Fuel 153 (2015) 559–568

Contents lists available at ScienceDirect

Fuel

journal homepage: www.elsevier.com/locate/fuel

On hot water flooding strategies for thin heavy oil reservoirs

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HIGHLIGHTS

- In Western Canada, ~80% of heavy oil resources are in reservoirs <6 m thick.
- Cold production has low recovery factor, <10%, for thin heavy oil reservoirs.
- Recovery strategy of thermal processes is unclear in thin heavy oil reservoirs.
- Optimization yields variable injection pressure/temperature hot water flood.
- Permeability distribution controls energy-to-oil ratio and economic performance.

ARTICLE INFO

Article history:
Received 31 January 2015
Received in revised form 10 March 2015
Accepted 11 March 2015
Available online 21 March 2015

Keywords:
Heavy oil
Hot water flood
Thin reservoirs
Optimization
Thermal efficiency
Recovery process design

ABSTRACT

Cold production methods for heavy oil resources in Western Canada yield recovery factors averaging about 10% and as yet, there are no commercially successful technologies to produce oil from these reservoirs with recovery factor greater than 20%. This means that the majority of oil remains in the reservoir. The objective of this study is to determine technically and economically feasible recovery processes for thin heavy oil reservoirs by using a simulated annealing algorithm. The results reveal that high injection pressure is critical to a successful hot water flooding strategy. Also, they show from a thermal efficiency point of view that it is most efficient to adopt an injection temperature profile where the injection temperature starts high earlier in the process and ends at lower water temperature. The lower temperature injection at later stages of the recovery process partially recovers the heat stored in the reservoir matrix and therefore increases the overall heat utilization efficiency. A sensitivity analysis shows that the permeability distribution affects the performance of the hot water flooding process most significantly. The existence of a higher permeability zone in the lower part of the reservoir leads to earlier oil production and water breakthrough. High permeability was found to lead to more oil and water production in the early stage of operation and achieved the best economic performance. The low permeability case exhibited relatively low oil production volume. Although it has the lowest cumulative injected energy to oil produced ratio, poor oil production renders the operation process uneconomic. Given the volume of currently inaccessible thin heavy oil resources, the optimized strategies developed here provide important guidelines to convert these resources to producible reserves.

1. Introduction

The majority of heavy oil resources, roughly 1.3 trillion barrels of oil, in the Western Canada Sedimentary Basin are found in thin reservoirs with thickness less than 6 m [1]. Due to heat losses to the overburden or understrata or both, current commercial steam-based techniques such as Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) are not economically feasible in thin heavy oil reservoirs (<6 m). In these processes, in thin reservoirs, the amount of steam invested in the reservoir versus the oil revenues renders the processes uneconomic. In cold production (CP) processes, the only energy input is that of the pump to move the produced fluids from the reservoir to the surface; thus their energy investment is relatively small. However, the average recovery factors of cold production processes are low being equal to about 10% [1]. By encouraging sand production along with oil recovery, the Cold Heavy Oil Production with Sand (CHOPS) technique can recover as much as 15% of the OOIP [2]. In CHOPS operations, sand production creates an extensive connected wormhole network in the reservoir with zones adjacent to the network depleted of reservoir pressure [3].

In Western Canada, after primary production, in most cases, water flooding and polymer flooding have been the most widely

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http://dx.doi.org/10.1016/j.fuel.2015.03.024
0016-2361/

used techniques to raise the overall recovery factor of the reservoir [4,5]. In heavy oil reservoirs, due to the high viscosity of the oil versus that of the water, flooding processes may suffer with respect to water bypassing [4–6]. In most cases, the viscosity of the live oil ranges from 1000 to 10,000 times that of water which implies water fingering occurs. Despite this, water flooding has been actively applied in Saskatchewan and Alberta since it is technically simple to implement and has relatively low operating cost even though incremental oil recovery factors are not significantly larger than primary production.

Solvent-aided thermal recovery methods have also been proposed for bitumen and heavy oil reservoirs. For example, Gates [7] examined a solvent-aided thermal recovery process for thin oil sands reservoirs by using optimization. The optimized process had lower net energy (both steam and solvent retained in the reservoir) to oil ratios compared to traditional SAGD. Solvent-only processes, such as cyclic solvent injection, have advantages in that there are no heat losses to the surrounding overburden and understrata. These methods appear to have promise for use in post-CHOPS reservoirs [8,9].

