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

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| Principal Investigator: | Scott Hara - Tidelands | |
| Program Manager: | Gary Walker - National Petroleum Technology Laboratory | |
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## 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 June 2002, 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 post-steamflood pilot and Tar II-A post-steamflood projects.

During the Third Quarter 2002, the project team essentially completed implementing the accelerated oil recovery and reservoir cooling plan for the Tar II-A post-steamflood project developed in March 2002 and is proceeding with additional related work. The project team has completed developing laboratory research procedures to analyze the sand consolidation well completion technique and will initiate work in the fourth quarter. The Tar V pilot steamflood project terminated hot water injection and converted to post-steamflood cold water injection on April 19, 2002. Proposals have been approved to repair two sand consolidated horizontal wells that sanded up, Tar II-A well UP-955 and Tar V well J-205, with gravel-packed inner liner jobs to be performed next quarter. Other well work to be performed next quarter is to convert well L-337 to a Tar V water injector and to recomplete vertical well A-194 as a Tar V interior steamflood pattern producer. Plans have been approved to drill and complete well A-605 in Tar V in the first quarter 2003. Plans have been approved to update the Tar II-A 3-D deterministic reservoir simulation model and run sensitivity cases to evaluate the accelerated oil recovery and reservoir cooling plan.

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±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. Well work related to the Tar II-A accelerated oil recovery and reservoir cooling plan began in March 2002 with oil production increasing from 1009 BOPD in the first quarter to 1145 BOPD in the third quarter. Reservoir pressures have been increased during the quarter from 88% to 91% hydrostatic levels in the “T” sands and from 91% to 94% hydrostatic levels in the “D” sands. Well work during the quarter is described in the Reservoir Management section.

The post-steamflood production performance in the Tar V pilot project has been below projections because of wellbore mechanical limitations and the loss of a horizontal producer a second time to sand inflow that are being addressed in the fourth quarter. As the fluid production temperatures exceeded 350°F, our self-imposed temperature limit, the pilot steamflood was converted to a hot waterflood project in June 2001 and converted to cold water injection on April 19, 2002. See Operational Management for more details.

## Reservoir Simulation

The project team is updating the Tar II-A 3-dimensional deterministic reservoir simulation model to analyze post-steamflood operations to date and to evaluate alternatives for reducing peak reservoir temperatures to safe levels throughout the project area. The objective of updating the model is to minimize the risk of further shale compaction and associated surface subsidence. Multiple sensitivity cases will be run to evaluate where and how much water to inject to reduce reservoir temperatures to safe levels as quickly as possible while maximizing oil production and ultimate oil recovery at the lowest cost. The next quarter will be spent comparing the differences between the CMG STARS thermal reservoir simulator versions used during the latest model run in July 1999 (STARS 98 UNIX) and the current STARS 2002 PC version.

An updated reservoir simulation model will address two main technical challenges that cannot be determined intuitively or manually. The first is the model's ability to predict formation temperatures over time throughout the vertical and areal extents of the steamflood project for each operating plan scenario. Reservoir pressures and temperatures in the project area are affected by the following occurrences: mixing of the hot and cold fluids at the water injection sites; continuous heat loss in the mature steamflood area to the overburden and underburden formations; steam chest collapse and expansion in the structurally updip areas; and the movement and production of hot fluids throughout the steamflood project area. Taken together, these parameters make the prediction of reservoir temperatures and pressures too difficult without a viable reservoir model. The second challenge the model can address is determining the effective water injection rates into the northerly and southerly flank injection wells to minimize water loss into the aquifer and the associated expense.

The last modeling work performed on the Tar II-A was in July 1999. Once the STARS model comparison tests are completed, the plan is to test how well the model can history match the post-steamflood operations to date. The model will be updated to include the last three years of production and injection data and the new pressure and temperature survey data. The temperature data are from both the gross fluid production from individual wells and from temperature profile surveys. The pressure data are from the monthly fluid level surveys and periodic Amerada bomb pressure recordings on idle wells. The reservoir simulation model was used as a reservoir management tool in late 1998 to convert the high pressure - high temperature Tar II-A steamflood to a cold waterflood in a stress-sensitive formation to minimize surface subsidence. The model provided several operating strategies and justified the flank cold water injection plan ultimately selected. Whereas the initial plan was to idle all producing wells until steam chest fillup occurred, the simulation model successfully provided for limited oil production. The model provided the water injection and gross fluid production rates to use and correctly predicted steam chest fillup by October 1999. Oil production in August 1998 averaged 2253 BOPD. Following termination of steamflooding in January 1999, oil production in February was reduced to 781 BOPD, bad but much better than no oil production.

