Heat and Mass Convective Effects in a Multifield Cyclic Steam Stimulation (CSS) Process

Jiaming Liua, Xinfeng Jiab, Steven Samoila, Zhangxin Chenc,b

a Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, AB T2N1N4, Canada

b State Key Laboratory of Petroleum Resources and Prospecting in China University of Petroleum, Beijing, 102249, China

c Eastern Institute of Technology, Ningbo, China

Abstract:

As one of the earliest developed and widely used thermal recovery technologies, cyclic steam stimulation (CSS), also known as steam huff and puff, has contributed a large part of heavy oil production since the 1960s. Rich in-site operation scenarios by different geological types have led to a tough understanding of heat and mass transfer mechanisms during CSS development. Even though CSS is a mature technology by taking advantage of temperature sensitivity of the heavy oil viscosity, the accurate control and prediction should be based upon precise mathematical modeling of the physical evolution which is still limited in literature. For example, the effect of a convective velocity is unclear during injection and production periods in which the velocity directions are opposite. In this work, we propose a mathematical model to couple temperature, concentration and pressure fields in a CSS process with assisted gas and further analyses a multicycle situation. Calculation results show the distributions of temperature, pressure and concentration in a reservoir at different developing periods of a CSS process, and further show that the convective effect plays a less important role in heat transfer than in mass transfer and even could be neglected when the heat transfer model only considers conduction and convection effects. In addition, due to radical drops in operating parameter values, in a near-well region there appears an obvious temperature inverse phenomenon. It is fatal to production because the inverse temperature will inevitably lead to an inverse viscosity and the high-viscosity oil nearby will prevent the low-viscosity oil from flowing into a wellbore.

1. Introduction

Heavy oil is a type of crude oil and its viscosity can range from 50 cP to 50,000 cP under reservoir conditions [1]. When temperature increases, the intermolecular forces of heavy oil weaken, which results in a decrease in the strength of the spatial network structures of resin and asphaltene, and, therefore, the viscosity of heavy oil decreases and its mobility increases [2]. Thermal recovery methods thus become the primary choice to develop heavy oil reservoirs. Among all the thermal recovery methods, CSS has become the main development method for heavy oil reservoirs due to its high-speed production and short investment payback period.

A CSS process mainly includes three periods: a steam injection period, a well soaking period and a production period. A certain amount of steam is injected into a formation at injection periods and then a well is shut in for soaking for several days to let the injected heat spread in a reservoir as far as possible to improve the mobility of heavy oil. After a period of soaking time, the well is opened again for the oil production period. Within a single cycle, as the production time prolongs, some of the injected heat dissipates deeper into the formation, while the other part is carried out by the produced fluid, causing the heated oil layer to gradually cool down, resulting in an increase in the viscosity of the crude oil flowing to the wellbore due to a decrease in temperature and a gradual decrease in crude oil production. When the output decreases to a certain limit, this round of production ends and the next round of steam stimulation development begins.

Therefore, a viscosity reduction by heat transfer has been the most important recovery mechanism of CSS for a long time. A viscosity reduction by dilution after dissolution is another important recovery mechanism which is worth discussion. Hydrocarbon gases have strong dissolving ability for resins and asphaltenes in heavy oil, and general gases are highly volatile. If hydrocarbon gas is injected at the same time as steam is injected, the hydrocarbon gas will volatilize with the movement of the steam and move with a steam front. Therefore, as the steam continues to expand, the viscosity reduction area also continues to expand.

Traditionally, companies and scholars prefer to use commercial software, e.g., the CMG STARS, to simulate complex geological models, which requires grid coarsening for computational resources saving but results in lost accuracy for analyzing fundamental mechanisms. They also conduct a plenty of lab experiments to obtain more accurate information of a sample of a reservoir. However, intrinsic disadvantages like the errors caused by lab equipment and the limited scale of a model are inevitable. Turning to mathematical modeling to reveal the fundamental mechanisms of a complex physical model is a natural choice because it allows physics guided modeling without sacrificing any accuracy by equipment or humans. Nevertheless, there is still a lack of modeling work on CSS. Marx and Langenheim (1959) [3] calculated a heating area in ​​an oil layer through an energy balance equation. Boberg and Lantz (1966) [4] proposed a reservoir temperature profile and oil production prediction model. However, the use of empirical formulas makes it difficult for the model to adapt to other cases. In addition, for the calculation of a temperature field, heat conduction is always ignored in the model [5-6]. Ji et al. (2015) [7] studied the effect of thermal expansion of a steam chamber on heat and Wu et al. (2018) [8] established a nitrogen-assisted CSS heating radius model. But the lack of description of physical fields besides a temperature field makes it difficult for the model to be flexibly applied in various cases. Therefore, a fully coupled mathematical model for multifield problems in CSS is strongly needed.

