



Geological Feasibility and Operating Index Design of Volatile Oil Reservoir into Underground Gas Storage: Case Study of M Block in Jidong Oilfield

Cong Li¹(✉), Hai-yan He², Guang-liang Gao^{1,3}, Yan-chun Sun², Yi-ming Hu¹,
Zhi-bin Yang¹, Cai-yun Hu¹, Chao-feng Li¹, and Zhi-feng Zheng¹

¹ Gas Storage Construction Project Department, Jidong Oilfield Company, PetroChina,
Tangshan, Hebei, China
826962571@qq.com

² Research Institute of Exploration and Development, Jidong Oilfield Company, PetroChina,
Tangshan, Hebei, China

³ School of Geosciences, China University of Petroleum (East China), Qingdao, Shandong,
China

Abstract. At present, there is no precedent for reconstruction of Volatile Oil Reservoir into Underground Gas Storage (UGS) at home and abroad. Utilizes oil reservoirs to rebuild gas storage can fully utilize the mechanisms of gravity, miscibility, viscosity reduction, and imbibition, which can greatly enhancing crude oil recovery and gradually collabo-rate to build gas storage. This is a new approach to the rapid development of gas storage construction in China. Taking M Block in Jidong Oilfield as an example, The study starts from the geological characteristics of the reservoir, Analyzes the sealing condition, reservoir property, fluid feature and well productivity. Study results show that Es1 formation of the study area yield excellent reconstruction condition for its great sealing property, medium to high permeability, high productivity, no obvious interlayer and good internal connectivity, Furthermore, study also indicates there contain low hydrogen sulfide content. In response to the collaborative needs of gas drive oil recovery and UGS construction, Adopts the construction and operation mode of “initial top mild gas

Copyright 2023, IFEDC Organizing Committee

This paper was prepared for presentation at the 2023 International Field Exploration and Development Conference in Wuhan, China, 20–22 September 2023.

This paper was selected for presentation by the IFEDC Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the IFEDC Technical Team and are subject to correction by the author(s). The material does not necessarily reflect any position of the IFEDC Technical Committee its members. Papers presented at the Conference are subject to publication review by Professional Team of IFEDC Technical Committee. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of IFEDC Organizing Committee is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of IFEDC. Contact email: per@ifedc.org.

injection + pressure recovery → differential gas drive + efficient collaborative oil production → enhanced injection and production + long-term liquid carrying”. The UGS will be operated in pressure range of 17.5–40.0 MPa, with a effective storage capacity of $18.6 \times 10^8 \text{ m}^3$, constructs a three-dimensional injection and production well network of “high injection and low production, horizontal and vertical differentiation injection and production”, gradually form and expand secondary gas cap by gas injection and oil drainage in batches and stages, the study area is designed to be reconstructed with a mixed well pattern of 7 directional wells and 3 horizontal wells, Meets the effective control of gas storage capacity and the demand for unbalanced peak shaving gas production. It is estimated that the maximum production rate may yield $956 \times 10^4 \text{ m}^3$ and, the working gas may reach $9.0 \times 10^8 \text{ m}^3$, which is 48.4% of the total reserves and it can enhance crude oil recovery by 27.7%. In conclusion, volatile oil reservoirs have the geological feasibility of rebuilding underground gas storage, and can form relatively efficient gas production and peak shaving capabilities while injecting gas for enhancing crude oil recovery, resulting in significant economic benefits.

Keywords: Volatile Oil Reservoir · Collaborative type UGS · Feasibility Evaluation · Operation Index of Injection and Production · Enhance Crude Oil Recovery

1 Introduction

UGS, as an important component of the natural gas “production, supply, storage, and sales” industry chain, is a major livelihood project to ensure the safe and stable supply of natural gas. Accelerating the construction of gas storage is a mission responsibility to complete the national gas storage capacity construction task [1–8]. The types of gas storage tanks can be divided into five types: gas reservoir type, oil reservoir type, salt cave type, aquifer type, and abandoned mine pit type [9]. From a global perspective, Gas reservoir type gas storage accounts for 78%, while oil reservoir gas storage reservoirs only account for about 5% [10–13]. At present, gas reservoirs in the Beijing-Tianjin-Hebei Urban Agglomeration have basically been built with gas storage facilities, and the construction resources have been basically depleted. The types of gas storage facilities are extending from gas reservoir and salt cave types to oil reservoir types [14, 15]. The integrated construction of a reservoir type gas storage system, which combines natural gas flooding with enhanced crude oil recovery, is a new type of gas storage system developed in recent years. It is called a collaborative gas storage system. This technology can leverage the advantages of natural gas such as gravity, miscibility, pulse infiltration, and expansion to significantly improve crude oil recovery. At the same time, the natural gas injected into the reservoir is stored in high parts of the reservoir, forming a secondary gas cap and continuously expanding, Gradually transforming oil reservoirs into gas storage facilities [16]. At present, the key technologies for utilizing gas reservoirs to rebuild gas storage facilities in China are basically mature, but key technologies such as geological body sealing, reservoir capacity parameter design, and gas injection and production capacity evaluation for utilizing oil reservoirs to rebuild gas storage facilities are still in the exploratory stage [17, 18]. Most of the Jidong oil fields are volatile oil

reservoirs. Through the collaboration of gas drive oil recovery and reservoir construction, certain scale of gas storage capacity can be quickly built while improving oil recovery rate and economic benefits. Currently, there are no feasibility studies on the geological conditions of underground gas storage reconstruction for such reservoirs at home and abroad.

