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Computer Simulation of Single-Well Steam Assisted Gravity Drainage
(SW-SAGD)

SUPRI TR 119

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Abstract

Steam assisted gravity drainage (SAGD) is an effective method of producing 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. Obvious advantages of SW-SAGD include cost savings and utility in relatively thin reservoirs. However, the process is technically challenging.

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 are interested in optimizing the start-up procedure.

An investigation of early-time processes to improve reservoir heating will be discussed. We performed a numerical simulation study of combinations of cyclic steam injection and steam circulation prior to SAGD in an effort to better understand and improve early-time response. Results from this study, including cumulative recoveries, temperature distributions, and production rates display variances within the methods. It is found that cycling steaming of the reservoir prior to SAGD offers the most favorable option for heating the near-wellbore area and creating conditions that will improve initial SAGD response.

We will also discuss the influence of certain reservoir parameters on the performance of SW-SAGD. A sensitivity analysis of reservoir height, oil viscosity, horizontal to vertical permeability anisotropy, and dead oil versus live oil was performed. We find that operating performance varies significantly between cases. More favorable reservoir conditions such as low viscosity, thick oil zones, and solution gas, improved reservoir response. Under unfavorable conditions, response was limited and may prove to be uneconomical in actual field cases.

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1. INTRODUCTION

1.1 Background

Steam assisted gravity drainage maximizes the role of gravity forces during steam flooding of heavy oils. Generally, it is applied with a pair of horizontal wells. Single-well steam assisted gravity drainage is similar in concept to conventional SAGD. As steam enters the reservoir, it heats up the reservoir fluids and surrounding rock, allowing hot oil and condensed water to drain through the force of gravity to a production well at the bottom of the formation. Heat is transferred by conduction, convection, and latent heat of the steam. In conventional SAGD, illustrated in Fig. 1, steam is injected through a horizontal injection well placed directly above a horizontal production well. Thus, a steam chamber forms directly above the production well. In SW-SAGD, we attempt to create a similar recovery mechanism through the use of a single horizontal well. 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.

In a reservoir where cold oil is very viscous and will not flow easily, initial production rates via SAGD are very low. Conceptually this makes sense when the SAGD process is visualized. In a strict definition of SAGD, steam only enters the reservoir to fill void space caused by produced oil. However, if the oil is cold and will not gravity drain into the wellbore at appreciable rates, we must heat the oil to reduce the viscosity so that it will flow. Therefore, initial heating of the area around the wellbore is required so that SAGD can take place.

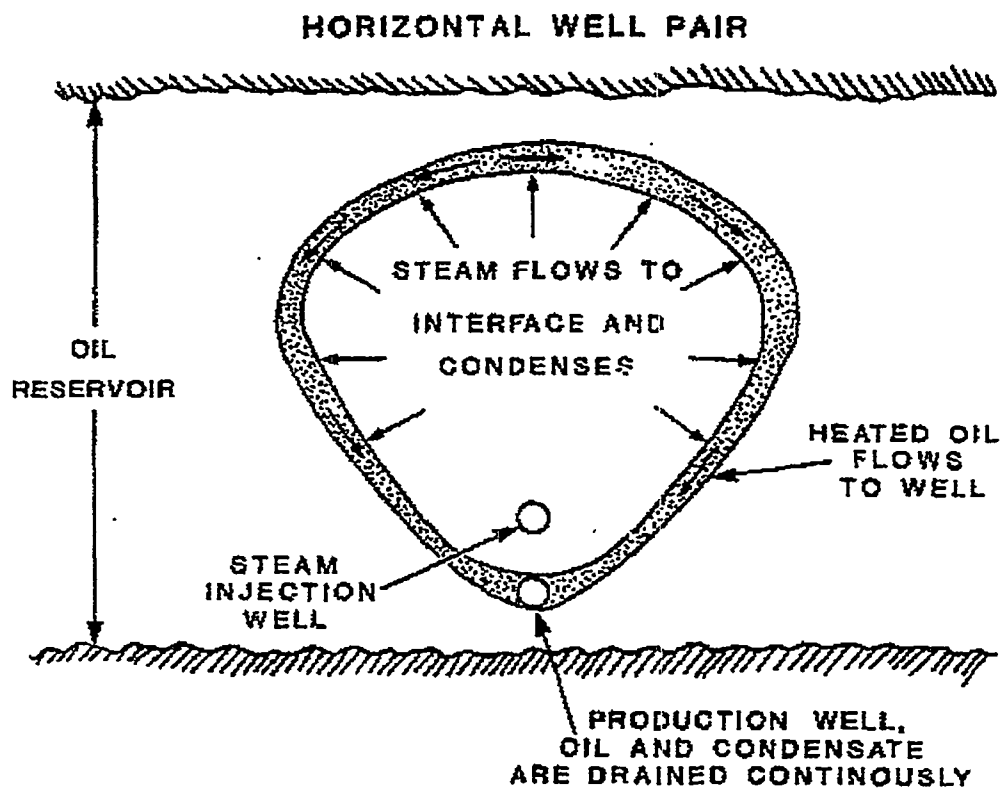


Figure 1: Steam Assisted Gravity Drainage Concept as Described by Butler

After SAGD is initiated, a steam chamber will grow in the reservoir. Butler notes that the steam chamber will initially grow upward to the top of the reservoir and then begin extending horizontally (Butler, 1991). 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 (Butler, 1991). Figure 1 provides a visual description of the process.

Joshi found 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 (Joshi, 1986). 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 (1996) simulated various scenarios to evaluate the difference between cyclic steam injection and SAGD. They focused, partially, on the interactions 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.

Falk *et al.* (1996) provide an overview of the completion strategy and some typical results for a SW-SAGD field test. For example, a roughly 850 m long well in a section of the Cactus Lake Field, Alberta Canada with 12 to 16 m of net pay was installed to produce 12 °API gravity oil. The reservoir is a clean, unconsolidated, 3400 md permeability sand. Oil production response to steam was slow and gradually increased to more than 100 m³/d. The cumulative steam-oil ratio was between 1 and 1.5 for the roughly one-half year of reported data.

McCormack *et al.* (1997) also describe operating experience gained after ELAN Energy Inc. drilled nineteen SW-SAGD wells in Canada. Field results for approximately two years of production performance were mixed. Of their seven pilot projects, five were either suspended or converted to other production techniques because of poor performance. Positive results were seen in fields with relatively high reservoir pressure, low oil viscosity, foamy oil, and/or insignificant bottom-water drive. Poor results were seen in fields with very high viscosity, strong bottom-water drive, and/or sand production problems. They suspect that the production mechanism is a mixture of gravity drainage, increased primary recovery because of near-wellbore heating via conduction, and hot water induced drive/drainage (McCormack *et al.*, 1997). The authors note that the production mechanism is not clearly understood.

One advantage of SW-SAGD, as in the Cactus Lake example, is that it may allow us to apply SAGD to thinner reservoirs where it is not possible to drill two vertically spaced horizontal wells (Falk *et al.*, 1996). Furthermore, cost savings associated with drilling one horizontal well rather than two are substantial.

1.2 Problem Definition

Our research can be grouped into two general topics:

1. A review of early time operating performance of SW-SAGD
2. A sensitivity analysis of basic reservoir parameters and their effect on performance of SW-SAGD

Understanding the operating conditions to improve the crucial early-time 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 and fluid conditions where the process would be an appropriate production technique.

1.3 Methodology

We gained a better understanding of early-time performance by building and comparing various computer simulations. The early-time processes examined include cyclic steaming, steam circulating, 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, and permeability anisotropy. Computer Modeling Groups's (CMG) STARS thermal simulator was used to perform the work.

2. Model Description

The base case is STARS example *sthrw009.dat* released with Version 98.01 (1998). It represents a typical Alberta reservoir (The operating conditions and well completion are modified to develop additional cases.

2.1 Grid System

Figure 2 displays cross-sections along the length of the well (Fig. 2a) and perpendicular to the well (Fig. 2b). 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 modeled using two individual discretized wellbores, each equal in length and placed directly end to end. This gives us freedom to explore various completion strategies and operating conditions. In the sensitivity analysis, the base case includes one empty grid block, representing a distance of 30 m between the injection and production sections of the well; whereas, in the early-time analysis base case, the sections are placed end-to-end without a grid block in between. 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, the pressure distribution is hydrostatic, and the reservoir temperature is 16 °C. Further simulation information is located in Appendix 1.

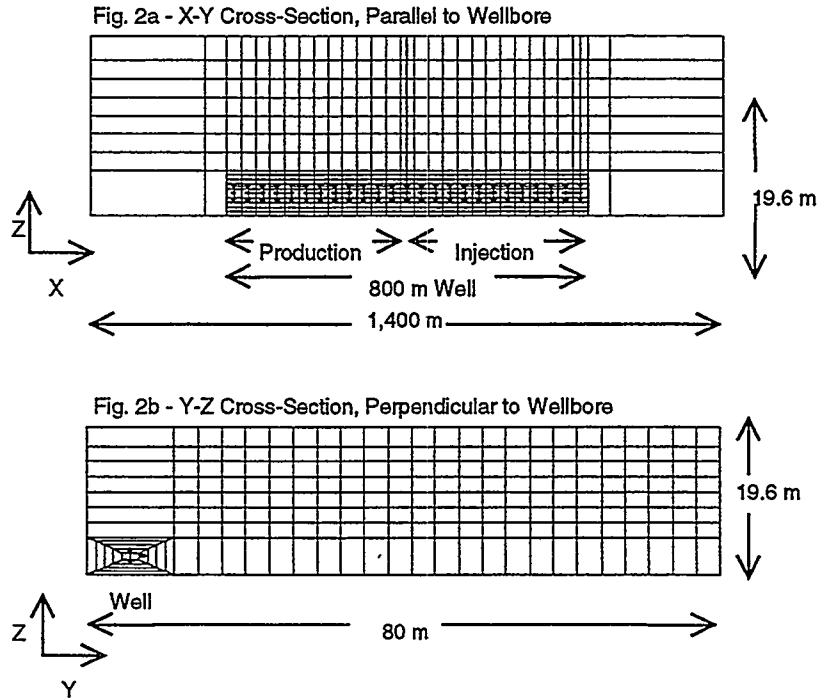


Figure 2: Visual Description of Base Case Grid System

Table 1: Model Description

Grid System	
3D Cartesian System	
Hybrid Grid Surrounding Well	
Total Number of Blocks:	5,568
X-Dimension (m):	1,400
Y-Dimension (m):	80
Z-Dimension (m):	19.6
Well Length (m):	800
Reservoir Properties	
Initial Pressure (kPa):	2,654
Initial Temperature (C):	16
Initial So (%):	85
Initial Sw (%):	15
Rock Properties	
Porosity (%):	33
Kh (mD):	3,400
Kv (mD):	680
Fluid Properties	
Live Oil	
Water, Oil, & Gas Components	
Initial Oil Phase Composition: 90% Oil, 10% Gas	

2.2 Rock Properties

Reservoir properties are also given in Table 1. Figures 3 and 4 display graphically the water-oil relative permeability and gas-liquid relative permeability curves, respectively. Table 1 displays the porosity and initial saturations of the reservoir. 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. The homogeneous porosity is 33%.

2.3 Fluid Properties

A live, black-oil model is used. The initial oil phase is made up of 90% by mole oil component and 10% gas component for a solution gas-oil ratio (GOR) of about 28. The effect of solution GOR on oil recovery is explored in the sensitivity analysis. Oil viscosity at the initial reservoir temperature is 4000 mPa-s. Figure 5 displays the viscosity versus temperature relationship. An increase of oil temperature to 100 °C decreases the oil viscosity to 30 mPa-s.

2.4 Operating Conditions

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. Each of the constraints will be discussed in more detail in the *Early-Time Performance* section.

Table 2: Description of Operating Conditions (Early-Time Performance Cases)

Property	Operating Condition			
	SAGD	Extreme Pressure Differential	Cyclic	Circulating
Steam Temp. (C):	295	295	295	295
Steam Pres. (kPa):	8014	8014	8014	8014
Injection Well Max Rate Constraint (m3/D):	200	600	300	300
Injection Well Max Pres. Constraint (kPa):	10,000	10,000	10,000	10,000
Production Well Max Rate Constraint (m3/D):	300	600	300	300
Production Well Minimum Pres. Constraint (kPa):	500	500	500	500

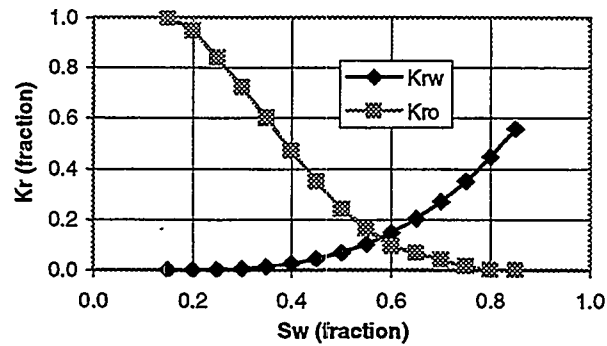


Figure 3: Water-Oil Relative Permeability Curve

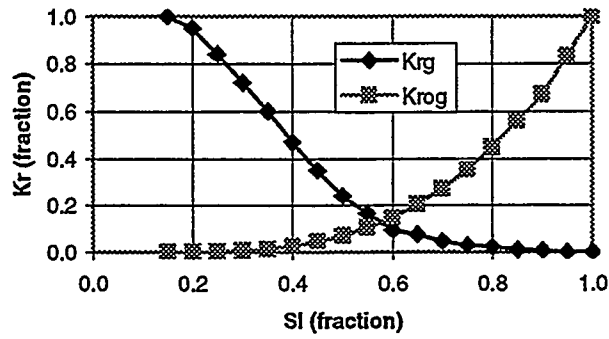


Figure 4: Gas-Liquid Relative Permeability

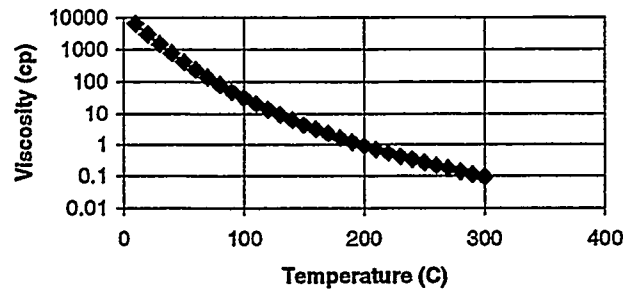


Figure 5: Base Case Viscosity/Temperature Relationship

Table 3 lists the operating constraints for the base case created to perform the sensitivity analysis. The case consists of two steam injection cycles followed by SAGD operating conditions. More details are included in the *Sensitivity Analysis* section.

Table 3: Description of Simulation Cases, Early-Time Performance Analysis

Case	Description
1	SAGD Operating Conditions from Start
2	Extreme Pressure Differential Conditions for 100 d, Followed by SAGD Operating Conditions.
3	Circulate 100 d, Followed by SAGD Operating Conditions
4	Circulate 100 d, Followed by Extreme Pressured Differential Conditions for 100 d, Followed by SAGD Operating Conditions
5	Cycle 1X, Followed by SAGD Operating Conditions
6	Cycle 2X, Followed by SAGD Operating Conditions
7	Cycle 3X, Followed by SAGD Operating Conditions

3. Early-Time Performance Study

3.1 Overview

In an attempt 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 various cases displayed in Table 3. There are four operating condition scenarios and seven cases overall. In each case, an initial preheating phase precedes SAGD.

Figure 6 displays recovery factor versus time curves for each case for the first year of production. Recovery factor refers to the percentage of oil produced from the entire simulation volume. Case 1 represents a base case in which SAGD was initiated from the beginning without a preheating phase. This case produced the lowest percent recovery curve. It is obvious from the curves that it is possible to improve initial production response. In general, cyclic steaming leads to most rapid oil recovery.

Figure 7 displays recovery factor versus time curves for each case for ten years of production. For all cases, the late-time performance is similar. Recovery factor ranges from 19-22% and all curves increase at similar rates. The late-time performance of our SW-SAGD process is similar, regardless of the early-time strategy.

