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NUMERICAL MODELING OF ENHANCED HEAVY OIL EXTRACTION USING GEOTHERMAL ENERGY

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Abstract: Oil has been used in industry, but EGS are novel. It takes technology to generate steam, oil, and power from diverse sources. Geothermal is renewable, the Upper reservoir geothermal and deep reservoir micro-heavy oil systems increase EGS oil extraction. Simulations of EGS and heavy oil reservoir steam injection are examined. Three-dimensional, three-phase numerical models improve heavy oil reservoir EGS/reservoir development and parameter sensitivity. The fracture and plasticity model were utilised to design a new heat transfer control equation for heavy oil reservoirs with steam injection fluid behaviour using thermal fluid properties under change law situations during heavy oil steam flooding contingency building. EGS water-flood recovery numerical modelling optimises thickener-EGS collaboration, reservoir, fracturing, well space, heat removal, and steam injection flooding.

Temperature impacts well spacing, injection, and reservoir permeability. Standard optimisation sensitivity testing aids EGS. EGS field optimisation increases thermal extraction efficiency and energy output by optimising reservoir, fracture, and well spacing. Finally, well-spacing models optimise EGS/heavy oil co-development and secondary steam recovery requires horizontal wells. Another well's surface water steam powers a turbine. Many components of the analysis model can be used to assess and, more importantly, design energy, steam, and oil production potential. The main source of energy is steam from Wells. The steam output is more significant than oil because steam drives energy turbines. After heating the turbine, the steam is injected into the heavy oil reservoir by lowering or increasing the temperature to control the steam temperature of the oil flow. Computer-Modeling Group, Inc.'s reservoir simulation tool, CMG, is used for simulation forecasting to predict better technical and engineering results for energy, steam, and oil. By establishing a strong and stable connection between the enhanced geothermal system (EGS) and enhanced oil recovery (EOR) systems, mathematical models are developed that show initial concentration, fracture length, surface water injection rate, steam production, reservoir energy, and oil production to achieve stable production of energy, steam, and oil.

Keywords: Enhanced Geothermal System (EGS); Enhanced Oil Recovery (EOR); Heavy Oil Reservoir

1. Introduction

1.1.Research field background

Global heavy oil and bitumen reserves, totalling 10 trillion barrels three times that of conventional oil are abundant and driving an increase in world heavy oil production (Butler, 1991). Enhanced cold and recovery procedures produce bitumen and heavy oil along with the foaming oil and wormholes aid cold output *(*Zhang *et al.,* 2011*)*. This approach recovers only a small amount of heavy reservoir oil, but thermal recovery systems enhance oil mobility by reducing its viscosity. Most Canadian thermal operations utilise one-well cyclic steam stimulation, where steam can recover an additional 10–15% of oil. At Cold Lake, Alberta, oil recovery is currently over 25% and is expected to reach 35%. The presence of oil with a viscosity of 1,000 mPa.s aids in steam flooding, which can recover over 30% more oil from the original oil in place (OOIP). In-situ combustion and steam-assisted gravity drainage (SAG-D) are also effective in improving recovery from thick, premium oil reservoirs. For SAG-D to be effective, the reservoir typically needs to be at least 20 meters thick; however, our analysis revealed reservoir thicknesses ranging from 5 to 16 meters, suggesting insufficient thickness for SAG-D in our hypothesis.

Global energy comes from offshore and Low heavy oil output offshore conventional reserves dominate (Samuelsen *et al.*, 1994). It was found that China's Bohai offshore oilfield possesses 85% heavy oil OOIP. The rare Bohai heavy oil exceeds 350mPa and traditional multilateral wells and cold sand manufacture have limited productivity and recovery. Standard methods provide poor single-well production, efficiency, and recovery. Starting in October 2005, the Chinese Bohai oilfield regained 2.8% in March 2010 (Dong *et al.*, 2014; Yu, 2001). More viscous south-facing Bohai blocks rose 1.2%. The past methods were failed to optimise production and oil recovery due to offshore platform running costs and limited operational lifespan, thus, Oil and power production needs inventive recovery (Guo and Su, 2013). Moreover, Cold production and thermal recovery create offshore heavy oil and both relate to offshore heavy oil reservoirs. Chinese onshore and offshore heavy oil production separates offshore oil into two types: Type 2 is heavy oil above 10,000mPa (Xu *et al.*, 2013). Normal heavy oil is Type 1, 350–10,000mPa.

