



# Article Investigation of the Water-Invasion Gas Efficiency in the Kela-2 Gas Field Using Multiple Experiments

Donghuan Han <sup>1,2,3,\*</sup>, Wei Xiong <sup>2</sup>, Tongwen Jiang <sup>4</sup>, Shusheng Gao <sup>2</sup>, Huaxun Liu <sup>2</sup>, Liyou Ye <sup>2</sup>, Wenqing Zhu <sup>2</sup> and Weiguo An <sup>2</sup>

- <sup>1</sup> University of Chinese Academy of Sciences, Beijing 100049, China
- <sup>2</sup> Research Institute of Petroleum Exploration and Development, PetroChina, Beijing 100083, China; xiongwei69@petrochina.com.cn (W.X.); gaoshusheng69@petrochina.com.cn (S.G.); liuhuaxun@petrochina.com.cn (H.L.); yeliyou69@petrochina.com.cn (L.Y.); zhuwengging@petrolchina.com cn (W.Z.); anweiguo6@petrochina.com cn (W.A.)
- zhuwengqing@petrolchina.com.cn (W.Z.); anweiguo69@petrolchina.com.cn (W.A.)
- <sup>3</sup> Institute of Porous Flow and Fluid Mechanics, Chinese Academy of Sciences, Langfang 065007, China
   <sup>4</sup> Department of Science and Technology Management, PetroChina Company Limited, Beijing 100007, China;
- jiangtw-tlm@petrochina.com.cn
- Correspondence: handonghuan19@mails.ucas.edu.cn

Abstract: Although improving the recovery of water-invaded gas reservoirs has been extensively studied in the natural gas industry, the nature of the efficiency of water-invaded gas recovery remains uncertain. Low-field nuclear magnetic resonance (NMR) can be used to clearly identify changes in water saturation in the core during high-pressure water-invasion gas. Here, we provide four types of water-invasion gas experiments (spontaneous imbibition, atmospheric pressure, high-pressure approximate equilibrium, and depletion development water-invasion gas) to reveal the impact of the water-invasion gas efficiency on the recovery of water-invasion gas reservoirs. NMR suggested that imbibition mainly occurs in medium to large pores and that residual gas remains mainly in large pores. The amount of gas driven out from the large pores by imbibition was much greater than that driven out from the small pores. Our findings indicate that the initial gas saturation, contact surface, and permeability are the main factors controlling the residual gas saturation, suggesting that a reasonable initial water saturation should be established before the water-invasion gas experiments. Additionally, the water-invasion gas efficiency at high pressures can be more reliably obtained than that at normal pressures. After the high-pressure approximate equilibrium water invasion for gas displacement, a large amount of residual gas remains in the relatively larger pores of the core, with a residual gas saturation of 42%. In contrast to conventional experiments, the residual gas saturation and water displacement efficiency of the high-pressure approximate equilibrium water invasion for gas displacement did not exhibit a favorable linear relationship with the permeability. The residual gas saturation ranged from 34 to 43% (avg. 38%), while the water displacement efficiency ranged from 32 to 45% (avg. 40%) in the high-pressure approximate equilibrium water invasion for gas displacement. The residual gas saturation in the depletion development water-invasion gas experiment was 26–40% (average: 33%), with an efficiency ranging from 45 to 50% (average: 48%), indicating that the depletion development experiment is closer to the actual development process of gas reservoirs. Our findings provide novel insights into water-invasion gas efficiency, providing robust estimates of the recovery of water-invasion gas reservoirs.

**Keywords:** water-invasion gas efficiency; Kela-2 gas field; recovery rate; residual gas saturation; depletion development

# 1. Introduction

The United States is one of the world's largest natural gas producers, and its waterinvaded gas reservoir development activities are mainly concentrated in Texas, Louisiana, Oklahoma, and other areas [1]. Canada is also an important natural-gas-producing country,



**Citation:** Han, D.; Xiong, W.; Jiang, T.; Gao, S.; Liu, H.; Ye, L.; Zhu, W.; An, W. Investigation of the Water-Invasion Gas Efficiency in the Kela-2 Gas Field Using Multiple Experiments. *Energies* **2023**, *16*, 7216. https://doi.org/10.3390/en16207216

Academic Editor: Riyaz Kharrat

Received: 18 August 2023 Revised: 26 September 2023 Accepted: 4 October 2023 Published: 23 October 2023



**Copyright:** © 2023 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https:// creativecommons.org/licenses/by/ 4.0/). and its typical water-invasion gas reservoir development activities are located in Alberta [2]. Argentina is one of the largest natural-gas-producing countries in South America, and its typical water-invasion gas reservoir development activities are located in Patagonia [3]. China is the world's fourth-largest natural-gas-producing country, and its water-invasion gas reservoirs are mainly distributed in the Sichuan Basin and Tarim Basin. The Kela-2 gas field is located in the central-western section of the Kuche Depression within the Kuye structural belt [4]. It is characterized by a nearly east–west-trending, north–southsymmetric, long-axis anticline with a prominent arc-shaped fault that protrudes southward. The target reservoir of this gas field comprises Paleogene dolomite, conglomerate, and Cretaceous sandstone, which are classified as mesoporous and low-permeability reservoirs. The average porosity is 12.44%, and the average permeability is  $49.42 \times 10^{-3} \ \mu\text{m}^2$ . The buried depth of the reservoir ranges from 3500 to 4100 m, with a gas column height of 468 m [5]. This gas field is categorized as a blocky bottom-water-invasion ultrahighpressure dry gas reservoir, with an initial reservoir pressure of 74.3 MPa and a temperature of 100 °C. The pressure coefficient reaches 2.02. The Kela-2 gas field is the largest proven ultrahigh-pressure dry gas reservoir in China. Since 2010, this gas field has experienced water breakthroughs in seven wells due to geological reasons, posing significant risks to its long-term stable production. It is crucial to deepen the understanding of the water intrusion mechanism and determine the water-invasion pattern to effectively mitigate these risks.

In the late depletion development stage of gas reservoirs, the gas production rate is typically low, and recovery is low. Water invasion is commonly employed to improve recovery. However, after the energy of the water invasion is depleted, spontaneous imbibition often occurs. There are certain contradictions in the development of water-invasion gas reservoirs. On the one hand, the invasion of water in water-invasion gas reservoirs is the driving force for natural gas development; on the other hand, the invasion of water results in the occurrence of a two-phase gas–liquid flow in the reservoir, reducing the flow capacity of natural gas. When water invades the wellbore, the gas flow rate is lower than the critical liquid-carrying flow rate, and liquid accumulates in the gas well, eventually causing the shutdown of gas well production, which greatly reduces the final recovery rate of gas wells [6]. It has been previously shown that the recovery rate of water-invasion gas reservoirs [7,8]. Due to different driving methods and driving energy levels, the final recovery rates of water-invasion gas reservoirs also vary greatly. Therefore, studying how to improve the recovery rate of water-invasion gas reservoirs is very important.