Third quarter 2002 oil production averaged 1145 BOPD. The reservoir simulation work and post-steamflood plan and initial operation are reported in SPE Paper #62571 entitled "Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California"[1].

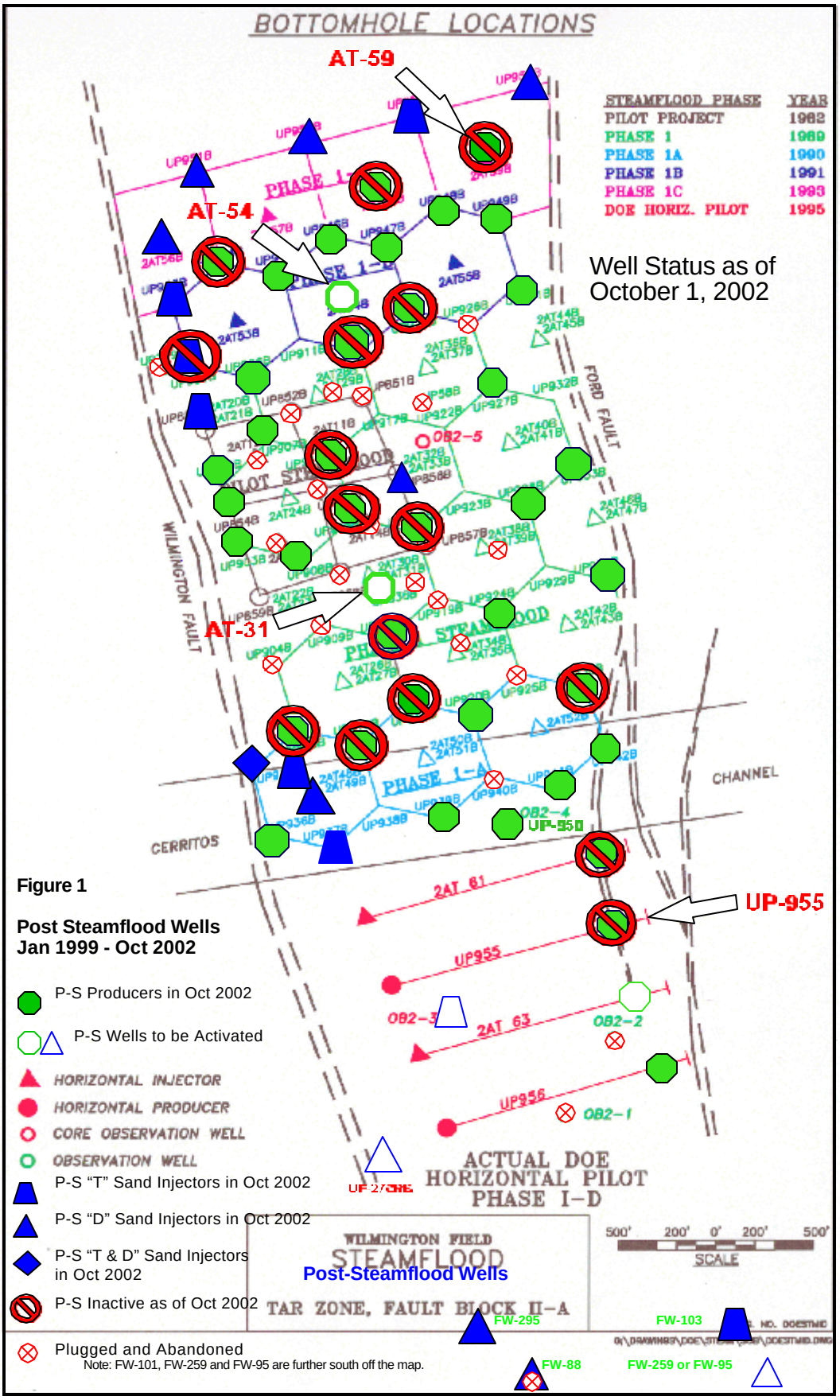
## Reservoir Management

The Tar II-A steamflood project was terminated in January 1999 when the project lost its inexpensive steam source. An operational post-steamflood plan was 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. A geomechanics study and a separate reservoir simulation study were 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 by March 2000. Since then, reservoir pressure has been maintained at 90 - 91% hydrostatic through June 2002. The reservoir has begun acting more like a waterflood that can 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 Wilmington 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 95% hydrostatic in March 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, the reduced injection caused reservoir pressure to drop rapidly to 92% hydrostatic in June 2001 and 89% hydrostatic in September 2001. Reservoir pressures continued to decline slowly through March 2002 to 88% hydrostatic even though “T” water injection was increased back to normal in October 2001. Since then, reservoir pressure stabilized at 88% hydrostatic in June 2002.

