Evaluation of Horizontal, Radial, and Vertical Injection Wells in a Pilot Steamflood

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ABSTRACT

A unique pilot steamflood incorporates one horizontal, one radial, and three vertical steam injection wells. The horizontal and radial wells were designed to alleviate steam override and improve sweep efficiency. The horizontal injector is a medium radius well with 400' of completion in the horizontal section. The radial well has four completed, near-horizontal, ultra-short radius laterals drilled within a short vertical section. The vertical injectors are conventional completions, with perforations in one or two sand lobes. Production data from offset producers, injection profile data, produced fluid and downhole temperature data, and a comprehensive log suite conducted on three temperature observation wells were used to compare the three injection strategies. While a significant increase in oil production has not yet been seen, changes in water production, cut and flowline temperature provide clear indications that many of the offsets are being affected by steam injection.

The pilot steamflood is located in a 5-acre area in the southwest portion of Unocal's Bremer lease, Midway Sunset Field. The steamflood targets the Miocene-Pliocene age Potter formation, a highly permeable sand comprised of massive debris and grain flows deposited as proximal submarine fans. The pilot and surrounding areas have been cyclically steamed for over 10 years. The pilot steamflood has been in place for just under 2 years. In addition to comparisons within the pilot area, comparisons are also made with the eastern portion of the lease which has been successfully steamflooded for over 10 years.

The horizontal injector has efficiently heated a very localized, previously unswept, portion of the thick, sub-homogeneous reservoir being steamflooded. To date, the radial well has been used as a huff-n-puff producer. Despite the short steam injection periods, producers surrounding the well have responded dramatically. Observation well data, rates from offset producers, and temperatures in the offset producers confirm that the vertical injectors are distributing heat and affecting oil production less effectively than the horizontal and radial methods.

INTRODUCTION

Unocal's Bremer Fee is located in the northern portion of the Midway Sunset Field, approximately 35 miles west of Bakersfield, California (Figure 1). The property consists of 360 acres entirely within Section 16, T31S, R22E, MDB&M. Approximately 180 acres are productive. Current production averages 5,000 BOPD from 247 producing wells. Although the Marvly, "D" Channel and Spellacy horizons have been produced sporadically, all production from the lease is currently from the Potter formation.

Primary development began in 1968. Cyclic steaming in the southwestern area of the lease was initiated in 1976. Up until initiation of the pilot steamflood in 1990, the area had been successfully produced under cyclic stimulation only. Steamfloods in the northeast portion of the lease was initiated in the late 1970's, with a major expansion in 1980-1983. At the start of the pilot steamflood project, log-derived oil saturations in unswept areas were close to initial, implying that significant steam channeling had occurred during cyclic operations. This, along with comparisons with the successful steamflood in the northeast, provided the incentive for steamflood in the southwest. Vertical discontinuities in the sands were recognized,
providing further evidence that injecting the steam into unswept zones could provide incremental reserves.

The pilot steamflood consists of six inverted five-spot patterns on approximately 5/8-acre spacing (Figure 2). Two of the patterns are affected by horizontal injector I-49. Three vertical injectors (I-50, I-51, and I-52) impact three connecting patterns. Radial well RI-53 affects four producers separated from the other patterns by one well spacing.

RESERVOIR CHARACTERISTICS

**Geology**

The Mio-Pliocene age Potter formation is a massive sand sequence deposited in a shallow water environment as grain and debris flow turbidites. The Potter unconformably overlies the Antelope Shale. The Tulare formation truncates the top of the Potter, causing the Potter to pinch out in a northeast-southwest direction approximately 800' north of the pilot area. A typical Induction/GR log is shown in Figure 3.

Structure on the property is a southeast trending homocline with a dip of 10°, increasing to 30° at the base of the productive interval. There are no recognized faults. Top Potter in the pilot area is at approximately +1,500' s.s., 250' TVD.