Figure 8 displays cumulative steam-oil ratio (CSOR) versus time curves for each case for the first year of production. Cumulative steam-oil ratio refers to the cumulative steam volume injected divided by the cumulative hydrocarbon production. CSOR varies substantially during this period because significantly different production and injection schemes were used. At late time, however, the CSOR for all cases averages 3.0, as seen

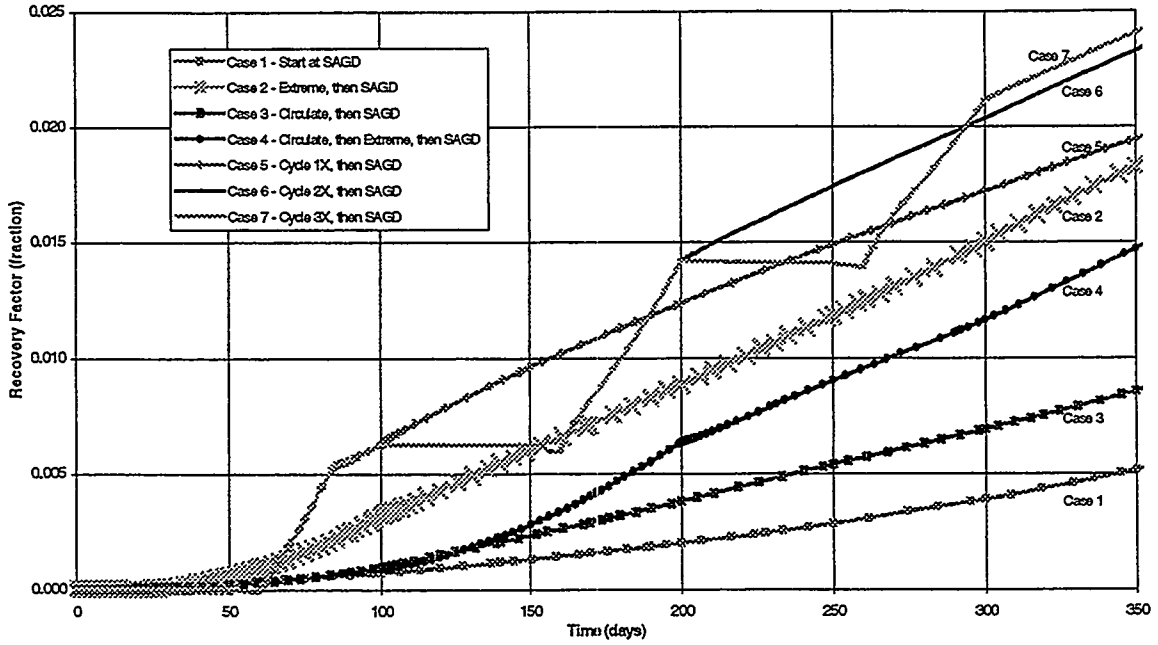


Figure 6: Recovery Factor vs. Time for All Cases (First Year of Production)

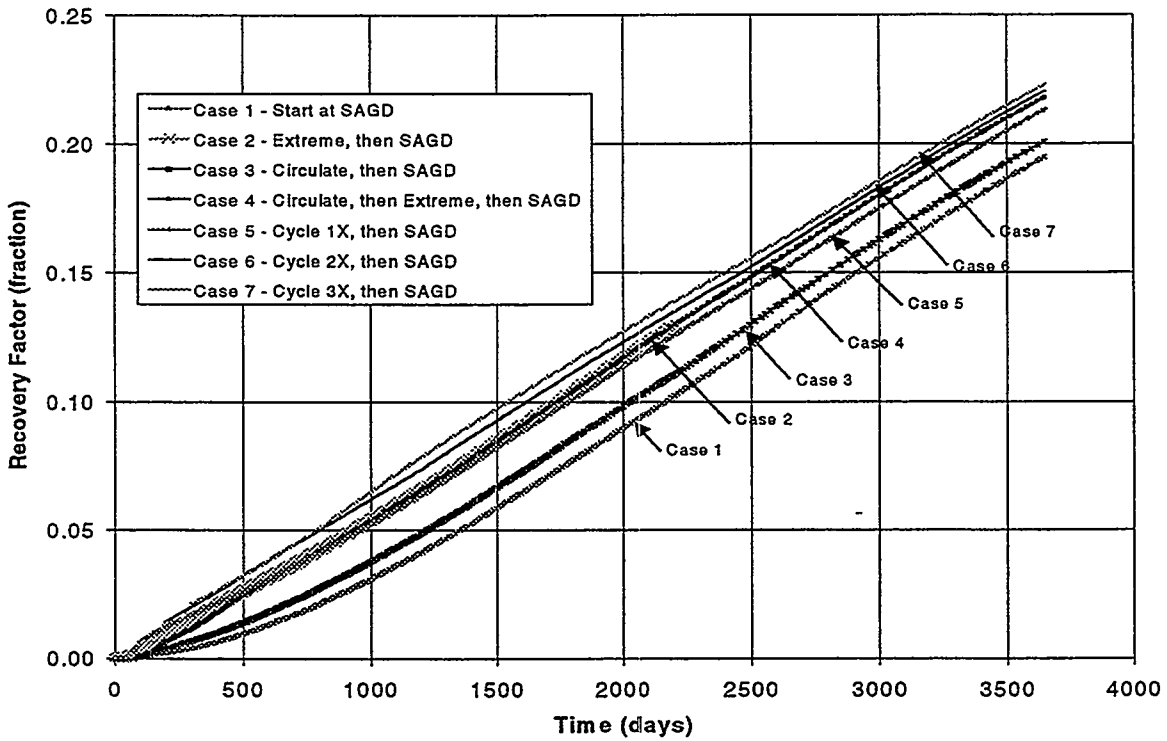


Figure 7: Recovery Factor vs. Time for All Cases (10 Years Production)

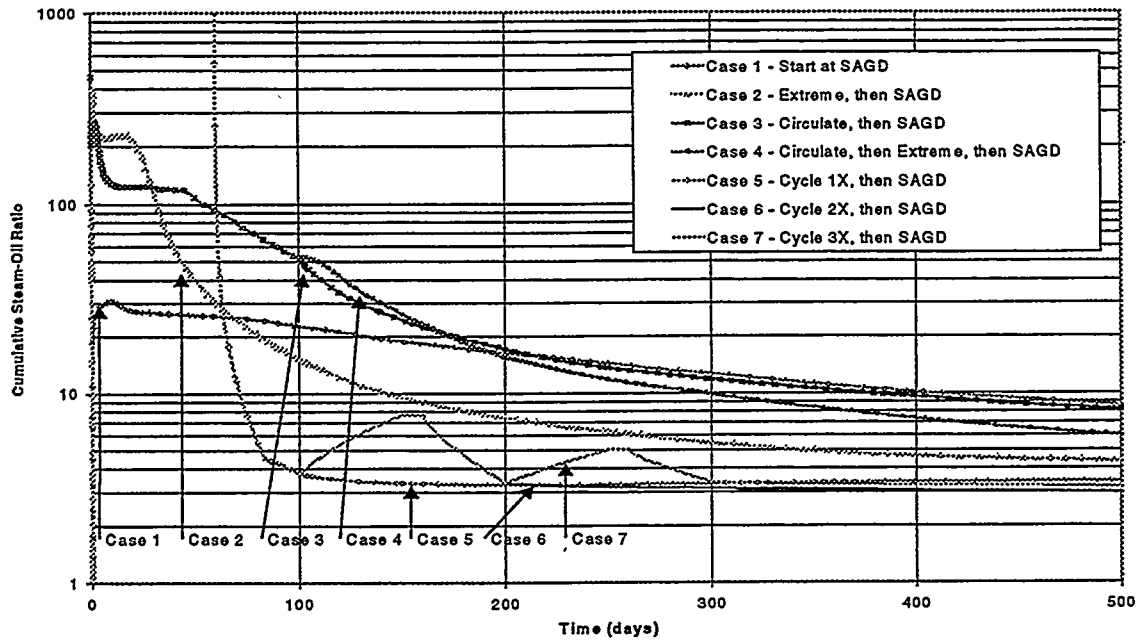


Figure 8: Cumulative Steam-Oil Ratio vs. Time for All Cases (First Year of Production)

in Fig. 9. Note, however, that the cyclic cases generally perform better, with regard to CSOR, in initial and late-time response.

The “Circulate” phase in Cases 3 and 4 is a modified form of steam circulation in the well. We did not simulate true steam circulation where steam exiting the tubing is allowed only to 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. We discuss Cases 1—Continuous SAGD, 2—Extreme Pressure Differential, and 5—Cyclic Steam Injection in more detail in the following section to gain insight into the early-time behavior.

3.2 Case Studies

3.2.1 Case 1, Continuous SAGD

In Case 1 we immediately operate at SAGD conditions and do not include a preheat phase. In this case, and the cases to follow, production rates, well pressures and temperature profiles around the well are examined. Figure 10 displays the injection and production curves for Case 1. The darkest curve in Fig. 10 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 m³/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

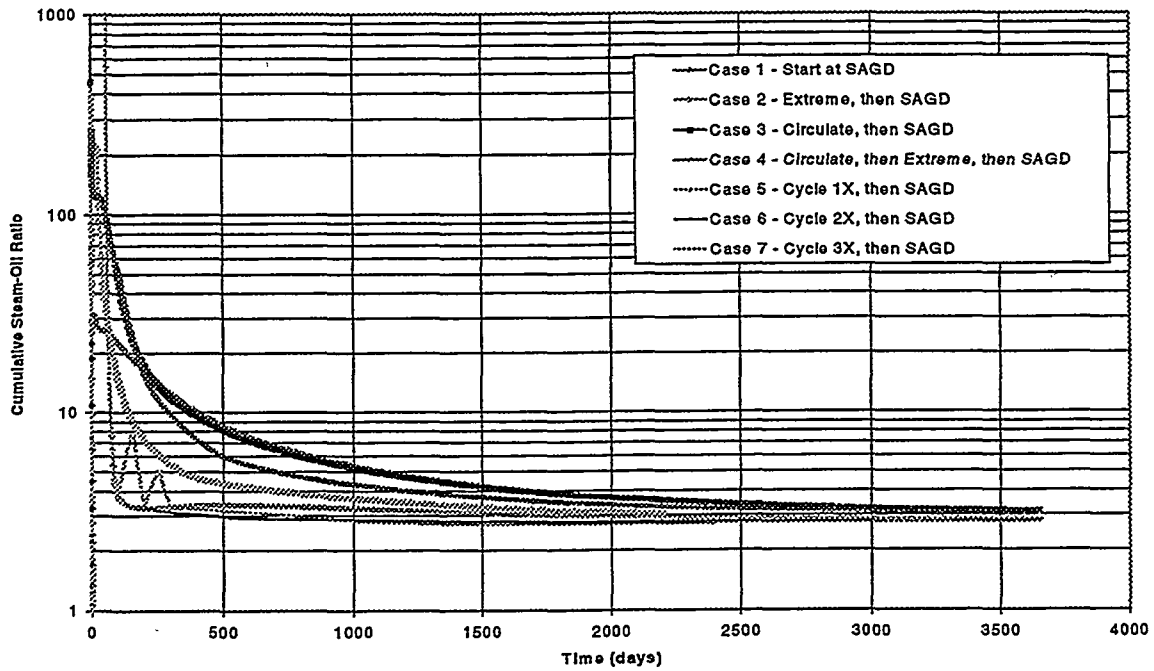


Figure 9: Cumulative Steam-Oil Ratio vs. Time (10 Years Production)

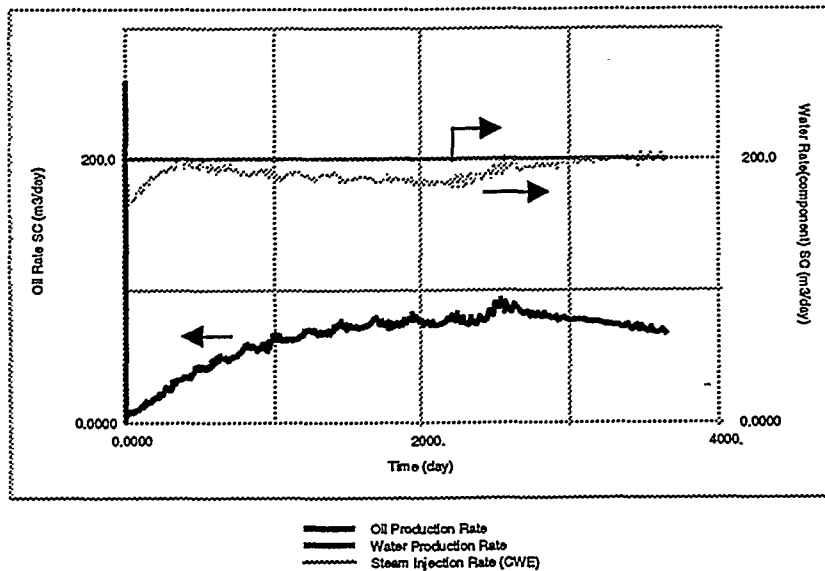


Figure 10: Production & Injection Rates vs. Time; Case 1, Continuous SAGD, Early-Time Analysis

from the similarity between the steam injection rate and water production rate in Fig. 10 that steam short-circuits from the injection region to the production region and the contact time for steam with the reservoir is short. Recall that in our model 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 immediately the short distance through the reservoir from the injection region to the production region. Increasing the spacing between the injection and production points and/or reducing the pressure differential would certainly reduce the amount of short-circuiting. Albeit inefficiently, a steam chamber is created within the reservoir as heated oil drains to the production well and steam migrates up to fill the void space. Optimizing the well spacing and pressure drawdown represents another interesting problem to be addressed later in this report.

Figure 11 displays bottom-hole pressure curves for injection and production in Case 1. A large pressure differential of about 2000 kPa exists 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 12 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 this point, however, the steam chamber is just beginning to grow above the short-circuiting area between the injection and production sections. We will see that the same profile at similar relative times in the other cases displays a much larger heated area. It is important to maximize

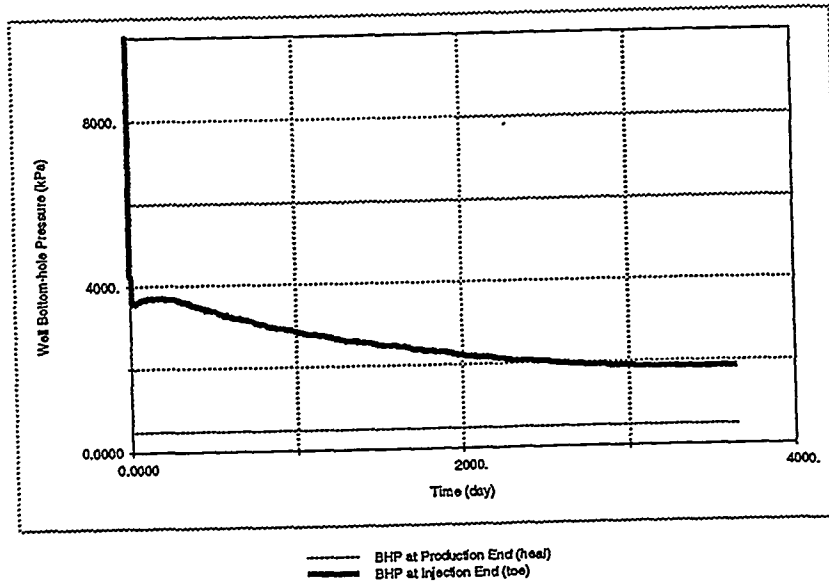


Figure 11: Well BHP vs. Time; Case 1, Continuous SAGD; Early-Time Analysis

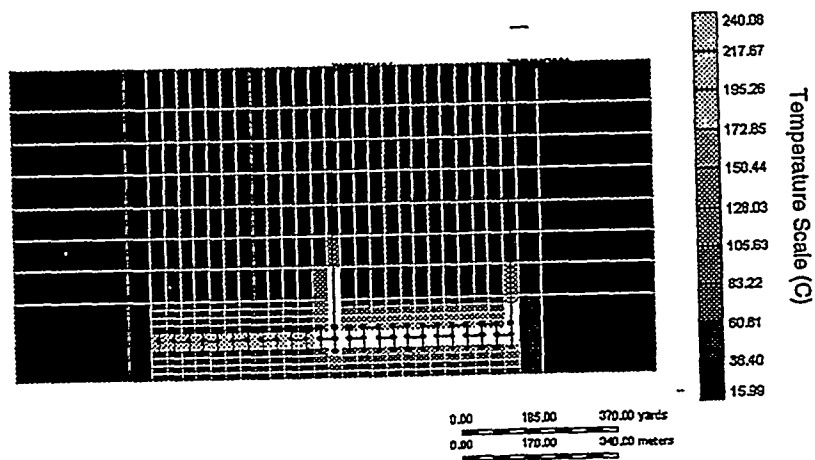


Figure 12: Temperature Profile at 100 Days; Case 1 - Continuous SAGD; Early Time Analysis

the amount of net heat injection into the reservoir at early times, therefore, maximizing the size of the heated volume surrounding the wellbore.

3.2.2 Case 2, Extreme Pressure Differential Prior to SAGD.

In the extreme pressure differential case we increase the injection rate constraint which thereby increases the pressure differential between the injection and production wells. Figure 13 displays the bottom-hole pressure versus time curves. For the first 100 d, steam is injected at roughly 7000 kPa forcing steam into the formation and increasing the average reservoir pressure. Figure 14 displays the production response for the extreme period in the first 100 days followed by SAGD operating conditions. Observing the oil rate in the first 100 days and comparing to Fig. 10, 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 13 also indicates that a very high injection bottom-hole pressure is obtained between 0 and 100 d of injection. High pressure results because the water production rate is substantially less than the steam injection rate, as shown in Fig. 14. 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. 14 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 lead to high reservoir pressure at the beginning of SAGD, causing significant production through pressure depletion in

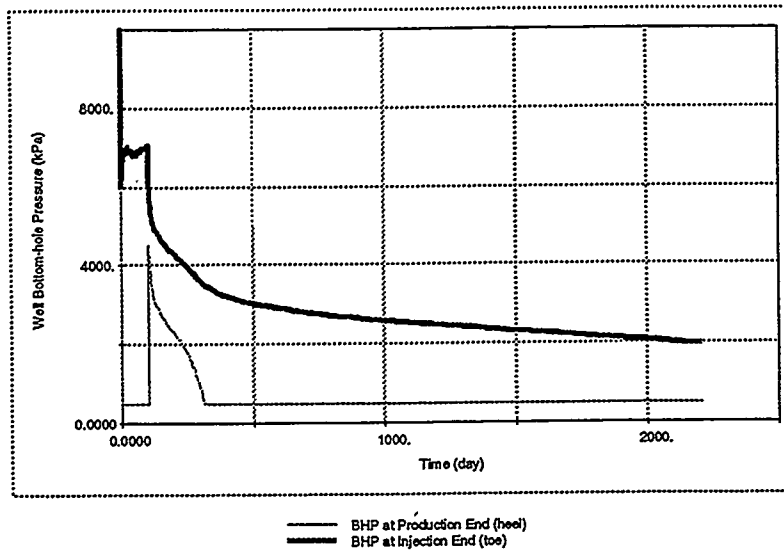


Figure 13: Well BHP vs. Time; Case 2, Extreme Pressure Differential, then SAGD; Early-Time Analysis

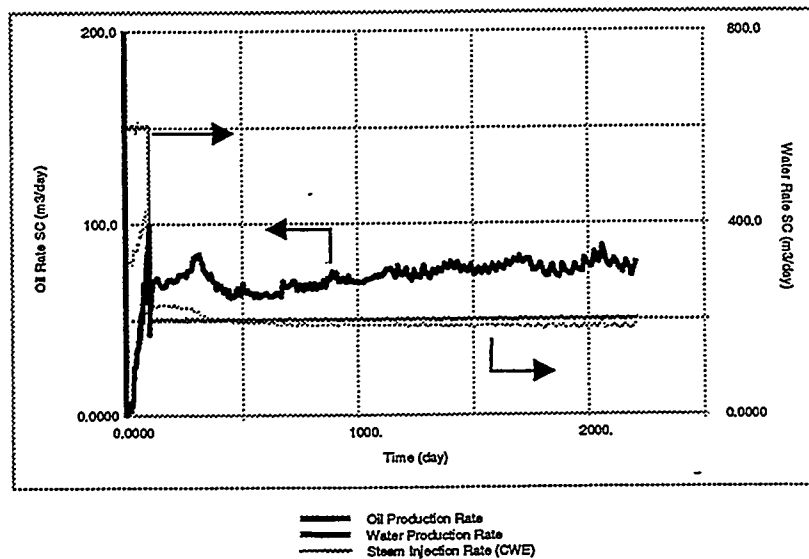


Figure 14: Production & Injection Rates vs. Time; Case 2, Extreme Pressure Differential, then SAGD; Early-Time Analysis

addition to gravity drainage of heated reservoir heating fluids. A better comparison is the temperature profile along the length of the well displayed in Fig. 15. The profile represents a relative time similar to 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 and the corresponding steam chamber is larger. The steam chamber forms in the middle of the well because pressure drawdown is large in this vicinity and in this region the steam flux into the reservoir is largest.

3.2.3 Case 5, One Cycle Prior to SAGD.

Our cyclic case is very similar to typical cyclic operations 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 120 days. The injection and production profiles in Fig. 16 summarize this cycle of steam injection, shut in, production.

