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INCREASING HEAVY OIL RESERVES IN THE WILMINGTON OIL FIELD THROUGH ADVANCED RESERVOIR CHARACTERIZATION AND THERMAL PRODUCTION TECHNOLOGIES

Cooperative Agreement No.: DE-FC22-95BC14939

Contractor Names: City of Long Beach Department of Oil Properties (City) and
Tidelands Oil Production Company (Tidelands), Long Beach,
CA.

Date of Report: January 31, 2002

Award Date: March 30, 1995

Anticipated Completion Date: March 29, 2001* Budget Period 1
March 29, 2004* Budget Period 2

DOE Award: \$6,216,865 (Cum Actual through December 2001)
\$127,263 (December 2001 YTD Actual)
\$468,593 (Remaining funds in BP 1)
\$1,206,355 (Remaining funds in BP 2)

Principal Investigator: Scott Hara - Tidelands

Program Manager: Gary Walker - National Petroleum Technology Laboratory

Reporting Period: October 1, 2001 to December 31, 2001

*Request for two-year, no cost extension of Budget Periods 1 and 2 submitted to Keith Miles on March 29, 2001. Project team is still awaiting DOE approval.

Objectives

The project involves using advanced reservoir characterization and thermal production technologies to improve thermal recovery techniques and lower operating and capital costs in a slope and basin clastic (SBC) reservoir in the Wilmington field, Los Angeles Co., Calif.

Summary of Technical Progress

Through September 2001, project work has been completed on the following activities: data preparation; basic reservoir engineering; developing a deterministic three dimensional (3-D) geologic model, a 3-D deterministic reservoir simulation model and a rock-log model; well drilling and completions; and surface facilities on the Fault Block II-A Tar Zone (Tar II-A). Work is continuing on research to understand the geochemistry and process regarding the sand consolidation well completion technique, final reservoir tracer work, operational work and research studies to prevent thermal-related formation compaction in the Tar II-A steamflood area, and operational work on the Tar V steamflood pilot and Tar II-A post-steamflood projects.

The project team spent the Fourth Quarter 2001 performing routine well work and reservoir surveillance on the Tar II-A post-steamflood and Tar V pilot steamflood projects.

The Tar II-A post-steamflood operation started in February 1999 and steam chest fillup occurred in September - October 1999. The targeted reservoir pressures in the "T" and "D" sands are maintained at $90 \pm 5\%$ hydrostatic levels by controlling water injection and gross fluid production and through the bimonthly pressure monitoring program enacted at the start of the post-steamflood phase. The project team ramped up well work activity from October 2000 through November 2001 to increase production and injection. In December, water injection well FW-88 was plug and abandoned and replaced by new well FW-295 into the "D" sands to accommodate the Port of Long Beach at their expense. Well workovers are planned for 2002 as described in the Operational Management section.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field, including the Tar V horizontal well pilot steamflood project, is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The steamflood operation in the Tar V pilot project is mature and profitable. Recent production performance is below projections because of wellbore mechanical limitations that were being addressed in 2001. As the fluid production is hot, the pilot steamflood was converted to a hot waterflood project in June 2001. See Operational Management for more details.

Reservoir Management

The Tar II-A steamflood project was terminated in January 1999 when the project lost its inexpensive steam source from the Harbor Cogeneration Plant as a result of electric power deregulation in California. An operational post-steamflood plan was developed and

implemented to mitigate the effects of the lost steam injection and possible thermal-related formation compaction by injecting cold water into the flanks of the steamflood. The purpose of flank injection has been to increase and subsequently maintain reservoir pressures at a level that would fill-up the steam chests in the "T" and "D" sands before they could collapse and cause formation compaction and to prevent the steam chests from reoccurring. A new 3-D deterministic thermal reservoir simulation model provided operations with water injection rates and allowable production rates by well to minimize future surface subsidence and it accurately projected reservoir steam chest fill-up by October 1999. Figure 1 shows the post-steamflood wells active in 2001 compared to the original steamflood patterns. Five of the post-steamflood wells were idled (crossed out). The most southerly "D" sand water injector, FW-88, was abandoned in December and replaced by a new well, FW-295, located just to the north of the original bottom hole location. Work is proposed for the First Quarter 2002 on four wells (arrows). A geomechanics study and a separate reservoir simulation study have been performed to determine the possible causes of formation compaction, the temperatures at which specific compaction indicators may be affected and the projected temperature profiles in the over and underburden shales over a ten year period following steam injection.

