Transactions C: Chemistry and Chemical Engineering
Vol. 16, No. 2, pp. 125–139

Research Note

SCIENTIA IRANICA

Application of Cyclic Steam Stimulation by Horizontal Wells in Iranian Heavy Oil Reservoirs

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Abstract. *In Iran, there are a number of heavy oil reservoirs whose importance is growing as the conventional resources deplete. This study concerns the numerical simulation of cyclic steam stimulation of one of the heavy oil reservoirs. Results are encouraging and should be tested by field pilots. Heavy oil is characterized by its high viscosity. Thermal methods reduce viscosity and residual oil saturation to improve mobility and achieve an economical recovery. Cyclic Steam Stimulation (CSS) which has faster production, lower capital costs and lower pressure operations than steam-flooding is of great interest in thermal methods. Oil recovery with steam injection has been enhanced with horizontal wells by increasing sweep efficiency, the contact area opened to flow, producible reserves, steam injectivity and also by decreasing the number of wells required so that higher oil production is reached. K-Field is one of the Iranian fractured heavy oil fields with low °API of 7.24 and high viscosity of 2700 cp. Although steam injection in naturally fractured heavy oil reservoirs provides extremely challenging issues, it can be considered as a potentially effective and efficient improved recovery method. In this study, using STARS, a thermal dual-porosity model was constructed based on the available measured data to study CSS. Comprehensive and comparative studies and a sensitivity analysis of various operational parameters were conducted in order to find the optimum conditions for a high RF. This work shows that oil recovery could be improved from 0.66% by cold production to more than 10% by CSS during a 10 year period.*

Keywords: *Heavy oil; Enhanced oil recovery; Thermal methods; Steam injection; Cyclic steam stimulation; Horizontal well.*

INTRODUCTION

Two criteria usually characterize heavy crudes: the viscosity and the density. Light oil has an °API gravity of at least 20 and a viscosity of less than 100 centipoises. Conventional heavy oil is an asphaltic, dense (low API gravity) and viscous oil. Although variously defined, the upper limit for heavy oil has been set at 20°API gravity and a viscosity of 100 centipoises [1].

The identified volumes in place of heavy oil, extra-heavy oil and bitumen are estimated at about 4800Bbbl, that is to say the equivalent of the remaining resources in place of conventional oils discovered until now. Few of those heavy crude resources have already been produced; only 1 to 2%. Global technically recoverable heavy crude resources are evaluated at 1000 Bbbl, i.e. the equivalent of the proven reserves of conventional oils. Recovery factors could be very different depending on the production method [2].

Heavy and extra-heavy oil and natural bitumen production accounted for only about 5.5 Mbbl/d, which represented only 7% of the total world crude oil production in 2003 (it was estimated at 76.9 Mbbl/d). Compared to light oil, these resources are generally more costly to produce and transport. The extra production, transportation and upgrading costs explain why development and production of extra-heavy oil and bitumen are still limited. But their abundance, strategic geographic distribution, quality and cost will shape their role in the future of oil supply [2,3].

In Iran, according to the latest studies, there are more than 80 billion bbls of heavy oil. This kind of Iranian oil is defined as oil with °API less than 20 and movable in a reservoir. Assuming an ultimate recovery factor of 15% for heavy oil and 33% for conventional

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Received 8 July 2007; received in revised form 13 March 2008; accepted 19 May 2009

oil, the reserves are nearly equal. But the ultimate recovery factor for heavy oil could be much higher.

Fractured reservoirs are estimated to contain 25-30% of the world supply of oil. Many of these reservoirs contain heavy oil that can only be recovered by a thermal recovery technique. Steam injection could be a good thermal method for oil recovery from fractured reservoirs. Physical processes taking place during steam injection should be understood thoroughly, and reliable models should be developed for the effective and economic recovery of oil from fractured systems [4].

Thermal enhanced oil recovery methods that have been applied in the field include hot water drive, steam injection and in-situ combustion. Steam injection is a more effective method than hot water drive, on account of the latent heat of vaporization that can be harnessed from the steam. Due to well-bore heat loss, steam injection may not be feasible in deep reservoirs. For deeper reservoirs, in-situ combustion may be a more suitable thermal EOR method.

Main mechanisms during steam injection are oil viscosity and residual oil saturation reduction by increasing the reservoir temperature. In addition, injection of fluid into the reservoirs has also the beneficial effect of enhancing oil displacement and providing reservoir pressure support. Steam injection has two forms: steam flooding or steam drive, and cyclic steam injection or huff-and-puff [5].

In steam flooding, steam is continuously injected into fixed well patterns of injection wells while fluids are produced in designated wells. In CSS, steam is injected and produced from the same well. CSS provides thermal energy in the vicinity of the well-bore, using the steam as the heat transfer medium and allowing the rock to act as a heat exchanger for temporary storage of the injected energy. Each cycle consists of three periods: injection, soak and production. Usually steam is injected for a short period of time during the injection stage. After that, the well is closed for a short time, i.e. the soaking period, allowing the steam to heat up a larger part of the reservoir. Most of the latent heat of the steam is transferred to the formation surrounding the well, lowering the viscosity of the oil. Finally, the well is put back on production for a period of time to produce the oil and the condensed injected steam. The initial production rate of the hot fluids is higher than that of the primary cold production. However, the rate declines with time to near the pre-stimulation values as the heat is removed with produced fluids and dissipated into nonproductive formations [5].

The main advantages of CSS over steam flooding are faster production response, lower initial capital costs and lower pressure operations. From a technical point of view, two main factors are necessary for the success of this kind of process: A significant effect of temperature on the viscosity of the heavy crude oil to reduce the flow resistance around the producing well, and a natural production mechanism or a driving force present in the reservoir initially. Typically, gravity drainage and the solution gas drive are the most important mechanisms in providing driving forces during the production phase. In addition, rock compaction may be a significant drive mechanism for some reservoirs. From an operational point of view, CSS has been accepted because the application of the process is simple; simple steam generators may service a large number of wells. In addition, if the process is successful, increased oil production happens immediately, since the oil remains hot as it flows to the well. Oil recovery with steam injection has been enhanced by the incorporation of horizontal wells. The main advantages of horizontal wells are improved sweep efficiency, increased producible reserves, increased steam injectivity and a decreased number of wells required for field development.

A horizontal well allows us to manage higher injection rates and the contact area opened to flow is larger than in vertical wells. Thus, the heat zone around the horizontal well is larger than that around the vertical well. That means a higher oil viscosity reduction and, therefore, typically higher oil production is reached, since horizontal wells access a larger volume of the reservoir compared to vertical well [5].

There are several studies on CSS using horizontal wells: some experimental and simulation studies and some analytical modeling. In 1984, Toma et al. [6] conducted an experimental study for CSS in a horizontal well. The experiment was conducted for a sizeable portion of a horizontal well in an oil sand formation. The scaled model represents a section of formation with radius 1.5 m containing a horizontal well that is 12 m in length. The experimental results show that the recovery of cyclic steaming in a horizontal well is affected by the axial and radial components of recovery [5].

In 1999, Rodriguez presented a three dimensional thermal and compositional simulation study to evaluate the performance of horizontal wells under cyclic steam injection and steam flooding. The results show that the recovery of the field can be increased by steam flooding with additional producer wells around the horizontal well injector. The main advantages of steam flooding are reservoir re-pressurization and improved thermal efficiency [5,7].

In 1999, Utpal presented a model which accounts for the gravity-drainage of oil along the steam-oil interface and through the steam zone. Oil viscosity, effective permeability, the geometry of the heated zone, porosity, mobile oil saturation and the thermal diffusivity of the reservoir influence the flow rate of oil in the model. The change in reservoir temperature with time is also modeled, and it results in an expected decline in oil production rate during the production cycle as the reservoir cools. This model holds for heavy oil, pressure-depleted reservoirs where the main driving force for production is gravity [8].

In 1999, Gunadi presented an analytical model for CSS using horizontal wells consisting of two sub-models as follows: a sub-model for the injection period and a Sub-model for the soaking and production period. The mathematical model for CSS using vertical wells incorporates previous and new sub-models as follows: The Marx and Langenheim model for the injection period (as in the Boberg and Lantz method) and a horizontal well sub-model for soaking and production periods but with the well in the vertical position [9].

