Research

Impact of Operational Parameters and Reservoir Variables during the Start-up Phase of a SAGD Process

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Abstract

This paper highlights how numerical simulation can be used as a tool to optimize the start-up phase of a (Steam Assisted Gravity Drainage) SAGD process. During start-up, the main objective is to create a uniform communication path between the two wells by first circulating steam in both the injector and the producer well and then imposing a differential pressure between them. The dynamics of this process leads to important temperature and pressure transients that should be carefully considered when developing a start-up strategy. Usually, this start-up strategy aims at minimizing the time in which the well pair can be converted to full SAGD operation without causing any adverse effects on the long-term process performance.

A fully coupled wellbore/reservoir thermal simulator was used to conduct a sensitivity analysis, in which the effects of steam circulation rate, tubing diameter, tubing insulation and bottom hole pressure were investigated. The effects of the pressure differential between the wells, and the timing of imposing such pressure differential, were also looked at. To better account for the interaction between the processes happening in the wellbore and in the reservoir, the discretized wellbore was placed inside a hybrid reservoir grid. Aiming at investigating the influence of vertical and horizontal permeability, reservoir pressure, initial oil/water saturation and fluid properties, the start-up strategy was examined for three different cases representing the main heavy oil production areas in Alberta, Canada: Athabasca, Cold Lake and Peace River.

Introduction

Vast quantities of heavy and extra heavy oil are trapped in shallow and easily accessible reservoirs in Western Canada, but due to the intrinsic high-viscosity nature of the crude, producers face significant challenges in recovering oil from these reservoirs. Using steam-based in-situ recovery methods, coupled to horizontal well technology, has emerged as an economic and efficiently way to produce those reservoirs [1,2]. Currently, one of the most promising of these methods is the so-called Steam Assisted Gravity Drainage (SAGD) process. The most common implementation consists of two parallel horizontal wells, the first drilled near the bottom of the reservoir and the second located a short distance above it, typically 5 to 10 m. The top well provides continuous steam supply into the reservoir and the lower one allows for continuous production of oil, gas and condensed water.

Experiments carried out by the Alberta Department of Energy in the early 1990's showed recovery factors in the zone between the wells of more than 50% [3], which increased the producers' interest for the SAGD process and motivated them to try its implementation in actual field applications. Nowadays, a huge expansion of SAGD in commercial applications in the Alberta oil sands seems to be inevitable.

In these reservoirs, the cold oil is most of the times immobile initially. Therefore, before converting the well pair to full SAGD operation, it is necessary to preheat the reservoir and create an effective thermo-hydraulic communication between the two parallel wells. The start-up phase consists of three steps, as illustrated by Vincent et al. [4]. First, steam is circulated in both wells, and the heat transfer within the reservoir occurs mainly by conduction. In the second step, a pressure differential is imposed between the wells, adding a convection component to the heat transfer process in the reservoir. In the third step, the well pair is converted to full SAGD operation. Steam is injected continuously through the top well and rises within the reservoir, developing a steam chamber. The injected steam heats up the cold oil around the chamber, and this now mobile oil, along with any condensed water, flows down by gravity in the reservoir and is drained by the lower well, in which the fluids are continuously being produced.

Modeling the start-up phase adequately allows one to properly define well completion and operational parameters, which is key to the optimization of the whole process. This means choosing such parameters in a way that facilitates the development of an even steam chamber along the injection well, avoiding the breakthrough of steam in certain portions of the production well.

Adequate reservoir models of the process must properly take into account the transient pressure and temperature variations along the wellbore, because the wellbore conditions are quite influential in how the steam chamber develops inside the reservoir. The classical sink/source approach to model the wellbore cannot be used, because it does not account for such variations [5]. Therefore, a fully coupled wellbore/reservoir thermal simulator, in which the main variables along the wellbore are solved simultaneously with those of the reservoir grid, is required.

The literature contains several examples of wellbore models fully coupled to commercial reservoir simulators. In the particular case of thermal simulators, the enhancement of the multi-segment well model developed by Stone et al [6] and the fully coupled discretized wellbore model described by Tan at al [5], are good examples of this modeling approach.