The Potter averages 650' in thickness in the pilot area, of which approximately 400' are currently productive. The remaining Potter sand is steam/air saturated. The Potter is separated by diatomaceous clays or siltstones into the "B" and "C" zones. The existence of separate steamchests below these individual silts suggests that these zones serve as permeability barriers.

**Rock and Fluid Properties**

The base of the productive interval contains conglomeratic, poorly-sorted, coarse-grained sands. Upper Potter sands tend to be better sorted and contain less conglomeratic material. Average overburden-corrected porosity across the interval is 28%. Air permeabilities range from 1,000 to 6,000 md. Lea.ve average initial oil saturation is 61%.

The 11.4° API gravity oil, typical of the northern end of the Midway Sunset Field, shows significant biodegradation. Viscosity variation with temperature (Figure 4) indicates that at the current reservoir temperature range of 150° F to 250° F, viscosity varies from 520 cp to 25 cp. Current reservoir pressure in the southwest area of the lease ranges from 50 to 150 psi. Table 1 provides a summary of pertinent reservoir data.

PILOT DESCRIPTION

The location of the pilot was chosen to (1) provide similar structural position among the injectors, thereby facilitating comparisons between injection methods, and (2) maximize future development potential. Four new injectors, one radial cyclic producer, and three observation wells were drilled in May and June 1990. Detailed information on the drilling of these wells can be found in Reference 1. The seventeen direct offsets (producers) were drilled between 1977 and 1984; eight were drilled in 1984.

Well I-49 is a medium radius horizontal well. Total measured depth is 1,480' at a vertical depth of 937'. The well is completed in the Potter "C" zone with 400' of slotted liner in the horizontal section (Figure 5). Although it was drilled as a continuous injector, an attempt was made to produce the well. After several pump changes required due to sand production, a 5,000 MMBTU steam cycle and a foam cleanout, economic rates were not achieved. The well was placed on continuous injection in July 1990 at rates consistent with the other new injectors but at a lower tubing pressure.

Well RI-53 was drilled as a joint Unocal/Perrophysics/DOE project. Eight ultra-short radius radials were drilled in the vertical section between 881' and 885' MD (Figure 6). The radials ranged in length from 14' to 103'. Four of the radials were completed, one with a flexible sand barrier (FSB), two with gravel packs and one with a gravel pack around coiled tubing which was cut and left in place. While originally intended to be a continuous injector, production following the well's first steam cycle was encouraging enough to warrant an extended production test. The well was subsequently cycled a second time and has produced a total of 22,000 BO to date.

Conventional vertical injectors I-50, I-51, and I-52 were completed with 5-1/2" casing cemented to surface and perforated in one or two intervals with one shot every 2 feet (Figure 7). Observation wells O-2, O-3, and O-5 were completed with 5-1/2" casing cemented to surface.
PILOT EVALUATION

Producers

Production response was evaluated using data acquired on a daily basis (measured total fluid rate, calculated oil rate, measured cut and measured flowline temperature), calculated monthly average data (gross, net and cut), and annular temperature surveys. Pilot production is also compared to production from the existing steamflood.

Daily Production Data

Based on daily production data, several wells have exhibited an obvious response to continuous steam injection in I-49. For instance, Bremer 183's gross rate has remained steady since horizontal well I-49 was placed on injection (Figure 8). Oil production is on an incline. Flowline temperature is 50°F higher than before injection began in I-49, and has remained high. Clouding the analysis, however, is the fact that the well was cycled two months after I-49 went on line. Despite that fact, it is obvious that the well is not showing the response typical of cyclic steam; it is therefore assumed that the response is due to injection in I-49.

Analysis of other wells is not as clear cut. For instance, Bremer 103 (Figure 9) appeared to be responding to injection in I-49 just prior to being steamed in January 1991. Gross production then dropped in a typical cyclic fashion. The well was steamed again in January 1992 and is showing a good initial response.