1.1.1. EGS Steam Flood Generator introduction

Similar to onshore heavy oil resources, thermal recovery is essential for offshore heavy oil extraction, but it requires compact and efficient technologies suited for platforms. Cold production limits the extraction of offshore high-viscosity oil, making thermal recovery necessary. The development of offshore oil resources faces stricter criteria due to operational challenges, crane limitations, and limited platform space. Therefore, an offshore oilfield needs a thermal recovery system that can accommodate wide well spacing and effectively manage reserves, all while using a small, lightweight heat generator (Zhou, 2007). The combustion chamber of a rocket engine is where the fuel and air are burned to create steam, flue gas, and high-temperature, pressured air. El for offshore space gazing and eco-friendly high-temperature steam come from EGS. Cold EGS water and seawater desalting equipment exist. EGS production uses water from future water treatment plants. The control system measures steam quality, temperature, and pressure via effusion meters.

2. Method

This research analyses the application of steam injection and EGS integration with an extensive numerical simulation model to assess the efficiency of the processes in increasing oil recovery from heavy oil reservoirs. The study seeks to determine the ability to tune key reservoir variables, including steam injection temperature and well spacing, for recovery.

2.1.Numerical Simulation Model

For the purpose of the quantitative analysis of the processes of geothermal-assisted steam injection, the Computer Modeling Group's STARS software was used. The thermal fluid properties, heat transfer, and fluid flow during the steam flooding operation were modelled in a three-dimensional and three-phase system (Shutler, 1970). The model is especially relevant to the heavy oil reservoir of the Bohai NB35-2S, with inputs such as reservoir depth, permeability, porosity, and formation temperature.

The actual geographical outline of the Bohai NB35-2S reservoir was followed in order to design the grid system. Other essential input parameters, including reservoir depth (1100m), thickness (5-16m) and porosity (30%), were incorporated into the model. The reservoir has an initial oil viscosity of 828mPa·s at room temperature, and the viscosity reduces substantially with an increase in temperature; this makes the use of steam to inject the oil to be recovered as efficiently.

2.2.Experimental Setup and Reservoir Properties

The simulation adopted distances of 100m, 150m, and 200m between the wells to study the impact of the distance between wells on the efficiency of oil recovery. Also, steam injection temperatures of 150°C, 200°C and 250°C have been used to analyse the effect of this process on the reduction of oil viscosity and recovery rates. Furthermore, steam for the injection process involves the stimulation of the reservoir through steamed injection, which heats the oil and hence increases its flow rates through a decrease in its viscosity. The model is designed to determine the influence of temperature on the efficiency of the oil flow at high injection rates. Inject steam into the reservoir continuously, and the oil saturation and temperature distribution are taken periodically.

2.3.Steam Injection Process

The steam flooding process was simulated with different steam injection rates and temperatures from 150°C to 250°C. Based on the simulation, the impact of injection temperature on oil viscosity, reservoir pressure, and oil recovery rates was tested. The process sought to find the thermal parameter in the steam injection that would yield the highest oil recovery with the lowest energy consumption (Willman *et al.*, 1961). The effects of how far wells are from each other on the eventual recovery of the oil were also explored through a sensitive analysis. As shown below, well distances of 100m, 150m and 200m were tried with the results of the oil recovery factor assessed. The research also sought to determine the impact of injection temperatures on steam-oil ratio and production well bottom-hole pressure.

3. Result and Discussion

3.1.Reservoir parameters sensitivity analysis

The improvement is more effective than the steam flooding process, which, while having higher dislodging capability and obvious efficiency, is less optimal overall. By utilising the mathematical reproduction strategy, the study concentrates on various supply boundaries and actual liquid boundaries during the steam flooding process. Oil saturation, the net-to-net proportion, penetrability, porosity, and the proportion of vertical porousness and even penetrability are taken into clarification. This review used the business mathematical test system CMG STARS® (PC Demonstrating Gathering Ltd.) to streamline the steam infusion process in the heavy oil repository. The primary test in creating and delivering from heavy-oil arrangements is the additional high consistency of the oil (bitumen) set up, whether steam flooding is applied to heavy or light oils and high or low penetrability repositories, the overall systems continue as before.

3.2.Optimisation in steam injection in heavy oil recovery

The presence of mobile water in the fractures provides a potential opportunity for steam-driven recovery processes, such as thermally assisted gas/oil gravity drainage (TA-GOGD) (Alpak and Karanikas, 2020) or an effective subsurface combination of in-situ-upgrading process (Alpak *et al.*, 2013; Perez–Perez *et al.*, 2019) and steam-heating processes referred to as the steam recovery process. The main driver for developing a steam and oil recovery process is to improve the energy balance and enhance the performance of the in-situ-upgrading process scheme.