Hot water flooding is a relatively low cost thermal oil recovery technique [9] since it only involves sensible heat. Compared with conventional water flooding, the use of hot water improves the mobility ratio due to a reduction of the oil phase viscosity arising from it being heated. Furthermore, heating also reduces the interfacial tension and residual oil saturation which both lead to potentially higher recovery factor. However, in hot water flooding, the heated water for injection delivers less heat to the reservoir compared to that with steam due to absence of latent heat and therefore it is less effective in reducing oil viscosity. On the other hand, for thin heavy oil reservoirs, hot water flooding has advantages over steam flooding. First, it provides larger displacement drive than steam flooding since water viscosity is much larger than that of steam [9–11]. Second, it permits the use of much higher injection pressure than steam flooding at a given temperature. Furthermore, higher-pressure injection enables greater temperatures while remaining in the hot water state. Third, due to smaller reservoir temperature, heat losses to the overburden and understrata will be substantially smaller than that encountered in steam flooding. However, less heat losses to the overburden and understrata will mean less heat delivery to the heavy oil interval. Martin et al. [10] describe the results of hot water injection into a 5–7 m thick sandstone reservoir containing oil with viscosity equal to 600 cP. They found that water injectivity and oil rates were significantly enhanced over that of cold water flooding. However, although they did not have detailed thermocouple observation wells, they concluded that 60 percent of the injected heat was lost to the overburden and understrata. Thus, there is a need to design hot water recovery processes for thin reservoirs that manage heat delivery and recovery to and within the reservoir.

In the study documented here, hot water-flooding strategies are optimized by using simulated annealing, a stochastic optimization algorithm. We aimed to understand the effects of injection pressure, water temperature, as well as different reservoir conditions on the recovery process performance.

2. Models and methods

2.1. Reservoir simulation model

The reservoir evaluated here has properties typical of that of a typical thin heavy oil reservoir in the Lloydminster area of Alberta, Canada described in a previous study [12]. The base case reservoir model is two-dimensional with two horizontal wells spaced 50 m apart. The thickness of the heavy oil interval is equal to 4 m thick. The models were discretized into a regular Cartesian grid, displayed in Fig. 1, with dimensions 1 m in the cross-well direction, 1000 m in the down-well direction (into the page) and 0.4 m in the vertical direction. The length of the perforated sections of the horizontal wells in all models is equal to 1000 m. A commercial thermal reservoir simulator (CMG STARS™) was used. The commercial thermal reservoir simulator uses the finite volume approach. At the top and bottom boundaries, heat losses were permitted and were approximated by using Vinsome and Westerveld's [14] heat loss model. At the side boundaries of the model, no flow and no heat transfer boundary conditions were applied.

The reservoir simulation model and fluid properties are listed in Table 1. The relative permeability curves, listed in Table 1, are independent of temperature. The spatial distributions of oil/water saturations (average oil saturation equal to 0.65), porosity (average equal to 0.32), and base case horizontal permeability (average equal to 3650 mD) are, displayed in Fig. 1(a)–(c), respectively. The average oil saturation, porosity, and horizontal permeabilities were derived from core data taken from one of Devon Canada's heavy oil fields located in eastern Alberta. The spatial distributions of the porosity, oil saturation and base case permeability (described below) were randomly assigned using uniform probability distributions. Given that the sand is relatively clean, the vertical-to-horizontal permeability ratio is set equal to 0.8. The initial reservoir pressure and temperature are equal to 2800 kPa and 20 °C, respectively. The solution gas-to-oil ratio at original reservoir conditions is equal to 6.17 m^3/m^3.

To investigate the effect of permeability and its variations on the reservoir performance, five permeability cases were optimized (including the base case). These cases were chosen to span the range of reservoir characteristics that are typical in thin heavy oil reservoirs in Western Canada.

Case 1: This is the base case reservoir model with permeability distribution as shown in Fig. 1(c). The average permeability is equal to 3650 mD. This case represents the expected permeability case in the study conducted here.

Case 2: In this case, a permeability distribution is created with the same average permeability of Case 1 (3650 mD) but enhanced permeability at the bottom and lower permeability at the upper zone, as shown in Fig. 1(d). This vertical permeability profile would be expected in a reservoir where the sand grains were larger in size at the base of the reservoir with the finest grains at the top of the reservoir.

Case 3: In this case, a permeability distribution is created with same average permeability of Cases 1 and 2, but with higher permeability at the upper zone and lower permeability at the lower part of the reservoir, as displayed in Fig. 1(e). The vertical permeability distribution of this case would be expected where the sand grains are largest at the top of the reservoir and finest at the base of the oil column.

Case 4: The permeability distribution for this case, shown in Fig. 1(f), is created by scaling up the permeabilities of the gridblocks of Case 1 universally by a factor of 2. This gives rise to an average permeability of 7300 mD. This case represents the best permeability case examined here and is at the upper limit of permeabilities expect in thin heavy oil reservoirs in Western Canada.

Case 5: The permeability distribution of this case, displayed in Fig. 1(g), is created by scaling down the permeabilities of the gridblocks of Case 1 universally by a factor equal to 0.6. This gives rise to an average permeability equal to 2190 mD. This case represents the worst permeability case evaluated in this study.

For each of above reservoir model cases, an individual optimization of 800 runs was conducted to determine the optimum parameter set for each case. The optimization run and simulations were executed on a personal computer (3.4 GHz, dual quad core