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Full Length Article

Improving Steam-Assisted Gravity Drainage performance in oil sands with a top water zone using polymer injection and the fishbone well pattern

Xiang Zhou [a], Fanhua Zeng [a,*], Liehui Zhang [b]

[a] Petroleum Systems Engineering, Faculty of Engineering and Applied Science, University of Regina, Regina, Saskatchewan S4S 0A2, Canada
[b] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, Sichuan 610500, PR China

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ABSTRACT

In western Canada, a significant number of oil sands reserves have little or no cap rock with a top water zone. Due to huge heat loss to the top water zone, the conventional Steam-Assisted Gravity Drainage (SAGD) process is uneconomical when applied directly in this type of reservoir.

In this study, it is proposed that a high temperature polymer solution can be injected into the bottom of the top water zone to establish a stable high viscosity layer that will prevent steam from leaking into the top water zone. In order to select a suitable polymer that has stable viscosity under high temperature, the viscosities of different polymer solutions at different temperatures were measured and the concentration of the selected polymer solution was optimized. Furthermore, in order to extend the connection area between the oil sands and the steam chamber, the fishbone well pattern was applied instead of the single well pair pattern.

Numerical simulations were performed to evaluate the feasibility of using the selected polymer in the fishbone well pattern to improve SAGD performance in oil sands with a top water zone. The numerical simulation model was based on a typical Athabasca oil sands reservoir. In this study, the effects of steam injection pressure, polymer solution injection time, steam injection rate, and different fishbone well patterns on the performance of the SAGD process were studied and optimized.

The numerical simulation results suggest that the fishbone well pattern could extend the steam distribution and that polymer injection is able to prevent heat from leaking into the top water zone. Compared to the conventional SAGD process in an oil sands reservoir with a top water zone, the optimal case using a one-fishbone well pattern and polymer injection could enhance the oil production significantly. Under these conditions, the oil recovery factor in this study increased from 10.58% to 59.02%; the cumulative steam oil ratio decreased from 10.44 m^3/m^3 to 3.85 m^3/m^3; and the cumulative injected energy oil ratio decreased from 24.00 GJ/m^3 to 8.87 GJ/m^3. This indicates that the SAGD process with the one-fishbone well pattern and polymer injection is able to improve SAGD performance in oil sands with a top water zone.

1. Introduction

The production potential of heavy oil and bitumen in Alberta, Canada, is high [1]. The original heavy oil/bitumen in place is 1.7 trillion barrels [2–4]. A significant amount of this oil/bitumen is contained in reservoirs with a top water zone, for instance, reservoirs in Surmont leases, Kearl Lake and Wabiskaw-McMurray deposit [5–8].

The SAGD process has been approved as a leading technology for the in-situ recovery of heavy oil and bitumen [9–12]. However, the efficiency of the SAGD process for reservoirs with a top water zone is too low to make this process economical. The reason for this is that the existence of a top water zone can result in significant water influx into the steam chamber [13] and tremendous heat loss from the steam chamber into the top water zone, such that it significantly reduces the thermal efficiency.

Some experimental and numerical simulation studies have been conducted to analyze fluid flow behaviors and study the relationship of the oil recovery factor (RF) and heat loss for reservoirs with a top water zone. Nasr et al. conducted 3-D laboratory

* Corresponding author.
E-mail address: fanhua.zeng@uregina.ca (F. Zeng).

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experiments for the SAGD process by using an elemental physical model with a top water zone [14]. They concluded that about 10% of the initial oil in place moved into the top water zone. Furthermore, steam penetrated into the top water zone, leading to great amounts of heat loss. Based on their laboratory experiments, Law et al. developed lab scale numerical simulations [15]. In their study, by using the well-history-matched model, they concluded that the higher-pressure differential between the steam chamber and the top water zone resulted in more oil and steam movement into the top water zone. This led to less oil production and a higher cumulative steam oil ratio (cSOR). Law et al. posited that the results from the field scale numerical simulation also showed that the higher-pressure differential between the two zones led to a lower RF and greater SOR [16]. Therefore, the field simulation results indicated the numerical simulation captured the major mechanism of oil movement from the oil zone into the top water zone, as observed in the experiments. In addition, Bao et al. indicated that a higher injection pressure caused an earlier steam breakthrough into the top water zone and the water draining into the steam chamber [17]. Moreover, they optimized the subcool temperature at 10–30 °C in their study.

Different techniques have been proposed to improve the performance of the SAGD process for reservoirs with a top water zone. Gao et al. conducted a numerical study on N_2 co-injection into a reservoir with a top water zone [18]. They concluded that N_2 would mainly distribute in the upper part of the steam chamber and form an insulating layer, which would reduce the heat loss to the top water zone. Although the highest oil RF in their study by reached 43.7%, the thickness of the effective N_2 layer was 10–15 m, which was beyond the limit in the studied reservoir. Alturki et al. studied the ES-SAGD process on the reservoir with top water zone [19]. In their study, the ES-SAGD with solvent co-injection achieved good production performance in which the highest RF was over 85%. However, the thickness of the top water zone in their study was only 5 m, which was much smaller than the thickness in this study.

