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Report Title:	Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies
Report Type:	ANNUAL
Reporting Period Start Date	04/01/2002
End Date:	03/31/2003
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Report Issue Date:	08/25/2003
DOE Award No.:	DE- FC22 -95BC14939
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ABSTRACT

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California through the testing and application of advanced reservoir characterization and thermal production technologies. The successful application of these technologies will result in expanding their implementation throughout the Wilmington Field and, through technology transfer, to other slope and basin clastic (SBC) reservoirs.

The existing steamflood in the Tar zone of Fault Block II-A (Tar II-A) has been relatively inefficient because of several producibility problems which are common in SBC reservoirs: inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil and non-uniform distribution of the remaining oil. This has resulted in poor sweep efficiency, high steam-oil ratios, and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery and reduce operating costs, including:

1. Compiled a computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data to enable work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models.
2. Developed a basic reservoir engineering study to evaluate the role of aquifer water influx, determined the original oil in place from gas production data to support the material balance work, and calculated the cumulative oil, gas and water recovery from the Tar zone.
3. Developed a new, cost-effective procedure to analyze new core data and correlations to revise old core analysis data.
4. Developed a neural network system and tested a procedure for correlating geologic markers in turbidite sequences.
5. Tracer studies to track water salinity and non-radioactive chemicals provided mixed, but valuable results for future tracer work.
6. Developed a petrophysical rock-log model that identified five rock types to describe the sands and shales within the “T” and “D” formations in Tar II-A. An associated study evaluated stress-dependent porosity and permeability in unconsolidated sand formations.
7. Developed three-dimensional (3-D) deterministic thermal reservoir simulation models to aid in steamflood and post-steamflood reservoir management and subsequent development work. The development of a 3-D stochastic thermal reservoir simulation model was completed through the geostatistical analysis of formation porosity and permeability in the Tar II-A.

8. Developed computerized three-dimensional (3-D) visualizations of the geologic and reservoir simulation models to aid analysis.
9. Performing detailed studies on the geochemical interactions between the steam, formation rock and associated fluids.
    a. *Researching the use of steam injection to create sand consolidation well completion in unconsolidated sand formations.
    b. Completed study on mineralogy and source of wellbore scales.
    c. *Evaluating shale sensitivity to steam and heat.
10. Drilled three observation wells and two core hole/observation wells to monitor steam drive operations and to obtain critical log and core data for the stochastic geologic and reservoir simulation models.
11. Drilled and completed four horizontal wells in Tar II-A utilizing a new and lower cost drilling program.
12. Installed a 2100-ft, 14" insulated steam line, underneath a harbor channel to Terminal Island to service the four new horizontal wells.
13. Testing and proposed application of thermal recovery technologies to increase oil production and reserves:
    a. Performing pilot tests of cyclic steam injection and production on new horizontal wells.
    b. Performing pilot tests of hot water-alternating-steam (WAS) injection in the existing steam drive area to improve thermal efficiency.
14. Performing pilot steamfloods with the horizontal injectors and producers in the Tar II-A and Tar V using a pseudo steam-assisted gravity-drainage process.
15. Performing advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.
16. *Developed and implemented a post-steamflood operational plan for Tar II-A based on the 3-D reservoir simulation model to address the loss of steam injection and apparent steamflood-related surface subsidence.
17. *Maintaining post-steamflood reservoir fill-up of steam chest using flank cold water injection.
18. *Reservoir pressure monitoring system developed for post-steamflood operations.
19. Developed a scrubber to strip H_2S from steamflood-related produced gas streams at less than half the previous cost.
20. Developed a 7ppm NO_x 50MMBtu/hr oil field steam generator for Tar V steamflood that uses the non-commercial low Btu produced gas from Tar II-A steamflood.
21. *Expanded the steamflood project to include the five well horizontal steamflood pilot in the Fault Block V Tar zone.
22. *Test new well completions for controlling sand in unconsolidated sand formations.

Note: The items listed above with asterisks (*) are activities that are addressed in this report and are either ongoing or have been completed.

The Project Team Partners include the following organizations:

1. The City of Long Beach - the operator of the field as a trustee of the State of California-granted tidelands;

2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in-charge of implementing the project;

3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and

4. GeoSystems, formerly David K. Davies and Associates - consultants to the project regarding petrography, rock- based log modeling, and geochemistry of rock and fluid interactions.

5. Stanford University, Petroleum Engineering Department – consultants to the project, performing laboratory research on sand consolidation well completion process effective January 2003.

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EXECUTIVE SUMMARY

Introduction

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California. This is realized through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves the implementation of thermal recovery in the Tar zone of Fault Blocks II-A (Tar II-A) and V (Tar V). The more mature Tar II-A steamflood has been relatively inefficient due to several producibility problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

Through March 2003, 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, 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.

The first two years of the project, from March 30, 1995 to March 31, 1997, began with the application of advanced reservoir characterization methods to enable improved design and application of thermal recovery methods, including the drilling of four horizontal steamflood wells and five observation wells. Historical data was compiled and new data was acquired to perform basic reservoir engineering and to develop advanced geologic and rock-log models. A state-of-the-art 2100 ft steam line was installed under a harbor channel to provide steam to the horizontal wells on Terminal Island. The horizontal wells underwent a new completion technique that controls sand production by injecting steam through limited-entry perforations. The injected steam also resulted in high peak oil production rates of 200-300 BOPD per well. Other completed work included a neural network analyzer that can recognize key log traits for correlating sand sequences and a study on the comparative thermal recovery efficiencies of vertical and horizontal wells.

During the next three years, from April 1, 1997 to March 31, 2000, the project experienced the end of the steamflood phase and beginning of the post-steamflood phase in the Tar II-A and the expansion of the DOE project to include the Tar V horizontal well steamflood pilot. Members from all four original project partners performed the studies and the topics encompass the entire range of upstream petroleum technology including reservoir characterization, reservoir simulation, rock mechanics, reservoir surveillance, sub-surface and facility engineering and operations.

From April 1, 2000 to March 31, 2003, the work has focused on the post-steamflood operation in Tar II-A, the Tar V horizontal well steamflood and post-steamflood pilot, developing laboratory procedures to further research on using hot alkaline-steam to create a sand consolidation well completion in unconsolidated sand formations and developing supplemental laboratory tests to narrow the temperature window under which steam injection and heat into the project oil sands adversely affect the competency of the overburden shales.

The remainder of the Executive Summary is divided into two sections, the work completed prior to the current reporting period from March 1995 to March 2002, and followed by the work completed during the current reporting period from April 2002 to March 2003.

Work Completed Prior to Reporting Period

Compilation and Analysis of Existing Data

A computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data was completed to start work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models. Logs from 171 wells were digitized and normalized for use in the rock-log and geologic models. The digitized logs included the electric or induction and the spontaneous potential (SP) and/or gamma ray (GR) for all of the wells and the formation density and compensated neutron logs for the nine cored wells used for the rock-log model. The 171 wells (of over 600 wells penetrating the Tar zone in the area) are distributed throughout the fault block. New data acquired included Measurement While Drilling (MWD) and Logging While Drilling (LWD) data from the installation of four new horizontal wells, open hole logs and conventional cores from five new observation wells and a tracer study.

Advanced Reservoir Characterization

Tar II-A Steamflood

A basic reservoir engineering study was conducted and a report generated that evaluated the role of aquifer water influx, determined the original oil in place from gas production data to support the material balance work, and calculated the cumulative oil,

gas and water recovery from the Tar zone. Allocating oil, gas, and water production to each well and to each zone completed in the wells was a problem because multiple sands were commingled in most of the wells. This problem was evident from using the production and injection well data in the analysis of primary and waterflood recoveries and material balance. For this reason, multiple approaches were used to calculate original oil in place (OOIP) and cumulative oil, gas and water recoveries from the Tar sands. The study included permeability estimates from performance data, compared water injection profile surveys to the allocated injection volumes for each sub-zone, determined vertical communication between sands, evaluated the aquifer for water influx and determined original oil in place from gas saturations to support the material balance work. The quality of the new and old well logs was evaluated for determining log-derived OOIP, oil saturations over time, and the validity of geologic marker picks. The calculated OOIP using the different methods ranged from 98-100 million stock tank barrels of oil, a surprisingly tight range that provided more confidence of the methodologies used and OOIP estimates.

A study was also completed on the projected steam drive recoveries from vertical and horizontal wells and the diagnostic methods for evaluation of steam displacement between horizontal injectors and producers. The study utilized the TETRAD™ thermal reservoir simulator program, a product of Dyad 88 Software Inc. The aim of the study was to compare recovery from vertical and horizontal well completions as a function of reservoir properties, crude oil characteristics, and injection strategies.

A field pilot study demonstrated a low cost and operationally simple reservoir tracer alternative to obtain information about reservoir rock anisotropy from produced water chemistry data. Normally, reservoir tracer work is expensive and generally performed in one batch treatment that can lead to inconclusive results. This study periodically acquired inexpensive water chemistry data from producers to measure naturally existing cations and anions (salinity) in the produced formation water as affected by dilution from the condensed fresh water in the steam in the Tar II-a steamflood project. The project was conducted over a three-month period on two 7.5-acre inverted seven-spot well patterns with two steamflood injectors per pattern and ten producers. The correlation study showed that the reservoir sand connectivity or preferential permeability path of the steam condensate front trended in a northeast to southwest direction, which is consistent with the geological description of interpreted sand deposition. Water salinity data continues to be collected in the Tar II-A post-steamflood project wells to indicate water breakthrough of the injected cold-water to the producers.

Two reservoir tracers, ammonium thiocyanate (AT) and lithium chloride (LC), were injected into two, Tar II-A hot water-alternating-steam pilot injectors on February 14, 1997. The tracer work included issues related to tracer selection, concentrations and volumes and to field sampling, laboratory analyses and interpretation of the produced water results for tracer hits. Samples of produced fluids collected from the first and second rows of producers were analyzed for the ammonium and lithium tracers. The tracer analysis work recorded very few tracer hits above background levels. Upon further review of the tracer selection criteria and steamflood pattern wells

used, the project team believes that the disappointing results occurred because the tracers possibly broke down in the very high temperature reservoir environment and because of operational changes related to the rapid conversion of steam injectors to hot water injectors.

Three observation wells and two core hole/observation wells were drilled in 1995 to monitor steam drive operations and to obtain critical log, core and reservoir pressure data for the stochastic geologic and reservoir simulation models. Observation well OB 2-4 was converted to well UP-950 in July 2001 and producing from the "T" and "D" sands. Core-hole/observation well OB 2-3 will be converted to water injection into the "T" sub-zone sands and renamed well 2AT-64 in the second half 2002. Core-hole/observation well OB 2-5 is still a critical temperature observation well in the Tar II-A Phase I steamflood area. Two observation wells, OB 2-1 and OB 2-2, were plugged and abandoned in 1999 at the request of the surface landowner.

A three-dimensional (3-D) deterministic geologic model was completed using the EarthVision™ 3-D imaging software by Dynamic Graphics, Inc. The geologic model was initially completed in June 1995 with ten defined sand tops in the Tar II-A. The geologic model was used to drill four horizontal steamflood wells and five observation wells, two of which were conventionally cored throughout the two-steamflooded Tar sub-zone formations in the "T" and "D" sands. The geologic model was also used to develop the framework of the 3-D deterministic reservoir simulation model to optimize reservoir management and thermal recovery methods. Since then, the fault picks were re-evaluated and the defined sand tops were increased from ten to eighteen. The model and newly acquired data have identified the existence of a northeast-southwest gradient of higher sand quality, the presence of a major channel sand cutting through the upper "T" sands, and the existence of previously unmapped faults.

A petrophysical rock-log model was completed that identified five rock types to describe the sands and shales within the "T" and "D" formations. Building the model required the development of empirical relationships between the core and log data and the porosity and permeability data. The study was performed on the seven wells drilled from 1988-89 that had modern log suites (gamma ray [GR], resistivity, formation density and compensated neutron) and conventional cores through the Tar sands. Defining the five rock types with similar log and reservoir characteristics is critical for the stochastic geologic modeling as it provides an objective means of predicting petrophysical rock types and permeability profiles for "T" and "D" sands in locations where only minimum log data and no core data are available. The model has been applied to uncored wells within the area to aid in reservoir description and permeability modeling for the stochastic and reservoir simulation models. Another important outcome of this study is that traditional log analysis techniques can significantly overestimate shale content in thin-bedded sands and consequently underestimate oil saturation and net oil sand picks. This modeling technique corrects for that problem.

For the stochastic geologic model, a neural network analyzer was developed to analyze the similarities of various zones and sub-zones in terms of sequence

stratigraphy using GR logs. Sample stochastic grid block models were test run on the 3-D EarthVision™ visualization software to ensure compatibility. A neural network analyzer can identify the unique well log characteristics of geologic markers in turbidite sequences and quickly correlate hundreds of digitized well logs. The required changes in the character of lithology logs / sand-shale, makes the visual correlation often a very difficult task. With over 600 penetrating well logs through the Tar II-A sands, the need for developing a neural network analyzer to expedite the stochastic geologic modeling was evident.

Following development of the 3-D deterministic geologic model, work began on a 3-D stochastic geologic model to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. The reservoir characterization work was first partitioned into sand modeling and shale description projects. Determining sand continuity is of particular importance for turbidite sands, because sand sequences in adjacent wells may look similar but in fact may not be connected because of the lobated nature of the sand sequences. The detailed core analyses work on eleven cored wells located throughout the Tar II-A zone provided the backbone of the stochastic model. The core analysis work on the two wells cored in 1995, OB2-3 and OB2-5, were performed under both in situ overburden pressure of 1800 psi and "routine" minimum pressure of about 300 psi. Most core analysis work performed on unconsolidated sands, including the nine Tar II-A wells cored from 1981-88, use the routine minimum pressure to hold the core sample together. Performing core analysis at higher in situ overburden pressure is cost-effective because the results give lower porosity measurements that more closely match log porosity data. To further refine permeability measurements, core tests were performed under overburden stress to calculate liquid permeabilities compared to the typical air permeabilities measured in the lab. Relatively clean Tar sands that would normally be measured at 700 – 2000 md of unstressed air permeability would have adjusted overburden liquid permeabilities of 300 – 600 md. By analyzing the differences in formation characteristics between the core samples measured under the two pressures, the older core data could be normalized for the stochastic geologic model. Shaliness indicators were identified from density and neutron logs and correlated with the corrected core permeability. The vertical and horizontal geostatistical spatial correlation studies applied the core data work to develop variogram models for the stochastic geologic model.

