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EFFECT OF WATER INJECTION ON RESERVOIR TEMPERATURE DURING POWER GENERATION IN OIL FIELDS

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ABSTRACT

The effects of injection rate and the temperature of injected (or re-injected) water on reservoir temperature during power generation by utilizing hot fluids co-produced from oil and gas field were studied using numerical simulation approach. The chosen target reservoir was LB oil reservoir from Huabei oil field. The reservoir temperature was about 120°C. It has been found that there was significant temperature decline if the water injection rate was greater than a specific value and the temperature of injected water was less than a specific value. Also studied were the effect of water injection rate on oil production and water cut in LB oil reservoir. The results demonstrated that the oil production increased with the water injection rate, which is reasonable and would be helpful to conduct the power generation project in LB oil reservoir from the economic point of view.

INTRODUCTION

Oil and gas resources are traditionally considered as high CO_2 emissions. In some oil fields, a significant portion of crude oil is burning to provide heat for transportation of oil in winter. However there is a huge amount of geothermal energy co-existed with oil and gas in these petroleum reservoirs. As Erdlac et al (2007) reported, Texas has thousands of oil and gas wells that are sufficiently deep to reach temperatures of over 250°F (121°C) and sometimes 400°F (204°C) (also see the reports by Swift et al, 1999; Erdlac et al, 2004; McKenna et al, 2005; Erdlac et al, 2006). The possible electricity generation from the hot water, estimated by Erdlac, was about 47-75 billion MWh (equivalent to about 29-46 billion bbls of oil).

Milliken (2007) reported that the geothermal resources at Naval Petroleum Reserve #3 located at Teapot Dome field in Natrona County, Wyoming. Fractured Precambrian basement granitic rocks at depths of 7000 ft and more may yield large volumes of water at temperatures exceeding 250° F (121°C). Gross power potential at NPR-3 from 130 MBWPD at 220° F would be 76 MW (Milliken, 2007). The initial power generation unit was installed at the Naval Petroleum Reserve No. 3 and was put into service in September, 2008. The ORC power unit was designed to use 40,000 bpd of 170 °F produced water from the field's Tensleep formation to vaporize the working fluid, isopentane. This power unit has averaged about 180 kW net power output (Johnson and Walker, 2010).

Much attention has been paid to the direct use of geothermal energy and power generation by utilizing hot fluids co-produced from oil and gas reservoirs (Li, et al., 2007; Erdlac et al., 2007; Zhang, et al., 2009; Sun and Li, 2010; Johnson and Walker, 2010). However there are many problems to be yet solved in order to make it profitable. One of the problems is that the total liquid (oil and water) production is not enough to generate sufficient amount of power because of the relatively low reservoir temperature. Increasing the production and injection rates could be one of the solutions. Although water injection has been proved a successful engineering technique in geothermal and oil reservoirs to maintain reservoir pressure and sustain well productivity, many questions related to water injection into reservoirs still remain unclear. For example, is there any significant temperature decline in oil reservoirs because of the injection of cooled water? What are the suitable water injection rates? To answer these questions, we studied the effects of injection rate and the temperature of injected water on reservoir temperature using numerical simulation. The chosen target reservoir was LB oil reservoir from Huabei oil field. The reservoir temperature was about 120°C. Also studied were the effect of water injection rate on oil production and water cut in LB oil reservoir.

GEOLOGICAL BACKGROUND

Huabei oilfield, located 150 kilometers south of Beijing, China, is composed of many naturally fractured carbonate oil reservoirs. Most of these reservoirs are naturally fractured. A large water system exists at the bottom of these oil reservoirs. Some of the produced water, with a temperature of over 100℃, has been used directly for crude oil transportation, space heating, but not yet for electricity generation. One of these naturally fractured reservoirs is LB oil reservoir, located in Renqiu County (See Figure 1), Hebei province, northern China.

LB oil reservoir is a buried hill oil field in the east of Huabei. The peak surface morphology of LB buried hill is a nose structure along the direction of north east. The west side of LB buried hill is cut by the main fault, and the buried depth of high spot is 3216 m. The oil layer is located in Mesoproterozoic Jixian System Dolomite.

