INTRODUCTION

Heavy oil is a major fossil fuel resource to fulfill global growing fuel consumption and has been acknowledged as promising underground resource. The oil deposits from heavy oil reserve are estimated at around 5.6 trillion barrels, which are six times as much as conventional crude oil resource. The key to exploiting heavy oil is the innovative technology to reduce oil viscosity effectively and economically. The heavy oil reserves in Liaohe Oilfield are mainly distributed in the deep, ultra-deep, and extra-deep layers of the reservoir. In recent years, development problems such as high recovery, high throughput rounds, low cycle oil-steam ratio, and low-pressure lifting of reservoirs have been encountered in Wa 59 reservoirs, and it is imminent to switch development methods. Through previous pilot experiments, it was found that mature
steam oil, SAGD, and hot water flooding technologies are not suitable for the development of this block. Therefore, Liaohe Oilfield innovatively proposed gravity drainage to assist steam flooding. Among the current heavy oil thermal recovery technologies, gravity-drainage-assisted steam flooding is one of the key technologies for further enhanced oil recovery after deep steaming of ultra-heavy oil reservoirs. It is significantly different from SAGD, adding steam injection horizontal wells and drainage horizontal wells. Its development mode is a combination of vertical wells and horizontal wells: steam is injected in the upper horizontal wells, water is drained to assist in the bottom horizontal wells, and the nearby vertical wells produce oil. After the reversal is achieved, the steam heats the reservoir. The condensate depends on its own gravity and the production pressure difference between the lower superimposed horizontal well and the upper superimposed horizontal well to fully realize the drainage of the lower superimposed horizontal well. Increasing the injection-injection ratio of the gravity-drainage-assisted steam flooding well group increases the dryness of the steam at the bottom of the well, fully expands the volume of the air cavity, and increases the volume of steam. The numerical model of heavy oil gravity-drainage-assisted steam flooding quantifies the actual reservoir and uses the data to describe features intuitively. In order to ensure that the experimental values are closer to the actual production situation on site, the physical model experiment uses similar principles to complete the characterization of the production laws in different stages. The production conditions in the Wa 59 test area verified the numerical and physical models and provided a theoretical basis for the next stage of production in the oilfield.

2 ESTABLISHMENT OF THE MATHEMATICAL MODEL

The numerical model is based on the basic theory of thermal recovery and numerical solution methods. Reservoir modeling and simulation have become important elements of reservoir management. The simulation process used by numerical simulation software is complicated and time-consuming, the overall procedure is large, and the limitations are great. And high computational cost associated with the use of numerical simulators makes them cumbersome, especially with large-scale simulation models and complex oil recovery processes. For large reservoir models, the computation becomes very time-consuming, and it is almost impractical to derive all possible solutions. However, the C programming language has the characteristics of abundant data types, large degree of freedom in program design, and high program execution efficiency. Therefore, the program was written in C, using Surfer drawing software to realize the image processing of simulation results. In the establishment of the mathematical model, we considered the influence of the flow factor in the longitudinal direction, and the model can solve the turbulence problem between the reservoir layers, so that the numerical simulation results of multilayer reservoirs connected between the layers are closer to the conditions of the actual reservoir. This improves the accuracy of numerical simulations and provides reasonable reservoir guiding ideas for the site. The structure of the well group unit established in this paper is shown in Figure 1.

2.1 Established coupled partial differential equations

The basic control model consists of the flow terms (the conservation equations for the mass of oil, steam, and water phases), the energy equation, the vapor-water phase equilibrium, and additional equations (boundary and initial conditions). In the process of oilfield development, multiphase seepage is more common. In general, single-phase fluids are rare in reservoirs. But most of them are insoluble oil and water two-phase fluid or oil, gas, and water three-phase fluid. There are three-phase fluid seepage in the formation: oil, gas (the gas phase is only water vapor), and water. So it is assumed that there are only two components, oil and water, and that Darcy’s law is satisfied. In the reservoir development process, the heat transfer of the porous media in the reservoir plays a leading role in the convective heat transfer of the fluid. In addition to the thermal properties of the fluid, the velocity and direction of fluid percolation are the main factors determining the convective heat transfer. According to Darcy’s Law, the driving force of percolation velocity is the pressure gradient of porous media. Thus, during the reservoir development process, the mathematical model of the change process of the reservoir porous media is a set of coupled partial differential equations describing the coupling process of the
temperature, pressure, and percolation velocity of the reservoir porous media. Therefore, the following three-phase percolation coupling partial differential equations of oil, steam, and water can be established:

Mass Conservation Equation:

\[
\begin{align*}
\frac{\partial}{\partial x} \left( \frac{\Delta y \Delta z K K_{rw} \rho_{o}}{\mu_{o}} \frac{\partial p}{\partial x} \right) + \frac{\partial}{\partial z} \left( \frac{\Delta x \Delta y K K_{rw} \rho_{o}}{\mu_{o}} \frac{\partial p}{\partial z} \right) \Delta x + \frac{\partial}{\partial y} \left( \frac{\Delta x \Delta z K K_{rw} \rho_{o}}{\mu_{o}} \frac{\partial p}{\partial y} \right) \Delta y = q_{w} + q_{g} - \Delta x \Delta y \Delta z \frac{\partial}{\partial t} \left( \phi S_{w} \rho_{o} \right)
\end{align*}
\]

Water Component:

\[
\begin{align*}
\frac{\partial}{\partial x} \left( \frac{\Delta y \Delta z K K_{rw} \rho_{w}}{\mu_{w}} \frac{\partial p}{\partial x} \right) + \frac{\partial}{\partial z} \left( \frac{\Delta x \Delta y K K_{rw} \rho_{w}}{\mu_{w}} \frac{\partial p}{\partial z} \right) \Delta x + \frac{\partial}{\partial y} \left( \frac{\Delta x \Delta z K K_{rw} \rho_{w}}{\mu_{w}} \frac{\partial p}{\partial y} \right) \Delta y = \Delta x \Delta y \Delta z \frac{\partial}{\partial t} \left( \phi S_{w} \rho_{w} \right)
\end{align*}
\]

Energy Conservation Equation:

\[
\begin{align*}
V_{b} \lambda_{R} \left( \frac{\partial^{2} T}{\partial x^{2}} + \frac{\partial^{2} T}{\partial y^{2}} + \frac{\partial^{2} T}{\partial z^{2}} \right) + V_{b} \frac{\partial}{\partial x} \left[ \rho_{e} e_{o} K_{sx} \frac{\partial p_{o}}{\partial x} + \rho_{e} e_{w} K_{sx} \frac{\partial p_{w}}{\partial x} + \rho_{e} e_{g} K_{sx} \frac{\partial p_{g}}{\partial x} \right] + V_{b} \frac{\partial}{\partial y} \left[ \rho_{e} e_{o} K_{sy} \frac{\partial p_{o}}{\partial y} + \rho_{e} e_{w} K_{sy} \frac{\partial p_{w}}{\partial y} + \rho_{e} e_{g} K_{sy} \frac{\partial p_{g}}{\partial y} \right] + V_{b} \frac{\partial}{\partial z} \left[ \rho_{e} e_{o} K_{sz} \frac{\partial p_{o}}{\partial z} + \rho_{e} e_{w} K_{sz} \frac{\partial p_{w}}{\partial z} + \rho_{e} e_{g} K_{sz} \frac{\partial p_{g}}{\partial z} \right] = \rho_{e} C_{e} \frac{\partial T}{\partial t} + \rho_{e} C_{e} \left( \phi S_{o} \rho_{o} e_{o} + \phi S_{w} \rho_{w} e_{w} + \phi S_{g} \rho_{g} e_{g} \right)
\end{align*}
\]

Saturation Equation:

\[
S_{o} + S_{w} + S_{g} = 1
\]