The water-invasion gas efficiency is a key parameter affecting the recovery rate of water-invasion gas reservoirs. Based on the definition of the water-invasion oil efficiency, a water-invasion gas efficiency model is established [6–8]. The water-invasion oil efficiency is defined as the ratio between the underground original oil displaced and the oil within the range affected by the displacement process. Alternatively, the water-invasion gas efficiency is the ratio of the change in the gas saturation before and after water invasion to the original gas saturation. The original gas saturation is a property of the rock itself, which is determined by the reservoir properties, while the residual gas saturation is influenced by multiple factors, including the rock properties, pressure, and pressure difference. In contrast to the rigid displacement phenomenon in the oil–water exchange process of conventional oil reservoir development, natural gas is a compressible fluid, and the gas saturation is greatly influenced by pressure. This is the most notable difference between gas reservoir development and oil reservoir development. Therefore, it is crucial to conduct experimental studies to investigate the factors influencing water-invasion gas efficiency and to develop effective methods for improving the recovery rate of water-invasion gas reservoirs.

The water-invasion gas efficiency depends on the residual gas saturation, which is jointly affected by the reservoir properties, pressure, and pressure difference. The principle of measuring the residual gas saturation through the water-invasion gas method is as follows: the experimental core is fully or partially saturated with the nonwetting phase fluid (gas), and the wetting phase fluid (water) is injected to displace the nonwetting phase fluid in the porous medium of the rock core under the action of capillary forces or other driving forces until the saturation of the nonwetting phase fluid no longer changes [5]. The methods for measuring the residual gas saturation include spontaneous imbibition, steadystate water invasion, and unsteady-state water invasion. Spontaneous imbibition is widely used to measure the residual gas saturation due to its simplicity. It refers to the process in which the wetting fluid spontaneously enters rock pores under the action of capillary forces in porous media, displacing the nonwetting phase fluid [6]. The bottom end face of the rock sample is brought into contact with water, and water gradually enters from the bottom of the rock sample, while gas is produced from the upper end face of the rock sample [7]. This method is referred to as unidirectional imbibition. Multidirectional imbibition occurs when the core is completely immersed in formation water, and formation water enters the rock core from all directions, while gas is produced from all directions of the rock core [8]. In the late depletion development stage of gas reservoirs, the gas production rate is typically low, and recovery is low. Water invasion is commonly employed to improve recovery. However, after the energy of the water invasion is depleted, spontaneous imbibition often occurs. It was first found in the Spraberry Sandstone reservoir in the United States that spontaneous imbibition in rocks could effectively enhance the recovery factor of fractured oil reservoirs in the 1950s [9]. Initially, the field had a high production rate during the early stage but then experienced a sudden decline in production, resulting in poor oil recovery. To address this issue, petroleum engineers combined the production status and geological characteristics and discovered a secondary oil recovery method utilizing the mechanism of spontaneous imbibition in rocks. The presence of imbibition in rocks and the utilization of this principle to enhance the recovery factor were first recognized by Brownscombe and Dyes [9]. They found that, due to capillary forces, water would spontaneously enter the matrix core of the rock when it came into contact with water, thereby displacing the crude oil from the rock core.

Steady- and unsteady-state methods are classical methods for measuring relative permeability in the laboratory [9,10]. The steady-state method is based on Darcy's law [11–13]. In the experimental process, a mixture of oil and water (at certain proportions) is passed through a standard rock sample to reach a stable flow rate, and the pressure difference and flow rate are recorded. By adjusting the injection ratio of oil and water and repeating the above process, a series of experimental data points can be obtained, and the relative permeability under different water saturations can then be calculated based on Darcy's law of single-phase flow. The steady-state method is usually performed under high-temperature and high-pressure conditions, which are consistent with the reservoir conditions, and the experimental results are very accurate [11–13]. The steady-state method can be employed to measure the relative permeability of gas and water in a wide range of saturation, and the experimental results are easy to process. However, the steady-state method requires a long stabilization time when measuring the relative permeability and must be conducted under conditions where stability is reached under different gas-liquid ratios [14]. The capillary end effect significantly impacts the saturation experimental results, especially for low-permeability or tight rock cores [15,16]. However, Honarpour et al. demonstrated the reliability of the steady-state method for measuring the relative permeability of highpermeability rock cores [17,18].

In the unsteady-state method, water invasion is directly performed at a certain injection speed or injection pressure under the condition of satisfying the similarity criterion, and the gas production, cumulative liquid production, and pressure difference between the two ends of the rock core are measured at intervals [19]. However, in the unsteady-state method, a sufficiently high displacement speed or displacement pressure must be established to eliminate the end effect [20,21]. Compared with the steady-state method, the advantages of the unsteady-state method are that the measurement time is shorter, and the experimental intensity is lower [22]. However, the data analysis method requires solving implicit equations and using different mathematical fitting regression methods. The most

commonly used method at present is the JBN method, which is based on the assumption of ignoring gravity and capillary forces [23].

Agarwal et al. combined the material balance equation of water-invasion gas reservoirs with the calculation equation of traditional water invasion to derive a relationship between the reservoir pressure and cumulative gas production [24]. The maximum gas production of a gas reservoir is a function of the water-invasion volume wave coefficient, residual gas saturation, and abandonment pressure [25]. Geffen et al. experimentally demonstrated that the residual gas saturation is not significantly affected by the imbibition mode and that injecting the wetting phase fluid and nonwetting phase gas together into the core does not affect the magnitude of the residual gas saturation [26]. Several researchers have concluded through spontaneous and passive imbibition experiments that the imbibition rate slightly affects the residual gas saturation test results [27,28]. The type of rock imposes a significant influence on the residual gas saturation, which increases with increasing clay content in sandstone and with decreasing sorting and particle size [29]. The initial gas saturation is not a decisive parameter affecting the residual gas saturation [30-32]. However, based on many spontaneous imbibition physical simulation experiments, empirical equations for the residual gas saturation under the corresponding experimental conditions have been established, among which the classic curve of the relationship between the residual gas saturation and initial water saturation is still widely used [33]. Keelan obtained the relationship between the residual gas saturation and rock physical properties, such as permeability, porosity, pore throat type, and original gas saturation, through many experiments [30]. Holtz found that, under general conditions, with decreasing original gas saturation, the pore network of the rock becomes increasingly complex, and both the porosity and pore throat size decrease, which leads to an increase in the residual gas saturation [34]. Fishlock et al. used sandstone cores in water-invasion gas experiments and attempted to continue production by reducing the pressure to cause gas expansion [35]. The experiment showed that this method could not ensure residual gas flow unless the gas saturation was increased to the critical saturation [36]. To investigate the influence of the pore throat type on the residual gas saturation, scholars previously used advanced laser-etching technology to produce microvisual glass sheet models for water-invasion gas experiments [37]. The experiments revealed four stages of bubble movement in the two-phase gas-water flow process, including static, moving, trapped, and broken [38]. It was found that the flow of the gas phase in fractured reservoirs is discontinuous, and different forms of trapped gas can occur in the water-invasion gas process, including viscous fingering, breakoff, blind pores, and water blocking [39]. Water-invasion gas experiments using microvisual models were performed to reveal the relationship between the pore structure and fluid displacement process, fluid distribution, formation of trapped gas, and flow characteristics of the rock [34].