In this paper, based upon the governing equations of heat transfer, mass transfer and pressure diffusion, we propose a mathematical model to calculate the temperature, pressure and concentration distribution of a CSS process and further analyze the heat and mass transfer mechanisms. Heat transfer and pressure diffusion modules are coupled by Darcy flow equation. Convective velocities obtained from pressure gradients both contribute to the heat and mass transfer governing equations. Three groups of linear systems are simultaneously solved through Newton-Raphson iteration method. This model has flexible gridding cells depending on the scale of real cases. Heat and mass transfer mechanisms are well studied through the distributions above. Our model also allows different types of heavy oil reservoirs by adjusting boundary conditions and initial conditions of the operation and formation parameters. In-situ data is applied to the model to provide professional and valuable advice to engineers.

1. Methods

## 2.1 Model formulation

Diagram of a steam chamber

Description automatically generated

Fig. 2.1 shows a single central injection and production well as a physical model for mathematical modeling. The physical model consists of two parts: the steam region (steam chamber) filled with hot steam and the oil region. Take a certain cycle in the middle of a multi-cycle development of CSS as a modeling target. Mathematical descriptions and solutions are conducted for the two operation stages (steam injection stage and production stage) within the single CSS cycle, with the aim of obtaining the changes in parameters such as temperature and pressure across the entire reservoir range during each stage.

Model assumptions

1. Cylinder horizontal formation with homogeneous properties. Equal thickness and closed outer boundary.
2. Constant temperature inside of the steam chamber, which value is equal to the injecting temperature.
3. Ignore the heat loss at all spatial directions.
4. The fluid is slightly compressible. The flow obeys Darcy’s law, and the capillary force is ignored.

Heat transfer

The governing equation of heat transfer can be described as a combination of heat conduction and convection without heat loss and fluid fingering.[11]

(2-1)

Where represents the reservoir thermal conductivity, . *T* represents the reservoir temperature, . *x* represents the distance, m. represents the convective velocity, m/s. and represent the densities of formation fluid and rock, respectively, . and represent the heat capacities of formation fluid and rock, respectively, . t represents the time, s.

A vertical well is generally used in a case of a CSS development. Therefore, the modeling process of heat transfer applies the two-dimensional form of the governing equation, which is obtained from the equation (2-1),

(2-2)

Convert it to polar coordinates for solution, so let

(2-3)

Substitute the equations (2-3) into the equation (2-2). A radial formula for heat transfer is compiled as follows.

(2-4)

Since this model considers that the oil reservoir is homogeneous, the magnitude of heat transfer on the plane is independent of the angle, resulting in the final heat transfer equation in the form of

(2-5)

As for the reservoir thermal conductivity , according to the research of Butler et al. [12], its numerical value is related to factors such as reservoir rock mineral composition, degree of cementation, and fluid properties in pores. Referring to Butler’s results, the thermal conductivity of oil reservoirs in this model is taken within the range of 0~3 .

Convective velocity obeys Darcy’s law:

(2-6)

Initial and boundary conditions (IC and BC) at an injection stage:

(2-7)

(2-8)

(2-9)

Where represents the reservoir initial temperature distribution, °C. represents the injecting steam temperature, °C. represents the distance of steam zone, m. represents the distance of oil zone, m.

IC and BCs at a production stage:

(2-10)

(2-11)

(2-12)

Mass transfer

The polar coordinate expression of the mass transfer equation [13] that used to describe the gas concentration distribution in the oil zone is

(2-13)

Where *c* represents the gas concentration distribution, mol %. *D* represents the effective diffusion coefficient between the oil and gas, m2/s.