Figure 17 shows that the bottom-hole pressure increases to about 8000 kPa during the injection phase, but still remains within a feasible range. Because the oil is very viscous, this energy is rapidly depleted from the reservoir when the well begins production. From the oil production rate after the cycling period in Fig. 16, it is again obvious that we have improved SAGD response. The slow increase of production rate found in Case 1 is not evident here. The minimum production rate at roughly 200 d occurs because reservoir pressure is depleted somewhat following the cyclic period, as shown by the plot of well bottom hole pressure in Fig. 17. Again, the maximum oil production rate is about 80

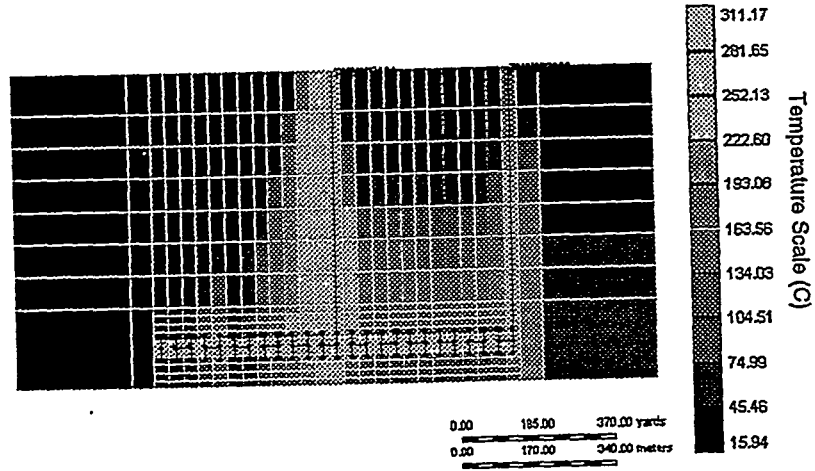


Figure 15: Temperature Profile at 200 Days (100 Days after SAGD began), Case 2, Extreme Pressure Differential, then SAGD; Early-Time Analysis

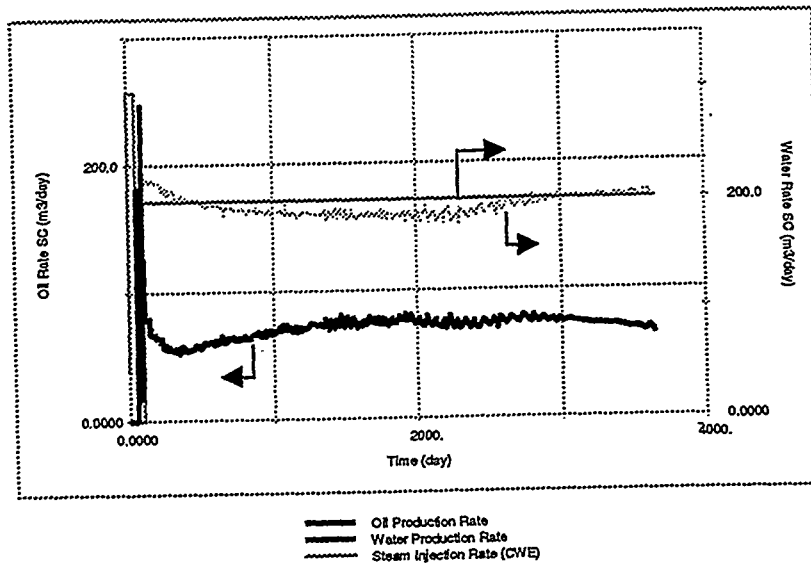


Figure 16: Production & Injection Rates vs. Time; Case 5, Cycle 1X, then SAGD; Early-Time Analysis

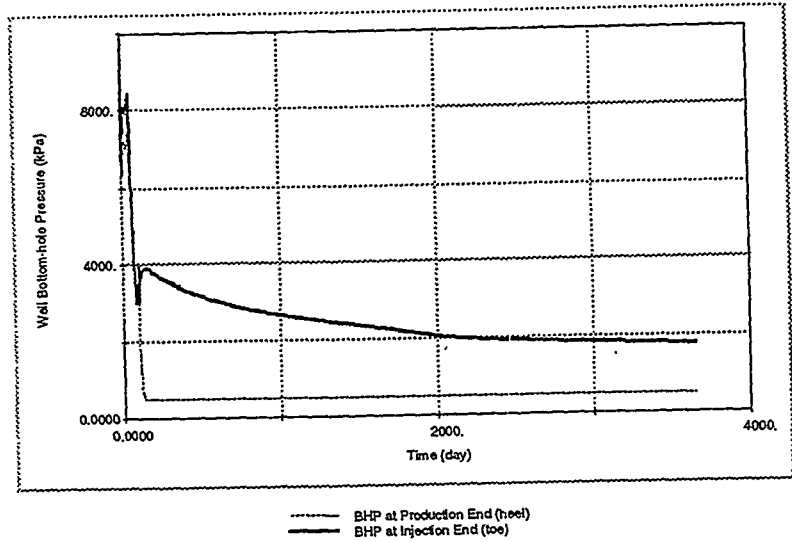


Figure 17: Well BHP vs. Time; Case 4, Cycle 1X, then SAGD; Early-Time Analysis

m³/day. In this case, the reservoir pressure at SAGD inception is similar to that in Case 1. Therefore we conclude that SAGD performs better because the near-wellbore area is heated, creating favorable SAGD conditions.

Figure 18 displays the temperature profile at a relative time similar to the Case 1 profile, 120 days after SAGD inception. The temperature distribution is more uniform along the entire wellbore. In this case, a large steam chamber is growing in the middle of the reservoir. Additionally, the shading indicates that the entire horizontal length of the well has been heated somewhat. Hence, the rapid production response displayed in Fig. 16.

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. In the scope of our research up to this point, we have not optimized the cyclic process. However, Fig. 6 does illustrate the benefit of repeated cyclic steam injection. The problem of optimizing cycle times, operating conditions, and the number of cycles should be studied in more detail.

3.3 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 to take place. More specifically, in order for a steam

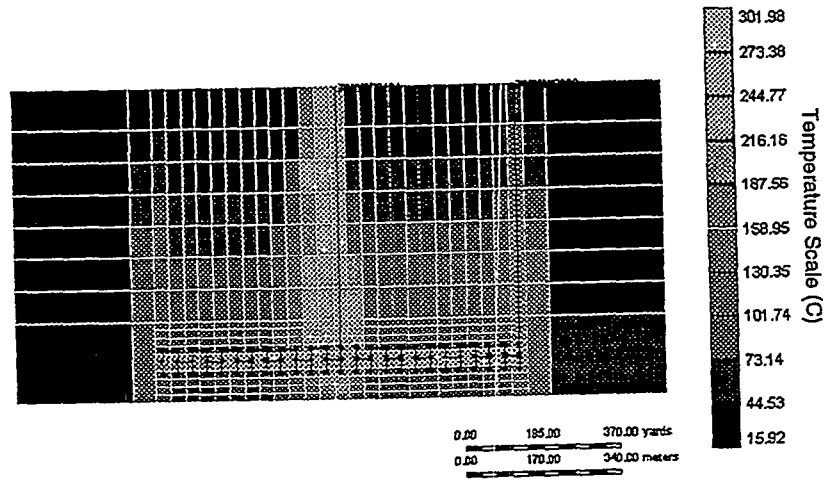


Figure 18: Temperature Profile at 300 Days (120 Days after SAGD began), Case 5, Cycle 1X, then SAGD; Early-Time Analysis

chamber to grow, oil viscosity must be low enough so that fluid drains to the wellbore creating volume that steam can fill and thereby migrate upward in the reservoir. 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.

After comparing 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 should be further studied.

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 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 (1986) finding that a steam chamber will grow in the reservoir and favorable recovery factors are obtainable regardless of the injection/production configuration.

As a final observation, there are obvious factors that will improve or inhibit SW-SAGD performance. For example, lower viscosity will certainly improve response, as will higher permeability and system compressibility. Our model, however, represents a base case from which we draw general conclusions. The actual variance in performance due to varying reservoir parameters is an interesting problem that should be studied in more detail. A sensitivity analysis of reservoir properties is performed next.

4. Sensitivity Analysis

4.1 Overview

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 4, on page 28, displays the operating conditions for the sensitivity analysis base case. We adjusted the operating conditions in an attempt to reduce steam short-circuiting and to improve steam efficiency. During SAGD conditions, operating conditions are chosen so that the process operates near the original reservoir pressure of 2654 kPa. Maximum injection pressure was set slightly above initial reservoir pressure at 3610 kPa; minimum production pressure was set slightly below initial reservoir pressure at 2230 kPa. The steam injection temperature was reduced to 244 °C from 295 °C. A steam temperature of 244 °C corresponds to a steam pressure of 3610 kPa. The rate constraints remained the same at 300 m³/d maximum liquid production and 200 m³/d maximum steam injection rate.

Table 4: Description of Operating Conditions (Sensitivity-Analysis Cases)

Property	Operating Condition	
	SAGD	Cyclic
Steam Temp. (C):	244.32	295
Steam Pres. (kPa):	3,610	8,014
Injection Well Max Rate Constraint (m ³ /D):	3,610	300
Injection Well Max Pres. Constraint (kPa):	8,000	8,000
Production Well Max Rate Constraint (m ³ /D):	300	300
Production Well Minimum Pres. Constraint (kPa):	2,230	500

During cyclic conditions, 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 is 296 °C, which corresponds to a steam pressure of 8004 kPa.

Between the injection and production sections of the horizontal well, one empty grid block was added in an attempt to reduce the amount of steam short-circuiting and increase the amount of steam entering the reservoir. The two sections are separated by 30 m. Physically, this corresponds to a section of well that is not perforated. To determine a reasonable amount of separation between the two sections, we performed the following analysis.

The Darcy velocity of a particle or volume of steam in the vertical direction (u_v) above the horizontal injection section as in Fig. 19 is given by

$$u_v = -\frac{k_v k_{rs}}{\mu_s} \Delta\rho \frac{g}{g_c} \quad (4.1)$$

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, g is the acceleration due to gravity, and g_c is the gravitational constant.

The Darcy velocity in the horizontal direction (u_h) between the injection and production sections is given by

$$u_h = -\frac{k_h k_{rs}}{\mu_s} \frac{dp}{dx} \quad (4.2)$$

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

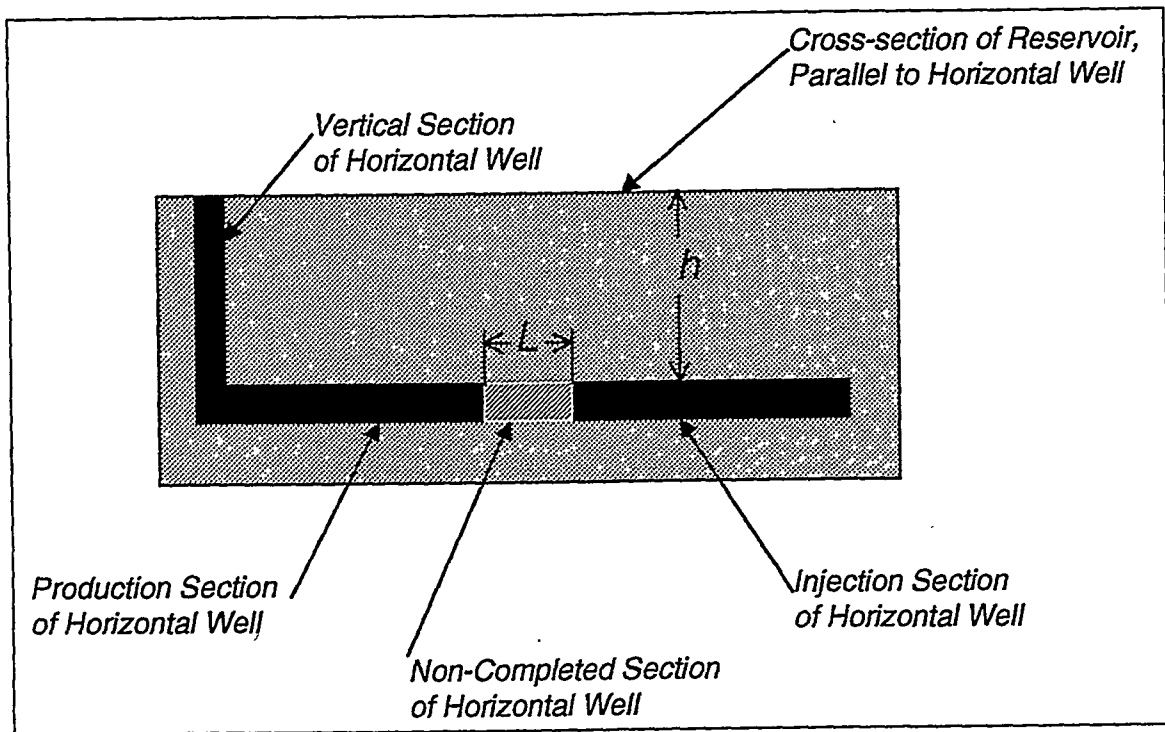


Figure 19: Visual Description of L and h Dimensions

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

$$t_v = \frac{h}{u_v} \quad (4.3)$$

and

$$t_h = \frac{h}{u_h} \quad (4.4)$$

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 would suspect a large amount of steam short-circuiting. Conversely, if the t_v/t_h is less than one, 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.

$$\frac{t_v}{t_h} = \frac{h u_h}{L u_v} \quad (4.5)$$

or,

$$\frac{t_v}{t_h} = \frac{h \frac{k_h k_{rs} dp}{\mu_s dx}}{L \frac{k_v k_{rs} \Delta \rho g}{\mu_s g_c}} \quad (4.6)$$

simplifying,

$$\frac{t_v}{t_h} = \frac{h k_h \frac{dp}{dx}}{L k_v \Delta \rho \frac{g}{g_c}} \quad (4.7)$$

We can approximate dp/dx as,

$$\frac{dp}{dx} \cong \frac{\Delta p}{L} = \frac{P_{inj} - P_{prod}}{L} \quad (4.8)$$

Substituting this into Equation 4.7 we get

$$\frac{t_v}{t_h} = \frac{h k_h P_{inj} - P_{prod}}{L^2 k_v \Delta \rho \frac{g}{g_c}} \quad (4.9)$$

For our base case and using the properties displayed in Table 5, we calculate a t_v/t_h value of 0.012. Therefore, we expect steam to have more of a tendency to flow up rather than short-circuit to the production section. Although this analysis is just an approximation, it does help us estimate if short-circuiting will be an immediate production problem. A more thorough analysis would consider variations in temperature, pressure, density, and viscosity.

4.2 Sensitivity Cases

Table 6 lists the various cases created in the sensitivity analysis. The recovery factor vs. time and cumulative steam-oil ratio vs. time curves presented in Figs. 20 and 21 display significant variation in production response between the cases.

Table 5: Parameters Used to Calculate t_w/t_h

Parameter	Value
h (m)	19.6
L (m)	30
k_v (mD)	3400
k_h (mD)	680
P_{inj} (kPa)	3230
P_{prod} (kPa)	2230
Oil Density (kg/m^3)	950
Steam Density (kg/m^3)	42.6
g (m/s^2)	9.8
g_c ($kg\ m)/(N\ s^2)$)	1

Table 6: Description of Sensitivity Analysis Cases

Case	Description
Base	Base case from which other cases were modified
Dead Oil	Dead Oil; 1% Gas Component, 99% Oil Component
Height = 100 ft	Reservoir Height = 100 ft
Height = 10 ft	Reservoir Height = 10 ft
$KhKv = 1$	Kh/Kv Permeability Anisotropy = 1
$KhKv = 2$	Kh/Kv Permeability Anisotropy = 2
$KhKv = 10$	Kh/Kv Permeability Anisotropy = 10
Viscosity = 20K cp	Initial Oil Viscosity = 20,000 cp
Viscosity = 40K cp	Initial Oil Viscosity = 40,000 cp

Comparison of All Sensitivity Cases
 Recovery Factor vs. Time
 Cycle 2X, then SAGD

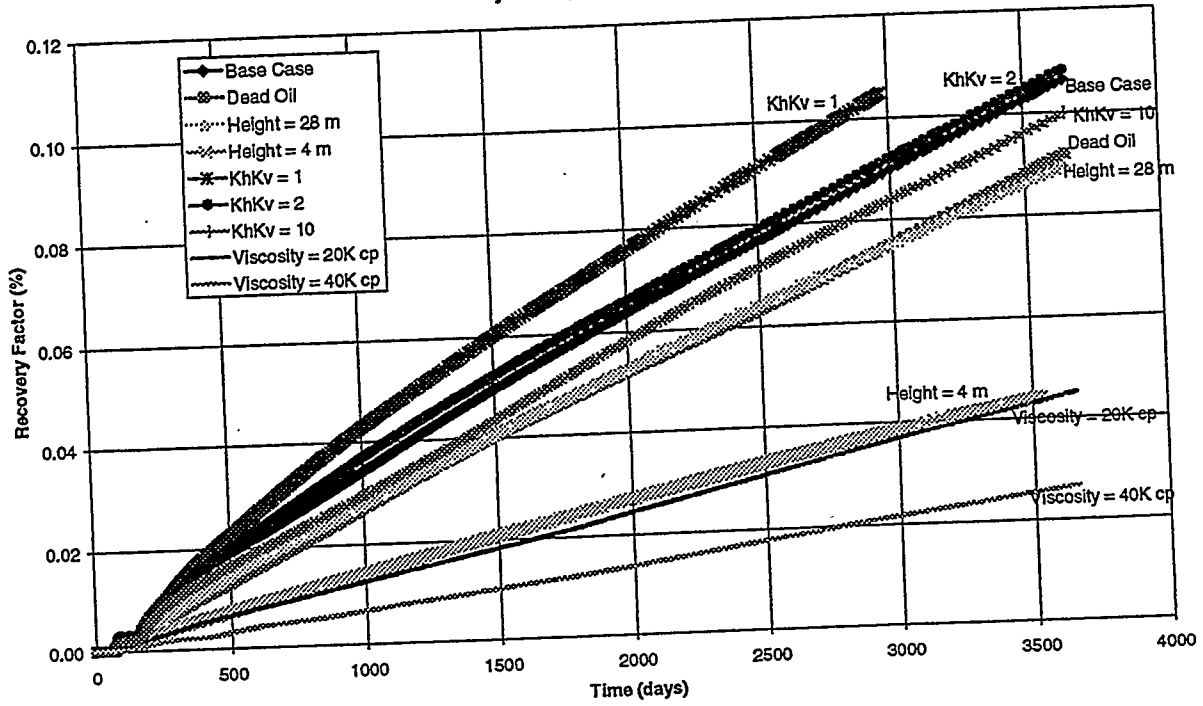


Figure 20: Recovery Factor vs. Time for Sensitivity Analysis Cases (Up to 3650 Days)

**Comparison of All Sensitivity Cases
SOR vs. Time
Cycle 2X, then SAGD**

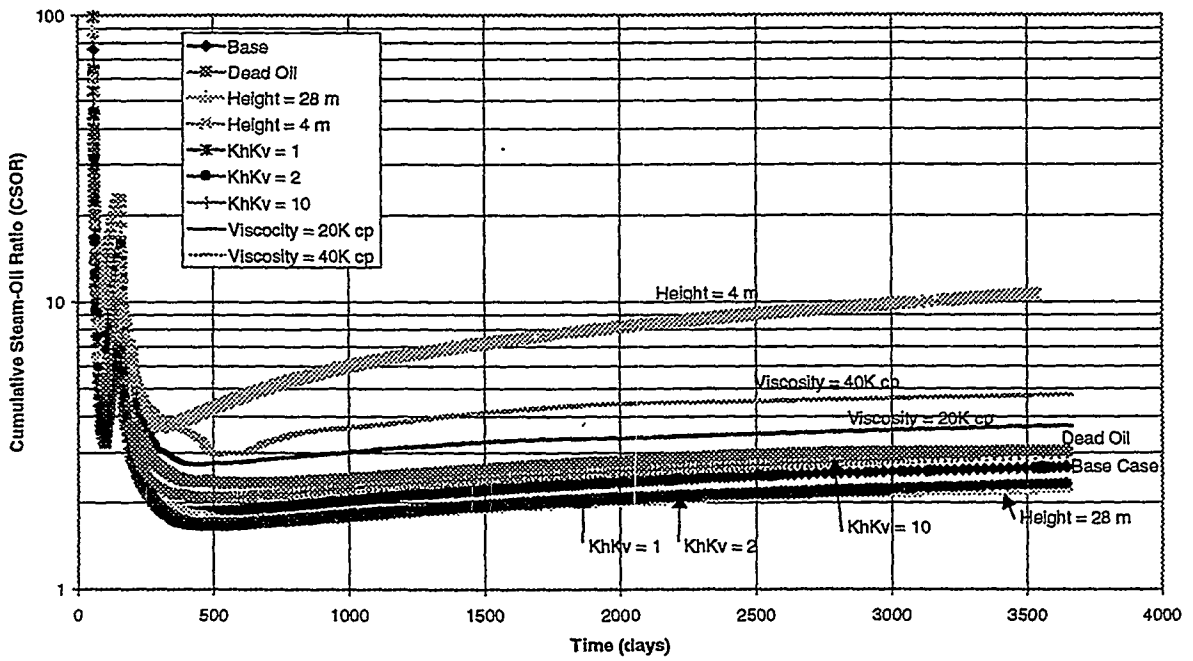


Figure 21: Cumulative Steam-Oil Ratio vs. Time for Sensitivity Analysis Cases (Up to 3650 Days)

Figure 22 displays the injection and production curves for the Base Case. The production rate values on the curve actually represent half of the actual rate. These curves were generated using CMG Results Version 1999.10 which, in error, did not double the rates to account for the symmetry element. All of the production values in this paper refer to the correct rate, or double the rate value read from the graph.