Currently, there is only one relative permeability curve for the Kela-2 gas field obtained using the imbibition method by the Russian company Gazprom [4]. The experimentally measured residual gas saturation is 4.78%, which does not conform with the actual gas reservoir development conditions [4]. The other gas-water relative permeability curves are displacement curves obtained through the gas flooding method, and, therefore, the residual gas saturation cannot be determined [4]. For these reasons, researchers have previously calculated the residual gas saturation in the Kela-2 gas field using various empirical equations based on relevant parameters, resulting in a wide range of values (0.164–0.329) [4]. A large range of values has been provided empirically, but the mechanism for improving the water-invasion efficiency in the water-invasion area is unclear [8]. Therefore, it is necessary to obtain the residual gas saturation of the Kela-2 gas field through residual gas saturation testing methods, specifically the water-invasion gas recovery method, to accurately calculate the water-invasion gas efficiency of the Kela-2 gas field. This could provide support for explaining the water-invasion dynamics of the Kela-2 gas field and improving the recovery efficiency after encountering water. In this study, the effects of the initial gas saturation, porosity, and permeability on the residual gas saturation were verified

through spontaneous imbibition and water-invasion gas experiments under atmospheric pressure conditions. The water-invasion gas efficiency of the Kela-2 gas field was accurately determined using approximate equilibrium water-invasion gas and depletion development water-invasion gas experiments under high-pressure conditions, and a residual gas volume evaluation model for highly water-invaded gas reservoirs was established. Technical means for reducing the residual gas volume in water-invasion areas were proposed. In this study, we revealed the mechanism of the water-invasion gas efficiency of the Kela-2 gas field and provided new technical ideas for improving the development effect of the Kela-2 gas field.

This study focuses on the Kela-2 gas field, which is an anomalous high-pressure waterinvasion gas reservoir. We investigated different water-invasion gas methods, including spontaneous imbibition water-invasion gas, atmospheric pressure water-invasion gas, high-pressure approximate equilibrium water-invasion gas, and depletion development water-invasion gas. The experimental results showed that the residual gas saturation after water invasion is influenced by the initial gas saturation, size of the rock-formation water contact surface, and permeability. We also identified the importance of establishing a reasonable initial water saturation before conducting water-invasion gas experiments. Furthermore, we demonstrated that the water-invasion gas efficiency at normal pressures is higher than that at high pressures, and the results of high-pressure water-invasion gas experiments are more reliable. Finally, depletion development water-invasion gas was shown to more closely reflect the actual development conditions of gas reservoirs, with a residual gas saturation ranging from 26 to 40% and a water-invasion gas efficiency ranging from 45 to 50%. Overall, this study provides valuable insights into the factors affecting water-invasion gas efficiency and contributes to the development of effective methods for improving the recovery rate of water-invasion gas reservoirs.

#### 2. Materials and Methods

In this study, all the core samples used in the experiment were obtained from well KL2-J3. The basic rock properties of the core samples are provided in Table 1. The porosity of the reservoir core samples from well KL2-J3 ranges from 7 to 13%, and the permeability ranges from 0.1 to 38 mD, which basically covers the porosity and permeability ranges of the Kela-2 gas field reservoir.

Number	Core Number	Length (cm)	Diameter (cm)	Dry Weight (g)	Wet Weight (g)	Pore Volume (mL)	Porosity (%)	Permeability (mD)
1	4-21/29 ②	4.94	2.53	60.95	63.02	2.07	8.38	0.17
2	4-21/29 6	3.66	2.52	45.20	46.62	1.43	7.82	0.12
3	4-21/29 ①	5.14	2.53	62.12	64.62	2.50	9.73	0.66
4	4-21/29 ⑦	3.91	2.52	46.89	48.78	1.89	9.71	0.68
5	4-21/29 ④	8.32	2.52	101.11	105.10	3.99	9.63	0.81
6	4-12/29 ②	4.87	2.53	57.20	60.12	2.92	11.91	7.87
7	4-21/29 ③	4.87	2.53	58.59	61.01	2.42	9.94	3.59
8	4-21/29 (5)	4.18	2.53	49.32	51.67	2.35	11.23	6.32
9	4-12/29 ①	5.16	2.52	60.72	63.80	3.09	12.00	7.24
10	4-25/29 6	8.81	2.53	104.12	109.23	5.12	11.61	4.45
11	4-25/29 ③	4.96	2.53	57.28	60.54	3.26	13.13	33.95
12	4-25/29 ①	8.57	2.53	99.08	104.72	5.64	13.08	30.47
13	4-25/29 ②	8.46	2.52	98.36	103.79	5.43	12.89	29.41
14	4-25/29 ④	7.48	2.51	86.48	91.36	4.87	13.22	31.19
15	4-25/29 (5)	7.05	2.53	81.14	85.78	4.64	13.15	28.61
16	4-25/29 ⑦	8.09	2.53	93.50	98.83	5.33	13.17	38.05

Table 1. Basic rock properties of the experimental cores from well KL2-J3.

The steps of the spontaneous imbibition experiment are as follows (Figure 1): (1) The experimental core is dried for 12 h, and the dry weight is recorded as  $m_1$ . (2) After

vacuuming the dried core for 12 h, it is saturated with formation water under a pressure of 10 MPa for 24 h. After removing the core, it is weighed to obtain the wet weight, which is recorded as  $m_2$ . (3) The experimental core is placed in a core holder, a confining pressure of 10 MPa is applied, the core fluid is displaced at a constant flow rate (0.05 mL/min) until no more water flows from the outlet, and the flow rate is then increased to obtain a constant flow rate of 0.1 mL/min until no more water flows from the outlet, are  $m_3$ . (4) The core with bound water saturation is placed in a water imbibition apparatus filled with formation water, the imbibition time is recorded, and the core is weighed after imbibition, which is recorded as  $m_4$ .

The porosity of a core using liquid measurement data can be calculated as [38]:

$$\phi = \frac{m_2 - m_1}{\rho_w V} \tag{1}$$

Electronic balance

</tab

where  $\rho_w$  is the density of formation water in g/cm<sup>3</sup>, and *V* is the external volume of the core in cm<sup>3</sup>.

