TITLE: REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JAOQUIN BASIN, CALIFORNIA

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Objective

This project reactivates ARCO's idle Pru Fee lease in the Midway-Sunset field, California and conducts a continuous steamflood enhanced oil recovery demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming is being used to reestablish baseline production within the *reservoir characterization phase* of the project. During the *demonstration phase* scheduled to begin in January 1997, a continuous steamflood enhanced oil recovery will be initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained in this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to optimal commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

The 40 ac Pru Fee property is located in the super-giant Midway-Sunset field and produces from the late Miocene Monarch Sand, part of the Monterey Formation. The Midway-Sunset Field was drilled prior to 1890. In 1991 cumulative production from the field reached two billion barrels, with remaining reserves estimated to exceed 695 MMBO. In the Pru Fee property, now held by ARCO Western Energy, cyclic steaming was used to produce 13° API oil. However, the previous operator was unable to develop profitably this marginal portion of the Midway-Sunset field using standard enhanced oil recovery technologies and chose rather to leave more than 3.0 MMBO of oil in the ground that otherwise might have been produced from the 40 ac property. Only 927 MBO had been produced from the property when it was shut-in in 1987. This is less than 10% of the original oil-in-place, which is insignificant compared to typical heavy oil recoveries in the Midway-Sunset field of 40 to 70%. The objective of the demonstration project is to encourage a similar incremental increase in production in all other marginal properties in the Midway-Sunset and adjacent fields in the southern San Jaoquin Basin.

A previously idle portion of the Midway-Sunset field, the ARCO Western Energy Pru Fee property, is being brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steam flood production design that will balance optimal total oil production against economically viable steam-oil ratios and production rates.

Expected oil rate for the project is based on the 9 spot “no cycles” base case simulation results. The initial rate per new well is estimated at 10 BOPD, ramping up to 29 BOPD (320 BOPD total pilot) in 16 months, flat for 28 months then declining at 40% harmonically to the economic limit. Steam rate is forecasted at 300 BSPD per injector constant for the life of the project. Total peak steam rate is 1200 BSPD for the pilot. The gross capital investment of $1.9 MM will produce 550 MBO ($2.89/BO) with a PW10 of $1,177 M and rate of return of 49%, based on uninflated economics. Recoverable reserves are determined by the economic limit. However, gross expected recoverable reserves are 550 MBO for the 8 ac pilot. Target additional recoverable oil reserves from the 40 ac property are 2.75 MMBO or greater The methods used in the Class III demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize declining production of heavy oils throughout the region.

Summary of Technical Progress

Reservoir Simulation

The primary objective of the reservoir simulation activity was to determine optimum operating conditions for the economic exploitation of the lease. The important parameters that were considered in this optimization process were:

- The type of process to be employed (cyclic, flood, etc.)
- Injection-production patterns
- Completion strategies
- Rates of injection

The idea was also to study the sensitivity of uncertain reservoir characteristics on production performance.

The approach adopted was as follows:

1. Perform two-dimensional sensitivity studies using generic models.
2. Conduct three-dimensional simulations using geostatistically generated reservoir images.

The two-dimensional simulations were used to examine the effectiveness of three different processes; the *cyclic* process, the *steam flood* and the *cyclic-steam flood*, wherein, the producers were cycled every so often during a steam flood. In addition, simulations were performed to study the effects of the reservoir dipand the thickness of the bottom-water zone. Updip and downdip injection strategies were investigated and three different injection and production well-completion plans were studied. The above-mentioned two-dimensional studies were conducted using a homogeneous model. The geologic investigations showed thick oil bearing zones separated by thin, lower permeability surfaces. Hence, an eleven-layer, two-dimensional model was used to study the sensitivity of parameters such as permeability and thickness of the surfaces. Simulation results using the layered model were compared with the results using a homogeneous analog of the layered model.

Geostatistically generated reservoir properties (described in detail in the previous quarterly report) were employed in the three-dimensional simulations. Patterns, completion strategies and injection rates were of interest.

All the simulations were conducted using STARS, a thermal simulator developed by Computer Modeling Group (CMG), Inc.

Two-dimensional Simulations

Processes

The two-dimensional simulations were performed on system 1200 ft x 10 ft x 300 ft in size. The grid blocks were 80 ft long, 10 ft wide and 50 ft in thickness. There were a total of eight wells. In flooding processes half of them were injectors and the other half were producers, while in the cyclic processes all the wells operated on definite cycles. Three different processes were investigated:

1. *Cyclic* steam stimulation in which two weeks of injection was followed by a week of soak period and a production duration of 20 weeks.
2. *Steam flood*, which involved continuous steam injection in the injectors and production in the producers.
3. *Cyclic-steam flood*, which was a combination of cyclic steam stimulation and steam flooding processes. In this process, during a steam flood, the producers were steam stimulated every two years.

The cumulative oil production for the three processes is compared in Figure 1. The performances of the steam flood and the cyclic-flood processes are identical and appear superior to the cyclic process. Most of the oil in the flooding processes is recovered in about two years, while the duration of the cyclic steam process was 10 years to reach ultimate recovery. The flood processes were better than the cyclic process due to better reservoir sweep.

