Numerical Simulation Study on The Feasibility of Gas Production By CO_2 Injection

Wenlong Zhang

Department of Petroleum Engineering, Northeast Petroleum University, Daqing 163318, China

3124126858@qq.com

Abstract

In order to study the development mode of gas condensate reservoir to gas injection and mothball excessive emissions of carbon dioxide, the feasibility of developing condensate gas reservoir by injecting carbon dioxide is studied whose study object is field experiment block by means of numerical simulation software on the basis of fine geologic modeling. Two development schemes, which are depleted development and development of carbon dioxide injection respectively, are designed. But the development of carbon dioxide injection is divided into two mining schemes which are one injection well and four production wells scheme and two injection wells and three production wells scheme respectively. Numerical simulation results are shown that: the effect of carbon dioxide injection is better than depleted development, in two kinds of maintaining pressure development schemes, The scheme of two injection wells and three production wells is improved by 7.38 percentage points in stage recovery percent compared to the other scheme. In addition, this development mode is helpful to save the excessive emission of carbon dioxide.

Keywords

Gas condensate reservoir, numerical simulation, co2 injection, depleted development.

1. Introduction

The common mining mode of gas condensate reservoir are depletion type mining and maintaining pressure[1]. For the early exploitation of the oil reservoir, we mostly chose the depletion development because of low cost and simple process[2]. the basic principles of maintaining pressure mining is that Making up the volume of underground shortfall caused by gas production by displacement agent injection, it makes hydrocarbon system of formation keep the state of single-phase gas flow so as to make sure that the gas well can be produced stably with high production in a long time[3]. The displacement agent mainly includes hydrocarbon gas, air, flue gas, carbon dioxide and so on. Carbon dioxide is the main factor that leads to the greenhouse effect in the process of human development[4]. Whether it is from the perspective of human responsibility or sustainable development, we have the necessary to solve the problem of excessive emissions of carbon dioxide[5]. So we can collect excessive emissions of carbon dioxide to use as displacement agent for gas reservoir development[6]. It will not only help to improve the gas reservoir recovery, to some extent, but also help to solve the sequestration of carbon dioxide. In this paper, the feasibility of the development of carbon dioxide injection of gas condensate reservoir is studied by numerical simulation.

2. General situation

2.1 Geologic general situation

The target block is a semi-anticline block condensate gas reservoir with complex fault. The distance from south to north is about 2500m, and the distance from east to west is about 4000 m, so the gross area is approximately 10 km^2. The oil field structure is a northeast-trending semi-anticline complicated by many faults. There is a longitudina fault in eastern boundary of structure block, and a series of associated faults which is runs east to west formed because of its effect , so the development of fracture in the area is common. The depth of main gas reservoir is about 3400m~ 3600m, and the formation temperature is about 110℃. The geological reserves is about $1.53\times10^7 m^3$.

2.2 Rock physical property of reservoir

The study measured the conventional porosity and permeability of 50 samples provided by the site. Porosity distribution is from 13.2% to 47.8% and mean value is about 35.2%. Permeability distribution is from $0.12 \times \mu m^2$ to $150\times \mu m^2$ and mean value is $98 \times \mu m^2$. Median saturation pressure distribution is from 0.098 MPa to 15.529 MPa, And average pore throat radius distribution is from 0.198 μm to 15.327 μm, In summary, the reservoir media is a middle porosity and middle permeability reservoir.

2.3 Fluids Physical Properties

The measured C_{11+} molecular weight of condensate gas was 179. Its relative density is 0.8133 and Gas oil ratio is 8159.2 m^3/m^3. The formation fluid deviation coefficient is 0.8213 under reservoir condition. Viscosity of crude oil is 1.28mPa s under the conditions of 0.101MPa of atmospheric pressure and 20℃ of temperature. What's more, the maximum reverse condensate pressure is about 9.6 MPa.