Water Vapor State Equation:

\[
T_{s} = 174.62 p_{s}^{0.265}
\]

Cap Bottom Energy Loss:

\[
\rho_{e} C_{e} \frac{\partial T}{\partial t} = \nabla \cdot \left( \lambda_{c} \nabla T \right)
\]

\[
\overline{q}_{loss} = \rho_{e} C_{e} \frac{\partial T}{\partial t} = | \nabla \cdot \left( \lambda_{c} \nabla T \right) |
\]

2.3 | Initial conditions

The average effective porosity is 24.5%, the average permeability is \(1.462.6 \times 10^{-3} \, \mu m^2\), the longitudinal-to-transverse permeability ratio is 0.615, the 20°C crude oil density is 1.048 g/cm³, and the 50°C ground degassed crude oil viscosity is 271,044 mPa·s. The pressure is 4.1 MPa, the formation temperature before flooding is 110°C, and the oil saturation and water saturation are both 50%, as shown in Figure 2.

2.4 | Grid division

The 3D model divides the heavy oil reservoir gravity-drainage-assisted steam drive unit into grids as below:

1. The reservoir has a total horizontal direction of 490 m, a width of 500 m, a vertical direction of 70 m, vertical well spacing of 100 m, and horizontal well spacing of 20 m. The front, rear, left, and right boundaries of the model were set at a constant pressure of 4.1 MPa with reference to the initial pressure, and the upper and lower boundary conditions were defined as nonpermeable boundary conditions.
is 500 m in total, and a grid with $\Delta x = 20$ m divided this into 25 grid cells. A total of 70 m in the vertical direction, using a grid of $\Delta z = 5$ m, produced a total of 14 grid cells in this direction. The entire 3D model was divided into a total of 17,150 grid cells.

2. The overlying strata and the lower strata are 200 m, and a grid of $\Delta x = 10$ m was used in the horizontal direction; the total plan was divided into 49 grid cells. With $\Delta z = 20$ m in the vertical direction, the grid was divided into 10 grid cells.

3. The heavy oil reservoir gravity drainage auxiliary steam drive unit was located in the middle of the grid system.13

2.5 Analysis of the Effect of Gravity-Drainage-Assisted Steam Flooding

This study used a production ratio of 1.2, a longitudinal-to-transverse permeability ratio of 0.615, a steam injection rate of 0.1 kg/s, steam dryness of 0.6, horizontal well spacing of 20 m, and reservoir bottom water grid saturation. Under the conditions of bottom water setting of 0.6 and initial water saturation of 0.5, the drainage effect of gravity-drainage-assisted steam flooding was analyzed under the condition that the bottom water was 15 m, 25 m, or 35 m from the lower rock (where 15 m is to the level of the horizontal production well and 35 m is to the level of the horizontal injection well).

As shown in Figure 3, with increasing bottom water height, the lower the pressure of the reservoir, the faster the overall pressure of the formation decreases, the more obvious the funnel pressure drop, and the smaller the pressure gradient between the two horizontal wells, which is not conducive to water discharge. As the height of the bottom water increases, the injected steam will encounter the bottom water in the lower part of the reservoir and be condensed to hot water; this will be produced together with the bottom water through the lower horizontal well, taking away a large amount of heat and resulting in a decrease in the heat utilization rate. The above phenomenon is especially remarkable when the bottom water height is more than 15 m, that is, when the bottom water has flooded the horizontal production well.

This study calculated the same time step and drew the relationship curves between the bottom water height and the cumulative oil-steam ratio, instantaneous oil-steam ratio, and vertical well water content. As shown in Figure 4(A), as the bottom water height increases, the cumulative oil-steam ratio decreases. When the bottom water height is $>15$ m, the lower horizontal well is submerged and the amount of accumulated oil is slightly larger than the decline.

