A mass balance method for measuring condensed water content in gas reservoirs

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Abstract
The accurate measurement of condensed water content in gas reservoirs is critical for the effective development of gas reservoirs. In this study, a more accurate and faster method for measuring the condensed water content in gas reservoirs was developed by using a high-temperature and high-pressure PVT device combined with the law of conservation of matter. A condensed water content test was subsequently conducted in the Dong Fang X (DF13) gas reservoir as an example to investigate the variation of condensed water content in gas reservoirs with different temperature and pressure. The results indicate that the condensed water content decreases with the increase in pressure, demonstrating a good exponential relationship, and vice versa. Based on the test results, a comprehensive prediction model for the variation of condensed water content in different sand bodies of the DF13 reservoirs with temperature and pressure was established, which could predict the precipitation of condensed water, thereby laying a solid foundation for the design of waterproof and water control strategies of the DF13 gas reservoir.

Keywords: gas reservoir, condensed water, test method, condensed water prediction model

Nomenclature

\[ V_1 \] the original total volume, ml
\[ V_2 \] the total volume on equilibrium after the injection of water at the same \( T \) and \( P \), ml
\[ W_g \] the volume of saturated water vapor in the natural gas, ml
\[ G_w \] the volume of the dissolved gas in formation water, ml
\[ T \] temperature, °C
\[ P \] pressure, MPa
\[ L \] the amount of liquid upon equilibrium after the injection of formation water at constant \( T \) and \( P \), ml
\[ V_w \] the saturated vapor content in the natural gas, mol mol\(^{-1}\)
\[ V_g \] the natural gas content in the formation water, ml
\[ W_{in} \] the volume of injected water, ml
\[ M_w \] the molar mass of water, g mol\(^{-1}\); PSTD is the standard atmospheric pressure, MPa
\[ G_{wl} \] the liquid volume of water-soluble gas, ml
\[ C_w \] the compression coefficient of water, MPa
\[ a \] functions of temperature
\[ b \] functions of temperature

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1. Introduction

In recent years, natural gas, as an alternative energy source to oil, has experienced a substantial increase in its production and consumption (Jiang et al. 2014; Reagan et al. 2015; Jia 2018; Ou et al. 2018). Many scholars have promoted the advancement of the natural gas industry by carrying out research on the characteristics of gas reservoirs (Cai et al. 2017; HarpREET & Cai 2018; Yin & Ding 2018; Connell et al. 2019; Mehrdad et al. 2019; Yin et al. 2019). Among them, there are obvious physical environmental differences between condensate gas reservoirs and other conventional gas reservoirs. Condensate gas reservoirs are significant parts of natural gas reservoirs, and it has been discovered via exploration that many condensate gas reservoirs present a formation temperature of up to 150°C (Barnum et al. 1995; Ellafi et al. 2018). Studies have shown that, even in high-temperature gas reservoirs and condensate gas reservoirs without edge water and bottom water, owing to their thermodynamic characteristics, condensed water will still be precipitated from gas wells during the production process (Afidick et al. 1994; Guo et al. 2003; Tao 2003; Hui et al. 2004; Zhu 2015). In addition, the amount of such condensed water is associated with the pressure (P) and temperature (T) of the gas reservoir. When gas reservoirs have a high T and P, the natural gas is saturated with a certain amount of formation water in the reservoir so it will be cooled and depressurised during depletion development, which causes changes in the saturated water vapor content of the natural gas, thereby producing condensed water. Production practices have demonstrated that, in some low-yield gas wells, the precipitation of condensed water may lead to liquid loading in the shafts of the gas wells, resulting in reduced productivity and even well shut in. To determine the condensed water precipitation mechanism so as to provide a theoretical basis for studies on the risk prediction and prevention of condensed water liquid loading, improve recovery rate and avoid early dead wells, the variation of condensed water content in the natural gas in shafts and gas reservoirs during the production process must be accurately identified.

As is known, condensed water makes the phase changes of the gas reservoir system extremely complicated, attracting the attention of many scholars (Baghmolaei et al. 2020; Moloney et al. 2020; Salahshoor & Fahes 2020). Lindeloff & Michelsen (2013) confirmed the phase in the system of a gas condensate/water system using a new algorithm. Wang et al. (2017) found that vapor can influence the properties of gas, such as increasing the pressure of dew point, by the phase behavior experiments of gas condensate system. Therefore, it can be observed that the phase change mechanism of the condensate gas reservoir system under high T and P is complicated, and it is difficult to provide a theoretical formula that describes the variation of condensed water content during the depletion development of gas reservoirs.