A sequential gaussian simulator was used to help create the 3-D stochastic geologic model. For input, the simulator used the variogram models of the porosity and permeability fields, density log porosity data, permeability cloud transforms, and permeability-normalized neutron log porosity data. Stochastic simulations were conducted on porosity and shaliness indicators. Permeability fields were generated from shaliness indicator results through cloud-transforms. Detailed shale mapping was partially created based on resistivity and density log responses to define the shale streaks accurately. The shale streaks control the effective vertical permeability. A method for upscaling the model is discussed for porosity, sand permeability and the combination of the shale spatial continuity information and the sand permeability.

The original intent of the 3-D stochastic geologic modeling work was to address the lateral variations in rock geology using geostatistical correlation methods. Upon completion of the geostatistical work, the plan was to convert the 3-D deterministic geologic model and examine various stochastic realizations of reservoir conceptual models for simulation purposes. With the extended time to complete the core analysis work and the unexpected shutdown in January 1999 of the steam injection process in the Tar II-A zone, the project priorities were modified by the City of Long Beach to address their concerns about steamflood-related surface subsidence and how to safely operate the Tar II-A wells during the post-steamflood phase. In mid-1998, stochastic geologic modeling work was discontinued so the project team could concentrate on developing a post-steamflood operating plan using the 3-D deterministic thermal reservoir simulation model.

Tar V Pilot Steamflood

In 1995, five horizontal wells were drilled into the Fault Block V Tar zone as part of a steamflood pilot operation. The wells were drilled on average 1500 feet horizontally within the S_4 sand. Three-dimensional (3-D) geologic modeling and visualization were used from planning through completion of the wells.

A deterministic geological model was created from which the maps and cross-sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than in the earlier Tar II-A project, as the lateral sections of the horizontal wells were in unfaulted areas with relatively little structural relief. Customized 2-D and 3-D visualizations were used during drilling for interpreting the Logging-While-Drilling (LWD) resistivity, gamma ray and well survey data and for monitoring well progress. Map and section plots brought to the rig site allowed the drilling team to correlate real-time drilling to the geologic maps, thus providing a strong confidence factor that drilling operations were on target. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

Overall, the Tar V drilling project was a major technical and economic success. Based on what was learned in the Tar II-A project and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, only one pilot hole in FJ-204 was necessary. As a result, time and money were saved. Well J-203 took only six days from rig up to rig down to drill and case the 4,661 ft measured depth hole.

For the drilling team, having 2-D and 3-D visuals at the rig site stimulated better feedback and established a clearer understanding of how the geology affected drilling performance. Drilling efficiency was improved because 2-D and 3-D visuals provided

the ability to see quickly what a particular directional tool set accomplished. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well drilling budget was based on the Tar II-A horizontal wells. The average savings per well was US$12,400 on directional costs and US$18,000 due to fewer drilling days. In total, US$152,000 was saved on the five horizontal wells drilled. The monetary savings and management's confidence in the 3-D model allowed all five laterals to be extended an extra 12%, on average, effectively increasing the producible area and adding 382,000 stock tank barrels (STB) or 60,734 stock tank m^3 (STCM) of oil reserves.

Reservoir Simulation

For reservoir simulation work, benchmark tests were conducted on several advanced thermal reservoir simulation packages and computer workstations. The project team selected the STARS™ thermal reservoir simulation software by the Computer Modelling Group (CMG) of Calgary. The software was installed on a R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) for modeling purposes.

The 3-D deterministic reservoir simulation model incorporated the 3-D deterministic geologic model for the Fault Block II-A Tar Zone created for this project. The reservoir simulation study started in January 1997. The model consisted of 26,660 grid blocks (43 X 155 X 4 grids), with aquifers on the north and south flanks. The model successfully history-matched primary production in the Tar II-A sands starting in 1938, waterflood operations starting in 1960, and the steamflood pilot and expansion operations starting in 1981. Development work included how the model was built, the key reservoir and modeling assumptions used, the testing of the model to predict waterflood and steamflood performance versus actual rates, and the development of a rock compaction subroutine that was incorporated into the CMG STARS™ thermal reservoir simulation software. During the preliminary runs, the single component oil (dead oil) feature of STARS was applied in simulations to speed up the modeling work. The project team identified two dynamic reservoir processes that significantly affected the history matches: compaction-related deformation of the rock and gas liberation. The formation compaction / rebound irreversibility was quantitatively determined and the contribution of the Tar Zone to the total surface subsidence was also estimated. The model's four layers were expanded to 13 layers to account for steam gravity override to simulate the 20-acre steamflood pilot and 150 acres of steamflood expansions. This increased the number of grid blocks to 86,645. The model was validated when a seven-year projection of oil and water production for the 20-acre steamflood pilot compared favorably with actual total project production data. The model subsequently was able to closely match ten years of production from the 150 acres of steamflood expansions.

The USC and Tidelands project members used the 3-D deterministic thermal reservoir simulation model to develop the post-steamflood plan. The objective was to use the model as a reservoir management tool to convert the high pressure - high temperature Tar II-A steamflood to a cold waterflood in a stress-sensitive formation

without any surface subsidence. The model was used to create multiple sensitivity cases to optimize oil production while accelerating steam chest fill-up within the reservoir by measuring the mass fluid and heat balance effects as they pertained to reservoir pressure. Reservoir pressures in the target 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 pressures too difficult without a viable reservoir model. The model results demonstrated the importance of carefully monitoring and managing the reservoir pressure.

Model sensitivity cases were developed assuming the conversion of various wells to water injection at various rates. The model confirmed the project team's plan to convert structurally downdip wells to create a flank water injection strategy. Whereas the City's initial plan was to idle all producing wells until steam chest fillup occurred from flank water injection, the simulation model successfully provided for limited oil production while filling the steam chest before it could collapse from heat loss to the overburden formation. 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. The model accurately predicted steam chest fillup in October 1999 due in part to operations successfully meeting the model's gross production and water injection rate projections.

A study was performed to quantify the heating of over and underburden shales and sands in a typical Tar II steamflood pattern over a ten year period subsequent to steamflooding. The purpose was to determine the potential for thermal-related shale compaction over time. The CMG STARS thermal reservoir simulator was used to develop a 1/12 of a seven-spot, 2025 grid block (5 x 5 x 81 grids) model to determine how much, how far vertically, and for what length of time the reservoir heat is thermally conducted from the Fault Block II-A Tar Zone steamflood to the overburden and underburden sands and shales. The model mimicked an area in the middle of the steamflood project and had two injectors (one for the T Sand & one for the D Sand), one producer, and an observation well halfway between the injectors and the producer. Two basic scenarios were run, one with continual 500°F hot water injection and one with 135°F cold water injection. Injecting 500°F water for ten years after steam injection only cooled off the steam zone by 53 – 67°F while the shale layers above and below continued to heat up. Injecting 135°F cold water to maintain a 90% hydrostatic reservoir pressure in the T and D sands would cool the reservoirs to 135°F within five years after the steam was shut-in.

Reservoir Management

Four Tar II-A horizontal wells (two producers and two steam injectors) were drilled in late 1995 utilizing a new and lower cost drilling program. The four wells were drilled with measured depths of 4380-4820 ft and 1700-2075 ft of section in the target

"D1" sands at a true vertical subsea depth ranging from 2410-2660 ft. The two steam injectors were completed with eleven 0.25" limited-entry perforations over an interval range of 330-465 ft at the end of the wells. Both wells underwent cyclic steam injection to consolidate the sand grains in the perforation tunnels to control sand movement into the wellbore and to thermally stimulate oil production. The two producers were completed across the same correlatable interval as the injectors but with 36-48 quarter inch perforations to increase productivity. Both producers were cyclically steamed after the injectors.

A 2100 ft steam line was installed under the Cerritos Channel and placed in service in December 1995 to provide steam to Terminal Island for the four horizontal steamflood wells. The steam line operated without problems until it was idled in January 1999 with the loss of the Harbor Cogeneration Plant steam source.

Two pilot projects were envisioned for the horizontal wells, one for cyclic steam stimulation and the other for steamflooding. Cyclic steam stimulation was initiated in injection wells 2AT-61 and 2AT-63 (146,000 and 186,000 bbls steam, respectively) during the first half of 1996 and production commenced in early summer. Gross production ranged from 1200-1600 BPD/well compared to projected production rates of 2100 BPD/well. Peak oil production rates ranged from 41-60 BPD/well compared to projected rates of 300 BPD/well. Production wells UP-955 and UP-956 underwent cyclic steam stimulation (114,000 and 183,000 bbls steam, respectively) during the second half of 1996. UP-955 achieved cyclic peak production rates of 1267 BPD gross and 105 BPD oil in December 1996, while UP-956 achieved cyclic peak production rates of 1934 BPD gross and 206 BPD oil in April 1997. The four wells initially would accept only low injection rates of about 300-500 barrels of cold water equivalent steam per day (BCWESPD) at 1300 psi injection pressure and 900 psi reservoir pressure. This would increase to the desired injection rate of 1500 BCWESPD per well gradually over two months (process accelerated in two wells by breaking down the perforations with high pressure water). Each well was given a one-month steam soak period prior to initiating production. Cyclic steam production operations in the horizontal wells were disappointing because of the lower than expected peak oil rates and the relatively short peak oil producing period of less than three months. Of note is that all four horizontal wells had no sand fill during well pulling operations, indicating successful sand consolidation jobs.

Injection wells 2AT-61 and 2AT-63 were converted to permanent steam injection in November 1996 and January 1997, respectively, at rates ranging from 1700-2000 BCWESPD. The horizontal steam drive wells have been operated based on a pseudo "steam assisted gravity drainage (SAGD)" technique. The SAGD technique was designed by Butler[D2, D4] and has been tested extensively in the heavy oil fields in Canada. Several articles have been written on the SAGD technique in the Canadian Journal of Petroleum Technology. A good article summarizing the heavy oil recovery techniques used in Canada was written by Polikar and Redford[D5]. The pseudo SAGD method involved completing the last 400-500 ft of the horizontal wells in the most updip section of the reservoir. The horizontal segments of the wells average 1300 ft and were drilled going west to east at a 96-99° angle (going uphill) to compensate for the reservoir dip. The

concept is to concentrate the steam updip in a smaller area to take advantage of gravity segregation of the steam in order to promote earlier development of a steam chest. As the steam chest grows to envelop the producer completion intervals, more perforations will be opened downdip and the updip perforations will be plugged off, if necessary. The pseudo SAGD technique is preferred over a conventional SAGD technique because the Tar zone has more mobile oil (13° API gravity) than the bitumen in Canada and has very mobile free water located primarily downdip and along the bottom of the sands caused by prior waterflooding.

Both horizontal producing wells responded to steam injection in wells 2AT-61 and 2AT-63, UP-955 beginning in April 1997 and UP-956 in September 1997. UP-955 steam drive response peaked in August 1997 at 2102 BPD gross and 200 BOPD. The well maintained good oil rates ranging from 60-170 BOPD until the well sanded up in June 1999. Throughout its producing life, UP-955 always had a high producing fluid level ranging from 1200 – 1700 ft over the pump. The well still has excellent production potential and will be repaired in 2002 as described in the Reservoir Management section. UP-956 steam drive response peaked in November 1997 at 1706 BPD gross and 153 BOPD. The well suffered from pumping short in 1998, which hindered its oil and gross fluid rates and caused the well to have extraordinarily high producing fluid levels from 1500 – 2000 ft over the pump and high water cuts. The well was idled at the start of the post-steamflood project in January 1999. UP-956 was reactivated in October 2000 and quickly experienced the same type of pump problems as before with production averaging 1200 BPD gross and 40 BOPD with a producing fluid level of 1900 ft over the pump. This well, like UP-955, still has excellent oil production potential.

A hot water-alternating-steam (WAS) drive pilot project was initiated in 1995 in four mature vertical well steamflood patterns. Four steam injection wells (wells 2AT-32, 2AT-33, 2AT-40, and 2AT-41) were converted to hot water injection from March 1995 to February 1996. Injection rates ranged from 500-3000 barrels of water per day (BWPD). Steam injection was resumed from February to November 1996 and hot water injection resumed in November at 4400 BWPD. No significant beneficial or adverse production response was observed that could be attributed to the hot waterflood injection. One major difficulty in observing response is scale buildup in the producers, which reduces productivity until the wells are acidized. Four additional steam injectors (wells 2AT-36, 2AT-37, 2AT-44, and 2AT-45) were converted to hot waterflood injection in February 1997. Reservoir tracers were injected into wells 2AT-32 ("T" sand) and 2AT-33 ("D" sand) on February 14, 1997 as described in the Reservoir Characterization section.

Reservoir management at the end of the Tar II-A steamflood phase in 1998 was focused on developing and implementing a post-steamflood plan. The availability of a history-matched simulator for the Tar II-A was quite timely and it became the basis for a reservoir management study of the conversion process.

Thermal-related formation compaction is a concern of the project team due to observed surface subsidence in the local area above the steamflood project. On January 12, 1999, the steamflood project lost its inexpensive steam source from the

Harbor Cogeneration Plant as a result of the recent deregulation of electrical power rates in California. A post-steamflood operational plan was developed and implemented to mitigate the effects of the two situations by injecting cold water into the flanks of the steamflood. The purpose of flank injection is to increase and subsequently maintain reservoir pressures at a level which would fill-up the steam chests in the "T" and "D" sands before they can collapse and cause formation compaction and prevent the steam chests from reoccurring. Intensive reservoir engineering and geomechanics studies have been performed to determine the possible causes of formation compaction and the best ways to operate the Tar II-A zone in post-steamflood mode while minimizing any future surface subsidence.