Steam chest fill-up of the "D" sands occurred in September 1999 when the pressure throughout most of the reservoir exceeded 90% hydrostatic or about 960-1000 psi. Maintaining reservoir pressure is important to prevent steam chest reoccurrence. In mid-September 1999, net water injection was reduced substantially in the "D" sands and reservoir pressure plummeted about 100 psi within six weeks, even though injection to production ratios (I/P) ratios were still above 2.0. Starting in late-October 1999, net "D" sand water injection was increased and reservoir pressure rose back to the desired steam chest fill-up pressure

of 90% hydrostatic pressure by March 2000. Since then, reservoir pressure has been maintained at 90 - 91% hydrostatic through December 2001 and the reservoir has acted more like a waterflood that could be operated at lower net injection rates and lower I/P ratios of about 1.4-1.5, still high compared to the 1.05 in most of the other waterflood projects.

After reaching steam chest fill-up in October 1999, net "T" sand injection remained at a high rate through April 2000 and reservoir pressures stabilized at 98% hydrostatic pressure. The objective has been to lower "T" sand pressure slowly to 90% hydrostatic. Net injection was reduced and "T" sand reservoir pressure averaged 96% hydrostatic in December 2000, 95% in March 2001 and 92% in June 2001. A flurry of "T" sand injector failures occurred from January to September 2001, the most serious ones in the third quarter. Although the wells were repaired promptly, one well required four rig jobs and two others required two rig jobs each. The reduced injection caused reservoir pressure to drop to 89% hydrostatic in September 2001. Reservoir pressures have since stabilized and averaged 89% hydrostatic again in December 2001. Table 1 lists the "T" and "D" sand average reservoir pressures before the post-steamflood phase began and thereafter in quarterly periods.

A reservoir pressure monitoring program was developed as part of the post-steamflood reservoir management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. The fluid levels have been calibrated for liquid and gas density gradients by comparing them with a number of wireline downhole Amerada bomb pressures taken within a few days. This data allows engineering to respond quickly to rises or declines in reservoir pressure by either increasing injection or production or idling production.

Operational Management

The Tar II-A project averaged 1,100 BOPD and 22,119 BPD gross fluid (19.10 water-oil ratio [WOR]) with 31,845 BPD water injection during the Fourth Quarter 2001. The oil rates are the highest of the post-steamflood phase while maintaining water cuts at or below 95%. Fourth quarter water injection rates increased following the injection well repairs in the third quarter, which allowed an increase in oil and gross fluid production. Routine rig work was performed on many producers to repair bad pumps and to stimulate scaled-up wells. Well UP-924 went from 50 BOPD/977 BGFPD just prior to acid stimulation work in early November to a stable rate of 110 BOPD/ 2245 BGFPD through the remainder of the year. During the next quarter, well work is proposed on four wells in the north flank of the steamflood area as shown with arrows in Figure 1. The proposed work includes converting two former steamflood injectors (952-UP and 954-UP) to water injection into the "D" sands, plugging back "D" sand

TABLE 1					
TAR II-A STEAMFLOOD PROJECT - RESERVOIR PRESSURE					
"T" Sands - Phase 1-1C Wells			"D" Sands - Phase 1-1C Wells		
Reservoir Pressure			Reservoir Pressure		
	psi	hydrostatic %		psi	hydrostatic %
Jun-97	818	79	May-96	594	54
			Aug-98	748	68
Mar-99	888	85	Mar-99	881	79
Jun-99	925	89	Jun-99	1026	92
Sep-99	976	94	Sep-99	1056	95
Dec-99	1002	96	Dec-99	954	86
Mar-00	1008	97	Mar-00	1009	91
Jun-00	1011	97	Jun-00	991	90
Sep-00	1000	96	Sep-00	995	90
Dec-00	1003	96	Dec-00	999	90
Mar-01	992	95	Mar-01	1005	91
Jun-01	955	92	Jun-01	1009	91
Sep-01	926	89	Sep-01	1008	91
Dec-01	920	89	Dec-01	1005	90

injector 953-UP and recompleting it into the "T" sands, and plugging back watered out producer AT-59 out of the lower "D" sands and recompleting it into the upper "D" sands with perforations and a gravel-packed inner liner. Figure 2 is a production graph of the Tar II-A steamflood project from inception in 1982 through December 2001.

