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A feasibility study on heavy oil exploration by in-situ electric heating

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There are many problems on the current exploration technologies of heavy oil, thus finally it often fails to enhance the oil recovery ratio. Based on analyses on the current problems, in-situ electric heating under the exploration well is proposed to eliminate the problem from other improved exploration technologies, e.g. small influence zone and low recovery. The physical model of heating heavy oil is established in this study based on the obtained weight-loss ratio under different temperatures from thermogravimetric tests, which is further used to simulate the in-situ temperature distribution of heavy oil. Production of crude oil from reservoir as well as electric energy to heat the reservoir under different temperatures is calculated according to the formula of weight-loss. Given the different saturation degrees of oil, the internal rate of return and the net present value methods are adopted to evaluate the economic feasibility of oil exploration by in-situ electric heating. Results indicate that fluid is required during the in-situ heating otherwise no heating effect is anticipated. The in-situ oil heating is very efficient as most of heavy oil can be recovered within the first three days. After that the recovery reduces significantly. It is not technically feasible for our domestic heavy oil reservoir to carry out recovery by in-situ electric heating given the current saturation degree and price of oil as the consumption in power is huge.

Keywords: Heavy Oil; in-situ heating;temperature distribution; weight-loss; feasibility;economic evaluation.

INTRODUCTION

Current exploration techniques worldwide on heavy oil can be classified into three types, e.g. thermal recovery, cold production and the compound production. Thermal recovery represents the use of heating on oil reservoir to reduce the viscosity of oil, even to decompose the heavy oil so as to enhance its mobility, including steam huff and puff, steam flooding, hot water flooding, Combustion of oil and in-situ electric heating (use of electricity, microwave and electromagnetism),etc. Cold production is to reduce the viscosity through changing the structure or composition in heavy oil, including chemical viscosity reducing method, carbon dioxide injection method, micro-organic method, magnetic viscosity reducing method, sound wave viscosity reducing method and etc. Combined technique is the comprehensive combination of both technologies associated with higher recovery ratio than the use of single technique. The steam flooding and steam huff and puff are commonly used in China with the mature technique. Problems occurring in the current exploration methods include: (a) the energy consumption is huge during the heating process for methods like steam huff and puff, steam flooding and hot water flooding. Even though the thermal insulation measure is taken, the base temperature is no more than 350°C; (b)formation combustion, oil is hard to control and the combustion consumes plenty of resources; (c)for the cold production it is difficult for the injected fluid to contact well with heavy oil due to the existence of underground high permeable channel such that the influence zone is limited and the recovery is hard to be enhanced. (d)Methods like magnetic viscosity reducing or sound wave viscosity reducing take some effects but unable to realize high efficient recovery. The in-situ electric heating (including use of electricity, and electromagnetism) heats the reservoir directly, preventing the energy loss during hot fluid injection. By this method the temperature of reservoir can be increased to over 1000°C and under control. The heavy oil with reduced viscosity can be further completely decomposed into hydrocarbon fluids with coke remained, which prevents the resource loss as well as treatment after coke production on the ground due to the entry of oxygen in the combustion method. More importantly, the reservoir can be directly heated through the conduction and convection so that problems like small influence zone and low recovery in the other techniques can be finally resolved.

The in-situ electric heating has been currently applied on oil shale[2] recovery with the heating temperature of radiator of 343.3°C. Temperature of 371°C was reported by Yaqing Fan[3] for this application. Electric heating model on oil sands has been established by B.C.W. MCGEE[4] to simulate