The steam process can potentially arise as a more efficient alternative to the standalone in-situ-upgrading process for the reasons discussed here. The concept of a hybrid steam/electricity system has been used in the power generation industry for decades. A typical example is the co-generation steam/electricity system in which optimal system efficiency is achieved by producing steam and electricity at the same time. It is important to remember that steam alone can heat the formation to steam temperature (approximately 150-200^{o}C), which is lower than the IUP temperatures (>320^{o}C). Here, the study has to distinguish between the onset of thermal cracking (and associated reduction in bitumen viscosity) and the upgrading process. It is well-known in the literature that carbon bond cracking reactions start at temperatures lower than 300^{o}C (Ovalles, 2019).

3.2.1. The EOR processes of steam flooding

(1) Hot-water flooding-steam quality, like conventional water flooding, can help maintain reservoir pressure and supplement displacement energy. (2) Heating and viscosity reduction as temperature rises, the viscosity of heavy oil lowers considerably, reducing viscosity inform on and therefore improving areal sweep efficiency. (3) Reduced mobility ratio as oil viscosity falls, the mobility ratio between oil and water drops, allowing oil to flow more freely. (4) Improved vertical sweep proficiency infused steam specially streams to the upper layer of the reservoir because of its lower thickness, while infused steam can convey the held heat of steam to the base district under gravity because of its higher thickness, in this way further developing the repository's upward clear productivity. (5) Formation pressure recovery is made possible by the thermal expansion of rock and fluid, which is produced by injecting hot water into a reservoir. This impact is less noticeable in reservoirs heated by steam injection. Because rock and fluid thermal expansion is significantly more significant. (6) Changes in relative permeability and wettability polar compounds like asphaltene and colloid are not absorbed on the rock as the temperature of the water rises. The remaining oil saturation decreases as the rock surface becomes more hydrophilic.

3.2.2. Effects of well distance and temperature on oil recovery

Figure 1 shows the results of the impact of well distance on oil yield. The discoveries of three distinct injector-maker distances, 100m, 150m, and 200m, show that the more limited distance brought about higher oil recovery than the bigger distance. Notwithstanding, as you move further away from the source, the temperature decreases. The creation proficiency and recovery factor (RF) through different infusion rates going from 100 to 200 m^3/d are investigated by an established model to expect improved in fact and stable accomplishment since the temperature is one of the critical boundaries that influence the improvement impact of viscous oil. Temperature affects oil viscosity, making it easier to recover oil via steam flooding because the viscosity reduces substantially as the temperature increases. The study predicts the oil flow efficiency by injecting steam at different temperatures, such as 150°C, 200°C, and 250°C.

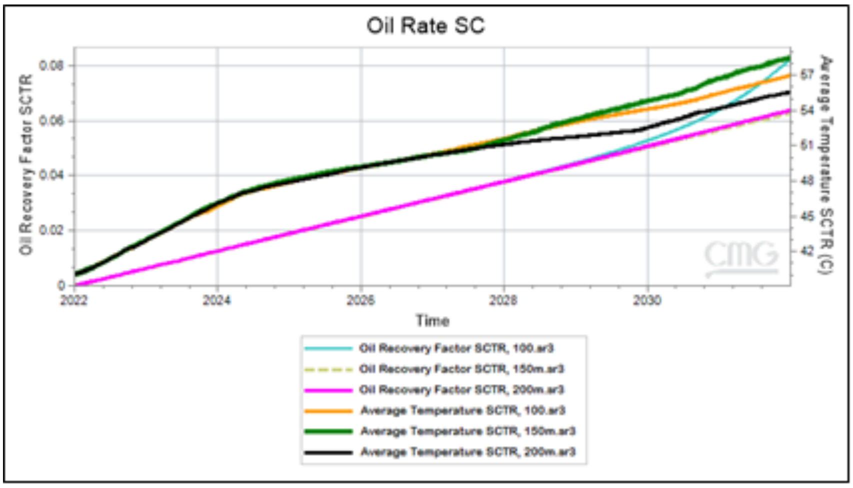

Figure 1. ***Effect of well distance on reservoir temperature and oil recovery factor steam injection***

3.2.3. Sensitive analysis of steam injection of 150°C, 200°C and 250°C in a well distance of 100m model

When the steam temperature is optimized and kept at 250°C, the steam flooding can obtain the best oil recovery, and the lowest oil rate SC can achieve by steam flooding 150°C, but after considering bottom-hole pressure and cumulative oil from **Figure 2**, the stale flow rate of oil can be achieved from the steam temperature of 150°C among 200°C and 250°C. The optimal conversion point occurs when the steam injection's oil recovery reaches the last stags, indicating that steam flooding can prolong the oil production phase and increase oil recovery beyond the intended time frame.