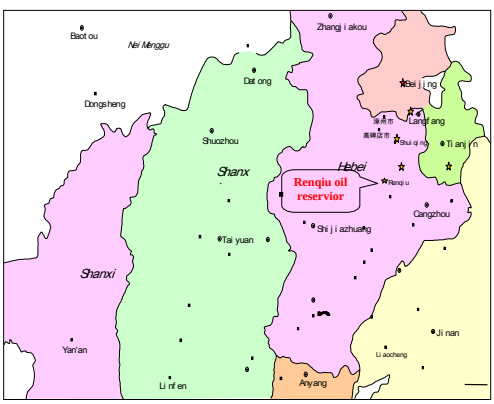

Figure 1: Location of LB reservoir (*Renqiu*).

The reservoir characteristics of LB buried hill are as follows: The rock is a dual porosity porous media with a porosity of about 6.0% and a permeability of around 158 md. The density of micro fractures is great, about 1~2 fractures/cm^2. However the fracture aperture is small. The rock is dominated by small vuggs, and the fractures are the main channel for fluid flow. The structural fractures are characteristic of high-angle, whose dip angle ranging from 70º to 90º. These high-angle fractures accounted for 87.8%. The fracture aperture ranged from 0.1 to 5 mm; those with aperture between 0.1 and 0.2 mm accounted for 74.5%.

HISTORY OF OIL PRODUCTION

LB reservoir was developed in June 1978, and water injection started in October of the same year. The entire reservoir is in the same pressure system. So the formation pressure will decline uniformly in the stage of elastic drive, and rise up in the stage of water injection. At the early development period, the largest single well liquid production was about 700 m^3/day and the minimum about 150 m^3/day. At the late development stage, the single well liquid production decreased significantly.

The geothermal gradient is about 3.5□/100 m and the average formation temperature is around 120 □. Table 1 show the pressure and temperature statistics of LB oil reservoir at the time of production test.

Table 1: The pressure and temperature statistics of LB oil reservoir at the time of production test

Well #	Static P (MPa)	Static T (^{o}C)	Flow P (MPa)	Flow T (^{o}C)
L 1			26.34	122
L 2	32.41	119	26.24	119
L 3	31.73	123	27.38	125
L 4			25.69	115
L 5	31.97	118		
L 6	32.34		31.95	108
L 7	33.13	115	32.87	124
L 8	31.53			
L 9	32.25	120	31.61	121
L 10	32.34		31.47	124
L 11	32.79	118	28.91	124

*P represents pressure and T temperature.

RESULTS AND DISCUSSION

Numerical simulation of the entire LB reservoir in Huabei oil field

Model parameters

LB reservoir had 23 wells, of which there were 7 injection wells and 16 production wells, the grid number is Nx × Ny × Nz = 44 × 25 × 50 = 55000, as shown in Figure 2. Other basic parameters of the reservoir used for numerical simulation are listed in Table 2. The porosity and permeability models of LB reservoir are shown in Figures 3 and 4 respectively. Figure 5 shows the oil-water relative permeability data used in the numerical simulation.

Table 2: Basic model parameters.

Original formation pressure, (MPa)	30
Original formation temperature, (^{o}C)	120
Residual oil saturation, %	37
Thermal conductivity of rock, (W/(m.K))	5.00
Thermal conductivity of water, (W/(m.K))	0.650
Thermal conductivity of oil, (W/(m.K))	0.135

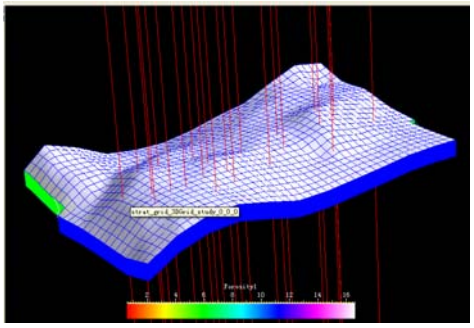

Figure 2: Grid map of LB reservoir.

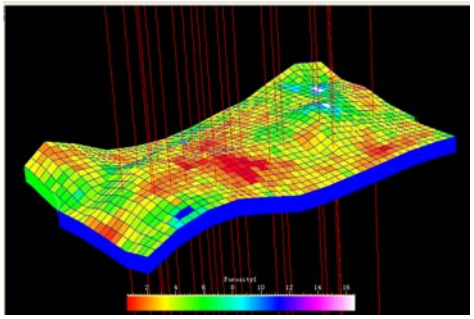

Figure 3: Porosity model of LB reservoir.