This model considers that the gas is in a stable state mixing with steam in the gas zone, thus the attention of the model is the mass transfer in the oil zone. Hydrocarbon gas, together with hot steam, can greatly change the viscosity of crude oil, and thereby improve the mobility of underground crude oil.

The initial condition for gas diffusion is expressed as

(2-14)

The inner boundary condition of oil zone is expressed as

(2-15)

The outer boundary condition of oil zone is expressed as

(2-16)

Where represents the gas concentration distribution at the end of the previous cycle in oil zone. represents the saturation concentration of the gas at the boundary.

(2-17)

(2-18)

(2-19)

(2-20)

Pressure diffusion

The polar coordinate form of the pressure diffusion equation [14] is:

(2-21)

Where *p* represents the formation pressure, Pa. *μ* represents the viscosity of the reservoir fluid, cp. Z is the compressibility factor of the fluid, %. represents formation porosity, %; represents the comprehensive compressibility coefficient of the reservoir, 1/Pa. Through research, it was found that the viscosity and compression factor of water vapor have a linear relationship with formation pressure, and the values are relatively small. The values at 250 °C are shown in Figures 2.3 and 2.4, and their product at 250 C. The specific value of is shown in Figure 2.5. According to the calculation results of combined with the form of equation (2-17), it can be approximated as a constant in the formula. Therefore, after organizing the equation (2-17), we can obtain:

(2-22)

Initial conditions at injection stage:

(2-23)

Inner boundary conditions:

(2-24)

(2-25)

When the inner boundary pressure does not reach the set maximum pressure, the inner boundary is set to a constant injection flow rate, as shown in formula (2-24); as the bottomhole pressure continues to rise, when it reaches the maximum pressure, it is then chosen to maintain this pressure until the end of the injection stage, and the internal boundary conditions are shown in Equation (2-25).

Outer boundary condition:

(2-26)

Rearranging the equation (2-22) into the p2 form, we have

(2-27)

The corresponding initial condition and boundary conditions become

(2-28)

(2-29)

(2-30)

For the convenience of formula expression, let

(2-31)

Then the pressure diffusion governing equation becomes

(2-32)

(2-33)

(2-34)

(2-35)

The settings of the initial conditions and boundary conditions of the pressure diffusion model in the production stage are similar to those of the heat transfer model. The initial condition at production stage is the formation pressure distribution at the end of steam injection stage. The outer boundary keeps the conditions of the closed boundary unchanged, and the inner boundary (bottom hole pressure) is set to reasonable values.

## 2.2 Solution

As mentioned above, the model requires coupling the solution in which the initial temperature, viscosity and pressure profiles are given. At each time step, the pressure diffusion model is solved and the numerical value of the pressure gradient within the reservoir range is calculated. Subsequently, the convective velocity of the fluid is solved according to Darcy's law, and the convective velocity is respectively incorporated into the heat transfer equation and mass transfer equation for temperature and concentration calculation. Afterwards, the viscosity of crude oil is calculated from the temperature and gas concentration. At this point, the calculation for a time step is completed. In the initial stage of the next time step, the temperature profile and pressure profile of the reservoir are updated with the viscosity of the crude oil. The coupled calculation flowchart is shown in Figure 2.2. The Newton-Raphson method is then needed to solve the three governing equations due to their nonlinearity.

1. Result and Discussion
   1. Base case, without assisted gas

Injection period

Figure 3.1(a-d) shows the temperature, viscosity, pressure and convective velocity distributions along the oil zone at day 2, 4, 6, 8, 10, 12 and 14. Figure 3.1a shows the reservoir pressure distribution at each time point. The pressure continuously decreases with an increase in distance, and the magnitude of the decrease becomes lower and lower, ultimately tending to stabilize. For different time points, the pressure profile continuously rises over time. When the bottom hole pressure reaches the maximum injection pressure 4MPa, the bottom hole pressure no longer rises. At this point, the remaining time of the steam injection stage is completed with a constant pressure boundary. Finally, at the end of the steam injection, the pressure profile reaches its maximum, reaching 4MPa within a range of 50 meters of the reservoir.