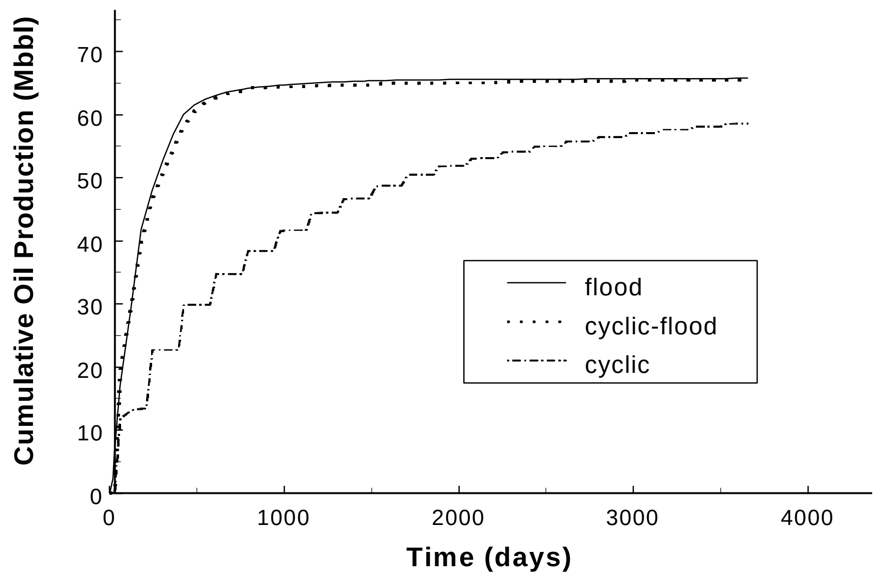


Figure 1: Comparison of cumulative oil production for the three processes using two-dimensional simulations.

Dip and Bottomwater Study

Updip injection was determined to be better for faster oil production. The reservoir dip also contributed to faster production. However, there was not significant difference in ultimate recovery when dip increased. Of the completion practices investigated, the practice of injecting steam into bottom third of the reservoir and producing oil over the entire pay interval was found most effective. A bottomwater zone, modeled as 50 ft thick, decreased oil recovery significantly. For this case, it was found that completing the injector and the producer 50 to 100 ft above the oil water contact improved oil recovery and steam oil ratios.

Effect of Lower Permeability Surfaces

Stratigraphic reservoir characterization revealed that the reservoir between the top of the Monarch Sandstone to the oil-water contact consists of six high-permeability oil-bearing zones separated by thin zones of relatively lower permeability. The effect of the presence of these surfaces on oil production was examined by inserting five lower-permeability layers between the oil bearing zones of the previous two-dimensional model. The permeability of the oil-bearing zones was modeled as 3000 mD, while the permeabilities of the lower permeability layers was varied from 10 to 1000 mD. The thicknesses of these layers were varied from 0.5 - 2 ft.

The effect of permeability of the "barriers" or surfaces on the cyclic process is shown in Figure 2. The thickness of the surfaces (layers) was kept uniform at 2 ft. It can be seen from the figure that production was not very sensitive to the surface permeability unless the surface permeability was as low as 10 mD. For the flood process, the presence of a lower permeability surface had a much larger impact (Figure 3). The surface thickness had little impact on production when the permeability was 300 mD (Figure 4). However, when the permeability was reduced to 10 mD, thickness did have considerable effect (Figure 5). Surface properties affected production because the surfaces inhibited vertical migration and thus vertical reservoir sweep.

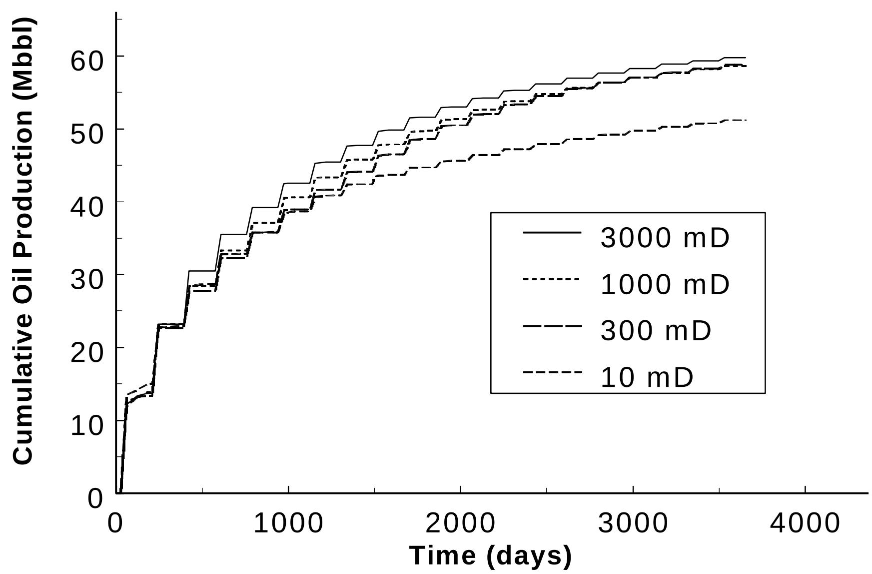


Figure 2: Effect of the permeability of lower permeability surfaces on oil production; cyclic process (2-D simulations).