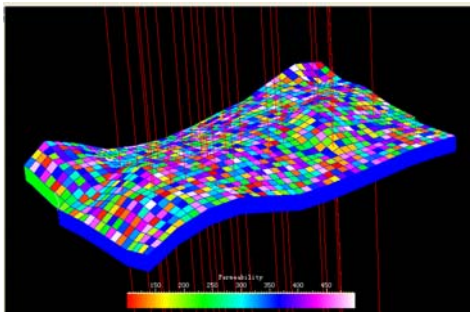

Figure 4: Permeability model of LB reservoir.

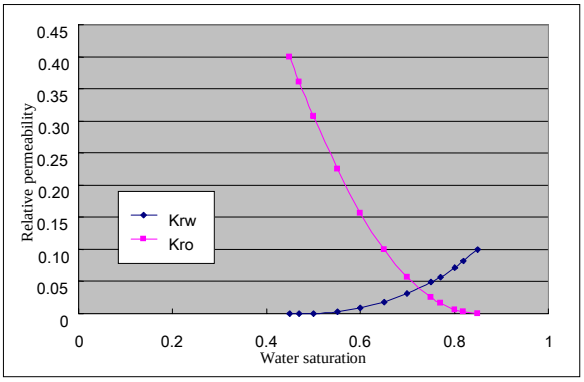

Figure 5: Oil-water relative permeability curve.

Cases of numerical simulation

In order to better analyze the effect of the injected water temperature and thermal conductivity on reservoir temperature, we designed multiple simulation cases. Table 3 shows 18 simulation cases with different water injection rate of single well and different temperature of water injected.

Table 3: Simulation cases of different water injection rate and injection temperature

Case No.	Injection temperature. (℃)	Single well water injection (m^3/day)
1	20	500
2	20	1000
3	20	2000
4	20	3000
5	20	3500
6	20	8000
7	35	500
8	35	1000
9	35	2000
10	35	3000
11	35	3500
12	35	8000
13	50	500
14	50	1000
15	50	2000
16	50	3000
17	50	3500
18	50	8000

In addition, we also studied the influence of rock thermal conductivity on reservoir temperature by numerical simulation. Relevant parameters are shown in Table 4.

Table 4: Simulation cases for different values of thermal conductivity of rock.

Case No.	Rock thermal conductivity (W/(m.K))	Injection temperature (℃)	water injection rate (m^3/day)
19	2.76	35	3000
20	7.153	35	3000

Results and discussion of numerical simulation

Figure 6 shows the simulation results in the case in which the temperature of re-injected water was assumed to be 20 ℃. The average reservoir temperature decreases with the development time at different water re-injection rates (ranging from 500 to 8000 m^3/day) of single well.

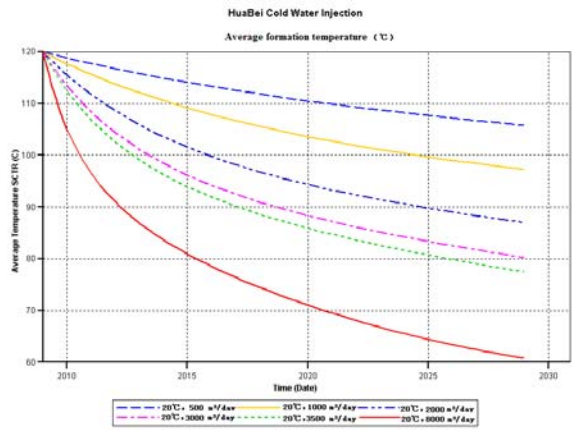

Figure 6: The relationship between average formation temperature and time at different water re-injection rates (temperature of re-injected water = 20 ℃)

As can be seen from Figure 6, with the continuous injection of cold water, the average reservoir temperature will decline incessantly. In the case in which the original reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 20 ^{o}C for a re-injection rate of 500 m^3/day, the decline rate of the average reservoir temperature is less than 0.75 ^{o}C /year for a 20-year water re-injection period. As water re-injection rate increasing from 500 to 1000 m^3/day, the decline rate of the average reservoir temperature is less than 1.2 ^{o}C /year for a 20-year water re-injection period. The decline rate of the average reservoir temperature increases with water re-injection rate at the same temperature of re-injected water.