FIELD PROPERTIES

This field is a giant structure located on the coast of the Persian Gulf. Development of the field has not begun yet. The field is like a symmetrical anticline, 90 km in length and 16 km width at the surface. This includes 60 km length and 10 km width on the 1000 mss depth of Jahrum and 60 km length and 9.8 km width on the 2000 mss depth of the Sarvak formations. Jahrum and Sarvak formations have been considered for Ultra Heavy Oil project. The Jahrum formation, which is located between Asmari on the top and Pabdeh below it, is mainly dolomite. The average thickness of this formation is about 500 m. The Sarvak formation with an average thickness of 300 m is an important formation in the Ultra Heavy Oil project. This formation mostly consists of limestone with some interbedded shaley layers. Laffan overlies it and a Kazhdumi formation, which mostly consists of shale, underlies it. By using the results gained from cores and surface studies, mud losses data and the method of the radius of curvature, it is concluded that this field, especially the reservoirs (Jahrum and Sarvak), is highly fractured in such a way that most of these fractures are vertical. The Jahrum formation is divided into 3 zones. Basically, all zones consist of dolomite and limestone. Zones 1 and 2 are free of shale. Porosity distribution in Zone 1 is better than Zone 2, but both zones are saturated with oil. The Sarvak formation is also divided into 3 zones, basically matrix composed of limestone with very small amounts of dolomite.

MODEL DESCRIPTION

Grid Size and Coordinates

A geological model with 5400 grids exported from RMS: 60 grids along the X-direction, 10 grids along the Y-direction and 9 grids, representing 9 layers for the reservoir model, for the Z-direction. Coordinates of 4 corners and the depth of the top of each grid are given by an exported file of RMS. To define null blocks, "PINCHOUT ARRAY" should specify to zero for the blocks which are not in the reservoir (see Figure 1).

PVT Analysis of the Reservoir Fluid

PVT data were obtained from a sample was taken from the Sarvak formation at a depth of 1150 m. The oil was extra heavy oil with the viscosity of 2700 cp and 7.24°API at an initial pressure of 927 psi and a temperature of 139.3°F. The bubble point pressure of the oil was 624 psi. A WinProp module of CMG was used in order to tune a suitable EOS for this sample. Due to the high viscosity of the oil, a Peng-Robinson EOS (1976) and, for the same reason, a Modified Pederson (1987), were chosen for the tuning of the viscosity equation. After lots of trial including splitting the C_{12}^{+} to C_{36}^{+}, lumping and reducing the components to seven components and selecting proper regressing parameters, simultaneously, an excellent match for the mentioned EOS and viscosity equation was obtained. Table 1 represents a relation between viscosity and temperature; this relation should be entered in the appropriate place in CMG's STARS thermal simulator.

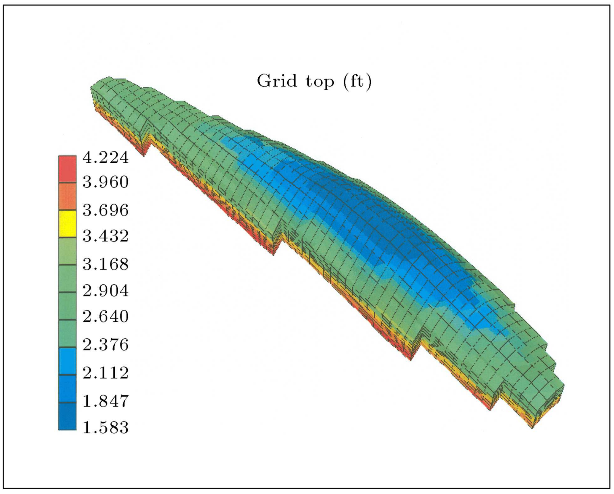

Figure 1. 3D view of top of grid blocks.

Table 1. Dependence of the oil viscosity on the temperature.

Temperature, °F	Viscosity, cp
50	300000
113	11200
122	6700
131	4025
140	2700
200	108
300	20
400	5
500	2

Relative Permeability and Capillary Pressure [4]

The matrix relative permeability and capillary pressure of this field were measured by R.I.P.I. (Research Institute of Petroleum Industry). The method which is used to find out the matrix relative permeability and capillary of this field was a special core analysis on the plug and whole core. Twenty three centrifugal experiments were done on plugs for Pc and seven experiments were done on the whole core for the matrix relative permeability (see Figures 2 and 3). To choose the proper curves for our model, steam flooding experiments on the core must be done, but here due to their lack, experiments #472 for Pc (Figure 4) and #438 for k_r (Figure 5) were taken from Figures 2 and 3, respectively.

The end point and relative permeabilities were considered to be independent of temperature. Temperature-dependent endpoint saturations for the water-oil system and hysteresis were not considered because of lack of data. For the multi phase in the fracture, the usual assumption is that the relative permeability k_{rlf} of phase l is proportional to the volume of phase l inside the fracture, i.e. $k_{rlf}= S_{lf}$. This equation is based on the assumption of segregated fluids in the fracture. Residual saturations are zero in this equation. Capillary pressure in the fracture is usually small and can be neglected. The relative permeability curves in fractures are shown in

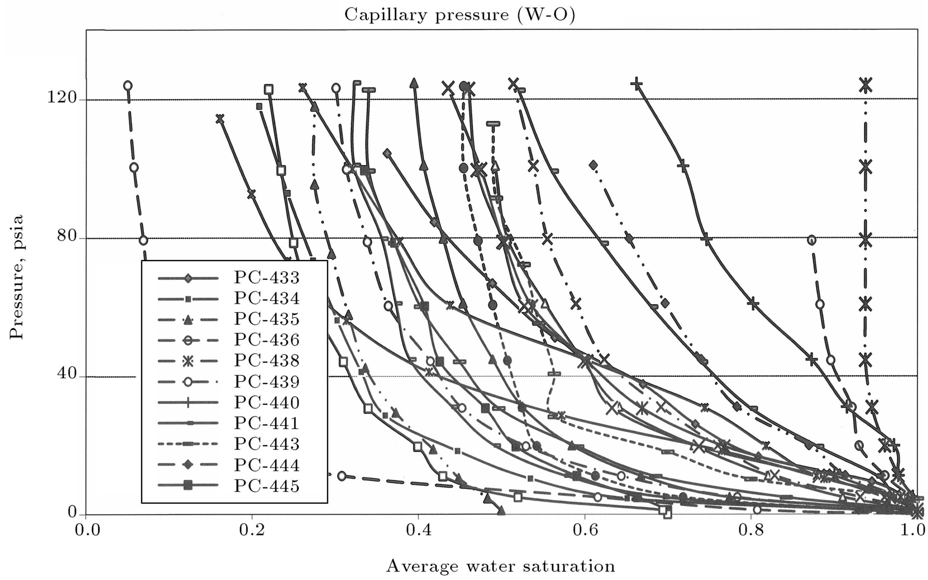

Figure 2. Capillary pressure versus average water saturation.

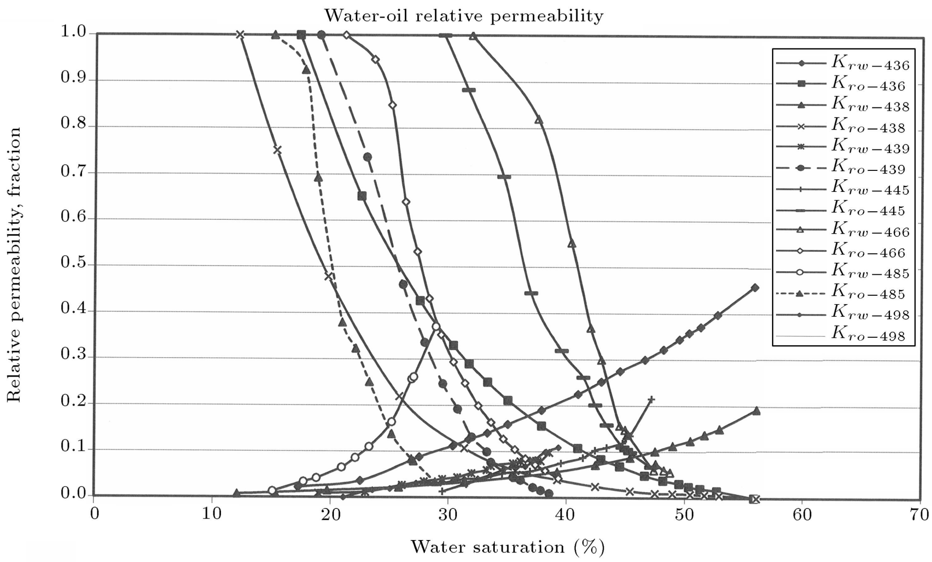

Figure 3. Relative permeability versus water saturation.

