low gas supply capacity and seepage capacity, which makes desorption difficult; therefore, it is difficult for these CBM wells to achieve high production.

2) The variation characteristics of the early drainage and production are different. The permeability of the vertical wells in the H1 well group almost all decrease during the production process (Fig. 8). The unreasonable drainage system damages the permeability of the coal reservoir and limits the production of the CBM. In addition, the D-96 communication aquifer also leads to high water production and low gas production. However,

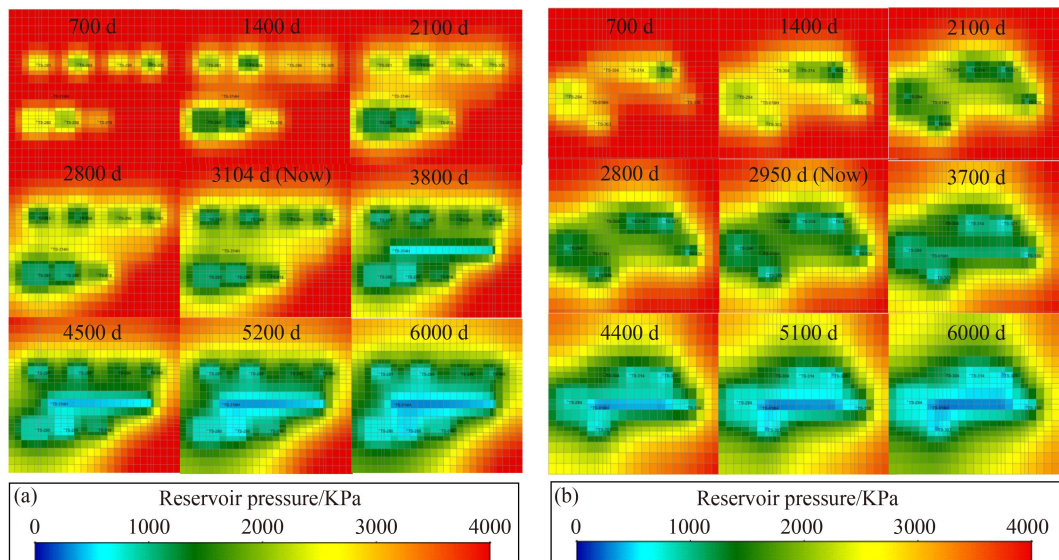


Fig. 11 Variation diagram of reservoir pressure before and after well group infilling. (a) H1 well group. (b) H2 well group.

during the production process of each well in the H2 well group, the reservoir permeability gradually recovers, and pressure interference forms between some wells before infilling. The deployment of the infill wells accelerates the recovery rate of the CBM.

The difference in the infilling effect between the two well groups also further verifies the influence of the dynamic change of the reservoir on the coupling pressure drop after the deployment of the infill wells in the process of CBM drainage and production. Therefore, in the deployment of horizontal infill wells, the dynamic change in the reservoir pressure of the old wells should be determined and the infill effect should be maximized as far as possible. For areas where reservoirs such as those in the H1 well group are damaged, only adjusting the well pattern and well type, combined with reservoir reconstruction technology and efficient drainage and production control mode, can help to achieve the overall coordinated pressure reduction in the low-efficiency area and achieve the effect of overall production increase in the block.

Therefore, well groups like the H2 well group should be selected for infill well deployment and stimulation. Infill well deployment and stimulation in these well groups is characterized by the gradual increase in permeability, low water production, medium gas production, short extension distance of the drainage radius in the early production process, and good coal seam resources and geological conditions.

5 Conclusions

Based on the geological and drainage data of CBM wells in the SZB, this study comprehensively evaluates the dynamic change characteristics of the reservoirs during the CBM wells production process; typical wells are selected for detailed analysis. Based on the reservoir change and the actual spacing of production wells, the productivity change after horizontal infill well deployment of each well group is predicted and analyzed. The following conclusions are drawn.

1) During the CBM production process, the differences in the dynamic changes of the coal reservoirs are reflected in the variation of the gas and water production. The reservoirs with high gas production wells have large ARP drop amplitude, long drainage radius, and recoverable permeability. In the low gas production wells, the ARP drop amplitude and drainage radius are small, and the initial permeability is low and damaged during the production process. The low gas production wells are drained independently, and, therefore, it is difficult for inter-well pressure interference to form.

2) The spacing of most of the CBM wells in SZB is between 300 m and 400 m, and the number of wells with a well spacing less than 300 m accounts for only 43% of

the total number of wells. However, at present, the effective drainage radius of most of the production wells is less than half of the well spacing, and infill wells are necessary and effective means to increase production.

3) The average daily production of the vertical wells in the H1 and H2 well groups after infilling is 2.78 times and 2.84 times higher than that before infilling, respectively. After the horizontal well is put into operation, the degree of pressure interference between the wells is high and the reservoir depressurization effect is obvious. The characteristics of the dynamic changes in the reservoir in the early stage of CBM wells affect the production effect after the development of infill wells. In the early production process, the well groups with a small drainage radius and recoverable reservoir permeability can be better stimulated through the deployment and development of infill wells.

Acknowledgments This work was supported by the National Natural Science Foundation of China (Grant Nos. U1910205 and 41872178) and the National Science and Technology Major Project of China (No. 2017ZX05064003).

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