A Numerical Analysis of the Single-Well Steam Assisted Gravity Drainage Process (SW-SAGD)[1]

K. T. Elliot and A. R. Kovscek
Department of Petroleum Engineering, Stanford University—U.S.A.

Abstract

Steam assisted gravity drainage (SAGD) is an effective method to produce heavy oil and bitumen. In a typical SAGD approach, steam is injected into a horizontal well located directly above a horizontal producer. A steam chamber grows around the injection well and helps displace heated oil toward the production well. Single-well (SW) SAGD attempts to create a similar process using only one horizontal well. This may include steam injection from the toe of the horizontal well with production at the heel. To improve early-time response of SW-SAGD, it is necessary to heat the near-wellbore area to reduce oil viscosity and allow gravity drainage to take place. Ideally heating should occur with minimal circulation or bypassing of steam.

Since project economics are sensitive to early production response, we have investigated early-time processes to improve reservoir heating. A numerical simulation study was performed to gauge combinations of cyclic steam injection and steam circulation prior to SAGD in an effort to better understand and improve early-time performance. Results from this study, include cumulative recoveries, temperature distributions, and production rates. Variances are displayed within the methods. It is found that cyclic steaming of the reservoir prior to SAGD offers the most favorable option for heating the near-wellbore area to create conditions that improve initial SAGD response. Additionally, a sensitivity analysis was performed with regard to reservoir height, oil viscosity, horizontal to vertical permeability anisotropy, and dead versus live oil. More favorable reservoir conditions such as low viscosity, thick oil zones, and solution gas, improved reservoir response. Under unfavorable conditions, response was limited and could prove to be uneconomical in actual field cases.

Introduction

Steam assisted gravity drainage maximizes the role of gravity forces during steam flooding of heavy oils. Generally, a pair of horizontal wells is used. As steam enters the reservoir, it heats the reservoir fluids and surrounding rock. Hot oil and condensed water drain though the force of gravity to a production well at the bottom of the formation. In conventional SAGD, steam is injected through a horizontal well placed directly above a horizontal producer. Thus, a steam chamber forms around the injection well. In SW-SAGD, a horizontal well is completed such that it assumes the role of both injector and producer [1]. In a typical case, steam is injected at the toe of the well, while hot reservoir fluids are produced at the heel of the well. Recovery mechanisms are envisioned to be similar to conventional SAGD. Advantages of SW-SAGD might include cost savings in drilling and completion and utility in relatively thin reservoirs where it is not possible to drill two vertically spaced horizontal wells. However, the process is technically challenging.

In a reservoir where cold oil is very viscous and will not flow easily, initial production rates via any gravity drainage process are very low. In a strict definition of SAGD, steam only enters the reservoir to fill void space left by produced oil. If the oil is cold, we must heat it to reduce viscosity. Therefore, initial heating of the area around the wellbore is required so that SAGD can take place. After SAGD is initiated, a steam chamber will grow upward to the top of the reservoir and then begin to extend horizontally[2]. At the steam-chamber boundary, steam condenses as heat is transferred to the oil. Condensed water and hot oil flow along the steam chamber to the production well[2].

Joshi found experimentally that under various injection/production well configurations, the steam chamber grows to cover a majority of the reservoir and the recovery efficiency is very good in all cases[3]. Therefore, we expect that early-time production results from SW-SAGD may vary from the conventional approach, but at late times, we expect similar recovery efficiencies. Additionally, Oballa and Buchanan[4] simulated various scenarios to evaluate the difference between cyclic steam injection and SAGD. They focused, partially, on the interactions

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between the reservoir, the well completion, and the recovery of oil. It was concluded that the drainage process may be feasible provided that a proper operating strategy is identified.

Field tests of SW-SAGD are not extensively documented in the literature. Falk et al overview the completion strategy and some typical results for a project in the Cactus Lake Field, Alberta Canada[1]. A roughly 850 m long well was installed in a region with 12 to 16 m of net pay to produce 12 °API gravity oil. The reservoir is a clean, unconsolidated, sand with 3400 md permeability. Apparently, no attempts were made to preheat the reservoir before initiation of SW-SAGD. Steam was injected at the toe of the well and oil produced at the heel. Oil production response to steam was slow and gradually increased to more than 100 m^3/d. The cumulative steam-oil ratio was between 1 and 1.5 for the roughly one-half year of reported data.

McCormack et al also describe operating experience with nineteen SW-SAGD installations[5]. Performance for approximately two years of production was mixed. Of their seven pilot projects, five were either suspended or converted to other production techniques because of poor production. Positive results were seen in fields with relatively high reservoir pressure, relatively low oil viscosity, significant primary production by heavy-oil solution gas drive, and/or insignificant bottom-water drive. Poor results were seen in fields with high initial oil viscosity, strong bottom-water drive, and/or sand production problems. Although the authors note that the production mechanism is not clearly understood, they suspect that the it is a mixture of gravity drainage, increased primary recovery because of near-wellbore heating via conduction, and hot water induced drive/drainage[5].

Problem Definition

This paper is grouped into two general topics: (i) a screening study of early time operating performance of SW-SAGD and (ii) a sensitivity analysis of the effect of reservoir and well completion parameters. Understanding the operating conditions to improve initial performance relates directly to understanding methods of heating the near-wellbore area at early-time. A central idea realized through our research is that the near-well region must be heated rapidly and efficiently for significant early-time response. The sensitivity analysis helps us understand reservoir properties, fluid conditions, and well completion strategies that make the process an appropriate production technique.

To gain an understanding of early-time performance, we build and compare various computer simulations. The processes examined include cyclic steaming, steam circulation within the well, and an extreme pressure differential between the injection and production sections of the well. Each initial operating period was followed by SAGD; that is, continuous steam injection and oil production with little net injection of steam. For the sensitivity analysis, we compared a base case against runs in which we varied oil viscosity and gas content, reservoir height, permeability anisotropy, and finally the well completion. Computer Modeling Group's (CMG) STARS thermal simulator was used to perform all of the work.

Model Description

The base case is STARS example sthrw009.dat released with Version 98.01[6]. Reservoir and fluid properties represent a typical Alberta reservoir. The operating conditions and well completion were modified to develop additional cases.

The grid system and dimensions are illustrated in Fig. 1. Figure 1a displays the cross section along the length of the well and Fig. 1b a cross section perpendicular to the well. The grid system is Cartesian with local grid refinement immediately around the 800 m long well. An element of symmetry, with one boundary lying along the wellbore, is used to represent the reservoir volume. We assume that wells will be developed in multiple patterns and thus all boundaries are no flux. The single horizontal well is represented using a discretized wellbore model that accurately represents fluid and heat transfer in the well. Additionally, the well is broken into two sections as if the well contained a packer. Each section is equal in length and they lie directly end to end. This gives us freedom to explore various completion strategies and operating conditions. Our initial simulation work suggested that this inject at the toe and produce at the heel strategy had greater probability of success than attempting to develop countercurrent steam and oil flow along the entire length of the well. Table 1 lists the exact dimensions of the reservoir model, grid-block information, and reservoir properties. Initially, the average reservoir pressure is 2,654 kPa (380 psi), the pressure distribution is hydrostatic, and the initial reservoir temperature is 16 °C.

