Full-cycle prediction of gas production variations in gas wells using different production methods

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Abstract. Gas production from gas wells is affected by formation pressure and wellbore outflow during gas production. To increase the daily gas production and obtain smooth and efficient gas production gas wells, methods such as wellbore shut-in pressure recovery and foam injection and drainage for gas production are usually adopted. In this paper, the gas-carrying liquid model, capacity prediction model, and pressure recovery model are utilized to establish a full-cycle production prediction method for newly developed gas wells. Combining the initial development pressure, gas production, and water production parameters of the gas well, the gas production prediction is obtained for the next few years. Meanwhile, the implementation time of the forced drainage method is calculated and obtained.

1 Introduction
The main difference between low-permeability gas fields and conventional gas fields is that their reservoirs have low permeability, low recovery, strong non-homogeneity, small porosity, and narrow channels for gas and water to flow. The output conditions are often accompanied by cracks and changes in the reservoir after diagenesis, in addition to the pore medium. Reservoir physical properties of a gas field are more complex compared to oil field, gas is different from liquid with certain compressibility, seepage resistance is very large, liquid-solid interface and liquid-gas interface interaction force is very large, so that the water-locking effect and stress sensitivity increased significantly, and lead to changes in oil, gas, water seepage law[1].

When the gas well production cannot reach the critical fluid-carrying flow rate, the gas well will produce fluid accumulation[2], which is easy to cause gas accumulation and capacity decline. At the beginning of gas well production, the formation energy is sufficient, and the gas itself has enough energy to carry the liquid to the wellhead, so there is no fluid accumulation at the bottom of the well[3]. As the gas well is exploited for a long time, there is no external energy supplement, and the formation pressure gradually drops. The energy of the gas itself is not enough to carry all the liquid to the wellhead, and the liquid begins to fall back and collects at the bottom of the well, forming a fluid accumulation at the bottom of the well. When fluid accumulates at the bottom of the well, it not only increases the resistance to fluid flow along the wellbore, but also exerts additional back pressure on the formation[6]. Excessive fluid accumulation can cause the gas well to completely shut down[5].

This paper establishes a gas well production cycle prediction method based on the gas well fluid accumulation prediction model, fluid carries prediction model and pressure recovery model. The production changes after the new wells are put into production, as well as the time nodes and corresponding parameters for the implementation of the drainage and gas extraction methods are calculated through well examples. The period for gas wells to maintain stable production is predicted.

2 Method
(1) Critical Carrying Fluid Flow Rate/Flow Rate Calculation Methods
Based on the two assumptions of "liquid droplet" and "liquid film", the critical fluid-carrying flow rate model of gas wells has been proposed, among which the "liquid film" assumption model is essentially a further development and refinement of the "liquid droplet" assumption model. The "liquid film" assumption model is essentially a further development and improvement of the "liquid droplet" assumption model. For engineering applications, the "droplet" model is more concise and still meets the requirements of engineering development. Among the existing models, the error of Peng's model is only 4.18%, and the accuracy of the prediction of gas well fluid accumulation is as high as 88.9%. Therefore, this paper mainly adopts the Peng model to calculate the critical liquid-carrying flow rate and critical liquid-carrying flow rate of gas wells. The formula of the Peng model for calculating the critical fluid flow rate is shown below:
The formula for calculating the critical carryover flow rate is shown below:

\[ V_{cr} = 4.54 \left( \frac{\sigma (\rho_s - \rho_g)}{\rho_g Z T} \right)^{0.25} \]  

(1)

The formula for calculating the dynamic index \( n \) is:

\[ n = \frac{\log q_s - \log q_g}{\log (p^2 - p_{wf}^2) - \log (p_s^2 - p_{wf}^2)} \]  

(5)

where: \( q_s \) is the gas production, \( m^3/d \); \( q_g \) is the flow resistance can be calculated by the following equations respectively:

\[ p_f = \rho \lambda \frac{hV^2}{2d} \]  

(8)

\[ p_{wf} = \sqrt{p_{wf}^2 + \frac{1.32 \times 10^{18} \lambda (\bar{T}Zq_s)^2 (e^{2q - 1})}{D^2 \sin \theta}} \]  

(9)

where: \( \lambda \) is the along-track resistance coefficient, dimensionless; \( \rho \) is the wellbore gas density, \( kg/m^3 \); \( h \) is the wellbore length, m; \( d \) is the inner diameter of wellbore, m; \( \bar{V} \) is the average velocity of wellbore interface, m/s.

The wellbore flow pressure can be calculated using the following equation:

3 Calculation results

Take a newly developed well as an example, the depth of the well is 3700 m, the unimpeded flow rate is 84×10⁴ m³/d, the oil pressure is 17 MPa, the casing pressure is 19 MPa, and the original formation pressure is 32 MPa. The initial average gas production is 9×10⁴ m³/d, and the average water production is 0.8 m³/d. In accordance with these data, the well's production change is predicted for the period of 5-10 years.