Figure 1. Flow chart of the spontaneous imbibition experiment.

The experimental process of atmospheric pressure water-invasion gas is as follows (Figure 2): Following the first three steps of the spontaneous imbibition water-invasion experiment, which involve drying and vacuuming the core, saturating it with formation water, and establishing the connate water saturation, the experimental core is placed in the core holder. The inlet is connected to an Isco pump, while the outlet is open to the atmosphere. Formation water is injected into the core from the inlet at a constant flow rate of 0.02 mL/min. The mass of the core is recorded after every 0.05 pore volume (PV) of injection, and NMR experiments are conducted at 0.2, 0.3, 0.4, 0.5, and 0.6 PVs of injection. The breakthrough time of water at the outlet is also recorded.

The procedure of the high-pressure approximate equilibrium water-invasion gas experiment is as follows (Figure 3): (1) The core is dried and vacuumed, it is saturated with formation water, and the connate water saturation is established following the first three steps of the spontaneous imbibition water-invasion gas experiment mentioned above. (2) The core with connate water saturation conditions is placed in the core holder, and a confining pressure of 40 MPa is applied. (3) Gas is slowly injected from a high-pressure cylinder into both ends of the core until the pressure in the system reaches 30 MPa. (4) The inlet end of the core is connected to an infinite water reservoir with a pressure of 30 MPa, and the outlet end of the core is connected to an intermediate container filled with natural gas

at a pressure of 30 MPa. (5) Gas water invasion is performed at a flow rate of 0.01 mL/min from the inlet end of the core to ensure that the pressure difference between both ends of the core is relatively small and an approximate equilibrium state is achieved. The so-called approximate equilibrium state refers to a production-pressure-difference-to-experimental-pressure ratio of less than 1%, i.e., a production pressure difference less than 0.3 MPa. (6) Gas water invasion is conducted until the production pressure difference cannot be maintained below 0.3 MPa, and the experiment is stopped once water breaks through in the gas well.



Figure 2. Flow chart of water-invasion gas in the atmospheric pressure experiment.



Figure 3. Flow chart of the high-pressure approximate equilibrium water-invasion gas experiment.

This paper introduces a novel concept of the "apparent permeability coefficient" through innovative experiments on nonuniform porous media flow resistance. The experiments involve mixtures of two different sizes of quartz sands and five different sizes of quartz sands. The Darcy linear permeability coefficient ( $\alpha$ ) is not a constant but varies with the change in seepage velocity, and its variation pattern is related to the average particle size of the porous media. The permeability coefficient, also known as hydraulic conductivity, is the measure of the ease with which fluid flows through a porous media under a unit hydraulic gradient. The traditional permeability coefficient determined based on Darcy's linear law to describe the seepage characteristics of porous media under different seepage velocities has flaws. To distinguish it from the traditionally defined permeability coefficient, this study defines the permeability coefficient ( $\alpha$ )', and the value of  $\alpha$  is determined to be 0.9 under

the experimental conditions in this study. The pressure difference during displacement between both ends of the core can be calculated using the modified Darcy's law [25]:

$$\Delta P_1 = \frac{\alpha q \mu_w L}{AK} \tag{2}$$

where *q* is the flow rate, mL/min;  $\mu_w$  is the viscosity of water, mPa·s; *L* is the length of the core, cm; *A* is the cross-sectional area of the core, cm<sup>2</sup>; *K* is the permeability of the core, mD; and  $\alpha$  is the apparent permeability coefficient, 0.9, in this research.

$$\frac{P}{P_i} = \frac{V}{V - \Delta V} \tag{3}$$

where *P* is the average pressure across both ends of the core at the initial time, MPa;  $P_i$  is the average pressure across both ends of the core at time *i*, MPa; *V* is the initial gas volume in the system, mL; and  $\Delta V$  is the total injected water volume, mL.

$$\Delta V_g = V_p \left( S_{gi} - S_g \right) \tag{4}$$

where  $\Delta V_g$  is the residual water saturation in the core, mL;  $V_p$  is the pore volume of the core, mL;  $S_{gi}$  is the initial gas saturation, dimensionless; and  $S_g$  is the current gas saturation at time *i*, dimensionless. The amount of water stored in the intermediate container can be calculated as follows [40]:

$$\Delta V_w = \frac{P}{P_i} V - V - \Delta V_g \tag{5}$$

The experimental steps of water invasion to achieve gas displacement in depleted reservoir development are as follows (Figure 4): (1) After drying the experimental core for 12 h, the dry weight is measured and recorded as  $m_1$ . (2) After vacuuming the dried core for 12 h, it is saturated with formation water under 10 MPa pressure for 24 h, and the wet core weight is measured and recorded as  $m_2$ . (3) the experimental core is placed in the core holder, and a confining pressure of 10 MPa is applied. First, a low constant flow rate (0.05 mL/min) is used for displacement until no water production is observed at the outlet, and the flow rate (0.1 mL/min) is then increased until no water production is observed at the outlet. The core in the bound water state is weighed, and the weight is recorded as  $m_3$ . (4) The core in the bound water state is placed in the core holder, and a confining pressure of 40 MPa is applied. The outlet is closed, and natural gas is injected from the inlet until the system pressure reaches 30 MPa and remains constant for 10 min. The inlet is closed. (5) the outlet is opened, and the water-free depletion development experiment is conducted at a gas production rate of 2%. The natural gas flow rate is recorded using a flowmeter. (6) Step 4 is repeated. (7) The middle container filled with formation water (10,000 mL) is connected to the inlet, and a pressure up to 30 MPa is applied. Both the inlet and outlet are opened, and the infinite water depletion development experiment is conducted at a gas production rate of 2%. The time when water production is observed at the core outlet and the weight of the core before and after the experiment are recorded. The natural gas flow rate is recorded using a flowmeter. (8) After depressurization, the core is removed and weighed, and the weight is recorded as  $m_4$ .

The key parameters of the NMR apparatus include a 2 MHz frequency, 0.5 T magnetic strength with a high internal field gradient, 0.205 ms echo time (te), 5000 ms waiting time (Tw), 8000 echoes (nech), and 128 superpositions (n). The  $T_2$  signal is obtained by the Carr–Purcell–Meiboom–Gill (CPMG) pulse sequence method [29]. The NMR experiments were conducted at the Research Institute of Petroleum Exploration and Development.



Figure 4. Flow chart of water invasion for gas displacement in a depleted reservoir.