The project team developed a well work plan in March 2002 to accelerate cooling of the Tar II-A steamflood reservoirs by increasing flank cold water injection and high temperature gross fluid production. The plan proposed activating ten producers and six injectors. All of the work has been completed through September 2002 except for one producer and one injector. Two producers and one injector not in the original plan were activated and several additional well activations are planned for the fourth quarter. Two fin fan coolers were repaired to restore tank farm operating ability to cool high volumes of hot produced fluids to protect pipeline coatings on oil shipping and water injection lines. Figure 1 shows the 24 producers and 14 injectors that are active in the Tar II-A post-steamflood area as of October 1, 2002 compared to the original steamflood pattern wells. Seventeen wells have been activated during the post-steamflood period and later idled.


BOTTOMHOLE LOCATIONS
AT-59
AT-54
AT-31
UP-955
STEAMFLOOD PHASE
YEAR
PILOT PROJECT 1982
PHASE 1 1989
PHASE 1A 1990
PHASE 1B 1991
PHASE 1C 1993
DOE HORIZ. PILOT 1995
Well Status as of October 1, 2002
WILMINGTON FAULT
FORD FAULT
CHANNEL
CERRITOS
PHASE 1-A
OB2-5
OB2-4
OB2-3
OB2-2
OB2-1
2AT 61
2AT 63
UP955
UP956
ACTUAL DOE HORIZONTAL PILOT PHASE I-D
WILMINGTON FIELD
STEAMFLOOD
Post-Steamflood Wells
TAR ZONE, FAULT BLOCK II-A
500' 200' 0' 200' 500'
SCALE
FW-295
FW-103
FW-88
FW-259 or FW-95
Figure 1
Post Steamflood Wells
Jan 1999 - Oct 2002
P-S Producers in Oct 2002
P-S Wells to be Activated
HORIZONTAL INJECTOR
HORIZONTAL PRODUCER
CORE OBSERVATION WELL
OBSERVATION WELL
P-S "T" Sand Injectors in Oct 2002
P-S "D" Sand Injectors in Oct 2002
P-S "T & D" Sand Injectors in Oct 2002
P-S Inactive as of Oct 2002
Plugged and Abandoned
Note: FW-101, FW-259 and FW-95 are further south off the map.

The Tar II-A well work completed from March 1 - September 30, 2002 has basically met the projected produced and injected volumes. The production acceleration plan called for increasing total gross fluid production by 9,600 BPD, oil production by 427 BOPD, and water injection by 12,500 BWIPD. Since February 2002, estimated gross fluid production has increased 12,300 BPD, oil production has increased 296 BOPD, and water injection has increased 11,939 BPD. The incremental oil production is actually higher as many wells have experienced higher water cuts since February. Through September 2002, implementing the plan has resulted in higher net water injection rates that increased reservoir pressures in the "D" sands to 94% hydrostatic and in the "T" sands to 91% hydrostatic. The pressures will be reduced as more producers are activated. Table 1 lists the "T" and "D" sand average reservoir pressures before the post-steamflood phase began in February 1999 and thereafter in quarterly periods.

**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 |
| Mar-02 | 910 | 88 | Mar-02 | 1009 | 91 |
| Jun-02 | 909 | 88 | Jun-02 | 1001 | 91 |
| Sep-02 | 940 | 91 | Sep-02 | 1040 | 94 |

The accelerated cooling plan included testing cold-water injection into one interior "D" sand pattern injector (2AT-33) to observe whether the formation would react like a normal waterflood or experience adverse formation compaction effects. The ten feet of "DU" shale above the "D" sands in this pattern have experienced formation compaction of about 6"-9" based on comparing the gross shale thickness in the original induction log (circa 1981 pre-steamflood) of interior pattern well 1F-10 with a follow-up Thermal Neutron Decay Time (TDT) log in December 2001.

Temperature survey data within the 2AT-33 pattern show that the high temperatures in the lower "DU" shale and at the top of the "D1" sands are cooling slowly, even with cold water injection into 2AT-33. At the start of the post steamflood injection in January 1999, well OB2-5 had a peak temperature of 479/F at the top of the "D" sands. The latest temperature survey on October 3, 2002 compared with the August 15, 2002 survey shows a constant peak temperature of 440/F at the top of the "D1" sands but rapid cooling at the top of the "D1b" sands from 444/F down to 416/F and at the bottom of the "D1d" sands from 380/F down to 287/F, indicating that cold water injection is segregating to the bottom of the reservoir.