The water-oil relative permeability and gas-liquid relative permeability functions are displayed graphically in Figs. 2 and 3, respectively. Table 1 also lists the initial fluid saturations of the reservoir. The homogeneous porosity is 33%. The horizontal permeability, k_h, is 3400 md, whereas the vertical permeability, k_v, is 680 md. Hence, the ratio k_h:k_v is about 5 to 1.

A live, black-oil model is used. The initial oil phase is made up of 90 % by mole oil component and 10 % by mole gas component for a solution gas-oil ratio (GOR) of about 28 SCF/STB. The effect of solution GOR on oil recovery is explored in the sensitivity analysis. The oil viscosity versus temperature relationship is given in Table 1, and the oil viscosity at the initial reservoir temperature is 4.043 Pa-s (4043 cP). An increase of oil temperature to 100 °C decreases the oil viscosity to 0.030 Pa-s (30 cP).

Table 2 lists the operating constraints for the four base cases created to explore a range of early-time procedures. Briefly the cases represent SAGD operating conditions, extreme pressure differential conditions where steam is injected near the fracturing or parting pressure of the formation, cyclic steam injection, and steam circulation through the well. Arbitrarily, 100 d was chosen as the duration of attempts to heat the near-well region. In all cases, SAGD conditions follow this initial period. Each of the constraints will be discussed in more detail below.

Early-Time Performance Study

To heat the near-wellbore area and improve the initial production response of SAGD, we combined the operating conditions displayed in Table 2 into the seven cases: (i) SAGD operation conditions from the start, (ii) extreme pressure differential between injector and producer sections for 100 days followed by SAGD, (iii) steam circulation for 100 days followed by SAGD, (iv) circulate for 100 days followed by 100 days of an extreme pressure differential followed by SAGD, (v) cycle once followed by SAGD, (vi) cycle twice followed by SAGD, and (vii) cycle three times followed by SAGD. In each case except the first, an initial preheating phase precedes SAGD.

Results of this screening study are displayed in Figs. 4 to 6. Figures 4 and 5 display recovery factor histories for the first year of production and for 10 years of production, respectively. Recovery factor refers to the fraction of oil produced from the entire simulation volume. The cumulative steam oil ratio (CSOR) versus time curves for each case are displayed in Fig. 6. It is obvious from the curves that it is possible to improve initial production response. In general, cyclic steaming as applied in cases 5 to 7 leads to the most rapid oil recovery. However, the late time recovery performances shown in Fig. 5 display similar behavior for all cases. Recovery factor ranges from 19-22% after 3650 days of injection and all curves increase at similar rates.

Case 1 represents a base case in which SAGD was initiated from the beginning without preheating. This case produced the lowest percent recovery curve. In Case 2, we increase the injection rate constraint which thereby increases the pressure differential between the injection and production wells; hence, the conditions are referred to as extreme. The pressurization of the system improves production somewhat relative to the base case.

The "Circulate" phase in Cases 3 and 4 is a modified form of steam circulation in the well. Steam is injected so as to maintain the initial reservoir pressure. We did not simulate true steam circulation where steam that exits the tubing may only flow in the well before it is produced. A true circulating case in which the near-wellbore area is heated only by conduction would be inefficient, and the other techniques that we explore present better options. Circulation here is similar to the SAGD case: steam may replace oil volume in the reservoir when oil is produced. Hence, our "circulating" condition is somewhat of a misnomer.

The cumulative steam oil ratio displayed in Fig. 6 is standard: the cumulative steam volume injected as cold water equivalent volume divided by the cumulative hydrocarbon production. The CSOR varies substantially among the studies during the initial period because significantly different production and injection schemes were used. At late time, however, the CSOR for all cases averages roughly 3.0. Note, however, that the cyclic cases perform somewhat better, with regard to CSOR, in initial and late-time response.

Case Studies

Three of the cases above will be examined in greater detail to explain the differences in oil recovery and heating of the reservoir volume. The reference continuous SW-SAGD, extreme pressure differential, and one cycle prior to SW-SAGD cases will be discussed. Production rates, well pressures, and temperature profiles around the well will be examined.

Case 1,Continuous SAGD. In Case 1 we immediately operate at SAGD conditions and do not include a preheat phase. Figure 7 displays the injection and production curves for Case 1. The darkest curve in Fig. 7 represents the oil production rate. As expected, the initial oil rate is low, but increases with time as a steam chamber slowly develops and more oil is heated. Oil production peaks at roughly 80 m^3/day.

Note that our "SAGD" case is actually a combination of SAGD and pressure draw-down. Production well conditions are such that reservoir pressure must decline. It is clear from the similarity between the steam injection rate and water production rate in Fig. 7 that steam short-circuits from the injection region to the production region and the contact time is short between steam and reservoir. Recall that we represent the horizontal well with two separate sections placed end to end. The pressure differential between the regions and the proximity of "injection" and "production" perforations causes steam to travel quickly between them. Albeit inefficiently, a steam chamber is created within the reservoir as heated oil drains to the production region and steam migrates up to fill the void space. Optimizing the effect of spacing between injection and production sections represents another interesting problem to be addressed later in this report.

Figure 8 displays bottom-hole pressure curves for injection and production in Case 1. A large pressure differential of about 3000 kPa exists initially between the two sections of the well. Over time, the reservoir pressure decreases because we produce more fluids than we inject. This also causes the injection pressure to decrease. Figure 9 displays a temperature profile at 100 days for Case 1. Light shading corresponds to high temperature, and dark shading to low temperature. At late times, a large steam chamber grows in the middle region of the system. At 100 days, however, the steam chamber is just beginning to grow above the area between the injection and production sections. It is important to maximize the amount of net heat injection into the reservoir at early times to maximize the size of the heated volume surrounding the wellbore.

Case 2, Extreme Pressure Differential Prior to SAGD. In the extreme pressure differential case, the injection rate constraint is increased and this increases the pressure differential between the injection and production wells. Figure 10 displays the bottom-hole pressure histories. For the first 100 days, steam is injected at roughly 7000 kPa forcing steam into the formation and increasing the average reservoir pressure. Figure 11 displays the production response for the extreme period in the first 100 days followed by SAGD. Observing the oil rate in the first 100 days and comparing to Fig. 7, we see that the oil rate ramps up faster than Case 1. This is logical because Case 2 is an accelerated version of SAGD.

Figure 10 also indicates that a very high injection bottom-hole pressure is obtained between 0 and 100 days. High pressure results because the water production rate is substantially less than the steam injection rate, as shown in Fig. 11. Under the given conditions a limited amount of steam short-circuits, and an appreciable amount of steam enters the reservoir and increases the reservoir pressure. Pressure does not exceed the critical pressure where the formation parts or fractures.