3. Establishing geological model

Fine geological model is established by PETREL geological modeling software. The grid division should follow the following principles: The well number of grid partition of the relative concentration area should be more dense, The number of grids among the wells should be appropriate, and the grid can be slightly sparse from the far zone of the well; In order to ensure the production authenticity of four-boundary mesh in the simulation process, we add 2 rows empty grid with no attribute Outside the well grid. In accordance with the modeling requirements, we applied of 25 m × 25 m model to build the grid In plane. So grid number is 160×110. In the longitudinal direction, 5 sedimentary layers were established according to the different of sedimentary period of microfacies and sedimentary environment. In the whole reservoir geological model, the total number of grids is 440000. Three dimensional map of gas condensate reservoir is as follows.

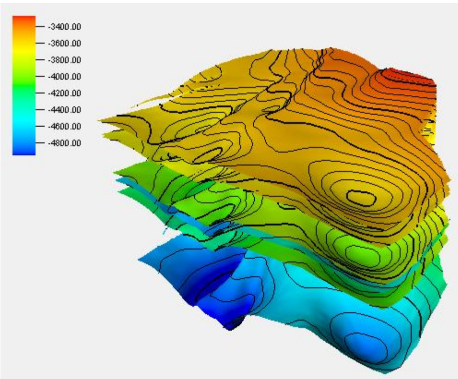

Fig.1 Three dimensional map of gas condensate reservoir

4. History matching of numerical simulation

The test block is put into production in early 2011 which is developed by depletion type. Therefore, it is needed to fit the numerical model according to the known production data when the geological model is established. The formation pressure is about 21.65MPa at present and the stage recovery degree is 13.26%. The fitting results of the numerical simulation and the actual production data are generally match, and the fitting effect is better. The following figure is the fitting curve of stage recovery degree and formation pressure.

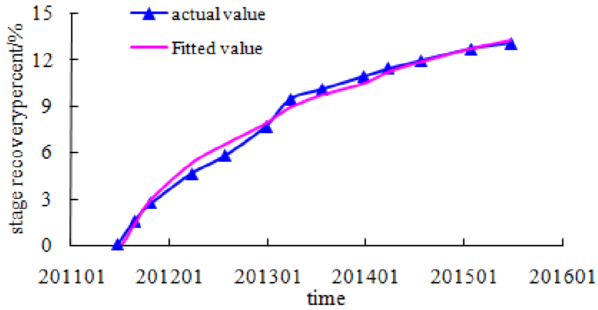

Fig.2 fitting curve of stage recovery degree

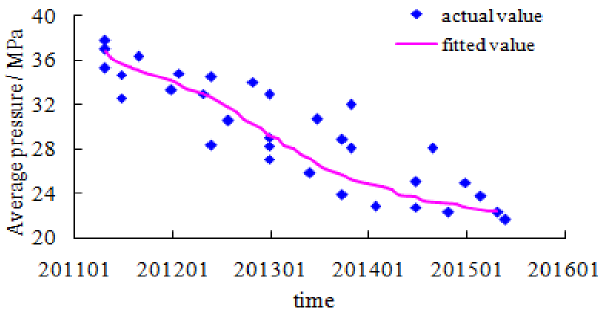

Fig.3 fitting curve of formation pressure

5. Scheme and scheme prediction

On the basis of the current depleted development, three schemes are designed by eclipse numerical simulation software. scheme 1 continue to maintain the depleted development which is regarded as the basis scheme; scheme 2 is the development of one injection well and four production wells; scheme 3 is the development of two injection well and three production wells. In order to minimize the generation of condensate, we stop developing when formation pressure drop to maximum reverse condensate of 9.6MPa. The three schemes regard the beginning of 2016 as the initial time of development.

In order to characterize the buried quantity of carbon dioxide, we introduce the concept of storage ratio of CO_2 . The expression of the storage ratio of CO_2 is like the formula(1). It can be seen from the formula: the more natural gas is produced, the higher storage ratio of CO_2.

$$S_{co_2} = \frac{In_{co_2} - Out_{co_2}}{V_{pore}} \times 100\% \quad (1)$$

Where:

S_{co2}—storage ratio of CO_2; In_{co2}—cumulative injection of CO_2, m^3;

Out_{co2}—cumulative production of CO_2, m^3; V_{pore}—total pore volume,m^3.