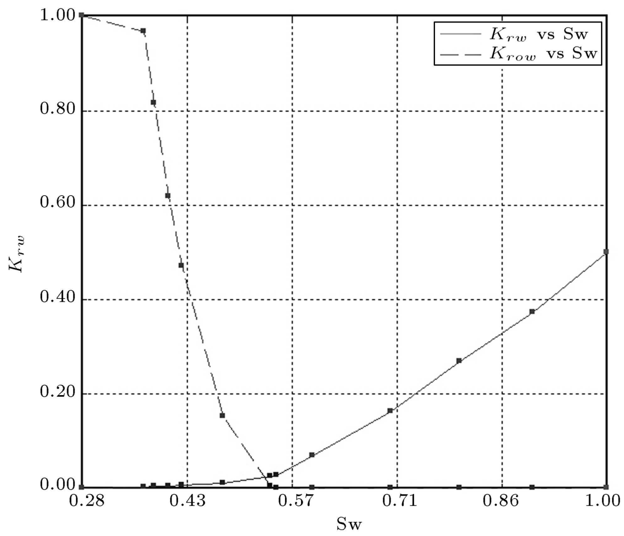

Figure 4. Relative permeability versus water saturation in matrix.

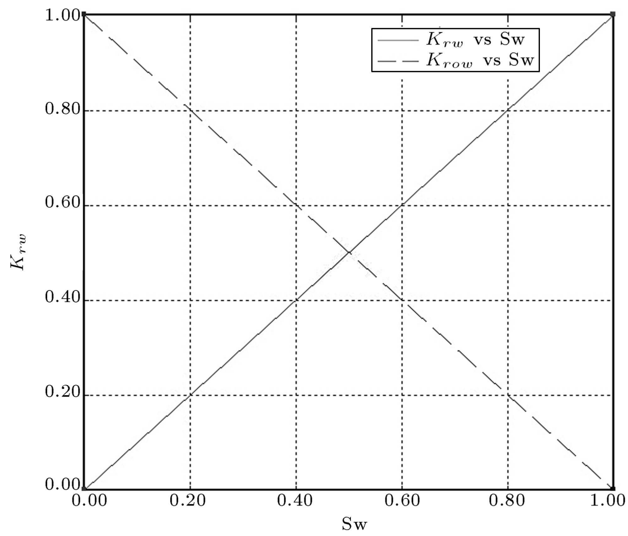

Figure 6. Water-oil relative permeability versus water saturation in fracture.

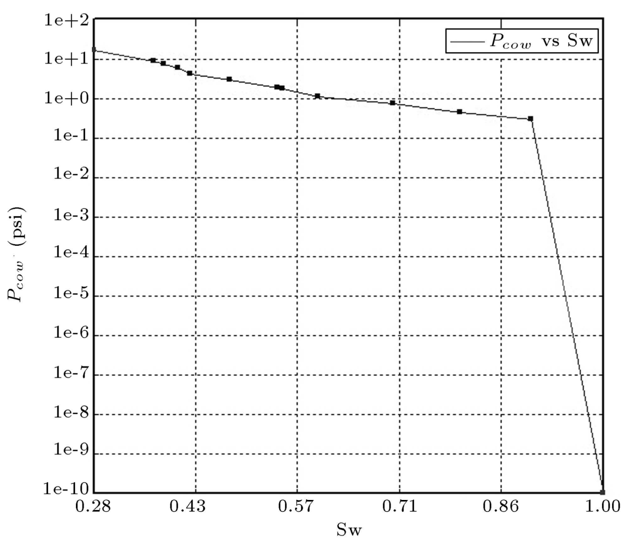

Figure 5. Capillary pressure versus water saturation in matrix.

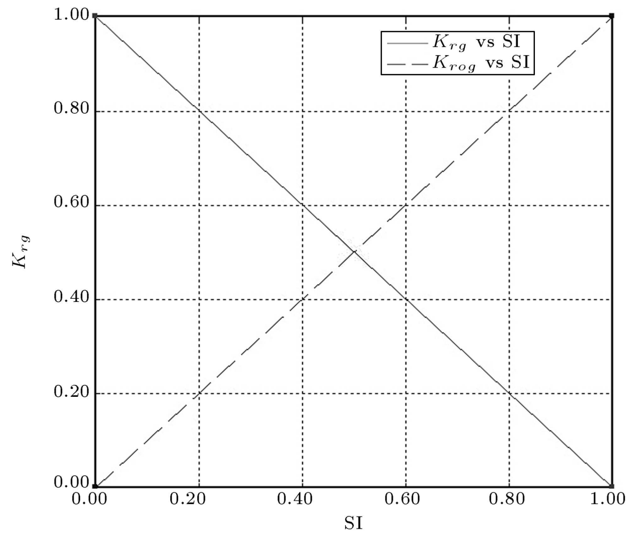

Figure 7. Oilgas relative permeability versus water saturation in fracture.

Figures 6 and 7. For the matrix relative permeability, the experiments were performed under an unsteady-state condition at constant pressure and the pressure, time and effluent data were utilized for calculating k_{rw} and k_{ro} values, which were then plotted as a function of the water saturation. The water cut and the water input were also drawn as a function of the oil recovered.

The Jones and Roszelle method was used to determine the unsteady state constant pressure water-oil relative permeability.

The Centrifuge Technique was used for measuring the capillary pressure in the matrix. For drainage tests, an oil (or water) saturated sample is placed in a centrifuge and spun at a series of speeds. Being the more dense fluid, the oil (or water) is forced further away from the center of rotation, out of the core plug and into a receiving tube. Air (or oil) is allowed to flow into the sample to replace the oil (or water). An equivalent capillary pressure is calculated from the centrifugal force. Imbibition tests can be performed where the core plug is further away from the center of rotation than the receiving tube. In this case, water is forced into the core plug and displaced oil moves into the receiving tube. At hydrostatic equilibrium, Pc at any point is equivalent to the difference in hydrostatic pressure between the phases, such that:

$$Pc_{(r)} = \frac{\Delta\rho.\omega^2}{2}(r_e^2 - r^2),$$

where "r" is the distance from the center of rotation, "r_e" is the distance of the core outlet face from the center of rotation, "$\Delta\rho$" is the density difference and "ω" is the rate of rotation. At each value of Pc, there is a corresponding value of So.

Porosity and Permeability

While the porosity of the model was presented in the geological model, the permeability data was gathered from offset data of well #6 in the Ilam and Sarvak formations. The relationship between porosity and permeability was determined and then applied to the field (see Figure 8). It is notable that horizontal permeability is ten times greater than that of vertical permeability, $K_{ri} = K_{rj} = 10K_{rk}$.

Fracture Properties

Fracture spacing in all direction was adjusted to 10 ft. The fracture porosity of 1% was used in the model and the fracture aperture of 0.0035 mm was taken in order to estimate the fracture permeability in all 3 directions.

$$K_{fi} = K_{fj} = K_{fk} = \frac{W^2}{12}$$
$$= \frac{(1000 \times 0.0035)^2}{12} \cong 1 \text{ Darcy}.$$

Initialization

A pressure of 927 psi at a depth of 1700 ft and the water-oil contact of DWOC = 2600 ft are set to initialize the model. Oil saturation was also presented in a geological model, which was imported to the model made by the Builder module.

Wells and Recurrent

The initial oil in the place in this sector is 2.4 MMM bbl of oil and the reservoir boundary is a No Flow Boundary. The full field Sarvak reservoir with $60 \times 10 \times 9(I \times J \times K)$ orthogonal grid blocks was considered in the model. Many different numbers and patterns for horizontal wells are considered. Also, 10, 20 or 30 for the number of wells, a one-layer two-layer distribution of wells and X, Y and Z directions for well orientations are considered.

The horizontal length and average depth of the wells are about 200 ft and 1800 ft from sea level; the top of the Sarvak formation is around 1113 m. Now, if we consider the oil as an incompressible fluid with a constant density of 985 kg/m^3, the minimum pressure for the reservoir to have a natural flow to the well head is 1558 psi. The initial pressure of the reservoir is 927 psi, and we set the pressure constraint for the producers at about 700 psi. So, in order to have oil flow up to the wellhead, we need pumps to generate about a 900 psi pressure difference, in order to have about 50 psi extra pressure at the surface and to drive the oil to the surface facilities.

Optimum Refinement of Grid Blocks

The length and width of the reservoir are 85000 ft and 18000 ft, respectively. The thickness of the reservoir is varied between 21 to 224 ft. There are 60 grids in a X direction, 10 in a Y direction and 9 in a Z direction to represent 9 layers in the reservoir. So, grid block dimensions in X and Y directions are 1416 ft and 1800 ft. In the Z direction, grid sizes vary between 2.3 ft and 24.8 ft. The aforementioned dimensions will be used from this point forward as a base for grid sizes.