2 Geological Characteristics

Block M is located in the southwest of the No.3 structural belt in the Nanpu Depression, with a target area of 6.6 km² for Gas Storage Construction. From bottom to top, the Paleogene Shahejie Formation, Dongying Formation, Guantao Formation, Minghuazhen Formation, and Quaternary Plain Formation are developed in sequence. Ed₃ is the upper cover layer, with an average effective thickness of 227 m. Ed₃III oil formation is the direct sealing layer, with an average thickness of 90 m. The layer between Es₁II bottom oil formation and Es₁III oil formation is the bottom layer, with a thickness of 30 m. Es₁III oil formation is the bottom monitoring layer.

The target layer of Block M in this study is the first member of Shahejie Formation, which is located on the fault slope break zone formed by Nanpu No.3 fault and secondary NE trending regulating fault, which is transitional from Sha-Lei-Tin uplift to Caofeidian sub sag. It belongs to a deep lake semi deep lake sedimentary environment. The foreset aggradation braided river delta sand body from the south-ern Sha-Lei-Tin uplift provides sufficient material source for the deposition of debris flow in the study area.

Block M is located in the downthrow wall of Nanpu No.3 Fault (F1), and the top surface of Es₁ is characterized by a fault anticline structure, which is complicated by nearly east-west and northeast trending faults, forming multiple fault blocks or nose structures. The Gas Storage Construction area is Block A to Block D (Fig. 1). The entire block is cut into three parts: south, middle, and north by two nearly east-west oriented faults, and the central fault block is further cut and complicated by several oblique faults, resulting in differences in the stratigraphic occurrence of each fault block.

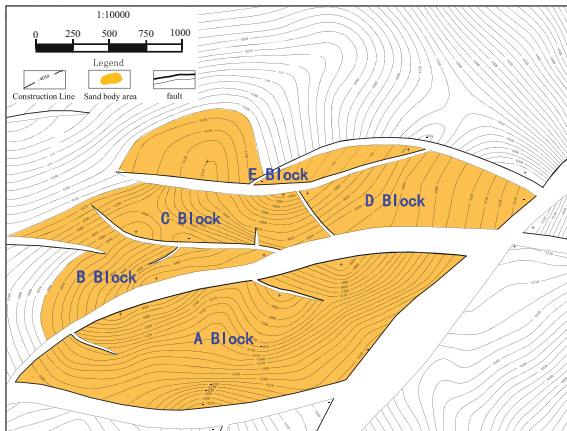


Fig. 1. Structural map of the top surface of block M

3 Geological Feasibility Evaluation of Reconstructed Gas Storage Reservoir

3.1 Sealing of Traps

The primary condition for evaluating the location of UGS is to require the overall underground gas storage system to have long-term sealing. The more developed faults and complex structures are, the more difficult it is to evaluate the sealing of underground gas storage systems [19]. The reservoirs in Jidong Oilfield are generally characterized by fractured structures and strong reservoir heterogeneity, which puts forward higher requirements for trap sealing. Unlike oil reservoir development, under the conditions of alternating injection and production, the study of gas storage trap sealing not only needs to evaluate its original static sealing, but also needs to evaluate the trap integrity under long-term alternating injection and production stress [20].

The mudstone cover layer in Block M has a stable planar distribution, wide range, and large thickness (227 m), with a clay mineral content of up to 61.4–70%, with an average of 64.7%. Combined with new drilling and coring laboratory experiments, the cover layer permeability ranges from 0.0016 to $0.0108 \times 10^{-3} \mu\text{m}^2$, average $0.0779 \times 10^{-3} \mu\text{m}^2$, with a dynamic breakthrough pressure of 45.6 MPa, exhibiting good micro sealing properties. For the tensile failure capacity of the caprock, the current common standard at home and abroad is to take 80% of the minimum principal stress as the upper limit of its tensile failure capacity. According to the crustal stress test results in the mine, the safe gas injection pressure for evaluating that no tensile failure of the caprock occurs is 49.2 MPa. Based on the Coulomb Moore criterion and effective stress inversion in rock mechanics, the safe gas injection pressure without shear failure is 47.8 MPa.

On the basis of research on fault development characteristics, the mechanism of fault lateral sealing mainly includes lithology juxtaposition, mudstone smearing, fragmentation and diagenesis [21–23]. On the basis of studying the juxtaposition relationship of lithology, this article uses the mudstone smear factor SGR method [24] to evaluate the safety gas injection pressure of lateral sealing of faults as 45.1 MPa; The core and difficulty of fault sealing evaluation of gas storage is to study the longitudinal dynamic sealing of fault under alternating action [25], Aiming at the dynamic change of crustal stress field of complex structures around the fault and the stability of fault mechanics, four-dimensional geomechanical simulation was carried out, and the slip index of fault of M gas storage was obtained, The safety gas injection pressure of vertical sealing of the fault was evaluated to be 45.0 MPa.