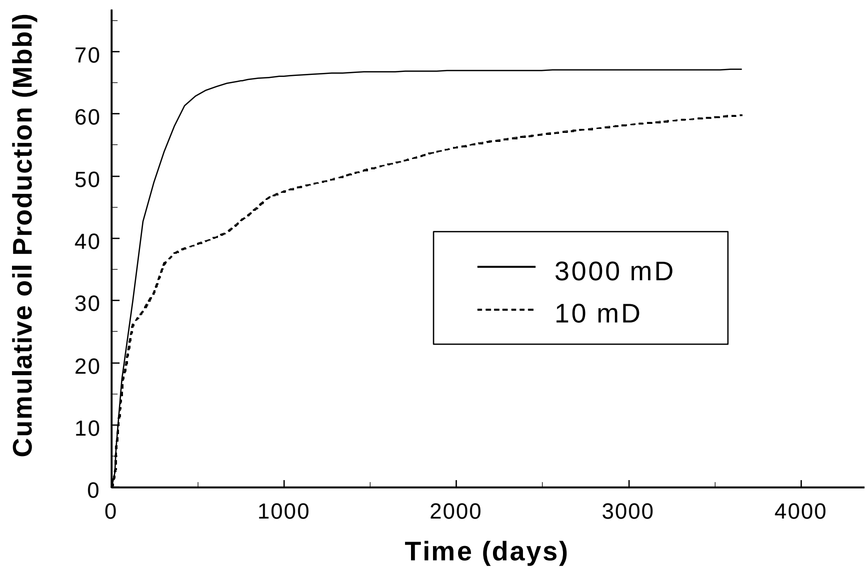


Figure 3: Effect of the permeability of lower permeability surfaces on oil production; steam-flood process (2-D simulations).

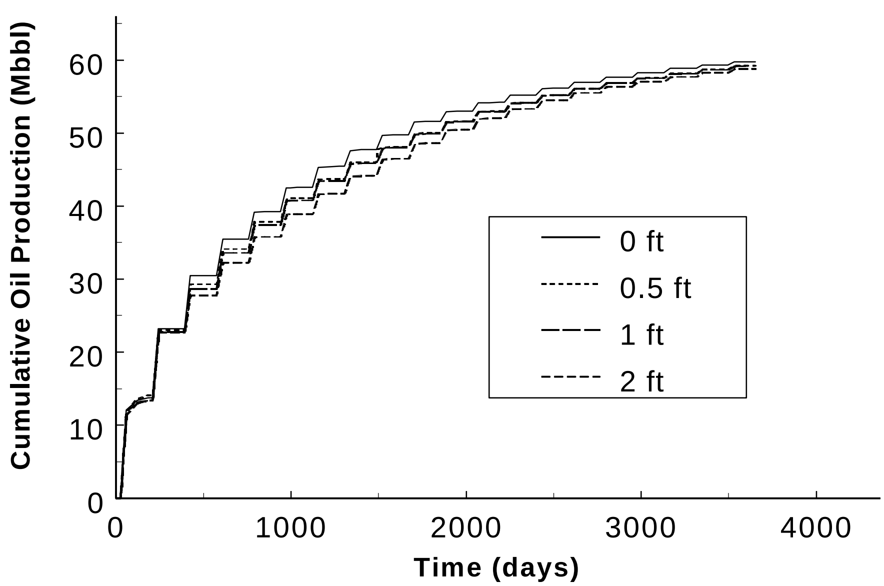


Figure 4: Effect of the thickness of lower permeability surfaces on oil production; permeability of all the surfaces was 300 mD (2-D simulations)

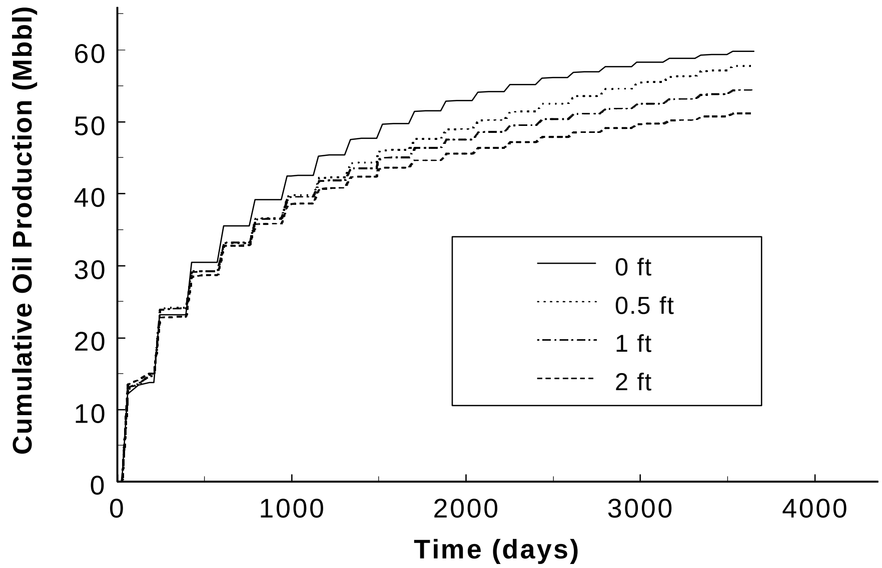


Figure 5: Effect of the thickness of lower permeability surfaces on oil production; permeability of all the surfaces was 10 mD (2-D simulations).

A homogeneous analog of the multi-layer system was constructed. The heterogeneous system had five surfaces with permeabilities of 10 mD and each with a thickness of 2 ft. The production performance of the true heterogeneous system was compared to the homogeneous analog. It was observed that for the steam flood, there was a significant difference between the heterogeneous and its homogeneous analog, with the analog overpredicting recovery (Figure 6). For the cyclic process, where the vertical and lateral connectivity in the reservoir were of lesser significance than for the steam flood process, the difference was minimal (Figure 7).