The temperature survey data from well 1F-10 show an interesting heating trend in the upper "D1" sands in five surveys from January 9, 2002 to October 3, 2002 where temperatures have risen from 356/F to 392/F. Prior to injection into 2AT-33, the temperature in the upper "D1" sands declined from 385/F at the start of the post-steamflood (February 1999 survey) to 356/F in January 2002, at a rate typically observed in other wells. This type of heating trend is normally observed within a well when conductive heat from hotter sands are transferred vertically to cooler sands. Horizontal areal heating is expected to happen too, but conductive heat transfer is slow moving and has not been observed recently in temperature

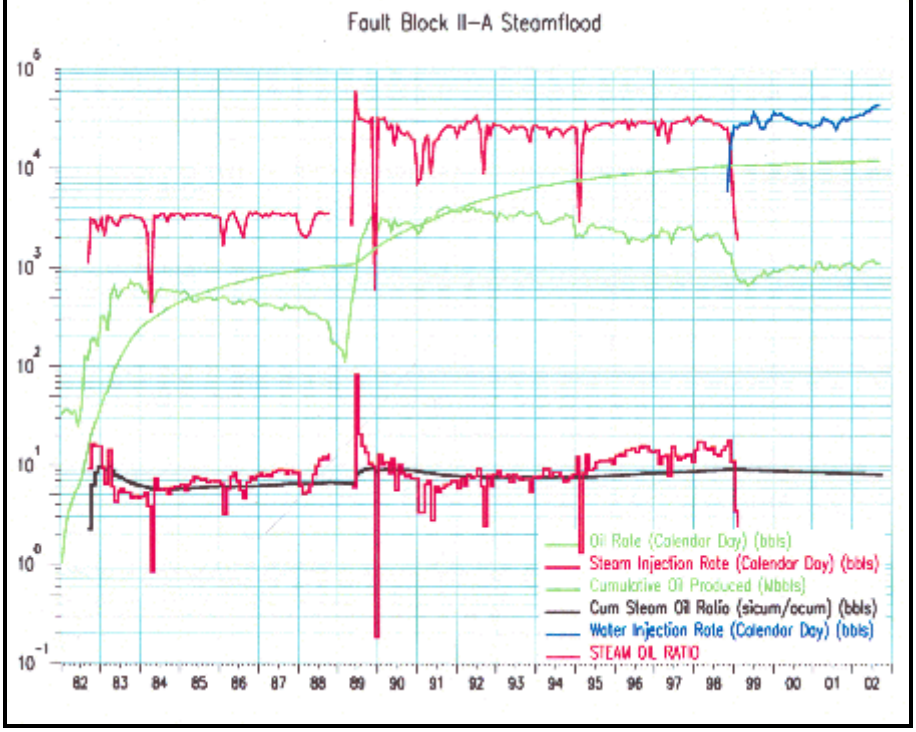
surveys except in this case. One reasonable explanation is that some of the injected cold water from 2AT-33 was heated over a short distance to above 400/F which then convectively heated the surrounding "cooler" sands.

A comprehensive reservoir surveillance program was developed for the post-steamflood reservoir management plan. A sonic fluid level program measures the static fluid levels in all idle wells monthly to monitor reservoir pressures. 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. Formation compaction and surface subsidence are monitored through the use of biannual GPS surveys and comparing new TDT neutron logs with pre-steamflood induction logs in key wells. Contact temperature surveys are run as needed in key observation wells.