Based on multiple indicators such as geology, seepage, and mechanics, the maximum formation pressure that the geological body in Block M can withstand to maintain dynamic sealing is 45.0 MPa (Table 1).

3.2 Reservoir Characteristics

According to the observation of cast thin sections, the main types of pores are primary pores and secondary pores, accounting for 48.1% and 51.9% respectively, and there are fewer flaky or curved throats, pore narrowing throats, and necking throats [26]. Pore radius range 29.4 to 163.8 μm , Average 78.3 μm . Throat radius range 1.7 to 12.2 μm ,

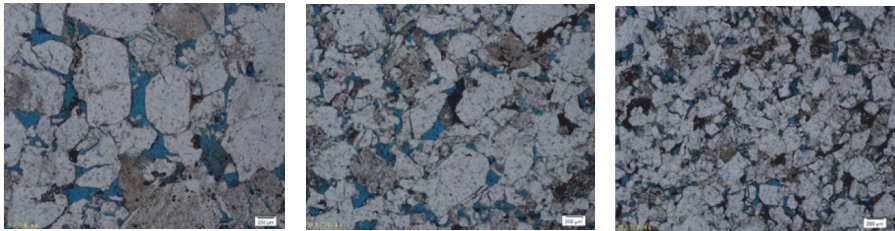
Table 1. Theoretical Ultimate Pressure Bearing Capacity and Safety Gas Injection Pressure Evaluation Table of M Gas Storage Reservoir Geological Body

Object	classification	Sealing factors	Measurement Index	Evaluation result	Ultimate bearing capacity	Safe gas injection pressure
Caprock	Static factors	geological characteristics	Lithology and thickness	227 m mudstone	-	-
	Dynamic factors	Capillary sealing	Dynamic breakthrough pressure	45.6 MPa	45.6 MPa	45.6 MPa
		Tensile failure	Minimum horizontal principal stress	60.1 MPa (regional)	60.1 MPa (regional)	49.2 MPa
				61.5 MPa(Field)	61.5 MPa(Field)	
Resistance to shear failure	Shear safety index	0.74	59.7 MPa	47.8 MPa		
Fault	Static factors	lateral seal	SGR	upthrown side Breakthrough Pressure > 5.6 MPa	45.1 MPa	45.1 MPa
	Dynamic factors	vertical seal	Slip critical bearing capacity	56.3 MPa	56.3 MPa	45.0 MPa

Average 5.6 μm (Fig. 2). The physical properties of sandy debris flow reservoirs in the study area are mainly controlled by sedimentary microfacies, reservoir lithofacies and diagenesis. Statistics show that there are significant differences in sand body thickness, main lithofacies types, and physical properties among reservoirs in different parts of the sandy debris flow fan. The sand bodies of reservoirs located in the main and braided channels of the sandy debris flow are mostly composed of multi-stage superposition, mainly composed of sandy conglomerate and coarse sandstone facies, The mud content is generally low, with an average porosity of 14.7% and an average permeability of $198.7 \times 10^{-3} \mu\text{m}^2$, with relatively good physical properties and the thickness between 40–90 m; The sand body located on the side of the sandy debris flow channel is mainly composed of thin layers of powder and fine sandstone that gradually transform from sandy debris to turbidity flow, with an average porosity of 11.6% and an average permeability of 78.8%, with relatively poor physical properties and a thickness of 10–20 m. For the reconstruction of UGS, The local relatively high permeability thickness of the Es1 reservoir in Block M is relatively large, with strong seepage capacity, which is conducive to obtaining relatively high storage space and gas well injection and production capacity for gas storage.

3.3 Internal Connectivity of Reservoirs

Block M is a blocky oil reservoir with large sand body widths and stable sand body distribution at different stages. The interlayer development in the sand body is unstable, and it is connected up and down in a maze shape, with a sand body connectivity rate of 92%. Based on the continuous coring of new drilling, there were no obvious interlayer observed in the core. The thin section observation of interlayer between water channels confirmed that the lithology of the interlayer was composed of unequal grained lithic feldspar fine sandstone and some argillaceous sandstone, further confirming the



(a) Large pore middle throat (b) Mesoporous fine throat (c) Small pore micro throat

Fig. 2. Type of pore structure in Es1 reservoir of Block M

geological characteristics of the M reservoir block. The monitoring results of formation pressure and tracer during the gas injection process show that the pressure response of adjacent wells is obvious and some oil wells have seen the agent. The formation pressure of 82% of adjacent wells in the test area has increased by 0.9–3.7 MPa; 26% of adjacent wells have tracer indications, with gas drive speeds ranging from 3.6 to 6.8 m/d, with an average of 4.4 m/d. The dynamic and static comprehensive evaluation of reservoir plane and vertical connectivity is good, which is conducive to centralized injection and production of UGS.