Three-Dimensional Simulations

These simulations were performed using geostatistically generated reservoir images. The permeability and porosity statistics for the realization that was employed for all the *base* simulations are shown in Table 1. Simulations were performed on a half-acre symmetry element of either a 2-acre, inverted nine-spot pattern or a 1-acre five spot pattern. In both the patterns, the newly-drilled Pru 101 well was in the northwest corner (Figure 8). The half-acre symmetry element was divided into a 10 x 10 grid system areally with a grid size of about 15 ft in the two horizontal dimensions. Vertically, there were 20 layers with geostatistically generated thicknesses. Trend lines were drawn through the water saturation versus depth data (interpreted through logs) for PRU-101. The resulting water saturation profile was extrapolated over the entire simulation volume. Water saturation profile used in the simulations is shown in Figure 9. The top of the reservoir was

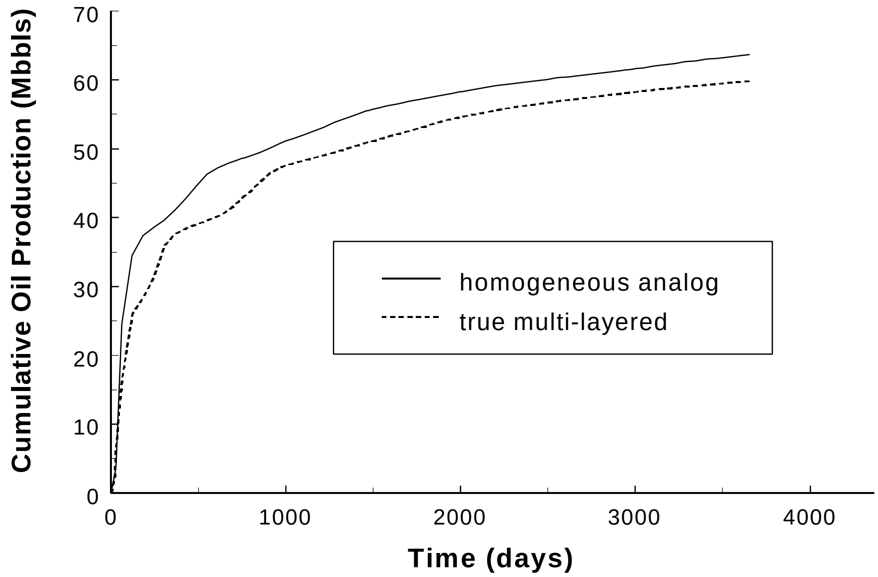


Figure 6: Comparison of cumulative oil production for the heterogeneous (layered) reservoir and its homogeneous analog (steam-flood process, 2-D simulations)