The new 3-D deterministic thermal reservoir simulation model was used to provide sensitivity cases to optimize production, steam injection, flank cold water injection and reservoir temperature and pressure. The model provided operations with the necessary injection rates and allowable production rates by well in order to operate the reservoir safely. The model accurately projected reservoir steam chest fill-up by October 1999. Fill-up occurred in the “D” sands in August 1999 and in the "T" sands in October. Steam chest fill-up was accompanied by steeply rising reservoir pressures, as would be expected in a fully liquid, relatively incompressible fluid situation.

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 monthly pressure monitoring program enacted at the start of the post-steamflood phase. To ensure better reservoir pressure control, only a few of the best producers remained active at the start of water injection. Tar II-A oil production declined from over 2600 BOPD from 48 producing wells in December 1997 to about 700 BOPD from eight producers in early 1999. Following steam chest fill-up, it was believed that once the steam chest was filled, the reservoir would act more like a waterflood and production and cold water injection could be operated at lower I/P ratios and net injection rates. In mid-September 1999, eleven additional wells were activated and net water injection was reduced substantially in the “D” sands. This caused reservoir pressures to plummet about 100 psi within six weeks. Starting in late-October 1999, net “D” sand injection was increased and reservoir pressures increased back to steam chest fill-up pressures as of March 2000. Oil production increased to an average rate of 1033 BOPD (5.18% oil cut and 18.3 water-oil ratio (WOR)) and water injection averaged 29,252 BWIPD during the reporting period from April 2000 to March 2001. Most of the 2001 and early 2002 well work resulted in maintaining oil and gross fluid production and water injection rates. Oil production from Aoril 2001 to March 2002 averaged 1086 BOPD (4.97% oil cut and 19.1 WOR) and water injection averaged 31,230 BWIPD. As of February 2002, there were sixteen active producers and eleven active injectors. During the First Quarter 2002, the project team developed a plan to accelerate oil recovery and reservoir cooling within the most mature and hottest Tar II-A 7-spot steamflood patterns and began implementing the proposed well work in March 2002. The “D” sand reservoir pressures have been maintained above 90% hydrostatic levels (approximately 1000 psi) from April 2000 to

March 2002 The "T" sand reservoir pressures were reduced from 97% to 88% hydrostatic levels (approximately 910 psi) from April 2000 to March 2002 with measures being taken to increase pressure back up to 90% hydrostatic.

The reservoir pressure monitoring program is ongoing and a key part of the Tar II-A post-steamflood management plan. This 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 a number of them with 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

A novel well completion technique tailored towards stabilizing unconsolidated, porous and permeable sands has been successfully applied in the Tar Zone of the Wilmington Field. This well completion technique, which involves the application of steam, has been applied in 12 horizontal wells and 22 vertical wells with over 90% of the wells capable of production or injection after two years. This completion has been used in place of the more expensive gravel-packed slotted liner completions. Sand control was achieved without any adverse effects on well productivity. The successful application of this technique has resulted in significantly lower drilling and completion costs, better control of fluid profiles into the well-bore, interchangeability of production and injection wells as they now share common drilling and completion methods, and more workover flexibility.

A geochemical study of the scale minerals being created in the steamflood producing wells was completed that determines the mineralogy and source of the scales and how to prevent their occurrence. Wellbore fill samples (sand, scale, gravel pack) from the existing steamflood wells were analyzed and found to contain several types of scale, including calcites, dolomites, barites, anhydrites, and magnesium-silicates. Although only the carbonate scales are soluble in hydrochloric acid (HCl), performing HCl jobs appear to eliminate most of the wellbore scale damage and increase production to typical Tar zone rates. The problem occurs mostly in wells that produce very hot fluids. To minimize the problem, most of the hot wells are produced with more backpressure on the formation. This initial geochemical study points to the importance of performing more thorough high temperature lab work on the cores and formation fluids before initiating a steamflood.

Operational management focused on the apparent steamflood-related surface subsidence for the Tar II-A project due to shale compaction above the "D" sands. A study was performed to confirm steamflood–related shale compaction, to determine where this phenomenon is occurring, to measure the extent of shale failure and identify the critical temperatures and reactions that occur during shale failure.

The study suggests that the shale compaction process occurs in two stages, an early compaction stage and a late compaction stage. The early compaction stage is a result of a relatively gradual expulsion of fluids from the shales through the matrix pore system into the surrounding sand laminations and its overall subsidence effect is minor. The late compaction stage is a result of fluid expansion causing pore pressures to build up high enough to cause hydraulic microfracturing throughout the shale matrix and its overall subsidence effect can be severe.

The temperature ranges for the early and late compaction stages have not been clearly defined, but evidence uncovered to date can place some temperature limits on the processes. For early stage compaction, clay dewatering is known to start at 60°C or 140°F. Based on paleo-thermometry, a sample of post-steamflooded core in well OB2-5 experienced mineral transformations (chlorites and vitrinite reflectance values) indicative of late stage compaction. The core underwent minimum temperatures of 192 -202°C (398-416°F) to create chlorites and could not have experienced temperatures above 280°C or 536°F or else the chlorites would have dissolved. Vitrinite is a kerogen-based hydrocarbon that provides reflectance values of the highest temperatures it encounters. The vitrinite reflectance values further reduced the upper range to 250°C or 482°F. The native 13°API crude oil tends to coke at approximately 285°C or 545°F and epidotes exist and commonly form at 260-270°C or 500-518°F, so discrepancies still exist. Therefore, it is safe to conclude that early stage compaction starts at 60°C or 140°F and late stage compaction starts between 135-192°C or 275-398°F. The upper temperature limits cannot be determined, other than to conclude it is below the steam injection temperature of 316°C or 600°F or to assume the maximum thermal reservoir simulation model temperature of 273°C or 523°F in the shales at the end of steamflood injection. These findings indicate that more ReSpec-type "open" shale compaction tests should be performed, perhaps at 177°C and 218°C (350°F and 425°F, respectively), to determine the critical microfracture temperature and measure the physical expansion and contraction of the samples.

The 2400 ft steam transmission line under the Cerritos Channel was installed and hooked up to the existing steam distribution system and to the new horizontal wells on Terminal Island and placed in service in mid-December 1995. A low initial steam rate of 300 barrels of cold water equivalent steam per day (BCWESPD) was delivered to allow the line to expand slowly. Through the end of December, the steam rate was increased to 600 BCWESPD. By April 1996, the steam rate through the channel crossing was over 2500 BCWESPD and the line has performed very well with no problems. In review, the steam line included a 42 in. bore under the channel, a 30 in. outer line which was pulled through the bore and cemented in place, and dual concentric lines consisting of a 14 in. insulated steam line inserted inside a 24 in. backup line which were pulled through the 30 in. line together.

An improved H_2S caustic scrubber was designed and implemented by a joint team of engineers from T.J. Cross Engineers and Tidelands Oil Production Company, adapting the H_2S caustic scrubber principle proposed by Dow Chemical (Patent No. 2,747, 962). The scrubber is utilized for stripping H_2S from steamflood-related produced gas streams at

less than half the previous cost. The new scrubber process (entitled Lo~CoST^{SM}) improves the caustic mixing system by gas contact by way of an ejector-venturi contactor, followed by gas separation. The added efficiency allows for a lower caustic concentration. A more effective caustic substitute called SulfaTreat^{TM} removes lower H_2S concentrations to < 4 ppm in the latter of a two-stage process. The net cost of removal of a pound of sulfur is $0.43, which translates into a yearly operating cost of $226,000. This is significantly lower than the original four-stage process, which cost $0.74 per pound of sulfur and a yearly operating cost of $393,000.

A 7ppm NO_x 50MMBtu/hr oil field steam generator utilizing the non-commercial low Btu produced gas from Tidelands Operations was installed in the Fault Block V area. The lowest quality gas is produced from the Fault Block II-A, Tar zone. A pilot steamflood was initiated in the Fault Block V, Tar zone in 1996 based on drilling and operating lessons learned in this project and by turning a negative situation (waste gas) into a growth opportunity. The unit was the first 50 MMbtu/hr-steam generator permitted in the Los Angeles Basin since the 1980s. The steam generator, by Struthers, was delivered in February 1996 and system check out started in June 1996. The burner was designed and built by North American Manufacturing Company and guaranteed to emit under 9ppm NO_x without selective catalytic reduction (SCR). NO_x control was dictated by maintaining the air-fuel mix at lean condition. The SCAQMD (South Coast Air Quality Management District) requires that stack emissions data be sent to the SCAQMD via a modem using a Continuous Emissions Monitoring System (CEMS). Stack emissions were in compliance with the SCAQMD guidelines, with stack emissions tested at 5.44ppm without FGR (Flue Gas Recirculation) and a burner not equipped with SCR. A third party stack-testing laboratory, World Environmental, verified this.

Work Completed This Reporting Period

Advanced Reservoir Characterization

Reservoir Simulation

The project team began updating the Tar II-A post-steamflood model from June 1999 to June 2003 to provide a comparison of model projections to actual reservoir temperatures and pressures for the past four years and to evaluate alternatives for reducing peak reservoir temperatures to safe levels below 350EF throughout the project area. The actual temperature data are from gross fluid production from individual wells and temperature profile surveys. The pressure data are from the monthly fluid level surveys and periodic Amerada bomb pressure recordings on idle wells. Once the model is adapted for actual temperature and pressure conditions, using it can help optimize the post-steamflood operations by increasing oil production rates, minimizing operating costs and addressing the remaining high reservoir temperature areas that have contributed to thermal-related formation compaction.

A new 3-D deterministic reservoir simulation model is planned for the Tar V steamflood pilot, similar but simpler than the Tar II-A model, to determine the status of reservoir heating from steam injection. The model will estimate the temperatures and pressures throughout the reservoir over time and forecast gross fluid production and injection rates to prevent formation compaction. The Tar V project, unlike the Tar II-A project, has only a few temperature observation wells that provide an indication of reservoir heating, but not a comprehensive three-dimensional estimate over the entire project area. Optimizing steamflood operations and oil recovery will require a 3-D deterministic model. This work will need to be performed during Budget Period 2.

Reservoir Management

Tar II-A Project

The Tar II-A post-steamflood operational plan was successful in filling the steam chests in the "T" and "D" sands and significantly reducing further surface subsidence in the steamflood area. Most of the 2001 and early 2002 well work resulted in maintaining oil and gross fluid production and water injection rates. As of February 2002, there were sixteen active producers and eleven active injectors. During the First Quarter 2002, the project team developed a plan to accelerate oil recovery and reservoir cooling within the most mature and hottest Tar II-A 7-spot steamflood patterns and began implementing the proposed well work in March 2002. The plan included converting a number of wells to flank water injection and activating several producers that had been idle since post-steamflood operations began in January 1999. The plan also included injecting water into an interior pattern injection well in the "D" sands to observe whether the formation can withstand the extreme temperature changes without serious compaction problems in the sands or shales. Activating idle producers to test them hurt production results because better wells had to be idled to meet injection / production ratios and many of the activated wells tested at very high water cuts. Twenty producers and five injectors were activated or worked over from March 2002 through March 2003. The Tar II-A project averaged 1,102 BOPD (3.45% oil cut and 27.4 WOR) with 43,836 BPD water injection during the First Quarter 2003. Several producers have experienced water breakthrough and high water cuts from the increased water injection and were idled. As of March 2003, there were twenty-five active producers and fourteen active injectors. The project team is continuing to activate and repair wells to accelerate oil recovery and reservoir cooling. Reservoir pressures in the "T" and "D" sands were at 89% and 93% hydrostatic pressure levels, respectively, in March 2003, within the desired 90±5% hydrostatic levels.

Once good reservoir pressure control is maintained in both the "T" and "D" sands at 90% ±5% for a year, reservoir pressures will be allowed to gradually decline about 2% hydrostatic pressure per year until overall reservoir pressures approach the 80% hydrostatic pressure level, as this is the pressure theoretically necessary to keep the saturated steam in the reservoir in solution (approximately 900 psi steam is at 532°F).

As mentioned earlier in the completed work section, the reservoir pressure monitoring program is ongoing and a key part of the Tar II-A post-steamflood management plan. High confidence with this technique is allowing the current ramp up of Tar II-A production and injection, the results of which will be provided in this and subsequent reports.

Tar V Steamflood Pilot Project

As the Tar V fluid production temperatures began to exceed 350°F in the center horizontal production well J-203, a self-imposed temperature maximum limit was reached and the pilot steamflood was converted to a hot waterflood project in June 2001. On April 19, 2002, hot waterflood injection was terminated and the pilot was converted to post-steamflood operation with only cold water injection into the four peripheral vertical injectors and the two former horizontal steam injectors. The post-steamflood production performance in the Tar V pilot project has been below projections because of wellbore mechanical limitations. Horizontal well J-205 produced about 1685 BGFPD and 70BOPD until May 2002 when the well sanded up. A gravel-packed inner liner was installed in October 2002 to restore sand control, but the well completion experienced formation damage as the well was only produced 1500 BGFPD and 40 BOPD pumped off following the job and fluid production was declining through March 2003. A deeper zone producer well, L-337, was recompleted into the Tar zone and converted to water injection well FL-337 in November 2002 to supplement injection so the horizontal producer rates could be increased and to support a new horizontal well, well A-605, to be drilled in the second quarter 2003. Well FL-337 is located to the south of the pilot, provides more reservoir pressure support for surface subsidence control similar to the flank water injection in the Tar II-A project, and was injecting 2000 BWIPD at 1080 psi in March 2003. Another deeper zone producer, well A-194, was recompleted into the Tar zone with selected perforations and an inner liner gravel pack in February 2003. The well has severe formation damage and even after acid stimulating, it only produced 38 BGFPD and 6 BOPD in March 2003. The well is strategically located next to horizontal injection well FJ-204 and was completed high in the S4 steamflood sands to take advantage of the remaining heat in the reservoir.

