ARTICLE IN PRESS

Petroleum xxx (2018) 1–11

Contents lists available at ScienceDirect

Petroleum

journal homepage: www.keaipublishing.com/en/journals/petlm

Pad-scale control improves SAGD performance

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ARTICLE INFO

Article history:
Received 5 September 2017
Received in revised form
9 January 2018
Accepted 5 June 2018

Keywords:
Steam-assisted gravity drainage
SAGD pad
Control strategies
PID
cSOR
Oil sands emissions

ABSTRACT

Steam Assisted Gravity Drainage (SAGD) is widely used in the Athabasca oil sands deposit to recover bitumen. Since the viscosity of bitumen is high at original reservoir conditions, heat is required to lower its viscosity to the point it becomes mobile enough to be recovered under gravity drainage. To heat the reservoir, steam is injected into the formation and thus SAGD is energy intense. Given that the fuel used to generate steam is the largest operating cost, the steam-to-oil ratio is one of the key parameter for evaluating the economics of any SAGD project. Here, the use of dynamic distributed steam injection within a pad of SAGD wellpairs is explored. The results demonstrate that feedback control leads to improvements of the SOR over that of constant pressure. The results show that the controller is able to detect the “sweet spots” (oil zones with better geological properties) in the reservoir and dynamically deliver more steam to that region. Meanwhile, it reduces the steam injection towards relatively worse quality zones to lower the local SOR.

1. Introduction

For Athabasca oil sands reservoirs, due to low solution gas drive and relatively shallow depth, Steam-Assisted Gravity Drainage (SAGD) is the recovery process of choice. In SAGD, shown schematically in Fig. 1, two horizontal wells are drilled into the reservoir, one atop the other. The top well is the injection well whereas the bottom well is the production well. In typical practice, the separation between the two wells is equal to about 5 m [1]. At the start of the process, steam is circulated for several months in both wells until thermal communication is established between them after which SAGD-mode ensues [2]. As steam is continuously injected into the formation through the upper injection well, a steam chamber grows within the reservoir and heated oil drains at its edge to the base of the chamber where the production well is located.

A few studies have examined automated control of SAGD operations via proportional-integral-derivative (PID) feedback control. Gotawala and Gates [3] employed a PID feedback control algorithm to control steam injection conditions to promote steam trap control by maintaining a subcool (defined as the temperature difference between the injected steam and produced fluids) to a target value. The study focused on a single SAGD well pair and divided it into 6 segments so that each has its own injection pressure. Their results demonstrated that the key benefit of dynamic well control was that steam injection was adjusted smartly along the injection well so as to better address geological and fluid heterogeneities along the horizontal well pairs. As a result, steam chamber conformance along the wellpair was improved. In the base case, steam was injected at 3500 kPa and fluids were produced with a maximum steam production rate of 2 m^3/day (cold water equivalent, CWE). The results show that PID control both lowered the cumulative steam-to-oil ratio (cSOR) and raised the cumulative oil volume produced over 2 years' operation, as compared to non-PID-controlled base case. One other result they found was that control based on the subcool works only over the early stages of SAGD where the steam chamber conformance and subcool are strongly linked. After the chamber became mature, the PID controller had less effect on the process. This is because the subcool is a near well indicator whereas steam conformance after the chambers have grown should be controlled by variables remote from the well pair.

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Peer review under responsibility of Southwest Petroleum University.

Production and Hosting by Elsevier on behalf of KeAi

https://doi.org/10.1016/j.petlm.2018.06.001

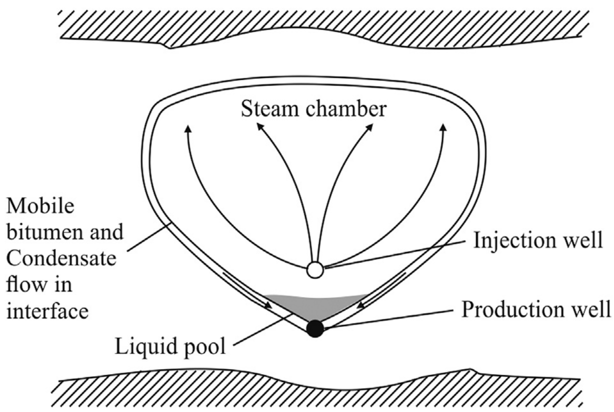

Fig. 1. Cross-section of the Steam-Assisted Gravity Drainage (SAGD) process: in typical practice, the injection well is ~5 m above the production well.

Stone et al. [4–7] extended Gotawala and Gates' [3,8] work on PID feedback control and instead of the six segment well configuration, he proposed to use a dual/triple tubing structure with a PID controller on each injection string to modify steam injection rates, so as to improve steam trap control. By examining several case studies, he suggested that an earlier PID control kick-in would benefit steam conformance and that more frequent updates of steam rates allows the feedback controller to achieve better steam conformance and steam trap control. Although both works made progress in the PID feedback control on SAGD operations, they only dealt with a single well pair SAGD operation, which does not address the issue of dynamic steam distribution for pad-scale operations. Also, a single well model would not be able to capture the effect of multiple steam chamber interactions.