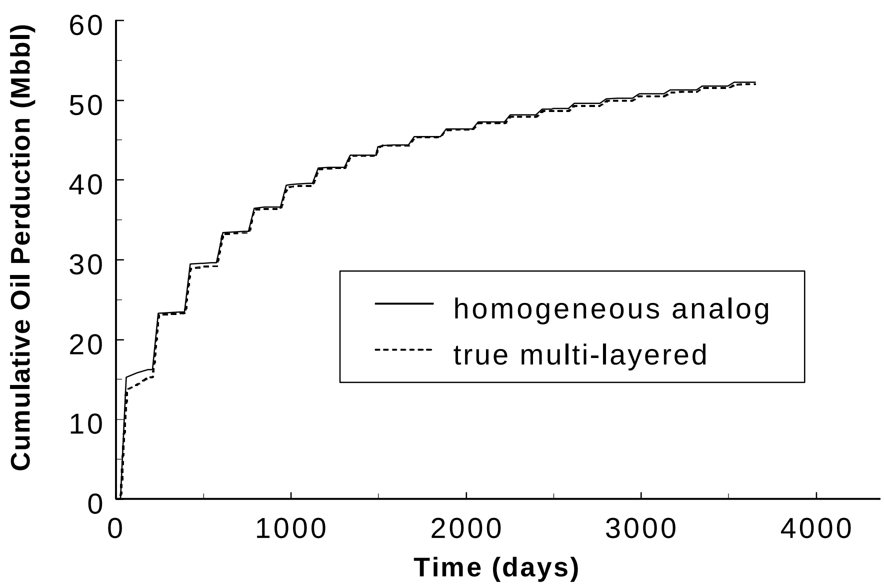


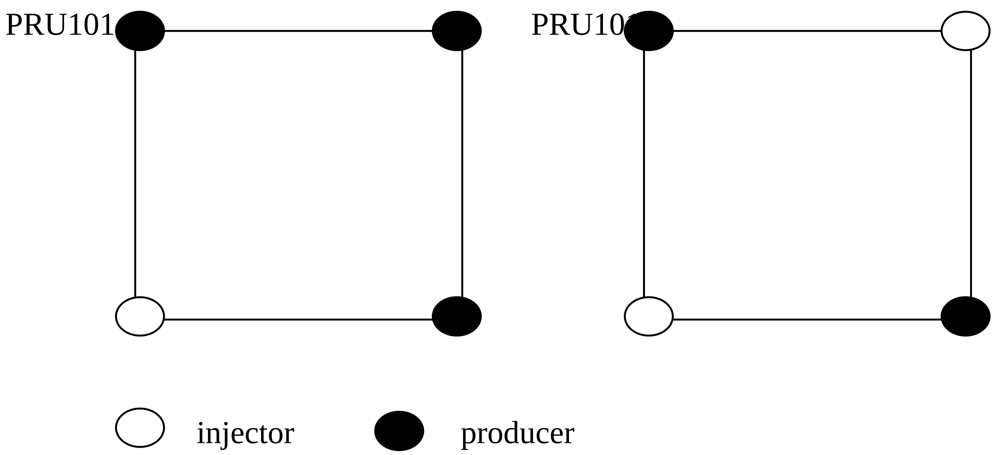
Figure 7: Comparison of cumulative oil production for the heterogeneous (layered) reservoir and its homogeneous analog (cyclic process, 2-D simulations)

Table 1: Petrophysical property statistics of the geostatistical realization employed in three-dimensional simulations

Property	Permeability (mD)	Porosity (%)
mean	3234.1892	31.3640
std. dev	713.0391	1.1580
coef. of var	0.2205	0.0369
maximum	5576.8809	35.5808
upper quartile	3631.0457	31.9924
median	3257.3384	31.3037
lower quartile	2885.3328	30.6228
minimum	573.9968	27.8415

Table 2: The initial fluid distributions in the three-dimensional model

Oil (Mbbl)	Water (Mbbl)	Average Water Saturation
156.55	198.69	0.56



(a) (b)

Figure 8: Schematic representation of the half-ac simulation area;
(a) symmetric element of a two-acre inverse nine-spot pattern
(b) symmetric element of a one-acre five-spot pattern

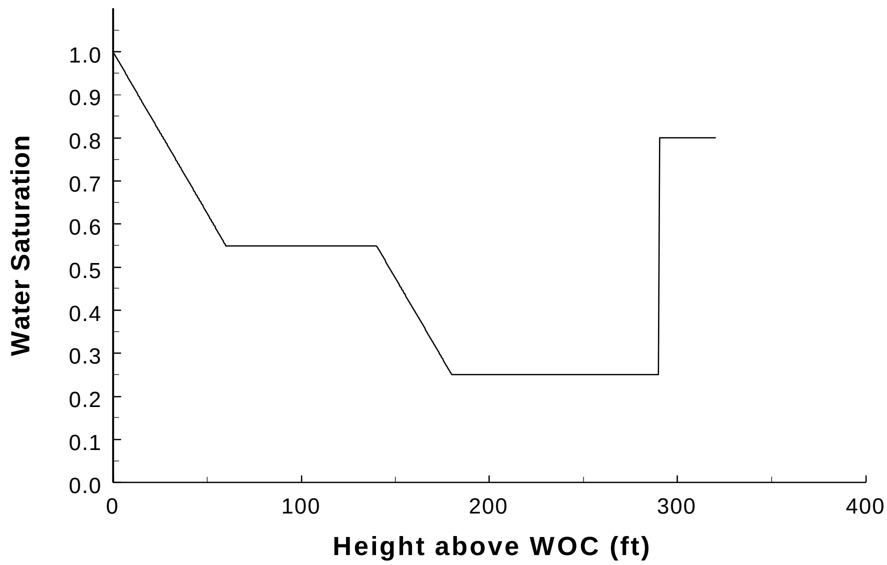


Figure 9: Initial water saturation profile used in the three-dimensional simulations

characterized by a depleted zone. This was followed by a region of high oil saturation and a fairly large transition zone leading to an oil-water contact. The initial fluid distributions are tabulated in Table 2. It should be noted that the average water saturation in the reservoir is relatively high.

Effectiveness of the Three Processes

Recoveries, oil-steam ratios (OSR), and water-oil ratios (WOR) for the cyclic, the steam flood and the cyclic-flood processes are compared in Table 3 for a project life of 10 years. The recoveries from the two flooding processes were more or less the same, while the recovery for the cyclic process was less. The cumulative production versus injection for the three processes is compared in Figure 10. It is clear from the figure that for an equivalent amount of injection the flooding processes recover larger amounts of oil. Insufficient dip and lack of natural pressure drive were the two main reasons for the lack of success of the cyclic process. Additional simulations performed with an initial reservoir pressure of 500 psi showed that on the basis of oil recovered for equivalent steam injection, the cyclic process outperformed the steam flood process.

The OSR behavior of the two flooding processes is compared in Figure 11. For the cyclic-steam flood process, peaks coinciding cycling of the producers are observed. However, no definite advantages could be identified for the cyclic-steam flood process based on OSR or oil recovery. Cyclic steaming of the producers is often an operational necessity to overcome problems related to cold-spots and solids precipitation, phenomena which could not be accounted for in the current series of simulations. Hence, when considering the effect of other operational parameters, the cyclic-flooding process was chosen as preferable.

Table 3: Process comparison (3-D simulations)

Process	years	Recovery (%)	OSR	WOR
cyclic-flood	10	25.2	0.13	9.2
	6	21.0	0.16	7.4
steam flood	10	24.3	0.14	8.5
cyclic	10	19.7	0.15	8.3

Pattern Studies

The oil production rates and OSRs for two patterns, a one-acre five spot and a two-acre nine spot, are compared in Figures 12 and 13. The cumulative recoveries and OSRs are compared in Table 4. The difference in performances of the two patterns are insignificant. The five-spot pattern has a better peak OSR value and a correspondingly higher peak oil-rate. The oil-rate and OSR decline more gradually for the nine-spot pattern.