## Operational Management

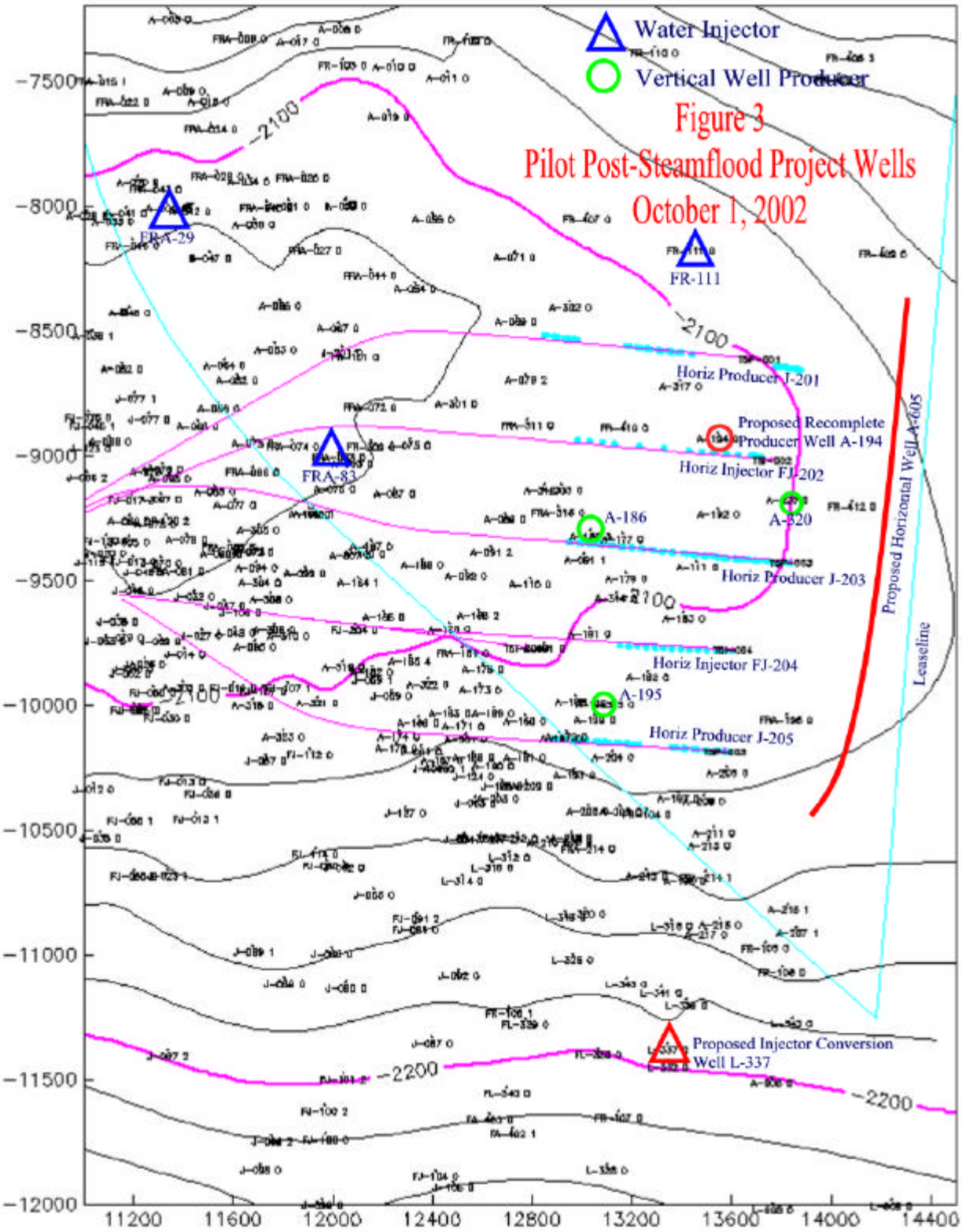
The Tar II-A project averaged 1,145 BOPD and 28,082 BPD gross fluid (24.5 water-oil ratio [WOR]) with 38,964 BPD water injection during the Third Quarter 2002. The oil and gross fluid production and injection rates are all significantly higher than the previous quarter because of the well work that started in March 2002. The post-steamflood is experiencing higher water cut production because the wells being activated had higher water cuts than the initial post-steamflood wells prior to the shutdown of steamflooding and because of water breakthrough from the higher cold water injection rates. Last quarter, the WOR was 21.9, gross fluid production was 25,785 BGFPD, oil production was 1126 BOPD and water injection was 36,981 BWIPD. Figure 2 is a production graph of the Tar II-A steamflood project from inception in 1982 through September 2002.