As shown in Figure 4(B), the instantaneous oil-gas ratio decreases as the bottom water height increases. The greater the bottom water height, the smaller the maximum instantaneous oil-vapor ratio. As more bottom water is added, the heat of the injected steam is absorbed by the water and extracted by the lower horizontal well. With the extraction of a large amount of bottom water, the proportion of heat obtained by the crude oil increases. A large amount of hot oil is driven to the production well and produced by it, and the instantaneous oil-gas ratio reaches the highest value. After that, the instantaneous oil-gas ratio starts to decrease slowly. After the bottom water floods the steam well, the instantaneous oil-gas ratio decreases severely.

As shown in Figure 4(C), the instantaneous water content of the well group unit increases with increasing bottom water height. It was found through the mathematical model that during the experiment, the horizontal well must not be submerged in the bottom water. At the same time, the study of the drainage effect provides theoretical guidance for the feasibility of gravity-drainage-assisted steam flooding and provides a basis for physical model experiments and field production.

3 3D PHYSICAL SIMULATION EXPERIMENT

3.1 Similarity principle

According to the similarity theory, a 3D physical simulation experiment was carried out to reproduce the oil production process in the oilfield. The results obtained through the experiment can then be transferred back to the oilfield according
FIGURE 3  Water saturation maps with different bottom water heights: (A) bottom water height 15 m, (B) bottom water height 25 m, (C) bottom water height 35 m

FIGURE 4  Bottom water height change curves: (A) bottom water height and cumulative oil-vapor ratio relationship curve; (B) bottom water height and instantaneous oil-vapor ratio relationship curve; (C) bottom water height and well group water content
to the similar criteria. The third oil layer of the Shahejie group of the Paleogene in the 60-H25 test well group unit in Wa59 block was selected as the basic module, and the actual module was reduced by 400 times according to the similarity theory. The actual model parameters of the reservoir and the indoor model parameters are as shown in Table 1.

## 3.2 Experiment parts

### 3.2.1 Experiment materials

The experimental oil was a crude oil sample collected from the Wa59 block of the Lengjia branch of the Liaohe oilfield company, and upon measurement using an indoor rheometer, the viscosity-temperature data were found to be as shown in Figure 5. The experimental water was prepared according to the mineralization degree of the third oil layer formation water of the Paleogene Shahejie Group in the 60-H25 test well group unit in block Wa59. The formation water type was NaHCO₃, and the total salinity was 3463.5 g/L, wherein the Na⁺+K⁺ mass concentration was 1102.9 g/L.

### 3.2.2 Experiment equipment

In order to mimic the actual production environment to the greatest extent, through continuous exploration and improvement, the best experimental system was finally designed. The experimental system includes a 3D simulation experiment device for heavy oil gravity-drainage-assisted steam flooding, a core model, a steam generator, a temperature-pressure collecting device, a back pressure device, and a bottom water reservoir system.

The 3D physical simulation experimental device for heavy oil gravity-drainage-assisted steam flooding is a cylinder with an inner diameter of 380 mm and a height of 380 mm. It is equipped with 4 vertical wells and 2 horizontal

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**FIGURE 5** Curve of the viscosity-temperature relationship of a heavy oil sample from the 60-H25 test well group unit in block Wa59
wells, 19 temperature monitoring points, 4 pressure monitoring points, 8 saturated oil holes, and 1 reservoir bottom water injection hole. The main body of the device and the cover plate are of welded stainless steel, and the inner surface of the model was roughened to avoid turbulence of the fluid along the surface during the experiment. The core model was prepared by mixing 0.38 mm quartz sand, high-alumina cement, and water in a mass ratio of 2:1:1 in the 3D experimental apparatus, then compacting it to 15 MPa and holding at constant pressure for 10 minutes. The steam generator consists of a flat flow pump, a temperature control device, a heating electrode with a diameter of 3 mm and a length of 380 mm, and a white steel tube of 6 mm diameter. The temperature and pressure monitoring device consists of 20 pressure sensors, 30 temperature sensors, and a computer, which can record the temperature and pressure data during the experiment in real time through software. The back pressure device is mainly composed of a back pressure valve and a pressure vessel for simulating the formation pressure. The reservoir bottom water is mainly realized by injecting formation water into the saturated oil hole at the bottom of the 3D physical simulation experimental device. The main experimental device is shown in Figure 6.