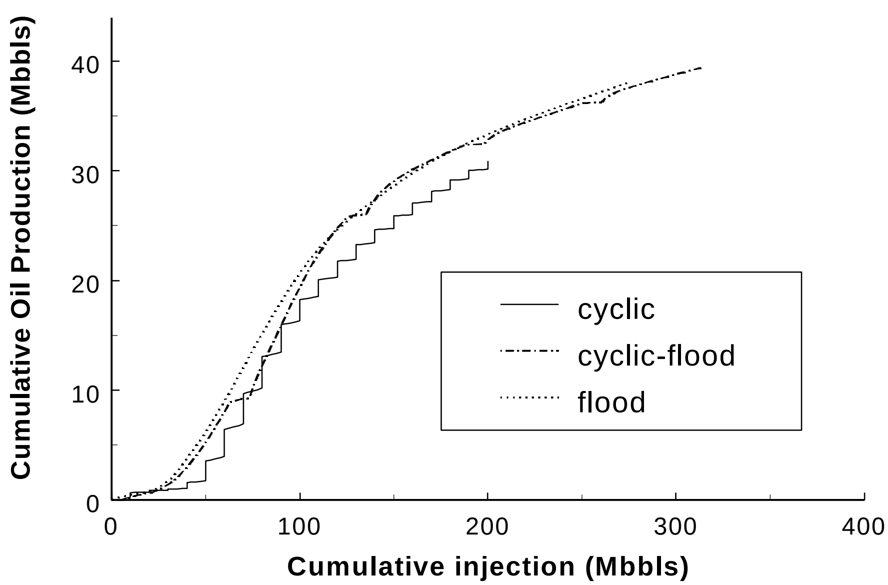


Figure 10: Comparison of cumulative production versus injection for the three processes (3-D simulations).

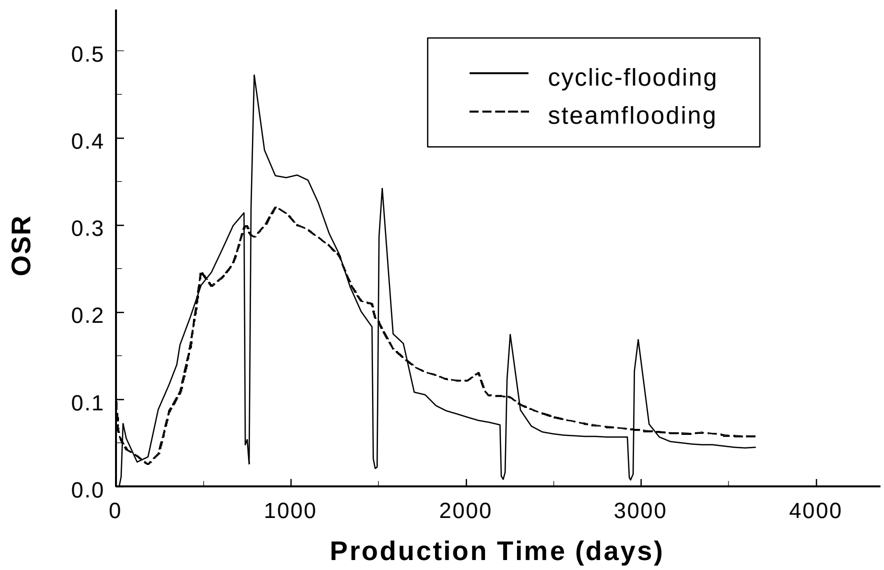


Figure 11: Oil-steam ratios of the flood and cyclic-steam flood processes (3-D simulations).

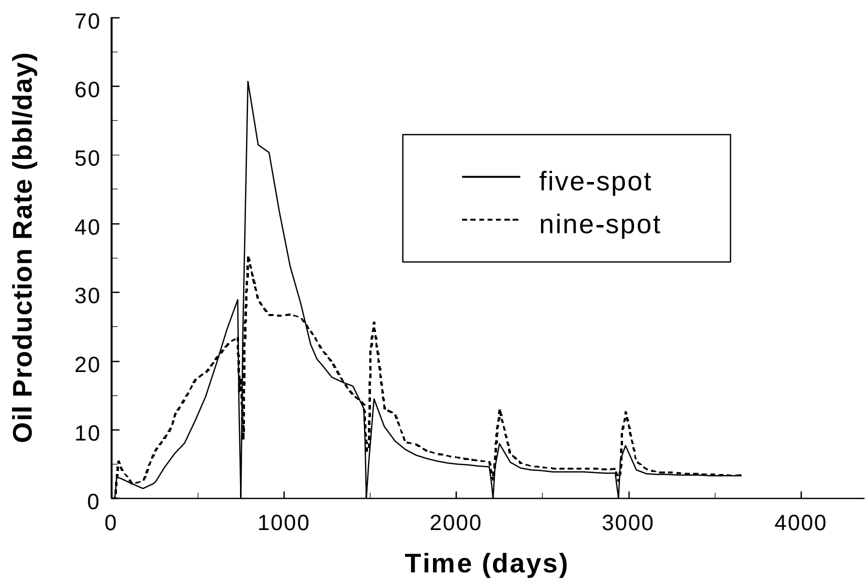


Figure 12: Comparison of the oil production rate for the five- and inverted nine-spot patterns (3-D simulations).