If we view the oil production rate in Fig. 11 during and after the extreme period, it is obvious that we have improved response. Direct comparison of Cases 2 and 1 is somewhat misleading. Injection conditions have led to high reservoir pressure at the beginning of SAGD, causing significant production through pressure depletion in addition to gravity drainage of heated reservoir fluids. A better comparison is the temperature profile along the length of the well displayed in Fig. 12. The profile represents a relative time similar to the Case 1 profile, 100 days after SAGD inception. Again, light shading is high temperature and dark shading is low temperature. The profile for Case 2 is much more favorable. There is a larger heated area with a larger steam chamber. The steam chamber forms in the middle of the well because pressure drawdown is large; thus, the steam flux is largest in this location.

Case 5, One Cycle Prior to SAGD. Our cyclic case is very similar to typical cyclic conditions common in many thermal recovery operations. We inject steam along the entire well for 50 days, let it soak for 10 days, then produce along the entire length of the well for 60 days. The injection and production profiles in Fig. 13 summarize this cycle of steam injection, shut in, production followed by SAGD.

Figure 14 shows that the bottom-hole pressure increases to about 8000 kPa during the cyclic phase, but still remains within a feasible range. Because the oil is very viscous, this energy is rapidly depleted from the reservoir when production begins. From the oil production rate after the cycling period in Fig. 13, it is again obvious that SAGD response is improved. The slow increase of production rate found in Case 1, Fig. 7, is not evident here. The minimum production rate at roughly 200 days occurs because reservoir pressure is depleted somewhat following the cyclic period, as shown by the plot of well bottom hole pressure in Fig. 13. Again, the maximum oil production rate is about 80 m^3/day. In this case, the reservoir pressure at SAGD inception is similar to that in Case 1. We conclude that SAGD performs better because the near-wellbore area is heated.

Figure 15 displays the temperature profile at 120 days following SAGD inception. The temperature distribution is more uniform along the entire wellbore. Also, a large steam chamber is growing in the area immediately above the injection/production section. Additionally, the shading indicates that the entire horizontal length of the well has been heated somewhat. Hence, the rapid production response displayed in Fig. 14. Also, by comparing Figs. 15 and 12, it is apparent that the heated zone is larger than Case 2 above.

Contrary to the extreme pressure differential and SAGD cases where short-circuiting caused much of the steam to exit the reservoir immediately, the cyclic case is more efficient. All of the injected steam enters the reservoir and heats the near-wellbore area. One consequence of this is the uniform temperature distribution along the entire wellbore. Because of the increased thermal efficiency of the cyclic process, it appears that this procedure is the most appealing method of initiating SAGD.

Discussion of Early-Time Analysis

The problem of improving early-time performance of SW-SAGD transforms, essentially, into a problem of heating rapidly the near-wellbore area to create conditions that allow gravity drainage of oil. More specifically, for a steam chamber to grow, oil viscosity must be low enough so that fluid drains creating voidage for steam to fill. After the conditions necessary for gravity drainage of oil have been initiated by preheating, the SW-SAGD process allows for continuous steam chamber growth and oil production. Comparing the various simulation results, cyclic steam injection appears to be the most efficient method of heating the near-wellbore area. The problem of optimizing the early-time cyclic procedure is studied further in our companion paper [7].

An important general observation is that regardless of the process, early-time procedures should be carried out to maximize steam injection and heat delivery to the reservoir. The goal of any early-time procedure should be to heat the near-wellbore area as uniformly as possible. This goal is easier to achieve when operating at a maximum steam temperature. Later in the SAGD process, pressure can and should be reduced to a target operating pressure which optimizes efficiency and production rate.

The late time performance for all of the cases is favorable regardless of the early-time process. This confirms Joshi's finding that a steam chamber will grow in the reservoir. Favorable recovery factors are obtainable regardless of the injection/ production configuration[3].

There are obvious factors that will improve or inhibit SW-SAGD performance. For example, lower viscosity will certainly improve response, as will larger rock permeability and system compressibility. The actual variance in performance due to differing reservoir parameters is an interesting problem that we begin to address using a sensitivity analysis in the next section.

Sensitivity Analysis

We performed a sensitivity analysis of various reservoir parameters to gain a better understanding of their effect on production performance. Oil viscosity and gas content, reservoir thickness, and horizontal to vertical permeability anisotropy were studied.

The sensitivity analysis base case varies slightly from the base case used in the early-time analysis. Table 3 displays the operating conditions for the sensitivity analysis base case. The base case consists of two steam injection cycles followed by SAGD operating conditions. We adjusted the operating conditions in an attempt to reduce steam short-circuiting, reduce steam-oil ratio, and to improve efficiency. During the initial cyclic period, we reduced the maximum reservoir pressure to 8,000 kPa from 10,000 kPa while keeping the rest of the operating conditions the same. The steam injection temperature was 296 °C, which corresponds to a steam pressure of 8004 kPa. During SAGD, operating conditions were chosen so that the process operated near the original reservoir pressure of 2654 kPa. Maximum injection pressure was set slightly above initial reservoir pressure at 3230 kPa; minimum production pressure was set slightly below initial reservoir pressure at 2230 kPa. The steam injection temperature was reduced to 238 °C from 295 °C. Recall that initial reservoir conditions were chosen to approximate field conditions[4]. The rate constraints remained the same at 300 m^3/d maximum liquid production and 200 m^3/d maximum steam injection rate.

Between the injection and production sections of the horizontal well, a 30 m long unperforated section was added. This is an attempt to force steam to penetrate substantially far into the reservoir and reduce the amount of steam short-circuiting.

Sensitivity Cases

The various cases created in the sensitivity analysis include: (i) a base case with the properties in Table 1 and operating conditions shown in Table 3, (ii) dead oil to examine the effect of solution gas, (iii) an increase in pay thickness to 28 m, (iv) a reduction in pay thickess to 4 m, (v) permeability anisotropy k_h:k_v of 1, (vi) k_h:k_v equal to 2, (vii) k_h:k_v equal to 10, (viii) oil viscosity of 20 Pa-s at initial reservoir temperature (20,000 cP), and (iv) oil viscosity of 40 Pa-s (40,000 cP) at initial reservoir temperature. The viscosity versus temperature relation for the base case is given in Table 1 and those for the 20 and 40 Pa-s cases are listed in Table 3.

All calculations in the sensitivity cases include a separation of 30 m between injector and producer sections of the well to achieve better steam distribution in the reservoir. Two periods of cyclic steam injection precede continuous injection and production. In both periods, steam is injected for 50 days at a rate of 300 m^3/day with a maximum allowed pressure of 8000 kPa. The soak period is 10 days and the length of production is a relatively short 40 days to avoid large heat withdrawal from the reservoir. Continuous SAGD operating conditions follow. All of the various sensitivity runs follow this procedure.