The decline rate of the average reservoir temperature should be less than 1 ^{o}C /year in order to maintain sustainable power generation. According to this rule and the results shown in Figure 6, the single well water re-injection rate in LB reservoir should not be more than 800 m^3/day approximately in the case in which the original reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 20 ^{o}C.

Figure 7 shows the relationship between cumulative oil production and time in the case in which the original average reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 20 ^{o}C at different water re-injection rates. One can see from this figure that the increase in oil production due to the increase in water re-injection rate is significant.

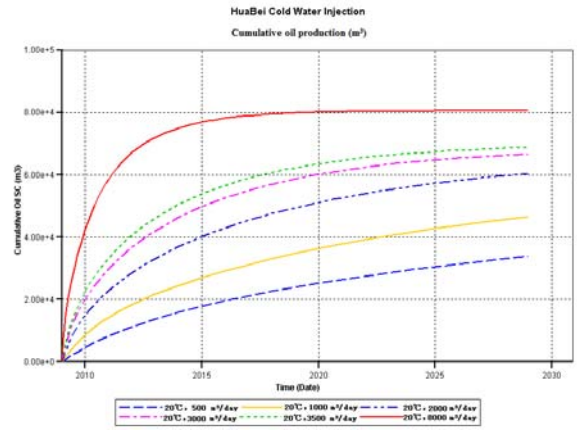

Figure 7: The relationship between cumulative oil production and time at different water re-injection rates (temperature of re-injected water = 20 ℃)

The effect of water re-injection rate on water cut is shown in Figure 8 in the case where the original average reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 20 ^{o}C. The water cut does not change with water re-injection rate significantly.

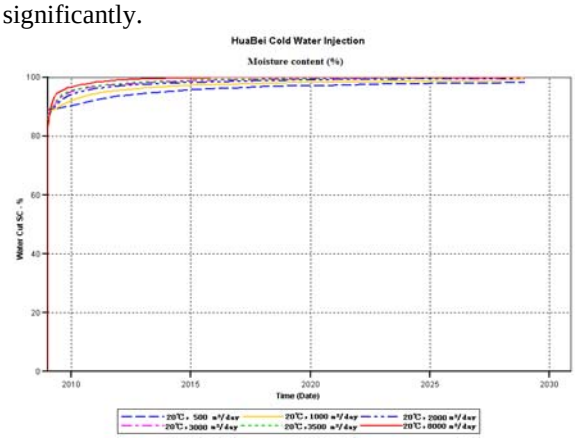

Figure 8: The relationship between water cut and time at different water re-injection rates (temperature of re-injected water = 20 ℃)

Figure 9 demonstrates the effect of water re-injection rate on cumulative oil production in the case in which the original average reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 35 ^{o}C. The average reservoir temperature also decreases with production time at different water re-injection rates in this case.

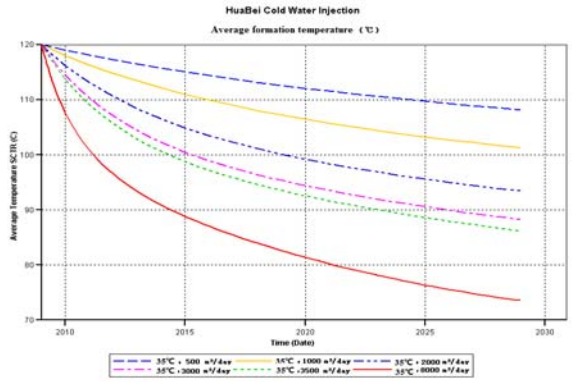

Figure 9: The relationship between average formation temperature and time at different water re-injection rates (temperature of re-injected water = 35 ^{o}C)

In the case in which the original reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 35 ^{o}C for a re-injection rate of 500m^3/day, according to Figure 9, the decline rate of the average reservoir temperature is less than 0.6 ^{o}C /year for a 20-year water re-injection period. As water re-injection rate increasing from 500 to 1000 m^3/day, the decline rate of the average reservoir temperature is less than 1 ^{o}C /year for a 20-year water re-injection period.

