Feasibility Study on Collaborative Development of Gas Storage and Enhanced Oil Recovery

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Abstract. Underground gas storage (UGS) is an effective way to alleviate the shortage of natural gas supply and improve oil recovery. Ma 19 block is located in the west of Liaohe Oilfield. It is a gas cap and bottom water reservoir with a production history of more than 48 years since 1973. In the later stage of production, oil production and gas production are extremely low, water content reaches more than 95%, and the benefit is very poor. The block is currently being studied for co-development of enhanced oil recovery in the UGS process. The component model was established by numerical simulation software, PVTI fitting and historical fitting were carried out, and the parameters of each phase in the next 15 years were predicted for the three operating pressure intervals of the underground gas storage and the original water injection recovery plan. It was found that Ma19 block is suitable for the collaborative construction scheme of UGS to enhance oil recovery. The results show 12–26 MPa is the optimal working pressure range of UGS. Compared with the original production scheme, the crude oil production is increased by 13 times and the oil recovery factor is increased by 4.65% . UGS has accumulated 99.7×10^8 m^3 of gas injection, 13.83×10^4 m^3 of oil production and 96.2×10^8 m^3 of gas production in 15 years of operation. The peak load adjustment and supply capacity of natural gas exceeds 550×10^4 m^3/d.This paper puts forward the operation strategy of enhancing oil recovery during the operation of gas storage, which can greatly improve oil recovery, gas storage capacity. It provides a certain reference value for enhancing oil recovery through UGS operation in Ma 19 block.

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1 Introduction

With the gradual control of COVID-19, China's economic development has recovered rapidly, and the demand for natural gas has grown rapidly, with an annual increase of 20 billion cubic meters, and the contradiction of seasonal peak adjustment has become increasingly severe [1–3]. Low-carbon economy and environmental protection have become the theme of today's world development. To develop low-carbon economy, the first step is to build a stable, economic, clean and safe energy supply system. As a kind of efficient, clean and high-quality energy, natural gas causes far less pollution to the environment than oil and coal. It is the inevitable choice for developing low-carbon economy and realizing energy conservation and emission reduction in recent decades. China has also put forward the natural gas pipeline development goal of "reasonable distribution of natural gas pipelines and supporting facilities, basically forming the basic natural gas pipe network covering the whole country, and realizing the diversification of gas sources, network of pipelines, matching of gas storage, automation of management and unification of dispatching" [4–8]. The establishment of underground gas storage is the most effective and mature means of natural gas peak regulation and supply protection in the world. For countries with more than 50% external dependence on natural gas, according to foreign experience, the working gas of underground gas storage should account for about 15% of the national natural gas consumption, while China's gas consumption is only 4.4%, only a quarter of that of developed countries. (Table 1) The peak load regulation and supply capacity of gas storage is very low, and there is a great development space and prospect [9–12].

At present, most of the domestic gas storage is reconstructed from depleted oil and gas reservoirs, and there is still a huge potential for enhancing oil recovery during the operation of the gas storage. The combination of enhanced oil recovery and gas storage can shorten the construction period of gas storage and reduce the construction cost. Ensure natural gas imports to meet seasonal demand and prevent supply shortages. Through the establishment of collaborative gas storage, gas injection in spring, summer and autumn, and gas recovery in winter can give full play to the oil displacement mechanism of pulse imbibition, improve oil recovery, and realize the benefits of both reservoir construction and oil displacement [13–15].

The collaborative construction of gas storage and oilfield development can be divided into two categories: one is based on oilfield development and the other on gas storage. The main task of Coordinated construction based on oilfield development is to greatly improve oil recovery by injecting natural gas into the top of reservoir. Through the evaluation of remaining oil distribution and optimization and adjustment of injection-production parameters, the formation pressure is kept above the minimum miscible pressure for natural gas injection, so as to ensure miscible state to improve oil displacement efficiency and oil recovery. The pressure operating interval of this scheme is narrow, and it is necessary to control reasonable injection-production speed to prevent gas channeling. The main task of Coordinated construction based on gas storage is gas injection

Table 1. China and major developed countries gas storage construction statistical table.