(1) Calculate the cumulative production curve for the well, dividing it into pre-production, mid-production, and post-production periods, and determining clear date boundaries. (2) Draw the curve of the gas production of the well with the date of production, divide the production curve into three segments as well according to the date boundaries determined in the previous step, and then fit the curve to the data of the daily gas production with time for each segment separately and derive the characterization formula. The results of the calculations are shown in Fig. 1 and Fig. 2.
(3) Calculate the critical liquid-carrying flow rate, and the intersection of the critical liquid-carrying flow rate and the daily gas production curve is the time to implement the method. After the date of gas production at the intersection point, the well has the potential or tendency of fluid accumulation and needs to implement the drainage method. It is predicted that the oil pressure at the junction of the early and middle stages of gas production is 8 MPa, the casing pressure is 12 MPa, and the oil pressure at the junction of the middle and late stages is 4.24 MPa, the casing pressure is 7.05 MPa. It is assumed that the density of the liquid at the bottom of the well is 1000 kg/m$^3$, the density of the gas at the bottom of the well is 150 kg/m$^3$, the surface tension of water is 0.06 N/m, the inner diameter of the production tubing is 62 mm, and the average temperature of the wellbore is 330 K. This example calculates the critical fluid flow rate at wellhead oil pressure of 4.24 MPa and 8 MPa, which is calculated by substituting into the formula: $q_c=1.63\times10^4$ m$^3$/d at wellhead oil pressure of 4.24 MPa. $q_c=3.07\times10^4$ m$^3$/d at wellhead oil pressure of 8 MPa.

(4) Execute the intermittent production switching method when the production rate drops to a critical value. Assuming that the well uses the intermittent production switching method from a certain production rate such as $0.5\times10^4$ m$^3$/d, and the well belongs to a low production rate at this time, and assuming that the oil pressure corresponding to this production rate is 3 MPa, one can calculate the time required for the gas well production rate to recover from $0.5\times10^4$ m$^3$/d to a different target production rate according to the MDH method. In essence, this is equivalent to calculating the time required to recover from the bottomhole flow pressure corresponding to the oil pressure of 3 MPa to different bottomhole flow pressures. Assuming that the wellbore flow pressure corresponding to oil pressure of 3 MPa is 6 MPa, the average kinematic viscosity of natural gas is 0.31 mPa·s, the permeability $K$ is assumed to be 5 mD, the effective thickness of the gas layer is assumed to be 10 m, the pore vacation rate is assumed to be 5.5%, and the calculation of pressure conductivity coefficient can be obtained to be 0.01725. According to the calculation of Eq.(10), the time needed to recover the wellbore flow pressure from 6 MPa to 10 MPa is obtained as follows 2.29 h.

Based on the above calculations, it can be concluded that the time required for the well to recover from a bottoming-out flow pressure of 6 MPa to different bottoming-out flow pressures is shown in Table 1.

<table>
<thead>
<tr>
<th>Target recovery pressure/MPa</th>
<th>Time required/second (s)</th>
<th>Time required/hour (h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>3681.06</td>
<td>1.02</td>
</tr>
<tr>
<td>9</td>
<td>5519.91</td>
<td>1.53</td>
</tr>
<tr>
<td>10</td>
<td>8277.35</td>
<td>2.30</td>
</tr>
</tbody>
</table>
(5) Define the timing for the implementation of the forced drainage method. According to the gas production and casing pressure, define the timing of the implementation of inter-opening and bubble drainage, preferably inter-opening implementation, assisted by bubble drainage and liquid transportation. As shown in Fig. 4, in the well example, the implementation of continuous long interval opening started in October of 6 years, and the bubbling drainage and liquid transportation started in 10 years. After the implementation time is determined, oil pressure, flow pressure, formation pressure is determined, according to the production discount formula, the method of net increase in production formula, to get the predicted value after the implementation of the method.

(6) Evaluation of the effectiveness of drainage gas extraction methods. Based on the new gas production increase after the implementation of the method and the single-method production function, the production prediction curves of inter-week period open and continuous bubble drainage were derived. The well was divided according to the production value of 0.5×10⁴ m³/d for extra-low production wells, and the well was in stable production for 11 years when forced drainage and extraction was not implemented. After the implementation of the intermittent switching well, the stable production time was extended to 12 years and 4 months. Stabilized production was extended to 13 years and 10 months after the injection foam drainage gas extraction method was implemented. The theoretical gas production would have declined to a low production well in 6 years and 9 months, and the implementation of the intermittent switching method in the previous 6 months and 4 months extended the low production period to 7 years. Foam drainage was implemented in the well in 3 months of year 10, extending the period of exceptionally low production to 6 months of year 14, followed by forced drainage by the optional plunger gas lift method, depending on the amount of water produced.

4 Conclusion

This paper establishes a gas well fluid-carrying model and a production prediction model for gas production and pressure changes during gas well production, and predicts the production changes of newly developed gas wells. At the same time, based on the critical fluid flow rate and pressure recovery prediction, the implementation time and method of gas drainage are derived. Finally, the production changes during the gas production and development process of the gas wells and the gas production after the implementation of the drainage and gas extraction methods are derived.

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References