Plans have been approved to drill and complete well A-605 as a Tar V horizontal producer in the second quarter 2003. The well will be located along the north-south leaseline between Tidelands and Thums Long Beach Co. and perpendicular to the five horizontal wells to capture heated oil in the upper S4 sands.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. Thermal operations in the Wilmington Field were curtailed when the hot waterflood was terminated and recent facility modifications to purify and sell the natural gas production will make future steam more expensive to generate from the existing 50 MMBTU/hr steam generator. Favorable terms for obtaining steam were not expected to be available in the future. Future expansion of thermal recovery to

other parts of the Wilmington Field and other SBC reservoirs will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of the project.

Operational Management

The project team completed developing laboratory research procedures to analyze the sand consolidation well completion technique and a contract was approved with the Stanford University Petroleum Engineering Department to initiate work effective January 6, 2003. By the end of March 2003, Stanford was preparing the laboratory equipment and cores for the experiments. The main objective of the research is to see if the sand consolidation process can be duplicated in the laboratory. If so, then the objective will be to optimize and possibly commercialize the process. The sand consolidation well completion technique has been field tested on an empirical basis on thirty-five wells and proven to be a superior method that offers higher productivity, more operating flexibility, and significantly lower costs than the conventional open-hole, gravel-packed, wire-wrapped screen completions used to control unconsolidated sands. No failures can be attributed to the sand consolidation process in the twenty-two jobs performed on vertical wells. Several of the vertical and horizontal wells have over six years of sand-free service as producers and/or injectors.

Six of the thirteen sand-consolidated horizontally completed wells have sanded up for different reasons. To date, most of the wells with continual sand problems (wells J-201, J-205, J-17, A-113) are in the Tar V and Upper Terminal V zones and received their steam from the 50 MMBTU/hr steam generator on Parcel A. One possible explanation for the completion failures is that the steam generator was not outputting enough 80% quality steam because of operational problems related to using a fuel gas with variable BTU content. With the varying BTU gas fuel, a sudden flow of high BTU gas could cause the generator to create 90 - 100% quality steam before the controls could adapt, causing the generator to either shut down or the steam tubes to scale up. Therefore, the steam generator was operated to make an estimated 50 – 65% quality steam, which provided more operating flexibility. No doubt, the lower quality steam resulted in lower alkaline pH condensate that could have affected sandstone dissolution rates and volumes. A possible problem related to cyclic steam injection into the deeper Upper Terminal Zone well J-17 was that reservoir pressure was too high compared to the steam generator injection pressure (1200 psi compared to 1550 – 1600 psi) which resulted in too low an injection rate and a long drawn out injection cycle that probably experienced heavy heat losses. The sand consolidation process requires high steam injection rates to ensure each perforation in the well is being treated. When the rates are too low, only the sands with the highest permeability will get treated. The other two well failures occurred in wells SF-1 and UP-955. Well SF-1 was one of the first two horizontal wells in the field and was completed with a blank, uncemented liner, therefore the well had no way to isolate steam into perforations. Well UP-955 produced for thirty-one months at high gross fluid rates ranging from 1500 - 2400 BGFPD and high water cuts before sanding up, very good performance under the circumstances.

Four of the wells (J-201, J-205, J-17 and SF-1) were resteamed to reconsolidate the completions and all produced successfully for at least eighteen months. All except J-201 sanded up again. The completion failures will be evaluated to determine the weaknesses of the sand consolidation process and whether any completion or operating procedures can be changed to minimize the problem.

In light of the problems encountered with the sand consolidation completion, Tidelands has researched and applied different state of the art gravel-packed, slotted-liner completions for horizontal wells to maintain operating flexibility. In particular, the project team tried a new inner liner gravel pack technique for workovers and newly drilled wells and a new open-hole, slotted liner gravel-packed completion procedure for new wells to provide sand control.

Workovers were performed on two horizontal producers, one in the Tar II-A (UP-955) and one in the Tar V (J-205) to restore sand control and improve fluid productivity by installing inner liner gravel-packed completions to back up the current sand consolidation completions. The job on UP-955 has been successful in restoring full productivity to the well (1668 BGFPD and 58 BOPD with 1920 ft of fluid over pump), but J-205 experienced severe formation damage (1270 BGFPD and 37 BOPD with fluid at the pump) and requires an acid job or other stimulation technique to restore full productivity. The sand consolidation completions can fail if the wells are pumped too hard because the high differential pressures pull the formation sands into the wellbores. Theoretically, the wells like UP-955 could produce at 100 - 300% higher rates if pumped hard enough to draw the fluid levels down to the pump. The proposed inner liners were designed to allow the wells to be pumped at rates up to 3000 BGFPD, which is the limit for the pumping units. The goal is to increase oil production to over 125 BOPD per horizontal well.

Recent new horizontal wells (L-232 and L-233) drilled by Tidelands in the Wilmington Field were completed either with a cased through well with selective perforations and inner liner gravel pack completion (L:-232) or with an open-hole, slotted liner gravel-packed completion for sand control (L-233). The wells were drilled through the completion intervals with measurement while drilling and logging while drilling (MWD/LWD) tools and a sized calcium carbonate polymer mud system to minimize water loss. After reaching total depth, well L-232 had 7-5/8" casing cemented to total depth, selectively perforated, and completed with a gravel-packed 4-1/2 " wire wrapped screen. Well L-233 had 7-5/8" casing cemented to the Tar zone T sands and the completion interval was drilled with a 6-3/4" bit and opened with a 6-3/4" bull-nosed pilot hole reamer and a 4-1/2" wire wrapped screen was set inside. The 20-40 mesh gravel was packed at a concentration of 0.4 – 1.0 pounds per gallon (ppg) with filtered 9.0 ppg NaCl brine water through the top of the liner. When the gravel packed off prematurely, the tubing was connected to the GPC shoe at the bottom of the liner and gravel was packed through the bottom of the well. Well L-232 has produced since April 2001 and experienced some sand inflow that has caused a few pump failures. Well L-233 has produced problem free since December 2001. Both wells are producing from sands that have not been adequately waterflooded and therefore have relatively low

gross fluid rates ranging from 175 to 600 BGFPD and high oil cuts of 20-40%. Whether this completion technique can withstand high gross fluid rates and water cuts is unknown.

Thermal-related compaction of sands and shales in the Tar zone were studied in an effort to confirm one of the causes of surface subsidence in the Tar II-A steamflood area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are planned to determine the critical maximum reservoir temperature that can be reached before appreciable shale compaction occurs. This information will help determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects.

Project Expansion

The Budget Period 2 plan will utilize the technologies developed in Budget Period 1 to improve thermal and heavy oil recovery from the Tar zones in the Wilmington Field. These technologies include steamflooding, hot waterflooding and post-steamflooding the Tar II-A and Tar V steamflood projects, horizontal well drilling and completion technology, reservoir characterization, pilot testing, geologic and reservoir modeling, and reservoir management techniques. The first part of the plan includes obtaining current reservoir oil saturation data through reservoir simulation modeling, new cased hole logs, or drilling vertical wells penetrating all of the Tar subzones to obtain new open hole logs. This information will determine which sands have bypassed oil in the steamfloods and adjacent waterfloods. Projected well work includes well conversions from injection to production and vice-versa, plugback and selected liner isolation jobs to avoid watered out sands, well recompletions with selective perforations and one or more horizontal wells. New vertical wells will be selectively perforated with either gravel-packed inner liners or sand consolidation completions to increase oil production where existing wells have “watered out” and to replace failed wells. Horizontal wells will be drilled in structurally updip and stratigraphically high locations to improve Tar zone oil recovery in a post-steamflood setting and accelerate reservoir cooling.

The original Budget Period 2 plan to expand the Tar II-A steamflood project was revised because of the loss of the Tar II-A steam source from the Harbor Cogeneration Plant. Steam needed in Tar II-A, if any, would be supplied through a leased portable steam generator. The only anticipated steam needed in Tar II-A would be for sand consolidating new well completions. The Tar V steam generator is currently idle, but can be made operational when needed to service Tar V wells.

The objective of the proposed Budget Period 2 project work is to increase oil production and improve the water cuts and operating cost structure for the Tar II-A and Tar V projects, thereby extending the lives of the projects and increasing oil reserves by an estimated 2-3 million barrels.

Future thermal recovery work at Wilmington must consider potential oil rates and reserves, the cost-effectiveness of the sand consolidation or other completions over the life of the wells, and the sensitivity of the sands and shales to thermal-related formation compaction. The work remaining in Budget Period 1 addresses these concerns and proposed work in Budget Period 2 will utilize the technologies learned from Budget Period 1 and carry them forward.

Technology Transfer

Don Clarke of the City of Long Beach and Chris Phillips of Tidelands wrote a white paper entitled "Three-dimensional Geologic Modeling and Horizontal Drilling Bring More Oil Out of the Wilmington Oil Field of Southern California" which was published in a new 2003 AAPG book entitled "*Horizontal Wells: Focus on the Reservoir*"[2].

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.

Acknowledgments

This research is performed under the Class III Oil Program of the U.S. Department of Energy (DOE), Pittsburgh Energy Technology Center, and contract number DE-FC22-95BC14939. The Contracting Officer's Representative is Gary Walker, with the DOE National Petroleum Technology Laboratory in Tulsa, OK.

The following individuals and companies provided valuable assistance to this project through participation on the project team or as consultants to the team:

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INTRODUCTION

Report Overview

This is the sixth "annual" technical progress report for the project covering the period from April 1, 2002 to March 31, 2003. The contract was awarded on March 30, 1995 and Pre-Award Approval was given on January 26, 1995, however, initial project work began on October 1, 1994. The original Budget Period 1 was scheduled to end on March 31, 1999 and was extended two years to March 31, 2001. In 2001, the contract was extended was given to The first two annual reports submitted covered the period from project initiation to March 31, 1997, the third report covered a three-year period from April 1, 1997 to March 31, 2000 and the fourth and fifth reports covered the period April 1, 2000 to March 31, 2002.

This chapter provides an overview of the project implemented in the Wilmington Oil Field. Subsequent chapters conform to the manner consistent with the Activities, Tasks, and Sub-tasks of the project as originally provided in Exhibit C1 in the Project Management Plan dated May 5, 1995. These chapters summarize the objectives, status and conclusions to date of the major project activities performed during the reporting period. The report concludes by describing technology transfer activities stemming from the project and providing a reference list of all publications of original research work generated by the project team or by others regarding this project.

Project Overview

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project has primarily involved the implementation of thermal recovery in the Tar zone of Fault Block II-A (Tar II-A) and in 1999, the project expanded to include the Tar zone of Fault Block V (Tar V). The existing steamflood has been relatively inefficient due to several producibility problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves

A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery and reduce operating costs, including:

1. Compiled a computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data to enable work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models.
2. Developed a basic reservoir engineering study to evaluate the role of aquifer water influx, determine the original oil in place from gas production data to support the material balance work, and calculate the cumulative oil, gas and water recovery from the Tar zone.
3. Developed a new, cost-effective procedure to analyze new core data and correlations to revise old core analysis data.
4. Developed a neural network system and tested a procedure for correlating geologic markers in turbidite sequences.
5. Tracer studies to track water salinity and non-radioactive chemicals provided mixed, but valuable results for future tracer work.
6. Developed a petrophysical rock-log model that identified five rock types to describe the sands and shales within the “T” and “D” formations in Tar II-A. An associated study evaluated stress-dependent porosity and permeability in unconsolidated sand formations.
7. *Developed three-dimensional (3-D) deterministic thermal reservoir simulation models to aid in steamflood and post-steamflood reservoir management and subsequent development work. The development of a 3-D stochastic thermal reservoir simulation model was completed through the geostatistical analysis of formation porosity and permeability in the Tar II-A.
8. Developed computerized three-dimensional (3-D) visualizations of the geologic and reservoir simulation models to aid analysis.
9. Performing detailed studies on the geochemical interactions between the steam, formation rock and associated fluids.
   a. *Researching the use of steam injection to create sand consolidation well completion in unconsolidated sand formations.
   b. Completed study on mineralogy and source of wellbore scales.
   c. *Evaluating shale sensitivity to steam and heat.
10. Drilled three observation wells and two core hole/observation wells to monitor steam drive operations and to obtain critical log and core data for the stochastic geologic and reservoir simulation models.
11. Drilled and completed four horizontal wells in Tar II-A utilizing a new and lower cost drilling program.
12. Installed a 2100-ft, 14" insulated steam line, underneath a harbor channel to Terminal Island to service the four new horizontal wells.
13. Testing and proposed application of thermal recovery technologies to increase oil production and reserves:
    a. Performing pilot tests of cyclic steam injection and production on new horizontal wells.

b. Performing pilot tests of hot water-alternating-steam (WAS) injection in the existing steam drive area to improve thermal efficiency.

14. Performing pilot steamfloods with the horizontal injectors and producers in the Tar II-A and Tar V using a pseudo steam-assisted gravity-drainage process.
15. Performing advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.
16. *Developed and implemented a post-steamflood operational plan for Tar II-A based on the 3-D reservoir simulation model to address the loss of steam injection and apparent steamflood-related surface subsidence.
17. *Maintaining post-steamflood reservoir fill-up of steam chest using flank cold water injection.
18. *Reservoir pressure monitoring system developed for post-steamflood operations.
19. Developed a scrubber to strip H_2S from steamflood-related produced gas streams at less than half the previous cost.
20. Developed a 7ppm NO_x 50MMBtu/hr oil field steam generator for Tar V steamflood that uses the non-commercial low Btu produced gas from Tar II-A steamflood.
21. *Expanded the steamflood project to include the five well horizontal steamflood pilot in the Fault Block V Tar zone.
22. *Test new well completions for controlling sand in unconsolidated sand formations.

Note: The items listed above with asterisks (*) are activities that are addressed in this report and are either ongoing or have been completed.

The project consists of two budget periods including a research and testing period and an implementation period.

The Budget Period 1 has been applying advanced reservoir characterization techniques and testing thermal production methods as described above to reduce the capital and operating costs of the Tar II-A and Tar V steamfloods. The objective is to justify thermal operations in other SBC reservoirs with similar reservoir characteristics. The papers and presentations as listed in Section 7 on Technology Transfers and in the References section describe all of the technologies applied to this project to date.