# 3. Results and Discussion

3.1. Spontaneous Imbibition of Water-Invaded Gas

3.1.1. Effect of the Contact Area of the Core on Spontaneous Imbibition

There are many factors that affect spontaneous imbibition, the imbibition trends for different factors under different conditions vary, and there is no unified understanding at present [41]. Therefore, it is necessary to conduct corresponding imbibition experiments considering specific situations to study the effects of different factors on imbibition under different conditions and reveal the imbibition mechanism. In this study, spontaneous imbibition experiments were conducted involving Kela-2 cores based on the basic physical properties of the formation rock and formation water. By analyzing the imbibition-related production under different conditions, the imbibition rate and imbibition recovery rate were calculated to reveal the effects of the initial gas saturation and permeability on spontaneous imbibition, and the influencing mechanism was analyzed accordingly.

According to the principle of NMR, in the  $T_2$  pattern of rock samples, the envelope area of saturated water and bound water is the original gas volume in the pore space, and the envelope area of saturated water and water-driven gas is the water-sealed gas volume in the pore space. Combined with the NMR spectra obtained before and after imbibition, it could be observed that bound water mainly exists in small pores, while imbibition mainly occurs in medium to large pores (Figure 5b). Moreover, the larger the contact area, the higher the utilization degree of medium to large pores, while the residual gas mainly exists in large pores (Figure 5b). During imbibition, almost all the gas in the small pores was extracted, but the gas saturation in the small pores was limited, and the amount of gas driven out from the large pores by imbibition was much greater than that driven out from the small pores (Figure 5b). The area occupied by the double peaks of the NMR curve shows that the initial water saturation of the core is 34.9%, the water saturation of the core after unidirectional seepage is 49.4%, the water-driven gas efficiency is 22%, the water saturation of the core after multidirectional seepage is 58.9%, and the water-driven gas efficiency is 36.8%, which is within the error of 5% with that of the water saturation and water-driven gas efficiency obtained by the weighing method. The results of the calculation are reliable, and the low water-driven gas efficiency of the unidirectional seepage core is affected by factors such as the core length, formation water volatility, and force balance during the seepage process. The low water-driven gas efficiency of the unidirectional seepage core is affected by factors such as the core length, volatilization of formation water and imbalance of force during seepage; therefore, multidirectional seepage is more reflective of the actual development of gas reservoirs than unidirectional seepage. The physical properties of the core of the Clarke 2 gas field are relatively good, and the left and right peaks of the NMR spectra are not separated but are closely connected, which means that there is a difference in the nature of the fluids in the large and small pores, but it is not large.



**Figure 5.** Different factors affecting spontaneous imbibition for well KL2-J3 4-21/29 ①: (a) the impact of different contact surface sizes on the water-invasion gas efficiency; (b) the unidirectional and multidirectional imbibition  $T_2$  spectra; (c) the relationship between spontaneous imbibition gas saturation and permeability; and (d) the variation in water-invasion gas efficiency with permeability.

#### 3.1.2. Effect of the Permeability on Spontaneous Imbibition

The KL2-J3 well cores were subjected to spontaneous imbibition experiments according to the above steps, and the bound water saturation and water saturation after imbibition were calculated (Figure 5c). These two parameters correspond to the initial gas saturation and residual gas saturation, respectively. By plotting the permeability curve against the gas saturation curve, the trend of the effect of the permeability on spontaneous imbibition could be obtained (Figure 5c).

The initial gas saturation significantly increases with increasing permeability and exhibits a suitable functional relationship (Figure 5d). When the permeability is less than 1 mD, the initial gas saturation ranges from 50 to 60%. When the permeability ranges from 1 to 10 mD, the initial gas saturation ranges from 60 to 70%. When the permeability is higher than 10 mD, the initial gas saturation ranges from 70 to 80% (Figure 5d). However, there exists no satisfactory functional relationship between the residual gas saturation and permeability. The residual gas saturation ranges from 30 to 40% (avg. 35%). The water-invasion gas efficiency of spontaneous imbibition increases with increasing permeability. When the permeability is less than 10 mD, the water-invasion gas efficiency of spontaneous imbibition ranges from 46 to 53% (avg. 50%). In other words, the higher the core permeability is, the higher the water-invasion gas efficiency is.

# 3.1.3. Effect of the Initial Water Saturation on Imbibition

To investigate the effect of the initial water saturation on spontaneous imbibition, the same core was used for spontaneous imbibition experiments under both bound water

conditions and dry core conditions (i.e., without water). As shown in Figure 6a, the water saturation curve after imbibition is the water-invasion gas efficiency curve. The water saturation in the core after imbibition under dry conditions is lower than that in the core under bound water conditions, indicating that the core under dry conditions exhibits a higher residual gas saturation and less gas production. However, the water-invasion gas efficiency of the core calculated from the imbibition experiment under dry conditions is higher than that of the core under bound water conditions, indicating that the imbibition experiment under dry core conditions could result in a higher water-invasion efficiency. As shown in Figure 6b, after imbibition, water is uniformly distributed in both large and small pores under both dry core and bound water conditions. However, the space occupied by water in the small pores under dry core conditions is significantly smaller than that in the small pores under bound water conditions, indicating that the ability of the core to imbibe water is not necessarily greater with smaller pores. The amount of water imbibed under dry core conditions is greater than that imbibed under bound water conditions. However, the water saturation in the core after imbibition under dry conditions is lower than that in the core under bound water conditions. Therefore, performing water-invasion gas experiments under dry core conditions may not reflect the actual development status of gas reservoirs.



**Figure 6.** The effect of initial water saturation on imbibition for well KL2-J3 4-21/29 ①: (**a**) the waterinvasion gas efficiency at different initial water saturations; (**b**) the NMR spectra during spontaneous imbibition at different initial water saturations; (**c**) the relationship between initial gas saturation and residual gas saturation, the red curve is a binary equation fitted to the data in horizontal and vertical coordinates, the blue squares are the data of initial gas saturation and residual gas saturation; and (**d**) the fitting of the normalized model for the degree of spontaneous imbibition.

Compared to the residual gas saturation after imbibition, the initial water saturation is a relatively easy parameter to obtain. Based on the spontaneous imbibition experimental data for the KL2 cores, there exists a favorable quadratic relationship between the residual gas saturation and the initial gas saturation in the rock samples. The curve of the initial

#### 3.1.4. Mathematical Model for Spontaneous Imbibition

The Aronofsky normalized recovery index model was used to fit the variation in the degree of spontaneous imbibition and the rate of spontaneous imbibition over time for the KL2-J3 well cores from the KL2 gas field [33]. The process of the variation in the degree of spontaneous imbibition represents the process of the water-invasion gas efficiency (Figure 6d).

The degree of imbibition can be defined as follows [36]:

$$R = R_{\infty}(1 - e^{-\lambda t}) \tag{6}$$

The imbibition rate can be calculated as follows [41]:

$$q = \lambda R_{\infty} e^{-\lambda t} \tag{7}$$

where *R* is the degree of imbibition,  $R_{\infty}$  is the ultimate recovery factor for imbibition, and  $\lambda$  is an empirical constant related to the reservoir properties [39].