According to the results shown in Figure 9, the single well water re-injection rate in LB reservoir should not be more than 1000 m^3/day approximately in the case in which the original mean reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 35 ^{o}C if the decline rate in reservoir temperature is required to be kept at less than 1 ^{o}C /year.

The effects of water re-injection rate on cumulative oil production and water cut are shown in Figures 10 and 11 respectively in the case where the original average reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 35 ^{o}C. As in the case in which the temperature of the re-injected water is 20 ^{o}C, cumulative oil production also increases with water re-injection rate significantly but water cut does not change very much.

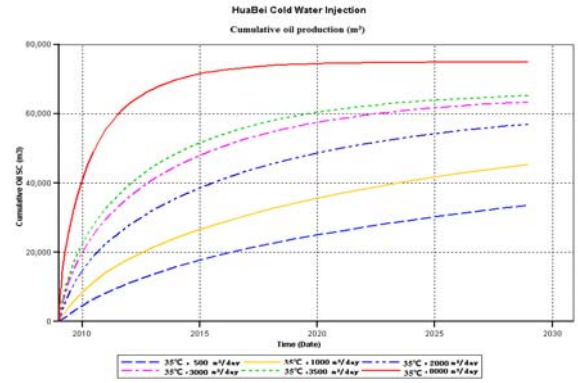

Figure 10: The relationship between cumulative oil production and time at different water re-injection rates (temperature of re-injected water = 35 ^{o}C)

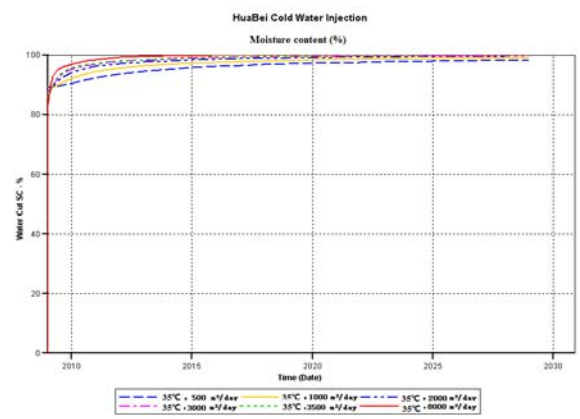

Figure 11: The relationship between moisture content and time at different water re-injection rates (temperature of re-injected water = 35 ^{o}C)

In the case where the temperature of the re-injected water is 50 ^{o}C and the original average reservoir temperature is the same (120 ^{o}C), the effects of water re-injection rate on average reservoir temperature, cumulative oil production, and water cut are shown in Figures 12, 13, and 14 respectively. Similarly as in the previous cases, the average reservoir temperature decreases and cumulative oil production increases with the increase in water re-injection rate. However water cut does not change very much at the same production time.

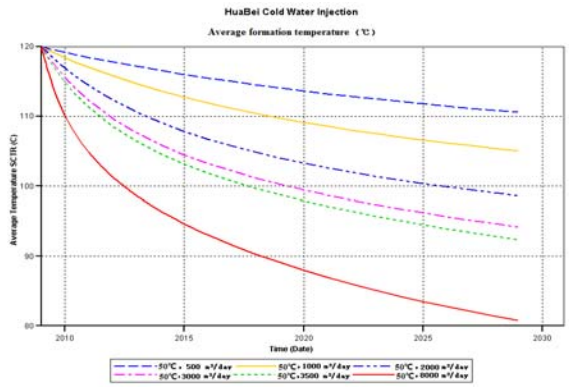

Figure 12: The relationship between average formation temperature and time at different water re-injection rates (temperature of re-injected water = 50 ^{o}C)

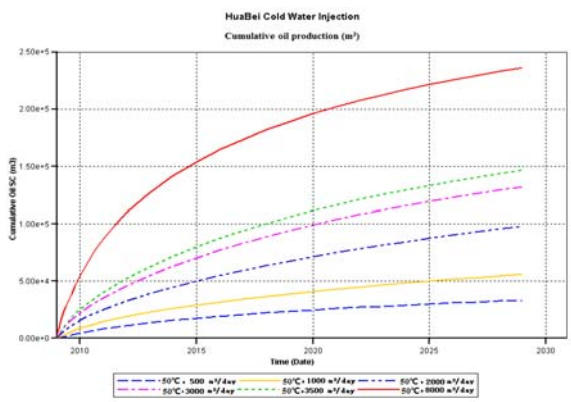

Figure 13: The relationship between cumulative oil production and time at different water re-injection rates (temperature of re-injected water = 50 ^{o}C)