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the heating mechanism on the asphalt of oil sands with the maximum temperature of 220°C, which validates the feasibility of electric heating on the recovery of oil sands. J.Y. Yuan [5] studied the electric heating process with the maximum temperature of 263°C at SAGD/VAPEX and carried out economic assessment. Comparatively only 150°C was achieved by B.C.W. McGee [6]. In the in-situ upgrading project (IUP) Deming Mao [7] reported the temperature of 350°C from the multiphase flow in the production well. R.S. Kasevich [8] studied the electromagnetic mechanism but only heating temperature of 200°C was achieved. Y. REN [9] conducted TGA (Thermo Gravimetric Analyzer) analysis on heavy oil and asphalts by heating them to 750°C at10°C/min and found that the temperature to complete decompose them in nitrogen was 425°C within the range of 374°C to 519°C. TGA analysis by Zhao Fajun [10] indicated that under 300°C no obvious pyrolysis was observed; from 300°C to 430°C,slow production of volatile materials was observed; the pyrolysis mainly occurred within 430°C to 550°C with the peak ranging 470°C to 480°C. The above indicates that the temperature range to activate TG (thermogravimetry) has not been reached by the current in-situ heating on heavy oil, oil shale and oil sand, e.g. the current heating temperature is not capable to fully decompose heavy oil, oil shale and oil sand thus the heating temperature shall be raised. But a question is raised: Is it economically feasible to carry out in-situ recovery?

This paper focuses on heavy oil. Firstly the weight-loss rate of heavy oil under different temperatures was obtained through TGAs and the physical model of electric heating on heavy oil was established. Secondly after simulation on the distribution of temperatures from in-situ heating of heavy oil, oil productions as well as profits from reservoir under different temperatures were calculated according to the curve-fitted weight-loss formula. Then the electric cost is obtained based on the calculated energy. The IRR(internal rate of return) method and NPV (net present value) method were adopted finally to assess the feasibility of recovery by in-situ electric heating on heavy oil.

TGA ANALYSIS ON HEAVY OIL

Testing apparatus and procedure

The process as well as the influencing factors of thermal decomposition and weight loss is studied in this paper by TGA method. The TGA apparatus of DTG-1 from Beijing Hengjiu scientific and equipment Ltdis adopted in laboratory experiments. Specifications are: a) heating rate of 0.1 ～ 80°C/min, b) accuracy of ±0.1°C, c) temperature range from indoor temperature to 1150°C, d) measuring capacity of 1mg~300mg, up to maximum 5g,e) resolution of 0.1μg, f) no shielding gas and g) natural cooling.

The heavy oil sample was taken from reservoir in Liaoning province, China. The sample was solid under normal temperature (30°C) and the heating rate was 10°C/min in nitrogen.

Testing program

The TGA apparatus adopted is automatically controlled by program specified as:

a)Activate the main switch and turn on the thermal balance; put the crucible into the heating chamber and measure its weight by the built-in balance; then take out the crucible and put in heavy oil, measure the total weight of the crucible plus the shale oil then the initial weight of oil can be determined from the total weight minus the weight of crucible;

b) Activate the control program, set the heating rate and termination temperature following the testing requirement, then put the crucible with heavy oil in the TGA chamber;

c) Turn on the heating unit of the TG, vary temperatures within the chamber by the built-in PID; the change in weight of heavy oil along with the variation in temperatures can be automatically recorded by the program;

d) When the temperature rose to the termination target, experiment was ended automatically and testing files were generated which include the weight loss curve and relevant data.

EXPERIMENTAL RESULTS

a. TGA tests

As seen from Figure 1 and 2, the normal steam temperature for steam huff and puff (steam flooding) is within 473.15K to 573.15K.

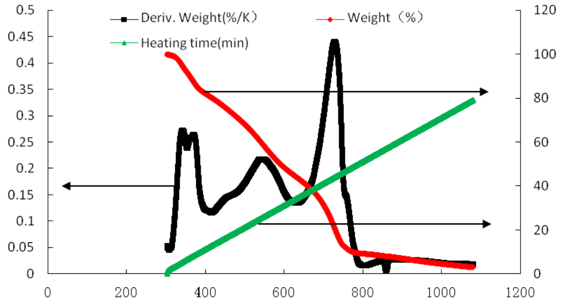


Fig. 1. Process of TGA tests.