The Budget Period 2 plan will utilize the technologies developed in Budget Period 1 to improve thermal and heavy oil recovery from the Tar zones in the Wilmington Field. These technologies include steamflooding, hot waterflooding and post-steamflooding the Tar II-A and Tar V steamflood projects, horizontal well drilling and completion technology, reservoir characterization, pilot testing, geologic and reservoir modeling, and reservoir management techniques. The first part of the plan includes obtaining current reservoir oil saturation data through reservoir simulation modeling, new cased hole logs, or drilling vertical wells penetrating all of the Tar subzones to obtain new open hole logs. This information will determine which sands have bypassed oil in the steamfloods and adjacent waterfloods. Projected well work includes well conversions from injection to production and vice-versa, plugback jobs to avoid watered out sands, well recompletions and one or more horizontal wells. New vertical wells will be

selectively perforated and increase oil production in the downdip areas where existing wells have “watered out” and in the mid-dip and updip areas by replacing failed wells. Horizontal wells will be drilled in structurally updip and stratigraphically high locations to improve Tar zone oil recovery and accelerate reservoir cooling.

The original Budget Period 2 plan to expand the Tar II-A steamflood project was revised because of the loss of the Tar II-A steam source from the Harbor Cogeneration Plant. Steam needed in Tar II-A, if any, would be supplied through a leased portable steam generator. The only anticipated steam needed in Tar II-A would be for sand consolidating new well completions. The Tar V steam generator is currently idle, but can be made operational when needed.

The objective of the proposed Budget Period 2 project work is to increase oil production and improve the water cuts and operating cost structure for the Tar II-A and Tar V projects, thereby extending the life of the projects and increasing oil reserves by an estimated 2 million barrels.

<u>The project is being implemented by a team including:</u>

1. The City of Long Beach - the operator of the field as a trustee of the State of California-granted tidelands;

2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in-charge of implementing the project;

3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and

4. GeoSystems, formerly David K. Davies and Associates - consultants to the project regarding petrography, rock- based log modeling, and geochemistry of rock and fluid interactions.

5. Stanford University, Petroleum Engineering Department – consultants to the project, performing laboratory research on sand consolidation well completion process effective January 2003.

Development and Production History

The Wilmington Oil Field is the fourth largest oil field in the United States, based on the total oil recovered. Almost 2.6 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion barrels.

The field is located in and around the City of Long Beach, in Southern California. Location maps of the field are in Figures 1 and 2. Figure 3 shows an aerial view of Fault Blocks I-VI. Divided into ten fault blocks (Figure 4), the field has seven major producing zones (Figure 5). Heavy oil occurs in the Tar, Ranger and Upper Terminal zones. This project is being conducted in the Tar zone within Fault Blocks II-A and V as shown in Figures 3, 4, 5 and 6.

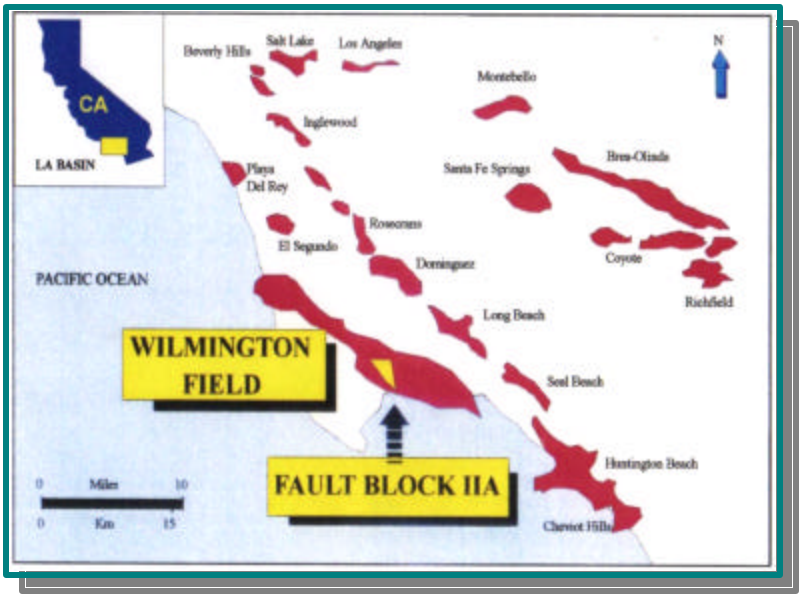


Figure 1: Map showing the geographical location of the Wilmington Field in Southern California.

Primary production from the field began in 1936. Large-scale waterflooding was introduced during the 1950-60s to increase oil recovery and control surface subsidence. Various tertiary recovery projects have been tried, but with only limited success. For most of the producing zones, the dominant form of economic oil recovery remains waterflooding. The current water cut is approximately 96.5%. Recoveries in the waterflood and tertiary recovery projects have been hindered by poor sweep efficiency, as is typical of heterogeneous reservoirs with turbidite geology.

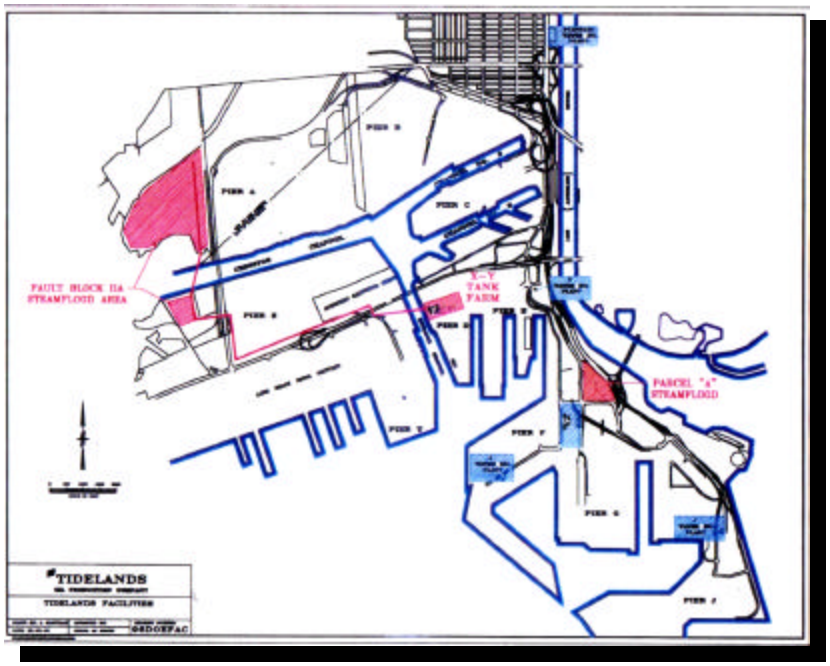


Figure 2: Plan view of Tidelands facilities showing the steamflood zone of Fault Block II-A Wilmington Field.

Tar II-A Production

The Union Pacific Railroad Company first produced the Tar II-A in 1937. The Fault Block II oil operations were unitized for secondary recovery operations (waterflooding) in 1960 to maintain reservoir pressures. Water injection began later that year. The Tar II-A cumulative oil production through 1979, after 19 years of waterflooding, was 20 million barrels; equivalent to a recovery factor of only 20% of the original oil in place (OOIP). These low recovery factors are due to adverse mobility ratio and sand heterogeneity, which have resulted in low areal and vertical sweep efficiencies. Because of the poor waterflood performance, applying steam injection was evaluated to improve heavy oil recovery (13° API). [A1, D3]

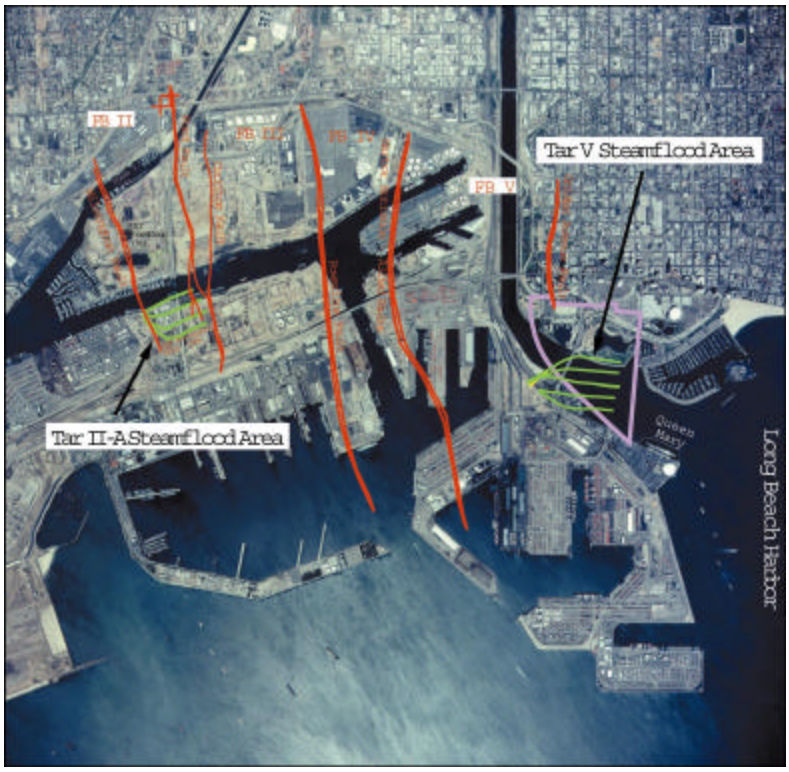


Figure 3: Aerial view of the Wilmington Field showing locations of FB II-A and V steamflood projects.

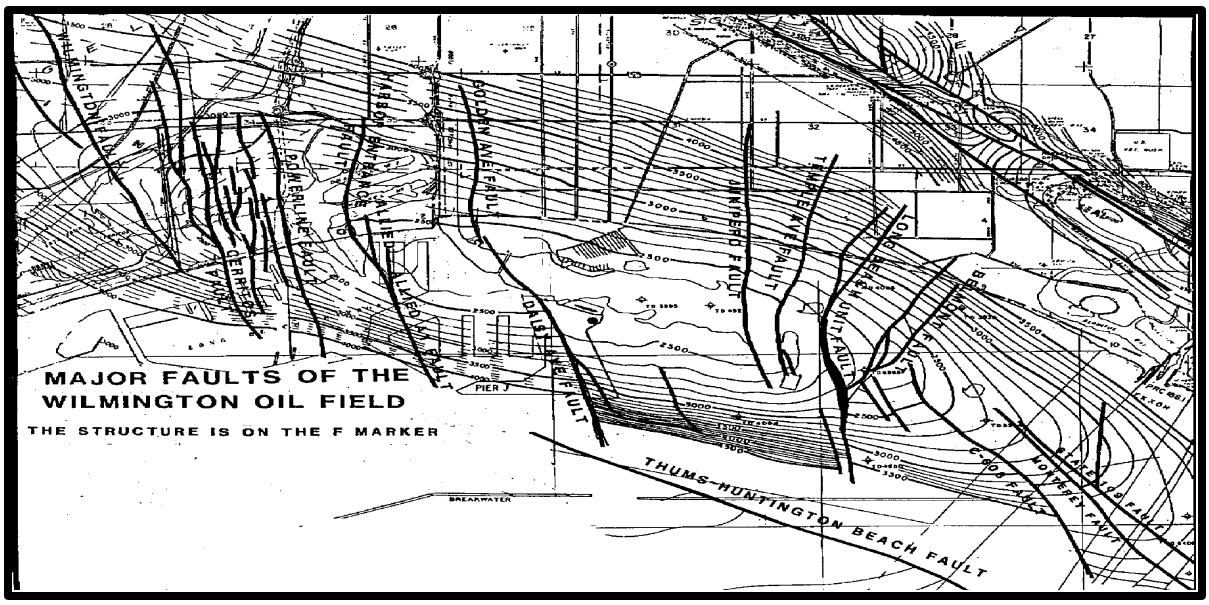
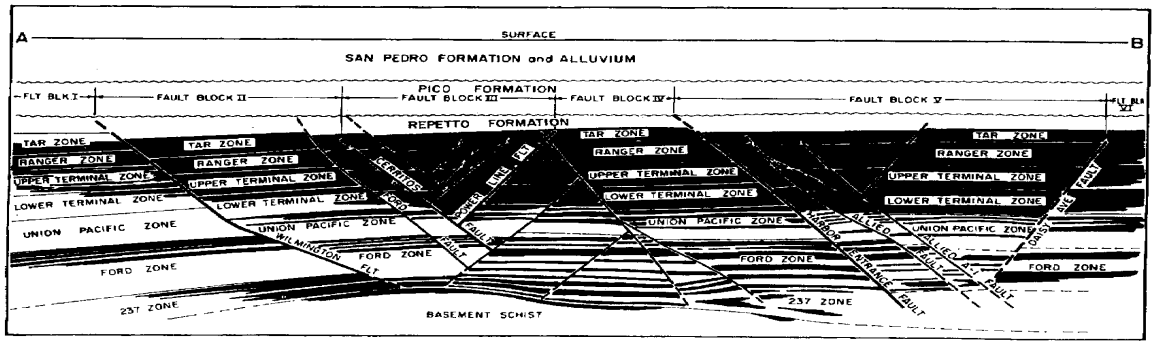


Figure 4: Geologic representation of the Wilmington Oil Field detailing fault line layout.



Northwest-southeast cross section, Wilmington field, showing producing zones. Trace of section is *A-B* on Fig. 1. Source—*California Oil and Gas Fields*, Pt. 2; courtesy California Division of Oil and Gas.

WILMINGTON FIELD, LOS ANGELES COUNTY, CALIFORNIA

Figure 5: Cross-section of a representative sector of the Wilmington field detailing producing zones.