Methodology

This paper describes a different approach to coupling a discretized wellbore to a commercial reservoir thermal simulator [7]. The discretized wellbore was placed inside a hybrid grid, in an attempt to better account for the interaction between the thermo and hydrodynamic processes occurring simultaneously in the wellbore and in the reservoir.

The paper also illustrates how this fully coupled wellbore/reservoir simulator can be a powerful tool to optimize the start-up phase of a SAGD process. Using the simulator, a sensitivity analysis was conducted, in which the effects of steam circulation rate, tubing diameter, tubing insulation and bottom hole pressure were investigated. The effects of the pressure differential between the wells, and the timing of imposing such pressure differential, were also looked at.

Aiming at investigating the influence of vertical and horizontal permeability, reservoir pressure, initial oil/water saturation and fluid properties, the start-up strategy was examined for three different cases representing the main heavy oil production areas in Alberta, Canada: Athabasca, Cold Lake and Peace River. **Table 1** shows the main reservoir parameters used during the simulations, for each of these three areas.

For modeling purposes, in each of the investigated zones, a 3-D model was used to represent a half of the reservoir produced by the well pair. Grid sizes of 34x10x27, 45x10x20 and 35x10x25 blocks were used for Athabasca, Cold Lake and Peace River areas, respectively. The block sizes in *i* and *k* directions were either 1 or 2 m for all zones. The wells were oriented in *j* direction using blocks of 100 m in the main grid.

All wells were assumed to have the same horizontal length (800 m) and all well pairs to have the same vertical spacing (5 m).

Closer to the wellbore, each main grid was further subdivided as follows: three sub blocks in the axial direction along the wellbore, four sections in the angular direction, and three concentric rings in the radial direction. The two inner rings define the wellbore tubing and tubing annulus (**Figure 1**).

Initial Circulation Phase

During the first stage of the preheating period, the goal is to carry the steam to the toe of both the injection and the production wells in a timely manner. This ensures an even temperature distribution along both wells and helps develop a uniform steam chamber in the nearby reservoir.

Table 1. Reservoir characteristics of three areas used in the simulations

	Athabasca	Cold Lake	Peace River
Reservoir Top Depth, m	200	400	600
Reservoir Thickness,m	30	20	25
Reservoir Pressure, kPa	1500	3000	4500
Porosity	0.35	0.30	0.30
Vertical Permeability, Darcy	2.5	1.3	0.7
Permeability Ratio, Horizontal/Vertical	2	2	3
Oil Viscosity, cp @ 12°C	2000000	60000	200000
Methane gas mole fraction	0	0.1	0.15
Oil Saturation	0.8	0.7	0.8

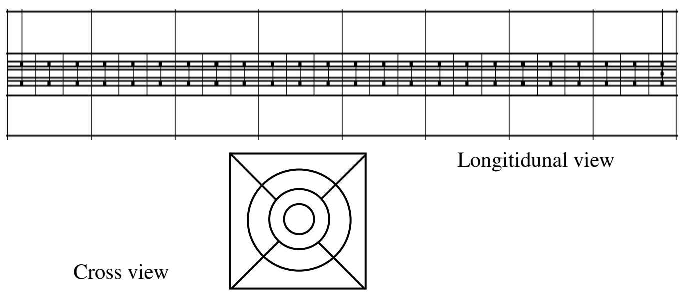

Fig. 1. Discretized wellbore embedded in a hybrid grid

For the simulations, it was assumed the steam quality was 95% at the bottom hole. The injection pressure (and temperature) was selected in a way such that the bottom hole pressure at the end of the tubing string (at the toe) was always close to the initial reservoir pressure (non fracturing conditions). The initial condition was that the well was filled up with water at the initial reservoir temperature.

As steam is injected into the tubing string, the heat loss to the adjacent formation cools it down, creating a condensation front, which advances through the wellbore. This front eventually displaces the original fluids in the wellbore. At this moment, steam will be present throughout the well, both in the tubing and in the annulus, at the saturation temperature corresponding to the given pressure at each location.

Figure 2 shows the advance of the steam front through the top wellbore for the Athabasca case, and for a steam circulation rate of 80 m^3/d and an injection temperature of 206 °C. For the other areas the temperature was adjusted accordingly to the reservoir pressure. The left side of the plot shows the temperature in the tubing, from heel to toe, and the right side of the plot shows the temperature in the annulus, from toe to heel. It can be observed that, after 2.41 days (58 h), one starts to get steam to the toe, but only after 7 days the temperature is evenly distributed along the tubing and the annulus.