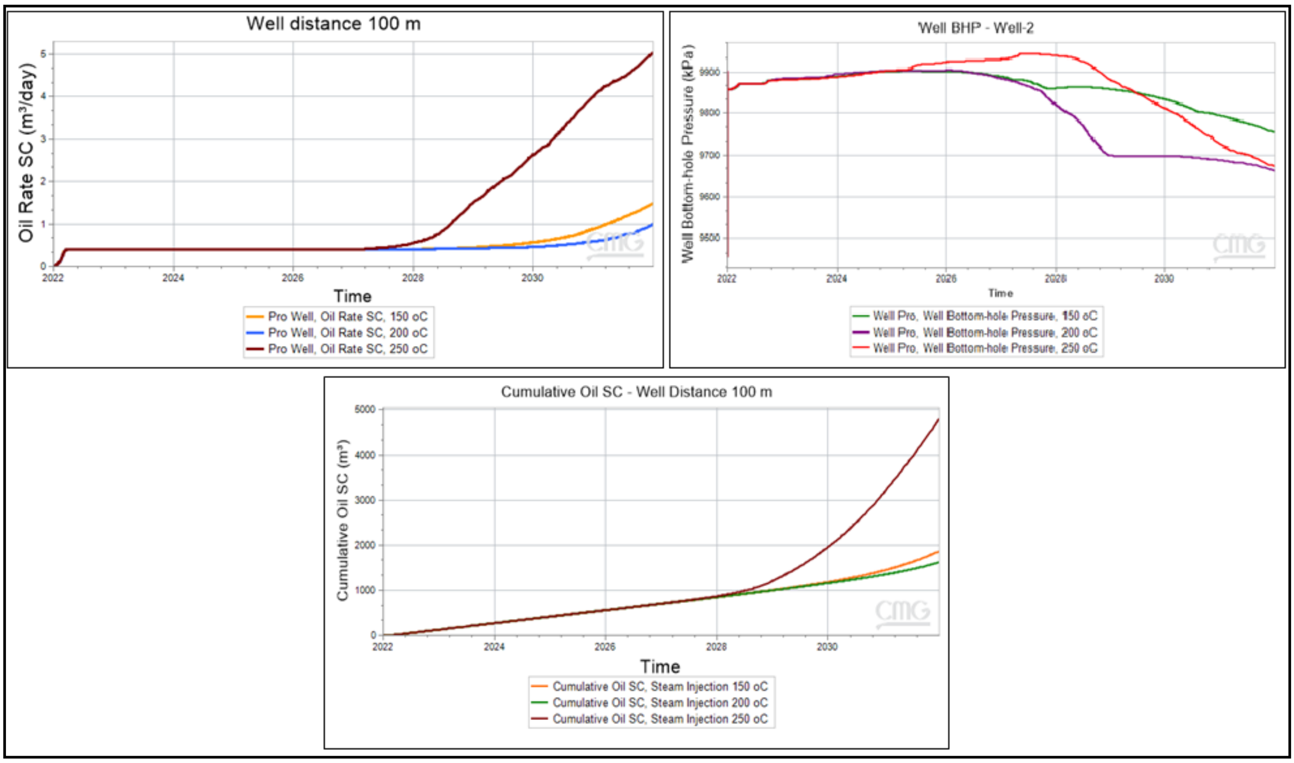

Figure 2. ***Daily oil rate, Production well bottom-hole pressure, and Cumulative oil production of model well distance 100m with 150 ºC, 200 ºC, and 250 ºC***

3.2.4. Sensitive analysis of steam injection of 150ºC, 200ºC and 250ºC in a well distance of 150m model

This section compares and evaluates the efficiency of various temperature rates in a 150m well model. At temperatures of 150ºC, 200ºC and 250ºC, three models are assessed, and the well bottom-hole pressure, cumulative oil output, and daily oil production are all compared. As depicted in the **Figure 3**, changing the injection steam temperature did not influence cumulative oil SC. It also shows that steam flooding increases the daily oil rate at 150ºC, 200ºC and 250ºC. Also, the graph shows that steam flood heat does not affect the output rate. **Figure 3** shows that after a while, stable oil production can be obtained by well steam flooding with 150ºC and stable and decreased bottom-hole pressure.