The recovery factor vs. time and cumulative steam-oil ratio (CSOR) versus time curves are presented in Figs. 16 and 17, respectively. Significant variation is found in production response between most of the cases. Briefly, production is highest when the reservoir permeability is isotropic, and is worst when the initial oil viscosity is high or the oil-saturated thickness is small. The steam-oil ratio is largest for the short formation thickness of 4 m. The next largest CSOR is for the viscous 40 Pa-s initial oil case. The smallest CSOR is found for the case with a pay zone thickness of 28 m and for cases where k_h:k_v approaches 1. Note that recovery factors are less here , Fig. 16, compared to the early-time study, Fig. 5, because the steam injection pressure has been reduced substantially as seen by comparing Tables 2 and 3.

Due to space restrictions, it is impossible to display the instantaneous production rates, bottomhole pressure, and temperature profiles for all of the sensitivity cases. However, a brief discussion of the results of each of the sensitivity cases will be given.

The base case oil viscosity is 4.043 Pa-s at initial reservoir conditions. Two additional cases were created by increasing the initial viscosity to 20 Pa-s and then 40 Pa-s. The recovery factors at 3650 days (10 years) for these two less favorable cases were 4.5% and 2.7%, respectively, as compared to 10.6% for the base case. The cumulative steam-oil ratios were also unfavorable. The CSOR were 3.7 and 4.8 after 10 years for the 20 and 40 Pa-s cases, respectively. The problem is quite simple: it is hard for the viscous oil to drain and therefore it cannot be replaced by steam. In the base case, the average oil production rate is 75 m^3/day over the 3650 days of production and excluding the startup period. For the 20 Pa-s case the average oil production rate is 30 m^3/day while for the 40 Pa-s case it is 20 m^3/day. As the viscosity increases the average oil production rate decreases, it becomes difficult to meet the steam injection target, and the size of the steam chamber is smaller compared to the less viscous cases.

The base horizontal to vertical permeability ratio, k_h:k_v, is 4.25. The vertical permeability was adjusted to create three more cases with ratios of 1, 2, and 10. In all cases, the horizontal permeability remained fixed at 3400 mD. Larger ratios present less favorable conditions for upward steam migration and oil drainage. As k_h:k_v increases, cumulative recovery at a given time decreases and the CSOR increases, as shown in Figs. 16 and 17.

The base case oil composition contained 10% gas by mole which translates to a solution gas oil ratio of about 28 SCF/STB. An additional case that models a dead oil was created by reducing the solution gas to 1% by mole. The two effects of solution gas in regard to the oil phase are to increase oil-phase compressibility and reduce the oil-phase viscosity. Oil phase viscosity is computed as a mole fraction weighted sum of the oil and gas component viscosities[6]. Recovery factor and CSOR were less favorable with the dead oil at 9.2 % and 3.0 after 10 years as compared to 10.4% and 2.8 for the base case. Likewise, the average oil production rate is 64 m^3/day over the ten year period as compared to 80 m^3/day for the base case.

Discussion of Sensitivity Analysis

Taken together, the results from the sensitivity analysis suggest that application of SW-SAGD to exceptionally viscous oils will be difficult. When the initial viscosity is greater than 10 Pa-s, oil drainage becomes very slow and it is difficult to form a large steam chamber. Likewise, the application of SW-SAGD to thin oil zones with thickness of roughly 4 m does not appear to be feasible. A steam chamber of significant height must develop for efficient oil drainage. On the other hand, the 19.6 and 28 m thick cases showed significant recovery and little difference was found between theses two cases.

The presence of solution gas also aids recovery somewhat. Even though the oil is viscous and the amount of gas low in both cases, volumetric expansion of the oil is aided by solution gas and cumulative recovery increases by 10% relative to the dead oil case at 3650 days.

As expected, oil recovery improves as the permeability anisotropy decreases. Both steam injection and oil drainage are aided as the vertical permeability increases relative to the horizontal. Resistance to flow in the vertical direction decreases relative to horizontal. Additionally, less short circuiting occurs as k_v increases relative to k_h.

Injector to Producer Spacing

In all of the runs in the sensitivity analysis, 30 m of unperforated well separated injection and production regions. Separating the regions further increases the length of time required for steam to flow from the injection to the production section and thereby improves growth of the steam chamber. However, separation between injection and production regions delays oil production.

To quantify the effect of separating injection and production regions, we performed the following highly approximate analysis. The Darcy velocity of a particle or volume of steam (u_v) flowing upward above the horizontal injection section is given by

$$u_v = -\frac{k_v k_{rs}}{\mu_s}\Delta\rho g \tag{1}$$

where k_v is the vertical permeability, k_{rs} is the relative permeability to steam, μ_s is the steam viscosity, $\Delta\rho$ is the density difference between the oil and steam, and g is the acceleration due to gravity. The Darcy velocity in the horizontal direction (u_h) between the injection and production regions is given by

$$u_h = -\frac{k_h k_{rs}}{\mu_s}\frac{dp}{dx} \tag{2}$$

where k_h is the horizontal permeability and dp/dx is the pressure gradient in the horizontal direction.

The characteristic times required for a particle to travel to the top of the reservoir (t_v) and from the injection section to the production section (t_h) are given by

$$t_v = \frac{h}{u_v} \tag{3}$$

and

$$t_v = \frac{L}{u_h} \tag{4}$$

where h is the height of the reservoir and L is the distance between injection and production regions. If the t_v:t_h ratio is larger than one, then the time required for a particle to travel to the top of the reservoir is larger than the time required to travel to the production section. Therefore, we expect a large amount of steam short-circuiting. Conversely, if the t_v:t_h is close to 1, we would expect limited steam short-circuiting, better steam flow through the reservoir, and increased steam chamber growth.

Substituting the Darcy velocity equations into the characteristic time equations and simplifying allows us to calculate the ratio in terms of available parameters.

$$\frac{t_v}{t_h} = \frac{h}{L}\frac{k_h}{k_v}\frac{\frac{dp}{dx}}{\Delta\rho g} \tag{5}$$

We can approximate dp/dx as,

$$\frac{dp}{dx} \cong \frac{\Delta p}{L} = \frac{p_{inj} - p_{prod}}{L} \tag{6}$$

The subscripts inj and prod refer to injection and production pressure. Substituting this into Eq. 5 yields

$$\frac{t_v}{t_h} = \frac{h}{L^2}\frac{k_h}{k_v}\frac{(p_{inj} - p_{prod})}{\Delta\rho g} \tag{7}$$

For the base case of the sensitivity analysis and using the properties displayed in Table 4, we calculate a t_v:t_h value of 12. Therefore, we do not expect steam to have a strong tendency to flow upward. Although this analysis is just an approximation, it does help us to estimate if short-circuiting will be an immediate production problem. A more thorough analysis would consider variations in temperature, pressure, density, and viscosity as well as a more complete description of the pressure distribution.