Typical cores with different permeability ranges were selected for normalization model fitting, and the results showed that, regardless of the permeability, there exists a high correlation between the degree of spontaneous imbibition and the imbibition rate of the core and the normalized model. The higher the permeability, the higher the degree of spontaneous imbibition rapidly increases at the beginning and then slowly increases with imbibition time, indicating that the imbibition rate gradually declines over time. The imbibition amount after 10 h reaches approximately 80% of the total imbibition amount. Therefore, to achieve the maximum effect of spontaneous imbibition on gas displacement, the focus should be on the early stage of imbibition. Simply increasing the imbibition time does not necessarily lead to an effective production increase. Additionally, the parameter  $\lambda$  controls the imbibition rate. The higher the permeability of the core is, the higher  $\lambda$  is, indicating that the imbibition rate of a core with a higher permeability is higher [10,34].



Figure 7. The fitting of the normalized model rate of spontaneous imbibition.

#### 3.2. Water-Invasion Gas under Atmospheric Pressure

3.2.1. Dynamic Characteristics of Water-Invasion Gas under Atmospheric Pressure

Permeability exerts a significant impact on the breakthrough time of water during water-invasion gas experiments under atmospheric pressure. In cores with a high permeability, water breakthrough occurs from 0.2 to 0.25 PV of injection; in cores with a moderate permeability, water breakthrough occurs from 0.25 to 0.35 PV of injection; and in cores with

a low permeability, water breakthrough occurs from 0.3 to 0.4 PV of injection (Figure 8a). After breakthrough, the water saturation in the core increases slowly, especially in cores with a low permeability. The water-invasion efficiency at breakthrough exceeds 90% of the final displacement efficiency, and, even after breakthrough, gas can still be slowly produced from highly permeable cores, with the water displacement efficiency at breakthrough reaching approximately 70% of the final displacement efficiency (Figure 8b).



**Figure 8.** Water-invasion gas under atmospheric pressure: (a) variation in water saturation and injected water in pore volume; (b) variation in water-invasion gas displacement efficiency and injected water in pore volume; (c) NMR spectrum of water-invasion gas under atmospheric pressure; and (d) r elationship between original gas saturation and residual gas saturation.

The NMR spectrum of the water-invasion gas experiment under atmospheric pressure reveals that the process of increasing the water saturation in the KL2-J3 well 4-21/29 (5) core during the experiment is continuous (Figure 8c). Water breakthrough at the outlet occurred at 0.3 PV of injection, and the change in the NMR spectrum after breakthrough was slight, indicating that the water saturation in the core changed very little after breakthrough (Figure 8c). In addition, connate water in the core mainly exists in small pores, and, due to the lower flow resistance of larger pores, water invasion to achieve gas displacement mainly occurs in medium to large pores [41].

# 3.2.2. Efficiency of Water-Invasion Gas Experiments under Atmospheric Pressure

The residual gas saturation of water invasion for gas displacement under atmospheric pressure ranges from 25 to 44% (avg. 35%). The displacement efficiency ranges from 40 to 55% (avg. 45%), which is lower than the efficiency of spontaneous imbibition water invasion for gas displacement. The original gas saturation and residual gas saturation in the water-invasion experiment for gas displacement under atmospheric pressure show a favorable linear relationship (Figure 8d). The higher the original gas saturation is, the

higher the residual gas saturation is, and the difference is the extracted gas saturation, which ranges from 23 to 35% (avg. 28%). The displacement efficiency decreases with increasing permeability, mainly because the water breakthrough speed is higher in highly permeable cores, resulting in near-piston displacement characteristics (Figure 9). After breakthrough, the gas production rate sharply decreases, and the residual gas saturation is high.



**Figure 9.** Relationship between the efficiency of water-invasion gas and permeability. The straight line is a linear equation fitted to the data in horizontal and vertical coordinates. The dot is the data of permeability and efficiency of water invasion gas.

#### 3.3. High-Pressure Approximate Equilibrium Water-Invasion Gas

Due to the high compressibility of natural gas, the physical properties of natural gas under high-pressure conditions in the reservoir significantly differ from those at atmospheric pressure [24,25]. The gas compressibility factor curve of the Kela-2 gas field shows that, at 30 MPa, the gas volume coefficient is 0.00436, which suggests that the volume of natural gas per unit underground pore space is equivalent to 230 pore space units at the surface (Figure 10a). Moreover, the curve slowly changes at pressures above 30 MPa. To address the effect of pressure variation on gas saturation during experiments, a new testing method of high-pressure approximate equilibrium water invasion for gas displacement was established in the laboratory under 30 MPa conditions. This method eliminates the influence of gas saturation changes caused by pressure changes and can be combined with nuclear magnetic resonance online monitoring technology to eliminate the impact of water produced due to pressure relief on the experimental results. This new method enables the accurate simulation of water invasion for gas displacement under reservoir conditions and the precise testing of the water displacement efficiency.



**Figure 10.** Results of high-pressure approximate equilibrium water-invasion gas: (**a**) gas volume compressibility factor curve of the Kela-2 gas field; (**b**) NMR spectra of high-pressure approximate equilibrium water-invasion gas in the KL2-J3 well 4-25/29 ④; (**c**) comparison of NMR results for atmospheric pressure and high-pressure water-invasion gas in the 4-21/29 ①; and (**d**) experimental results of efficiency and residual gas saturation.

3.3.1. Dynamic Characteristics of High-Pressure Approximate Equilibrium Water-Invasion Gas Experiments

NMR monitoring technology can be used to clearly identify the changes in the water saturation in the core during high-pressure water invasion for gas displacement [28,29]. Figure 10b shows a continuous increase in the water saturation during high-pressure water invasion for gas displacement in the KL2-J3 well 4-25/29 ④ core with a permeability of 31.2 mD. High-pressure water-invasion state 2 corresponds to the core state where water production is observed at the outlet. At this point, the water saturation in the core is 55%, and the water displacement efficiency is 38%. After water breakthrough, the gas production capacity of the core rapidly decreases until it is completely water-invaded. The pressure difference between both ends of the core greatly increases, and the approximate equilibrium state can no longer be maintained. The final state is high-pressure water-invasion state 3, where the water saturation in the core is 58% and the water displacement efficiency is 44%. After the high-pressure approximate equilibrium water invasion for gas displacement, a large amount of residual gas remains in the relatively larger pores of the core, with a residual gas saturation of 42%.

Comparing the NMR curves of the atmospheric pressure and high-pressure water invasion for gas displacement experiments, it is evident that the right peak of the atmospheric pressure water-invasion curve occupies a larger space than that of the high-pressure water-invasion curve (Figure 10c). This indicates that the residual gas saturation is higher, and the water displacement efficiency is lower in high-pressure water invasion for gas displacement than in atmospheric pressure water invasion for gas displacement (Figure 10c).