Many scholars have proposed methods to measure the condensed water content in gas reservoirs under high T and P, and have established empirical formulas to describe the variation of condensed water content under different temperatures and pressures to guide the actual production. Li et al. (2002) designed an experiment to measure the condensed water content in gas reservoirs using a DBR-PVT mercury-free device. Alternatively, on the basis of the principal of material balance, Liu et al. (2011) considered the effects of gas-phase water vapor content and the elastic expansion of rock in reservoirs, and derived the high T and P condensate gas reservoir material balance equation for gas-phase water vapor content, natural water flooding and gas injection conditions. Zendehboudi et al. (2012) proposed an intelligent model based on an artificial neural network optimisation, which can accurately estimate the ratio of condensate and gas for gas condensate reservoirs. Zemenkov et al. (2015) proposed an improved method to calculate the saturated steam pressure of gas condensates.

In this paper, by using a high-precision PVT device, combined with the law of conservation of matter to calculate phase changes, a more accurate and faster method to measure the condensed water content in gas reservoirs is established. The Dong Fang X (DF13) area is used as an example, whose DF13 gas reservoir pressure coefficient is 1.90–1.94, formation temperature 138–143°C, average daily gas production per well 150 × 104 m3/d and water produced is condensed water with extremely low salinity. The new method is applied to measure the condensed water content of the DF13 gas reservoir condensate gas samples, and the variation of condensed water content in gas reservoirs with temperature and pressure is analysed to provide a theoretical basis for the design of a rational working system for gas wells.

2. The new condensed water content measurement method

2.1. Principle and steps of the new condensed water content measurement method

According to the material balance, for a closed container containing water and gas, the total mass of materials in the closed space is constant. In addition, under high T and P, part of the water evaporates into gas, while part of the gas dissolves into water, eventually reaching equilibrium as shown in figure 1. Therefore, it is possible to monitor the volume of gas at the target T and P, and then add water quantitatively and monitor the volume change on equilibrium to, in turn, calculate the volume change of each component in the closed space.

Based on this principle, a new method for measuring the condensed water content was proposed. First, the HBPVT400/100 multi-function high-pressure fluid PVT analyser with a volume monitoring precision of ± 0.001 mL
and pressure monitoring precision of $\pm$ 0.01 MPa was used, as shown in figure 2. Its visualisation window not only allowed the user to observe the high $T$ and $P$ state of the fluid, but also calibrated the volume through image processing via matching working software, which improved the accuracy of the measurement. Subsequently, according to the measured data, the condensed water content in the natural gas under specific temperature and pressure conditions was calculated using the material balance equation.

The experimental steps for measuring the condensed water content were as follows:

1. Add an appropriate amount of natural gas to the PVT device.
2. Adjust the temperature and pressure to the specified point, and once stable, record the temperature, pressure and volume.
3. Change to the next temperature and pressure point, and repeat step 2.
4. Once the tests are completed at all temperature and pressure points, inject an appropriate amount of formation water to the PVT kettle, and repeat steps 2 and 3.
5. Process data and calculate the condensed water content in the natural gas.
6. The calculation process is described as follows.

Under constant temperature and pressure, the volume change of the PVT kettle after the water sample is added is

$$ \Delta V = V_2 - V_1 = W_g - G_w + L. $$

The saturated water vapor volume in the natural gas is

$$ W_g = (V_1 - G_w) \times V_w. $$

The volume of natural gas dissolved into the formation water is

$$ G_w = \left\{ \frac{W_{in} - M_w \times PW_g}{(RT)} \right\} \times V_g \times P_{std}/P. $$
At gas–water equilibrium, the volume of liquid in the PVT kettle is

\[ L = \{ W_{in} - M_w \times PW_w/(RT) \} \times C_w + G_{wl}. \] (4)

If, in the gas reservoir, the content of water-soluble gases such as CO₂ is small because the volume of the injected water sample is small, the volume of the dissolved gas is correspondingly small, which becomes even smaller after liquefaction and can be ignored. Therefore, by combining equations (1)–(4), the volume of saturated water vapor in the natural gas can be obtained, which is

\[ W_g = \frac{V_2 - V_1 + V_g \times P_{std} \times W_{in} - W_{in}}{1 + M_w \times V_g \times P_{std}/(RT) - PW_w/(RT)}. \] (5)