3.4 Temperature and Pressure Systems and Fluid Properties

The burial depth of the reservoir in Block M is 3900–4150 m, the original pressure is 40.17 MPa, and the pressure coefficient is 1.0, which belongs to the normal pressure system. The temperature in the middle of the oil layer is 157°C, and the geothermal gradient is 3.2 °C/100 m, which belongs to the normal temperature system. The reservoir type is a highly volatile oil reservoir, with conventional light oil. The density of formation crude oil is 0.49 g/cm³, the viscosity of formation crude oil is 0.2 mPa·s, the gas oil ratio for single degassing is 445 m³/m³, and the volume coefficient of crude oil is 2.66. The natural gas in Block M is dissolved gas, with a relative density of 0.76, methane content of 75.26%, ethane content of 10.8%, propane content of 5.1%, CO₂ content of 5.6%, nitrogen content of 6.54%, and H₂S content of 47 mg/m³.

3.5 Reservoir Development Features

In 2012, M block was put into development and went through three stages: “rolling production”, “water injection development”, and “pilot testing”. In the initial stage of production, the average daily oil production of a single well was 119t, and the average daily gas production of a single well was 115000 m³. The average single well production was high and the gas volume was large, making it easy to establish a high single well gas injection and production capacity. As of before the pilot test, the cumulative oil production of the reservoir was 115.3 × 10⁴t, cumulative gas production 13 × 10⁸ m³, the pressure is 27.3 MPa, and the pressure coefficient is 0.68. The reservoir is mainly flooded at the bottom, with residual oil enriched in mid to high parts, the overall water washing ratio of the reservoir is small (0.2), and the upper part of the reservoir has obvious

degassing, with relatively high gas saturation (20–30%), making it a high-quality area for forming storage capacity.

4 Design of Operational Indicators for UGS

4.1 Upper Limit Pressure and Storage Capacity

Block M is a block like volatile oil reservoir that is developed by water injection. The reservoir capacity, operating pressure, and working gas volume of the gas storage reservoir are optimized and designed using oil and gas reservoir engineering methods. According to the dynamic sealing evaluation results of the geological body in Block M, from the perspective of the static and dynamic limit pressure of the cap rock and fault, the comprehensive evaluation of the ultimate pressure bearing capacity of the geological body in Block M is 45 MPa. The main control factors are fault slip, lateral sealing, and capillary sealing of the cap rock in sequence. Considering the high seepage resistance during the gas drive and liquid discharge process of reservoir construction, the formation pressure in the near wellbore area during the gas injection process in Block M is 43–45 MPa, which is close to the pressure limit of the gas storage geological body. At this time, the corresponding average formation pressure is 40 MPa. Therefore, it is recommended to use the original formation pressure (40 MPa) as the upper limit pressure for the operation of M gas storage.

The construction of a fixed volume or water drive gas reservoir involves gas injection expansion to form a reservoir capacity and gas drive water to form a reservoir capacity, and the original gas-bearing pore space still exists or is only affected by natural water invasion. The fluid stored in the reservoir formation is a complex gas oil water three-phase, and the reservoir construction process is an interactive displacement of oil, gas, and water three-phase, making the formation process of the reservoir capacity more complex [27]. This article innovatively proposes a calculation method for the capacity of oil reservoir type gas storage reservoirs. The total storage capacity is the sum of the pure oil/water flooded zone storage capacity, the pure oil zone remaining oil contraction storage capacity, and the remaining oil secondary saturation expansion dissolved gas capacity (Fig. 3). The effective storage capacity is the difference between the total storage capacity and the stable final remaining oil dissolved gas volume during the construction of the reservoir. After long-term contact and mass transfer between volatile oil and dry gas during the construction and operation of the reservoir, the crude oil shrinks and its properties tend to stabilize. Based on the demonstration of upper limit pressure, a material balance injection production dynamic model was established to predict the total storage capacity of the gas storage reservoir at $28.6 \times 10^8 \text{ m}^3$, effective storage capacity $18.6 \times 10^8 \text{ m}^3$, total cushion capacity $19.6 \times 10^8 \text{ m}^3$, supplementary cushion capacity $8.8 \times 10^8 \text{ m}^3$.

4.2 Gas Production and Peak Shaving Mode

For seasonal peak shaving gas storage, the general design gas injection time is 180–200 days, and the gas production time is 100–120 days. The periodic gas injection

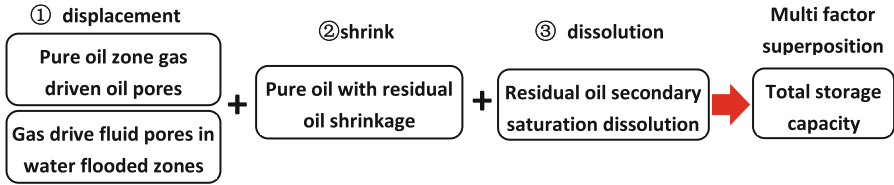


Fig. 3. Design considerations for M gas storage capacity

capacity of the gas storage is greater than the periodic gas production capacity, so the gas production capacity is the key to restricting the working gas volume of the gas storage. Different gas production parameters have a significant impact on the maximum working gas output of the gas storage within a limited time. Through material balance and nodal analysis, calculation and comparison, the non-uniform coefficient of peak shaving gas production of gas storage is designed (Fig. 4) to give full play to the peak shaving capacity of gas storage, so as to meet the winter peak shaving demand of Beijing-Tianjin-Hebei region, the main target market of M gas storage.