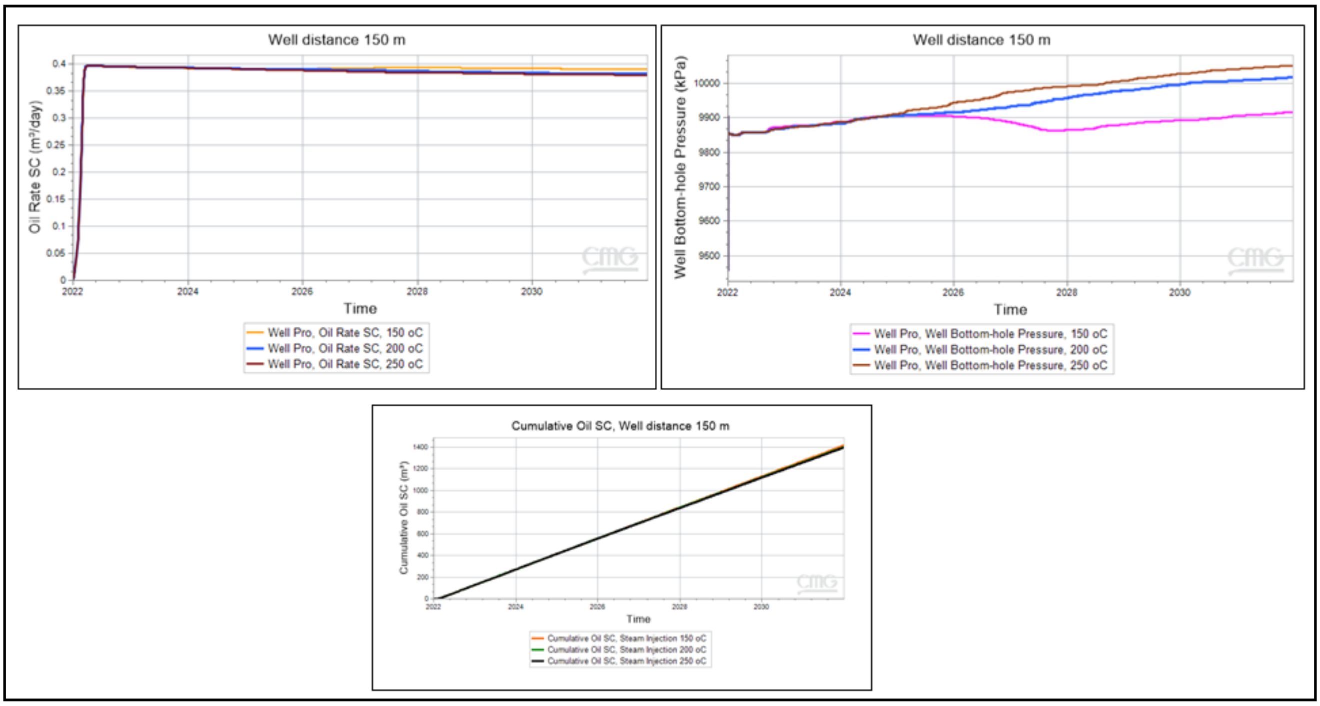

Figure 3. ***Daily oil rate, Production well bottom-hole pressure, and Cumulative oil production of model well distance 150m with 150 °C, 200 °C, and 250 °C***

3.2.5. Sensitive analysis of steam injection of 150°C, 200°C and 250°C in a well distance of 200m model

The effectiveness of various temperature rates in the model of a reasonable distance of 200m is compared and analysed in this section. Three models are considered, with temperature rates of 150°C, 200°C, and 250°C. The simulation time is set to 10 years; however, the effective period may vary depending on the results of each model. The three variables are compared i.e. cumulative oil output, daily oil production, and production well bottom hole pressure.

Figure 4 represents the cumulative oil production rate while considering temperature rates of 150°C, 200°C and 250°C. They also depict the daily oil production rate with steam injection temperatures of 150°C, 200°C and 250°C. This chart also shows that the difference in steam flood heat did not affect the output rate. The figure also shows the production well bottom hole pressure for a model well distance of 150m and a steam flood heat rate of 150°C, 200°C and 250°C. The bottom-hole pressure increases as the steam heat rate increases. As shown in figure, the cumulative oil production rate did not change significantly when the injection steam temperature was changed.