The darkest curve represents the oil production rate. The early-time procedure of cycling steam in the wellbore successfully increased the early-time production performance. The oil rate levels and remains fairly constant at around 75 m³/d. The dashed curve represents the steam injection rate and the gray curve represents the water production rate. Just after the cyclic process ends, steam injection rate increases rapidly. At about 500 days, the water production rate begins to follow closely the steam injection rate. It appears that breakthrough between the injection and production sections occurs at 500 days and steam short-circuiting occurs after that point. The amount of vertical separation between the water production and steam injection curves gives an indication of the amount of short-circuiting. As we will see, less favorable conditions lead to more short-circuiting and less separation between the curves.

Figure 23 displays the temperature profile along the horizontal wellbore for the Base Case after 3650 days of production. The lighter shades of gray represent higher temperatures. The profile shows a large heated area above the injection section. The heated area closely corresponds with the steam saturated area.

Figure 24 displays the bottom-hole pressure curves for injection and production in the Base Case. The light curve represents the production bottom-hole pressure and the

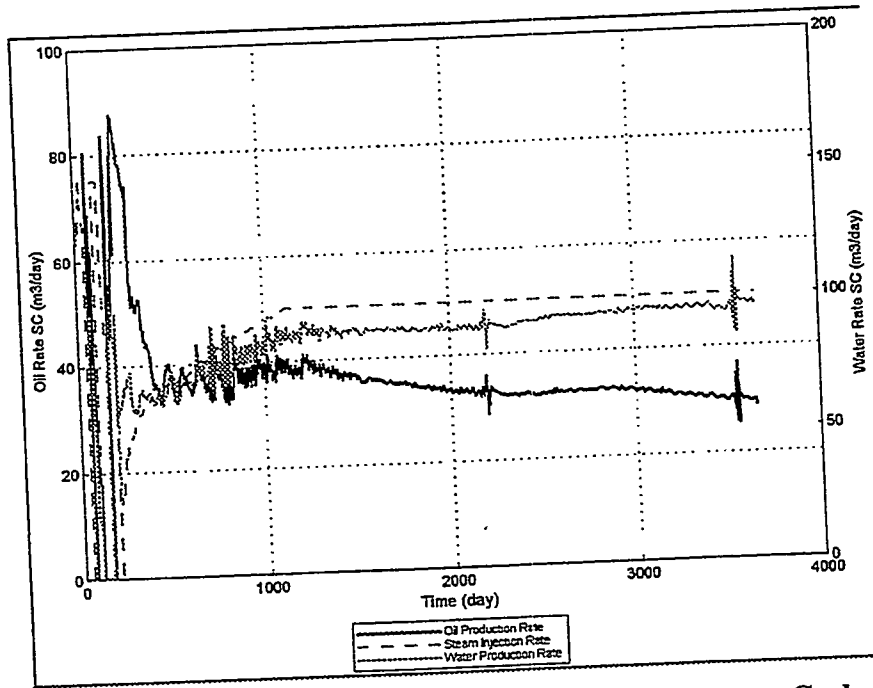


Figure 22: Production & Injection Rates vs. Time; Base Case, Cycle 2X, then SAGD; NOTE: Rate values on graph should be multiplied by 2

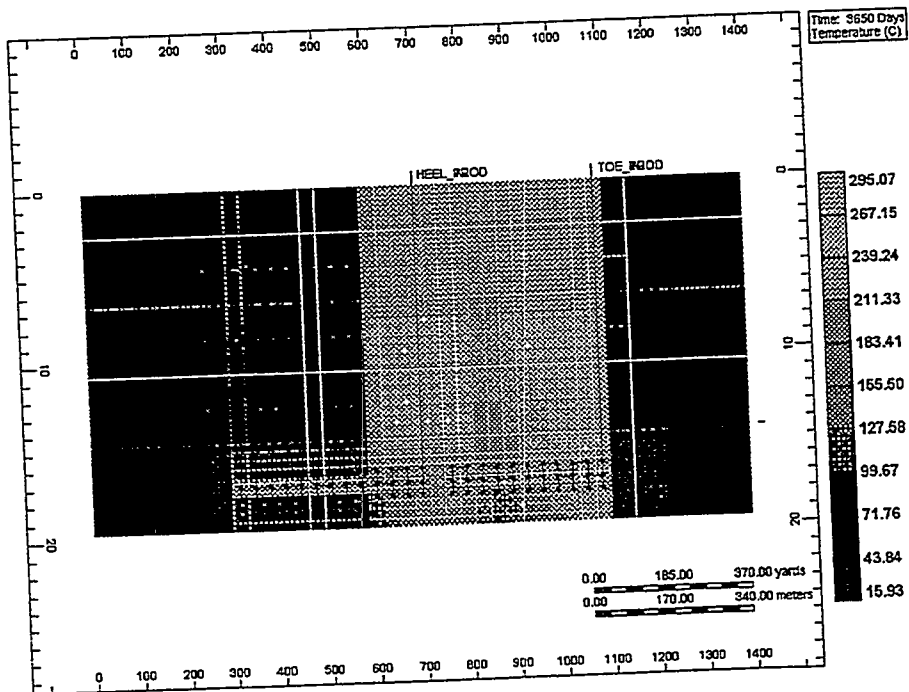


Figure 23: Base Case; Temperature Profile at 3650 Days

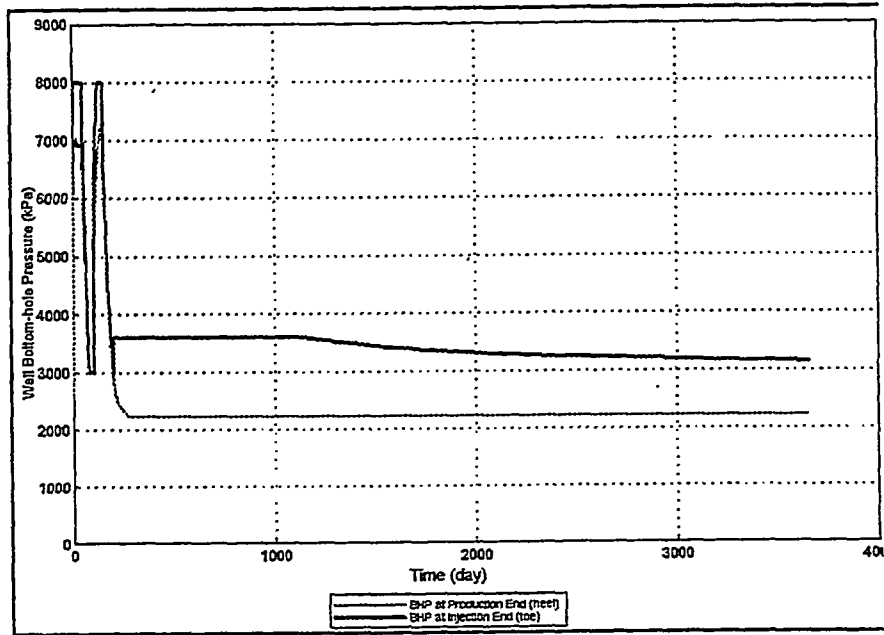


Figure 24: Base Case; Bottom-hole Pressure vs. Time for Injection and Production

dark curve represents the injection bottom-hole pressure. In the early part of SAGD the injection pressure and production pressure are constant; the well is operating against the maximum injection pressure and against the minimum production pressure. As more fluids are produced than injected, the reservoir pressure decreases steadily. At around 1100 days the injection pressure begins to slowly decrease when injection shifts to operate against the maximum rate constraint.

In the next few sections we compare the Base Case results with the other sensitivity cases.

4.2.1 Oil Viscosity

The base case oil viscosity at initial conditions is 4,043 cp. We created two more cases by increasing the initial viscosity to 20,000 cp and 40,000 cp. The recovery factors at 3650 days for these two unfavorable cases were low; 2.7% and 4.5% for the 20,000 cp and 40,000 cp cases as compared to 10.6% for the Base Case. The cumulative steam-oil ratios were unfavorable also; 3.7 and 4.8 for the 20,000 cp and 40,000 cases.

Figure 25 displays the injection and production curves for the 20,000 cp case. The average oil production rate of 38 m³/d during SAGD is significantly less than the Base Case. The steam injection rate increases steadily but never hits the injection rate limit. The bottomhole pressure curves displayed in Fig. 26 show that the injection and production sections are both pressure constrained. The temperature profile in Fig. 27 shows a smaller heated region as compared to the Base Case, and the steam chamber is not as well developed. Basically, it is hard for the viscous oil to drain, therefore it can not be replaced by steam.

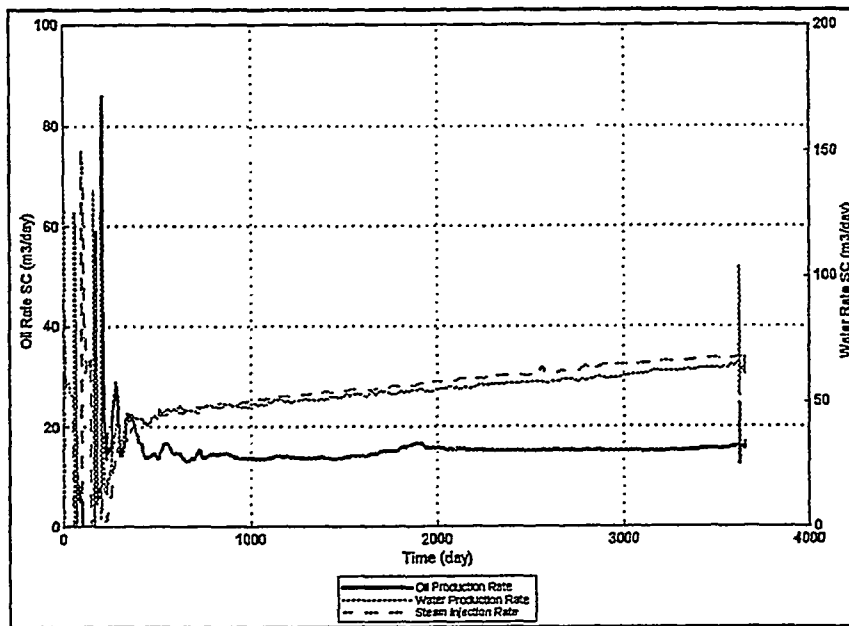


Figure 25: Viscosity = 20,000 cp Case; Production & Injection Rate vs. Time;
 NOTE: Rate values on graph should be multiplied by 2

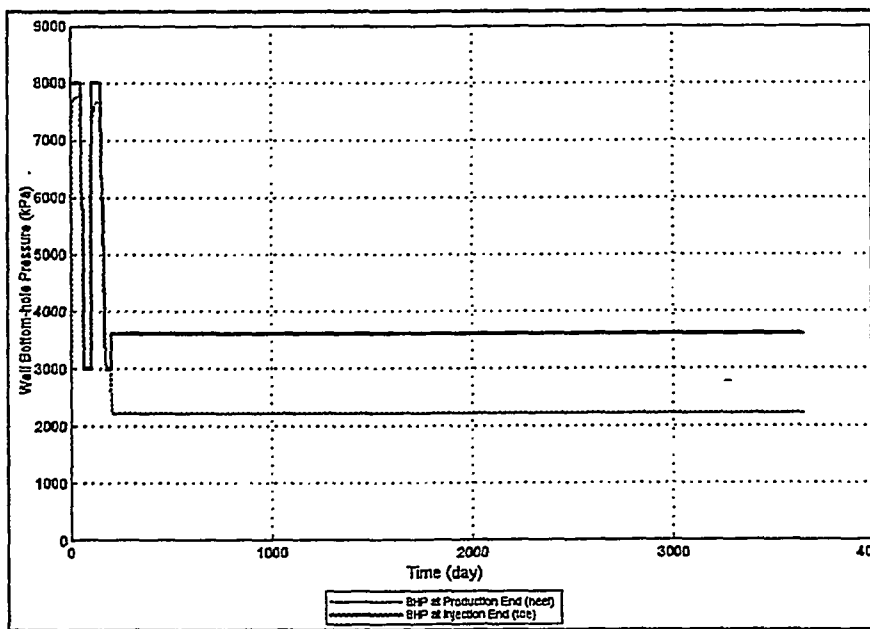


Figure 26: Viscosity = 20,000 cp Case; Bottom-hole pressure vs. Time

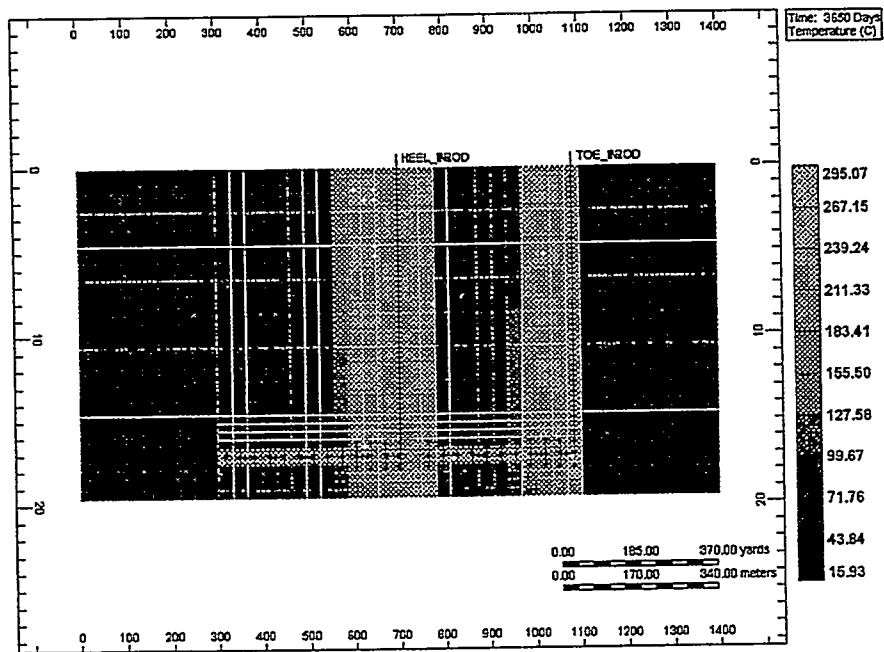


Figure 27: Viscosity = 20,000 Case; Temperature Profile

The 40,000 cp case shows an even smaller production rate, as seen in Fig. 28. The average oil production rate is 20 m³/d during SAGD. The steam injection rate increases slightly but remains fairly constant at around 100 m³/d and never reaches the injection rate limit. The bottomhole pressure curves displayed in Fig. 29 show that the injection and production sections are both pressure constrained. The temperature profile in Fig. 30 shows an even smaller heated region as compared to the 20,000 cp case. The steam chamber is not as well developed as the previous and Base cases.

4.2.2 Permeability Anisotropy

The Base Case kh/kv ratio is 5. We adjusted the vertical permeability to create three more cases with ratios of 1, 2 and 10. Larger ratios represent less favorable conditions. In all cases we left the horizontal permeability at 3400 mD and modified the vertical permeability to create the desired ratio. The recovery factors and cumulative steam-oil ratios for all cases varied only slightly from the base case.

Figure 31 displays the injection and production curves for the more favorable case of Kh/Kv = 1. Oil production rate is significantly higher than the base case at early time but decreases steadily. The steam injection rate is constrained during most of the SAGD period by the maximum rate. The bottomhole pressure curves displayed in Fig. 32 show that the injection pressure decreases steadily to a larger extent than in the base case. The production pressure is constrained by the minimum pressure.