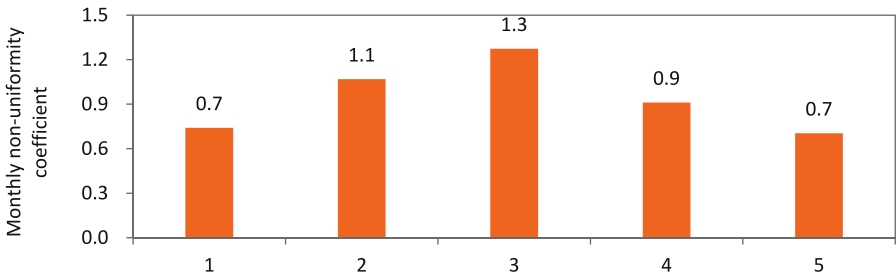


Fig. 4. Comparison of Monthly Uneven Coefficients of Different Peak shaving Modes

4.3 Lower Limit Pressure and Working Gas Volume

The operating pressure range of the UGS is linked to the working gas volume, and the operating pressure should aim to achieve the optimal configuration among the working gas scale, peak shaving capacity at the end of gas production, and the number of injection and production wells simultaneously [28]. Under different lower limit pressures, there is an intersection point between the number of wells required for effective well control and the number of wells required for node coordination (Fig. 5). At this intersection point, the matching lower limit pressure and well network achieve effective inventory control and node coordination lifting, which is the optimal lower limit pressure for technology. Based on the determination of the optimal lower limit pressure in technology, the optimal lower limit pressure in technology and economy is ultimately determined by taking into account factors such as the requirements for gas production at the end of the production period, formation water invasion, and reservoir heterogeneity. By using the above method, the lower operating pressure of M gas storage is determined to be 17.5 MPa, which can

generate a working gas volume of $9.0 \times 10^8 \text{ m}^3$, with a working gas volume accounting for 48.4% of the storage capacity.

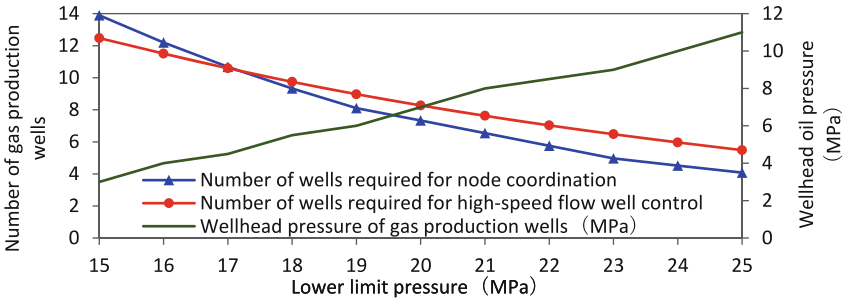


Fig. 5. Schematic Diagram of Intersection of High Speed Flow Well Control and Number of Gas Production Wells in a Single Well of Gas Storage

5 Deployment and Operation Plan Design of Injection and Production Wells

5.1 Evaluation of Gas Well Production Capacity

In view of the particularity of the lack of data on gas production and productivity test of single wells in reservoir construction, and the change of percolation conditions of gas drive liquid drainage reservoirs, this paper innovatively adopts the multiphase flow equivalent percolation theory, conducts the conversion of gas and oil relative permeability, predicts the effective percolation capacity of gas phase, and then establishes the IPR curves of gas wells under different pressures and gas saturations based on the binomial productivity equation (Fig. 6).

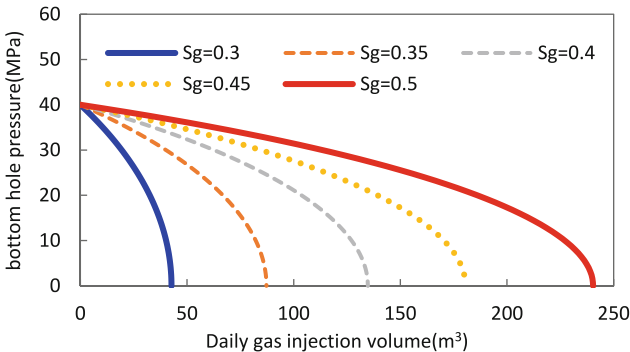


Fig. 6. Gas well IPR curves under different gas saturations

Based on the inflow and outflow performance curves of gas wells, and taking into account factors such as node coordination, erosion critical flow rate, liquid carrying

critical flow rate, and critical sand production pressure difference [29], a multi cycle production capacity prediction chart for oil reservoir reconstructs gas storage has been established (Fig. 7). Under the 41/2 production string parameters, the production capacity of newly drilled directional wells is $107.7 \times 10^4 \text{ m}^3/\text{d}$, the production capacity of newly drilled horizontal wells is $154.8 \times 10^4 \text{ m}^3/\text{d}$, and the production capacity of old gas wells is $51.6 \times 10^4 \text{ m}^3/\text{d}$.