To gauge the effect of greater distance between the injection and production regions, additional simulations were conducted using the properties of the base case for the sensitivity analysis, Table 3. As previously, two cycles of steam stimulation preceded continuous steam injection. Separation sizes of 60, 90, and 120 m were examined. These distances correspond to t_v:t_h of 3.0, 1.3, and 0.75, respectively. In all cases, the length of the injection and production regions is the same only the distance between the two changes.

Recovery factor and CSOR histories for these calculations are given in Figs. 18 and 19. The general trend over 3650 days is that recovery decreases as the injection to production region spacing increases. The recovery factor for the 30 m separation distance is 10.4 % after 3650 days whereas that for the 90 m separation is 9.7%. On the other hand, the CSOR decreases only slightly as the separation size increases. This indicates that recovery efficiency has not increased greatly with the addition of unperforated well between the injection and production regions.

Throughout, we have specified equal lengths of injection and production regions of the well for simplicity. In practice, this is both unnecessary and unlikely to be the case. It is probable that the injection region could be shortened considerably thereby devoting a greater portion of the well to production. As steam is much less viscous and dense than the oil, steam mobility is large. Thus, it should be possible to distribute steam in the reservoir and develop a steam chamber over the horizontal well with a much smaller perforated section provided that steam short circuiting from injector to producer regions is minor. We do not attempt such an analysis here.

Conclusions

Here it is shown that to improve early-time performance of SW-SAGD, it is necessary to heat the near-wellbore region rapidly and uniformly to reduce oil viscosity and promote gravity drainage. Cyclic steaming, as a predecessor to SW-SAGD, represents the most thermally efficient early-time heating method. Uniform heating along the length of the wellbore appears achievable with cyclic steam injection. Immediately placing a cold well on SAGD hinders the early-time heating process and initial production response in this case will be low. Regardless of the early-time process, it should be performed to provide maximum heat delivery to the reservoir. Additionally, despite different initial procedures, the oil production rates after several years of steam injection are all very similar.

The sensitivity analysis performed here indicates that SW-SAGD is most applicable to heavy oils with initial viscosity below 10 Pa-s (10,000 cP) Additionally, the reservoir must be sufficiently thick to allow significant vertical steam chamber growth. Recovery from thin oil zones is not significant. The sensitivity analysis also indicates that the presence of relatively small amounts of solution gas aids the recovery process by enhancing volumetric expansion of the oil on heating.

A simplified analysis was completed to examine the effect of increasing the distance between regions of the well dedicated to injection and production. The cumulative steam-oil ratio did not decrease substantially with increased separation indicating that this strategy does not enhance steam chamber growth or recovery efficiency, contrary to the results of the analysis.

Nomenclature

CWE	cold water equivalent
g	acceleration due to gravity
h	net reservoir height
k	permeability
kr	relative permeability
L	distance between injection and production regions
p	pressure
t	characteristic time
u	Darcy velocity
x	distance

Greek

μ	viscosity
ρ	phase density

Subscripts

h	horizontal

s steam
v vertical

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6. Computer Modelling Group LTD, "STARS Version 98 User's Guide," Calgary, Alberta, Canada, 1998.
7. Diwan, U. K. and Kovscek, A. R., "Thermal Oil Recovery Using a Single Horizontal Well," in preparation, 1999.

Table 1: Grid, rock, and oil property description.

Grid System		Rock Properties	
total number of blocks	5,568	porosity	33%
x-dimension	1,400 m	k_h	3,400 mD
y-dimension	80 m	k_v	800 mD
z-dimension	19.6 m		
well length	800 m		
Reservoir Properties		**Oil Properties**	
initial pressure	2,654 kPa	components	water, oil, and gas
initial temperature	16 °C	initial composition	90 % (mole) oil
initial S_o	85%		10% (mole) gas
initial S_w	15%	viscosity (mPa-s) versus temperature (K) function	$\mu = 1.74\text{x}10^{-6}\ \exp\left(\frac{6232.74}{T}\right)$

Table 2: Operating conditions for early-time performance study.

Property	Operating Condition			
	SAGD	Extreme	Cyclic	Circulating
steam temperature (°C)	295	295	295	295
maximum injection rate (CWE m^3/day)	200	600	300	300
maximum injection pressure (kPa)	10,000	10,000	10,000	10,000
maximum production rate (m^3/day)	300	600	300	300
minimum production pressure (kPa)	500	500	500	500

Table 3: Description of sensitivity analysis.

Property	Operating Condition	
	Initial Cyclic	SAGD
steam temperature (°C)	295	238
maximum injection rate (CWE m^3/day)	300	200
maximum injection pressure (kPa)	8000	3230
maximum production rate (m^3/day)	300	300
minimum production pressure (kPa)	2,230	500
Oil Viscosity		
20,000 mPa-s case (μ (mPa-s), T(K))	$\mu = 8.61\text{x}10^{-6}\ \exp\left(\frac{6232.74}{T}\right)$	
40,000 mPa-s case (μ (mPa-s), T(K))	$\mu = 1.72\text{x}10^{-5}\ \exp\left(\frac{6232.74}{T}\right)$	

Table 4: Parameters used to calculate t_v/t_h.

Parameter	**Value**
h	19.6 m
L	30 m
k_h	3400 mD
k_v	800 mD
p_{inj}	3230 kPa
p_{prod}	2230 kPa
oil density	950 kg/m^3
steam density	42.6 kg/m^3
g	9.8 m/s^2

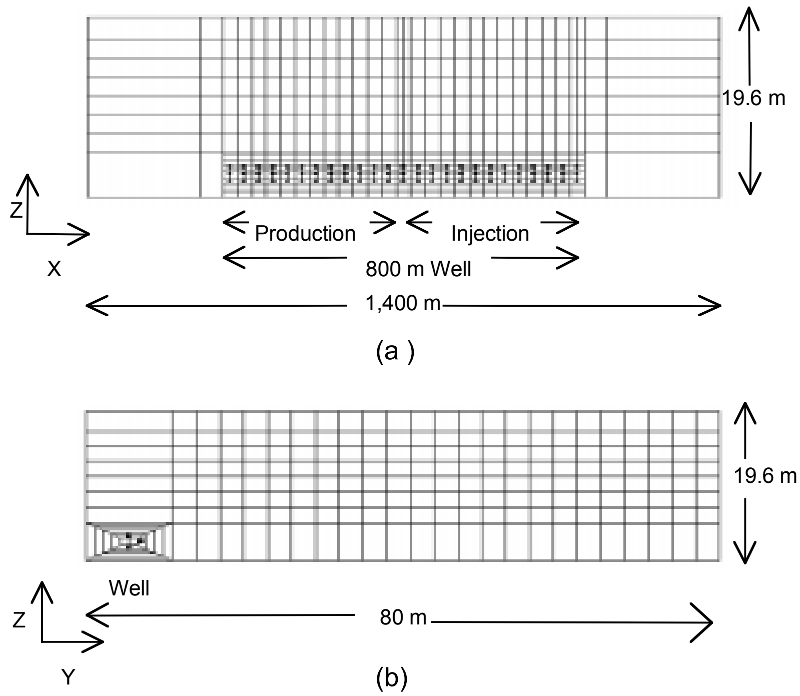

Figure 1: Schematic of grid system: (a) parallel to well bore and (b) perpendicular to wellbore.