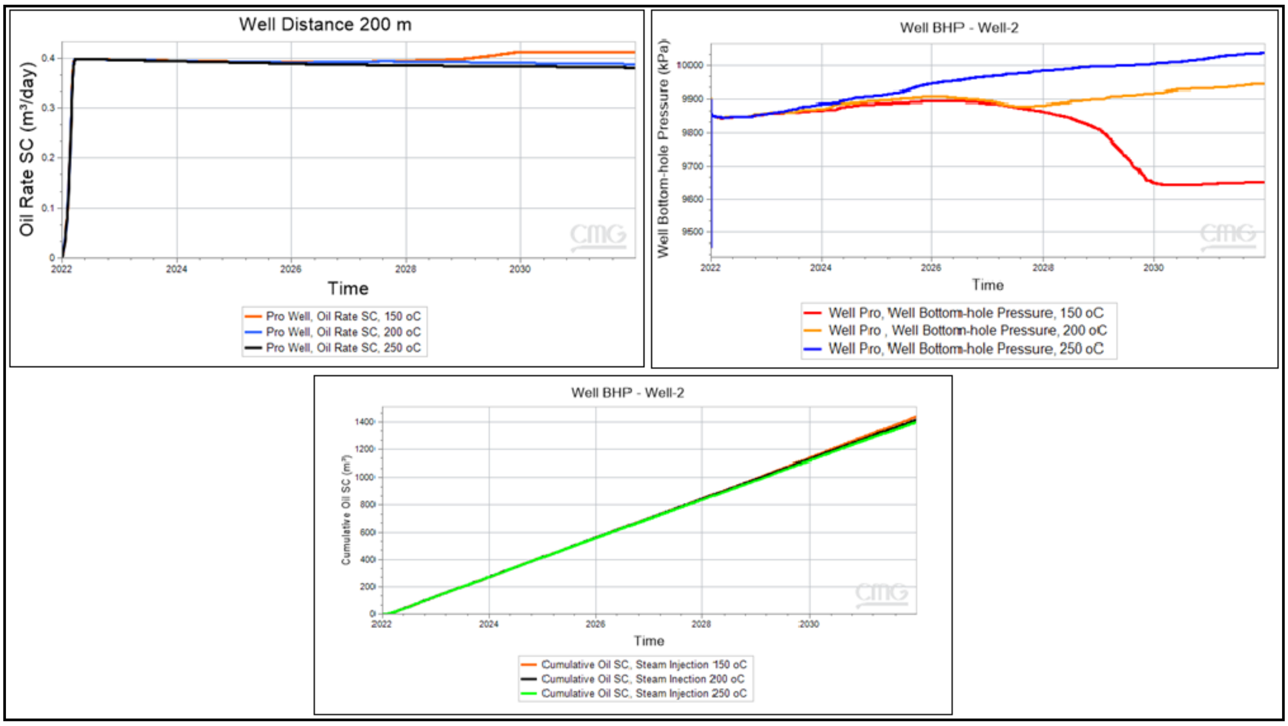

Figure 4. ***Daily oil rate, Production well bottom-hole pressure, and Cumulative oil production of model well distance 150m with 150°C, 200°C, and 250°C***

4. Experimental Section

4.1.The study of the application of steam flooding in real operation

Almost 85% of the OOIP (original oil in place) in the Bohai seaward oilfield is heavy oil. Contrasted and the standard steam stimulation are generally basic. It typically manages heating to decrease consistency, changing rock wettability and expanding oil penetrability. In light of the qualities of the Bohai heavy oil repositories, we assess the impacts of viscosity, supply thickness, porousness, and oil saturation to analyse the creation effectiveness and repository flexibility states of these two thermal recovery systems. Under different circumstances, we make a mathematical simulation model to foresee the creation of a productivity steam flooding feeling.

4.1.1. Parameters of the numerical simulation model

The key parameters mentioned further below (see **Table 1**) of the Bohai reservoir are important to model and match the actual properties of the reservoir. For instance, depth of 1,100 meters, viscosity of 828 mPa.s, thickness of 5-16 meters and porosity of 30% was chosen. These characteristics affect the oil's mobility, as well as extraction rates during steam flooding. To this end, the described metrics were incorporated into the simulation and the hope is to obtain realistic energy production rates and efficient recovery.

Table 1. ***The basic physical parameters of the NB35-2S reservoir***

Properties	Reservoir	Properties	Reservoir
Reservoir depth (m)	1,100	Initial oil saturation	0.647
Thickness (m)	5-16	Reservoir Compressibility (kPa^{-1})	1.16×10^{-6}
Porosity (%)	3,000	Dead Oil density (m^3/kg)	955.98

Horizontal permeability	2300-11000	Oil viscosity (mPa.s @R.T.)	828
Vertical permeability	120-1100	Water/oil net ratio* (decimal)	0.3
Formation temperature (°C)	56	Formation pressure (MPa)	1.6×10^{-5}

4.1.2. Grid system of model

This model employs a three-dimensional grid system (see **Figure 5**) which corresponds with the geographical arrangement of the Bohai reservoir; an essential characteristic of any model of the Bohai reservoir. This is feature allows for detailed study of the granular analysis of heat and fluid flow dynamics within the reservoir. In particular, it’s used to monitor variations in temperature distribution and oil saturation due to the effect of steam injection over time. The grid system allows the study to analyse the reservoir performance when changed, for example, the distance between the wells and rates of the steam injection toward optimum extraction techniques.