Countries	Annual consumption /10^8 m^3	Sum/a	Annual peak regulation capacity /10^8 m^3	Proportion
China	3316	27	147	4.40%
America	7786	393	1360	17.50%
Russia	3909	23	718	18.40%
Canada	999	66	265	26.50%
Germany	805	49	238	29.60%
Italy	645	12	173	26.80%

and gas recovery and peak regulation and supply protection. After the stable operation of the gas storage is achieved by expanding the capacity of the gas storage, the upper and lower working pressures should be reasonably determined to gradually improve the working gas capacity of the gas storage. Based on the understanding of geological conditions and surface conditions, natural gas should be injected as soon as possible to reduce the number of injection-production Wells, reduce operating costs, avoid edge and bottom water intrusion as much as possible, and improve oil displacement and reservoir construction benefits [16, 17].

The production and operation model of the gas storage is that the natural gas received by the external pipeline system is injected into the gas storage layer by compressors. According to the market demand, the gas is injected in summer and extracted in winter, and the natural gas is extracted from the gas storage layer and transported to the external pipeline network during the peak gas consumption period. In addition, there are three basic requirements for underground gas storage: one is to ensure that the reservoir has a certain good sealing, to prevent the injection of natural gas loss; Second, the reservoir must have certain permeability so that the high-pressure gas can enter the reservoir smoothly. The third is in the gas production stage can be successful gas production, ensure a certain gas production capacity, and must have emergency peak adjustment ability.

Based on the in-depth study of Ma 19 block, it is found that the minimum miscibility pressure in this block is high, and it is not easy to produce miscibility by injecting natural gas. Therefore, the coordinated construction based on displacement of reservoir oil is not suitable for this block. This block is suitable for the coordinated construction based on gas storage, which basically maintains the medium pressure scale gas injection, and generally maintains the operation mode of massive gas injection and massive gas extraction.

To sum up, in view of the importance of peak regulation of Qinshen Pipeline, China-Russia pipeline and Da Shen pipeline and the favorable conditions of underground gas storage in Liaohe oilfield area, it is necessary to build Ma19 gas storage in order to ensure the safe operation of long-distance pipeline and the long-term planning of national strategic energy reserve.

2 Reservoir Characteristics and Production History

Ma 19 block is located in the south of The Xinglongtai fault anticline structural belt in the western depression of Liaohe Oilfield. The block is mainly developed in Dongying Formation, with an oil-bearing area of 10.33 km^2 and oil geological reserves of 763 × 10^4t. It has been more than 40 years since the development of The Ma 19 block in 1973 [18–27]. After more than 47 years of water-flooding, the reservoir is in the late stage of development and has a complex fluid distribution in which oil, gas and water coexist. The original reservoir pressure in this block is 30.6 MPa, and the current reservoir pressure is 19.4 MPa (the pressure dropped to the lowest in 1986, and the production wells with too high water cut were shut down and the water injection wells continued to maintain pressure, and the pressure gradually recovered).

As of July 2020, The Ma19 block has produced 200.4 × $10^4 m^3$ of crude oil, plus 20.09 × 10^8 m^3 of gas cap gas and dissolved gas. It is important to note that the volume of expected working gas in the storage is of the same order of magnitude as the volume of produced gas. The recovery factor of oil and gas was 38.26% and 63.24%, respectively. Converting fields to UGS provides opportunities for enhanced oil recovery as gas circulation in the reservoir generates additional oil production. Figure 1 shows the production history of Block Ma 19 from 1973 to 2021.

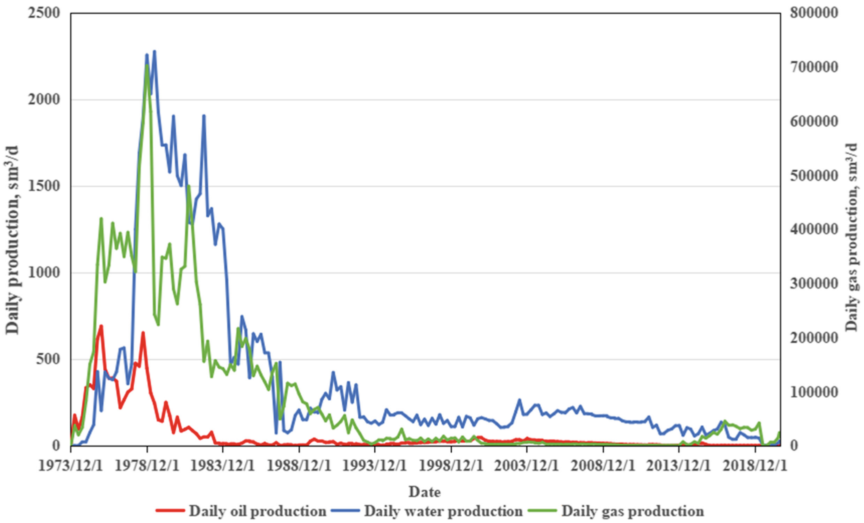


Fig. 1. Production history of Block Ma 19

In 1973–2021: Oil and gas development with water injection in Block Ma 19. During the first 14 years of production, the formation pressure decreased rapidly from 306 bar to 112 bar. (Fig. 2) Crude oil production peaked in 1975 at 690 m^3/d.