### 3.2.3 Experiment procedure

In the process of gravity-drainage-assisted steam flooding, the upper horizontal well injects steam through the steam generator, and the lower horizontal well acts as drainage; the discharged water includes steam condensate, reservoir bottom water, and condensed water after steam stimulation. A pressure backing device consisting of a pressure vessel and a back pressure valve was connected to the wellhead of the two vertical wells. The pressure monitoring points on the upper and lower floors of the model can monitor the pressure in the model. The temperature monitoring points at the top and bottom of the model can monitor the formation of steam in the chamber. The bottom of the experimental model was provided with bottom water, and a steam generating device was used to control the temperature of the steam and the amount of steam generated. The experimental model was placed in an incubator at 90°C to meet the thermal connection conditions between the injection and production wells.

The specific parameters of the experimental model are as follows:

1. The core model volume is 43,074 mL;
2. The porosity is 30%, and the pore volume is 12,900 mL;

![Figure 6](image)

**Figure 6** Main experimental device diagram: (A) 3D physical simulation experiment device, (B) steam generator diagram

![Figure 7](image)

**Figure 7** Test well group unit production rules: B denotes the second stage, C the third stage, D the fourth stage
3. The saturated oil is added in an amount of 10,000 mL, and the original oil saturation is 77.5%;
4. The instantaneous steam injection amount is 2 mL/min, and the instantaneous bottom water influx is 2 mL/min;
5. The steam injection temperature is 260°C;
6. The instantaneous steam injection amount is 2 mL/min;
7. The initial temperature of the core model is 90°C;
8. The Horizontal Well 2 and vertical well production levels are recorded every 2 hours.

3.3 | Experiment results and analysis

The experimental results show the change laws of the instantaneous liquid production capacity, instantaneous oil production capacity, and the water content rate with time for the test well group unit, Horizontal Well 2, and the vertical wells.

3.3.1 | Well group production law

According to the experimental capacity characteristics, the whole gravity-drainage-assisted steam drive production process can be divided into four stages as shown in Figure 7.

A Thermal connection stage: This phase is mainly carried out in the incubator. The experimental core model is preheated using the incubator and the simulated temperature is maintained above 90°C to simulate the formation temperature of the heavy oil to ensure the accuracy and authenticity of the experiment.

B Gravity-drainage-assisted steam chamber formation stage: Under the action of the injection-production pressure difference, the horizontal well steam chamber has a relatively high lateral expansion speed toward the vertical wells on both sides; the longitudinal steam chamber is narrow and wide, and the contents of the horizontal well are pulled to the steam chamber. The enthalpy effect is obvious, which reduces the over-covering effect of the steam chamber and contributes to the uniform expansion of the steam chamber. At the initial moment, the height of the steam chamber is small, the gravity drainage effect is weak, and the steam displacement is dominant. As the height of the steam chamber continues to increase, the gravity drainage function is continuously enhanced. The heated crude oil and condensed water are produced in the horizontal well and the vertical well under the dual action of gravity and driving force, and gradually realize the transition from steam flooding to gravity-drainage-assisted steam flooding. With the injection of steam, the amount of oil produced and the amount of liquid produced gradually increase, and the water content increases.

C Gravity discharge and steam displacement composite stage: The most obvious feature of this period is that the production wells of the test well group are stable and have experienced a process of stable oil production and a gradual decrease in production; also, the water content continues to increase. The instantaneous oil-to-gas ratio gradually decreases to 0.1, and the stage production rate increases steadily.

D Exhaustion and exploitation stage: In this stage, the liquid production of horizontal wells is reduced, the gravity drainage effect is gradually weakened, the steam chamber is getting closer and closer to the vertical well, the oil production in the lower horizontal well is less and less, the water content is relatively stable, and the water content of the vertical well is relatively low. The rise is faster, and finally, the large area of steam breaks through to the vertical well; the gravity discharge then assists the steam drive production to the end.