Expanding the DOE project in March 1999 to include the Tar V steamflood has allowed the project team to continue research related to the Tar II-A horizontal well pilot steamflood operations. The Tar V pilot steamflood began in June 1996 and initially included two new horizontal steam injectors (wells FJ-202 and FJ-204), two existing vertical water injectors (wells FR-111 and FRA-83), three new horizontal producers (wells J-201, J-203 and J-205), and three existing vertical well producers (wells A-186, A-195 and A-320). The steamflood project wells are completed in the Wilmington Field Fault Block V Tar Zone "S" sands as shown in the "S4" Sand structure map in Figure 3. Well FRA-29 was converted to a water injector in November 2000. A new horizontal producer, J-206, is being proposed to drill in 2002 along with converting a south flank well to water injection for additional pressure support (both shown in red).

Pilot steamflood performance was excellent for the first two years as shown in Figure 4 with oil production peaking at 743 BOPD in January 1998 at a cumulative steam-oil ratio (SOR) of 4.4. All five horizontal wells were given initial cyclic steam jobs to consolidate the formation sands and to stimulate heavy oil production. The three infill vertical

Figure 2

Figure 3

wells, A-186, A-195 and A-320, all responded favorably to steam injection in the horizontal wells. Wells A-186 and A-320 still contributed a combined 67 BOPD during the Fourth Quarter 2001. Well A-195 was idled in August 1998 because of steam breakthrough and is used as a temperature observation well. Table 2 lists the initial production date, the peak monthly oil production rate, the date of peak oil production, and the cumulative oil production for the five horizontal and three vertical producing wells through December 2001.

Table 2
Tar V Steamflood Pilot - Horizontal & Infill Wells

Well	Init Prod Date	Peak Prod, BOPD	Peak Prod Date	Cum Oil Prod Thru Dec 2001, 1000 BO
FJ-202 HW	Nov 96	280	Dec 96	40.8
FJ-204 HW	Feb 97	223	Apr 97	27.0
J-205 HW	Apr 97	328	May 97	99.8
J-203 HW	Jun 97	267	Mar 98	164.2
J-201 HW	Oct 97	283	Jan 98	105.7
A-186	Prior Jun 96	83	Mar 00	84.1
A-195	Prior Jun 96	86	Nov 96	19.5
A-320	Prior Jun 96	145	Nov 97	126.5
Pilot Total	Jun 96	734	Mar 98	667.5

Note: Wells FJ-202 and FJ-204 converted to injection Jun 97 and Oct 97, respectively.

After reaching peak production of 743 BOPD in January 1998, the pilot project oil production declined significantly to a low of 148 BOPD in October 1999 for various reasons including lower steam injection rates than planned, well downtime from sand control problems, and gross production restrictions to meet new injection to production ratio (I/P) requirements for surface subsidence control. Restricting gross production rates became a problem

because the horizontal producers began responding to steam and water injection that resulted in higher producing fluid levels and water cuts. Steam injection to the pilot project was increased in October 1999 and well work was performed to repair two of the horizontal producers for sand control and to convert one vertical well to water injection. This work resulted in oil production rising to 304 BOPD in December 2000 with a cumulative SOR of 6.4. Oil production dipped to 223 BOPD in February 2001 but increased in June to 261 BOPD as a result of speeding up the pumping units on the three horizontal well producers. In June, steam injection was terminated and converted to 350/F hot water injection to prevent overheating the overburden shales and causing formation compaction. Oil production declined to an average of 209 BOPD in the fourth quarter despite continuing to speed up pumping units and increasing gross fluid production rates. The wells still have high producing fluid levels averaging 1000+ feet over the pump that need to be pumped down further.

The projected oil reserves for the pilot project is 1.7 million barrels assuming the use of 8.5 million barrels of cold water equivalent steam at 80% quality and 16.7 million barrels of total steam and water injection over 14 years. As of December 2001, the pilot has produced 667,000 barrels of oil and 6,429,000 barrels of gross fluid (90% average water cut) and injected 5,031,000 barrels of steam and 7,800,000 barrels of total steam and water for an overall I/P ratio of 1.21. The steam flood

performance curves in cumulative barrels vs time for oil production, gross fluid production, steam injection and total steam and water injection are shown in Figure 5.