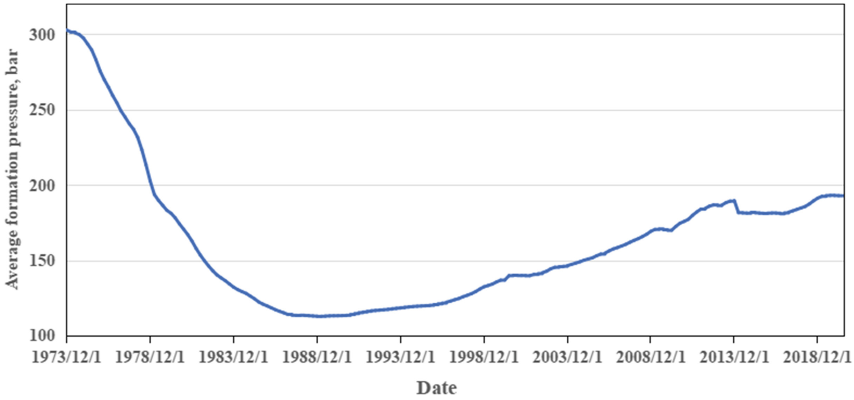


Fig. 2. Reservoir pressure history of Block Ma 19

3 Model Building and Scheme Design

In order to improve the development effect of Ma19 block, enhance oil recovery and effectively develop existing remaining oil, the following four basic principles are followed: combining geology and surface, designing reasonable well location, matching reservoir reserves, determining reasonable well type, classifying and evaluating zones, optimizing reasonable well spacing, unifying the construction of reservoir, construction and production, and giving reasonable consideration to oil and gas. Six production wells and three injection and production wells were selected (Fig. 3). Based on the deep understanding of the geological characteristics of Ma19 block, tNavigator software is used to build the numerical simulation model of the reservoir, and the historical fitting of its production time is made. The model is modeled by component model, and the total number of grids is 83808.

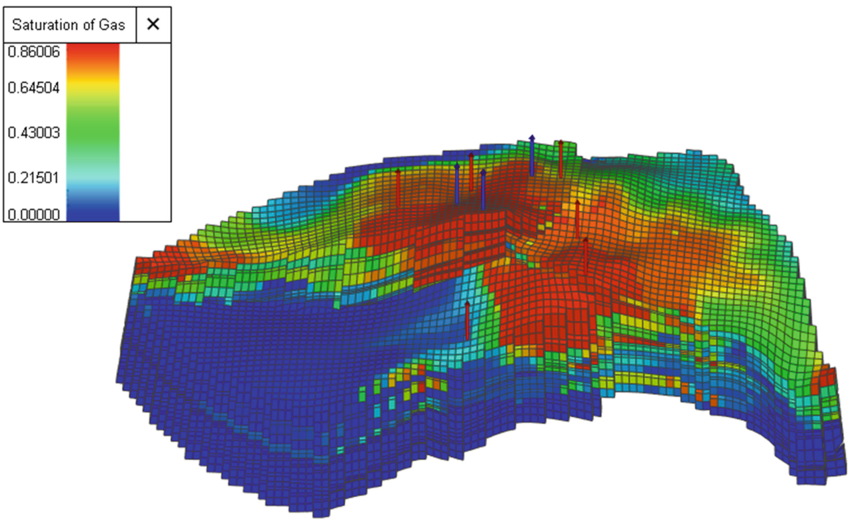
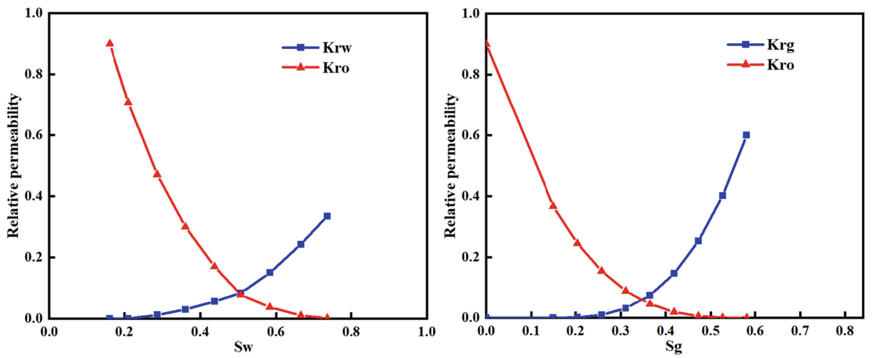


