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

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. The methods used in the Class III demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining production of heavy oils throughout the region.

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 discovered prior to 1890. Cumulative production from the field through 1995 was 2.3 billion barrels of oil and 563 billion cubic feet of gas, with remaining reserves estimated to exceed 450 MMBO. The average daily field production in 1995 was 163,400 barrels of oil. 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 Joaquin Basin.

In January 1997 the project entered its second and main phase with the purpose of demonstrating whether steamflood can be a more effective mode of production of the heavy, viscous oils from the Monarch Sand reservoir than the more conventional cyclic steaming. The objective is not just to produce the pilot site within the Pru Fee property south of Taft, but to test which production parameters optimize total oil recovery at economically acceptable rates of production and production costs.

**Summary of Technical Progress**

**General Statement**

During the last quarter of 1997 geostatistical studies of the Monarch Sand reservoir were conducted building on the results of the stratigraphic model reported for the third quarter. These studies involve stochastic modeling of the spatial distribution of porosity and permeability within the volume of Monarch Sand at the 8 ac pilot near the center of the Pru Fee property. Geomath's Heresim™ modeling package is being used for the analysis; Dr. Craig Forster is supervising the work, which is scheduled to be completed in the first quarter of 1998.

While waiting for the stochastic modeling of the Monarch Sand to be completed, Dr. Milind Deo has continued testing alternative production strategies for the Pru steamflood demonstration using the simulator developed for the initial phase of the project. In this exercise the effects of reducing the offset of injectors and use of a horizontal producer at some future time was examined. The results of these tests, which will be repeated with the new simulator developed from the revised stratigraphic and stochastic model, are presented here.

**Review of Previous Results and Motivation for Current Work**

Reservoir simulation studies performed in the first phase of the project revealed that the production is dictated by the initial saturation profile. The presence of bottom water in the reservoir and associated large oil-water transition zone was the most important factor affecting oil recovery. In order to minimize heat losses in the transition zone, the conventional well completion practice (completing injectors in the bottom third of the reservoir and producers over the entire pay zone) was modified. The new completion strategy addressed only the injectors and involved lifting the injection string a certain height above the water-oil contact. Significant improvements in production performance
(in flow simulations) were observed when this strategy was implemented. The predicted production performance with the use of five different production strategies is presented in Table 1. These results had been reported earlier and have been reproduced here for completeness. When the bottom of the injection string was lifted about 75-100 feet above the water-oil contact, an optimum oil recovery of about 25% of OOIP was observed.

<table>
<thead>
<tr>
<th>Injector Completion (feet above WOC)</th>
<th>Recovery (% OOIP)</th>
<th>Cumulative Oil Steam Ratio</th>
<th>Cumulative Water Oil Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>136</td>
<td>23.1</td>
<td>0.12</td>
<td>9.6</td>
</tr>
<tr>
<td>92</td>
<td>25.2</td>
<td>0.13</td>
<td>9.3</td>
</tr>
<tr>
<td>76</td>
<td>25.2</td>
<td>0.13</td>
<td>9.4</td>
</tr>
<tr>
<td>51</td>
<td>21.7</td>
<td>0.11</td>
<td>11.3</td>
</tr>
<tr>
<td>30</td>
<td>19.0</td>
<td>0.095</td>
<td>13.5</td>
</tr>
</tbody>
</table>

*Table 1- Comparison of production performance with the implementation of different completion strategies for the injection well.*

Even with improved completion strategies, only 25% of the original oil in place was produced. The cumulative oil steam ratio of 0.13 may only be marginally economical. Hence, an exploratory study was undertaken to see if the production performance could be improved by other means. It was observed from the visualization of saturation distributions in the reservoir prior to and post steam floods that a considerable amount of oil drained down to the bottom of the reservoir and was essentially unproducible. It was hypothesized that if means of recovering this oil are found, the overall process performance would improve. New simulations were performed to see how this could be accomplished. The strategy would be to flood more of the bottom portions of the reservoir later in the life of the flood by progressively moving the injector completion downward, toward the water-oil contact.

**Current Simulations and Significant Results**

All the simulations were performed on a quarter symmetry element of two-acre, inverse nine-spot pattern with the well PRU 101 in the northwest corner (Figure 1). The cyclic-flood, parameters for which were described previously was simulated for a duration of 10 years. A total of four different scenarios were simulated.

1. Completing the wells 136 feet above the water oil contact (WOC) for the first three years; operating the flood with wells completed 92 feet above the WOC over the following three years; and, moving the completions down to 30 feet above WOC over the last four years of the flood.
2. Completing the wells 92 feet above WOC in the first eight years and operating with the wells down to 30 feet above WOC in the last two years.
3. Completing the wells 92 feet above WOC in the first eight years followed by operation at WOC of 51 feet in the last two years.
4. Completing the wells 92 feet above WOC in the first eight years and introducing a horizontal producer that is 51 feet above the WOC in the final two years.

![Horizontal well, when used](image)

*Figure 1 – Schematic of the symmetry element simulated*

The production performance of the four scenarios is summarized in Table 2.

<table>
<thead>
<tr>
<th>Scenario Number</th>
<th>Recovery (%OOIP)</th>
<th>OSR</th>
<th>WOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>22.4</td>
<td>0.12</td>
<td>10.9</td>
</tr>
<tr>
<td>2</td>
<td>24.5</td>
<td>0.13</td>
<td>10.0</td>
</tr>
<tr>
<td>3</td>
<td>25.0</td>
<td>0.13</td>
<td>9.5</td>
</tr>
<tr>
<td>4</td>
<td>28.5</td>
<td>0.15</td>
<td>8.2</td>
</tr>
</tbody>
</table>

*Table 2 - Comparison of production performance of the four scenarios simulated*

When compared with the best recoveries in Table 1, it is clear that scenario number three is marginally better, while scenario number four is significantly better. Figure 2 shows a...
comparison of cumulative oil production for scenarios 3 and 4 with base case (optimum single completion – injector 92 feet above WOC). The OSR also improves considerably (Figure 3). This increase is mirrored by the oil rate since the steam injection rate is essentially the same for the three cases. Once the horizontal well is introduced, significant amount of additional oil is produced. A more optimum time to drill the horizontal well may be found in simulations currently underway (for instance, introducing the horizontal well after 6 or 7 years of operation may prove more beneficial). Thus, this exercise revealed that it may be feasible to produce the oil that accumulates at the bottom of the reservoir.

**Conclusions**

When injectors in the pattern are completed an optimum height above the WOC oil accumulates in the bottom portion of the reservoir. When several timed-completion strategies, wherein, injector strings were lowered toward the WOC as the flood progressed were attempted, it was discovered that there is only marginal improvement in the best of cases. The only feasible way (possibly economical) of recovering the oil would be to introduce a horizontal well in the later stages of the flood. It would be possible to optimize the time of introduction of the horizontal producer and its location.

![Figure 2 – Comparison of cumulative oil production for scenarios 3 and 4 (timed completions) with the case where the injector is completed 92 feet above WOC and not altered over the life of the project.](image)
Figure 3- Comparison of the OSR (oil-steam ratios) curves for Scenarios 3 and 4 and for the case where the injector is completed 92 feet above the WOC and not altered over the length of the project.