Figure 2

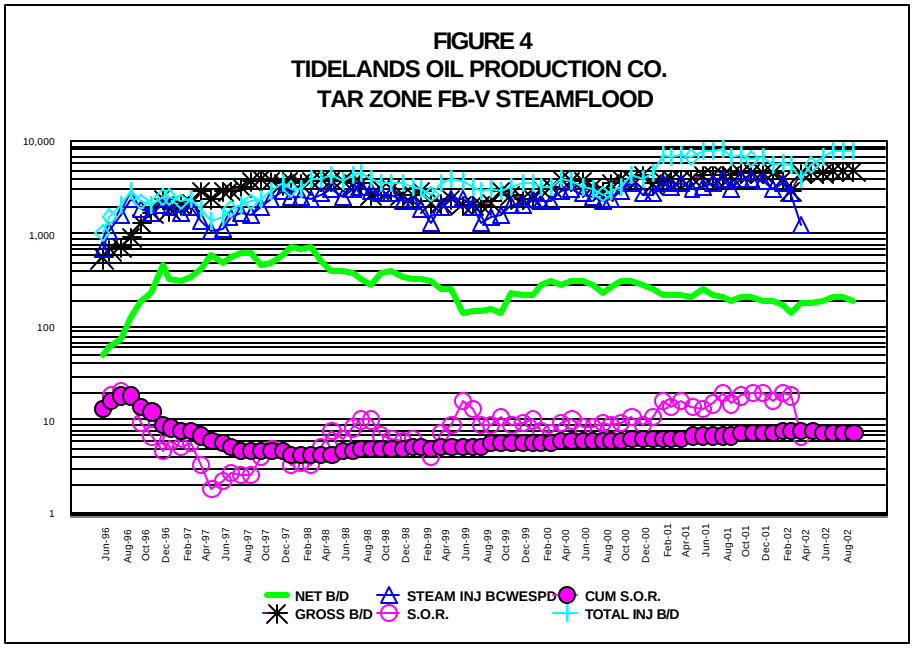



Expanding the DOE project in March 1999 to include the Tar V steamflood has allowed the project team to continue research related to the Tar II-A horizontal well pilot steamflood operations. The Tar V pilot steamflood began in June 1996 and initially included two new horizontal steam injectors (wells 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

Tar V S4 Structure Map. Scale: 1'' = 500'



injector in November 2000. Within the next six months, the plan is to drill a new horizontal producer, A-605, to capture oil reserves along the leaseline, convert south flank well L-337 to water injection for additional pressure support, and recomplete vertical well A-194 to the upper Tar "S" sands to recover post-steamflood oil reserves as an interior pattern well (all 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 4.5. 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 wells, A-186, A-195 and A-320, all responded favorably to steam injection in the horizontal wells. Well A-195 was idled in August 1998 because of steam breakthrough and was used as a temperature observation well, but was repaired in May 2002. The three infill wells contributed a combined 91 BOPD in September 2002 of the 194 BOPD from the pilot. Table 2 lists the initial production date, the peak oil production rate, the date of peak oil production, the current oil production rate, and the cumulative oil production for the five horizontal and three vertical producing wells through September 2002.

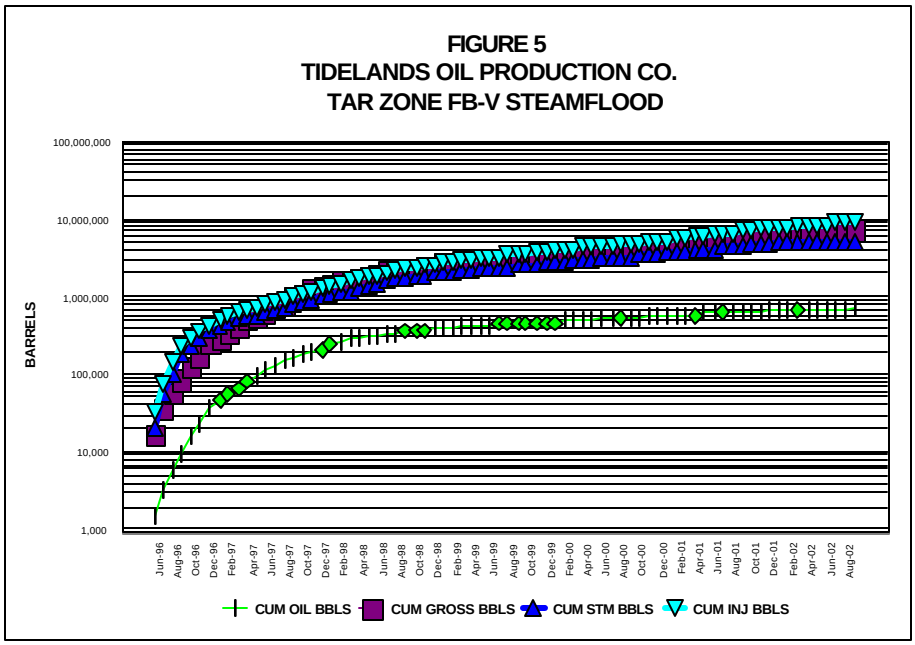
After reaching peak production of 743 BOPD in January 1998, the pilot project oil production declined significantly to a low of 148 BOPD in October 1999 for various reasons including lower steam injection rates than planned, well downtime from sand control problems, and gross production restrictions 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 326 BOPD in November 2000 with a cumulative SOR of 6.3. In June 2001, steam injection was terminated and converted to 350$^{o}$F hot water injection to prevent overheating the overburden shales and causing formation compaction. Oil production declined to a new low of 147 BOPD in March 2002 due to failing pumps in two horizontal wells that were replaced in March. Hot water injection was terminated in April 2002 and replaced with 100% cold water injection. In May, horizontal well J-205 sanded up. Even still, oil production in the third quarter 2002 averaged 204 BOPD from activating A-195 and continually pumping down well J-203, even without J-205. The plan for October is to repair J-205 with a gravel-packed inner liner to restore sand control and to allow the well to be pumped to capacity.