Fig. 3. Reservoir numerical simulation model scheme.

Table 2. The reservoir model

Rock properties		Fluid properties	
Property/Parameter (units)	Value	Property/Parameter (units)	Value
Reservoir dimensions	97 × 48 × 18	Water saturation, Sw (%)	54
Grid size	35 × 35 × 13	Initial oil saturation (%)	46
Average Perm,K (μm^2)	200	Water density (kg/m^3)	1001
Porosity, (%)	0.05	Water viscosity (cp)	0.33
Perm.V/Perm.H,Kv/Kh	0.1	Oil specific gravity (kg/m^3)	593
Reservoir temperature, (°C)	100		
Initial reservoir pressure (MPa)	40		
Formation depth (m)	2800		
Rock compressibility (1/bar)	0.0003		



(**a**) Oil-water relative permeability curve; (**b**) Oil-gas relative permeability curve.

Fig. 4. (**a**) Oil-water relative permeability curve; (**b**) Oil-gas relative permeability curve.

Table 2 shows the parameters of Block Ma 19, Fig. 4 shows the oil-water relative permeability curve and oil-gas relative permeability curve, and Table 3 shows the parameters of component model.

Table 3. Compositional reservoir parameters based on the reservoir system.

Component	Molecular weight	Tc (K)	Acentric factor	Pc (bar)
CO_2	44.01	304.7	0.225	73.8659
N_2	28.01	126.2	0.04	33.9439
C1	16.04	190.6	0.013	46.0421
C2	25	305.43	0.0986	48.8387
C3	44.1	369.8	0.1524	42.4552
C4–6	66.87	447.68	0.200028115	36.6415
C7+	120	567.13	0.344560888	29.6899
C16+	250	713.62	0.645319505	18.1739
C27+	420	851.15	1.3	10.1592

The influence of operating pressure range on working gas volume and storage capacity is mainly considered, so three schemes are designed for comparison. Scheme 1: The operating pressure range is 14−24 MPa; Scheme 2: Operating pressure range is 12–25.5 MPa; Scheme three: the operating pressure range is 10−26 MPa. In terms of time allocation in injection-production period and balance period, monthly peak adjustment coefficients are predicted according to the non-uniformity of monthly gas consumption in Liaoning, as shown in Fig. 5 considering that the main function of shuang6 gas storage is seasonal peak regulation and emergency gas supply capability, natural gas is injected into the formation in summer and recovered in winter, usually completing a complete injection and production cycle of 365 days. The specific arrangement is shown in Table 4.