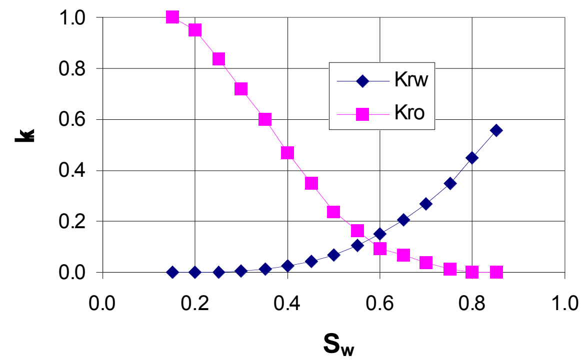

Figure 2: Water-oil relative permeability function.

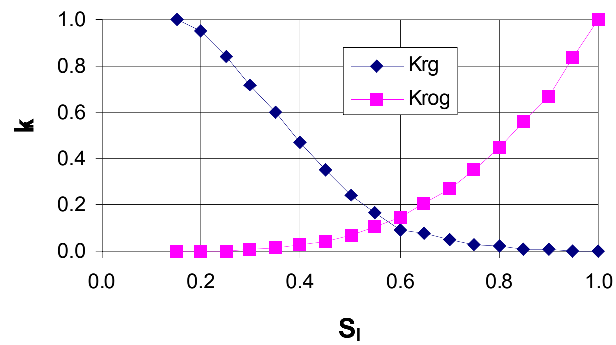

Figure 3: Gas-liquid relative permeability function.

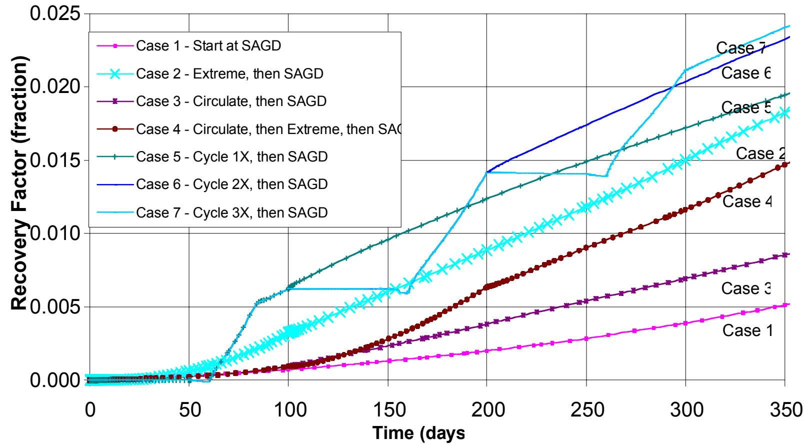

Figure 4: Recovery factor for the first year of production.

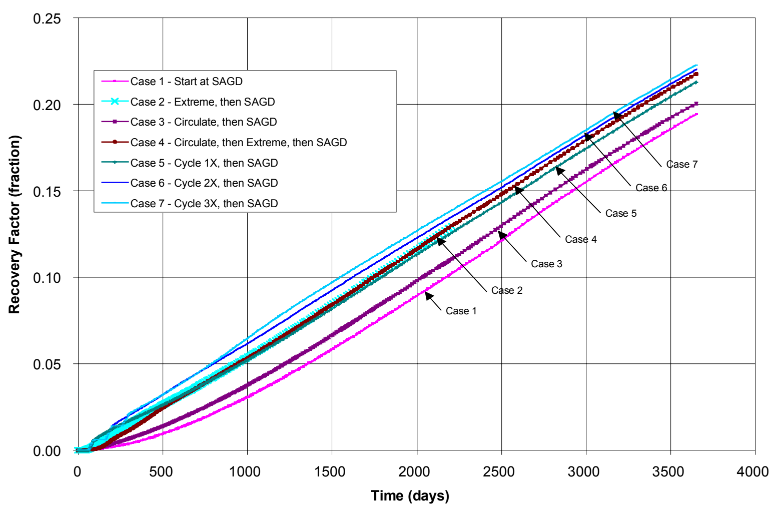

Figure 5: Recovery factor for 10 years of production.

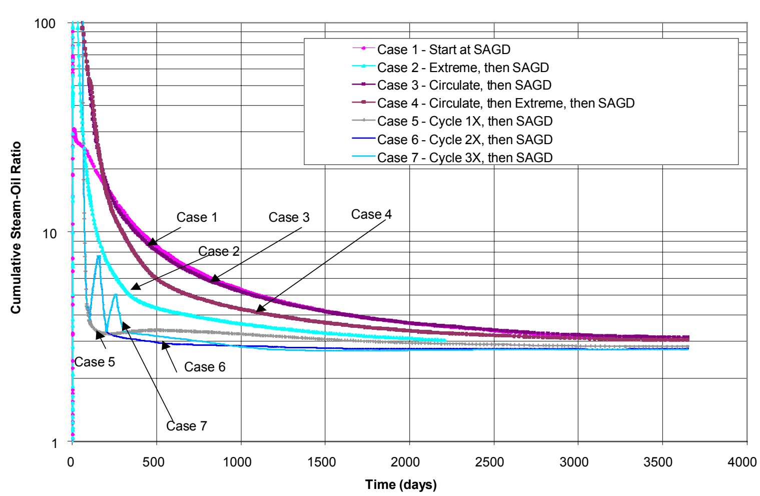

Figure 6: Cumulative steam oil ratio for 10 years of production.

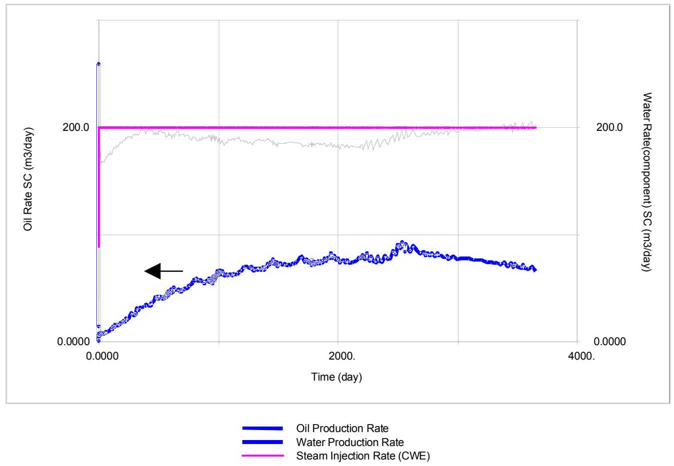

Figure 7: Steam injection and production history, SAGD from start-Case 1.

