Numerical simulation study on the volcanic gas reservoirs in block C of Xushen Gasfield

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Abstract. Block C of Xushen Field is one kind of the volcanic reservoirs with the bottom water. Since the development, the dynamic characteristics of the block are characterized by large differences in gas well productivity, formation water production, and low effective utilization of reserves. Using the dual-medium numerical model, through historical simulation and combination with gas well dynamic, the block pressure and, water body changes and remaining reserves distribution characteristics are clarified. The research shows that the remaining reserves of the block are mainly concentrated in the vicinity of xs901, xs903-p1 and the northwest periphery of xs902. With the increase of production allocation, the water production of six old wells such as XS9-7 increased rapidly and significantly, while the bottom water coning was obvious. Through six sets of gas production rate development plans with different magnification, consider whether the gas distribution can stabilize the output, water production, bottom hole flow pressure, and fluid accumulation. The optimal development plan of the old well in the block is determined comprehensively.

Key words: volcanic gas reservoir; numerical simulation; water change; remaining reserves; development countermeasures.

1. Introduction

Block C is a structural lithologic gas reservoir with low porosity and low permeability. The productivity of gas wells varies greatly, which is characterized by rapid pressure drop, formation water production and poor stable production capacity. The developed geological reserve of the block is 230.8% × At present, there are 16 gas wells in production, with an average of 7.1 m³ per well × 10⁴m³, the cumulative gas production is 20.4m³ × 10⁸ m³, recovery rate 8.84%. As the key block of production capacity construction, it plays an increasingly important role in the stable production of gas field. In order to do a good job in the stable production of the block and the subsequent development deployment, the numerical simulation research is carried out.
2. Establishment of block numerical model

2.1. Establishment of double medium geological model

According to the fracture development characteristics of gas reservoir in Block C, firstly, according to the fracture interpretation results of imaging logging and core identification in Block C, the fractures are grouped and the fracture density curve is calculated. Secondly, according to the existing velocity model, the seismic attributes in time domain are transformed into seismic bodies in depth domain, and ten related seismic attributes are extracted from the seismic data bodies in depth domain. According to the imaging logging results, the ten attributes are optimized, and finally five attributes are selected: ant body, coherence body, curvature body, chaotic body and similarity; Based on neural network technology, the correlation between seismic attributes, distance from fault and fracture density curve of single well is analyzed, and finally the fracture density volume is obtained. On the basis of two groups of fracture density bodies, the fracture model of Block C is established based on discrete network technology. The AKC correction technology of fracaflow software is used to calibrate the DFN model of Block C by using the KH value of well test interpretation, so as to ensure the accuracy of fracture model parameter setting, and the model conforms to the previous geological understanding, so as to achieve the consistency with the production performance. After calibration of DFN model, fracture porosity and permeability models are equivalent by analytical method. Combined with the block geological knowledge and fracture geological modeling results, it is considered that natural fractures are not the main control factor of effective permeability and productivity.

2.2. Establish the numerical simulation model

On the basis of the fracture geological model, a numerical simulation grid model is built, and the corner grid is used in the model. On the plane, the grid step size is about 100m × 100m. The vertical grid thickness is about 4m. The number of grids is 112 × one hundred and forty-five × seventy-six × 2, a total of 2468480 grids. A total of 16 faults are described. The average porosity and permeability of matrix are 5% and 0.09md respectively; The average fracture porosity is 0.09%, and the average fracture permeability is 1.34md.

First, the equilibrium region is determined. Block C includes xs9 well block and xs903 well block. The gas water interface in the block is not uniform, and the gas water distribution is mainly controlled by structure and lithology. According to the vertical k-sum distribution map and structure, fault strike, etc., 10 polygons are drawn, which are divided into 11 gas water system equilibrium zones.