First of all, to find the optimum grid blocks size, the base grids are refined to 3 grids in X, Y and Z directions and, therefore, each grid divided to 9 small grids around the wells. For both cases, we run the simulator with five wells each one of which produces 500 bbl/day for 2 months and, for the next 2 months, 500 bbl/day of steam will be injected. The average pressure of sector 1 for these two grid sizes is depicted in Figure 9. As can be seen from this figure, the results for these two grid sizes are different and it appears that the case with no refinement does not

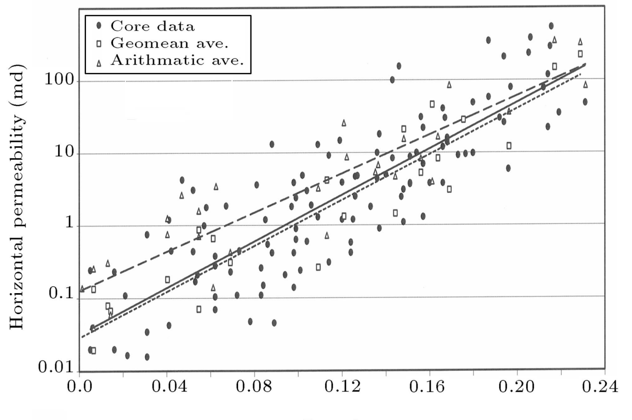

Figure 8. Relationship between porosity and permeability.

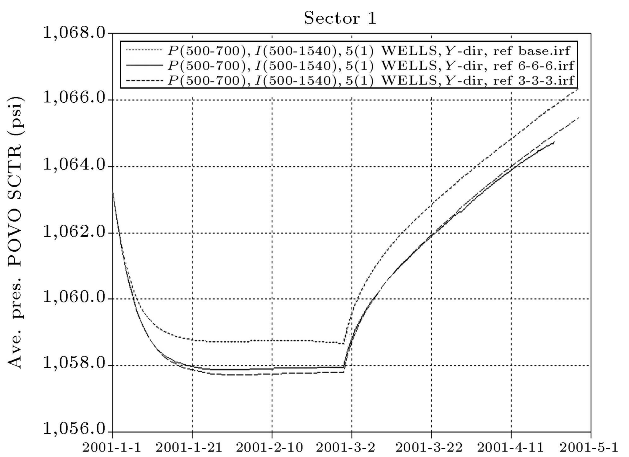

Figure 9. Comparison between base, 3 and 6 refinements.

provide a proper result for us. In the next step we refine the grids to smaller ones to see whether or not there is any difference between the results. In this step, the initial large grid dimension divided into 6 segments and, therefore, each grid becomes 36 small grids around the wells. No significant difference for the average pressure of sector 1 can be deduced from the information that is shown in Figure 9 for the cases of refining grids into 3 and 6.

In three forenamed cases with different grid sizes, the run time increases sharply as the model grid blocks become finer, and since there is no significant difference between the results for cases of 3 and 6 refinements, it seems that the optimum refinement of the grid blocks is achieved to be 3.

SENSITIVITY ANALYSIS

To see more clear and comparable results of the recovery factor, SOR and WOR, a sector through a part of the reservoir model was defined which contains all the wells with their patterns. While this sector is defined in layers one and two, it is the same for all cases to make it possible to have a reliable comparison between them. First of all a “production with no injection” scenario was considered for sector 1. After a short time due to a high pressure drop, evacuation of oil from the fractures, the high oil viscosity and low matrix permeability, the matrixes could not feed the fractures. Therefore, the entire field oil rate reached zero. Here, we just reach only 0.665% of oil recovery factor for the case of 10 wells in layer 1 and in a Y direction. The production constraint for the rate is 1000 bbl/day and steam quality is 0.8.

An extensive sensitivity was performed to determine the effect of operational parameters. The factors concerned were different numbers and patterns of wells, steam injection, oil production rates and pressures, cycle period’s arrangement, soak interval time and steam quality. In this study we tried to consider all the above parameters simultaneously, in order to investigate any scenario that is a combination of the above parameters.

For CSS thermal method, the results which should be considered are oil recovery factor, Water Oil Ratio (WOR) and Steam Oil Ratio (SOR). To find the best case, at first, the oil recovery factor is considered. The case with the most RF is acceptable if the other results are in the range. WOR and SOR for the CSS process could reach up to 10. Production constraints are 1000 bbl/day rates and 700 psi pressure and injection constraints are 1000 bbl/day rates and 1540 psi pressure. The steam temperature is 600 F. Water at 1540 psi and 600°F, is in a two-phase region. The quality of the steam is set at 0.8.

Well Different Numbers and Patterns

It is convenient to investigate the impacts of well directions and make a comparison between them. In such a case, at first, consider the 10 wells were drilled in an X-direction then in a Y-direction and, finally, in an XY-direction with a 45 degree slope (all the 10 wells are in the first layer). The results show that for the case of an XY-direction, the recovery is much lower than for the other cases, so it is better to ignore this direction for all the remaining cases (see Figure 10). The RF for the case of the Y is a little more in comparison with the case of the X-direction. As a result, we just consider the Y-direction (see Figures 10 and 11).

Two choices for cycle period arrangements are considered. The first one is considered when all the wells are injectors at the same time and change to producers with each other, simultaneously; it means

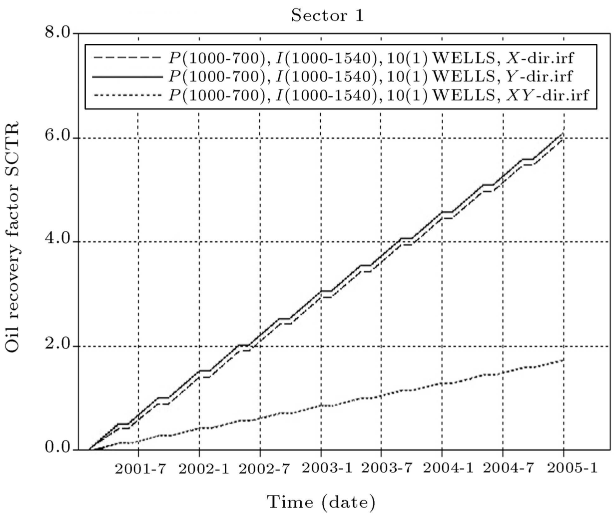

Figure 10. Comparison between directions of wells.

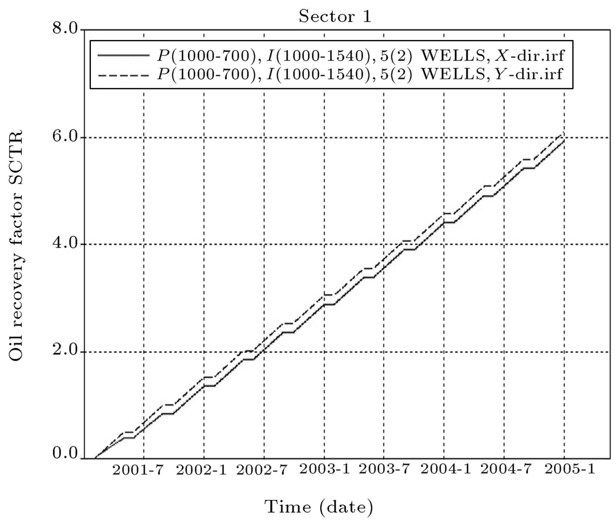

Figure 11. Comparison between X- and $Y-$directions for the case of 5(2).

that all the wells are acting the same. Another arrangement is considered when we have one injector and the next well is the producer and, in the next step, they act reversely; it means that the injector well acts as a producer and the producer well acts as an injector. This arrangement is called "periodic cycles". Figure 12 shows the oil recovery factor for the case of 10 wells in one layer in an X-direction for both conventional and periodic cycles. As seen from the results, there is no difference in the ultimate oil recovery factor for two cases. Therefore, we will only use the conventional results.

For the next cases, we just consider a Y-direction, one layer arrangement, a conventional and a cycle arrangement due to more oil RF. Now, we consider 9 different cases for three injection and production rates and three numbers of wells. In all 9 cases, wells are in a Y-direction, cycle periods are conventional and the steam quality is 0.8. To find the termination time of the process, we let all the 9 cases run for ten years to get a steady state manner for the oil recovery factor; it shows that the cumulative oil rate is decreasing to a very low value.