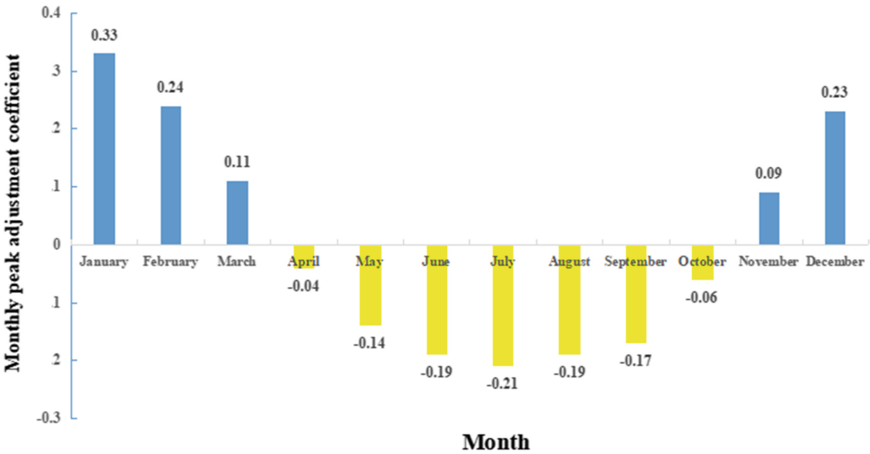


Fig. 5. Monthly peak regulation coefficients in Liaoning

Table 4. Ma19 gas storage operation parameters

Operating pressure range	Operation cycle		
	Gas injection cycle	Phase equilibrium	Gas recovery cycle
14 MPa–24 MPa	April 1 - September 30	October 1st - October 31th	November 1st - March 31st
12 MPa–25.5 MPa	April 1 - September 30	October 1st - October 31th	November 1st - March 31st
10 MPa–26 MPa	April 1 - September 30	October 1st - October 31th	November 1st - March 31st

4 Scheme Effect Analysis

As shown in Fig. 6 and Fig. 7, compared with the other two schemes, Case 3 has a larger operating pressure range. The accumulative working gas volume in 15 years reaches 111.79×10^8 m^3, which is 14.7×10^8 m^3 higher than Case 1 and 33.19×10^8 m^3 higher than Case 2, and the accumulative gas volume in 15 years reaches 99.7×10^8 m^3. The gas injection capacity and gas recovery capacity of Case 3 are significantly improved, and the oil recovery ratio of Case 1 and Case 2 is increased by 1.15% and 0.76% respectively after 15 years of operation. Therefore, the third scheme is optimized from the three cases.