The temperature profile in Figure 33 shows a temperature profile at 2750 days. The run was terminated before reaching 3650 days of production because time step size was

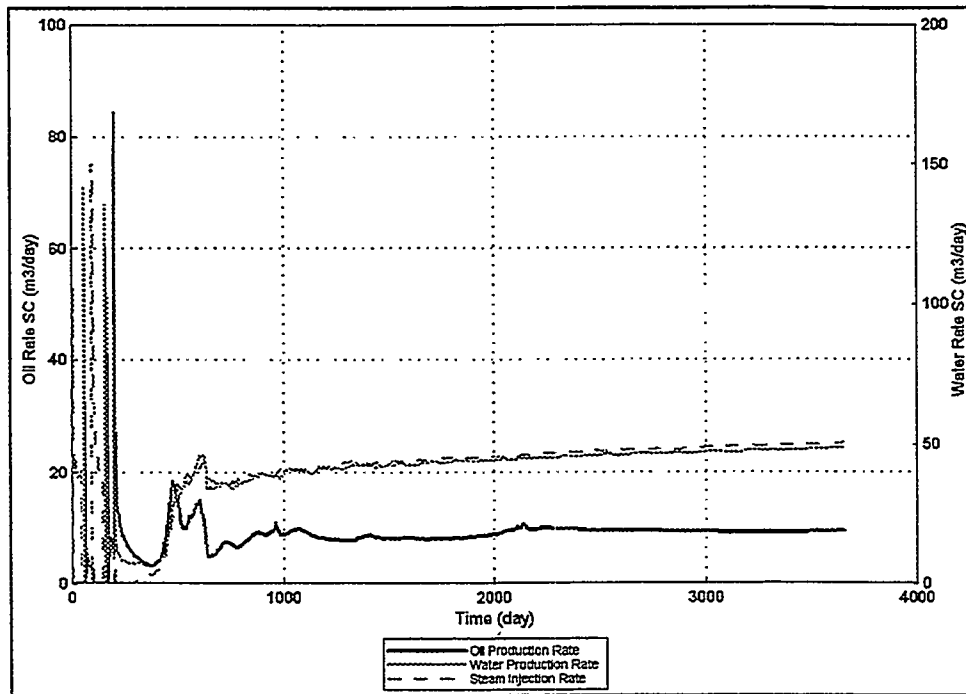


Figure 28: Viscosity = 40,000 cp; Production & Injection Rate vs. Time; NOTE: Rate values on graph should be multiplied by 2

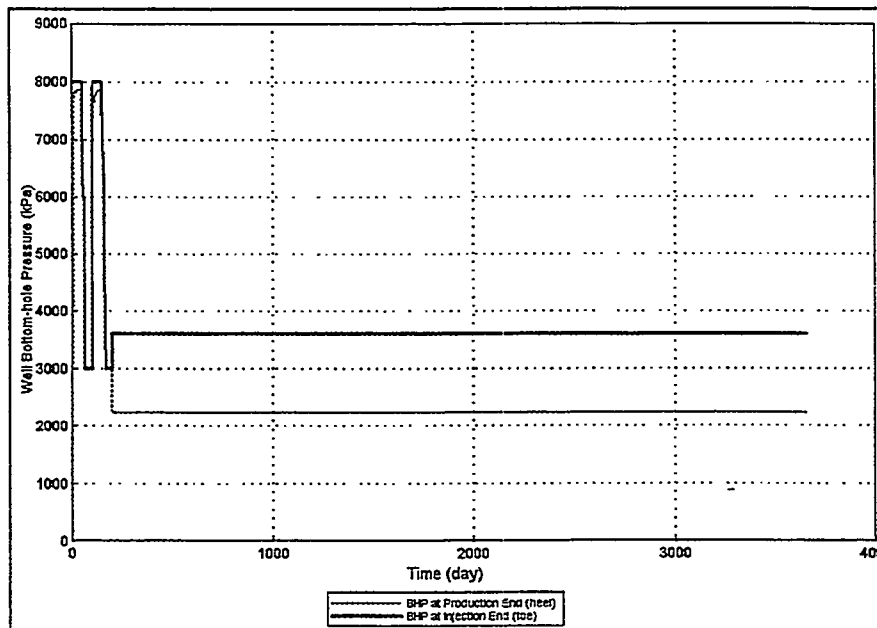


Figure 29: Viscosity = 40,000 cp Case; Bottom-hole Pressure vs. Time

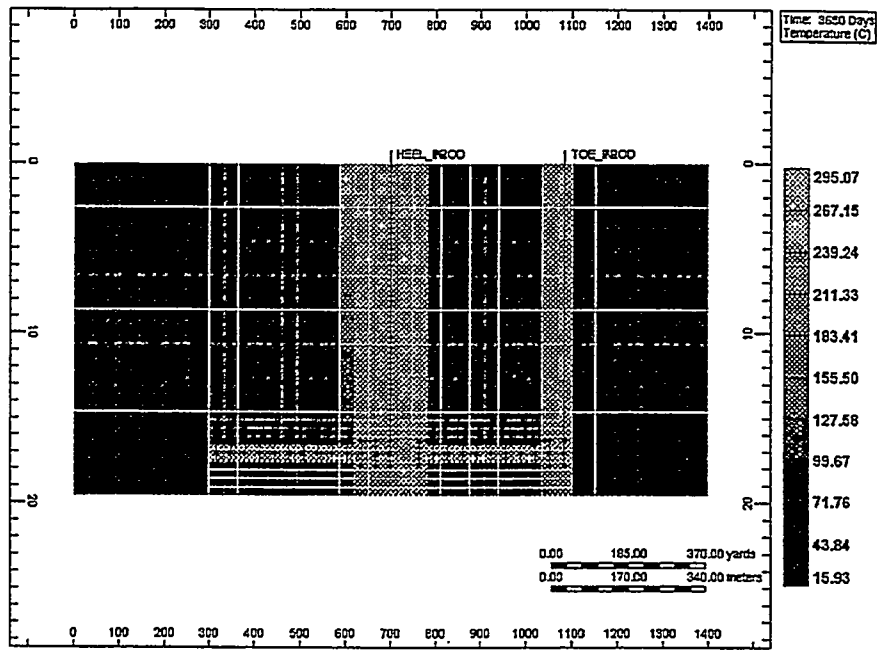


Figure 30: Viscosity = 40,000 cp Case; Temperature Profile at 3650 Days

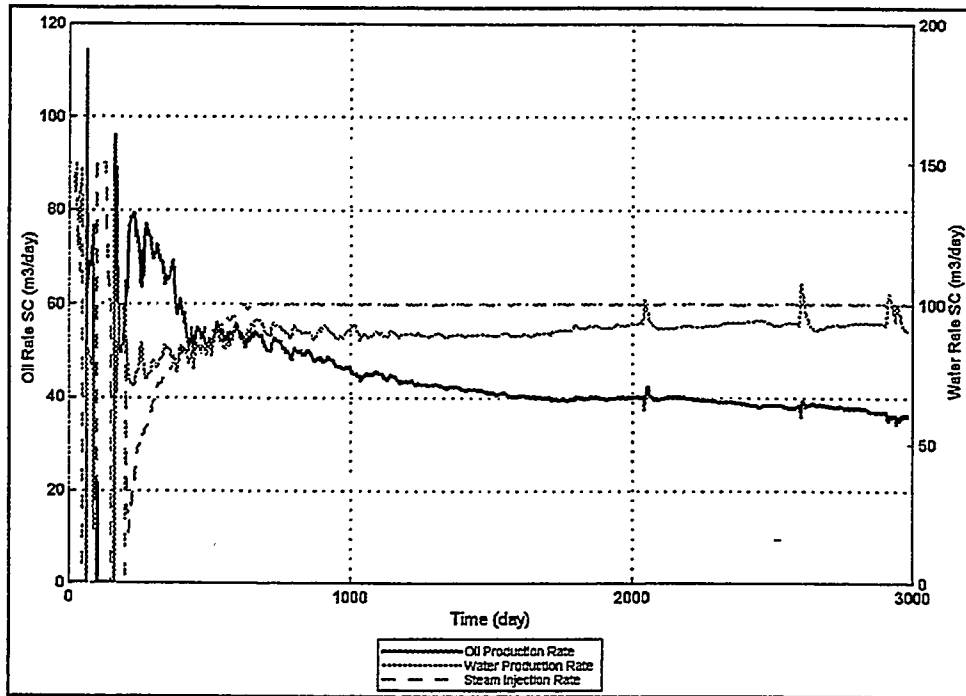


Figure 31: $K_h/K_v = 1$ Case; Production & Injection Rates vs. Time; NOTE: Rate values on graph should be multiplied by 2

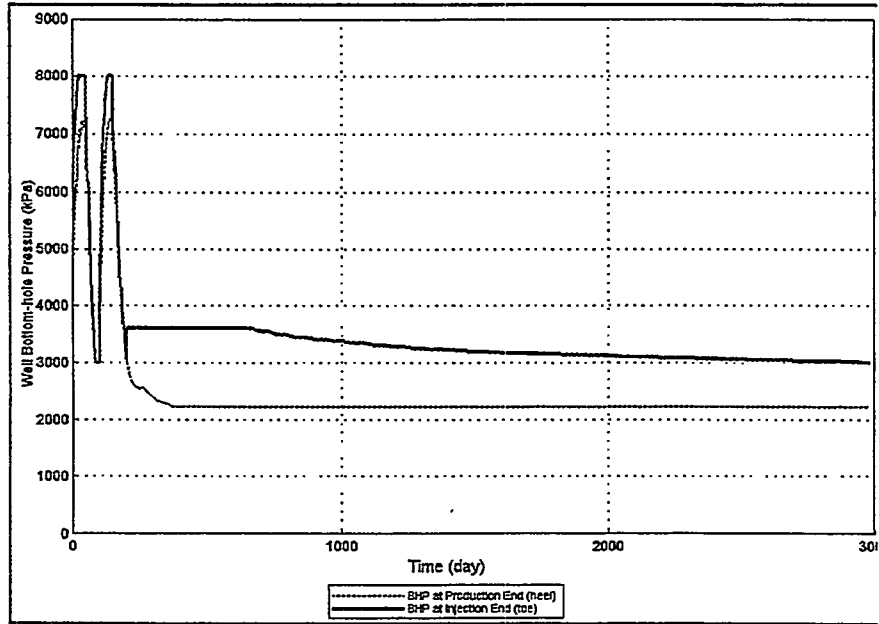


Figure 32: $K_h/K_v = 1$ Case; Bottom-hole Pressure vs. Time

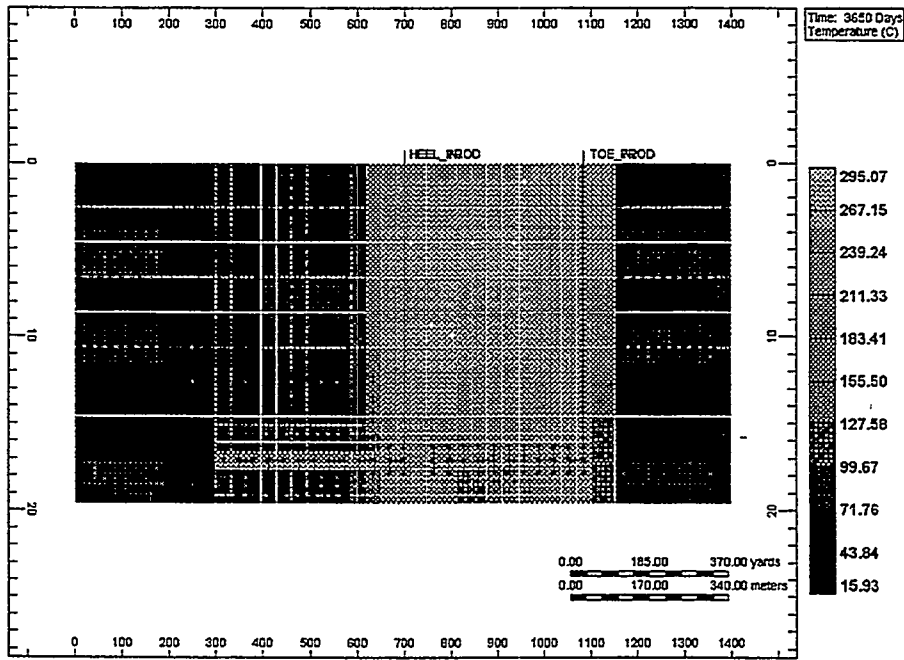


Figure 33: $K_h/K_v = 1$ Case; Temperature Profile at 2750 Days

excessively small. The steam chamber development at this point appears to be similar to the Base Case at 3650 days.

Figure 34 displays the injection and production curves for the $K_h/K_v = 2$ case. Similar to the $K_h/K_v = 1$ case, the oil production rate is higher at early-time and decreases steadily. The steam injection rate is constrained during most of the SAGD period by the maximum rate. The bottomhole pressure curves displayed in Fig. 35 show that the injection pressure decreases steadily. The production pressure is constrained by the minimum pressure. The temperature profile in Fig. 36 and the steam chamber development is similar to that of the Base Case.

Figure 37 displays the injection and production curves for the $K_h/K_v = 10$ case. The oil production rate is much lower than the previous cases, averaging $60 \text{ m}^3/\text{d}$ during the SAGD phase. The steam injection rate increases steadily and levels off at the maximum injection rate at 1500 days. The bottomhole pressure curves displayed in Fig. 38 show that the injection pressure begins to steadily decrease at 1500 days. The production pressure is constrained by the minimum pressure. The temperature profile in Fig. 39 appears similar to the Base Case profile.

4.2.3 Reservoir Thickness

The Base Case reservoir thickness is 19.6 m. We created two more cases by decreasing the reservoir thickness to 4 m and increasing it to 28 m. The grid dimensions were adjusted relatively to maintain the same grid geometry. The recovery factor for the 28 m case was 9% and CSOR was 2.3 at ten years of steam injection, both values are slightly

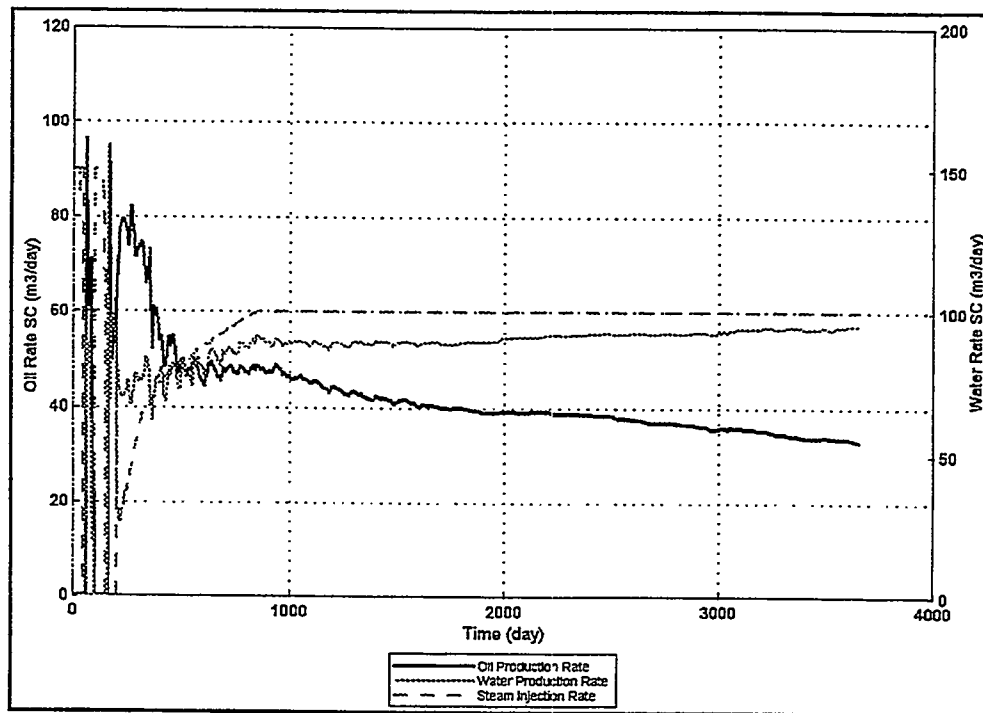


Figure 34: $Kh/Kv = 2$ Case; Production & Injection Rates vs. Time; NOTE: Rate values on the graph should be multiplied by 2