Here, we considered 10, 20 and 30 wells in layer one, in a Y-direction with three injection and production rates, i.e. 1000 bbl/day, 1500 bbl/day and 2000 bbl/day. The BHP for production is 700 psi, for injection is 1540 and the steam temperature is 600°F. Water at 1540 psi and 600°F, is in a two phase region. The quality of steam is set at 0.8. We will have a sensitivity analysis for the steam quality. The recovery factor for 10, 20 and 30 wells with a rate of 1000 bbl/day is shown in Figure 13. At early times, the recovery factor increases as the number of wells increase. But, after about ten years, we observe there is no significant difference between the oil recovery

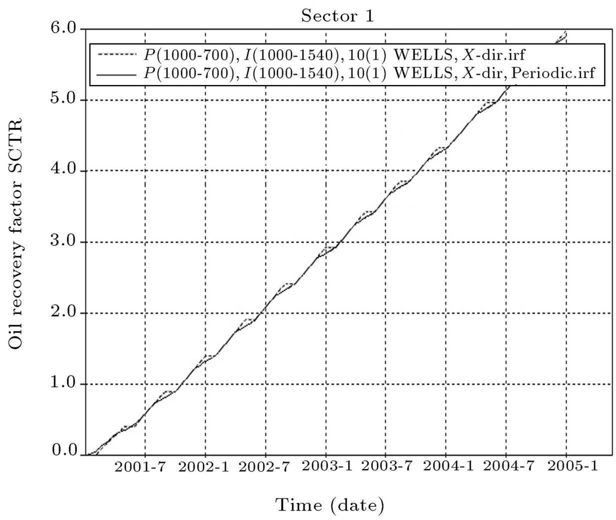

Figure 12. Comparison between conventional and periodic cycles.

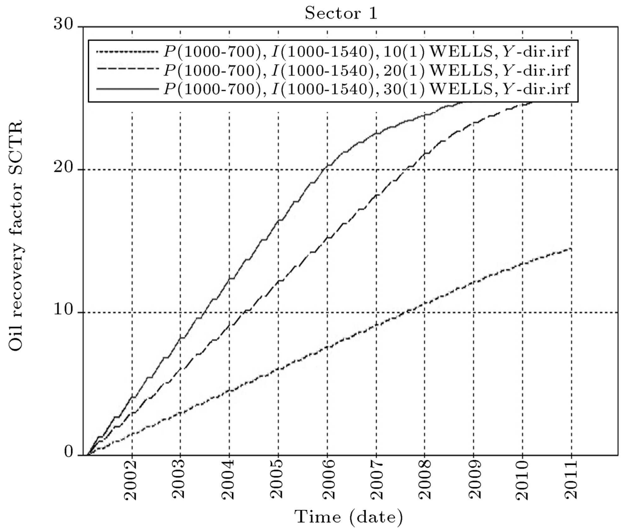

Figure 13. Comparison between recover factors for 10, 20, 30 wells, 1000 bblday.

of 20 and 30 wells. This means that after a specific time period, there would not be much difference in oil production as the number of wells increases. This also is shown in Figure 14 for the case of 30 wells; the oil rate starts to decrease earlier than the 20 wells and the same comparison for 20 and 10 wells is valid. SOR increases as the number of wells increases; for the case of 30 wells, SOR is more than 10 (bbl/bbl) and for 10 and 20 wells, SOR is in the desired range. The WOR for the case of 20 wells is much lower in comparison with 10 and 30 wells.

By comparing the recovery factor, SOR and WOR for these three sets of wells, it can be concluded that the optimum case is for 20 wells and that this is due to the equal recovery factor in a 30 wells case and for a lower WOR than the others. In addition, SOR is in less than 5 (bbl/bbl) (see Figures 15 and 16).

Injection and Production Constraints

Three cases for 1000 bbl/day were studied in the previous section. Results for oil RF, SOR and WOR for all the 9 cases are reported in Table 2. The results of RF for injection and production rates of 1500 and 2000 bbl/day are shown in Figures 17 and 18. RF and the cumulative produced oil trend in 20 and 30 well cases inverted after about 5 years. It can be seen that the trends of SOR and WOR are the same for the case of 1000 bbl/day and 1500 bbl/day.

The presented results in Figures 13, 17 and 18 and Table 2 can lead us to this point that the best case with the largest oil recovery factor, SOR and WOR is for the case of 20 wells in one layer and in a Y-direction with the rate of 2000 bbl/day and a steam quality of 0.8. As a result, the case of 20 wells can be chosen as an optimum number of wells.

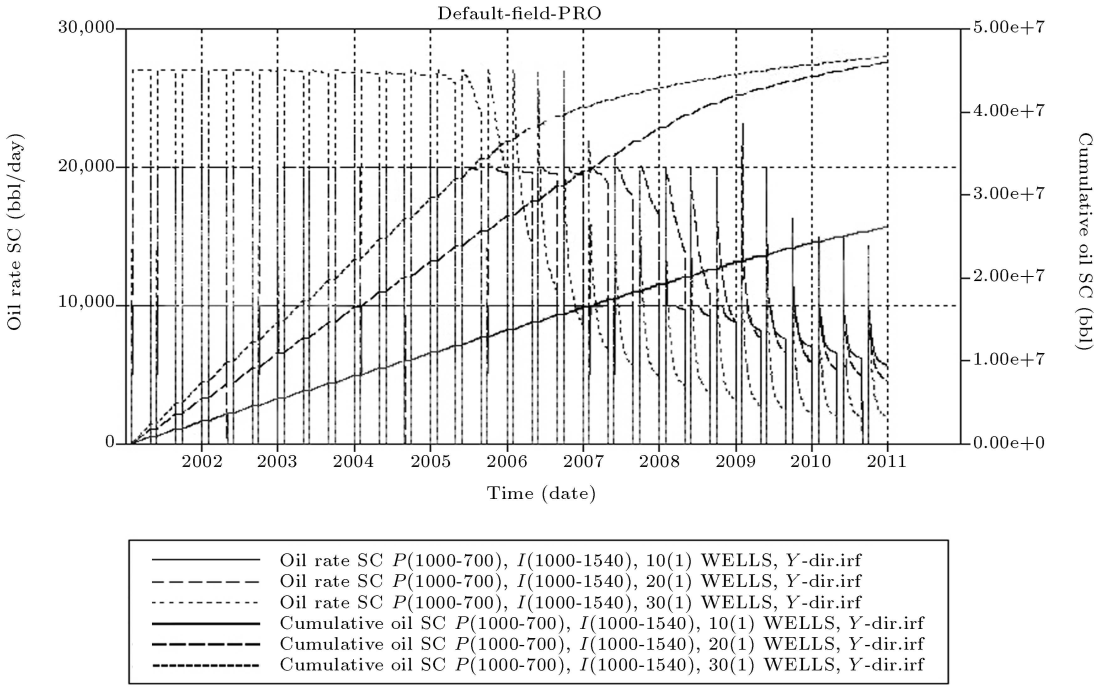

Figure 14. Comparison between oil rate and cumulative oil for 10, 20 and 30 wells, 1000 bbl/day.

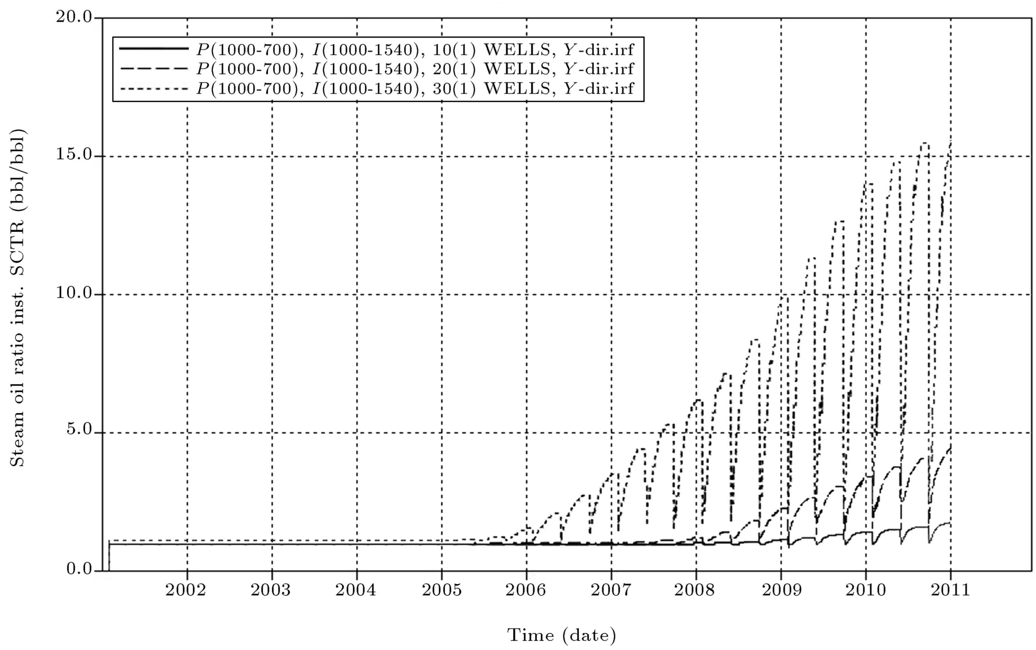

Figure 15. Comparison between steam oil ratios for 10, 20 and 30 wells, 1000 bbl/day.