Secondly, the relative permeability curve, initial parameters and fluid distribution are determined. Some microfractures are developed in Block C, but no high angle fractures are developed; The matrix is not only the reservoir space, but also the seepage channel; Most dynamic wells produce water when they are put into production, and there is no water free gas recovery period, that is to say, fractures also produce water at the initial stage of production. Based on the above three points and the attempt of actual fitting process, it is determined that fractures adopt the same relative permeability curve as the matrix. The gas reservoir has a unified pressure system, and the measured pressure at 3739m is 40.86mpa. The black oil model with water and dry gas is used to input the initial basic data, and the equilibrium method is used to initialize the fluid pressure data. After initialization, there is water at the lower part of the structure and bottom water at the bottom of the gas reservoir in the northern 3 well block of the top layer.

Finally, the water body model of Block C is established. The grid of water body and gas reservoir is connected at the bottom of gas reservoir, and some grids with high gas water interface structure are used to describe the water body.

2.3. Block history fitting

The numerical simulation adopts the fixed gas fitting system, and the fitting target is the gas production rate, water production rate and bottom hole flow pressure of the block and single well. Historical fitting quality of digital model: the relative error rate of reserves fitting is 0.1%. The relative error of cumulative gas production is 0.11%, the completion rate of single well bottom hole flow pressure fitting is 83.3%
(10 / 12), and the completion rate of single well gas production fitting is 100%. The completion rate of single well water production fitting is 81.25% (13 / 16), and the fitting error of single well is less than 5%.

3. Study on block numerical simulation

3.1. Characteristics of water production
Comparing the saturation map at the initial stage of gas reservoir bottom development with that at present, it can be seen that there is an obvious increase in water saturation. Combined with the development horizon, the wells developed at the bottom of gas reservoir are xs9, xs901, xs9-1 and xs9-2. Through the current saturation map at the bottom of the gas reservoir, we can see that the direction of water flowing into xs9 well in the northwest of xs9 well is very obvious; The water from xs901 comes from the formation water in the direction of xs9-2 well; Well xs9-1 produces water from formation water. The analysis shows that the water inflow direction is caused by gravity (gas goes up and water goes down) in the development process, water saturation increases at the bottom of the production layer, and water flows up due to pressure drop after development.

Combined with the engineering analysis of the gas reservoir, the three driving types of the gas reservoir: fluid expansion, pore volume expansion and water body have no change with time, which indicates that the water body does not have the phenomenon of bottom water cone breakthrough and edge water inflow, otherwise, the water body energy will suddenly increase. The relationship curve between dimensionless water influx and dimensionless time is a curve with different ratio of water body radius to gas reservoir radius. The blue point is the data of the gas reservoir, and the blue point is located in the horizontal section of the curve. That is to say, the water influx changes little with time, which indicates that there is no bottom water coning breakthrough or edge water inflow, otherwise, the water influx will increase greatly. It shows that the energy of edge and bottom water is weak and the water invasion rate is stable.
3.2. Characteristics of reservoir connectivity

According to the comparison of initial and present formation pressure distribution, the initial static pressure is uniform. With the production and development, the formation pressure drops obviously, and the distribution of single wells is uneven and the difference is large. Xs9-7, xs9-3, xs9, xs9-p2 in the West and xs9-p4 in the East are the low pressure points. The low value of wells in the west is related to the structure, and the two wells in the East are related to the development. The static pressure test data show that the static pressure test value of drilling after 2014 is basically around 40MPa, which is weakly affected by the static pressure drop caused by the production of developed wells, indicating that the connectivity between new wells and old wells is weak. There is no uniform gas water interface in the whole work area, and the maximum difference of elevation depth between single well gas water interface is 280m and the minimum is 7m, which also reflects the poor reservoir connectivity between wells.

![Fig. 3 Distribution of initial formation pressure](image1)

![Fig. 4 Current formation pressure distribution](image2)
From the distribution of reservoir permeability, the heterogeneity is strong. The permeability of well xs903-p2 is the highest, while that of well xs9-x6 is the lowest, and the plane gradient is 200 times. The K value high points on the East and west sides of the permeability are scattered, and most areas in the middle of the work area are low permeability areas, reflecting the poor connectivity of the whole work area.