Two wells in RI-53's pattern responded dramatically to the radial well's second steam cycle. Whether this response was not seen until the second cycle is due to the unusually large volume of heat injected (10,000 MMBTU compared to a typical vertical well cycle of 5,000 MMBTU) or simply because it would take more than the first cycle's 5,400 MMBTU to establish communication with the offsets, is unclear. Bremer 42 (Figure 10), updip of the radial well, responded to RI-53's second cycle as if it was the well that had been steamed. Bremer 190, basically on strike with RI-53, responded similarly. Bremer 106 (Figure 11), updip from RI-53, showed only a very brief spike in the gross and net rate, followed by a characteristic response to its November 1990 cycle. The fourth well in the pattern, Bremer 191, slightly updip from RI-53, also showed very little impact from cycles in RI-53.

Several of the eight wells in the vertical injector patterns seem to have responded to continuous injection. For instance, Bremer 102 (Figure 12) shows a fairly constant net rate since I-50 and I-51 went on line. The well has not been cycled for almost three years and still exhibits a flowline temperature of 175°F. However, just downdip from 102, Bremer 189 (Figure 13) has shown a negative response: water cuts are approaching 100%, unaccompanied by an increase in gross production. This type of response is a classic indication of steam channeling and premature breakthrough at the producer. Since this well is downdip from the injectors, a localized steamchest might have been present in the area around the well, enabling the steam to travel against the natural updip preference.

This type of analysis is admittedly very subjective, and is always clouded by interference from steam cycles, mechanical problems, inaccurate well tests, etc. Keeping this subjectivity in mind, an attempt was made to graphically summarize the effects of steam injection on each producer (Figure 14). Changes in oil production, oil rate decline, flowline temperature, and cut are depicted in four quadrants of a circle surrounding the well. A plus sign (+) indicates a positive response, e.g. oil production higher than before steam injection started, decline rate shallower, flowline temperature up, cut down. In some cases, decline rate is lower (+ for decline), but oil production is not actually higher than before continuous injection started (production quadrant left blank). A minus sign (-) indicates a negative response, e.g. cut higher. A zero (0) indicates no discernible impact, while a question mark (?) is used when the effects of steam injection are masked by interference from a steam cycle or mechanical problems.

Pattern average flowline temperatures are also shown in Figure 14. The southern horizontal well pattern exhibits the highest temperature; the radial well pattern exhibits the lowest temperature, consistent with that well's status as a cyclic producer.

Analysis of this daily data indicates that while several wells have exhibited an obvious response to continuous steam injection, the data does not support any conclusions regarding the effectiveness of one injection scheme over the others. Even though two of the wells in RI-53's pattern responded dramatically to the radial well's second cycle, injection periods were short and the effects once continuous injection is started cannot be inferred. In all patterns there are wells that have shown response as well as those that...
have not. In general, updip producers are responding no better or worse than downdip producers.

**Monthly Production Data**

Monthly production data was analyzed in three groups: 1) the horizontal injector with its six surrounding producers, 2) the three vertical injection wells with their eight immediate offsets, and 3) the radial well with its four surrounding producers. Figures 15 through 17 include production rates, steam injection rates, instantaneous steam oil ratio (SOR) and water cuts for each group. Since the radial well has to date been used only as a cyclic producer, that group's production is not indicative of response to continuous injection. The three vertical well patterns were grouped together to facilitate comparisons between injection strategies. Attempts to quantify the response of individual vertical well patterns are not included in this report.

The monthly data suggests that none of the groups have shown a sustained increase in oil production as a result of continuous steam injection. Water production, on the other hand, has increased markedly in both the horizontal group and the vertical group. It is significant to note that while both of these groups have seen a similar increase in gross production (400 BPD), the instantaneous SOR for the horizontal group is much lower (3 to 4) than the vertical group (4 to 8). This would indicate that the same response in gross production is being effected in the horizontal group by a smaller amount of steam. If increased water production is a precursor to increased oil production (as it was in the northeast portion of the lease), the lower SOR in the horizontal pattern could signify that the goal of a more efficient, vertically focused drive is being accomplished.