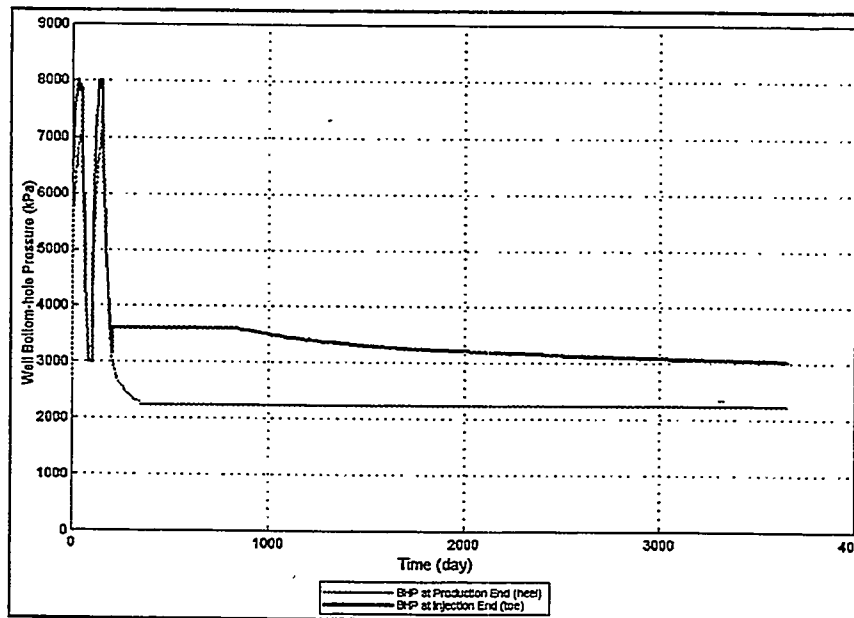


Figure 35: $Kh/Kv = 2$ Case; Bottom-hole Pressure vs. Time

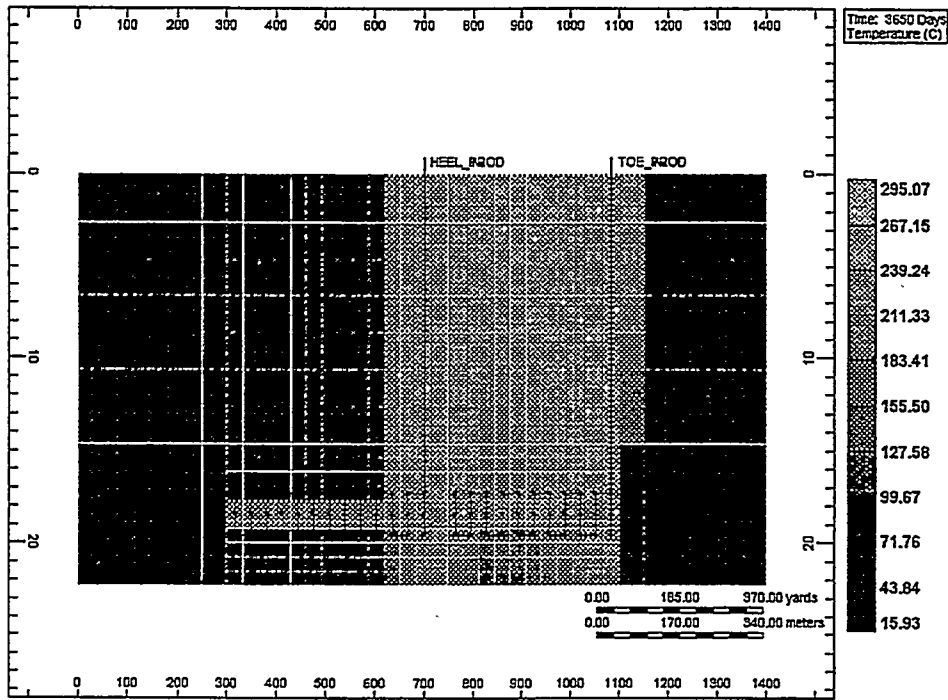


Figure 36: $K_h/K_v = 2$ Case; Temperature Profile at 3650 Days

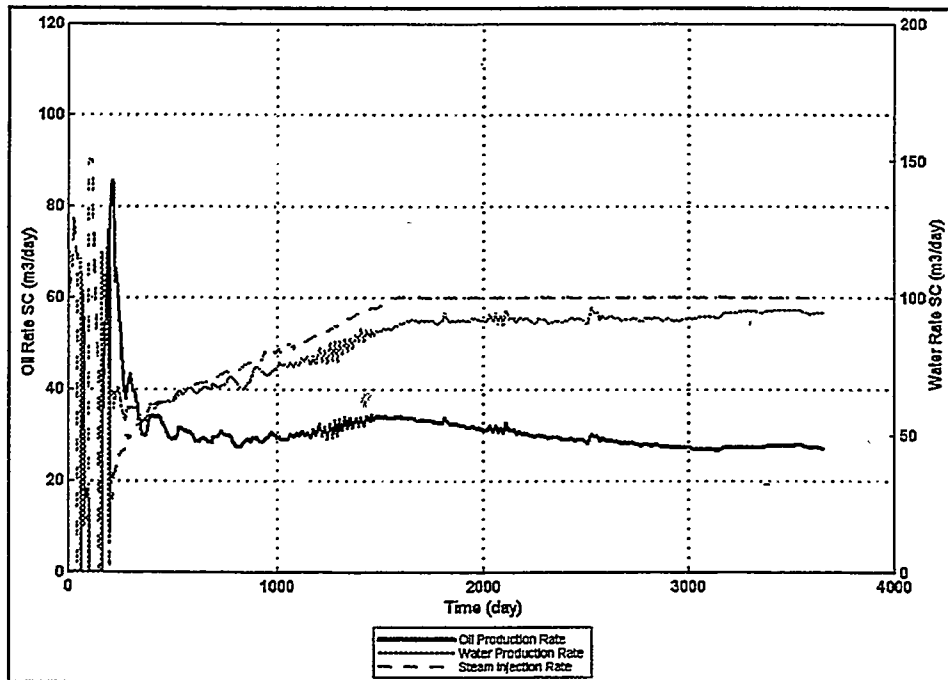


Figure 37: $K_h/K_v = 10$ Case; Production & Injection Rates vs. Time; NOTE: Rate values on the graph must be multiplied by 2

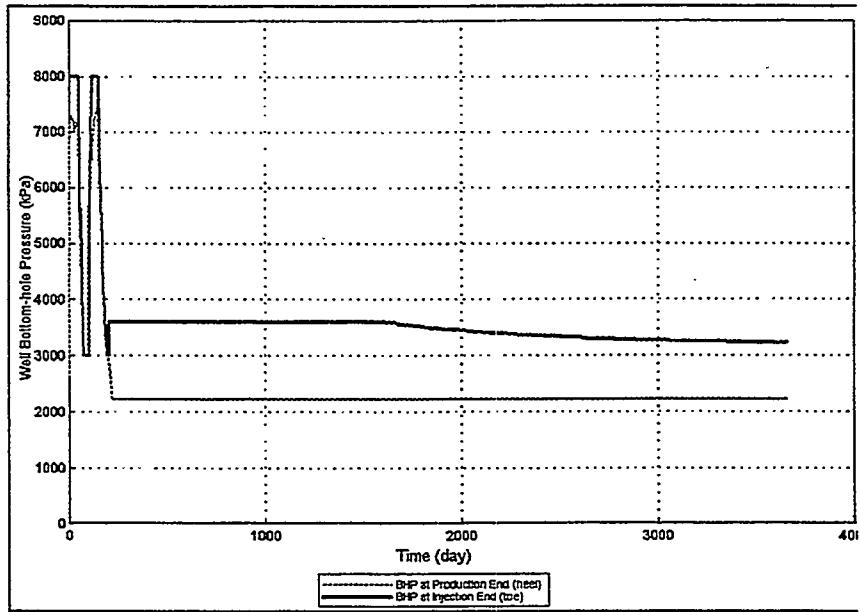


Figure 38: $K_h/K_v = 10$ Case; Bottom-hole Pressure vs. Time

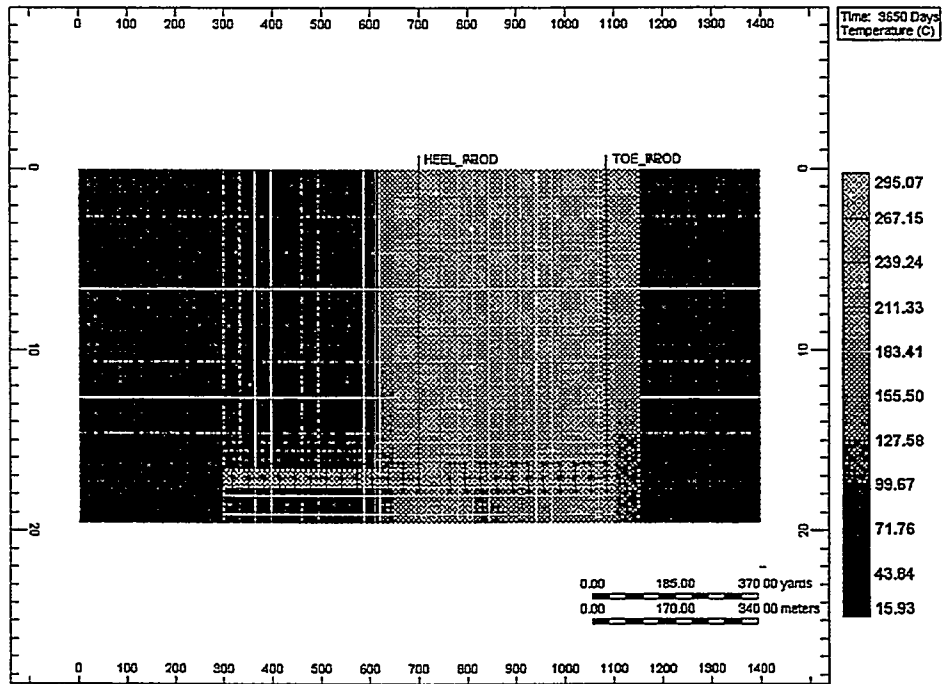


Figure 39: $K_h/K_v = 10$ Case; Temperature Profile at 3650 Days

lower than the Base Case. For the 4 m case, however, results were significantly less favorable than the Base Case. The recovery factor was 4.4% and CSOR was 10.6.

Figure 40 displays the injection and production curves for the 28 m case. The oil production rate is slightly higher than the Base Case, and levels to around 80 m³/d during late time. The bottom-hole pressure curves shown in Fig. 41 and temperature profile in Fig. 42 are similar to the Base Case.

Figure 43 displays the injection and production curves for the 4 m case. The oil rate is much lower than the base case and remains fairly steady at 20 m³/d. The steam injection rate increases slowly, and water production rate closely mirrors the injection rate. Figure 44 displays the bottom-hole pressure curves. The injection and production pressures remain constant during SAGD. The temperature profile in Fig. 45 shows a heated region that appears to extend to a larger amount over the production section than in the Base Case.

4.2.4 Live Oil vs. Dead Oil

The base case oil composition consisted of 10% by mole gas component. We created one additional case to model a dead oil which consisted of 1% by mole gas component. Recovery factor and CSOR were slightly less favorable than the Base Case at 9.2% and 3.0.

Results from the Dead Oil Case appear similar to the Base Case, as seen by comparing the production profile, bottom-hole pressure curves, and temperature profile in Figs. 46, 47, and 48.

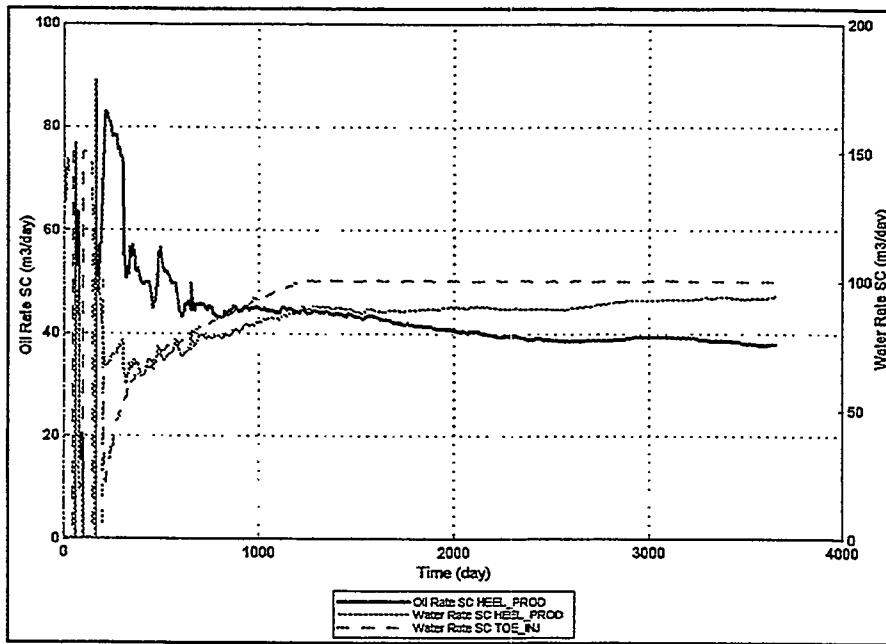


Figure 40: Height = 28 m Case; Production & Injection Rates vs. Time; NOTE: Rate values on graph should be multiplied by 2

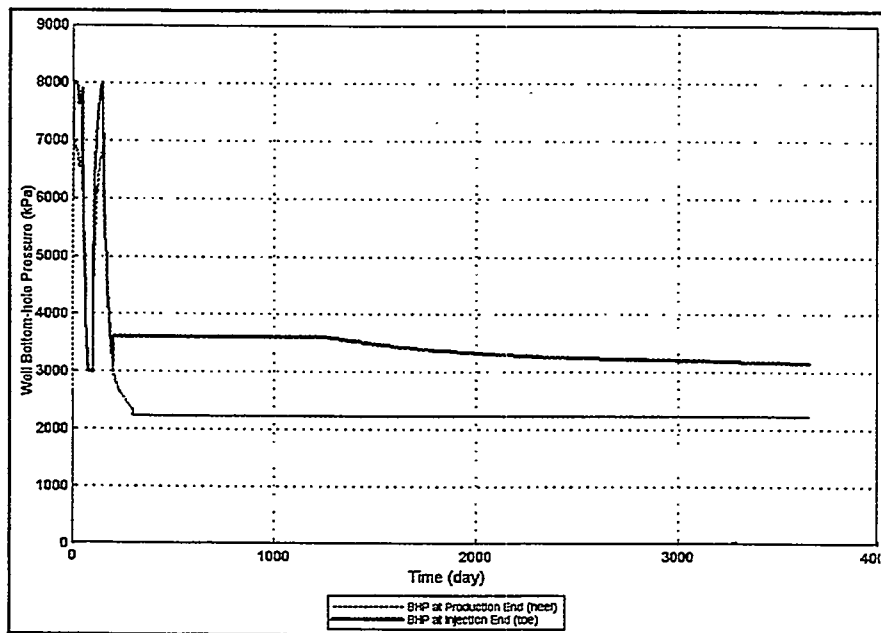


Figure 41: Height = 28 m Case; Bottom-hole Pressure vs. Time

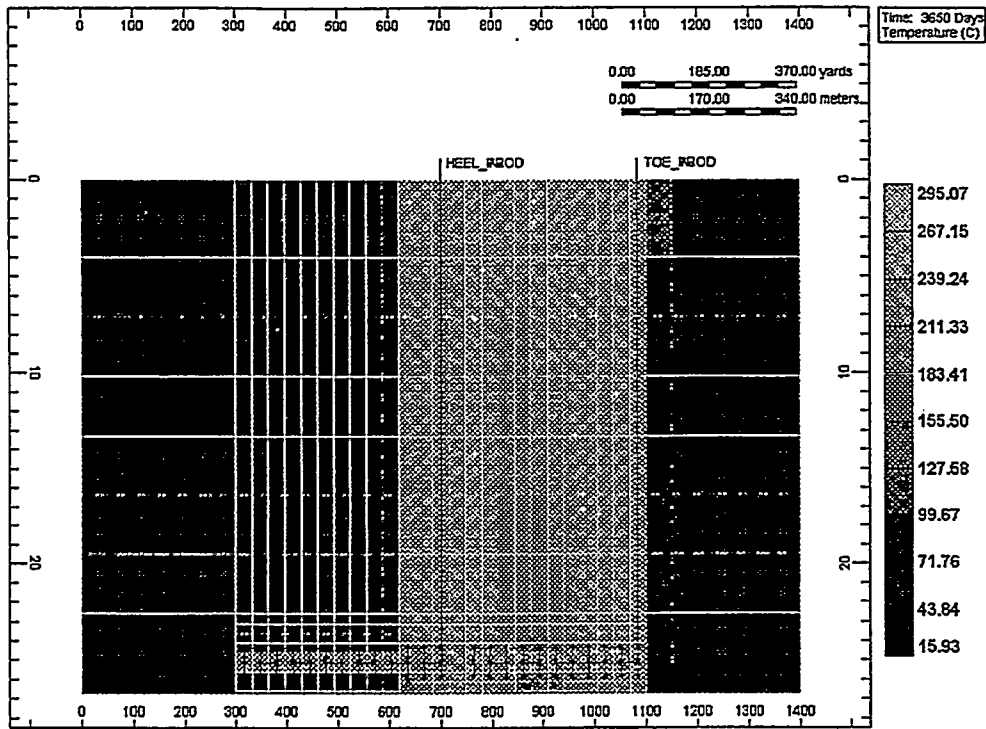


Figure 42: Height = 28 m Case; Temperature Profile at 3650 Days

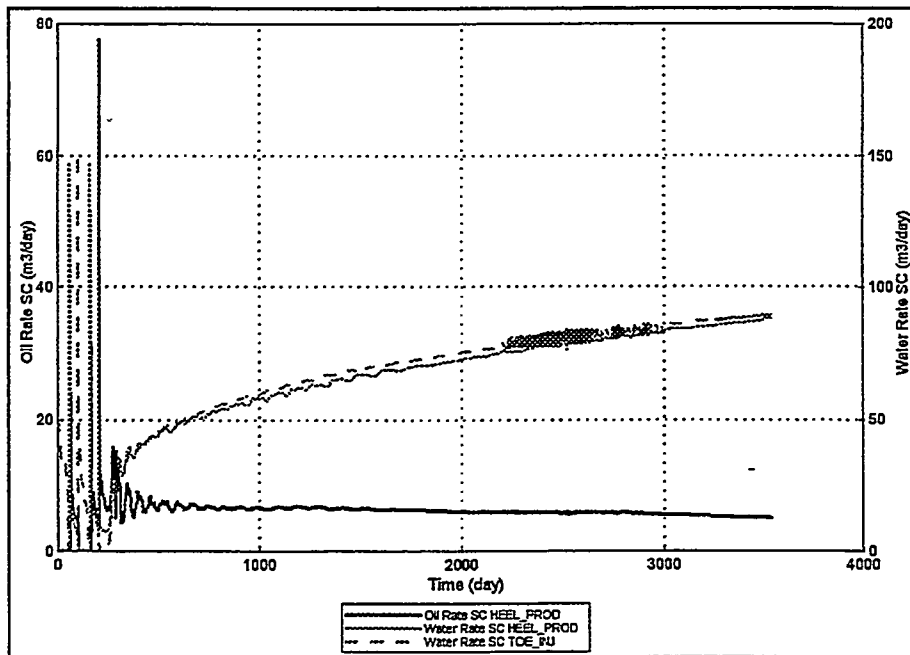


Figure 43: Height = 4 m Case; Production & Injection Rates vs. Time; NOTE: Rate values on graph should be multiplied by 2