An optimal steam to toe time not only leads to an efficient start-up, but also helps anticipate oil production and therefore improve the finances of the project. Since this time is almost solely related to the heat transport phenomena inside the wells, it can be expected that variables such as steam circulation rate, tubing diameter, tubing thermal conductivity, and bottom hole pressure have a significant influence on the results.

Sensitivity Analysis: Circulation Rate. To determine which would be the best steam circulation rate to start-up the process, one could first examine the evolution of the temperature at the toe with time, and its dependence on the circulation rate. Figure 3 illustrates the temperature at the toe as a function of time, for the Athabasca case, and steam circulation rates of 40, 60, 80, 100, and 120 m^3/d (cold water equivalent). As noted by Vincent et al [4], the steam-to-toe time depends on the quantity of injected heat.

As shown in the figure, for a circulation rate of 40 m^3/d, the condensation front would move so slowly that, even after 10 days of continuous injection, the toe temperature would come up to only 43 °C; consequently, steam saturation conditions would not exist.

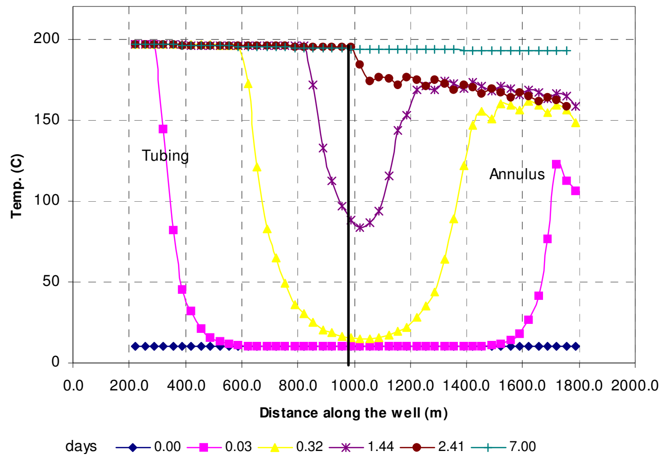

Fig. 2. Temperature profile along the wellbore.

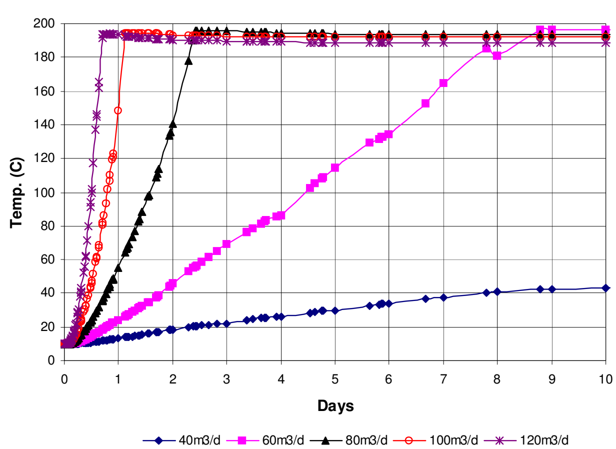

Fig. 3. Temperature at the toe as a function of time for different steam circulation rates, Athabasca case.

For a circulation rate of 60 m^3/d, the steam would reach the toe at approximately 9 days. This steam-to-toe time goes down to 2.41 days, 1.15 days and 0.70 days, when the circulation is increased to 80, 100 and 120 m^3/d, respectively. The effectiveness of increasing the circulation rate to get an earlier time to toe decreases as the steam circulation rate increases; in other words, the time gained by increasing the steam circulation rate becomes smaller as the steam rate increases. Consequently, there is an optimum steam circulation rate.

One way to determine this optimum steam circulation rate is to investigate the temperature behavior inside the reservoir as a function of the steam circulation rate. The average temperature of the central blocks between the two wells was the parameter used here to conduct this sensitivity analysis (**Figure 4**). This figure shows that, at a given instant in time, after 10 days of continuous steam circulation, the average temperature in the central blocks doesn't increase significantly when the circulation rate increases above 80 m^3/d.