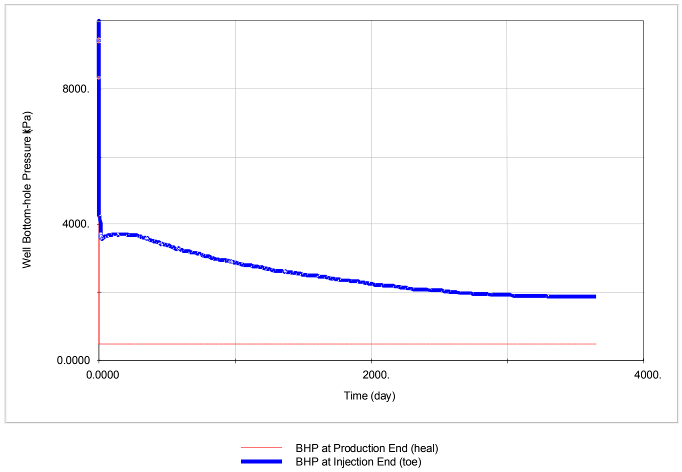

Figure 8: Bottomhole pressure, SAGD from start-Case 1.

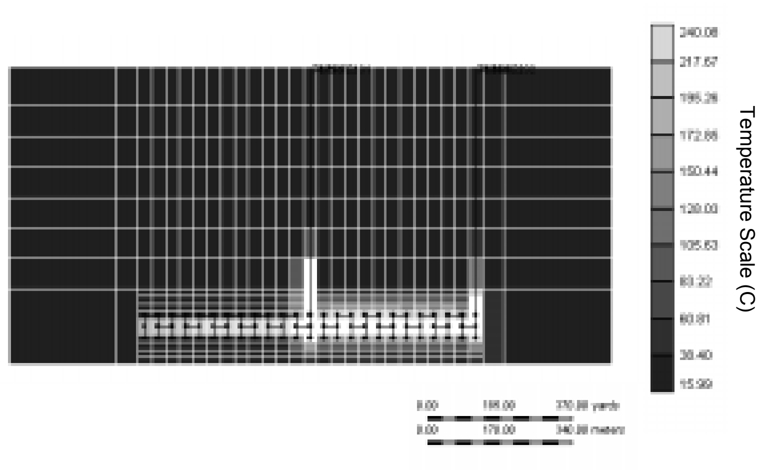

Figure 9: Temperature profile at 100 days, SAGD from start-Case 1.

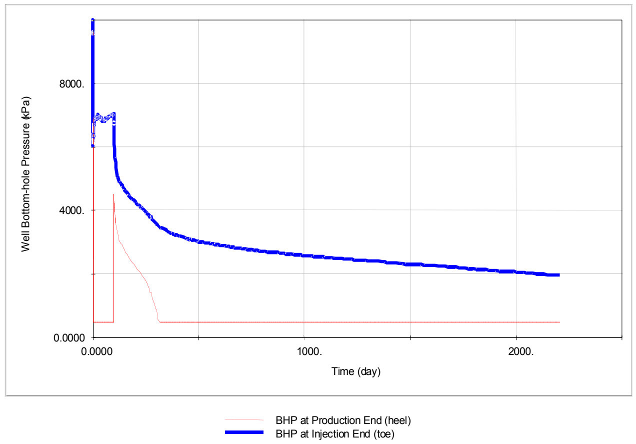

Figure 10: Bottom-hole pressure, extreme pressure differential then SAGD-Case 2.

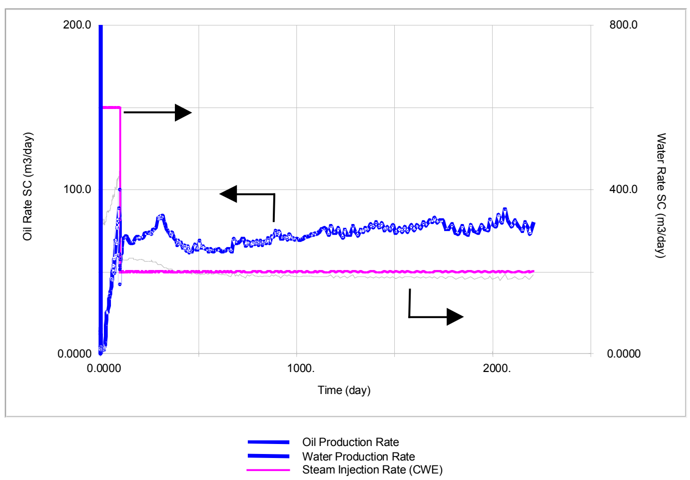

Figure 11: Steam injection and production history, extreme pressure differential then SAGD-Case 2.

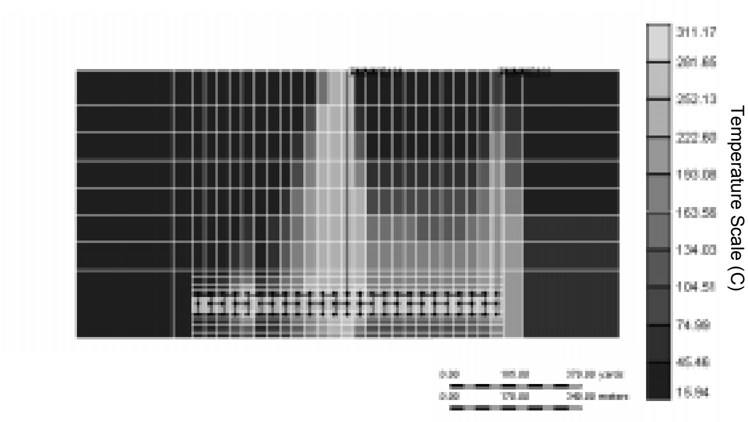

Figure 12: Temperature profile at 200 days, extreme pressure differential then SAGD-Case 2.

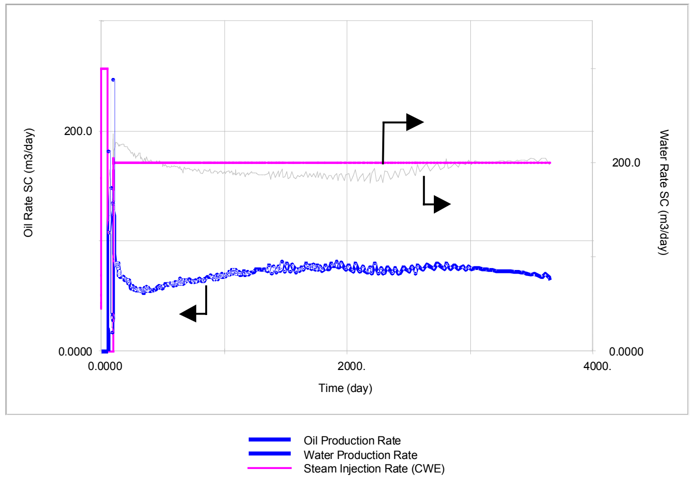

Figure 13: Steam injection and production history, 1 cycle then SAGD-Case 5.