Steam Quality

As steam quality increases, the heat carried by the vapor increases, therefore, causing an increased heated volume and an oil recovery factor. The cumulative oil production from the field also increases considerably. On the other hand, the cumulative water production from the field decreases. In real cases, usually, steam quality between 0.7 and 0.8 is used, but generally to choose the best one for any field, economical factors must be considered. This means that the cost of steam with a higher quality should be compared with the revenue that is obtained from incremental oil production. If the revenue is remarkably higher than the cost, then the steam with higher quality will be chosen.

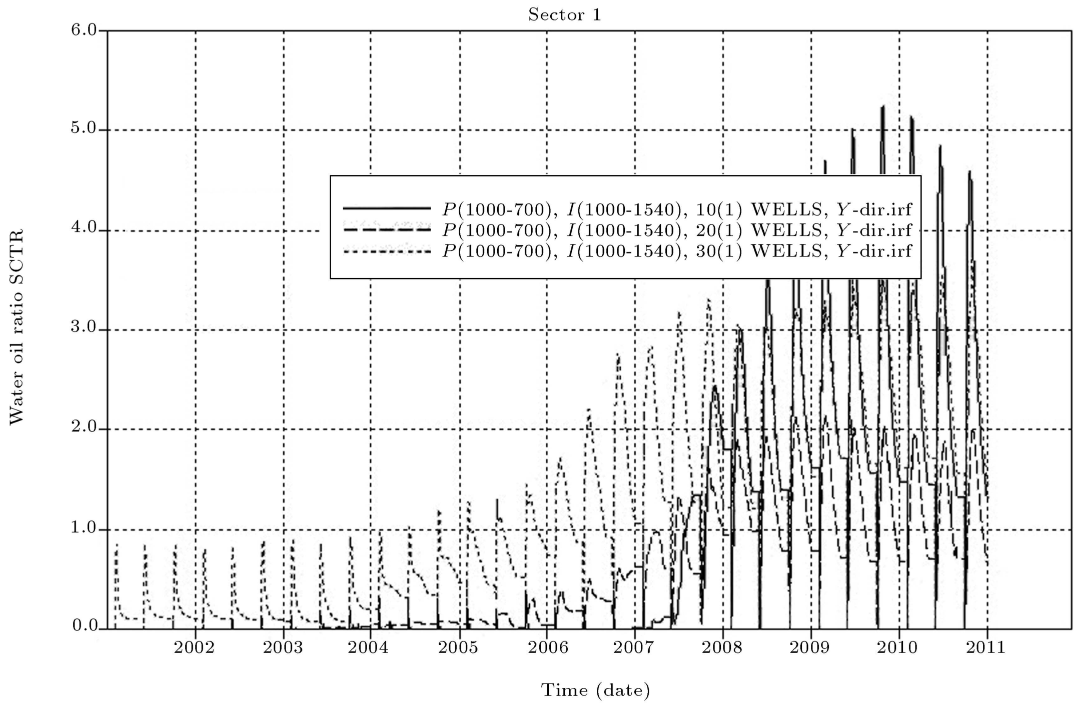

Figure 16. Comparison between water oil ratios for 10, 20 and 30 wells, 1000 bbl/day.

Table 2. Results for combination of rates and no. of wells for quality of 0.8.

Different Cases with $X = 0.8$	**Cum. Oil Prod. (MMbbl)**	**Oil RF (%)**	**SOR (bbl/bbl)**	**WOR (bbl/bbl)**
$P(1000-700)$, $I(1000-1540)$, 10(1) WELLS, Y-dir, $X = 0.8$	26.18	14.54	< 10	< 5
$P(1000-700)$, $I(1000-1540)$, 20(1) WELLS, Y-dir, $X = 0.8$	46.02	25.52	< 10	< 5
$P(1000-700)$, $I(1000-1540)$, 30(1) WELLS, Y-dir, $X = 0.8$	46.70	25.95	> 10	< 5
$P(1500-700)$, $I(1500-1540)$, 10(1) WELLS, Y-dir, $X = 0.8$	33.37	18.51	< 10	< 5
$P(1500-700)$, $I(1500-1540)$, 20(1) WELLS, Y-dir, $X = 0.8$	52.49	29.09	< 10	< 5
$P(1500-700)$, $I(1500-1540)$, 30(1) WELLS, Y-dir, $X = 0.8$	50.24	28.14	> 10	< 5
$P(2000-700)$, $I(2000-1540)$, 10(1) WELLS, Y-dir, $X = 0.8$	37.20	20.61	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $X = 0.8$	57.28	31.76	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 30(1) WELLS, Y-dir, $X = 0.8$	55.78	30.93	> 10	< 5

Another factor for choosing steam quality is the heat loss during steam injection. Steam with a high quality has more heat content than steam with a lower quality. This means that steam can give more heat without decreasing its temperature.

Since in our case study the formation is deep, steam must travel about 1800 ft to reach the formation. Therefore, if steam with a low quality is used, it quickly loses its energy, changes to hot water in the tubing and, when it reaches formation, loses its effectiveness. Hence, an almost maximum steam quality ($X = 0.8$) was selected for this field, but in future, the economical points must also be considered.

Up to here, all cases are run for a steam quality of 0.8, but it seems that steam quality could have an effect on the recovery factor. Therefore, all the above 9 cases are repeated for a steam quality of 0.6 and 0.4, to find out the type and magnitude of the quality effect on the results. SOR and WOR for the 18 new cases are almost similar to the previous results, it means that WOR's are less than 5 and SOR's are less than 10 except in the case of 30 wells. So, the toil recovery factor of the best

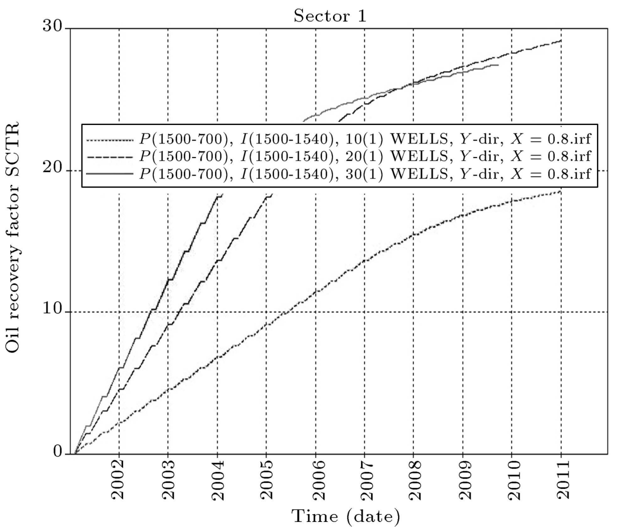

Figure 17. Comparison between recover factors for 10, 20 and 30 wells, 1500 bbl/day.

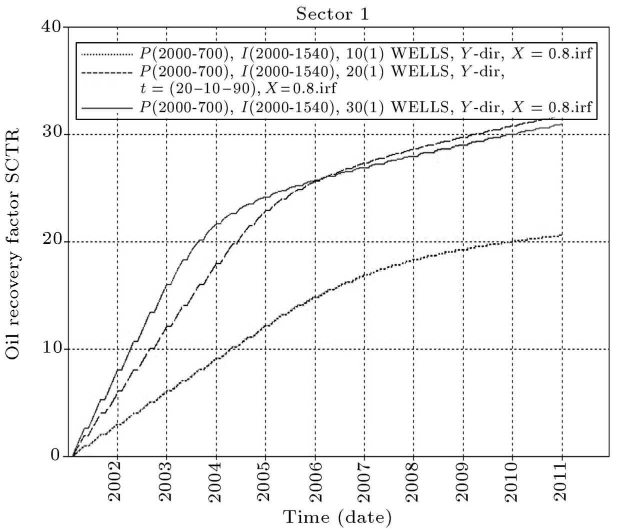

Figure 18. Comparison between recovery factors for 10, 20 and 30 wells, 2000 bbl/day.

case is just plotted in order to see the effect of quality. Figure 19 and Tables 3 and 4 represent the results of $X = 0.6$ and $X = 0.4$. The steam quality of 0.8 has more RF than 0.6 and 0.4, so the case of 20 wells in one layer and in a Y-direction with a production and injection rate of 2000 bbl/day and steam quality of 0.8 is again chosen as a best and optimum case.