The mass of heavy oil remained at 72.5%～52.5%, rate of thermal weight loss 27.5%～47.5%. Specifically the rate was respectively 80% and 90% for temperature at 728.15K and 773.15K. If the temperature kept rising, the increase in the rate became slow and meaningless, which however consumed huge energy. The peak weight loss occurred within 723.15K to 773.15K,e.g. good thermal decomposition occurred beyond the temperature of 773.15K. The curve-fitted accumulated rate of weight loss (η) is expressed as

η =3.181010980284×$10^{-17}T^6$-1.05679123568331×$10^{-13}T^5$ +1.33690015495866×$10^{-10}T^4$ -8.31027615576241×$10^{-8}T^3$ +2.75887986536105×$10^{-5}T^2$ -3.22429179914252×10^{-3}T-1.2×10^{-1}

R^2 =0.999717007448145

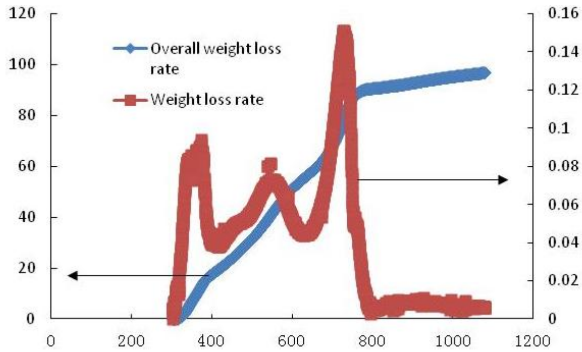


Fig. 2. Curve of Weight variations of heavy oil in TGA tests.

b. Decomposition of heavy oil

The heavy oil mainly consists of alkane, arene and asphaltene, etc. It is a particle composition of sulfur, nitrogen and oxygen. Decomposition of heavy oil experiences the following steps as[11]:

Thermal decomposition: C_xH_y→light dydrocarbon

Reconstitution of steam: $C_xH_y+2xH_2O \rightarrow xCO_2+(2x+y/2)H_2$

Transformation of water and gas: $CO+H_2O \rightarrow CO_2+H_2$

Desulfuration: C_xH_y $S_2+H_2O/H_2 \rightarrow H_2S$+light hydrocarbon.

PHYSICAL MODELING

A cube was built with side length of 10m to represent the reservoir of heavy oil. A horizontal injection well and a horizontal recovery well is set at 3m height and 8.5m height along the central axis. Diameter of the two wells amounts to 216mm and length 9m. Upper and lower layers of the reservoir are other stratums. The lower horizontal well is by fluid injection and in-situ electric heating. Increase in fluid temperature is realized by lower-access heating apparatus. The temperature of 873.15K can be maintained by adjustment of power and voltage. The upper horizontal well is coverage well.

The base depth of the reservoir is 2000m, temperature 353.15K, temperature gradient 3K/100m. The distributions [12]of initial temperatures are defined by:

$$T_o = -0.03 * z + 353.15 \qquad (1)$$

where z is the thickness of the reservoir within 0m~10m;If the normal pressure system is assumed,the distribution[12] of initial pressure is described by

$$P_0 = 9800 * (2000 - z) \qquad (2)$$

The uneven heating resulted to the change in fluid density of the porous media thus the effect of buoyancy is considered, which expresses[12] as:

$$F = 1000 * 9.8 * \beta * (T - T_o) \qquad (3)$$

where β is the expansive coefficient of fluid,1/K and 0.04342 is adopted in this study;T_0 is the initial temperature of stratum, K;T is the temperature of the reservoir;K is the instant temperature during heating.

NUMERICAL MODELING[12]

The Brinkman equation and heat transmission equation for porous media are adopted to simulate the heating transmission and fluid flow, incorporated by flow velocity.

Fluid flow equation:

$$\begin{cases} \frac{\mu}{K} u + \nabla P - \nabla \cdot \frac{\mu}{\varepsilon} (\nabla u + (\nabla u)^T) = \rho g \beta (T - T_c) \\ \nabla \cdot u = 0 \end{cases} \qquad (4)$$

Heat transmission of porous media:

$$\begin{cases} (\rho C_P)_{eq} \frac{\partial T}{\partial t} + \rho C_P u \cdot \nabla T = \nabla \cdot (k_{eq} \nabla T) + Q_1 \\ k_{eq} = \theta_p k_p + (1-\theta_p) k \\ (\rho C_p)_{eq} = \theta_p \rho_p C_{\rho,p} + (1-\theta_p) \rho C_p \end{cases} \qquad (5)$$