The depleted development can make full use of the natural elastic energy of gas reservoir. In order to prevent the emergence of a large number of condensate oil, the formation pressure is always higher than the initial dew point pressure of the condensate gas reservoir. Numerical simulation results are shown that: By the end of June 2028, the scheme 1 stops developing because the formation pressure was reduced to the maximum condensate pressure. The recovery rate was 28.56%, and stage recovery degree is 15.30%.

The development mode of complementing formation pressure by injecting carbon dioxide into the formation can effectively avoid the occurrence of retrograde condensation. Numerical simulation results are shown that: By the end of September 2033, the scheme 2 stops developing because the formation pressure was reduced to the maximum condensate pressure. The recovery rate was 43.82%, and stage recovery degree is 30.56%. In addition, storage ratio of CO_2 is 45.31%; By the end of February 2037, the scheme 3 stops developing because the formation pressure was reduced to the maximum condensate pressure. The recovery rate was 51.2%, and stage recovery degree is 37.94%. In addition, storage ratio of CO_2 is 53.42%. In contrast to carbon dioxide distribution map, it can be found: the content of carbon dioxide in the scheme 3 is higher than scheme 2 whether it is In the plane or in the vertical. The main reason is because high injection production ratio makes the injection of carbon dioxide have more extensive spreading scope for the scheme 2. In addition, the development time is delayed due to a more adequate energy supplement. In contrast to condensate oil saturation distribution map, it can be found: condensate saturation distribution area of scheme 3 is smaller than that of scheme 2. The main reason is because injection of carbon dioxide can reduce the dew point pressure and restrain the production of the reverse condensate oil in the near well. What's more, carbon dioxide can be rapidly dissolved in condensate oil to reduce the viscosity of condensate oil, so as to achieve the purpose of gas well production. Therefore, the stage recovery percent of scheme 3 is higher than scheme 2. When natural gas is replaced by carbon dioxide, carbon dioxide will remain in the pores, so it play a role in the sequestration of carbon dioxide.

compared with the numerical simulation results of three schemes, We can find that: the exploitation effect of compensating formation energy by injecting carbon dioxide into the formation is obviously better than depleted development which utilizes pure natural energy; in two kinds of maintaining pressure development schemes, the scheme of two injection wells and three production wells is improved by 7.38 percentage points in stage recovery percent and 8.11 percentage points in storage ratio of carbon dioxide compared to the other scheme. So the condensate gas reservoir can be developed by injecting carbon dioxide, and the high injection-production ratio scheme of two injection wells and three production wells is better than the scheme of one injection well and four production wells.

6. Conclusion

The exploitation effect of compensating formation energy by injecting carbon dioxide into the formation is obviously better than depleted development which utilizes pure natural energy.

The high njection-production ratio scheme of two injection wells and three production wells is improved by 7.38 percentage points in stage recovery percent compared to the scheme of one injection well and four production wells.

References

[1] Zheng Xiaomin, Zhong Lijun, Yan Wende: Analysis on Development Mode of Condensate Gas Reservoir, Special oil and gas reservoirs, Vol.15(2008) No.6,p.59-61.

[2] Li Qian, Zhong Bing, Yang Hongzhi: Proper Gas Injection Time For the Development of Gas Condensate Reservoir, Natural gas industry, Vol. 35(2015) No.10,p.78-83.

[3] Zhao Zihan: Numerical simulation study on enhancing oil recovery by injecting gas to Qiudong gas condensate reservoir, (MS., Southwest Petroleum University, China 2015), p.9.

[4] Ruan Hongjiang: Study on the feasibility of enhancing oil recovery by injecting CO2 to high gas condensate reservoirs, (MS., Southwest Petroleum University, China 2015),P.11.

[5] Hou Dali: Enhanced Oil Recovery Mechanism by CO2 Injection and Storage Study in Near-Critical gas condensate reservoir, (Ph.D.,Southwest Petroleum University, China 2014), P. 10.

[6] Jiao Yuwei, Xie wei, Di Baozhi: Gas Condensate Phase Behavior in Process of Cyclic Gas Injection, Xinjiang petroleum geology, Vol. 33(2012) No.6,p.704-707.