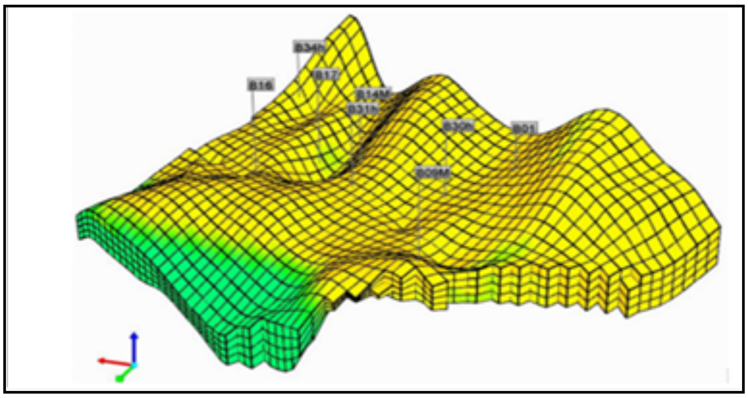

Figure 5. ***Bohai (NB35-2S) heavy oil reservoir in three-dimensional (3D)***

4.1.3. The basic physical parameters of the Bohai reservoir

The heavy oil reservoir Bohai's usual geographical limits were used to calculate the reservoir's depth, thickness, porosity, and permeability, and their results are shown in **Table 1**. **Figures 6** depict the oil viscosity vs temperature and permeability while considering the fluid properties of the heavy oil reservoir NB35-2.

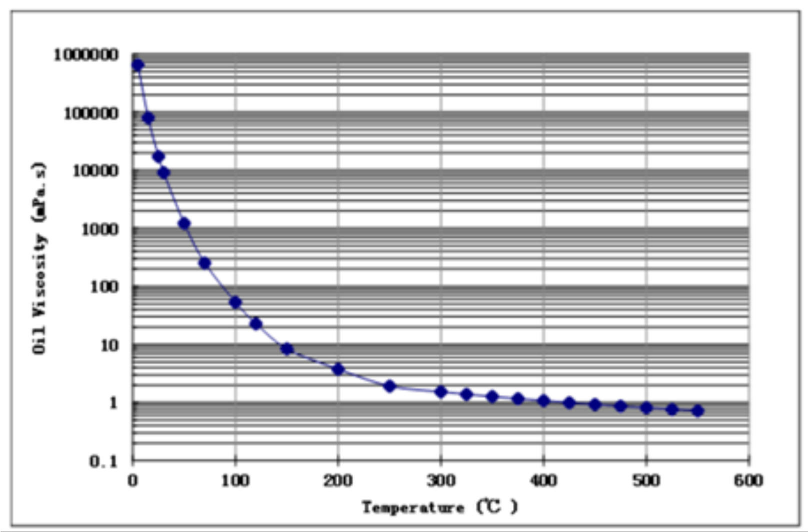

Figure 6. ***Crude oil from the NB35-2S reservoir viscosity vs. temperature curve (Dong et al., 2015).***

This curve reveals that oil viscosity reduces as temperatures raise; therefore, the process of steam injection is effective as it prompts oil mobility. Particular attention is paid to the effect of temperature on the viscosity of oils the videos also illustrate how heat helps to thin down oil and thus facilitate its movement in the reservoir. The research also shows that even though a pressure is directed towards the component, its viscosity reduces with increase in temperature from 150°C to 250°C enhancing the extraction performance of the oil. This is important for the verification of steam injector as a crucial thermal recovery technique particularly in the high viscosity reservoirs. This gives practical information as to why particular temperatures must be employed throughout lubrication of oils and demonstrates how enhanced mobility of oil can be achieved by thermal management with increased flow rates.