Heating transmission of fluid:

$$(\rho C_P)_{eq} \frac{\partial T}{\partial t} + \rho C_P u \cdot \nabla T = \nabla \cdot (k_{eq} \nabla T) + Q_2 \qquad (6)$$

where T is the temperature of oil shale reservoir during heating, K;C_p is the specific heat at constant temperature, J·kg^{-1}·K^{-1};K is the permeability of the porous media,m^2;$Q_1$is the absorbed energy,J;Q_2 is the absorbed energy by water, J; ρ is the fluid density under the reference temperature T_c, kg/m^3; μ is the effective dynamic viscosity,Pa·s^{-1}; u is the expansive coefficient of fluid,$m \cdot s^{-1}$;β is the coefficient of volumetric thermal expansion,K^{-1};ε is the porosity of the media; ∇ is the Laplace operator $\nabla = \frac{\partial}{\partial x} i + \frac{\partial}{\partial y} j + \frac{\partial}{\partial z} k$;k_{ep} is the general thermal conductivity; k is the effective thermal conductivity,$W \cdot m^{-1} \cdot K^{-1}$;$k_p$ is the heat transmission coefficient of solid; θ_p is the temperature without unit as $\theta = \frac{T - T_C}{T_H - T_C}$ in which TH is the temperature at injection, TC is the reference temperature, K. The model specification is in table 1.

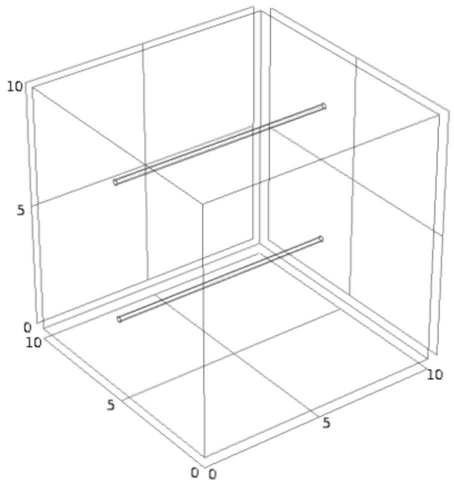


Fig. 3. Physical model of heating on heavy oil reservoir

TEMPERATUREDISTRIBUTIONS AFTER HEATING ON HEAVY OIL

The characteristics of temperature distributions for heavy oil within the reservoir are studied through injecting fluid into the stratum by radiator.

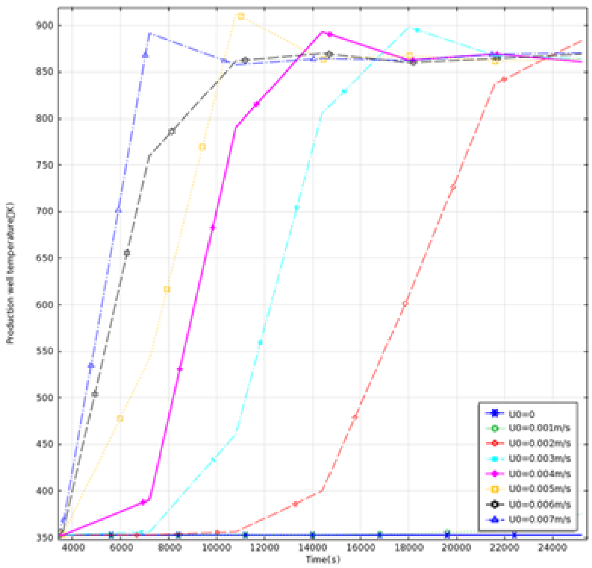


Fig. 4. Temperatures of production well given different injecting rates.

Optimization of injecting rate

At the oil stratum, the effect of water injection velocity (U0) on the pressure at the entrance was studied. As seen from Figure 4, along with the increase in injection rate, temperature at the recovery well increased significantly; at the velocity of 0, little change in temperature was observed, e.g. heating only took effect once the fluid was injected to the stratum. It can be seen from Figure 5 that, with the increase in injection rate, oil pressure at the entrance increased. Given the pressure of about 20MPa, rate of 3×10^{-3}m/s was adopted to prevent cracking of the reservoir as well as ensure the injection. The pressure amounted to 28MPaat this injection rate.