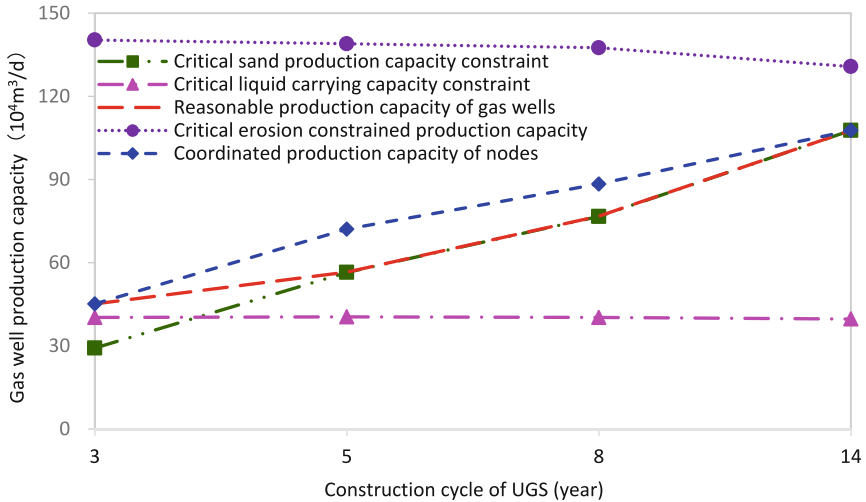


Fig. 7. Nodal analysis chart of directional wells in different injection production cycles

5.2 Deployment of Collaborative Type UGS Injection Production Well Network

Collaborative type UGS requires injecting natural gas from the top, relying on gravity to drive oil and water from the lower parts of the reservoir, gradually expanding the secondary gas cap, and ultimately forming a gas storage space. This technology can fully leverage the advantages of high oil displacement efficiency and large swept volume in gas drive oil recovery, significantly improving reservoir recovery efficiency. In this paper, the three-dimensional injection production well pattern of “high injection and low production, horizontal and vertical differential injection and production” is constructed (Fig. 8–9): the first line well lower section is drained to improve the vertical sweep, and the full well section of the second and third line wells in the lower part is drained to improve the plane sweep and strengthen the vertical sweep, so as to minimize the gas channeling and improve the reservoir capacity production efficiency. Adopting the method of “initial mild liquid discharge and later enhanced liquid discharge” to reach storage capacity gradually. 27 liquid discharge wells are deployed, after gas channeling, the wells will automatically be converted to gas production well or shut in. It is expected that the cumulative oil production will be $132.5 \times 10^4 \text{ t}$ before the gas storage reaches its capacity, improving crude oil recovery by 27.7%.

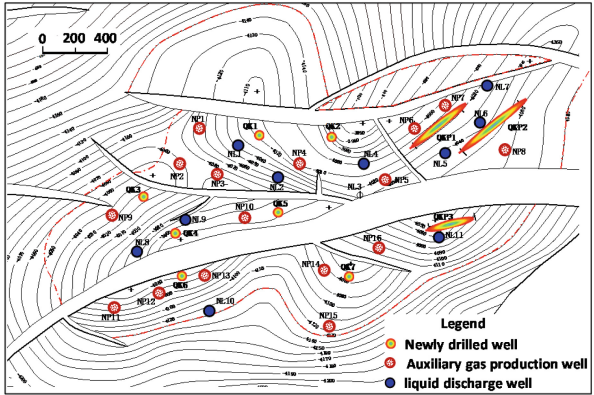


Fig. 8. Deployment diagram of M Gas Storage Injection Production Well Pattern

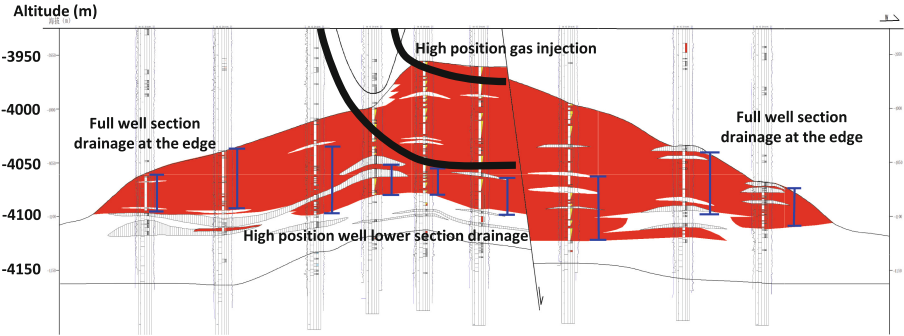


Fig. 9. Design diagram of three-dimensional well network for gas injection and liquid discharge in M gas storage

After the gas storage capacity is reached, the layout of the injection production well network should fully consider the characteristics of short-term strong injection and strong production, to meet the effective control of the gas storage capacity and the demand for unbalanced peak shaving gas production [30, 31]. By comprehensively analyzing the production capacity evaluation, well control constraints, and market gas demand of different well types, the minimum number of wells that meet the design of gas storage capacity parameters is determined. A reasonable well network density is proposed, and the injection production well network is comprehensively optimized and deployed based on structural location, reservoir characteristics, fluid distribution, and other factors. A comprehensive determination is made to adopt a three-dimensional combination of newly drilled directional wells, horizontal wells, and old wells for well layout. The deployment of the well network is a “10 + 16” plan (Fig. 8), which includes 10 newly drilled injection and production wells (including 7 directional wells and 3 horizontal wells), and 16 old auxiliary gas production wells (selected from 27 liquid discharge wells) to realize efficient utilization of inventory and meet pipeline transport requirements.