The content equation of saturated water vapor in the natural gas is thus

\[ V_w = \frac{PW_g \times M_w}{PV_1 - \{ W_{in} - M_w \times PW_g/(RT) \} \times V_g \times P_{std}}, \] (6)

where \( V_j \) is the original total volume in ml; \( V_i \) is the total volume on equilibrium after the injection of water at the same \( T \) and \( P \), ml; \( W_g \) is the volume of saturated water vapor in the natural gas, ml; \( G_{wl} \) is the volume of the dissolved gas in formation water, ml; \( L \) is the amount of liquid on equilibrium after the injection of formation water at constant \( T \) and \( P \), ml; \( V_w \) is the saturated vapor content in the natural gas, \( \text{mol mol}^{-1} \); \( V_g \) is the natural gas content in the formation water, ml; \( W_{in} \) is the volume of injected water, ml; \( M_w \) is the molar mass of water, g \( \text{mol}^{-1} \); \( P_{std} \) is the standard atmospheric pressure, MPa; \( G_{wl} \) is the liquid volume of water-soluble gas in ml and \( C_w \) is the compression coefficient of water, MPa⁻¹.

By monitoring the volumes of the PVT kettle before and after the injection of the water sample under constant \( T \) and \( P \), the condensed water content of natural gas under specific \( T \) and \( P \) conditions can be calculated.

Using this improved method, by monitoring the volumes of natural gas before and after the injection of water under constant \( T \) and \( P \) in conjunction with the data for natural gas solubility in formation water, the saturated water vapor content of the natural gas can be derived accurately.

### 2.2. Analysis of the advantages of the improved condensed water content measurement method

As the condensed water content in the gas phase is generally not very high and the test is performed under high \( T \) and \( P \), the measurement of condensed water content places a strict requirement on the accuracy and temperature and pressure performance of the device.

### 3. Application and analysis of the new condensed water content measurement method

Compared with the previous condensed water content measurement methods, the main advantages of the method proposed in this paper are as follows:

1. This method only requires a small amount of sample and is inexpensive, simple and quick. This method only requires the addition of gas once. When the gas volumes under different \( T \) and \( P \) conditions are measured, an appropriate amount of water is added. The volume of the gas–water mixture on equilibrium under the corresponding \( T \) and \( P \) condition is then measured, which is used to calculate the condensed water content.

2. This method requires less experimental equipment and has a high accuracy. As the experiment can only be conducted in a closed PVT device with visualisation, losses of gas and liquid owing to dead volumes in experimental parts such as pipelines and samplers are avoided.

3. This method prevents the volume changes owing to temperature and pressure fluctuations when the liquid flows out of the PVT kettle, thereby reducing the measurement error.

### 3.1. Principle and steps of the new condensed water content measurement method

Taking the DF13 gas reservoir as an example, our method for the condensate water content was applied. The DF13 area contains two fields, named DF13–1 and DF13–2, both of which are abnormal high \( T \) and \( P \) gas reservoirs. Affected by the high \( T \) and \( P \) environment, there is a certain amount of formation water saturated in the natural gas. As the natural gas is depressurised during depletion, the saturated steam content in the natural gas changes and condensate is produced. Production practice shows that in some gas-producing wells, the precipitation of condensate water easily leads to the accumulation of gas in the wellbore, resulting in reduced gas well productivity and even shut in. To grasp the change law of the condensate water content in the gas reservoir and the natural gas in the wellbore during the production process, the comprehensive prediction model for the condensate water content with temperature and pressure was established by using the data obtained by the new method of the condensate water content test.

### 3.2. Laboratory test

The natural gas used in the experiment was compounded according to the actual component data. The formation water used was obtained from the standard formation prepared in the laboratory. Table 1 lists the natural gas composition and salinity data of each sand body.
### Table 1. DF13 gas reservoir gas component and formation water salinity

| Gas reservoir | Sand body | C_1 | C_2 | C_3 | IC_4 | NC_4 | IC_5 | NC_5 | C_6+ | CO_2 | N_2 | H_2 | Salinity (ppm) |
|---------------|-----------|-----|-----|-----|------|------|------|------|------|------|-----|-----|----------------|
| DF13–1        | B         | 67.10 | 0.90 | 0.30 | 0.07 | 0.07 | 0.03 | 0.02 | 0.07 | 23.64 | 7.80 | 0.00 | 14 000         |
| DF13–2        | A         | 85.05 | 1.46 | 0.85 | 0.26 | 0.24 | 0.13 | 0.07 | 0.24 | 3.48  | 8.21 | 0.01 | 15 000         |
| DF13–2        | B         | 84.88 | 1.51 | 0.83 | 0.25 | 0.22 | 0.13 | 0.07 | 0.17 | 3.18  | 8.75 | 0.01 | 15 000         |

Figure 3. Variation of the condensed water content of the DF13 gas reservoir with pressure.

Figure 4. Variation of the condensed water content of the DF13 gas reservoir with temperature.