**Table 2**
**Tar V Steamflood Pilot - Horizontal & Infill Wells**

| Well | Init Prod Date | Peak Prod, BOPD | Peak Prod Date | Sept 2002 Prod Rate, BOPD | Cum Oil Prod Thru Sept 2002, 1000 BO |
|---|---|---|---|---|---|
| FJ-202 HW | Nov 96 | 280 | Dec 96 | Wtr Inj | 40.8 |
| FJ-204 HW | Feb 97 | 223 | Apr 97 | Wtr Inj | 27.0 |
| J-205 HW | Apr 97 | 328 | May 97 | 0 (repairing) | 103.1 |
| J-203 HW | Jun 97 | 267 | Mar 98 | 48 | 176.6 |
| J-201 HW | Oct 97 | 283 | Jan 98 | 55 | 122.9 |
| A-186 | Prior Jun 96 | 83 | Mar 00 | 39 | 91.7 |
| A-195 | Prior Jun 96 | 86 | Nov 96 | 27 | 22.7 |
| A-320 | Prior Jun 96 | 145 | Nov 97 | 25 | 135.2 |
| Pilot Total | Jun 96 | 743 | Jan 98 | 194 | 720.0 |

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

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. Through September 2002, the pilot has produced 720,000 barrels of oil and 7,687,000 barrels of gross fluid (90.6% average water cut) and injected 5,357,000 barrels of steam/hot water and 9,482,000 barrels of total steam and water for an overall I/P ratio of 1.23. The steamflood 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 affecting 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 significantly affected steamflood performance as the overall reservoir was not heated to adequate temperatures and cumulative steam injection was reduced by over 3.5 million cold water equivalent barrels from planned volumes. During the first quarter 2002, the pilot produced at an instantaneous "steam-oil" ratio of over 18. Through the end of hot water injection in April 2002, the cumulative SOR of the pilot was 7.6, marginal assuming steam costs based on market-priced fuel. Since only cold water is currently injected, the cumulative SOR will decline with time.

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 to consider when comparing projected to actual steamflood performance is to normalize actual steam usage to a BTU equivalent volume of 80% quality steam. For the Tar V project, the injected steam quality was rarely at 80% and probably was closer to 60% for the 4,223,000 barrels injected during the steam injection phase of the project (June 1996 - May 2001). The steam quality difference amounts to injecting about 89% of the BTU heat into the formation than planned per pound of water. The cumulative SOR through June 2001 was 6.9. If steam volumes are normalized based on heat transfer using 80% quality steam, the corrected SOR would be a much more reasonable 6.1 or about 11% lower. Hot waterflooding occurred from July 2001 through April 2002, with the hot water rate averaging 3188 BCWEPD. The hot water averaged about 330/ F at no steam quality, which has about 21% of the heat transfer of 80% quality steam. Therefore, the first quarter 2002 SOR of 18.2 using hot water injection would have a normalized SOR of 3.8 based on the equivalent heat transfer of 80% quality steam. As steam fuel cost and the steam-oil ration are the main parameters determining the profitability of a steamflood, a more thorough economic evaluation needs to be made of the Tar V pilot steamflood performance.

Although steam and hot water injection has been terminated, the pilot project still has potential for increasing thermal oil recovery. The plan is to install inner liners in one or possibly all three horizontal producers so they can be pumped off without sanding up. A new horizontal producer, well A-605, is planned to be drilled in a south to north direction along the Tidelands leaseline to capture the remaining thermally-heated oil in the pilot area. A vertical well within the horizontal well drive patterns, A-194, will be recompleted into the upper "S" sands. Water injection on the south flank of the project will be added by converting well L-337 to support

increasing production from the horizontal wells. The proposed wells are shown in Figure 3.