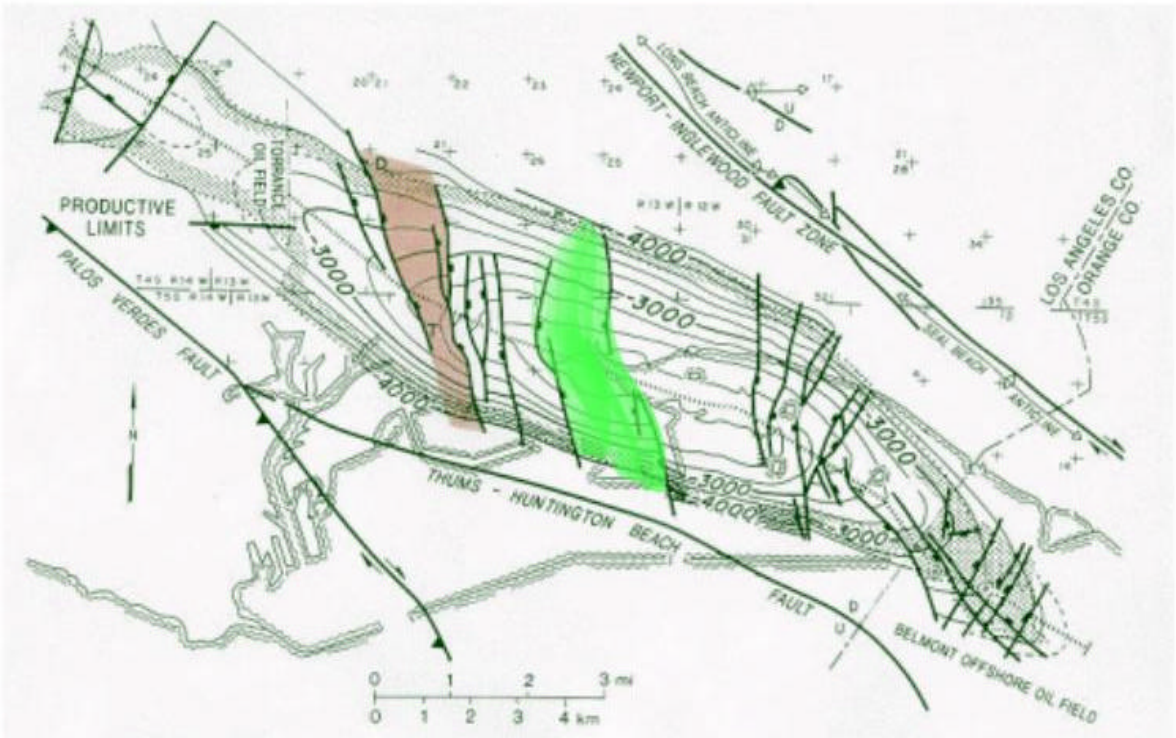


Figure 6: Fault Blocks II-A (red) and V (green), Wilmington Field. Structural contours on Ranger Zone.

Champlin Petroleum, later called Union Pacific Resources Company, performed a successful steam injection pilot test in the Tar zone of Fault Block II-A from 1982-1989.[D3] The pilot project comprised of four inverted 5-acre five-spot patterns and recovered 1.1 million barrels of oil for a recovery factor of 75% OOIP or an incremental recovery of 55% OOIP over waterflooding. The pilot had a reasonable cumulative steam/oil ratio (SOR) of 6.4 barrels of cold water equivalent steam (BCWES) per barrel of oil recovered, with the lowest annual SOR of 5.5 occurring in 1984. Steamflood expansion potential was

considered to be better than the pilot because most of the production wells would be backed up with steam injection from all directions.

The Tar II-A pilot was expanded to 98 acres using an inverted 7-spot pattern in the northern half of the fault block in 1989 (Figure 7). Subsequent phases were added from 1990 through 1995 for a total area under steamflood of 194 acres. The expanded steamflood project did not meet with the same degree of success as the pilot. Although the steamflood achieved peak oil rates exceeding 3,000 BOPD in 1991, the best instantaneous SOR for a month only went as low as 5.5. From 1991 to the end of steam injection in January 1999, steam injection rates maintained an average of 25-32,000 BCWESPD while oil production rates gradually declined to 2,000 BOPD. This resulted in a very high instantaneous SOR in 1998 averaging about 15 and a high cumulative SOR of 9 for the project (Figure 8). The project experienced several downhole and surface operational problems. Well problems included scaling of the slotted liners and downhole pumps and premature equipment failure due to the high produced fluid temperatures accompanying steam breakthrough. Costly and inflexible completion practices were utilized to control

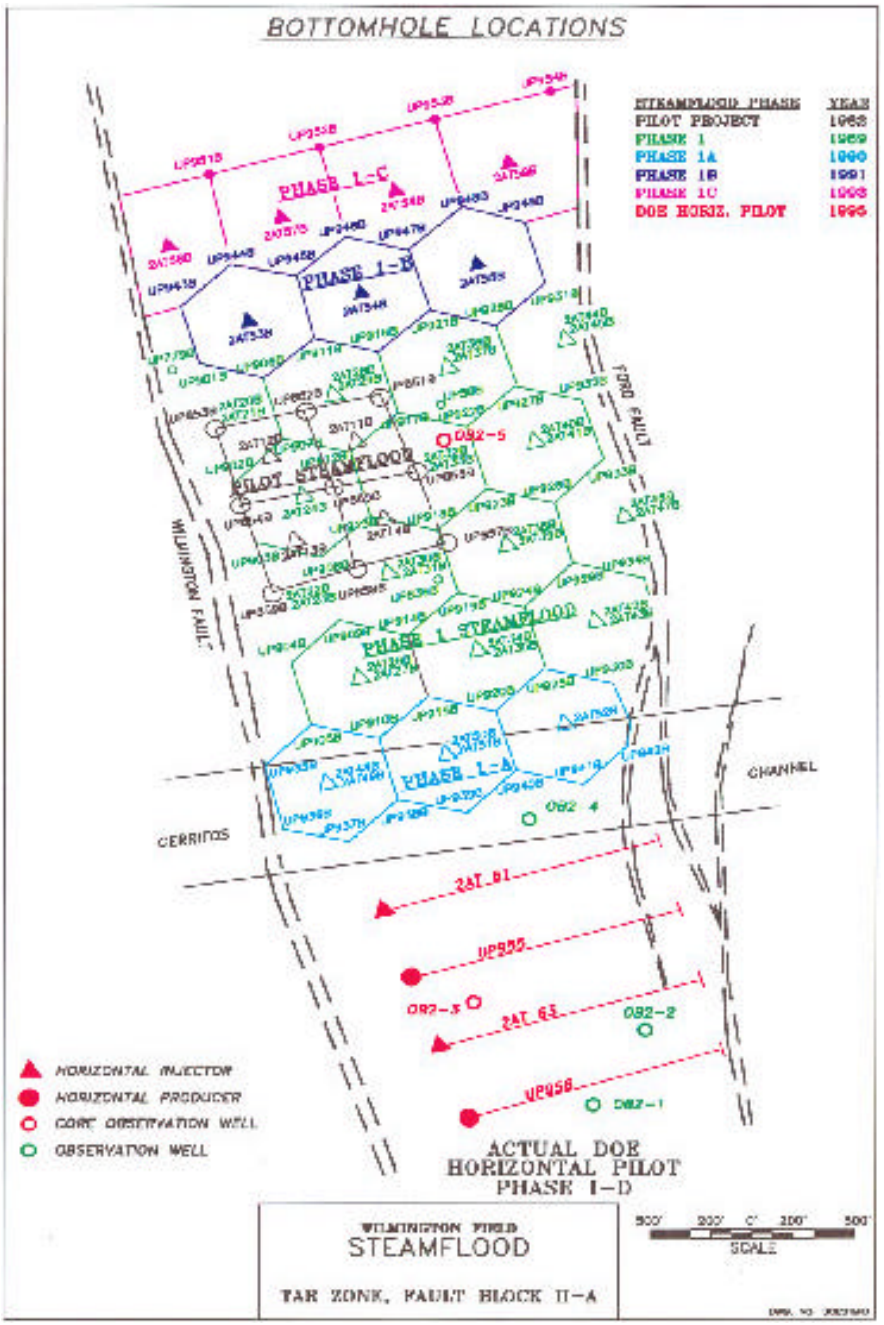


Figure 7: Tar II-A pilot and expansion steamflood projects. The steamflood expansion phases, start dates and well patterns are shown.

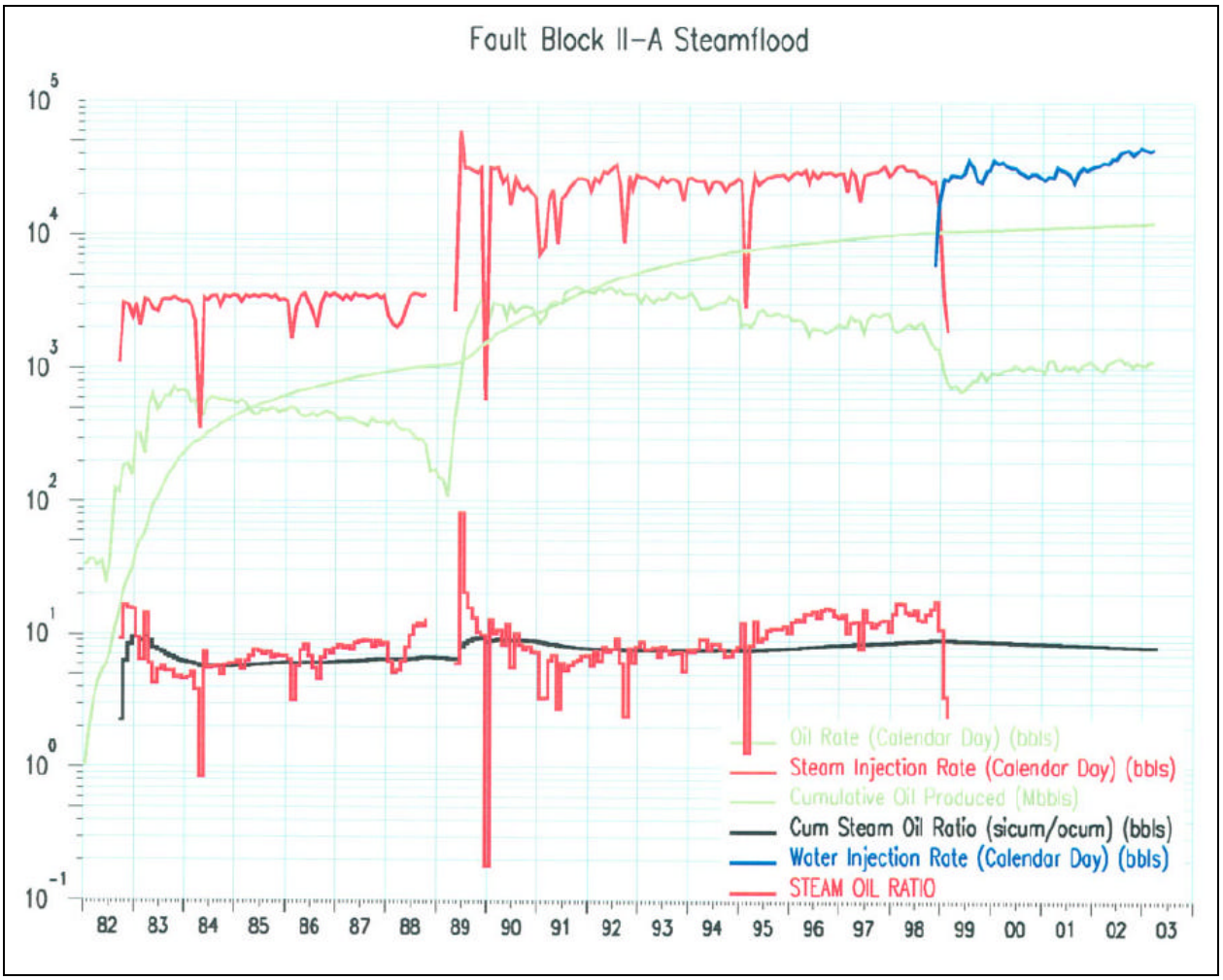


Figure 8: Tar II-A steamflood production and injection from 1/82 to 3/03.

sanding problems that have occurred elsewhere in the field. Surface facility problems included handling the hydrogen sulphide, mercaptans, and carbon dioxide gases created in the reservoir by the steam heat, controlling steam breakout in the production gathering lines, and monitoring tank farm fluid temperatures and pressures for safety and to prevent damage to vessels and pipelines. Many of these types of problems could have been anticipated with a better understanding of the mineralogy of the formation sands and water and the complex turbidite geology of SBC reservoirs in the Tar zone. The steamflood was primarily profitable because of a favorable steam purchase contract with the Harbor Electric Cogeneration plant. Harbor Cogen discontinued supplying steam in January 1999 after Southern California Edison Company purchased its favorable electric power contract through an electric deregulation incentive program.

The Tar II-A project area began experiencing severe surface subsidence just prior to the cessation of steam injection. There were several possible causes, including grading work by the Port of Long Beach that added several tens of millions of tons of compacted fill to the area to expand port facilities, the wholesale abandonment of adjacent waterflood

wells for port expansion that terminated water injection, and heat-related formation compaction in the steamflood sands. The last possibility jumpstarted the development of a post-steamflood operation plan to mitigate the problem. Strategically placed water injection wells along the structural flanks of the reservoir replaced pattern steam injection and gross production was curtailed by 75% to allow reservoir pressure to increase. This caused production to decline from 2253 BOPD and 33,241 barrels of gross fluid per day (BGFPD; 6.8% oil cut) with steam and water injection at 30,118 cold water equivalent barrels per day (CWEBPD) in August 1998 to 725 BOPD and 6145 BGFPD (11.8% oil cut) with water injection at 28,322 CWEBPD) in March 1999. The post-steamflood plan has been successful in significantly reducing surface subsidence and oil production and gross production increased to an average of 1036 BOPD and 20,836 BGFPD (5.0% oil cut) with water injection at 31,230 CWEBPD during the annual reporting period ending in March 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. Production during the current reporting year ending March 2003 averaged 1113 BOPD and 29,077 BGFPD (3.8%) with injection averaging 41,730 CWEBPD. Of the seventeen producers active before March 2002 and the twenty producers activated afterwards, eleven have been idled as uneconomic, mostly from high water cuts. The Tar II-A cumulative oil production through March 2003 is about 39 million barrels for a recovery factor of 39% OOIP.