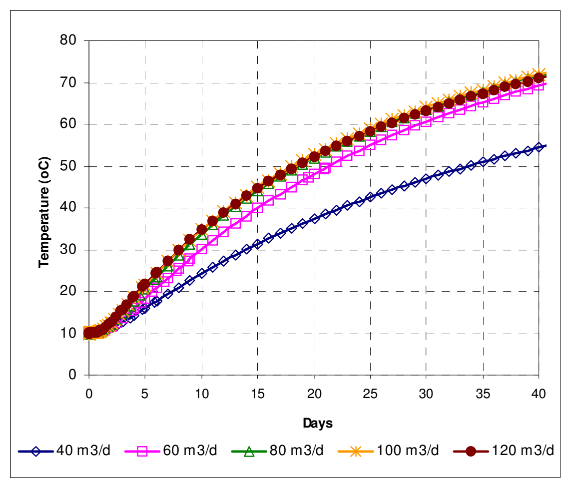

Fig. 4. Average temperature of central blocks between and along the wells vs. time, using different circulation rates, for Athabasca case.

After getting steam to the toe, there is a circulation rate which maximizes the conductive heat transfer from the wellbore annulus into the formation. A higher circulation rates implies a higher steam flow velocity, and there may not be enough residency time for the steam to efficiently heat up the formation; instead, it may return to surface carrying a large part of its original heat. Another explication could be that, the higher the circulation rate, the higher the pressure losses and therefore the lower the flow pressures along the annulus. This leads to lower saturation temperatures and therefore to lower heat fluxes into the formation.

The same analysis was completed for the Cold Lake and the Peace River cases. **Table 2** shows the optimum circulation rate for each case, and the corresponding time of steam to toe.

Table 2. Time to toe and circulation rate for each case

	Circ. Rate, m^3/d	Time to toe, days
Athabasca	80	2.4
Cold Lake	120	2.2
Peace River	140	2.8

Sensitivity Analysis: Tubing Diameter. The tubing diameter has an effect on the velocity of the flow and on the pressure drop along the steam path inside the wellbore, and therefore different tubing diameters yield different steam time to toe. Figure 5 illustrates the temperature and steam saturation at the toe, for the Athabasca case, and for a steam circulation rate of 80 m^3/d.

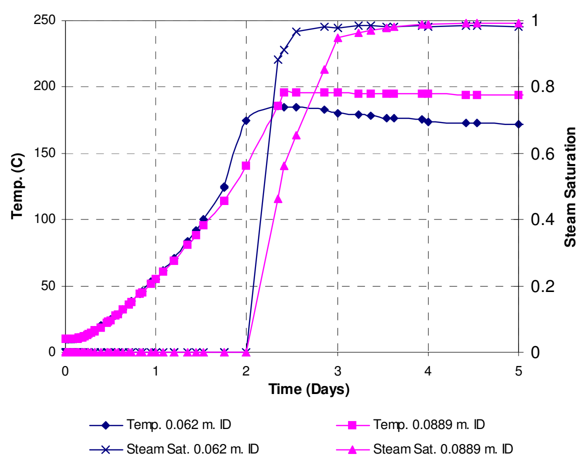

Fig. 5. Steam saturation and temperature at toe vs. time, using different inner diameters, for Athabasca case.

The smaller tubing (62.0 mm ID) allows the presence of steam at the toe in a shorter period of time because it allows for higher flow velocities, and thus for faster displacement of the saturation front. On other hand, the toe temperature is higher for the larger tubing (88.9 mm) because it allows for lower pressure drops, resulting in higher pressure, and higher saturation temperatures, at the toe (for the same injection pressure at the wellhead) and along the wellbore annulus. This improves the heat transfer to the formation. **Figure 6** shows that, at any specific time, the average temperature of the central blocks along the wells is always higher for the larger tubing.

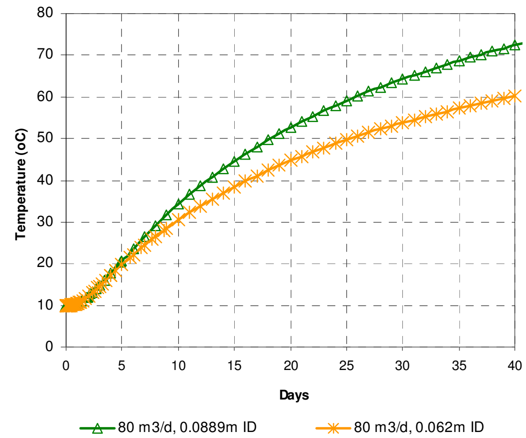

Fig. 6. Average temperature of central blocks between and along the wells vs. time, using different inner diameters, for Athabasca case.