Table 1. Model specification

Reservoir of heavy oil		Water		Heavy oil	
Porosity	0.25	Fluid density,g/cm^3	1	Fluid density,g/cm^3	0.9
Permeability,m^2	$2e^{-13}$	Viscosity,mPa•s	10^{-3}	Viscosity,mPa•s	1000
Thermal conductivity,W/(m•K)	2	Thermal conductivity,W/(m•K)	0.58	Thermal conductivity,W/(m•K)	0.1
Density,g/cm^3	2.5	Atmospheric heat capacity,J/(kg•K)	4200	Atmospheric heat capacity,J/(kg•K)	5000
Specific heat capacity,J/(kg•K)	1812	Specific heat ratio	1	Saturation degree of oil	So(0-1)

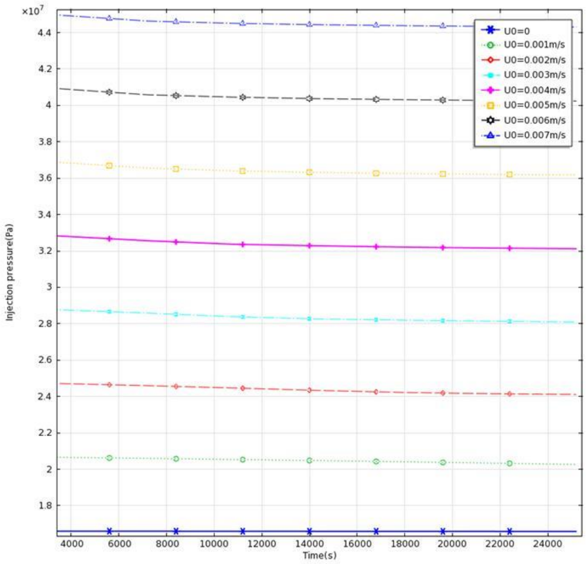
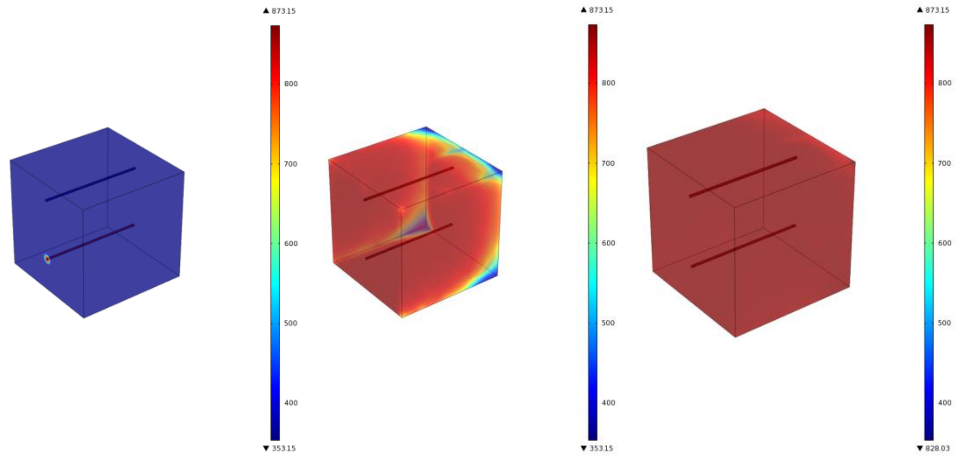


Fig. 5. Injecting pressures given different injecting rates.