Tar V Production

The Long Beach Oil Development Company (LBOD), as contract operator for the City of Long Beach, began Tar V production in 1951. Similar to Tar II-A, LBOD and the City of Long Beach implemented a non-unitized waterflood project in the Tar V in 1960 to increase and maintain reservoir pressure at about 80% of hydrostatic pressure or 800 psi to prevent further surface subsidence. The Tar V cumulative oil production through 1960 was 9.8 million barrels or about 5% OOIP. Reservoir pressure in 1960 averaged about 460 psig. After 36 years of waterflooding and just prior to the steamflood pilot, cumulative oil production through 1996 was 50 million barrels for a waterflood recovery factor of 25% OOIP. Waterflood operations in 2003 still represent 75% of the oil production from the Tar V sands. Tar V oil production from April 2002 through March 2003 averaged 740 BOPD, of which pilot steamflood production was 186 BOPD or 25%. Tar V total water injection for the same period was 23,523 BWPD, whereas steam and hot water injection ceased as of April 19, 2002.

Tidelands drilled five Tar V horizontal steamflood pilot wells in late 1995 to early 1996 and production began in late 1996. Figure 9 shows the locations of the wells. The Tar V pilot project was developed based on the Tar II-A horizontal well steamflood pilot. Each horizontal well received a cyclic steam-stimulation job to provide a sand consolidation well completion and to accelerate oil production. All five wells had early peak oil rates ranging from 223 - 328 BOPD. Two of the horizontal wells, FJ-202 and FJ-204, were converted to permanent steam injection following cyclic steam production. Steam drive response for each of the three horizontal producers (wells J-201, J-203 and J-

205) peaked at 91 - 151 BOPD. The three producers had continuously high producing fluid levels and should have been capable of producing at higher peak rates.

Peripheral water injection was increased in March 1998 to boost the project injection to production (I/P) ratio from 0.92 to above 1.05 to reduce the risk of surface subsidence. This operational change adversely affected oil production and water cuts and increased the instantaneous steam-oil ratio (SOR) of the project from an average of 4.3 from June 1996 through March 1998 to 6.9 from April 1998 - March 1999, to 9.5 from April 1999 - March 2000 and to 11.5 from April 2000 - June 2001, when steam injection was ended and converted to hot water injection. Significant oil production has been recovered from three pre-steamflood vertical producers (wells A-186, A-195 and A-320) located within the steamflood area that have recovered 267,491 barrels of oil from June 1996 through March 2003 or 35% of the cumulative steamflood oil recovery. A fourth vertical producer, well A-194, was recompleted to the Tar V pilot area in February 2003. Peripheral water injection in March 2003 is from four wells: FRA-29, FRA-83, FL-337 and FR-111 (Figure 9). A proposed horizontal producer, well A-605, will be drilled and completed in the Tar V pilot area along the north-south leaseline during the second quarter 2003.

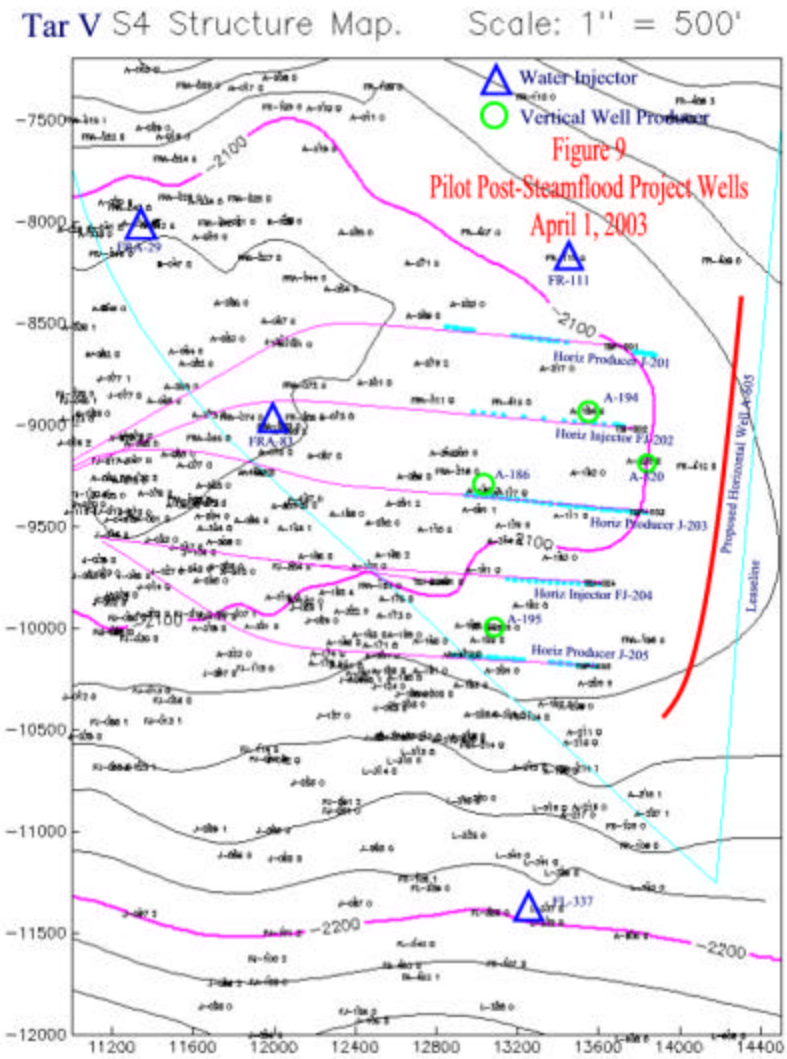
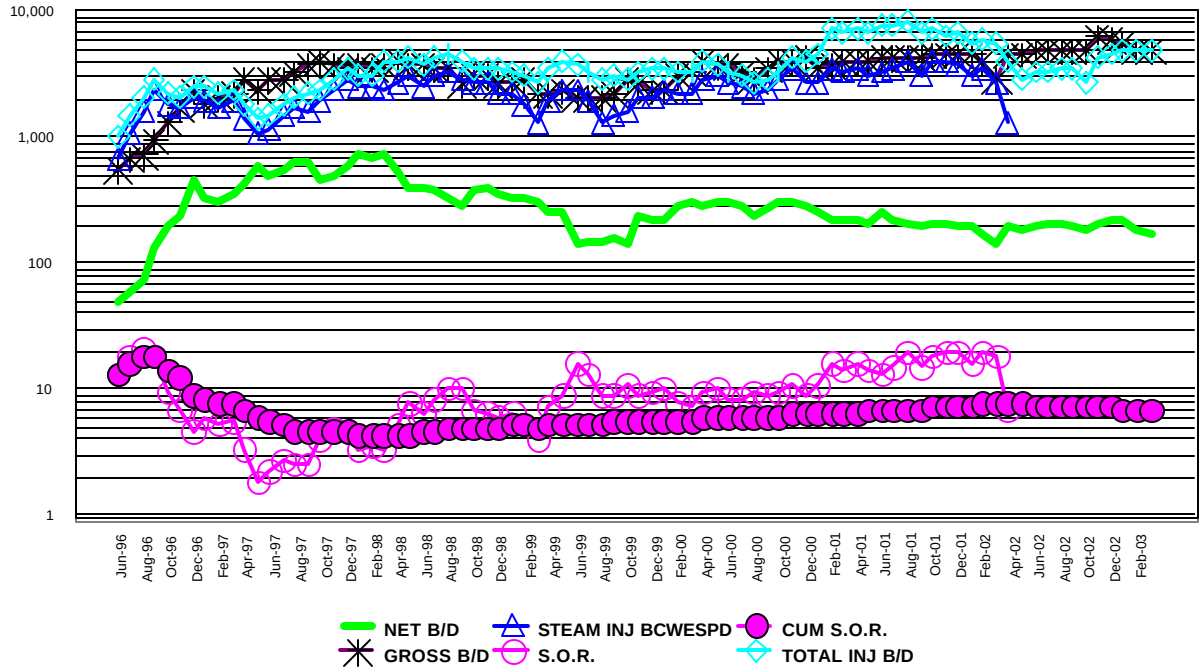


Figure 9: Tar V steamflood project wells as of March 31, 2003, including three horizontal producers (light blue "J" wells), two horizontal steam injectors (light blue "FJ" wells), four vertical infill producers (green circles) and four flank water injectors. (blue triangles)

Cumulative steamflood oil production from June 1996 through March 2003 is 757,137 barrels and current oil production in the first quarter 2003 averaged 201 BOPD. The project was originally estimated to ultimately recover 1.7 million incremental barrels from the steamflood pilot area. Total steam injection rates into Tar V have ranged from

1100 – 3700 BCWESPD, averaging 2637 BCWESPD from June 1996 through June 2001, the end of steamflood injection. The project initially had several months when the steam/oil ratio (SOR) was below 5. The cumulative SOR through June 2001 was 6.9, marginal assuming steam costs based on market-priced fuel. However, the cumulative SOR will improve with time as oil production continues without steam injection. The steam quality for the project probably averaged closer to 60% than 80%, an incremental difference of 107 BTU / lb of steam injected or 11% less heat transfer. Therefore, 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 March 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. Hot water injection into the steamflood project ceased on April 19, 2002. In addition to converting the two horizontal steam injectors to water injection, the pilot post-steamflood project currently has water injection to the northwest, northeast, west, and south to assure reservoir pressure is maintained. Figure 10 is a production and injection graph for the Tar V steamflood project from June 1996 through March 2003.

FIGURE 10
TIDELANDS OIL PRODUCTION CO.
TAR ZONE FB-V STEAMFLOOD



Geologic Setting

The Wilmington Oil Field is an asymmetrical, highly faulted, doubly plunging anticline, eleven miles long and three miles wide (Figures 4 and 6). The productive area consists of approximately 13,500 acres. Fault Block II-A is located near the western edge of the field and is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. Fault Block V is located just west of the center of the field and is bounded on the west by the Harbor Entrance and Allied faults and on the east by the Daisy Avenue and Golden Avenue faults. Neither the Daisy Avenue nor the Golden Avenue faults penetrate the Tar zone. The Tar sands stratigraphically thin and pinch out to the east before reaching the Junipero Fault. From the surface, Fault Block V lies within the eastern-most portion of the Port of Long Beach shipping operations. The north and south production limits of both fault blocks are governed by water-oil contacts within the individual sand members of the various zones (Figures 4 and 6). The seven zones within each fault block listed in order of increasing depth are: Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford and "237" (Figure 5).

Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene (8 –11 million years ago [mya]) and Upper Miocene (11 – 16 mya) age deposits. The Tar zone has the shallowest oil producing sands in the Wilmington Field. These sands are lower Pliocene, middle Repetto formation lobe deposits. The Pliocene age deposits go as deep as the "X" sands in the Ranger zone. The upper Miocene age Puente formations begin with the "G" sands in the Ranger zone and continue through the other five zones mentioned above. The "237" zone overlays a basement schist occasionally capped with a basal conglomerate. The schist is considered Jurassic age (130 – 180 mya), although it has similarities with local Cretaceous (65 – 130 mya) age formations. Wells have been completed into the Schist zone and are oil productive along the anticlinal axis at localized structural highs where the schist is fractured.

During the late Miocene, the Los Angeles Basin experienced a phase of accelerated subsidence during which the Puente Formation and Pliocene age sands were deposited. Structurally, the late Miocene Puente Formation deposits in the Wilmington Field appear to be drape-folded over a relative basement high, with generally thinner beds at the crest of the structure and thicker beds on the flanks. Starting in the middle Pliocene age to the current time, the Los Angeles Basin has experienced significant tectonic activity that has resulted in a major syncline within the central portion of the basin and uplift along the margins, as in the Wilmington – Palos Verdes area. For example, the basement schist top is found at 10,000 ft subsea depth in the Thums area and at 600 ft above sea level in Palos Verdes, a two-mile vertical change within a ten-mile distance! During the late Miocene to Pliocene ages is when the Wilmington Field developed its anticlinal structure. The Pliocene age sands were divided into two units, the Repetto Formation for the early Pliocene sands and the Pico Formation which unconformably overlies the Repetto formation. Both the Repetto and Pico formations contain prolific oil deposits within the Los Angeles Basin. In the Wilmington Field, the top of the Repetto Formation was eroded away, probably by the Pico Formation, which is relatively thin and probably also eroded

away. The Pleistocene (<1 mya) and Holocene (recent) age sediments cover the flat erosional surface of the upper Repetto - Pico sands. They buried the Wilmington anticline under 1,800 – 2,000 ft of horizontal younger beds. The Pleistocene and Holocene sands originally contained fresh water, but now contain filtered, low oxygen-filled seawater because of rapid fresh water removal for domestic and agricultural use in the early-mid 20th century. The Pleistocene Gaspur zone was the prime injection source water for the waterflood projects. [A36, D8, D9]

The upper Miocene Puente and lower Pliocene Repetto formations within the Wilmington Field consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathayal, slope and base-of-slope deposits. The upper Miocene sands are intercalated with shales and siltstones in the form of widespread thin turbidites. Large lobate fans dominate the Pliocene section.

Tar Zone Geology

The Tar zone consists of four major producing intervals, the "S", "T", "D" and occasionally "F_1/F_0" sands. The Tar II-A waterflood and steamflood wells produce from the "T" and "D" sands. The "S" sand has a relatively small oil productive area in Tar II-A that is completely underlain by water, therefore, only a few wells have been completed. The Tar V waterflood produces from the "S", "T", and "F_1/F_0" sands and the steamflood pilot is in the "S" sands. The "F_1/F_0" sands are defined as being in the Tar zone in most of Fault Block V, however, they are defined as in the Ranger zone throughout the rest of the field. Each subzone exhibits typical California-type alternation of sand and shale layers as illustrated by the type logs in Figure 11 for Tar II-A and Figure 12 for Tar V.