Sensitivity Analysis: Tubing Insulation. As it was explained by Tan et al [5], tubing insulation allows for a more even pressure and temperature distribution along the injection well, avoiding early steam breakthrough, particularly at the heel of the production well. During the initial circulation phase, tubing insulation allows for a faster steam to toe, as pointed out by Vincent et al [4].

The effect of tubing insulation on the steam time to toe is presented in Figure 7, for the Athabasca case, and for a steam circulation rate of 80 m^3/d. The insulation consisted of 10 mm thick material, with a thermal conductivity of $3x10^5$ J/m.day.°C. The time to get steam to the toe decreases by approximately 1 day with the tubing insulation.

Bottom Hole Pressure

The heat transfer process during the start up period can be improved by increasing the pressure at the annulus after getting the steam at the toe. In field operations, this can be accomplished by reducing the return choke [4]. In the simulator, the bottom hole pressure at the annulus is limited to the initial reservoir pressure in order to avoid any possible formation fracture. The annular bottom hole pressure is referenced where the first completion is specified, i.e. at the heel of the well.

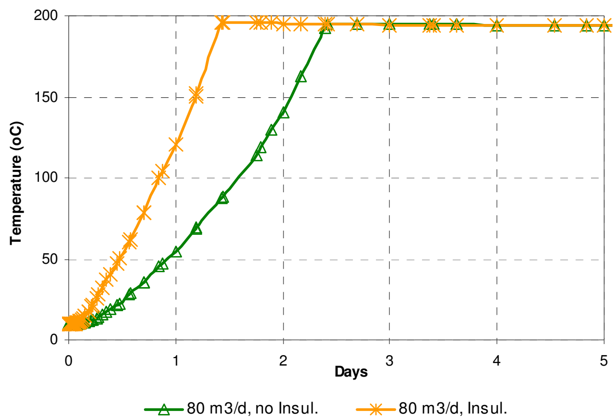

Fig. 7. Comparison of toe temperature vs. time, using tubing insulation and without insulation for Athabasca case.

To illustrate the effect of bottom hole pressure on the temperature at toe behavior, **Figure 8** shows a comparison between the Athabasca, Cold Lake and Peace River cases. The results were generated using the optimum circulation rate, a constant bottom hole at annulus pressure close to initial reservoir pressure and a 0.0889 m ID tubing. The timing used to increase the bottom hole circulation pressure was: Athabasca 2.5 days, Cold Lake 2.3 days and Peace River 2.8 days, right after getting steam at the toe.

Peace River has the highest initial reservoir pressure, and therefore the highest temperatures and pressures at the annulus.

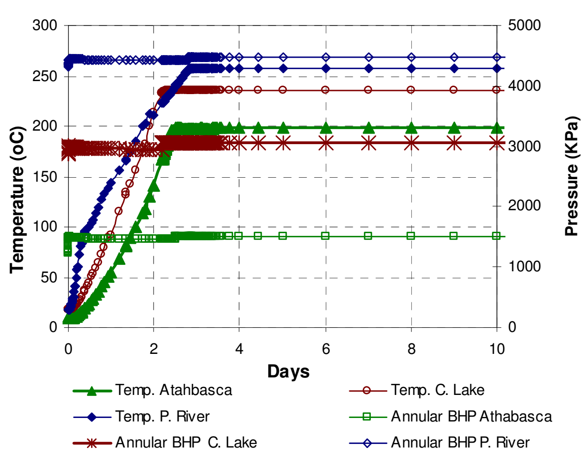

Fig. 8. Comparison of toe temperature vs. time, and annular bottom hole, for three different areas: Athabasca, Cold Lake and Peace River.

Pressure Differential Phase

The second step, after the initial steam circulation phase, is aimed at mobilizing the oil between the wells. This is accomplished by inducing a pressure differential between the wells. The risk of applying this pressure differential is to induce a preferential flow path between the wells, and determining when to best induce this pressure differential and how much pressure differential to apply is critical to the overall optimization of the process.