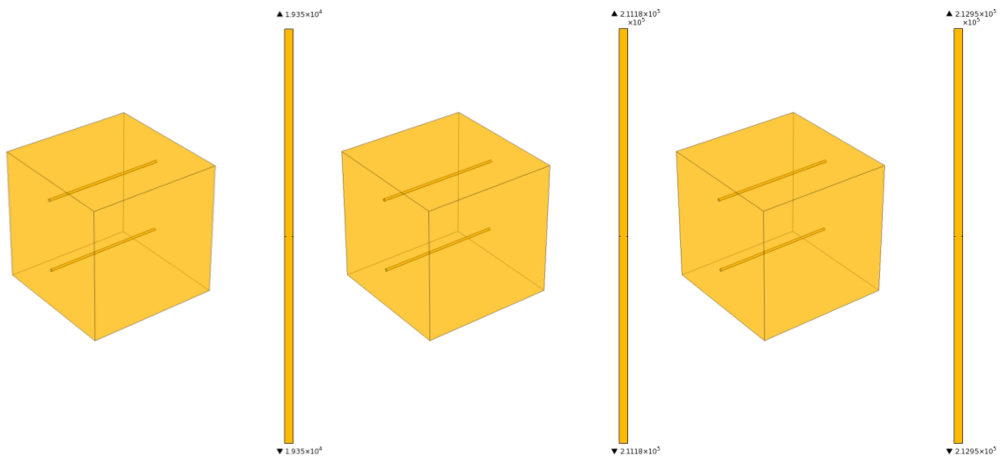
Characteristics of temperature distributions for heavy oil after electric heating

Given the rate of 3×10^{-3}m/s, difference in recovery pressure amounted to 3MPa. Figure 6 presents the distribution of temperatures at the injection times of 0, 5d, and 10d, respectively. Subsequent results are calculated based on this injection rate and pressure difference. As seen from Figure 6, it only took a short time before the heavy oil reached the temperature for decomposition, which indicates positive heating effect.



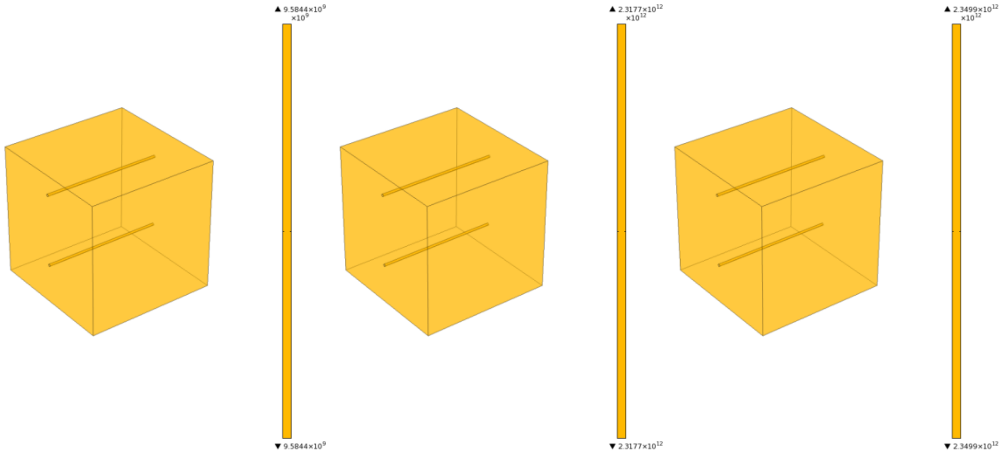
a. Injection time =0s b. Injection time $=4.32\times10^5$s c. Injection time $=8.64\times10^5$s

Fig. 6. Thermal distributions under different heating durations



a. Injection time =0s b. Injection time $=4.32\times10^5$s c. Injection time $=8.64\times10^5$s

Fig. 7. Accumulated productions under different heating durations.



a. Injection time =0s b. Injection time =4.32×10^5s c. Injection time =8.64×10^5s

Fig. 8. Required energy absorbed for temperature increase under different heating durations

Table 2. Production of oil gas under different heating durations.

	Duration ($\times10^4$s)										
	0*	8.64	17.28	25.92	34.56	43.2	51.84	60.48	69.12	77.76	86.4
Accumulative recovery, t	19.35	155.87	186.32	201.28	208.42	211.18	212.33	212.76	212.9	212.93	212.95
Stage recovery, t	19.35	136.52	30.45	14.96	7.14	2.76	1.15	0.43	0.14	0.03	0.02

*The oil gas mass denotes the required mass at time '0' for the radiator to increase the temperature to the target one (873.15K).