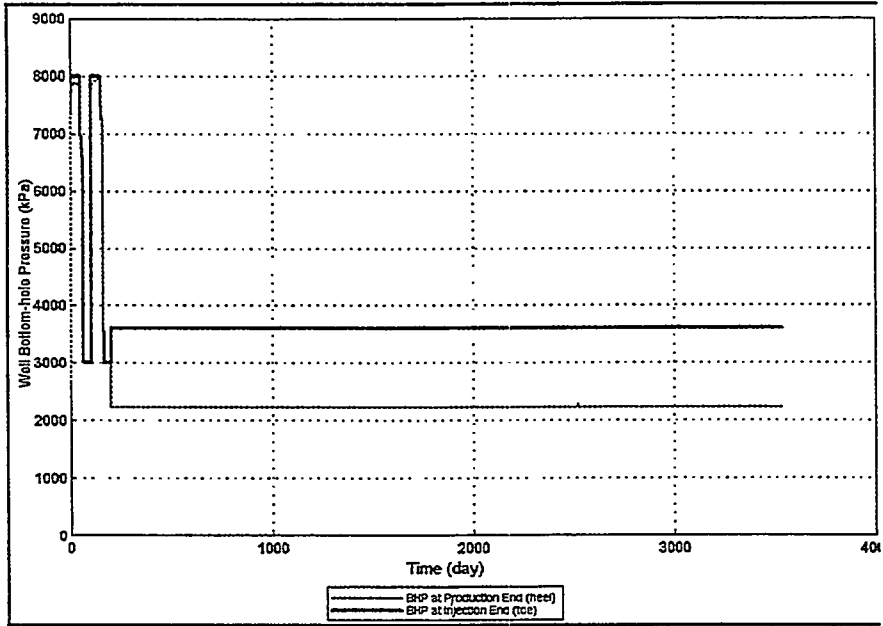


Figure 44: Height = 4 m Case; Bottom-hole Pressure vs. Time

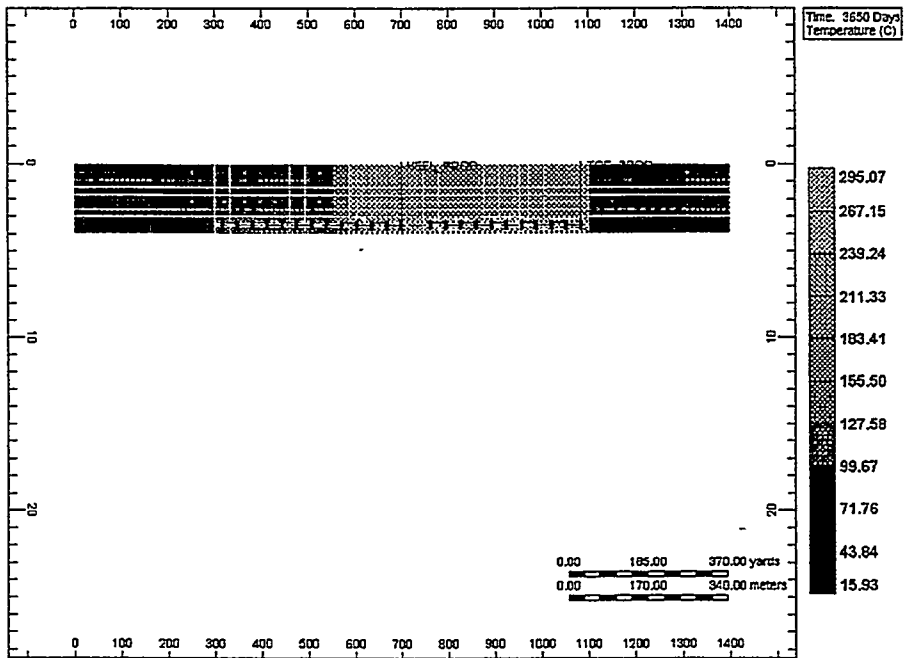


Figure 45: Height = 4 m Case; Temperature Profile at 3000 Days

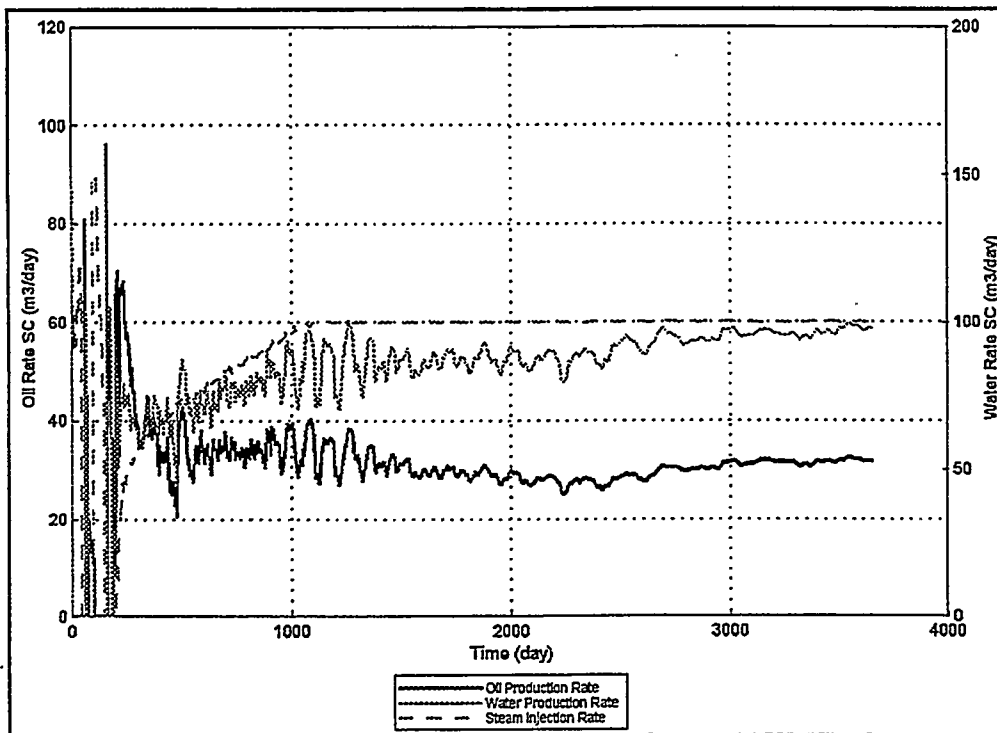


Figure 46: Dead Oil Case; Production & Injection Rates vs. Time; NOTE: Rate values on graph should be multiplied by 2

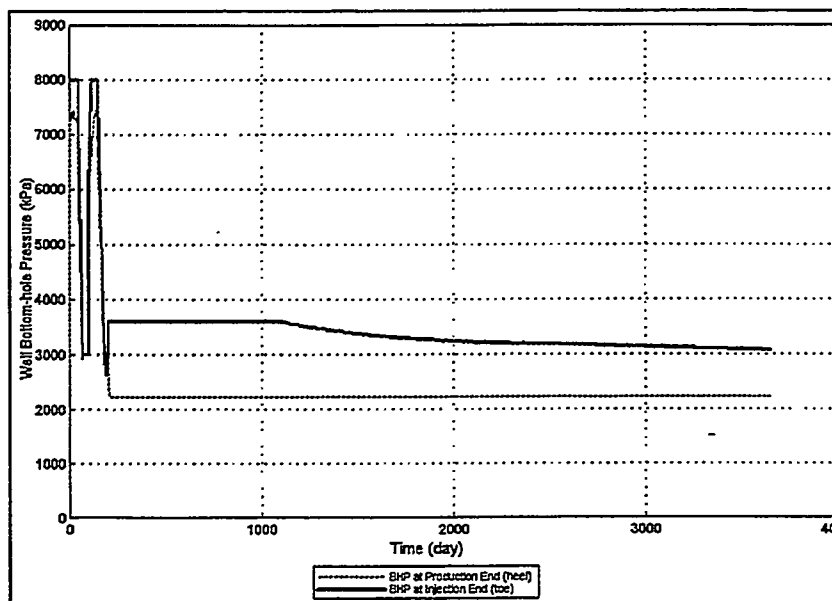


Figure 47: Dead Oil Case; Bottom-hole Pressure vs. Time

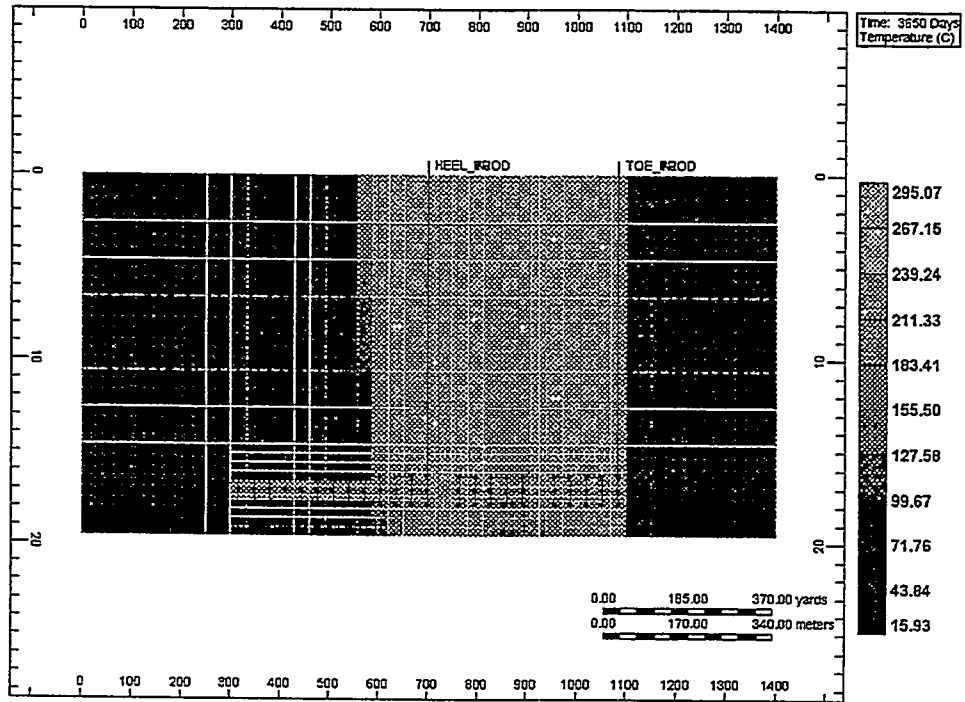


Figure 48: Dead Oil Case; Temperature Profile at 3650 Days

4.3 Discussion

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 10,000 cp, 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 these 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%.

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. Additionally, less short circuiting occurs as K_v increases relative to K_h .

5 Conclusions

A primary conclusion reached here is that to improve early-time performance of SW-SAGD, it is necessary to heat the near-wellbore region rapidly and uniformly to create conditions favorable to the SAGD process. 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 does not aid 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 10,000 cp. Additionally, the reservoir must be sufficiently thick to allow significant vertical steam chamber growth. Recovery from thin oil zones is not significant.

6 Further Areas of Study

Our analysis of the early-time performance of SW-SAGD provided qualitative ideas on how to improve early-time production response. An obvious extension of this work is to optimize each early-time procedure using quantitative results such as net heat injection and steam-oil ratio. Beyond early-time performance, there are also interesting issues regarding the SAGD process and steam-chamber development. The sensitivity analysis we performed provided insight into the effect of oil viscosity and gas content, reservoir thickness, and permeability anisotropy. We presented an analysis for maximizing steam chamber growth by optimizing the pressure differential and spacing between the injection and production portions of the well. However, short-circuiting between the injection and production sections still occurs; methods to reduce steam short-circuiting should be studied. Finally, cyclic steaming prior to SAGD is the most thermally efficient method of increasing the early-time response of SW-SAGD. Optimizing the cyclic process and the number of cycles prior to SAGD is an important topic for future study.

7 References

1. Butler, R.M., Thermal Recovery of Oil and Bitumen, Englewood Cliffs, N.J.: Prentice Hall, 1991, pp. 285-359.
2. Joshi, S.D., "A Laboratory Study of Thermal Oil Recovery Using Horizontal Wells," paper SPE/DOE 14916 presented at the 1986 SPE/DOE Fifth Symposium on Enhanced Oil Recovery held in Tulsa, OK, April 20-23.
3. Oballa, V., and Buchanan, W.L., "Single Horizontal Well in Thermal Recovery Processes," paper SPE 37115 presented at the 1996 International Conference on Horizontal Well Technology, Calgary, Canada, Nov. 18-20.
4. Falk, K., Nzekwu, B., Karpuk, B, and Pelensky, P., "Concentric CT for single-well steam-assisted gravity drainage," *World Oil* (July 1996), 85-95.
5. McCormack, M., Fitzgibbon, J., Horbachewski, N., "Review of Single Well SAGD Field Operating Experience," Canadian Petroleum Society Publication No. 97-191, 1997.
6. Computer Modeling Group, "STARS Version 98 User's Guide," Calgary, Alberta Canada, 1998.

Appendix 1: STARS Data Files

A.1.1: Early-Time Analysis, Case1, SAGD Operating Conditions from Start

```
**                               OVERVIEW
**                               =====

** The problem is a gravity drainage horizontal well.
** A three-dimensional study is required.
**

** Features:

** 1) Three-dimensional X - Y - Z coordinates.
** 2) Distinct permeability layering.
** 3) Black-oil type treatment of fluids.
** 4) Automatic initial vertical equilibrium calculation.
** 5) Multi-segment horizontal well modelled by the DP technique.
** 6) Discretized circulating wellbore for injection.
** 7) Hybrid grid surrounding discretized circulating injector.
** 8) Insulated Tubing String(4.00").
** 9) Use 9-5/8" Slotted Liner.
** 10) Increased cpor, rockcp, thconr and modified Rel Perm Curves

***** File Modification and Development Notes: *****

** I am creating Case 3 (Extreme pressure differential for 100 days,
** then SAGD conditions). I copied 009 directly and just created
** the new file by adjusting the operating conditions at early time.
** The new file is case009_3.dat. KTE 1/5/99

** Just added the RC and Component stuff. KTE 1/5/99

**
** Now adding the new wellbore completion. We will have two
** separate completions - one for injection at the toe and
** one for production at the heel. NOTE: I am leaving the
** wellbore indices the same at the moment - but you need to
** go through and understand them and then correct them!
** KTE 1/11/99 New File: stars/12_29/case3/case009_3b.dat

** Created Case 2: Start at and Maintain SAGD Op. Cond.
** Just copied case009_3b.dat, and will only change the operating
** constraints. Not too many changes.
** KTE 1/14/99 New File: stars/12_29/case2/case009_2.dat

** Cleaned up the file a bit and renamed 12_29/case2/case1.dat to include
** in the appendix of my thesis.
** Note: In my original series of runs, this file was case 2, I renamed
** it Case 1 for inclusion into my thesis. KTE 5/12/99

** ===== INPUT/OUTPUT CONTROL =====

**checkonly
**interrupt *stop

**TITLE1 'CASE 1, Live Oil, Continuous SAGD'
**TITLE2 'Single Discretized Wellbore Inside Hybrid Grid (SWSAGD)'
**TITLE3 '800-metre Well Model in Typical Alberta Reservoir'

inunit si
outunit si
outprn grid pres sw so sg temp
wprn grid 300
outprn well all
outprn iter *newton
```

```

wprn iter time
**prntorien 1 0

outsrf special delpblock 5943 5895 ** pressure drop in the Annulus(Well 1)
              delpblock 5894 5942 ** pressure drop in the Tubing(Well 2)
              blkvar temp 0 5895 ** produced fluid temperature at the Heel(Annulus)
              blkvar temp 0 5942 ** steam temperature at the Toe(Tubing)
              osr 1 2
              osr 1 2 cum

*****
*outsrfr *well *downhole
**All of this must be added to obtain data needed to calculate
** Recovery and SOR
*outsrfr *well *component all
*outsrfr *well *mass
**
*****

outsrf grid pres sw so sg temp
wsrf grid time
wsrf well 1

dim mdiclu 65000
dim mdptgl 150

** ===== GRID AND RESERVOIR DEFINITION =====

old-grid
grid cart 29 24 8 ** 1/2 Symmetry Element - Well Split along axis in x-direction.
kdir down
** Horizontal well = 800 meters in layer 6
** Inter-well spacing = 160 meters with 80 meters element of symmetry
di ivar 250 50 25*32 50 250 ** x-length = 1400 meters
dj jvar 11.0 23*3 ** y-length = 80 meters
dk kvar 2.6 6*2.0 5.00 ** z-height = 19.6 meters

** Single - Well SAGD :
** a) Modelled as a circwell, ie. same well has both tubing and annulus
** b) Producer is well #1 ; it is the annulus
** c) Injector is well #2 ; it is the tubing
** d) CIRCWELL is discretized lower wellbore with a second independent flow string in it
** CIRCWELL is located in
**      heel toe i j k
** regular grid i=3 i=27 1:29 1 8
**      heel toe ir jr kr
** hybrid grid ir=1 ir=1 1:3 1:4 1
**      heel toe i j k s/s well @
** PROD=WELL 1=annulus i=3 i=34 3:34 1 6 i=1 j=1 k=6
** INJ =WELL 2=tubing i=3 i=34 34:3 1 6 i=1 j=1 k=6
** e) Annulus Radius = 0.0594500 m = r3
** Outside Insulated Tubing Radius = 0.0508000 m = r2
** Inside Insulated Tubing Radius = 0.0450500 m = r1

** refine = place refined cylindrical hybrid grid having r radial grids;
** 4 radial spokes in theta direction; 1 grid
** 1 grid/grid parallel to the reg. grid i-direction around reg. blocks
** i=3:34, j=1, k=6

refine 3:27 1 8 into 5 4 1
      hybrid idir

** wellbore = discretized wellbore will be defined

wellbore 0.0450500 ** radius of tubing for Single Well SAGD in meters (90.1 mm ID)

***transient

** circwell ra i j k nwbwt
** ra = annular radius in meters
** i j k = regular grid location of toe of well tubing
** nwbwt = no. of regular grid blocks w/o tubing

      circwell 0.059450 15 1 8 0
      range 3:15 1 8
      **range 3:27 1 8 This one is the old one! KTE 1/11/99

**Added by KTE on 1/11/99*****

```

```

**Production Well defined above
**Injection Well defined below
wellbore 0.0450500
circwell 0.059450 27 1 8 0
range 16:27 1 8
*****

```

```

**      key      v      ai      aj      ak      **
vamod   3      0.5    0.5    1.0    0.5      ** J=1 plane
vamod   9      0.5    0.5    1.0    0.5      ** hybrid half-block *IDIR & *KDIR

```

```

** Assign geometry types to fundamental blocks.
vatype con 1
mod 1:29 1 1:8 = 3 ** J=1 plane

```

```

** Assign geometry types to hybrid blocks
**vatype rg 1:29 1 8 jvar 9 1 9 0 ** half grid
vatype rg 3:27 1 8 jvar 9 1 9 0 ** half grid
mod 1 1 1 = 9

```

```
por con 0.330
```

```

permi con 3400 ** kx, mD
permj equalsi ** ky = kx
permk con 680.0 ** kz, mD kh/kv = 0.2

```

```
end-grid
```

```

rocktype 1 ** Matrix heat properties
cpor 9.6e-6 rockcp 2.35e6 thconr 1.25e5 prpor 2654.0
thconw 1.495e5 thcono 1.495e5 thcong 1.495e5
hlossprop overbur 1.169e6 7.49e4 underbur 1.169e6 7.49e4

```

```

rocktype 2 ** Wellbore annulus heat properties
cpor 0 rockcp 3.61e6 thconr 3.89e6 ** thermal props of mild steel
thconw 1.495e5 thcono 1.495e5 thcong 1.495e5

```

```

rocktype 3 ** Wellbore tubing heat properties
cpor 1.0e-7 rockcp 3.61e7 thconr 1.495e2 ** Newsco insulated tubing
thconw 1.495e2 thcono 1.495e2 thcong 1.495e2

```

```

thtype con 1
thtype wellbore 3:27 1 8 con 3

```

```
** ===== FLUID DEFINITIONS =====
```

```

model 3 3 3 ** ncomp= W,OIL,GAS = Total # of Components
** numy = W,OIL,GAS = Total # of Components in 3 phases
** numx = W,OIL,GAS = Total # of Components in 2 Liq phases

```

compname	'Water'	'OIL'	'GAS'	
**	---	---	---	
cmm	0	0.508	0.01604	** kg/gmole
molden	0	1960.6	42411.0	** gmole/m3
cp	0	5.63E-7	9.48E-5	** 1/kPa
ct1	0	8.48E-4	2.30E-2	** 1/deg C
pcrit	0	1360.0	4640.0	** kPa
tcrit	0	624.65	-82.49	** deg C
cp11	0	1130.0	12.83	
cpg1	0	841.0	35.2	
hvapr	0	1346.0	1770.0	
avg	0	0	2.80E-4	
bvg	0	0	0.6670	
avisc	0	1.74E-6	1.90E-4	
bvisc	0	6232.74	3423.41	
kv1	0	0	0.4391E5	
kv2	0	0	0	
kv3	0	0	1.97	
kv4	0	0	-.19589E3	
kv5	0	0	-273.16	

```

** Reference conditions
prsr 101.3 tempr 21.0 psurf 101.3 tsurf 15.6