Based on the pressure profile, the magnitude of flow velocity in the oil region is calculated according to Darcy's law, and the calculation results are shown in Figure 3.1b. As shown in the figure, the distribution of flow velocity is mainly concentrated within the first 2 meters of the oil region. On the second day of a steam injection, the flow velocity at the boundary of the oil and gas zone (leading edge of the steam chamber) reached 2.88×10-6 m/s, followed by a continuous decrease over time. As the steam injection time increases, the slope of the velocity profile gradually increases, and there is a phenomenon of intersection between velocity profiles at different times.

Figure 3.1c shows that the temperature profile of the reservoir continuously increases over time. Under the parameter settings of this model, the temperature at the leading edge of the steam chamber reached the set maximum injection temperature of 250 °C after eight days of steam injection. The temperature at the boundary of the steam chamber remained unchanged. Based on the sparsity of the curve, it can be inferred that before the boundary temperature reaches 250 °C, the overall temperature profile increases significantly. Within the four days before the end of steam injection, there is no significant change in temperature, and ultimately the temperature changes tend to stabilize at 3 meters in the oil region. The variation area of crude oil viscosity mainly occurs within 3 meters in front of the oil zone, and over time, the viscosity profile of the crude oil continues to decrease as shown in Figure 3.1d. In addition, due to the continuous decrease of temperature with position, its viscosity continuously increases to the initial viscosity of crude oil.

Production period

The production time set in this section of the model is 130 days. Figure 3.2a shows the pressure distribution during the production stage, and compares the calculated results at the 1st, 5th, 10th, 20th, 60th, 100th, and 130th days of the production. As the production progresses over time, the pressure profile continues to decrease, with the fastest rate of pressure decrease at the bottom of the well, but the magnitude of the decrease is becoming smaller and smaller. For each curve, the pressure gradually increases from the bottom of the well to the depth of the formation and ultimately remains constant after 20m in the formation.

Figure 3.2b shows the magnitude of heavy oil flow velocity in the oil region during the production process. As shown in the figure, the distribution of flow velocity is mainly concentrated within the first 3 meters of the oil zone, which increases compared to the steam injection stage and gradually decreases with distance. Figure 3.2c shows the temperature distribution at various time points during the production stage. With the increase of production time, the heated fluid from the bottom of the well is continuously extracted, and the temperature of the front edge of the steam chamber is getting lower, thus driving the overall temperature profile of the reservoir to continuously decrease. However, due to the rapid decrease in temperature at the leading edge of the steam chamber, which was once lower than the temperature at adjacent positions, it was observed in the early stage of production (within 15 days) that the temperature profile near the leading edge of the steam chamber showed a trend of first increasing and then decreasing (reverse temperature difference). At this point we consider that the viscosity of crude oil is only a function of formation temperature, so there is a phenomenon of viscosity first decreasing and then increasing near the front edge of the steam chamber. The calculation results of the viscosity profile are shown in Figure 3.2d. For this phenomenon, the viscosity of crude oil in the reverse temperature difference zone first decreases and then increases with the position, and the high viscosity oil grids on both sides block the low viscosity oil with stronger fluidity in the middle. Therefore, it is necessary to strictly control the bottom hole temperature during the operation process to prevent it from dropping too quickly during the production process, otherwise it will have adverse effects on the development of the heavy oil.

Effect of operating conditions

Under the premise of the basic calculation case, two sets of curves of bottom hole pressure and temperature with time were added, as shown in Figure 3.3 (a, b). Subsequently, the temperature profiles at the end of production under the newly added bottom hole conditions are calculated, and the results are shown in Figure 3.4. It can be seen that the difference in temperature profile is mainly concentrated in the first 4m of the oil region. Although the difference is not significant, the slower the decrease in bottom hole parameters, the higher the corresponding temperature profile. The main reason for this difference is that the slowly decreasing bottom hole conditions can transfer more heat from the bottom of the well to the interior of the reservoir, resulting in a more sufficient heating effect for the crude oil.