# 3.3.2. Efficiency of High-Pressure Approximate Equilibrium Water Invasion for Gas Displacement

In contrast to conventional experiments, the residual gas saturation and water displacement efficiency of high-pressure approximate equilibrium water invasion for gas displacement did not exhibit a favorable linear relationship with the permeability (Figure 10d). The residual gas saturation ranged from 34 to 43% (avg. 38%), while the water displacement efficiency ranged from 32 to 45% (avg. 40%). The water displacement efficiency was lower than that during atmospheric pressure water invasion for gas displacement (Figure 10d). In atmospheric pressure water invasion for gas displacement experiments, even though the pressure difference between both ends of the core was only 1–2 atm, natural gas exhibits high compressibility at atmospheric pressure. A pressure difference of 1 atm could compress natural gas to half of its original volume, leading to the phenomenon of natural gas being heavily compressed during atmospheric pressure water invasion for gas displacement, which affects the gas saturation (Figure 10c). Although the pressure difference during high-pressure approximate equilibrium water invasion for gas displacement was greater than that during atmospheric pressure water invasion for gas displacement, its effect on the natural gas compressibility was minimal. Natural gas was completely displaced from the core, which is consistent with the actual underground development situation. Therefore, the results of the high-pressure approximate equilibrium water invasion for gas displacement experiments are more reliable.

#### 3.4. Water Invasion for Gas Displacement in Depleted Reservoir Development

In the process of depleted reservoir development, the depletion rate, gas production rate, and recovery rate are key parameters for predicting productivity and evaluating development effectiveness. Core experiments are the main way to simulate the depletion process, analyze depletion rules, and obtain parameters such as the recovery rate. The Kela-2 gas field is an abnormally high-pressure water-invasion gas reservoir with a pressure coefficient of 2.02 and a water-invasion index of 0.35. The gas reservoir exhibits high driving elastic energy, so at the early stage of development, due to the high rock compressibility and energy supplied by water, the formation pressure slowly decreases. When the formation pressure drops to atmospheric conditions, the rock elastic energy becomes lower than the natural gas elastic energy. At this time, the reservoir mainly relies on gas expansion to provide energy, and the pressure quickly drops, yielding a multistage abnormal high-pressure water-invasion gas reservoir depletion development process, which causes difficulties in dynamic prediction. This is manifested in the relationship curve between the formation pressure (P/Z) and cumulative gas production (Gp), which shows a turning point, and the slope of the later curve section increases [33,34]. Regarding gas reservoirs with a high rock compressibility, using early pressure drop data to calculate dynamic reserves may lead to overestimation. Therefore, a physical simulation experiment of rock depletion development was conducted involving a Kela-2 gas field core to simulate the development process of the gas reservoir, predict the development dynamics of the gas reservoir, obtain the influence of pressure changes on the dynamic reserves, calculate the water-invasion efficiency of depleted gas development, and evaluate the gas recovery rate.

#### 3.4.1. Full-Diameter Core Depletion Development Simulation Experiment

First, a closed gas reservoir depletion development simulation experiment was conducted. By using the gas reservoir material balance equation, the gas content in the core holder system at 30 MPa could be calculated, which represents the simulated original geological reserves of the reservoir in the bound water state, denoted as *G* (Table 2) [25].

$$G = \frac{m_6 - m_7}{\rho_w B_{gi}} \tag{8}$$

where  $m_6$  is the weight of the core in the saturated state (g);  $m_7$  is the weight of the core in the bound water state (g);  $\rho_w$  is the density of formation water (g/cm<sup>3</sup>); and  $B_{gi}$  is the natural gas volume coefficient at the original formation pressure (30 MPa) (MPa<sup>-1</sup>).

Table 2. Basic parameters of the full-diameter core depletion development water-invasion gas experiment.

Core Number	Length (cm)	Diameter (cm)	Permeability (mD)	Dry Weight (m <sub>5</sub> ) (g)	Wet Weight (m <sub>6</sub> ) (g)	Pre-Experiment Core Weight ( <i>m</i> <sub>7</sub> ) (g)	Post-Experiment Core Weight (m <sub>8</sub> ) (g)	Weight Difference of the Core (g)
4-12/29	8.78	10.10	7.56	1641.5	1727.1	1667.05	1695.79	82.66

The core pore volume is defined as [36]:

$$V_p = \frac{m_6 - m_5}{\rho_w} \tag{9}$$

The water-invasion volume is defined as [37,38]:

$$W_{\rm e} = V_w (C_w + C_f) \Delta p \tag{10}$$

where  $C_f$  is the porosity compressibility coefficient, MPa<sup>-1</sup>;  $C_w$  is the formation water compressibility coefficient, MPa<sup>-1</sup>; and  $\Delta p$  is the pressure drop of the water, MPa. The residual gas content in the core during the infinite water depletion development experiment is [39]:

$$G - G_p = \left(\frac{m_6 - m_7}{\rho_w B_g} - W_e\right) \middle/ B_g \tag{11}$$

where *G* denotes the simulated geological reserves of the core, mL;  $G_p$  is the cumulative gas production, mL; and  $B_g$  is the natural gas volume coefficient, MPa<sup>-1</sup>. The residual gas saturation is [42]:

$$S_{gr} = \frac{G - G_p}{B_g V_p} \tag{12}$$

The water-invasion efficiency is defined as [41]:

$$E_R = \frac{1 - S_{wi} - S_{gr}}{1 - S_{wi}}$$
(13)

The water-invasion coefficient is calculated as [42]:

$$E_v = \frac{W_e - W_p B_w}{G B_{gi}} \frac{1}{E_R}$$
(14)

where  $W_e$  is the amount of water invasion at the reservoir temperature and pressure, m<sup>3</sup>;  $W_p$  is the cumulative volume of produced water under the surface temperature and pressure, m<sup>3</sup>; and  $B_w$  represents the volumetric coefficient of water at the corresponding reservoir pressure p, m<sup>3</sup>/m<sup>3</sup>.