3.3. Distribution characteristics of remaining reserves
84%, which is relatively low. From the distribution of the remaining reserves, the eastern part of the work area is rich in the remaining reserves, and the reserves in the north by west direction are the least. By analyzing the distribution of the remaining reserves in each simulation layer of the gas group, it can be seen from the histogram that, controlled by the structure and lithology, the lower the formation, the smaller the reserves. Among them, the first layer is caprock and has no reserves.

Due to the weak connectivity between wells, the distribution of remaining reserves is mainly controlled by the distribution of original reserves. The remaining reserves around xs901 and xs903-p1 and the northwest outside of xs902 are accumulated. The reserves of the first two polygons are 1.6 billion cubic meters and 1.420 billion cubic meters respectively, which are the main potential areas of block C.

According to the profile of the northwest outer side of xs902 well, the remaining reserves abundance is the largest and most widely distributed, and the potential area is mainly located in the upper part of the reservoir vertically; In the northeast section of xs901 well, the potential area is mainly located in the middle and lower part of the reservoir vertically; According to the Northeast profile of xs903-p1 well, the reserve distribution area is large, the reserve abundance is small, and the potential is vertically located in the middle and lower part of the reservoir.

4. Study on production performance of block

4.1. Prediction of water yield of old wells
According to the prediction of numerical simulation, according to the current gas production scheme, the average water production of single well is 8 m³/d after 10 years, the highest water production well is xs9-p4, and the water production is about 35 m³/d after 10 years. According to different gas production rate schemes of single well, the higher the gas production rate is, the more water is produced. However, with the increase of gas production multiple, the water production of six wells xs903-p2, xs9-2, xs9-7, xs9-p2, xs9-p3 and xs9-p4 increases rapidly.

Edge and bottom water coning is the main reason for the rapid increase of water production in the above six wells with the increase of gas production. For the six bottom water coning wells, the reasonable gas production rate has a great influence on water production. In production, the field experience value of gas production and water gas ratio should be combined, the gas well production allocation should be done strictly, and peak shaving is not easy to be too large.

4.2. Prediction of stable production plan for old wells
Different gas production rate schemes are designed, which are 0.5 times, 0.7 times, base scheme (the current production system continues production for 10 years), 1.2 times, 1.5 times and 2 times respectively. The production situation in 10 years is predicted by numerical simulation.

Taking well xs9-5 as an example, the production of each scheme is more than 30000 m³/D, and the water gas ratio is slightly larger. For this well, 1.2 times, 1.5 times and 2 times schemes can not produce stably, but base scheme can produce stably in formation. The predicted value of bottom hole flowing pressure of base scheme is 5-10mpa. At present, the wellbore pressure loss of the well is 4-2mpa, and the minimum back pressure of wellhead is 4MPa. For fluid wellbore lifting and transportation, the bottom hole flowing pressure of the system can not be guaranteed. Therefore, the optimal scheme is 0.7 times scheme, with a production capacity of 53500m3, a cumulative gas production of 297 million cubic
meters ten years later, a water gas ratio of 2.74 cubic meters per 10000 cubic meters ten years later, and a production pressure difference of 13.93mpa.

As above, the optimal development strategy of old wells is determined by using the constraint method, which considers whether the gas distribution can produce stably, whether the water production changes with the production distribution, and the current situation of bottom hole effusion.

5. Conclusion
1) According to the numerical simulation and dynamic understanding, the pressure distribution in Block C is generally independent of each well, the connectivity between wells is weak, the energy of edge and bottom water is weak, and the water invasion speed is stable. At present, there is no single well edge and bottom water breakthrough phenomenon.

2) The numerical simulation prediction shows that the production allocation of six wells such as xs9-7 increases, the water production increases rapidly, and the bottom water coning is obvious. For this kind of bottom water coning into dangerous wells, it is necessary to strictly do a good job of production allocation. By using the constraint method, the reasonable production allocation scheme and reasonable production pressure difference of each single well are given, which provides the basis for stable production and efficient development of block C.

3) The remaining reserves of Block C are mainly concentrated in the vicinity of xs901 and xs903-p1 and the northwest periphery of xs902. From the perspective of development deployment of succeeding stable production, it is necessary to further combine with fine geological knowledge and do well in well location design demonstration.

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