The first question can be handled by identifying the time in which the mobilization of the oil starts due to gravity effects only. The second question can be answered by conducting a sensitivity analysis of the reservoir response to the magnitude of the pressure differential.

During the simulation, steam was initially circulated in both wells until the beginning of the oil mobilization could be detected, at which time a pressure differential was imposed between the wells, by decreasing the injection pressure of the production well.

Figure 9 shows a plot of oil flow rate at the production well during the initial circulation phase, i.e. without a pressure differential between the wells. For all three cases, Athabasca, Cold Lake and Peace River, there is an initial production peak due to thermal expansion of the oil near the wellbore, but after that the production stabilizes at a relatively low value for a few days. Then, the oil flow rate starts to increase gradually, indicating that the heated oil in the reservoir is starting to flow to the production well by gravity.

The differences in time at which this mobilization occurs are clear. Oil mobilization is faster at Cold Lake and slower at Athabasca. These differences are due not only to the oil viscosity (higher at Athabasca), but also due to the steam circulation temperature, which is direct function of the reservoir pressure (higher at Peace River); as discussed above, higher steam temperatures yield higher heat fluxes into the formation. Other variables influencing this time are vertical permeability and initial water saturation.

As noted by Vincent et al [4], the adequate magnitude of the pressure differential depends on the presence of zones of higher vertical permeability between the wells, as well as the water saturation and the distance between them. The differential should be enough to induce a gentle and uniform drive, accelerating the start up by adding a convective component to the heat transfer process, but without inducing a preferential flow path between the wells.

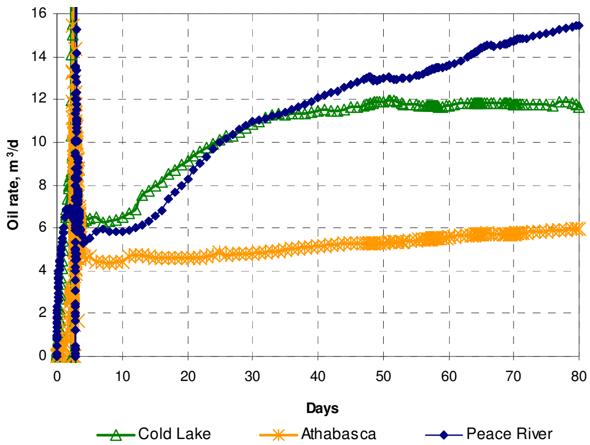

Fig. 9. Oil flow rate as function of time with no differential

The acceleration of the heating of the formation by the implementation of a pressure differential can be observed in **Figure 10,** which shows the temperature in the reservoir for the Athabasca case. **Figure 10a** shows the temperature 70 days after the beginning of the start up with no pressure differential, while **Figure 10b** and **Figure 10c** show the temperature at the same time but after imposing a 100 KPa and a 300 KPa pressure differential at 50 days, respectively. In **Figures 10b** and **10c,** an uneven temperature distribution along the injection well can be noticed, with the highest temperatures (and the highest heat losses to the formation) existing at the heel of the well. This can be improved by using an insulated tubing string.

It can also be observed that the higher the differential pressure the higher the convection effect over the heat transfer process When a 300 KPa pressure differential is imposed to the reservoir the temperature has increased in a larger number of blocks along the injection well than when a 100 KPa differential is imposed.

The simulations were performed first with a homogeneous reservoir, to observe the effect of increasing the pressure differential from 100 KPa to 300 KPa. Then, the vertical permeability in the blocks between the wells closer to the heel was increased to a value somewhat higher than the horizontal permeability, to investigate the effect of the heterogeneity. For all simulations the pressure differential was imposed at 50 days for Athabasca, 15 days for Cold Lake, and 20 days for Peace River.