Alturki et al. developed a numerical model, which consisted of a top water zone beyond an oil pay zone [20]. During their study, different injection pressures were simulated in a model where methane was injected into the reservoir along with steam to help reduce the relative permeability to water. From this study, they found that, the larger the top water zone, the lower the RF, and therefore, the lower the profitability of the SAGD process. Furthermore, the injected methane not only reduced the relative permeability to water, but it also reduced the relative permeability to bitumen at the edge of the steam. The highest RF in the study by Law et al. was around 30% [15], which was much lower than that in the traditional SAGD process (40–60%) [21].

Many lab tests [22–24] and field tests [25–27] reported that, with polymer injection in the heavy oil reservoir, oil production performance improved remarkably. Also, the application of polymer in a heavy oil reservoir is mainly focused on the polymer flooding process, owing to the higher viscosity of the injected polymer solution that can significantly increase heavy oil mobility [28,29]. The application of polymer injection in the SAGD process has not yet been studied, especially when it is used as a layer to prevent steam invasion.

The fishbone well pattern has high potential for enhancing oil production in the oilfield because its branches increase the contact area between the wellbore and oil formation and make it easier for oil to enter the wellbore or for fluids to be injected into the reservoir [30,31]. Fipke and Celli discussed the concept of using fishbone wells in a heavy oil reservoir and concluded that it can be a more practical way to improve the recovery factor of intended heavy oil reservoirs [32]. Gu et al. showed that, with the right direction of the fishbone well, steam stimulation can achieve the best production effect [31]. Zhou et al. studied fishbone wells in an offshore oilfield and gained a preferable exploitation performance compared to the conventional well pattern [33]. However, the application of the fishbone well pattern with polymer injection in an oil sands reservoir with a top water zone has not been reported.

In this study, it is proposed that high temperature polymer could be injected into the bottom of the top water zone to establish a stable high viscosity layer. The purpose of this layer would be to prevent steam from leaking into the top water zone. Also, fishbone wells are suitable for this thin reservoir [34], and different fishbone well patterns and injection rates were studied. Based on the Athabasca oil sands reservoir, numerical simulations were performed to evaluate the feasibility of using the selected high temperature polymer to improve SAGD performance in oil sands with a top water zone. From the simulation results, the best production performance occurred in the one-fishbone well pattern with the polymer injection process under the injection rate of 1200 m^3/d. The oil recovery factor (oil RF), cumulative steam oil ratio (cSOR), cumulative injected energy oil ratio (cEOR), which was defined as the cumulative injected energy (including the energy injected into the reservoir during the preheating process and that in the injected steam) divided by the cumulative produced bitumen volume, and the heat loss to top water zone ratio (cHWR) were 59.02%, 3.85 m^3/m^3, 8.87 GJ/m^3, and 38.15%, respectively. However, in the conventional SAGD process in the studied reservoir, the oil RF, cSOR, cEOR, and cHWR were 10.58%, 10.44 m^3/m^3, 24.00 GJ/m^3, and 49.32%, respectively.

2. High temperature polymer

High molecular weight water-soluble polymers in dilute concentrations increased the water viscosity significantly [35], and the polymer solution, which was injected into the bottom of the top water zone, increased the viscosity and reduced the mobility of water in the bottom of the top water zone. In the SAGD process, the viscosity of bitumen is reduced significantly after being heated by the injected steam, as shown in Fig. 1, and the mobility of heated bitumen is increased remarkably. This indicates that, if the mobility of the injected polymer solution is lower than that of the heated bitumen, the injected polymer solution can be an obstacle to prevent the heated bitumen and steam from invading the top water zone.

In this study, the viscosities of three kinds of polymer solutions under different temperatures were studied. The polymers

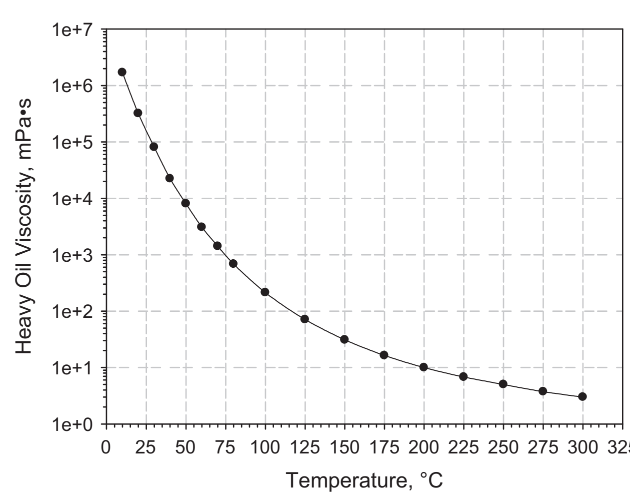

Fig. 1. Bitumen viscosity reduction with temperature increasing.