3.3.2 | Production rules of horizontal wells and production wells

It can be seen from Figure 8 that the production rules of the two vertical wells are not the same. Due to the heterogeneity of the core model, the peak oil production of Vertical Well 1 was larger than that of Vertical Well 2 at the beginning of the experiment, and the time taken to reach the peak was about 7 h. The difference was that the peak production time of Vertical Well 1 was longer than that of Vertical Well 2, and the water contents’ increase range and regularity were similar. In the middle of the experiment, production in Vertical Well 2 decreased faster than that in Vertical Well 1, and the oil production in Vertical Well 2 remained low. The production volume of Vertical Well 1 was decreasing at the end of the experiment, and the increase in liquid production by Vertical Well 2 was constant. The water content of the two vertical wells continued to approach 100%.

The production rule of the horizontal production wells is shown in Figure 9. The liquid production and oil production reached a peak at 4 h. After that, the liquid production was relatively stable, the oil production continued to decrease, and the oil production experienced three distinct stages. The initial decline was fast, the medium-term decline was slow, and the final decline was faster. The change law of the water content experienced three phases. The water content increased greatly in the initial stage of the experiment, and then the water content increased gradually. The water content in the later stage remained high at 98%-99%.

The comparison curves of instantaneous oil production and water content between the vertical and horizontal wells are shown in Figure 10. The water content of the horizontal
The water content of the horizontal wells increased rapidly in the initial stage and tended to be stable in the later stage. The water content of the vertical wells increased uniformly, and this period of time accounts for seven-tenths of the total experimental time. The production of the vertical wells was higher than that of horizontal wells, and the steady oil production time of the vertical wells was longer than that of the horizontal wells. After 48 h of experimental time, the water contents of the horizontal wells and vertical wells were similar and increased uniformly to 100%. The instantaneous oil production levels of the horizontal wells and vertical wells were close together and evenly decreasing.

According to the above analysis, the following was found: (a) According to the production capacity change law and production degree of the well group, the production process can be divided into four phases, namely, the thermal communication phase, the gravity-drainage-assisted steam cavity formation phase, gravity drainage and steam flooding, then the recombination and depletion mining stages. (b) The experiment confirmed the productivity relationship of the well group. The instantaneous oil production of horizontal wells was lower than that of vertical wells, and the instantaneous
The actual production was analyzed for the experimental area of the 60-H25 test well in the Wa59 block in Liaohe oilfield. The simulation results obtained by the mathematical model and physical model were further verified to provide data support for gravity drainage auxiliary steam drive percolation theory and provide guidance to the development of heavy oil reservoir gravity flooding.

**4.1 Experimental area development status**

There are currently 1 steam injection well, 9 vertical production wells, and 1 horizontal production well. The production parameters of each well are as follows.

Steam injection well: daily steam injection, 384 t/d; daily liquid production, 270.7 t/d; daily oil production, 35.3 t/d; moisture content, 86.96%; instantaneous oil-gas ratio, 0.092; instantaneous injection ratio, 0.705; cumulative steam injection, 53.821 $8 \times 10^4$ t; cumulative oil production, 9.890 $5 \times 10^4$ t; cumulative liquid production, 65.217 $10^4$ t; cumulative injection ratio, 1.212; cumulative oil-gas ratio, 0.1838.

Vertical production wells: daily production, 30.7 t/d; daily production, 195.8 t/d; average daily production of single wells, 3.41 t/d; average daily production of single wells, 21.76 t/d; moisture content, 84.32%; cumulative oil production, 8.908 $7 \times 10^4$ t; cumulative production, 51.508 $3 \times 10^4$ t.

Horizontal production well: daily oil production, 2.4 t/d; daily production, 20.1 t/d; moisture content, 88%; cumulative oil production, 0.987 $7 \times 10^4$ t; cumulative production, 13.735 $10^4$ t.