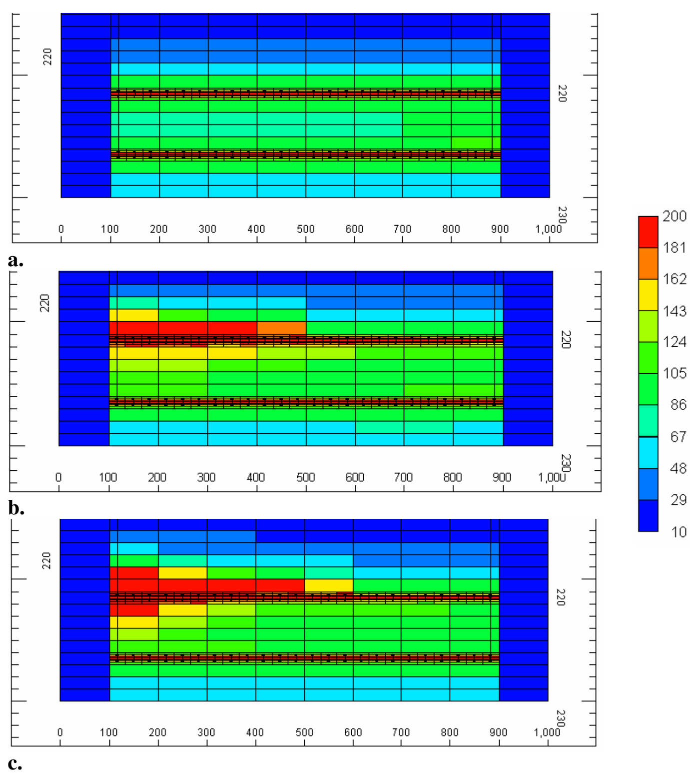

Fig. 10. Temperature map of a cross section view along wells at 70 days, for Athabasca. a. DP = 0 KPa, b. DP = 100 KPa and c. DP = 300 KPa.

Figure 11 shows the oil flow rate as a function of time, for the Athabasca case, and pressure differentials of 100, 150, 200 and 300 KPa (homogeneous reservoir). Higher differentials induce higher oil flow rate peaks, because they induce stronger oil mobilization, especially in regions where the oil is warmer, such as the heel of the well. Nevertheless, for the homogeneous case (where there wasn't any variation of vertical permeability), no preferential path between the wells was developed for any of the above values of pressure differential. The same result was found for the Cold Lake and Peace River cases.

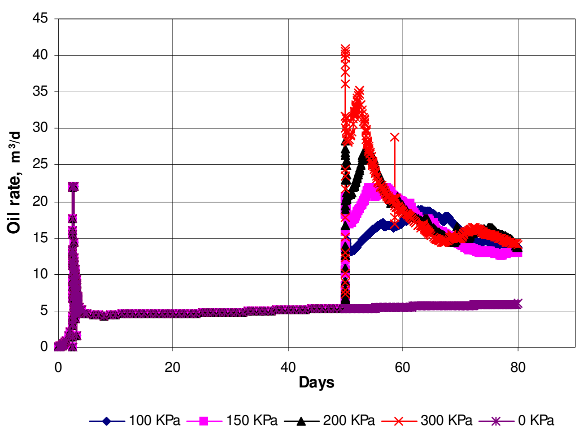

Fig. 11. Oil flow rate vs. time using different pressure differential, for Athabasca case.

Figure 12 illustrates the negative effects of a zone of high vertical permeability close to the heel of the wells. The figure shows a cross section view of the steam saturation, 59 days after the beginning of start up, after imposing a 200 KPa at day 50. It is clear that a preferential communication path was developed. Because this preferential path can develop when there is heterogeneity of the vertical permeability, determining the optimum differential pressure may require a more detailed analysis, including a better reservoir characterization and a close examination of the uncertainties.

Similar analyses for Cold Lake and Peace River indicated that a pressure differential of 150 KPa would be enough to create a preferential flow path between the wells, approximately 30 days after the start-up was initiated. The preferential flow path was developed approximately at the same time for both cases because the higher oil viscosity of Peace River is somewhat compensated by the higher temperatures. .