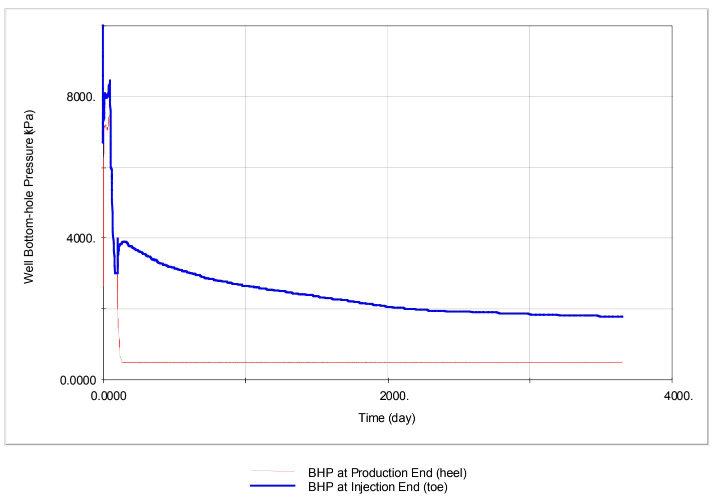

Figure 14: Bottomhole pressure, 1 cycle then SAGD-Case 5.

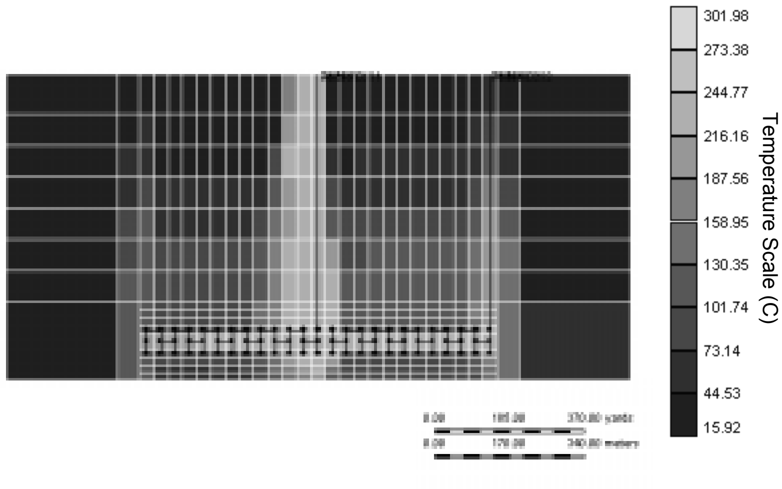

Figure 15: Temperature profile at 200 days, 1 cycle then SAGD-Case 5.

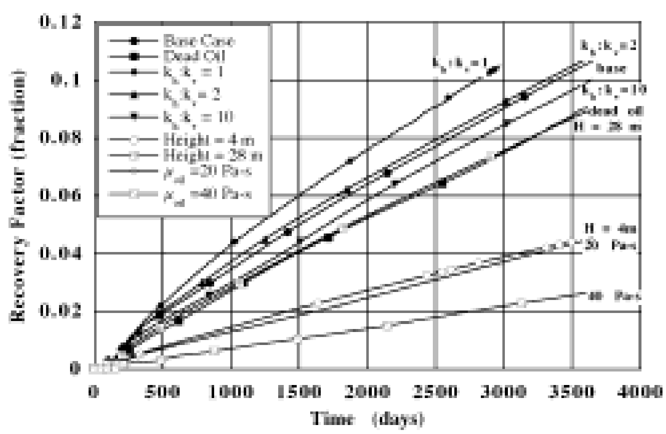

Figure 16: Recovery factor versus time, sensitivity analysis.

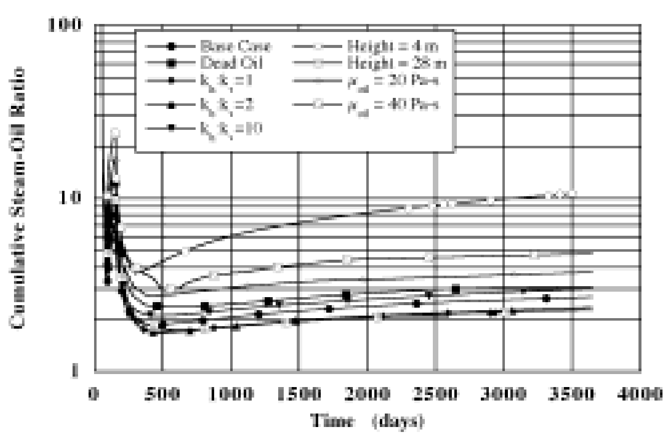

Figure 17: Cumulative steam oil ratio, sensitivity analysis.

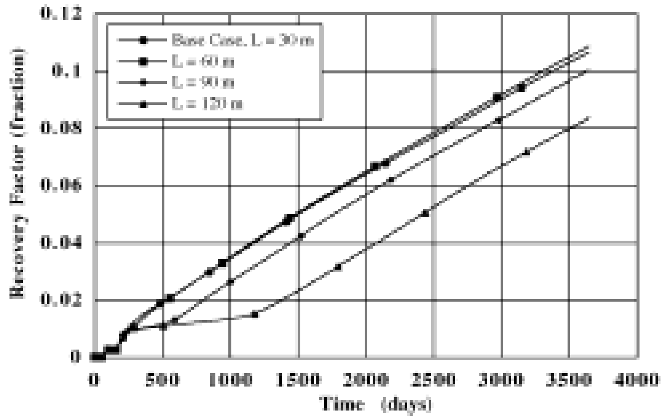

Figure 18: Recovery factor versus time, effect of injector to producer section spacing.

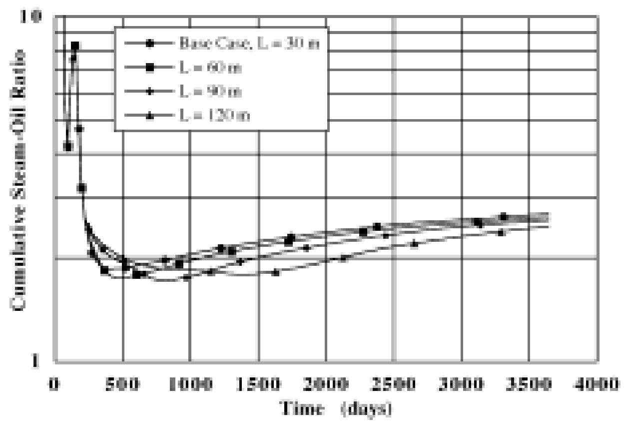

Figure 19: Cumulative steam-oil ratio, effect of injector to producer section spacing.