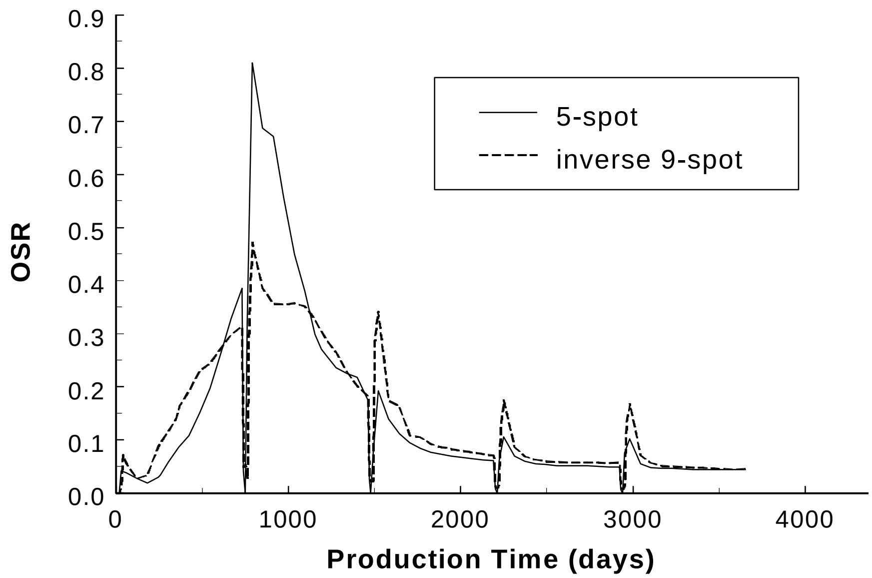


Figure 13: Oil-steam ratios compared for the five- and inverted nine-spot patterns (3-D simulations).

Table 4: Production performance of the five-spot and the inverted nine-spot patterns (3-D simulations)

Pattern	Recovery (%)	OSR	WOR
five-spot	25.7	0.14	8.5
inverse nine-spot	25.2	0.13	9.2

Due to the slower decline and the fact that more producers would be drilled under the nine-spot pattern (leading to better reservoir characterization), the inverted nine-spot pattern was selected for the pilot demonstration. When studying the effect of other parameters the inverted nine-spot pattern will be used.

Well Completions

The conventional practice in the Midway-Sunset field is to complete the injectors and the producers to the oil-water contact. The injectors are usually completed over a third (bottom third) of the pay, while the producers are completed over the entire pay interval. Because of the unusually large oil-water transition zone in this reservoir, it was hypothesized that completing both the injectors and producers above the oil-water contact would lead to more productive processes. This led to the consideration of different completion practices shown in Figure 14.

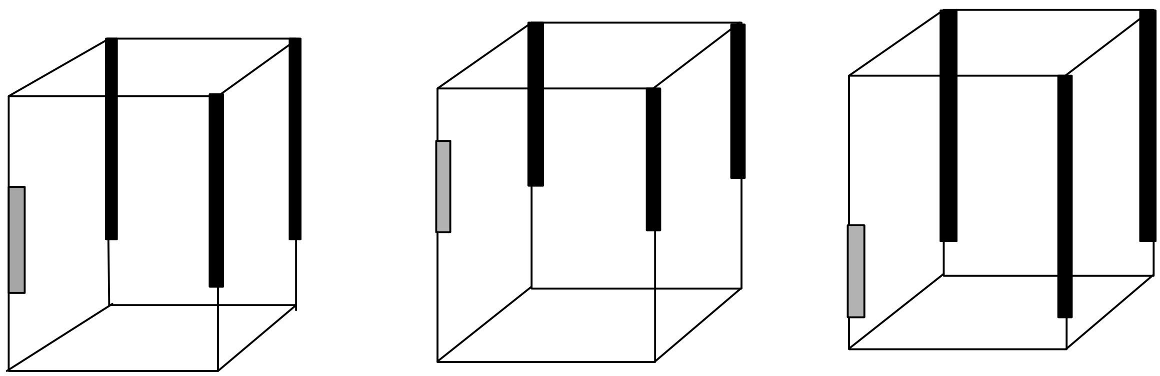


Figure 14: Different completions used in determining the "optimum" configuration; injectors and producers are completed at different heights above the oil-water contact

Cumulative recoveries and OSRs for a number of completions are listed in Table 5. Basically, the performance of the cyclic-flood process, in a nine-spot pattern was evaluated by completing incrementally higher and higher above the oil-water contact. Analysis of the recovery and OSR value listed in Table 5 leads to the conclusion that the “optimum” completion is pulling the injection and the production strings 75-100 ft above the oil-water contact. In all these simulations, wells were not completed in a depleted zone near the top of the Monarch Sandstone. Further analysis based on animation of the simulation results revealed that when injectors were completed deep into the transition zone, reservoir water was produced from the lower part of the reservoir with resultant lower oil recoveries. OSR also was lower due to heat input into “non-productive” region of the reservoir. When the wells were completed higher than the identified “optimum”, the vertical reservoir sweep was poor. Thus, producing water from the lower portion of the reservoir versus not sweeping sufficient quantity of oil out of the reservoir were the trade-off factors determining the optimum completion stand-off.