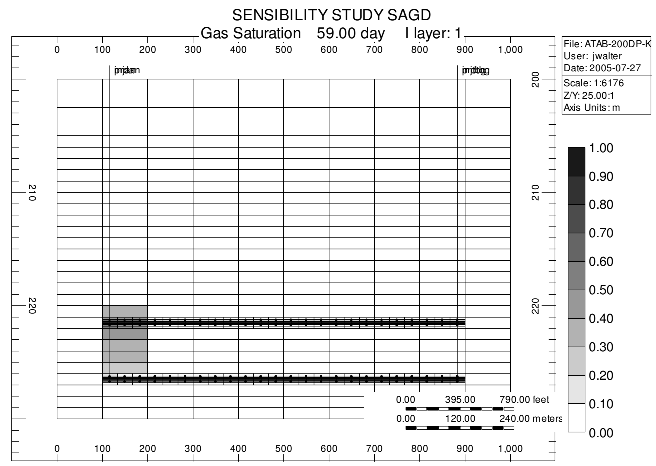

Fig. 12. Preferential flow path at 59 days for Athabasca case.

A summary of the optimum start-up conditions and the associated oil recovery factors result found for the three cases studied is shown in **Table 3**. The optimum conditions refer to: the steam circulation rate that maximizes the conductive heat transfer from the well to the formation; and the timing and extension of the pressure differential that should be applied between the wells to incorporate the convection component to the heat transfer process.

The optimum steam circulation rate has been determined as the maximum steam flow that promotes a significant increasing in the average temperature of the reservoir's central blocks between the wells. At a given time, higher flow rates don't increase this average temperature.

The time in which the differential pressure should be applied was defined as the required circulation time to start the displacement of bitumen between the wells by only gravity effects. After this time any pressure differential will promote the bitumen mobilization and thus convection will play a role in the heat transfer process. The extension of the pressure differential was defined qualitatively assuming that it should be gently enough to produce the bitumen mobilization without induce a preferential communication path for the steam when the formation is heterogeneous. A reliable reservoir characterization should be available to select the extension of the pressure differential to be applied.

Table 3. Summary of start-up conditions for the SAGD process

	Circ. Rate, m^3/d	Time to toe, days	Annular BHP, injec. well, KPa	Pressure Diff., KPa	Pressure Diff. timing, days	Oil Rec. Factor, %
Athabasca	80	2.4	1500	100 - 150	50	63.7
C. Lake	120	2.2	3070	50 - 100	15	51.7
P. River	140	2.8	4470	50 - 100	20	54.3

To convert the well pair to full SAGD operation, the production through the annular of the top well and the injection through the tubing of the lower well are stopped. The top well becomes a dedicated steam injection well and the lower well becomes a dedicated production well. Some simulations were performed to investigate the influence of the conversion time on the SAGD process. The results agree with those of Vincent et al[4]: once the temperature of the area surrounding area has raised enough to promote the oil mobilization, the time of conversion won't have a long-term impact over the oil rate.

Conclusions

A novel methodology that considers the use numerical reservoir simulation to enhance the understanding of the start-up phase of a SAGD process was conducted. A discretized wellbore model coupled to a commercial reservoir thermal simulator was used to investigate start-up strategies for a SAGD process. The discretized wellbore was placed inside a hybrid grid, to better account for the interaction between the processes occurring simultaneously in the wellbore and the reservoir. Results obtained in this study showed that the coupled simulator is an excellent supporting tool for studying the effect of wellbore transients into the reservoir performance.

Sensitivity analysis conducted with the simulator showed the effect of important variables, such as steam circulation rate, tubing size and tubing insulation, on the overall behavior of the system and the efficiency of the start-up process. Optimum steam flow rates maximize the conductive heat transference from the well to the reservoir, and larger tubing sizes and tubing insulation provided considerable reductions in the steam to toe time.

Three different areas in Western Canada were studied: Athabasca, Cold Lake and Peace River. It was shown that they have differences in reservoir characteristics and oil properties that also affect the start-up process. The time required to heat up the formation and mobilize the bitumen is greater in Athabasca, because of the higher oil viscosity and lower reservoir pressure.

There is a higher risk of generating a preferential flow path between the wells when the differential pressure is applied, which may compromise the long-term SAGD process efficiency. This risk increases when there are zones of higher vertical permeability and higher water saturation between the wells, and the wells are located closer to each other.

Field observations from Alberta's oil operators have confirmed the validity of the results reported in this work. Therefore, these results could be used as a preliminary guideline for choosing operational parameter values to be used during the start-up phase of SAGD projects in reservoirs with similar fluid and rock properties.

The importance of this work can be recognized by the innovation in using a reservoir thermal simulator to support decisions related to the operation of a SAGD well pair.

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