The relationship curve between the average simulated pressure of the core and the cumulative gas production in the depletion development process of the closed gas reservoir is basically a straight line (Figure 11a). The simulated geological reserves of the core calculated by the gas reservoir material balance equation are 18,872 mL, and the total flow rate recorded by the flowmeter is 19,029 mL, with a deviation of approximately 1%, which is caused by the dead volume of the experimental system. Then, a high-pressure water container with the same pressure of 30 MPa was connected, and an infinite water depletion development physical simulation experiment was conducted for the gas reservoir, where the container volume was 10,000 mL, which is considered infinite bottom water relative to the core porosity. The water-invasion and gas production dynamics were monitored

by pressure measurement points at the inlet and outlet of the core, and the corresponding cumulative gas production was recorded. Figure 11b clearly shows the influence of water invasion on the cumulative gas production of the infinite water reservoir. The production dynamics at the core outlet before and after water breakthrough significantly differ, indicating a notable difference in the production dynamics of the gas reservoir before and after water breakthrough in gas wells. Before water breakthrough, the average reservoir pressure slowly decreases, and the pressure drop curve at the same cumulative gas production is higher than that of the simulated closed gas reservoir depletion development process, with a higher gas production rate per unit pressure drop, indicating that water invasion provides energy for gas reservoir development (Figure 11c). At this time, water invasion is beneficial to efficient gas field development. The cumulative gas production at water breakthrough is 10,930 mL, and the recovery rate during the water-free period is 58%. After water breakthrough at the core outlet, the average simulated pressure rapidly drops, and the relationship between the average simulated pressure and the cumulative gas production shows a two-phase phenomenon (Figure 11c). The gas production rate per unit pressure drop significantly decreases, and the abandonment pressure is much higher than that of the closed gas reservoir, resulting in a significant reduction in the cumulative gas production. The cumulative gas production from water breakthrough to the end of production is 5944 mL, and the recovery rate during the gas-water coproduction period is 31%. The final abandonment pressure is 6.2 MPa, and the cumulative gas production is 16,874 mL, with a recovery rate of 89%.



**Figure 11.** Results of water invasion for gas displacement in depleted reservoir development: (**a**) the relationship between the average simulated pressure and the cumulative gas production in nonwater and infinite water reservoirs; (**b**) relationship between the pressure at the inlet and outlet and the cumulative gas production; (**c**) gas production per unit apparent pressure in the depletion development; and (**d**) variation trend of recovery rate in the depletion development of the infinite water reservoir.

Water breakthrough of the core is the critical point where the development effect of the infinite water reservoir undergoes a sudden change. At this point, the residual gas saturation is 37% and no longer changes. The water-invasion efficiency reaches the highest value of 49%, and the water-invasion coefficient is 1. However, due to the replenishment of energy by water, the depletion efficiency is only 16.4%. The main factor limiting the recovery rate during the water-free period is the slow decline in the formation pressure. Due to the experimental conditions, the produced water from the core is easily discharged, and the wellbore water column pressure exerts no influence. After water breakthrough, the formation pressure rapidly drops, and the depletion efficiency reaches 79%, with a high recovery rate during the gas–water coproduction period (Figures 11d and 12a). However, in real gas reservoirs, the bottomhole pressure in gas wells significantly increases after water breakthrough, and a large amount of water is produced, resulting in difficult drainage and well shut-in, which is the main reason for the higher recovery rate obtained in the core experiment.



**Figure 12.** Depletion development water-invasion gas recovery efficiency: (**a**) variation trend of recovery rate in the depletion development of the infinite water reservoir; and (**b**) the results of the water-invasion gas efficiency and residual gas saturation for high-pressure quasi-equilibrium water-invasion gas.

# 3.4.2. Depletion Development Water-Invasion Gas Recovery Efficiency

The residual gas saturation in the core during the depletion development of the simulated infinite water reservoir ranges from 26 to 40%, with an average of 33% (Figure 12b). The water-invasion gas recovery efficiency ranges from 45 to 50%, with an average of 48%, which is higher than that obtained in the experiments of spontaneous imbibition, atmospheric water invasion, and high-pressure quasi-equilibrium water invasion for gas displacement. The value is minimally affected by the permeability (Figure 12b).

#### 4. Conclusions

- (1) Spontaneous imbibition is a widely used water-invasion gas recovery method, and the imbibition rate and degree of gas production are well-fitted with the Aronofsky normalized recovery index model. Regarding the Kela-2 gas field core, the larger the contact area with reservoir water and the higher the permeability are, the higher the efficiency of spontaneous imbibition water invasion for gas displacement is.
- (2) Compared with normal-pressure and high-pressure approximate equilibrium waterinvasion gas experiments, the water-invasion gas efficiency of the former is higher than that of the latter. The high-pressure approximate equilibrium experiment fully considers the influence of natural gas compressibility, ensuring that natural gas is replaced by reservoir water during the experiment, and the experimental results are more reliable.
- (3) Depletion development water-invasion gas experiments can accurately capture the real-time water-invasion dynamics of edge- and bottom-water gas reservoirs during

depletion development. The development characteristics of the core before and after encountering water are completely different. Before encountering water, the reservoir pressure slowly drops, and the gas production rate per unit pressure drop is high. The invasion of water provides driving energy for gas reservoir development. Water invasion before encountering water is beneficial to the efficient development of gas fields. After water production occurs at the core outlet, the average pseudopressure rapidly drops, and the gas production rate per unit pressure drop significantly decreases. The abandonment pressure of water-free gas reservoirs is greatly increased, and the cumulative gas production is significantly reduced.

- (4) Comparing the four water-invasion gas experimental methods employed in this study, depletion development water-invasion gas more closely reflects the actual development situation of gas reservoirs. The residual gas saturation in the infinite water reservoir during the core depletion experiment ranges from 26 to 40%, with an average of 33%. The water-invasion gas efficiency is 45 to 50%, with an average of 48%, which is higher than that of the spontaneous imbibition, normal-pressure water-invasion gas, and high-pressure approximate equilibrium water-invasion gas experiments, and the value is minimally affected by the permeability.
- (5) The residual gas amount in the water-invasion zone includes residual gas in the water-invasion area and water-invasion gas in the closed structure, which is affected by the water-invasion volume, drainage volume, residual gas saturation, and nonuniform coefficient of reservoir water invasion. Water plugging, optimized allocation, horizontal well development, drainage gas production, and carbon dioxide injection are effective methods to reduce the residual gas amount in the water-invasion zone.

**Author Contributions:** W.X.; methodology, T.J.; software, S.G.; validation, H.L.; formal analysis, L.Y.; investigation, W.Z.; resources, W.A.; data curation, D.H.; writing—original draft preparation, D.H.; writing—review and editing, D.H.; visualization, D.H.; supervision, D.H.; project administration, W.X.; funding acquisition, W.X. All authors have read and agreed to the published version of the manuscript.

**Funding:** This study was supported by the project Recovery Factor of Different Types of Gas Reservoirs and Mechanisms for Improving the Recovery Factor (2021DJ1701) of the Science Research and Technology Development Project of the China National Petroleum Corporation.

Data Availability Statement: Not applicable.

**Acknowledgments:** This study was supported by the project Recovery Factor of Different Types of Gas Reservoirs and Mechanisms for Improving the Recovery Factor (2021DJ1701) of the Science Research and Technology Development Project of the China National Petroleum Corporation. We would like to express our gratitude to the three anonymous reviewers for their valuable comments and suggestions, as well as to the editor-in-chief.

Conflicts of Interest: The authors declare no conflict of interest.

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