**Downhole Temperature Data**

Downhole temperature profiles were recently acquired on thirteen of the seventeen direct offsets and one out-of-pattern producer near the horizontal injector. Profiles were run after shutting-in the wells for 48 hours. For the most part, the wells had not been cycled for at least six months.

A north-south cross section incorporating the updip producers of the horizontal and vertical patterns (Figure 18) shows a pronounced temperature elevation in the well closest to the top of I-49's completion. Travelling south down the course of I-49's well path, the temperature spike flattens and spreads upward. The spike is almost non-existent in the well furthest south in the pattern (Bremer 151), and peak temperature in that well is 13°F lower. This trend indicates that heat injection is decreasing with distance along the horizontal completion. To confirm these results, a direct measurement of the steam injection profile through coiled tubing production logging will be attempted in the near future.

A similar cross section incorporating the downdip wells and the out-of-pattern producer (Bremer 261) reveals a much less pronounced heated zone in the horizontal patterns (Figure 19). Peak temperatures are 25°F to 30°F less than in the updip wells.

Temperature data for the wells in the vertical patterns is sparse (two wells could not be surveyed) and difficult to interpret. On the updip side (Figure 18), Bremer 150A shows a temperature rise in the same stratigraphic interval that is 100°F colder in well O-3, just 150' to the north. On the downdip side (Figure 19), Bremer 189 shows an anomalous temperature increase at the bottom of the well, peaking at 250°F, the highest recorded temperature of any of the wells. Just one location south, however, Bremer 193 shows no evidence of continuous injection. Bremer 64, the next well to the south, shows some evidence of injection in I-52.

The shape of the temperature profiles in wells 187 and 261, the out-of-pattern producer, are similar. It is significant to note, however, that the peak temperature in the affected interval is 25°F lower in the out-of-pattern producer.

**Comparison With Existing Steamflood**

The production response seen to date in the pilot area is very consistent with steamflood response in the northeast portion of the lease. Figure 20 shows production data for the I-14 and I-15 patterns, typical patterns in the existing steamflood. Here production rates were allocated among injector patterns, thus Figure 20 includes one-fourth of the production from each of the offset producers. As in the pilot area, in the I-14 and I-15 patterns, gross production increased very rapidly following the beginning of steam injection. The pronounced increase in oil production that followed began approximately 28 months following the start of steam injection and peaked roughly 18 months later.

While it is difficult to predict when oil production will increase in the pilot area, applying simple ratios of pilot
to steamflood pattern area, pay and injection rate to
the time required for response in the existing
steamflood patterns should begin to increase sometime
around June 1992, two years after the start of injection.
Although the actual mechanics of steam zone growth
are obviously more complicated than simple ratios
would suggest, in this case they provide a rough
estimate of when to expect response.

Observation Wells

Temperature and Dual Spaced Neutron Logs
Figures 21 through 23 show the following data: 1) resistivity logs for both the observation well and the
nearest injector, 2) the temperature profiles that have
been obtained, and 3) an overlay of the far sensor
reading of a dual spaced neutron log. The overlay of
the current (4/92) vs. the initial neutron data provides
a qualitative evaluation of current gas saturation vs.
Initial gas saturation. All observation wells are located
upstructure from the corresponding injector, or injector
well path in the case of the horizontal well. The
observation well for the horizontal injector is downdip
of the vertical (logged) portion of the horizontal well
(as depicted in the N-S cross section in Figure 21), but
updip of the horizontal well path. Distances from the
injectors range from 55' to 100'.