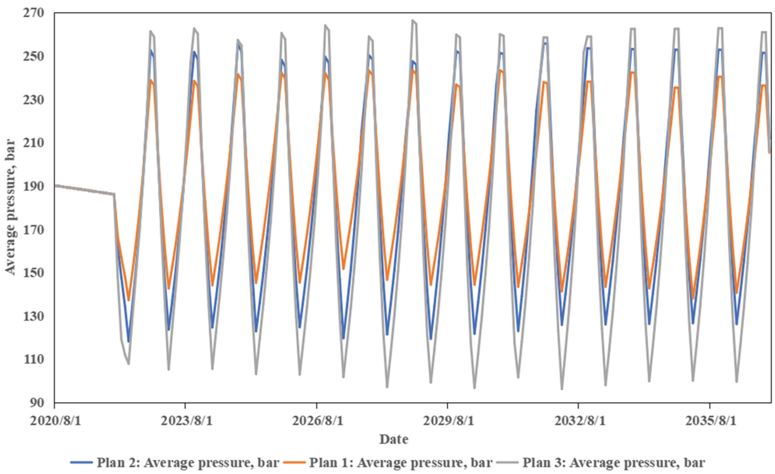


Fig. 6. Operating pressure diagram of the three cases

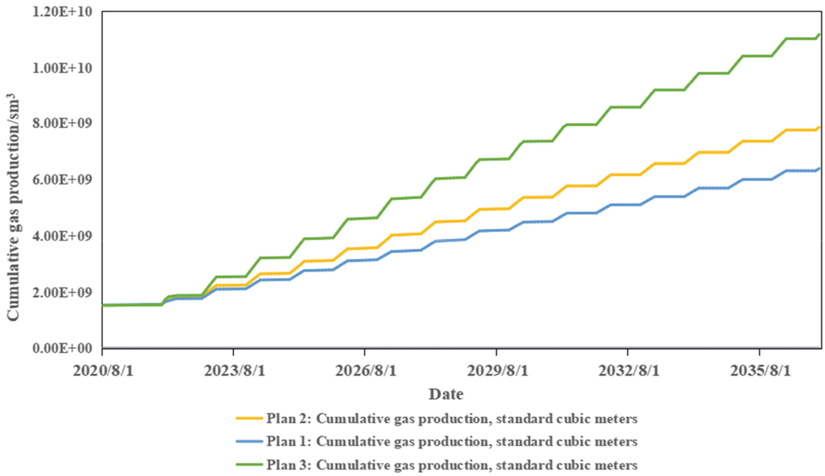


Fig. 7. Cumulative gas production of the three cases

The original plan is to extend the prediction of oilfield water injection development for 15 years. Compared with the original case, Case 3 is expected to increase the oil recovery by 4.65% after 15 years, with the maximum daily gas injection of 450 × 10^4 m^3, winter daily gas injection of 560 × 10^4 m^3 and annual working gas of 6.86 × 10^8 m^3. The cumulative working gas volume in 15 years is 96.2 × 10^8 m^3. By 2036, a strategic peak-adjusted gas storage with storage capacity of 13.4 × 10^8 m^3 and annual working gas capacity of 6.21 × 10^8 m^3 will be formed. In the case of underground gas storage operation, the oil recovery is 43.76%, while in the case of continuous waterflooding, the oil recovery is less than 40%. It can also be seen from Fig. 8 that on the basis of stable gas injection and production, the remaining oil in the oil ring is gradually recovered with the increase of the injection-production cycle. As ma 19 block is a bottom-water reservoir, the amount of injection-production gas should be controlled as much as possible to prevent bottom-water coning. In the absence of special requirements, the gas storage can be operated according to Case 3, but in the case of emergency peak regulation, the peak regulation amount of the gas storage can be appropriately increased according to the actual conditions.

From the comparison of the two schemes, it can be concluded that migration of injected gas in reservoir is an effective means to improve oil recovery. At the micro scale, after each injection-production cycle, more and more gas is trapped in the reservoir without being liquid, thus reducing the relative permeability of the gas phase. Therefore, the gas/oil fluidity ratio and the stability of oil-gas front at the micro scale are more favorable to oil and gas development and gas channelling mitigation. At the macro scale, the alternation of injection-production cycles is beneficial to the stability of the oil-gas front. The gas in the reservoir must connect bubbles in the pores in each cycle stage to recover oil. The wide variation of operating pressure of gas storage helps to drive more oil to production wells. In the gas production stage, with the decrease of formation pressure, the oil degassing, the increase of gas saturation is beneficial to the remaining oil in the reservoir out of the pores. In the gas injection stage, the formation pressure

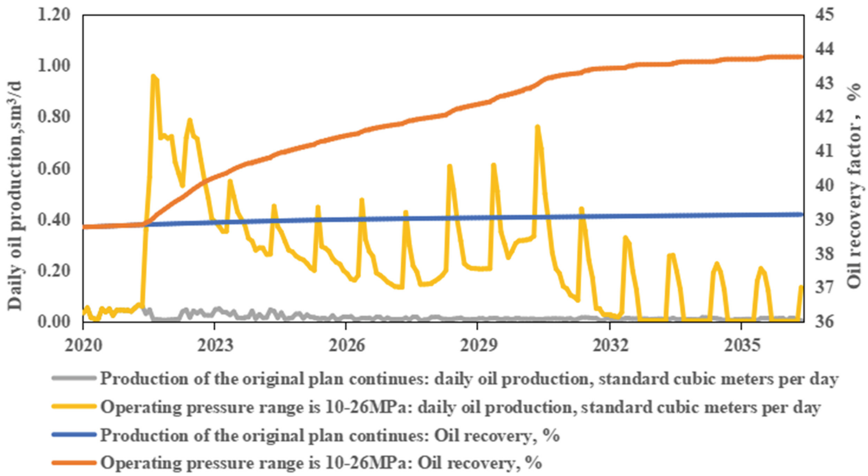


Fig. 8. Comparison of daily oil production and oil recovery between Case 3 and the original development plan

increases gradually with the increasing injection volume, and the compressibility of gas leaves more room for the oil to flow. Due to these different phenomena, the oil recovery of Block Ma 19 is predicted to increase by 4.65% after 15 years of operation in the gas storage phase.

5 Conclusions and Cognition

1) The construction of collaborative gas storage can take advantage of the gravity differentiation and mixing mechanism of natural gas injected at the top of oil and gas reservoir, which can not only greatly improve oil recovery, but also gradually build gas storage, shorten the construction period, and realize the dual benefits of oil displacement and construction.
2) Compared with the gas reservoir type, the synergistic gas storage has a better effect by considering both enhanced oil recovery and peak-adjustment gas storage models.
3) Through the production mode of collaborative gas storage, compared with the original development plan, the crude oil production is increased by 13 times, the accumulative gas injection is 99.7×10^8 m^3, the accumulative oil production is 13.83×10^4 m^3, the accumulative gas production is 96.2×10^8 m^3, and the peak adjustment and supply protection capacity of natural gas is more than 550×10^4 m^3/d.
4) Based on the numerical simulation of reservoir in Block Ma 19, the feasibility of constructing collaborative gas storage is preliminarily discussed. The results show that it is feasible and can be further studied.

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