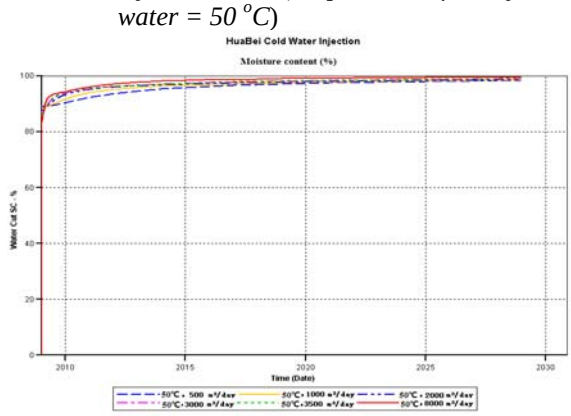

Figure 14: The relationship between moisture content and time at different water re-injection rates (temperature of re-injected water = 50 ^{o}C)

In the case in which the original reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 50 ^{o}C for a re-injection rate of 500m^3/day, according to Figure 12, the decline rate of the average reservoir temperature is less than 0.5 ^{o}C /year for a 20-year water re-injection period. As water re-injection rate increasing from 500 to 2000 m^3/day, the decline rate of the average reservoir temperature is less than 1.1 ^{o}C /year for a 20-year water re-injection period. The single well water re-injection rate in LB reservoir should not be more than 1800 m^3/day approximately in this case to keep the decline rate of the average reservoir temperature less than 1 ^{o}C /year.

In summarizing the above results, the higher the temperature of the re-injected water and the smaller the re-injection rate is, the slower the reservoir temperature drops. On the other hand, the oil production increases but water cut does not change very much with water re-injection rate and the temperature of the re-injected water in many cases.

Figure 15 shows the simulation result at different values of thermal conductivity in the case in which the original reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 35 ^{o}C for a re-injection rate of 3000m^3/day. One can see from Figure 15 that the thermal conductivity of rock has little effect on reservoir temperature in the range studied.

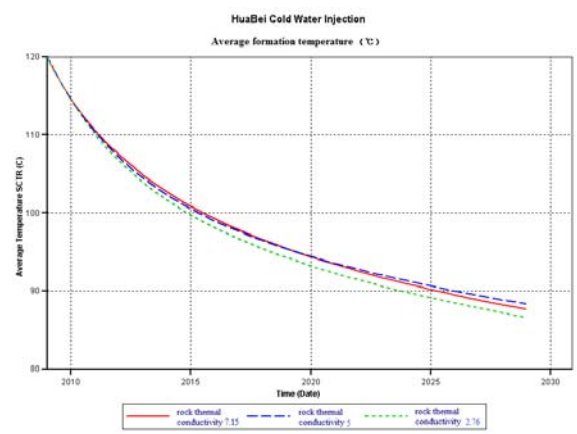

Figure 15: The relationship between average formation temperature and time at different value of thermal conductivity (temperature of re-injected water = 35 ^{o}C, re-injection rate=3000 m^3/day)

Based on the above results, appropriate water re-injection rates at different re-injection temperatures for LB reservoir in a 20-year water re-injection period is listed in Table 5.

Table 5: Appropriate water re-injection rate at different re-injection temperature for LB reservoir, Huabei oil flied.

Re-injection Temperature (℃)	Appropriate water re-injection rate (m^3/day)
20	800
35	1000
50	1800

CONCLUSTIONS

According to present study of numerical simulation in LB reservoir of Huabei oil field, we may draw the following preliminary conclusions:

1. The average reservoir temperature decreases and cumulative oil production increases with the increase in water re-injection rate. However water cut does not change very much at the same production time.
2. The appropriate water re-injection rate is affected by the temperature of re-injected water significantly.
3. In the case in which the original reservoir temperature is 120 ^{o}C and the temperature of the re-injected water is 35 ^{o}C for a re-injection rate of 3000m^3/day, the effect of thermal conductivity of rock on reservoir temperature decline is not significant.

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