Figure 22 shows that up until a short time ago,
injection into well 1-51 had not significantly affected O-
3. In stark contrast is the major temperature elevation
which occurred very rapidly in O-2, the observation
well opposite the horizontal injector (Figure 21). The
temperature in the sand lobe where the horizontal
Injector is completed has risen 160°F, and the
temperature rise has been fairly confined vertically.
The far data overlay also shows a significant increase
in gas saturation in the same area. These results are
significant for two reasons: 1) the observation well is
located approximately 160' down the horizontal
completion, indicating that heat is probably exiting at
least that far down the well path; and 2) the heated
interval appears to be vertically bounded.

Temperature profiles taken in the observation well
closest to the radial well are shown in Figure 23. Only
two of the eight radials drilled are depicted -- Radial 3,
which was 102' in length and was gravel packed, and
radial 1D, which was completed with 68' of coiled
tubing and gravel packed. Observation well
temperature data shows clearly that when RI-53 is
steamed, heat is segregated into two distinct lobes
(see 6/11/90 ar.d 2/25/91 curves). As heat from the
steam cycle dissipates over time, the temperature
differentiation is lost and the heat distribution appears
homogeneous. Here again, the impact is clear: when
injecting steam, the radial well is focusing the heat in
two very distinct vertical intervals.

GST and C/O Logs
A Gamma Spectroscopy Tool (GST), run in capture
mode and inelastic mode (to obtain carbon/oxygen
data), was run in each of the three observation wells
on completion. The first, and to date only,
carbon/oxygen monitor pass was conducted on O-2,
the well where temperature and neutron logs showed
significant anomalies. Figure 24 shows the computed
log, including lithology and saturations, around the
interval where I-49 is completed. Below 900' MD, very
little saturation change has occurred, considering the
tool's statistical resolution of ±5 saturation units.
Above 900' there are several intervals that have
exhibited measurable oil saturation increases,
particularly the Interval 855' to 890'. This interval is
approximately 50' above the projected course of I-49's
well path, but is well within the depth interval that has
exhibited the dramatic temperature increase.

Injectors

Monthly Injection Data
Figure 25 shows each injection well's monthly average
injection rate and tubing pressure. Also shown are
pseudo injectivities: BWPD Injected + tubing
pressure. Note that injection rates in the horizontal
well are very similar to the vertical wells. Pseudo
Injectivity, however, is higher in I-49 than in two of the
vertical wells. Assuming specific injectivity
(BWPD/psi/ft) would be constant, this would indicate
that I-49 is injecting steam into a longer (longer)
interval, not surprising when one considers that with
the desaturated intervals and gravity override, the
vertical injectors are probably effectively injecting
steam in a relatively short interval, plus the obvious
impact of injecting into the long horizontal section.

Injection Profile Data
Injection profile surveys run in August 1991 show that
in all three cases steam was exiting the wellbore
deeper than during a previous survey, and the profiles
were fairly uniform.

No attempt was made to correlate producer response
with depth of steam injection, or to quantify production
results based on amount of steam injected per foot of
interval, etc.
CONCLUSIONS

1. Continuous steam injection into the horizontal well has effected a rapid, localized temperature rise in the interval being targeted for sweep improvement.

2. The horizontal well patterns have exhibited the same increase in water production, considered a precursor to incremental oil, as the three vertical well patterns. Steam oil ratio in the horizontal group is half that in the vertical well group, indicating that injection in the horizontal well is more efficient.

3. Cyclic steam injection in the radial well has resulted in pronounced temperature increases in a nearby observation well, matching the shape of the observation well's resistivity log and indicating that the radials are effectively focusing steam in distinct vertical intervals. Consistent with the small amount of steam injected, this temperature character disappears with time.

4. Two of the four offsetting producers have responded very favorably to the second cycles in the radial well.

5. While several wells have shown increased oil production due to steam injection, pattern-wide production increases in the pilot area have not yet been seen. The lack of response is consistent with the time required before seeing incremental oil in the older steamflood area of the lease.

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REFERENCES


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