5.3 Design of UGS Injection and Production Operation Plan

According to the concept of “stable gas injection for oil displacement and efficient reservoir expansion”, the construction process of gas storage is divided into three stages: the initial stage of construction is the “stable gas injection and efficient energy recovery” stage. Under the multiple driving effects of gas injection displacement, gravity, and dissolved gas displacement, efficient oil displacement and liquid drainage are achieved, significantly improving crude oil recovery rate, and initially forming a small-scale secondary gas cap. The mid-term of construction is the stage of “differential gas injection and efficient collaborative extraction”, which forms an important foundation for the continuous expansion of the secondary gas cap and the final formation of storage capacity. The later stage of construction is the stage of “enhanced injection and production, long-term liquid carrying capacity expansion”. Through long-term enhanced peak shaving and continuous expansion of storage capacity, it is expected to achieve the design indicators in 14 cycles.

By using the linkage method of gas reservoir material balance equation and gas well productivity equation, an iterative relationship between inventory, formation pressure, gas well production capacity, and gas production time is established. Combined with the non-uniform coefficient of winter gas production peak shaving, the change in natural gas production of the gas storage during a 120 days gas production period is calculated (Fig. 10). It is predicted that the maximum daily peak shaving capacity will be $956 \times 10^4 \text{ m}^3$ between late December and early January of the following year, with a peak shaving capacity of $527 \times 10^4 \text{ m}^3$ at the end of gas production.

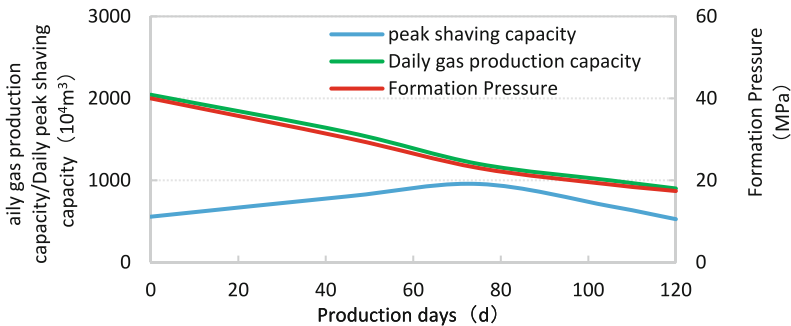


Fig. 10. Design of Gas Storage Injection and Production Operation

6 Conclusion

- (1) The blocky volatile oil reservoir in Block M of Jidong Oilfield has good sealing performance and belongs to a medium permeability reservoir with large thickness and no obvious interlayer. The internal connectivity of the reservoir is good, the water washing ratio is small, the hydrogen sulfide content is low, and the oil well production capacity is high. Case analysis shows that there are favorable geological conditions for constructing underground gas storage.

- (2) The equivalent percolation theory of multiphase flow is used to transform the relative permeability of gas and oil and predict the effective percolation capacity of gas phase. Based on the binomial productivity equation, the IPR curves of gas wells under different pressures and gas saturations are established. Based on factors such as node coordination, critical flow rate of erosion, critical flow rate of liquid carrying, and critical sand production pressure difference, a multi periods gas well productivity prediction chart for the expansion and production process of volatile oil reservoir reconstruction gas storage has been established.
- (3) Unlike the formation mechanism of fixed volume or water driven gas reservoirs, the construction process of volatile oil reservoirs involves oil, gas, and water three-phase interactive displacement. The total storage capacity is the sum of the storage capacity of the pure oil/water flooded zone, the remaining oil shrinkage storage capacity of the pure oil zone, and the secondary saturation expansion dissolved gas capacity of the remaining oil. The effective storage capacity is the difference between the total storage capacity and the final remaining dissolved gas.
- (4) Collaborative type UGS has dual functions of oil displacement and gas storage, and the volatile oil reservoir in Block M is rebuilt as a gas storage. The use of gas cap gravity oil displacement method not only forms the peak shaving capacity of gas storage, but also significantly improves crude oil recovery rate. It is expected that the construction of gas storage can increase crude oil recovery rate by 27.7%.
- (5) By designing and optimizing indicators such as injection production well network, injection production capacity, storage capacity, operating pressure, and liquid expansion, it is predicted that the effective storage capacity of the M block volatile oil reservoir for gas storage reconstruction is $18.6 \times 10^8 \text{ m}^3$, operating pressure of 17.5–40.0 MPa, and working gas volume of $9.0 \times 10^8 \text{ m}^3$. Adopting differentiated injection production well deployment, 7 injection production directional wells, 3 injection production horizontal wells, and 16 injection production old wells are designed to achieve a maximum daily peak shaving capacity of $956 \times 10^4 \text{ m}^3$, meeting the requirements of efficient gas storage with few wells.