* 1. Base case, with assisted gas

Injection period

The parameter settings are kept the same as the base case without assisted gas above. To combine the concentration field into the model, we take CH4 as the assisted gas during the injection period. Fig 3.5a shows the results of pressure distributions at different time steps of a injection period. It could be read from the figure that there is no obvious change comparing to the pressure distribution of the case without assisted gas. This is because adding gases cannot influence the total compressibility which is the key factor to determine the strength of pressure diffusion.

Figure3.5b shows the oil zone convective velocity at different injecting time steps. Gas assisted CSS shows a higher convective velocity profile. On the second day of steam injection, the convective velocity at the leading edge of the steam chamber reached 4.72×10-6 m/s. This is mainly because after injecting gas, the viscosity of the heavy oil in the front of the oil zone is further reduced by the dilution effect of the gas. The fluidity is therefore improved. In addition, it can be seen from the figure that the scope of the convective effect is mainly within the first 1m of the oil region. No obvious convective velocity can be observed in the area beyond 1m.

Figure 3.5c shows the temperature profile changes in the oil region during the steam injection stage. As the injected gas only affects the convective velocity within a small range of the front edge of the oil region, the temperature profile changes throughout the entire oil region have not changed significantly compared to the case without assisted gas. Figure 3.5d shows the calculation results of the viscosity profile of heavy oil in the oil region. In this section of the model, the viscosity of heavy oil is jointly determined by steam and gas, so compared to the viscosity profile to the case without assisted gas, the viscosity value assisted by gas is lower in the front of the oil region. There is no significant change in the overall variation pattern. Simultaneously, for the viscosity profile at each time, the viscosity also gradually increases with the increase of distance.

Figure 3.5e shows the gas concentration distributions in the oil zone at different times during the steam injection stage. The curve corresponding to t=0 represents the initial value of concentration in the reservoir (concentration distribution after the end of the previous round). At the leading edge of the steam chamber, the concentration of gas gradually increases over time and ultimately stabilizes at around 0.095. Subsequently, the overall concentration profile also increased over time, but the increase in amplitude gradually decreased within the same time interval. In addition, from the intersection point of the concentration profile and the horizontal axis, it can be seen that the gas's sweep range in the oil area is increasing. On the second day of steam injection, the gas can only reach a position 0.25m into the oil area, while at the end of steam injection, the gas sweep reaches a position of 0.7m in the oil area.

Figure 3.5f shows the difference in viscosity of crude oil after assisted gas development compared to pure steam development at the end of steam injection. It can be seen that the change in viscosity is within 0.5m of the front edge of the gas chamber. Although it can be seen from Figure 3.5e that the gas extends to 0.7m of the front edge of the gas chamber at the end of steam injection, the range of significant change in viscosity is smaller than its affected range, because a small amount of gas cannot have a significant impact on the viscosity of the whole range crude oil.

Figure 3.5g shows the changes in convective velocity in the oil zone after auxiliary gas development compared to before. It can be seen that after gas participation in development, the convective velocity in the oil region has been significantly improved, with an increase of about 35 percent at the leading edge of the steam chamber. But at the same time, it can also be seen that the change in convective velocity mainly occurs within 0.5m of the front edge of the air chamber, and the subsequent position is not different from before.

Production period

Figure 3.6 (a-g) shows the changes in reservoir parameters during the production phase. Figure 3.6a shows the pressure distributions at different time steps during the production stage (5th day, 10th day, 20th day, 120th day). It can be seen from the figure that the pressure rapidly decreases at the bottom of the well with the production period processing, resulting in a continuous decrease in the pressure profile of the entire reservoir. However, the magnitude of the decrease gradually decreases. At t=20 days, the pressure profile of the reservoir is basically a horizontal line, with a pressure of 0.58MPa. At the end of production, the pressure remains at 0.2MPa.

Figure 3.6b shows the variation of convective velocity profiles in the oil zone at different time steps. From the figure, it can be seen that the range of convection during the production stage is about 2 meters, and over time, the velocity profile continuously decreases. The convective velocity at the leading edge of the steam chamber decreases the fastest, and on the fifth day, the convective velocity at the leading edge is about 3×10-6 m/s, 8.1×10-7 m/s on the tenth day, a decrease of about 73%in just five days.