Table 5: Performance comparison of five different completion practices (3-D simulations)

Completion (ft above WOC)	Recovery (%)	OSR	WOR
136 (high)	23.1	0.12	9.6
92 (base)	25.2	0.13	9.2
76	25.2	0.13	9.4
51	21.7	0.11	11.3
30 (low)	19.0	0.095	13.5

Effect of Steam Injection Rate

All of the simulations discussed earlier were performed with steam injection rates of 0.5 barrel per acre-foot of pay per day. Simulation results with an injection rate of 1.0 barrel per acre-foot per day are compared to the lower rate in Table 6. The performance difference between the higher injection rate at 5 years versus the lower injection rate at 10 years is negligible. The oil rate and OSR curves for the two rates are compared in Figures 15 and 16, respectively. Even though the difference in a 10-year project period was negligible, computer animation revealed that the vertical reservoir sweep was more uniform in the lower injection case, which would result in higher ultimate recovery.

Table 6: Comparison of the cyclic-flood process for two different steam injection rates

Injection Rate (bbl/ac-ft-day)	Prod. Time (years)	Recovery(%)	OSR	WOR
0.5	10	25.2	0.13	9.2
1.0	5	24.8	0.13	9.0
1.0	10	30.0	0.08	13.6

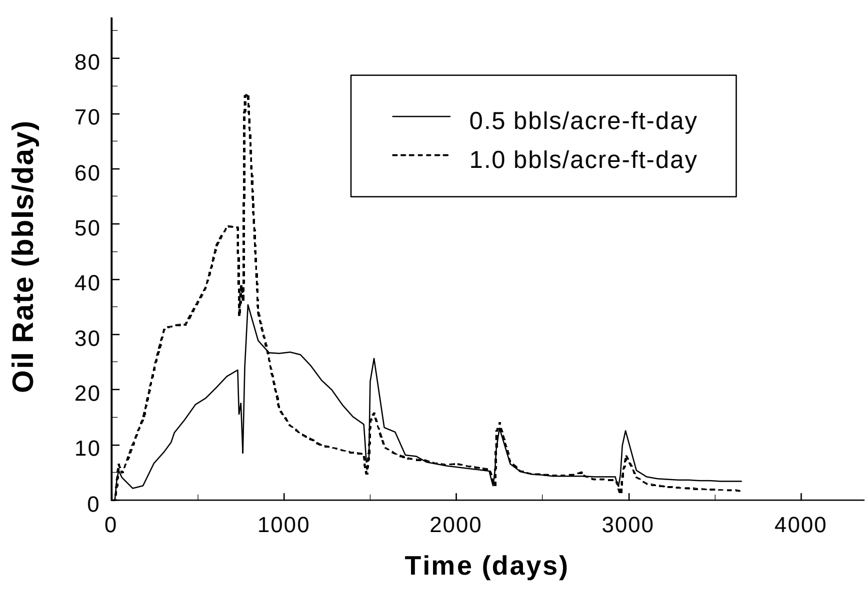


Figure 15: Oil production rates for the cyclic-flood process with two different injection rates (3-D simulations).

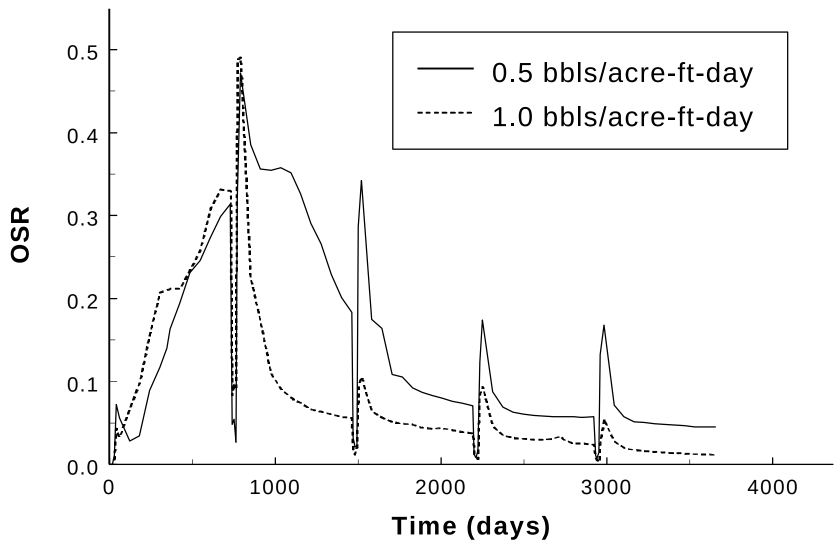


Figure 16: Comparison of OSRs for the cyclic-flood process with two different injection rates.

Conclusions

1. The simulation study identified the stweam flood processes to be better suited for this property than the cyclic process.
2. Updip injection was determined to be better for faster oil recovery.
3. It was found that continuous lower permeability features affect production only when their permeability is about two orders of magnitude lower than the base reservoir permeability. Other characteristics of these features (such as thicknesses) also affect production only when the permeability drops below that threshold.
4. For well completions, there is an optimum with respect to the height above the oil-water contact. This height is determined by the initial water saturation distribution. For the region around the Pru-101 well, which was simulated, this was determined to be about 80 ft above the oil-water contact.
5. Injection rates lower than the conventional one barrel per acre-foot per day appeared to provide marginally better recoveries.