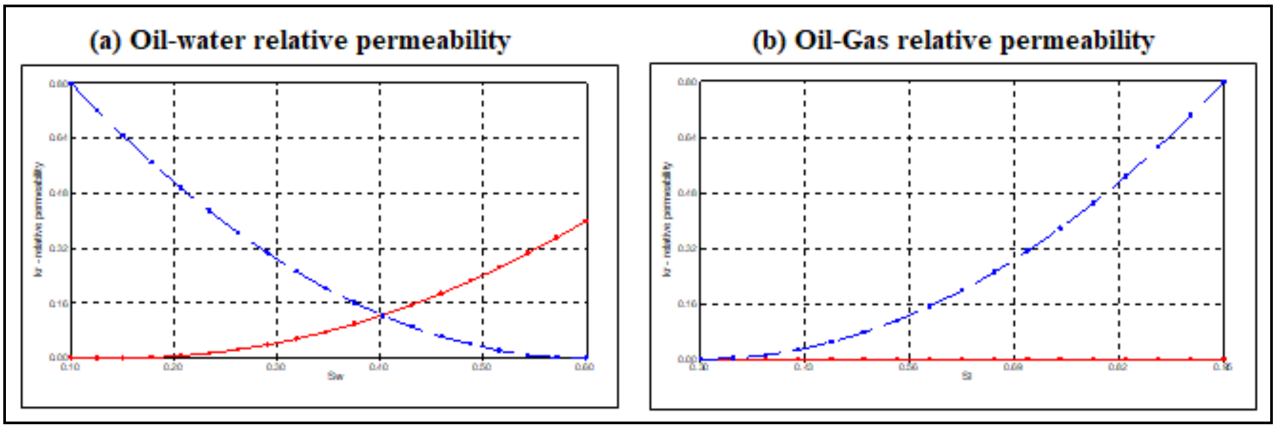

Figure 7. ***Relative Permeability Curves***

Also in **Figure 7**, permeability is analysed as it reveals how such factors as the horizontal and the vertical permeability affect the flow and rates of oil recovery. The curves demonstrate how steam alters the flow behaviour of fluids; injected steam alters both oil-water and oil-gas permeability, enhancing efficiency of recovery. Instead, it changes the relative permeability in a manner that boosts steam displacement of oil, which is crucial for the uplift of the recovery rates. They are essential in simulating fluid flow, hence important in exploring the part played by the steam on the reservoir behaviour. This detailed study offers the first level of information necessary for simulating the reservoir's behaviour to steam flooding and also assists in improve details for optimum performance.

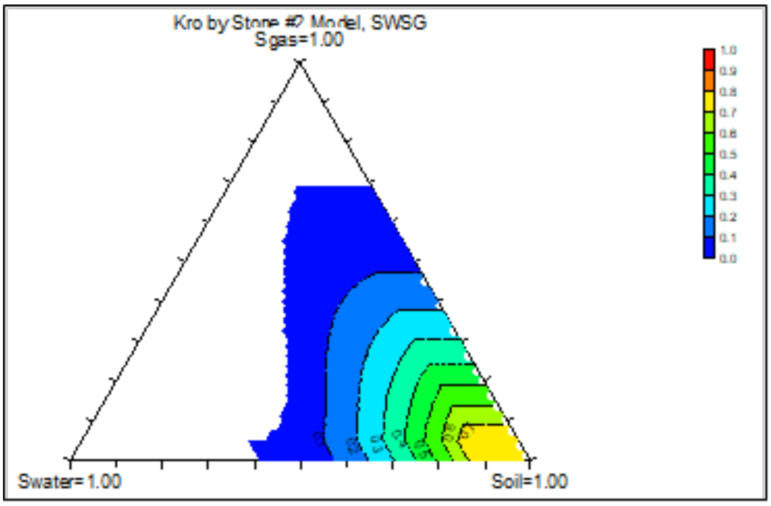

Figure 8. ***Oil, water and gas saturation model***

The saturation model as shown in **Figure 8,** illustrates the distribution of oil, water and gas in the reservoir. This model is essential for understanding how the movement of these fluids will occur when it is undergoing steam injection. Analysing saturation, the study can predict where and to what extent steam is going to replace oil and influence oil production. Hence, the saturation model becomes an integral part in the construction of the simulation, and due to its nature, it offers information pertaining to the proportion of oil that can be produced by the injected steam as well as the fluctuation of the reservoir saturation over time.

5. Conclusions

This study examines the performance of steam production for energy purposes and steam flooding to displace traditional heavy oil following steam injection. The following conclusions can be drawn based on the actual data field and numerical simulation findings. In a computer modelling group (CMG-IMEX), a typical HDR reservoir with low porosity and permeability was created to induce hydraulic cracks. In a suggestion to regenerate the effects of heat transfer and assess the quantity of energy produced by the reservoir, the IMEX model was converted to STAR. Both models include two wells, a surface water injector and a hot water producer. It is essential to consider varied fracturing half-lengths and rates of surface water injection when assessing the amount of energy generated. For the next ten years, the energy generated will be measured for two purposes (energy and oil production).

The optimal site or placement of injection and production wells for geothermal reservoirs has been determined by considering the highest possible energy output. The ideal temperature for the water is 150°C. Steam flooding is most effective for oil recovery and reducing residual oil saturation when the steam temperature is kept at 150°C. According to computer simulations, steam flooding to a neighbouring production well can still sweep huge amounts of leftover oil from the injection well during the latter stages of steam injection. When the oil recovery of steam injection reaches 24%, this is the optimal time to convert. It is possible to increase oil recovery by extending production with steam flooding. The steam flooding procedure is an effective method for extracting oil due to the low permeability variation coefficient of the Bohai oilfield's thin, heavy oil reservoirs. Steam flooding is beneficial in reservoirs with reverse and compound cycles but detrimental in reservoirs with positive time signatures due to gravity.

After optimising the same model with the previously specified factors, such as well distance, different steam injection temperatures, injection placement, and horizontal well production, a sufficient modification was considered to achieve a steady outcome in both steam and oil production. Thermal oil recovery is the most prevalent technique for tertiary oil recovery. Thermal EOR typically involves the injection of steam. It yields 30% of the initial oil. Other EOR techniques may be just as hazardous as steam injection. This permits deployment in countries with strict regulations.

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