Table 3. Required energy for the increase of temperature

	Time($\times10^4$s)										
	0*	8.64	17.28	25.92	34.56	43.2	51.84	60.48	69.12	77.76	86.4
Accumulative energy,10^3kWh	2.66	457.33	558.25	608.06	633.11	643.81	649.22	651.58	652.47	652.61	652.75
Stage energy, 10^3kWh	2.66	454.67	100.92	49.81	25.06	10.69	5.42	2.36	0.89	0.14	0.14

*: The energy denotes the required energy at time '0' for the radiator to increase the temperature to the target one (873.15K).

Application of TGA analysis

To incorporate the fitted accumulative weight-loss rate into the reservoir under different temperatures,the recovery mass at different temperatures, namely the production of oil gas, can be calculated.

The oil and gas mass after weight loss is defined by

$$W = 0.9\times10^3 \times \iiint \phi \eta s_o d_v \qquad (11)$$

where the density of oil is 900kg/m^3, porosity Φ of 0.25, and oil saturate s_0 of 100%. The unit of W is kg.

As seen from Figure 7 and Table 2, the gas recovery at the target temperature of the radiator (873.15K at time of 0) is small. The recovery increase quickly at the stage of constant temperature, e.g. the maximum recovery was obtained on the first day then the recovery decreased significantly and finally the recovery tended to be 0. Equipment to carry out in-situ electric heating can be reused due to the heating efficiency to reach the design temperature in a short time. Equipment for ground treatment of oil, gas and water shall also be reused to enhance the efficiency and reduce the production cost

Required energy of heavy oil to increase temperature through absorption

Based on the specific heat capacity to calculate the energy as

$$Q = cm\Delta T \qquad (12)$$

The energy J required to heat the stratum to certain temperature is defined by

$$Q = 1812\times 0.75\times 2500\times \iiint(T-T_o)dv + 5000\times 0.25\times So\times 900\times \iiint(T-T_o)dv + 4200\times 0.25\times(1-So)\times 1000\times \iiint(T-T_o)dv \quad (13)$$

It can be seen from Figure 8 and Table 3 that the energy required for the temperature increase of the reservoir is the highest at the initial stage and reduces significantly, which finally tends to be 0.

ECONOMICAL ASSESSMENTS

The combination of internal rate of return (IRR) and the net present value (NPV) is adopted to assess the economic feasibility of heavy oil recovery.

The NPV is defined by:

$$\sum_{t=0}^{n}(CI-CO)_t(1+IRR)^{-t} = NPV \quad (14)$$

where IRR is the internal rate of return; $(1+IRR)^{-t}$ is the present value at year t; n is the life time of the investment, year; CI is the incoming cash; CO is the outgoing cash; NPV is the net present value. When NPV is 0, the equation is transformed to the equation of IRR.

$(CI-CO)_t$ is the net cash income at year t. CI is the incoming cash, for instance the sale income of crude oil; CO is the outgoing cash, such as drilling, equipment, materials, fuels, salaries, depreciation, water and gas injection, underground mining, management, maintenance, repair, tax, treatment of water, gas and oil ,marketing, financial expense, etc. Based on the above calculated annual CI and CO, the net cash flow is calculated. Only if the calculated IRR is higher than the bank interest, economic benefit can be acquired in heavy oil recovery. Basically the IRR of 10% is adopted to evaluate the feasibility of a project.

Given the existing well net,100 thousand is required to establish the production line of in-situ electric heating assuming the daily expense of 10 thousand. Based on assumed price of heavy oil (93.7 USD per barrel), density (0.9g/cm^3) and every ton of crude oil equivalent to 7 barrels, the price of every ton of oil is 700USD, equivalent to 4 thousand RMB per ton given the exchange rate of 6.1. Separate IRR and NPV for oil with different saturation degrees can be obtained based on the recovery of heavy oil minus the expense and consumed electric charge (unit of 1RMB/kWh) within a certain period. Figure 9 presents the total recovery of oil gas and consumed electric charge for different recovery durations.