Soak Time Interval

To find the effect of soak time on the recovery factor, two more time intervals are defined. All the previous cases have 20 days, 10 days and 90 days for injection, soak and production intervals. Two new time intervals are 20, 5 and 95 days, and 20, 20 and 80 days for injection, soak and production, respectively. Figure 19 shows the results for the case of 20 wells in one layer

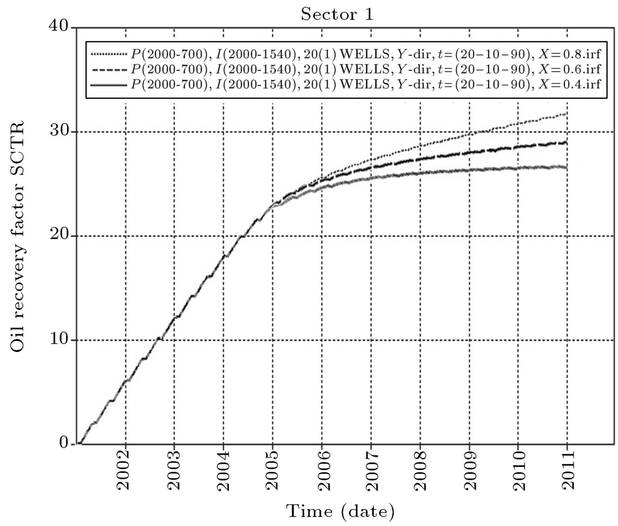

Figure 19. Comparison between steam qualities, 2000 bbl/day and 20(1) wells.

and in a Y-direction with a production and injection rate of 2000 bbl/day and steam quality of 0.8, which has been the optimum case up to now. As soak time decreases, oil RF increases. Therefore, if we change the time intervals of this case to 20-5-95 days, we will get a higher RF. So, the best case will be 20 wells in one layer and in a Y-direction with a production and injection rate of 2000 bbl/day and a steam quality of 0.8 with injection, soak and production interval times of 20, 5 and 95 days, respectively. An increase in the soaking interval implies a greater time for energy dissipation. In this case, the cumulative heat losses increase due to larger soaking periods. Therefore, the temperature of the heated zone at the end of the soaking interval is predictably lower. As a result, the oil viscosity is higher and the mobility of the oil is reduced. Hence, cumulative oil production decreases with increased soaking time. An increase of recovery factor, due to decreasing the soak time, is much smaller than that due to an increase in rate or a change in the number of wells, so it can be concluded that if the other 26 cases have a lower soak time, again the case of 20 wells in one layer and in a Y-direction with a production and injection rate of 2000 bbl/day and a steam quality of 0.8 has much more recovery than the other, even with the longer soak time. Therefore, we are quite sure that the case of $P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $t = (20-5-95)$, $X = 0.8$ has the highest recovery factor among all 81 different cases. The results for three different soak times are reported in Table 5, and Figure 20 shows RF for these three cases.

Change in Reservoir Properties, Best Case

In Figure 21, the average pressure and temperature of the reservoir with the enthalpy in place of the reservoir

Table 3. Results for combination of rates and no. of wells for quality of 0.6.

Different Cases with $X = 0.6$	**Cum. Oil Prod. (MMbbl)**	**Oil RF (%)**	**SOR (bbl/bbl)**	**WOR (bbl/bbl)**
$P(1000-700)$, $I(1000-1540)$, 10(1) WELLS, Y-dir, $X = 0.6$	24.53	13.63	< 10	< 5
$P(1000-700)$, $I(1000-1540)$, 20(1) WELLS, Y-dir, $X = 0.6$	43.48	24.16	< 10	< 5
$P(1000-700)$, $I(1000-1540)$, 30(1) WELLS, Y-dir, $X = 0.6$	43.54	24.19	> 10	< 5
$P(1500-700)$, $I(1500-1540)$, 10(1) WELLS, Y-dir, $X = 0.6$	30.67	17.04	< 10	< 5
$P(1500-700)$, $I(1500-1540)$, 20(1) WELLS, Y-dir, $X = 0.6$	46.67	25.93	< 10	< 5
$P(1500-700)$, $I(1500-1540)$, 30(1) WELLS, Y-dir, $X = 0.6$	45.25	25.14	> 10	< 5
$P(2000-700)$, $I(2000-1540)$, 10(1) WELLS, Y-dir, $X = 0.6$	32.54	18.08	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $X = 0.6$	51.39	28.55	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 30(1) WELLS, Y-dir, $X = 0.6$	51.28	28.49	> 10	< 5

Table 4. Results for combination of rates and no. of wells for quality of 0.4.

Different Cases with $X = 0.4$	**Cum. Oil Prod. (MMbbl)**	**Oil RF (%)**	**SOR (bbl/bbl)**	**WOR (bbl/bbl)**
$P(1000-700)$, $I(1000-1540)$, 10(1) WELLS, Y-dir, $X = 0.4$	23.13	12.85	< 10	< 5
$P(1000-700)$, $I(1000-1540)$, 20(1) WELLS, Y-dir, $X = 0.4$	41.81	23.23	< 10	< 5
$P(1000-700)$, $I(1000-1540)$, 30(1) WELLS, Y-dir, $X = 0.4$	42.24	23.47	> 10	< 5
$P(1500-700)$, $I(1500-1540)$, 10(1) WELLS, Y-dir, $X = 0.4$	26.83	14.91	< 10	< 5
$P(1500-700)$, $I(1500-1540)$, 20(1) WELLS, Y-dir, $X = 0.4$	43.07	23.93	< 10	< 5
$P(1500-700)$, $I(1500-1540)$, 30(1) WELLS, Y-dir, $X = 0.4$	41.49	23.05	> 10	< 5
$P(2000-700)$, $I(2000-1540)$, 10(1) WELLS, Y-dir, $X = 0.4$	27.05	15.03	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $X = 0.4$	47.35	26.31	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 30(1) WELLS, Y-dir, $X = 0.4$	47.28	26.27	> 10	< 5

Table 5. Comparison between different soak interval times for the case of $P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $X = 0.8$.

Different Cases with Soak Times	**Cum. Oil Prod. (MMbbl)**	**Oil RF (%)**	**SOR (bbl/bbl)**	**WOR (bbl/bbl)**
$P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $t=(20-20-80)$, $X=0.8$	55.54	30.86	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $t=(20-10-90)$, $X=0.8$	57.28	31.76	< 10	< 5
$P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $t=(20-5-95)$, $X=0.8$	57.83	32.13	> 10	< 5

is shown. It is obvious that the average temperature of the reservoir increases due to high temperature steam injection. In each cycle, average temperature increases compared with the previous cycles, because in each cycle some heat remains in the reservoir and does not produce fluid. This remaining heat adds to heat injected in the new cycle and causes an increase in the average temperature and enthalpy too.

Changes of average oil saturation, pore volume and cumulative oil produced are given in Figure 22. As can be seen during the CSS process, average pressure decreases due to the production of fluid in the pores, so pore pressure decreases with production and, therefore, the pore volume of the reservoir decreases (see Table 6).