Sand Consolidation Well Completion Method

Tidelands has been applying two well completion technologies for horizontal wells including the sand consolidation process and a new opened-hole, gravel-packed, slotted-liner completion procedure that has been successful to date in Tar V wells L-232 and L-233 (DOE Class 3 waterflood project). Tidelands' plan is to develop and improve both completion methods because each has advantages depending upon the type formation sands to complete, reservoir recovery method, existence of interbedded wet sands, and availability of steam or heated fluid source. Having viable and continuously improved completion options will be a key factor in successfully producing more complex customized wells that are drilled and completed to tap specifically targeted oil sands.

The project team plans to perform research to better understand the geochemistry that occurs within the Wilmington Tar zone sands at reservoir pressure when contacted by hot alkaline fluids at varying temperatures and alkalinity. The goal is to improve the sand consolidation well completion process by strengthening the cement bonds between sand grains to withstand more differential pressure without effectively reducing formation permeability around the wellbore. If successful, this research work will duplicate most of the aspects of the sand consolidation well completion process in the laboratory and confirm the mineralogy of the cementing materials being created at different fluid temperatures and alkalinity. The sand consolidation well completion has many advantages over the conventional gravel-packed, slotted –liner completions related to lower capital costs, higher fluid productivity, more reservoir and mechanical control, relative ease and lower cost of repair, and more operational flexibility.

All research to date on the sand consolidation well completion process has been empirical, as in trial and error in the field. Tests to date have been extremely encouraging, but not foolproof. The completion appears to have very high fluid productivity and can endure high flow rates at high water cuts. The biggest weakness observed is that it cannot withstand high differential pressures; therefore the wells cannot be pumped down to maximize fluid production. Even still, typical sand consolidated wells can produce over 1500 barrels of fluid per day with fluid levels over 1000 ft above the pump. The geochemical theory behind the technology is based on wellbore sand fill samples and not on actual cores of sands surrounding the perforation tunnels or lab tests. Lab research will attempt to recreate the process in Wilmington Tar sand cores.

Objectives of Laboratory Research:

1. Confirm sand consolidation process in the lab using typical Wilmington Tar zone cores using different injection fluids with varying alkalinity and temperatures. Confirm whether process is reproducible. The lab research entails performing hot waterflood potential-type tests through selected Tar II-A cores. The water would be at the same temperatures and pressures injected in the field and alkaline will be added to raise the pH to levels equivalent to the steam condensate. These tests will confirm whether our theories of hot alkaline steam condensate causing sand grain dissolution to form "worm holes" and sand consolidation are valid and may possibly show whether the steam vapor phase (or rather the lack of it) is beneficial to the process. Multiple sensitivity cases will be run to get a range of results. The objectives are to confirm the process and how to control it. Positive results may indicate reasons for our successes and failures in wells recently completed with this method and show how we can improve on the process.

2. Define geochemical bonding products and the origin of the products, whether they are from the formation rocks, formation water and/or injected water. The objective is to duplicate the empirical process in the lab.

Conceptual Stanford Lab Procedures
Stage 1: Define the Soups

Objective: Define the geochemical soups created from flowing high temperature alkaline fluids similar to typical steam generator condensate through unconsolidated sand cores from the Wilmington Tar zone. Tests are to be taken at 100°F intervals starting at 400°F to at least 700°F. Additional tests can be taken at 50°F intervals if deemed necessary.

Stage 2: Define the Sand Consolidation Precipitates

Objective: Define the mineral content of the cements that are precipitated at different temperatures onto Ottawa sand. The soup created will be continuously flowed through several ovens at different and declining temperatures, each containing a pressure vessel with Ottawa sands to mimic the precipitation that occurs with distance from the wellbore and as concentrations of various key minerals decline.

Stage 3: Determine the Strength of the Cements

Objective: Determine the strength of the cements binding the Ottawa sand grains in terms of differential pressures and flow velocities they can withstand. Empirically, the sand consolidated completion wells appeared to withstand high flow rates, but not high differential pressure conditions. This stage may also utilize mechanical stress-strain apparatus to measure the amount of compaction the test cores can withstand.

A separate study will calculate the productivity and injectivity indexes and formation well-face skin factors of wells completed with the sand consolidation process. This is an academic exercise utilizing actual well test and fluid level data to calculate the relative productivity and injectivity of the sand consolidation technique compared to other unconsolidated sand well completions.

## Technology Transfer

The project attracted interest from two organizations in Trinidad / Tobago and several papers of interest related to the sand consolidation well completion and formation geochemistry were emailed. No papers or oral presentations were made this quarter.

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.

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