It is seen from Figure 9 that the recovery and electric charge mainly occur at the 1^{st} to 3^{rd} day after the start of heating then decrease quickly till very close to 0;the higher the oil saturation degree, more total recovery of oil gas can be produced with also the higher electric charge. The little difference between the total recovery and the electric consumption indicates the high electric cost. No economic benefit is expected if the drilling expense and ground separation expense for gas, oil and water are considered in in-situ electric heating.

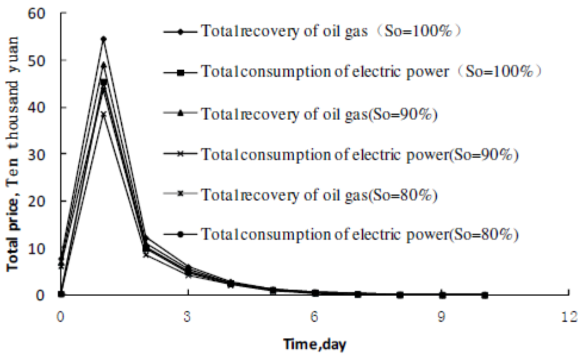


Fig. 9. Total recovery of oil gas and consumed electricity value at different time.

From Table 4 it can be seen that the higher IRR and NPV are associated with higher oil saturation (>90%),whereas for oil saturation of 80%, the NPV flows are all minus which indicates for oil with this saturation degree, no economic benefit is expected by electric heating. Since our current heavy oil reservoirs have been in the post-stage of development and the saturation degree only ranges 20% to 50%, no economic feasibility is expected once this technique is adopted.

Given the oil saturation degree lower than 20%, the required minimum oil price by electric heating on heavy oil reservoir is calculated.

In Table 5 when the NPV is 0, for the acquisition of 10% IRR, equation 14 is incorporated to calculate the oil price, namely 424USD/barrel, which indicates that for oil with 20% saturation degree, it is not economically feasible to carry out in-situ electric heating.

Table 4. Economic comparison among oil with various saturation degrees.

Saturation degree		Duration, day 0	1	2	3	4	5	6	7	8	9	10
100%	NPV*	-2.5	4.9	5.8	5.8	5.3	4.7	4.1	3.6	3.1	2.7	2.3
	IRR		2.223	2.351	2.351	2.345	2.342	2.341	2.34	2.34	2.34	2.34
90%	NPV*	-3.3	5.3	6.5	6.6	6.2	5.6	5.0	4.5	4.0	3.6	3.2
	IRR		1.881	2.019	2.024	2.018	2.015	2.013	2.013	2.013	2.013	2.013
80%	NPV*	-4.1	-6.5	-7.6	-8.4	-9.3	-10.0	-10.7	-11.2	-11.7	-12.1	-12.5

NPV*: that with IRR of 10%

Table 5. Production simulation by in-situ electric heating in heavy oil with 20% saturation degree

	Duration, day 0	1	2	3	4	5	6	7	8	9	10
Recovery, ton	3.9	27.3	6.1	3.0	1.4	0.6	0.2	0.1	0.0	0.0	0.0
Consumed power, kWH	2627.0	448650.8	99583.3	49111.1	24722.2	10555.6	5361.1	2305.6	888.9	138.9	166.7
Total oil production, 10k	6.97	49.15	10.96	5.39	2.57	1.00	0.42	0.15	0.05	0.01	0.01
Amount of consumption, 10k	0.26	44.87	9.96	4.91	2.47	1.06	0.54	0.23	0.09	0.01	0.02
NPV*, 10k	-3.3	**0.0**	**0.0**	-0.3	-1.0	-1.6	-2.2	-2.8	-3.3	-3.7	-4.1

NPV*: that with IRR of 10%

CONCLUSION

a. Put forward a new method of in-situ electric heating, simulation pointed out that in-situ electric heating should be injected into fluids, otherwise little heating effect is expected; recovery of heavy oil is mainly observed on the first 3 days, then decreases quickly and finally tends to be 0. In theory, in-situ electric heating can fundamentally solve the problem of heavy oil exploitation.

b. Simulated the economy feasibility of in-situ electric heating, under the reservoir conditions and prices, in-situ electric heating is not workable.

c. Heavy oil exploitation need to research and development more convenient and more efficient techniques.

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