Figure 3.6c shows the changes in temperature distributions at different time steps, and it can be seen that the temperature at the leading edge of the steam chamber continuously decreases over time, which drives the temperature of the entire profile to change. Within the first 2.5 meters of the oil zone, the temperature profile is continuously decreasing; Beyond 2.5 meters, the temperature profile actually increases over time. From this phenomenon, it can be seen that although the temperature at the leading edge of the steam chamber continuously decreases during the production process, it is still relatively high in the oil zone far away, so there is continuous heat transfer to the formation far away, resulting in a continuous increase in temperature 2.5 meters away from the oil zone.

Figure 3.6d shows the distribution of crude oil viscosity in the oil region. Under the combined action of steam and assisted gas, the viscosity of crude oil at the front edge of the steam chamber is significantly lower than that at the depth of the oil zone. The viscosity profile differences at different times during the production stage are mainly within the first 3 meters of the oil field, and as time increases, the viscosity profile continues to decrease.

Figure 3.6e shows the concentration profile changes in the oil region at different times. As low viscosity crude oil is extracted during the production stage, the amount of gas remaining in the oil zone decreases, resulting in a continuous decrease in gas concentration at the leading edge of the steam chamber. On the 20th day, it can be seen from the graph that the gas concentration first increases and then decreases with position, resulting in a phenomenon of inverse concentration difference. The main reason for this phenomenon is similar to the inverse temperature difference discussed previously, both of which are due to the rapid decline of the leading edge operation parameters. In addition, with the increase of time, the range of gas concentration spread becomes larger and larger, and at the end of production, the distance of gas concentration diffusion in the oil zone reaches about 1.5 meters.

* 1. Heat conduction vs heat convection

In order to determine the contribution of heat conduction and heat convection to the CSS heat transfer process, the convection velocity in the heat transfer model was set to 0, while the other parameters remained unchanged. The heat transfer results caused only by heat conduction were calculated, and then compared with the original calculation results, as shown in Figure 3.7a. From the figure, it can be seen that the difference between the two curves is mainly concentrated within the 0-2 meter range of the oil region, which is consistent with the convective range calculated in the previous text. Subsequently, the two curves corresponding to the temperature are subtracted, and the difference represents the contribution of thermal convection to the entire heat transfer process. This difference is compared with the temperature profile calculated solely from thermal conduction to represent the ratio of thermal convection to thermal conduction to the overall heat transfer contribution. The calculation results are shown in Figure 3.7b (2 days, 5 days, 10 days), and this ratio profile continues to rise with time, The ratio of thermal convection to heat conduction at all time points first increases and then decreases with position, with a maximum value of 12.6% reaching 0.5 meters in the oil region after 10 days of steam injection.

Figure 3.8 (a-d) is used to describe the contribution of thermal convection and conduction to the entire heat transfer process in production. Among them, Fig. 3.8a represents the temperature profile calculated on the 30th day (why 30th?) of production, which is only affected by heat conduction, and the temperature profile calculated under the combined action of heat convection and conduction. From the trend and numerical magnitude of the curve, the difference between the two is significantly smaller than the difference during the steam injection stage. Similarly, the ratio of the contribution of heat convection and heat conduction to heat transfer was also calculated (on the 1st, 10th, and 20th days of production), as shown in Figure 3.8c. It can be seen that on the 1st day of production, heat convection has a positive effect on the overall heat transfer of the reservoir, while on the 10th and 20th days, thermal convection mainly has a negative effect on the overall heat transfer of the reservoir. This is due to the rapid decrease in wellbore pressure during the production stage, The direction of convective velocity changes. Figure 3.8d shows the variation of convective velocity at the boundary of the gas chamber over the entire development time. It can be seen that the convective velocity at the boundary of the steam injection stage is divided into two descending stages, and the second descending stage is more severe than the first descending stage. During the production phase, the convective velocity exhibits a pattern of decreasing first and then increasing.