According to the natural gas component of each sand body, three sets of natural gas were compounded. Considering the actual temperature and pressure condition of the gas reservoirs, each sand body was tested under seven temperature points × six pressure points by using the new condensed water content measurement method.

Figures 3 and 4 demonstrate that the condensed water content decreases with the increase in pressure. The condensed water content drops faster in the low-pressure stage, but changes more gently in the high-pressure stage, and exhibits an exponential relationship with pressure. Alternatively, the condensed water content increases with the increase in temperature, which changes slowly below 100°C but quickly above 100°C. The effect of pressure is more significant.

In the low-pressure stage, the condensed water content is more significantly affected by temperature, whereas in the high-temperature stage it is more significantly affected by pressure. The two sand bodies of DF13–2 have similar condensed water contents, i.e. approximately 0.11 m³/10⁴ m³ under the formation condition. DF13–1 presents a slightly higher condensed water content, which is approximately 0.197 m³/10⁴ m³.

Figure 5 indicates that, at the same temperature, the condensed water content of DF13–1 is substantially higher than those of DF13–2, whereas the condensed water content of DF13–2 A is slightly higher than that of DF13–2 B. Table 1 suggests that, among the natural gas components, a high CO_2 content, low N_2 content, low natural gas density and low formation water salinity will lead to a higher condensed water content, thereby causing DF13–1 to have a significantly higher condensed water content than DF13–2. Alternatively, the natural gas composition and formation water salinity of the two DF13–2 sand bodies are relatively close. Although DF13–2 A has a slightly higher CO_3 content and, consequently, a higher condensed water content than DF13–2 B, the difference is not substantial.
be expressed as i.e. the mathematical model of condensed water content can be obtained by substituting the corresponding expressions of coefficients $a$ and $b$ into equation (9), as shown here:

$$V_{w_{DFX-1B}} = a \times P^{-b} = 0.0171 \times e^{0.0325T} \times P^{-(0.0035T+0.0752)},$$ (11)

$$V_{w_{DFX-2B}} = a \times P^{-b} = 0.0094 \times e^{0.0322T} \times P^{-(0.0036T+0.0677)},$$ (12)

$$V_{w_{DFX-2A}} = a \times P^{-b} = 0.0105 \times e^{0.0332T} \times P^{-(0.0034T+0.0845)}.$$ (13)

It is known that the original pressure and temperature of the formation DF13–1B are 54 MPa and 143°C, respectively, whereas the flowing pressure and temperature of the production are 5.8–6.3 MPa and 24°C, respectively. Therefore, the condensed water content of the natural gas in the formation is calculated to be 0.17 m³/10⁴ m³, whereas the condensed water content of the natural gas in the ground trap is measured to be 0.02783–0.0282 m³/10⁴ m³. The reduced condensed water content will be produced in the form of precipitated water together with gas. Through calculation, the theoretically predicted water production is 0.151–0.152 m³/10⁴ m³, whereas the actual water production of the platform is WGR = 0.17 m³/10⁴ m³. The actual value is slightly higher than the theoretical value, which is probably because: (i) the gas production also carries part of the pore water; (ii) under the effect of airflow, the bound water becomes more mobile and is consequently carried by the gas and (iii) during depletion development, the pressure is reduced and, therefore, the bound water is evaporated into the gas.

4. Conclusion

In this paper, an improved method for measuring condensed water content in gas reservoirs was established. At the same time, a comprehensive prediction model of condensed water content with temperature and pressure was established. This method was successfully applied to the test and research of condensed water content in the DFX area. This method lays the foundation for the development of waterproof and water control strategies for gas fields.

1. A more accurate method to measure the condensed water content in gas reservoirs was established by using a high-precision PVT device combined with the law of conservation of matter to calculate phase changes. Compared with traditional measurement methods,
it can provide more accurate measurement results through simple, low-cost and faster experimental operations.

(2) The DF13 gas reservoir was taken as an example, the variation of condensed water content in the gas reservoirs with temperature and pressure was analysed and the results showed that the condensate water content decreased with an increase of pressure, and increased with an increase of temperature.

(3) A comprehensive prediction model for the condensate water content of three sand bodies of DF13–1B, DF13–2A and DF13–2B with temperature and pressure was established based on the experimental data from the new method. The results showed that the content of condensate water in the two sand bodies of DF13–2 was relatively close. The content under the formation conditions was about 0.11 m$^3$/10$^4$ m$^3$, and the content of DF13–1 slightly higher, about 0.197 m$^3$/10$^4$ m$^3$. This provides a theoretical basis for the design of waterproof and water control strategies for the development of the DF13 gas reservoir.

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