By a simple material balance calculation, it can be seen that the difference of the product of average oil saturation by pore volume from the beginning to the end of the process is equal to the cumulative oil

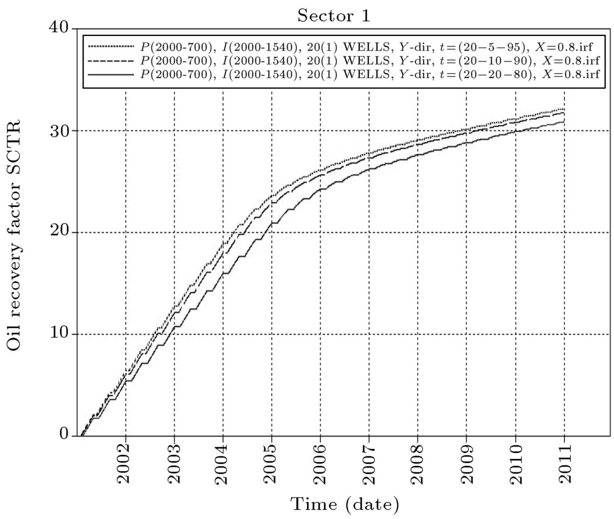

Figure 20. Comparison between different soak interval times.

produced during this period, which is shown at its curve in Figure 22.

$$\frac{(0.579)(2.44 \times 10^{10})}{5.615} - \frac{(0.573)(2.41 \times 10^{10})}{5.615} = 5.66 \times 10^{7} \text{ bbl.}$$

RESULTS AND DISCUSSION

The results showed that the best scenario for applying the CSS method using horizontal wells in the K-Field is the case with 20 wells located in one layer at the crest of the reservoir in a Y-direction, while the constraints are 2000 bbl/day and 700 psi for the production rate and minimum bottom hole pressure. For injectors, the steam rate is 2000 bbl/day equivalent water and a maximum bottom hole pressure of 1540 psi. Steam temperature and quality are 600°F and 0.8, respectively. Under these conditions, water is in a two phase region. Cycles should be arranged in such a way that all 20 wells inject steam with each other, then shut all of them, simultaneously, and after that, allow production to all 20 wells at the same time. Injection time is 20 days, soak time is 5 days and production lasts for 95 days. After about 10 years, the oil recovery factor becomes steady, no significant extra oil will produce and the oil rate tends to zero. Therefore, it could be said that after 10 years (30 cycles), this process will terminate and another method, like steam-flooding, may be replaced by CSS to produce more from this reservoir.

Because the K-Field is a highly fractured reservoir, the best way to recover more oil is by injecting steam, producing oil with the same amount and keeping the rates as low as possible. Increasing the steam injection and oil production rate will decrease the final oil recovery significantly, and a huge amount

Table 6. Changes of average oil saturation, pore volume and cumulative oil produced in entire field.

Date	2001/1/1	2011/1/1
Average Oil Saturation	0.579	0.573
Pore Volume (ft^3)	2.44E10	2.41E10

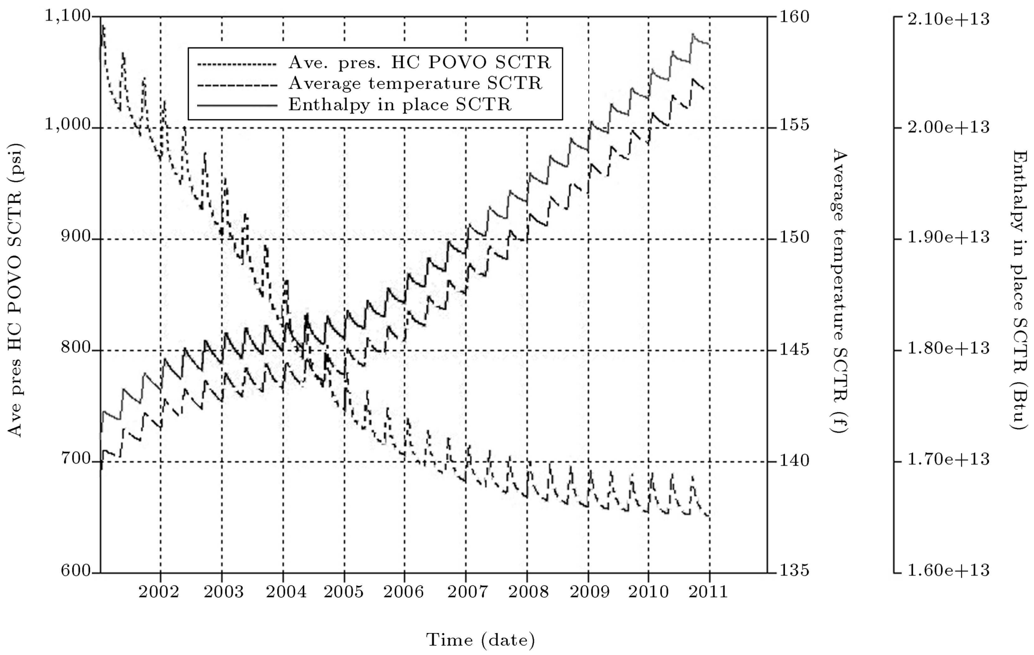

Figure 21. Change in average pressure and temperature of the reservoir with the enthalpy in place.

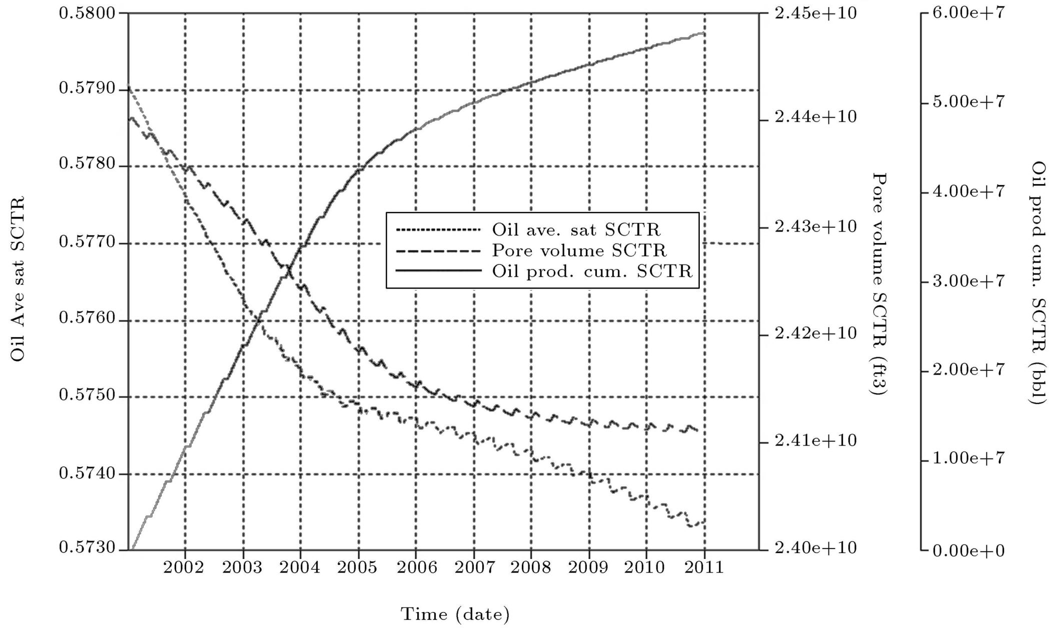

Figure 22. Changes of average oil saturation, pore volume and cumulative oil produced in entire field.

of oil will be trapped among the water in the reservoir. The reason is that, with a high rate of steam injection or oil production, steam quickly sweeps the fractures and reaches the producers, meanwhile, the matrix blocks do not have enough time to feed the fractures. Other contributing factors that will determine the final decision on steam injection and oil production rates from the field are: economical factors, steam production costs, steam generator capacity and costs, well injectivity, well-bore facilities, surface facilities, oil price and many others.

To get more reliable results, it is better to consider the effect of temperature on relative permeability and capillary pressure curves. Also, in order to determine suitable steam temperature and quality, some information about heat losses into the formation and heat losses during the traveling of steam from the surface facilities down to the tubing must be known. Fluid samples and cores must be gathered from different parts of the reservoir to determine if they are varying from one place to another. If they are, different rock types should be defined in the reservoir model.

Information related to the fracture system, thermal parameters of burden layers and production data are needed to have better results.

CONCLUSIONS

1. Reservoir simulation of this field illustrated that only 0.66 % of OOIP could be recovered by the cold production method. As a result, the use of thermal methods is unavoidable.
2. In order to achieve an optimum scenario for recovery from this field, several scenarios are defined and all the operational parameters are compared, simultaneously.
3. For CSS thermal method, the results which should be considered are oil recovery factor, Water Oil Ratio (WOR) and Steam Oil Ratio (SOR). The highest oil recovery factor with WOR and SOR smaller than 10, is the best case.
4. Among wells which are drilled in X, Y and XY-directions with 45 degree slopes, the recovery factor is the most in the case of a Y-direction.
5. A "conventional" period cycle has no significant difference from a "periodic" cycle arrangement, so a "conventional" period cycle is selected.
6. For having a different steam quality of 0.4, 0.6 and 0.8, the higher recovery factor was achieved for higher steam quality.
7. The results show that by decreasing the soak time, the oil recovery factor increases, so all 27 cases (3 sets) are done for soaking periods of 10.
8. The scenario of $P(2000-700)$, $I(2000-1540)$, 20(1) WELLS, Y-dir, $t = (20-5-95)$, $X = 0.8$ has the highest recovery factor (more than 30% of OOIP) among all 81 different cases.

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