References

1. Guosheng, D.: The status quo and technical development direction of underground gas storages in China. *Nat. Gas Ind.* **35**(11), 107–112 (2015)
2. Guosheng, D.: Review and prospect of China's underground gas storage in 20 years. *Oil Gas Storage Transp.* **39**(1), 25–31 (2020)
3. Xinhua, M.A.: Development directions of major scientific theories and technologies for underground gas storage. *Nat. Gas Ind.* **42**(5), 93–99 (2022)
4. Zhonghe, W.: Function and effect of underground natural gas storage. *Nat. Gas Oil* **22**(2), 1–4 (2004)
5. Shaohua, D.: Development status and prospect of safety insurance technologies for oil & gas reserves. *Oil Gas Storage Transp.* **37**(3), 241–247 (2018)
6. Shuhui, Z.: Development of China's natural gas industry during the 14th five-year plan in the background of carbon neutrality. *Nat. Gas Ind.* **41**(2), 171–182 (2021)
7. Daqing, D.: Natural gas market: 2022 review and 2023 prospect. *Petrol. Petroch. Today* **31**(2), 1–7 (2023)

8. Hengyang, L.: Opportunities and challenges of underground natural gas storage based on carbon peak and carbon neutrality goals. *Chem. Eng. Oil Gas* **51**(6), 70–76 (2022)
9. Tongwen, J.: Integrated storage technology of gravity flooding and storage on top of natural gas. *Petrol. Explor. Dev.* **48**(5), 1061–1068 (2021)
10. Xin, S.: Status and development trend of foreign underground gas storages. *Nat. Gas Oil* **25**(4), 1–4 (2007)
11. Xinhua, M.: *Underground Gas Storage (UGS) in China*. Petroleum Industry Press, Beijing (2018)
12. Xinhua, M.: Key technology and practice of gas reservoir construction under complex geological conditions in China. *Petrol. Explor. Dev.* **45**(3), 489–498 (2018)
13. Gangxiong, Z.: Challenges and proposals for underground gas storage (UGS) business in China. *Nat. Gas Ind.* **37**(1), 153–159 (2017)
14. Wei, L.: Feasibility evaluation of underground gas storage construction from volatile oil reservoirs based on experimental analysis of flow in multicycle gas injection–production. *Nat. Gas Ind.* **42**(12), 65–71 (2022)
15. Yuanrong, X.: Study on technical policy limits for rational construction of reservoir gas storage. *China Petrol. Chem. Stan. Qual.* **42**(17), 172–174 (2022)
16. Tongwen, J.: Practice and understanding of the coordinated construction of underground gas storage and natural gas flooding. *Nat. Gas Ind.* **41**(9), 66–74 (2021)
17. Dewen, Z.: Key evaluation techniques in the process of gas reservoir being converted into underground gas storage. *Petrol. Explor. Dev.* **44**(5), 794–801 (2017)
18. Guosheng, D.: The status quo and technical development direction of underground gas storage in China. *Nat. Gas Ind.* **35**(11), 107–112 (2015)
19. Yali, Z.: Connotation and evaluation technique of geological integrity of UGSs in oil-gas fields. *Nat. Gas Ind.* **35**(11), 107–112 (2015)
20. Wei, L.: Evaluation on the dynamic sealing capacity of underground gas storages rebuilt from gas reservoirs: a case study of Xinjiang H underground gas storage. *Nat. Gas Ind.* **41**(3), 133–141 (2021)
21. Shasha, S.: Sealing evaluation of underground gas storage in the conditions of multi-period alternating load. *Sci. Technol. Eng.* **16**(6), 1671–1815 (2016)
22. Miao, W.: Comprehensive evaluation technology of trap sealing performance in complex fault block reservoir construction. *Complex Hydrocarbon Reservoirs* **15**(3), 12–15 (2022)
23. Xiaofei, F.: Study on fault sealing mechanism and main influencing factors. *Nat. Gas Geosci.* **10**(3–4), 54–62 (1999)
24. Yielding, G.: Quantitative fault seal prediction. *AAPG Bull.* **81**(6), 897–917 (1997)
25. Junchang, S.: Injection–production mechanisms and key evaluation technologies for underground gas storages rebuilt from gas reservoirs. *Nat. Gas Ind.* **38**(4), 138–144 (2018)
26. Guangliang, G.: Geological characteristics of sandy debris flow reservoir in PG2 Block of Nanpu Sag. *Fault-block Oil Gas Field* **25**(1), 94–99 (2018)
27. Jieming, W.: Calculation method of gas storage capacity in sandstone gas cap reservoir reconstruction. *Nat. Gas Ind.* **27**(11), 97–99 (2007)
28. Hongcheng, X.: A new design method of minimum storage pressure of underground gas storage rebuilt from gas reservoir. *Nat. Gas Geosci.* **31**(11), 1648–1653 (2020)
29. Bin, W.: A method for assessing the gas injection–production capacity of H-shaped UGS in Xinjiang oilfield. *Special Oil Gas Reservoir* **22**(5), 78–81 (2015)
30. Pengcheng, L.: Optimization design of well pattern in heterogeneous gas storage. *J. Southwest Petrol. Univ. (Sci. Technol. Ed.)* **42**(2), 141–148 (2020)
31. Dewen, Z.: *Optimization Technology for Injection Production Operation of Gas Reservoir Type Gas Storage*. Petroleum Industry Press, Beijing (2018)