* 1. Mass transfer by convection

Figure 3.9a shows the comparison of the contributions of convection and diffusion to the entire gas concentration profile during gas mass transfer. It can be seen that diffusion plays a dominant role in the mass transfer process in this model, but the impact of convection on gas concentration is still very observable. It can be seen that under the combined effect of convection and diffusion, the gas solubility profile is significantly higher than the concentration profile caused solely by diffusion. Figure 3.9b shows the distribution of convective velocity in the oil region. It can be seen from the figure that as time progresses, the convective velocity profile gradually decreases, mainly due to the gradual decrease of pressure gradient in the oil region as steam injection time increases. Figure 3.9c shows the variation curve of the ratio of convection and diffusion at the leading edge of the gas chamber to the gas concentration profile over time. It can be seen from the figure that the ratio of the two first increases and then decreases over time. The ratio reaches its maximum on the third day, with a maximum value of 0.963. That is to say, on the third day of steam injection, convection and diffusion play a nearly equal role in the diffusion of gas in the oil region. Figure 3.9d shows the variation of convective velocity at the leading edge of the gas chamber over time under the combined effect of heat and mass transfer. It can be seen from the figure that the convective velocity is maximum at the initial moment of steam injection, and then decreases continuously with time, with a maximum value of about 1.5×10-5 m/s, which increases the speed by 31 percent compared to the previous section where only heat transfer is considered.

Figure 3.10 shows the effect of assisted gas convection on the mass transfer process during the production period. Comparing the concentration profile calculation results after setting the convective velocity to 0 with the original results, it was found that the concentration profile caused only by gas diffusion is significantly higher than the concentration profile caused by both convection and diffusion, indicating that convection during the production stage inhibits gas diffusion.

* 1. Multicycle analysis

In the actual development process of heavy oil steam stimulation, 6 to 10 rounds of development are often carried out on site to maximize the recovery rate of heavy oil. In order to study the changes in reservoir parameters during multiple cycles and further deepen our understanding of formation heat transfer, we simulated five production rounds without assisted gas and calculated the temperature profile at the end of each round, as shown in Figure 3.11. It can be seen that with the increase of production cycles, the temperature profile after oil recovery continues to rise, but the extent of its rise is limited and the amplitude decreases with the increase of cycles. Therefore, increasing production cycles to increase the reservoir temperature in the later stage of CSS development is a cost-effective choice. Comparing the temperature profiles at the end of the first and fifth rounds, it was found that multicycle development can effectively increase the heat coverage range, with the coverage range of the fifth round being approximately twice that of the first round.

Figures 3.12 a and b respectively represent the temperature and concentration changes with distance at the end of the production stages of five development rounds. From the figure, it can be seen that with the increase of production cycles, the temperature profile after production continues to rise, and the heating range of the oil reservoir also continues to increase; The concentration profile of the gas is also constantly increasing, and the phenomenon of inverse concentration difference at the leading edge of the steam chamber becomes increasingly apparent. Figure 3.12c shows the relationship between gas retention in the reservoir and development cycles. The retention mass of gas in the reservoir was calculated based on the gas profile after each round, and it was found that its value increased regularly with the increase of development rounds, but the slope of the curve continued to decrease. In addition to the corresponding trend line, the curve correlation coefficient R2=0.9995 is calculated, indicating the feasibility of the functional relationship.

1. Conclusion

1. Distribution of field parameters

By coupled mathematical modeling of injection and production periods of CSS and gas assisted CSS processes, the reservoir pressure, temperature and concentration distributions at any point and any time step are iteratively calculated. Based on these basic parameter distributions, the mechanisms of heat and mass transfer are discovered and discussed. Instructive and practical advice are also mentioned according to the inverse phenomenon that happened in production periods.

2. Convection in heat and mass transfer

The contributions of the convection effect in heat and mass transfer processes are analysed based on the temperature and concentration distributions of both injection and production processes. While heat convection plays a less important role in the heat transfer process, the convection in mass transfer is more obvious and cannot be neglected.

3. Distance and multicycle

Multicycle simulation in both CSS and gas assisted CSS are conducted. As development rounds increase, the temperature profile and concentration profile of the reservoir cannot be significantly improved, whether by injecting steam or injecting auxiliary gas. Enhanced recovery through steam and assisted gases reaches the upper limit of reservoir development. Different reservoirs have different development upper limits, which needs further study in the future.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.