The Tar V pilot project has been operated differently than originally planned because of thermal-related surface subsidence concerns regarding the Tar II-A steamflood project. Steam and water injection were increased to raise the cumulative I/P ratio to 1.16 through the steam injection phase, compared to the originally planned I/P ratio of 0.75 during the first four years of the project. The planned I/P ratio was lower because the Tar II-A project averaged a 0.75 I/P ratio from 1990 to 1994 without any apparent adverse surface subsidence effects. The lower I/P ratio in a steamflood was considered safe because injected high temperature steam displaces much more volume than its cold water equivalent volume, up to 35 times more at 800 psi reservoir pressure. The change in plan accelerated steamflood and waterflood response, hence the high producing fluid levels in the wells. Because the horizontal producers are completed at the bottom of the S4 sands, high oil production rates are dependent upon pumping the wells down. When the producing fluid temperatures reached 350/F in the interior horizontal producer well J-203 in May 2001, the City of Long Beach defined the project as mature and required the steam generator to output only hot water at a temperature not to exceed 350/F to prevent thermal-related formation compaction. This has

significantly affected steamflood performance as the overall reservoir was not heated to adequate temperatures. During the fourth quarter 2001, the pilot produced at the instantaneous "steam-oil" ratio over 18.

The pilot project through the Fourth Quarter 2000 met the original reservoir engineering projections based on oil recovery vs cumulative gross fluid production and cumulative steam injection. The original pilot projections showed that to recover 586,000 barrels of oil would require producing 4,990,000 barrels of gross fluid (actual is 2.5% lower) and injecting 3,643,000 barrels of steam (actual is 2.3% higher). However, the project was behind schedule because production and injection rates throughout the project have been too low. Based on the original projected volumes, the project should have recovered 586,000 barrels of oil by the second quarter of 1998 or 1.5 years earlier.

An important issue not considered when comparing projected to actual steamflood performance is that the injected steam quality was rarely at 80% and probably was closer to 40% during the steam injection phase of the project (June 1996 - May 2001). The steam quality difference amounts to injecting about 30% less BTU heat into the formation than planned. The 350/F hot water is only 13% of the heat injected compared to an equivalent weight of water as 1600 psi 80% quality steam. Because steam fuel cost is the main concern when correlating steamflood performance to steam-oil ratio, an evaluation needs to be made to normalize actual steam usage to a BTU equivalent volume of 80% quality steam.

The pilot project has potential for increasing oil production without further increasing hot water injection. All three horizontal producers have had high producing fluid levels for several years. Speeding up the pumping units on wells J-201, J-203 and J-205 during the second quarter increased oil production by 50 BOPD and reduced fluid levels about 150 feet. Theoretically, drawing down the fluid levels should increase production to about 2200 BPD gross and 125 BOPD per well (incremental of 900 BPD gross and 85 BOPD, 10.7% oil cut) based on leaving a safe producing fluid level to prevent sand inflow. Well FRA-29 was converted to injection in November 2000 to provide the necessary water injection support for production increases in wells J-201 and J-203. This well also provides more reservoir pressure support from outside the pilot area to improve well productivity similar to the flank water injection in the Tar II-A project. Additional water injection on the south flank of the project is needed to support increasing production in well J-205 as shown in Figure 3.

Technology Transfer

Scott Hara made an oral presentation entitled "Applying New Technology to an Old Field" to the Petroleum Engineering Department at Stanford University on November 2, 2001. The presentation focused on the Tar II-A post-steamflood modeling and operations and on the successful drilling of horizontal well L-232 to thin oil sand beds in the Tar V zone, both DOE Class III-related projects.

A project homepage can be viewed on the Internet at <http://www.usc.edu/dept/peteng/topko.html>. A CD-ROM of the project on IBM PC format will be distributed free upon request to Scott Hara, Tidelands Oil Production Company, phone - (562) 436-9918, email - scott.hara@tidelandsoil.com.

References and Notes

1. Hara, Scott, Tidelands Oil Production, "Applying New Technology to an Old Field", Stanford University Petroleum Engineering Dept., Stanford University, CA, 2 November 2001.