Steam generation is the major operating expense of SAGD. High steam-to-oil ratios (SOR, steam expressed as CWE) imply high water consumption and high fuel consumption and emissions of greenhouse gases from the steam generator. Thus, there are many incentives to lower the SOR. Here, we explore the use of automatically controlled dynamic steam injection into nine well pairs of a SAGD pad.

2. Geological and reservoir models

This study focuses on the 102-North (102 N) pad of ConocoPhillips' Surmont SAGD operation, displayed in Fig. 2, which consists of nine horizontal well pairs. The well pairs of the 102 N pad are drilled into the McMurray Formation and at its location it has both top and bottom water zones [9]. The 102 N pad was first steamed in June 2007 with oil production starting in October 2007 after four months of steam circulation. The operator used a declining steam injection pressure operating strategy illustrated in Fig. 3. In 2011, after about 4 years of operation, the injection pressure was dropped to 2500 kPa from the initial pressure of 4000 kPa to reduce heat losses and fluid invasion to the top water zone. According to the Annual Performance Reports filed by the operator, another pressure decline is planned in a few years so as to maintain a low cSOR. The cumulative SOR (cSOR) for the well pairs in the 102 N pad has ranged from 2.7 to 3.7 m^3/m^3 over the past six years [9].

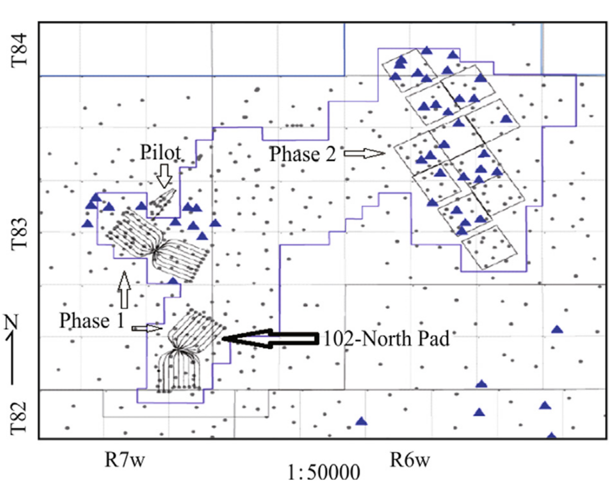

Fig. 2. Location of Surmont 102 North pad.

The three-dimensional (3D) model of the Surmont 102 N pad consists of three major layers: the top water zone, the middle oil zone and a thin bottom water zone. The formation ranges from 40 to 60 m in thickness and consists of mostly sandstones, interbedded with shale. The top layer is mainly composed of silty sands and is saturated with water – it is considered a thief zone [9]. For facies, the model consists of five rock types (rock type 1 is sand, rock type 2 is sand with breccia, rock type 3 is sand-dominated heterolithic strata, rock type 4 is mud-dominated heterolithic strata, and rock type 5 is shale) with relative permeability curves displayed in Fig. 4. The key reservoir properties are listed in Table 1. The porosity-permeability transforms for each rock type were generated from core data obtained from wells in the vicinity of the 102 N pad and are listed in Table 1.

The geological model was generated geostatistically by using Sequential Gaussian Simulation conditioned to available log and core data in a commercial geomodeling software package [10]. The average porosity and oil saturation of the oil column within the reservoir are equal to 0.34 and 0.86, respectively. In the horizontal directions, the average permeability is equal to about 3866 mD. In the vertical direction, the average permeability in clean sand is equal to 3635 mD. Low permeability layers are interbedded within the sandy intervals of the model and in some locations exist just above the injection wells, which impairs steam chamber growth.

The 3D geological model was directly converted into a reservoir simulation model and the nine wellpairs, listed with lengths in Table 2, were placed within the reservoir model, according to well trajectories available in public database [11]. A top view of the reservoir model is displayed in Fig. 5. A view of the 3D model is displayed in Fig. 6. The total number of grid blocks in the model is equal to about 5.7 million. The dimensions of the individual grid blocks are about 1 m in the cross-well pair direction, 25 m in the down-well direction, and 1 m in the vertical direction. The simulation is conducted by using a commercial thermal reservoir simulator, STARS™ [12]. The 3D model, solved in parallel by using 4 cores, took roughly 600 h to simulate 7 years of SAGD operation on a dual quad core (2.7 GHz) workstation. To ensure that the model provided a reasonable representation of the performance observed in the field, the relative permeability curves for each rock type were adjusted until the simulation results matched the field data. As shown in Fig. 4, the oil relative permeability curve remained the same for all rock types whereas the curvature of the water relatively permeability curves varied.

After the history match was complete, a two-dimensional (2D) slice was selected and cut from the 3D model, along the cross-well direction. The 2D model is 25 m long in the down-well direction and contains the 9 well pairs, as shown in Fig. 7. To confirm that the 2D model is a good representation of the 3D model, we compared the results of both models, in terms of SAGD performance in Fig. 8 (for constant injection pressure injection equal to 3500 kPa for all well pairs and 1 m^3/day maximum steam production rate

Please cite this article in press as: T. Guo, et al., Pad-scale control improves SAGD performance, Petroleum (2018), https://doi.org/10.1016/j.petlm.2018.06.001