The specific well number is shown in Table 2.

**4.2 Experimental area well group production characteristics analysis**

**4.2.1 Well group production rule**

According to the actual production data of the test well group, the production rule curve of the test well group (1 steam injection well and 10 production wells) was drawn. According to the development law and production characteristics of the steam chamber in the numerical simulation, the gravity-drainage-assisted steam flooding test was divided into four stages. The first stage was the thermal connection stage. The test was in the heating state of filling the temperature deficit; the liquid production and
water content rose, while the oil production and oil-gas ratio showed no obvious change. The second stage was the gravity-drainage-assisted steam chamber formation stage. The production volume of the well group was greatly improved, and the horizontally stacked wells assisted drainage. The liquid production and oil production increased, the temperature rose, and the water content decreased. The third stage was the gravity drainage and steam displacement stage. The steam chamber spreads evenly, and the oil production was stable. The fourth stage was the stage of exhaustion and exploitation. These are shown in Figure 11.

4.2.2 Production laws of vertical and horizontal wells

As shown in Figure 12(A), the average daily well production was 3.41 t/d, the average single-well fluid production was 21.76 t/d, and the water content was 84.32%. After December 31, 2011, the fluid production, water content, and oil production changed smoothly.

As shown in Figure 12(B), the liquid production volume of the horizontal production well in the test area increased drastically after 2 months, and liquid production reached 120 t/d in March 2011. After that, liquid production gradually decreased, and oil production increased steadily. The liquid production amount in May 2012 dropped to about 40 t/d and then gradually increased. In November 2012, the fluid production increased to about 80 t/d again. Thereafter, the fluid production gradually decreased, the water content decreased, and the oil production was stable. The current fluid production is about 20 t/d, while oil production is about 2.5 t/d.

It can be seen from Figure 13 that the transversion drive to the lower horizontal wells in 2012 had a significant drainage effect, resulting in higher oil production and lower vertical water content. From 2012 to the present, the daily oil production of the vertical wells fluctuated greatly, but the average daily oil production was relatively stable; the daily oil production of horizontal wells gradually decreased, and the water content of vertical and horizontal wells was similar. At present, the oil production in vertical wells is relatively stable, and the oil production in horizontal wells is significantly reduced, which highlights that the development of the test well group is nearing the end of its drainage phase, from gravity-drainage-assisted steam flooding to steam flooding.
1. In the numerical model, this study used the C programming language to analyze the drainage effect, avoiding the shortcomings of the complicated and time-consuming programs in 3D simulation software. It was found that the horizontal wells must not be submerged under the bottom water during mining.

2. Based on the mathematical model, physical model experiments were used to verify the group’s production capacity change law and extraction degree through actual production. The production process was divided into four stages, namely, the thermal communication stage, gravity-drainage-assisted steam cavity formation stage, the gravity drainage and steam flooding compound phase, and the mining exhaustion phase.

3. The physical model experiment and actual production also clarified the productivity relationship of the well group. The instantaneous oil production of horizontal wells was lower than that of vertical wells, and the maximum instantaneous oil production of horizontal wells was reached earlier than that of vertical wells. In the later period, production remained high, and the rate of increase of the water content in vertical wells was gentle, thus demonstrating the drainage effect of horizontal wells. This provided a reliable basis for the development of the next stage.

4. At present, the gravity-drainage-assisted steam flooding in the Wa 59 test area is still in the third production stage, that is, the gravity drainage and steam flooding stage. We suggest that it is not appropriate to gradually increase gas injection during this stage.

5. The advantage of gravity-drainage-assisted steam flooding is the unique characteristics of the well pattern, with steam injection horizontal wells and drainage horizontal wells, providing three-dimensional development. This technology is not only applicable to the Liaohe Oilfield in China. In other oilfields, the well pattern structure can be changed in accordance with the characteristics of the oilfield during the extraction process, thereby providing an enhanced mining effect.

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