```

```
** ===== ROCK-FLUID PROPERTIES =====
```

rockfluid

*rpt 1

*swt **

** Sw	Krw	Krow
0.15	0.0000	1.0000
0.20	0.20e-3	0.9500
0.25	0.163e-2	0.8400
0.30	0.55e-2	0.72
0.35	0.13e-1	0.60
0.40	0.254e-1	0.47
0.45	0.44e-1	0.35
0.50	0.698e-1	0.24
0.55	0.1040	0.1650
0.60	0.1480	0.930e-1
0.65	0.2040	0.700e-1
0.70	0.2710	0.400e-1
0.75	0.3520	0.150e-1
0.80	0.4470	0.00
0.85	0.559	0.0
** 0.90	0.6870	0.0
** 0.95	0.8340	0.0
** 1.0	1.0	0.0

*slt

** Sl	Krg	Krog
0.15	1.0000	0.0000
0.20	0.9500	0.20e-3
0.25	0.8400	0.163e-2
0.30	0.72	0.55e-2
0.35	0.60	0.13e-1
0.40	0.47	0.254e-1
0.45	0.35	0.44e-1
0.50	0.24	0.698e-1
0.55	0.1650	0.1040
0.60	0.930e-1	0.1480
0.65	0.750e-1	0.2040
0.70	0.450e-1	0.2710
0.75	0.270e-1	0.3520
0.80	0.2e-1	0.4470
0.85	0.1e-1	0.559
0.90	0.5e-2	0.6870
0.95	0.0	0.8340
1.0	0.0	1.0

** Assign rel perm sets

krtype con 1

** ===== INITIAL CONDITIONS =====

initial

pres con 2654.0

** Same conditions in wellbore and matrix

sw kvar 8*0.15 **3*0.16 2*0.21 0.29 0.65

**sw wellbore 3:34 1 6 con 1.0

so kvar 8*0.85 **3*0.84 2*0.79 0.71 0.35

**so wellbore 3:34 1 6 con 0.0

temp con 16 ** initial reservoir temp = 16 C

**temp wellbore 3:34 1 6 con 16.00

** water oil gas

** -----

**molefrac oil con 0 0.886 0.114

molefrac oil con 0 0.9 0.1

** ===== NUMERICAL CONTROL =====

numerical ** All these can be defaulted. The definitions

** here match the previous data.

time 350
time 500
time 730
time 1095
time 1460 time 1825
time 2190 time 2555 time 2920
time 3285 time 3650

STOP

A.1.2: Sensitivity Analysis Base Case

```
**                               OVERVIEW
**                               =====
**
** The problem is a gravity drainage horizontal well.
** A three-dimensional study is required.
**
** Features:
** 1) Three-dimensional X - Y - Z coordinates.
** 2) Distinct permeability layering.
** 3) Black-oil type treatment of fluids.
** 4) Automatic initial vertical equilibrium calculation.
** 5) Multi-segment horizontal well modelled by the DP technique.
** 6) Discretized circulating wellbore for injection.
** 7) Hybrid grid surrounding discretized circulating injector.
** 8) Insulated Tubing String(4.00").
** 9) Use 9-5/8" Slotted Liner.
** 10) Increased cpor, rockcp, thconr and modified Rel Perm Curves
**
** I am creating Case 3 (Extreme pressure differential for 100 days,
** then SAGD conditions). I copied 009 directly and just created
** the new file by adjusting the operating conditions at early time.
** The new file is case009_3.dat. KTE 1/5/99
**
** Just added the RC and Component stuff. KTE 1/5/99
**
** Now adding the new wellbore completion. We will have two
** separate completions - one for injection at the toe and
** one for production at the heel. NOTE: I am leaving the
** wellbore indices the same at the moment - but you need to
** go through and understand them and then correct them!
** KTE 1/11/99 New File: stars/12_29/case3/case009_3b.dat
**
** I just copied this directly from case009_3b.dat and renamed
** it stars/12_29/case4/case009_4.dat
** Case 4 is "Circulate for 100 d, then SAGD conditions. I only
** modified the well completion area. KTE 1/13/99
**
** Just copied this from case009_4.dat and renamed it
** stars /12_29/case5/case009_5.dat
** Case 5 is "Circulate for 100 d, then operate at extreme
** conditions, then SAGD conditions.
**
** Just copied this from case009_5.dat and renamed it
** stars/12_29/case6/case009_6.dat
** Case 6 is: "Cycle 1X, then SAGD Operating Conditions"
** I plan to inject, then soak, then produce (suck it all
** down), then go into SAGD op cond.
**
** Just copied from case009_6c.dat and renamed it
** stars/12_29/case7/case009_7.dat
** Case 7 is: "Cycle 2X, then SAGD Op Cond."
** Note that case 6 crashed two times during the production
** part, then I cut production time down so it ends at 100 d,
** or 40 days of production.
**
** Just copied this from case009_7.dat and renamed it
** stars/4_21/base/base.dat.
** I made the following changes: Changed operating constraints
** to make it a more pressure controlled system in the SAGD
** phase (min prod bhp 2230 kPa, max inj pres 3610 kPa, steam
** inj. pres. 3610 kPa/244.32 C)
** I also added one empty block between the producer and injector.
** KTE 4/21/99
```

```

** ===== INPUT/OUTPUT CONTROL =====

**checkonly
**interrupt *stop

*TITLE1 'BASE CASE, Live Oil, Cycle 2X, then SAGD'
*TITLE2 'Single Discretized Wellbore Inside Hybrid Grid (SWSAGD)'
*TITLE3 '800-metre Well Model in Typical Alberta Reservoir'

inunit si
outunit si
outprn grid pres sw so sg temp
wprn grid 300
outprn well all
outprn iter *newton
wprn iter time
**prntorien 1 0

outsrf special delblock 5943 5895 ** pressure drop in the Annulus(Well 1)
delblock 5894 5942 ** pressure drop in the Tubing(Well 2)
blkvar temp 0 5895 ** produced fluid temperature at the Heel(Annulus)
blkvar temp 0 5942 ** steam temperature at the Toe(Tubing)
osr 1 2
osr 1 2 cum

*****
*outsrf *well *downhole
**All of this must be added to obtain data needed to calculate
**% Recovery and SOR
*outsrf *well *component all
*outsrf *well *mass
**
*****

outsrf grid pres sw so sg temp fluidh
wsrf grid time
wsrf well 1
**wrst time ** write a restart record at every TIME card
**rewind 3 ** save only the last 3 restart records in the restart file

dim mdiclu 65000
dim.mdptgl 150

** ===== GRID AND RESERVOIR DEFINITION =====

old-grid
grid cart 29 24 8 ** 1/2 Symmetry Element - Well Split along axis in x-direction.
kdir down
** Horizontal well = 800 meters in layer 6
** Inter-well spacing = 160 meters with 80 meters element of symmetry
di ivar 250 50 25*32 50 250 ** x-length = 1400 meters
dj jvar 11.0 23*3 ** y-length = 80 meters
dk kvar 2.6 6*2.0 5.00 ** z-height = 19.6 meters

** Single - Well SAGD :
** a) Modelled as a circwell, ie. same well has both tubing and annulus
** b) Producer is well #1 ; it is the annulus
** c) Injector is well #2 ; it is the tubing
** d) CIRCWELL is discretized lower wellbore with a second independent flow string in it
** CIRCWELL is located in
** heel toe i j k
** regular grid i=3 i=27 1:29 1 8
** heel toe ir jr kr
** hybrid grid ir=1 ir=1 1:3 1:4 1
** heel toe i j k s/s well @
** PROD=WELL 1=annulus i=3 i=34 3:34 1 6 i=1 j=1 k=6
** INJ =WELL 2=tubing i=3 i=34 34:3 1 6 i=1 j=1 k=6
** e) Annulus Radius = 0.0594500 m = r3
** Outside Insulated Tubing Radius = 0.0508000 m = r2
** Inside Insulated Tubing Radius = 0.0450500 m = r1

** refine = place refined cylindrical hybrid grid having r radial grids;
** 4 radial spokes in theta direction; 1 grid
** 1 grid/grid parallel to the reg. grid i-direction around reg. blocks
** i=3:34, j=1, k=6

refine 3:27 1 8 into 5 4 1
hybrid idir

```

```

** wellbore = discretized wellbore will be defined

wellbore 0.0450500 ** radius of tubing for Single Well SAGD in meters (90.1 mm ID)

***transient

** circwell ra i j k nwbwt
** ra = annular radius in meters
** i j k = regular grid location of toe of well tubing
** nwbwt = no. of regular grid blocks w/o tubing

circwell 0.059450 15 1 8 0
range 3:15 1 8
**range 3:27 1 8 This one is the old one! KTE 1/11/99

**Added by KTE on 1/11/99*****
**Production Well defined above
**Injection Well defined below
wellbore 0.0450500
circwell 0.059450 27 1 8 0
range 17:27 1 8 **made Block 16 empty! KTE 4/21/99
*****

** key v ai aj ak
vamod 3 0.5 0.5 1.0 0.5 ** J=1 plane

vamod 9 0.5 0.5 1.0 0.5 ** hybrid half-block *IDIR & *KDIR

** Assign geometry types to fundamental blocks.
vatype con 1
mod 1:29 1 1:8 = 3 ** J=1 plane

** Assign geometry types to hybrid blocks
**vatype rg 1:29 1 8 jvar 9 1 9 0 ** half grid
vatype rg 3:27 1 8 jvar 9 1 9 0 ** half grid
mod 1 1 1 = 9

por con 0.330

permi con 3400 ** kx, mD
permj equalsi ** ky = kx
permk con 680.0 ** kz, mD kh/kv = 0.2

end-grid

rocktype 1 ** Matrix heat properties
cpor 9.6e-6 rockcp 2.35e6 thconr 1.25e5 prpor 2654.0
thconw 1.495e5 thcono 1.495e5 thcong 1.495e5
hlossprop overbur 2.347e6 1.496e5 underbur 2.347e6 1.496e5
**hlossprop overbur 2.347e6 1.169e6 7.49e4 underbur 1.169e6 7.49e4
**Just above is what was in the example. Above that is what I changed
**it to (more average values) on 4/21/99 KTE.

rocktype 2 ** Wellbore annulus heat properties
cpor 0 rockcp 3.61e6 thconr 3.89e6 ** thermal props of mild steel
thconw 1.495e5 thcono 1.495e5 thcong 1.495e5

rocktype 3 ** Wellbore tubing heat properties
cpor 1.0e-7 rockcp 3.61e7 thconr 1.495e2 ** Newsco insulated tubing
thconw 1.495e2 thcono 1.495e2 thcong 1.495e2

thtype con 1
thtype wellbore 3:27 1 8 con 3

** ===== FLUID DEFINITIONS =====

model 3 3 3 ** ncomp= W,OIL,GAS = Total # of Components
** numy = W,OIL,GAS = Total # of Components in 3 phases
** numx = W,OIL,GAS = Total # of Components in 2 Liq phases

compname 'Water' 'OIL' 'GAS'
** -----
cmm 0 0.508 0.01604 ** kg/gmole
molden 0 1960.6 42411.0 ** gmole/m3
cp 0 5.63E-7 9.48E-5 ** 1/kPa
ct1 0 8.48E-4 2.30E-2 ** 1/deg C
pcrit 0 1360.0 4640.0 ** kPa

```

```

terit      0      624.65  -82.49  ** deg C
cp11      0      1130.0   12.83
cpg1      0      841.0    35.2
hvapr     0      1346.0   1770.0
avg       0      0      2.80E-4
bvg       0      0      0.6670
avisc     0      1.74E-6  1.90E-4
bvisc     0      6232.74  3423.41
kv1       0      0      0.4391E5
kv2       0      0      0
kv3       0      0      1.97
kv4       0      0      -.19589E3
kv5       0      0      -273.16

```

```

** Reference conditions
prsr 101.3 temr 21.0 psurf 101.3 tsurf 15.6

```

```

** ===== ROCK-FLUID PROPERTIES =====

```

```

rockfluid

```

```

*rpt 1

```

```

*swt **
** Sw      Krw      Krow
** -----
0.15      0.0000   1.0000
0.20      0.20e-3   0.9500
0.25      0.163e-2 0.8400
0.30      0.55e-2   0.72
0.35      0.13e-1  0.60
0.40      0.254e-1 0.47
0.45      0.44e-1  0.35
0.50      0.698e-1 0.24
0.55      0.1040   0.1650
0.60      0.1480   0.930e-1
0.65      0.2040   0.700e-1
0.70      0.2710   0.400e-1
0.75      0.3520   0.150e-1
0.80      0.4470   0.00
0.85      0.559    0.0
** 0.90      0.6870   0.0
** 0.95      0.8340   0.0
** 1.0       1.0      0.0

```

```

*slt

```

```

** S1      Krg      Krog
** -----
0.15      1.0000   0.0000
0.20      0.9500   0.20e-3
0.25      0.8400   0.163e-2
0.30      0.72      0.55e-2
0.35      0.60      0.13e-1
0.40      0.47      0.254e-1
0.45      0.35      0.44e-1
0.50      0.24      0.698e-1
0.55      0.1650   0.1040
0.60      0.930e-1 0.1480
0.65      0.750e-1 0.2040
0.70      0.450e-1 0.2710
0.75      0.270e-1 0.3520
0.80      0.2e-1    0.4470
0.85      0.1e-1   0.559
0.90      0.5e-2    0.6870
0.95      0.0      0.8340
1.0      0.0      1.0

```

```

** Assign rel perm sets

```

```

krtype con 1

```

```

** ===== INITIAL CONDITIONS =====

```

```

initial

```

```

pres con 2654.0
** Same conditions in wellbore and matrix

```

sw kvar 8*0.15 **3*0.16 2*0.21 0.29 0.65
**sw wellbore 3:34 1 6 con 1.0

so kvar 8*0.85 **3*0.84 2*0.79 0.71 0.35
**so wellbore 3:34 1 6 con 0.0

temp con 16 ** initial reservoir temp = 16 C
**temp wellbore 3:34 1 6 con 16.00

** water oil gas
** -----
**molefrac oil con 0 0.886 0.114
molefrac oil con 0 0.9 0.1

** ===== NUMERICAL CONTROL =====

numerical ** All these can be defaulted. The definitions
** here match the previous data.

north 10 newtoncyc 15 itermax 50
unrelax -1 sdegree 2 sorder rcmrb **redblack ** precc 1.E-4
aim stab
minpres 101 ** minimum pressure limit for simulation.
dtmax 30

rangecheck off
norm press 800 satur .40 temp 50 y 0.30 x 0.30
**converge press 50. satur .050 temp 5.0 y .050 x .050
converge press 100. satur .12 temp 100.0 y .10 x .10
rangecheck on

**converge maxres

** maxsteps 1
**upstream klevel

run

** ===== RECURRENT DATA =====

date 1996 1 1.0 dtwell 5.0e-3

well 1 'HEEL_PROD' frac 0.5 ** Horizontal Producer
well 2 'HEEL_INJ' frac 0.5 ** Horizontal Injector
well 3 'TOE_PROD' frac 0.5 ** Horizontal Producer
well 4 'TOE_INJ' frac 0.5 ** Horizontal Injector

** Perforate producer only in the horizontal section

producer 1 ** attach to s/s well at heel i=3 j=1 k=6
operate max liquid 300.0 ** Maximum liquid (oil + water) rate
**operate max steam 5.0 ** Maximum Steam Production Rate.
operate min bhp 500 ** Minimum BHP
geometry -1 0 0 0 ** Use tube-end option
perfrg 1 ** i j k ir jr kr wi Horizontal s/s well
3 1 8 1 1 1 WB 220.8

injector mobweight 2 ** Inject through tubing; attach s/s well (3,1,6)
tinjw 295 qual .90
operate max bhp 8000 *cont ** Maximum BHP
operate max water 300.0
geometry -1 0 0 0 ** Use tube-end option
perfrg 2 ** i j k ir jr kr wi = 0.007082 *k * h / ln(0.5 * re / rw)
3 1 8 1 1 1 TU 4367.0

producer 3 ** attach to s/s well at heel i=3 j=1 k
operate max liquid 300.0 ** Maximum liquid (oil + water) rate
**operate max steam 5.0 ** Maximum Steam Production Rate.
operate min bhp 500 ** Minimum BHP
geometry -1 0 0 0 ** Use tube-end option
perfrg 3 ** i j k ir jr kr wi Horizontal s/s well
17 1 8 1 1 1 WB 220.8

injector mobweight 4 ** Inject through tubing; attach s/s well (3,1,
tinjw 295 qual .90
operate max bhp 8000 *cont ** Maximum BHP

```

operate max water 300.0
geometry -1 0 0 0      ** Use tube-end option
perfrg 4 ** i j k ir jr kr wi = 0.007082 *k * h / ln(0.5 * re / rw)
                17 1 8 1 1 1 TU 4367.0

```

```

*****
**Begin Cycles
*****

```

```

*****CYCLE 1*****
*****Injection for 50 days*****
*shutin 1 *shutin 3
*dtwell 0.001

```

```

*time 10
*time 30
*time 50

```

```

*****Soak for 10 days*****
*shutin 2 *shutin 4

*time 60

```

```

*****Production for 120 days **Just made it 40 days*****
*open 1 *open 3
*dtwell 0.001

```

```

producer 1
operate max liquid 300.0
operate min bhp 3000

```

```

producer 3
operate max liquid 300.0
operate min bhp 3000

```

```

*time 70
*time 100

```

```

*****CYCLE 2*****
*****Injection for 50 days*****
*shutin 1 *shutin 3
*open 2 *open 4
*dtwell 0.001

```

```

*time 110
*time 130
*time 150

```

```

*****Soak for 10 days*****
*shutin 2 *shutin 4

*time 160

```

```

*****Production for 120 days **Just made it 40 days*****
*open 1 *open 3
*dtwell 0.001

```

```

producer 1
operate max liquid 300.0
operate min bhp 3000

```

```

producer 3
operate max liquid 300.0
operate min bhp 3000

```

```

*time 170
*time 200

```

```

*****
**** BEGIN SAGD *****
*****

```

```

*shutin 3
*open 4
  dtwell 0.01
  producer 1
    **operate max steam 5.0  ** attach to s/s well at heel i=3 j=1 k=6
    operate max liquid 300.0 ** Maximum Steam Production Rate.
    operate min bhp 2230     ** Maximum liquid (oil + water ) rate
                           ** Minimum BHP

```

injector mobweight 4 ** Inject through tubing; attach s/s well (3,1,6)
tinjw 244.32 qual 0.9
operate max water 200.0
operate max bhp 3610 ** Maximum BHP

time 250
time 280
time 300
time 350
time 400
time 450
time 500
time 730
time 1095
time 1460 time 1825
time 2190 time 2555 time 2920
time 3285 time 3650

**time 7300
**time 10950
**time 14600
STOP