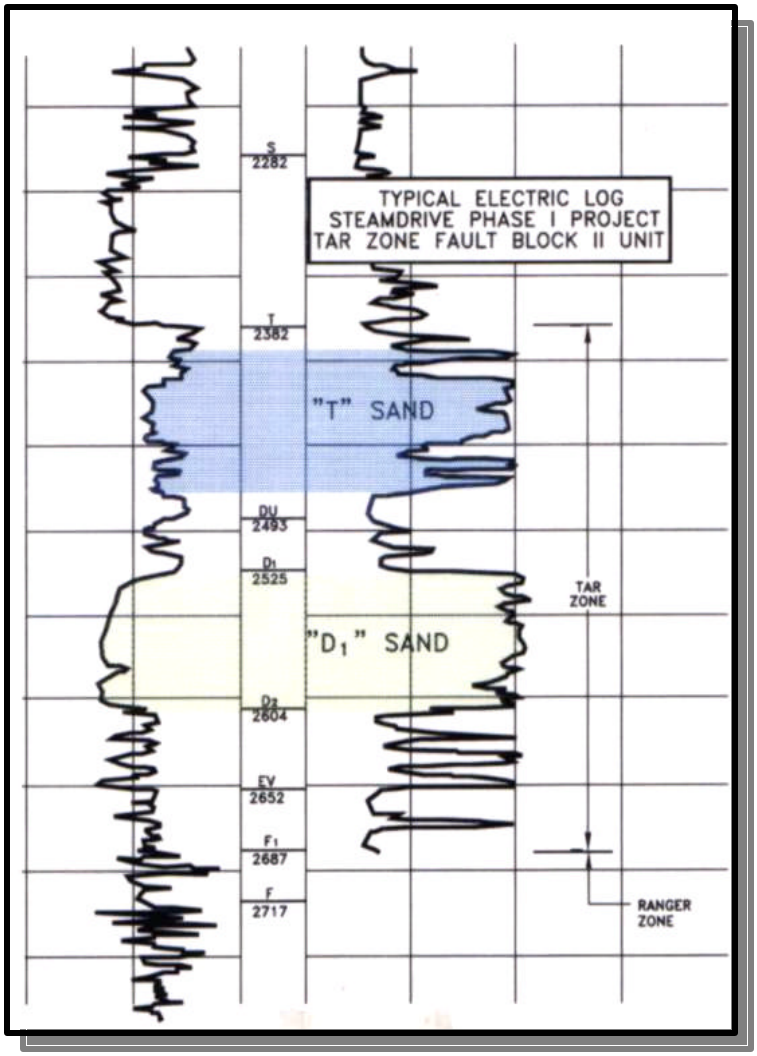


Figure 11: Type Log, Fault Block II-A Tar Zone, illustrating "T" and "D1" sands.

The Tar zone sands tend to be unconsolidated, friable, fine to medium-grained and contain varying amounts of silt. The thickness of the sand layers varies

from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale. The oil is of low gravity, ranging from 12-15° API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 30-35% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2,330 ft below sea level in Fault Block II and at 2,000 ft below sea level in Fault Block V.

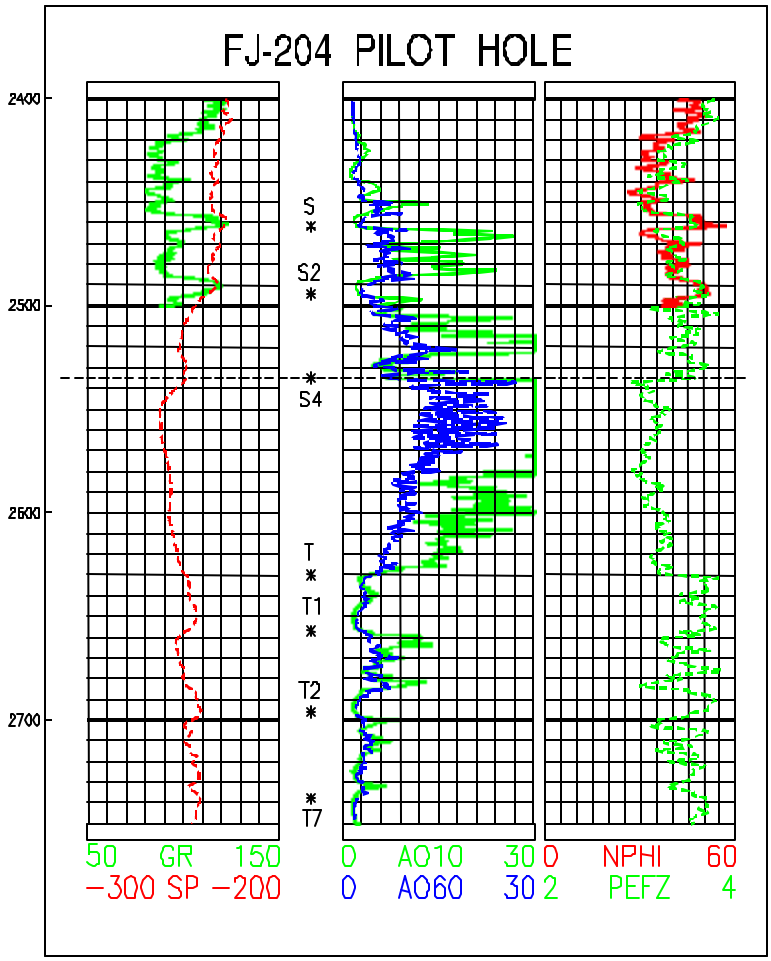


Figure 12: Type Log, Fault Block V Tar Zone, illustrating "S" and "T" sands.

Sedimentological analyses of the textures, sedimentary structures and fossils preserved in the Tar II-A conventional cores reveal that the Tar zone sediments were deposited in several related environments of a deep sea submarine fan system (Figure 13A). The sediments that compose the fan were supplied by gravity-induced flows that transported sands from the northeast (sediment source) towards the southwest (basin of deposition). Sand deposition occurred basinward of a slope break that lay to the east of the present field location. Shales were deposited by differential pelagic settling of fine particles from the overlying water column. The Tar II-A "T" and "D" sand reservoirs represent two unrelated submarine fan systems, as evidenced by the thick, basinal shale that separates them (Figure 11). The "S" sands in Tar II-A and Tar V represent another separate, unrelated submarine fan system that appears similar in description to the "D" sands (Figures 11 and 12). [A32]

Growth of a submarine fan system involves the repeated supply of coarse-grained detritus (sand) by individual gravity flows. The architecture of the reservoir is the result of this growth. Fan growth is accomplished in three ways:

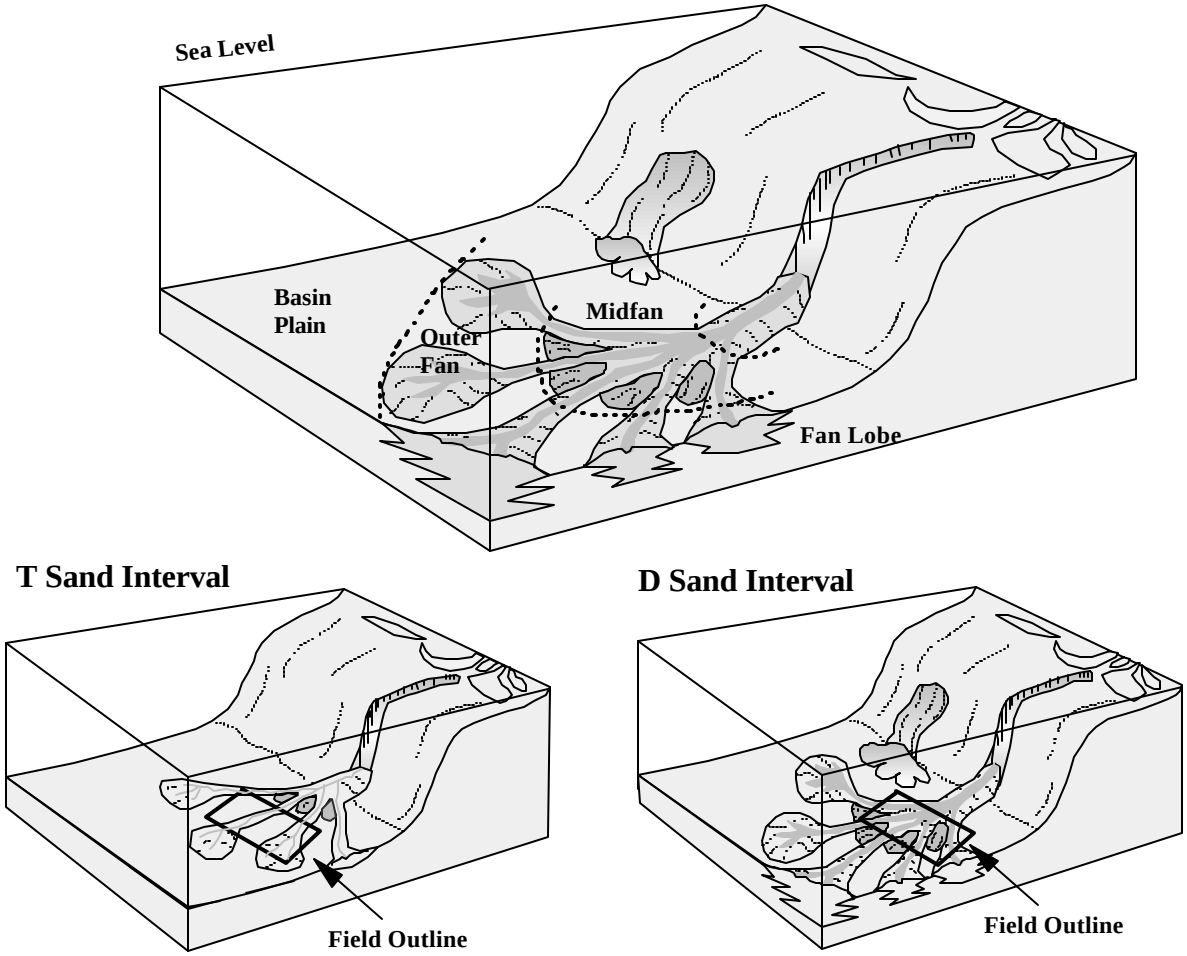


Figure 13: Diagrammatic reconstruction of submarine fan system.

1. Progradation: Sands are deposited basinward of the break-in-slope due to a decrease in flow velocity. Continued supply of sands to the basin floor results in the gradual basinward growth (progradation) of the sand-rich fan system out over previously deposited basin shales.

2. Avulsion and Lobe Switching: As the fan system progrades into the basin, individual feeder channels are avulsed (abandoned) and the feeder channels are re-directed into the topographically low areas adjacent to the existing lobes. As a result, new sand lobes are developed in these inter-lobe areas and the old lobes are abandoned.

3. Agradation: Continued supply of sands over time results in the overall vertical growth (agradation) of the reservoir sand bodies.

The model presented in Fig. 13 represents a submarine fan at one instant of time. The simultaneous operation of progradation, avulsion and agradation over a

period of time results in the random, vertical stacking of the various fan elements. This produces reservoirs that are internally complex and heterogeneous, such as those in the Wilmington Tar zones.

T Sands

The T Sand interval is approximately 85 ft thick (Figure 11). It was deposited in the outer fan environment, specifically in feeder channels and fan lobes (Figure 13B). The reservoir interval has a high degree of internal complexity, much higher than is indicated by a cursory evaluation of the wireline logs. In all conventional cores, the T Sand consists of numerous, thin (2 ft), porous and permeable sand beds each of which is capped by an impermeable shale (see the geological core description, Figure 14).

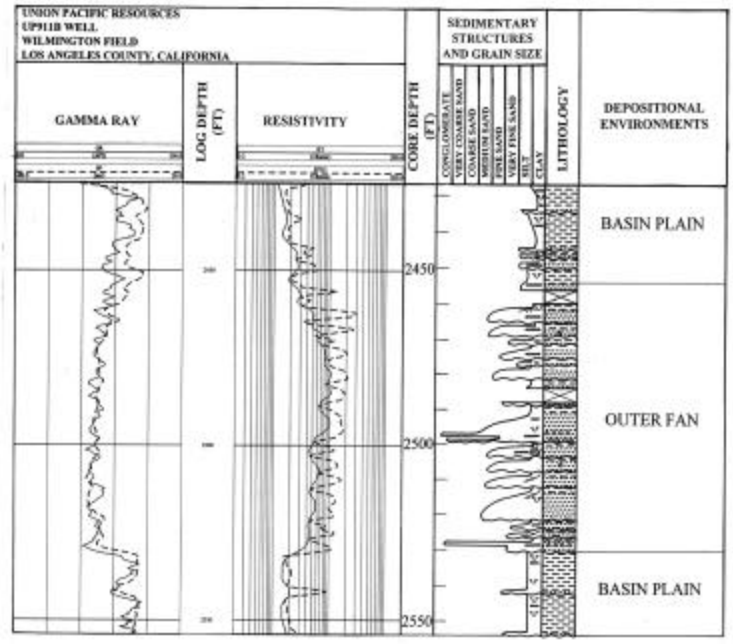


Figure 14: Log response and geological core description, outer fan environment, T Sand interval

Each sand bed was deposited from a single, gravity- driven turbidity current that carried coarse detritus (sand) from the nearby slope out onto the basin plain. Geological and petrophysical characteristics of these sand beds are presented in Figure 15A. The basal contact of individual sand beds with underlying shale is erosive, indicating high energy during sand transportation and deposition. Within each sand bed, grain size fines upwards – a characteristic of many turbidites. This internal, upwards fining of grain size reflects a reduction of current energy (flow velocity and turbulence) with time. The sands that make up most of the thickness (>90%) of any bed (central portion in Figure 15A) are homogeneous; they show little or no vertical change in grain size and contain <1% shale, based on thin section and X-ray diffraction analysis.

Shale beds cap virtually all of the numerous sand beds that comprise the T Sand reservoir. The shale beds are thin (0.5ft) but are known to be laterally very extensive in outer fan environments. The shales form effective barriers to vertical flow and therefore impact significantly the vertical sweep efficiency. In this field, this is demonstrated by the fact that post-steam cores (cores taken in areas of the field that have been swept by steam) show no change of oil saturation in thin (<1inch thick) sand layers that occasionally occur within the shale beds.

The presence of numerous interbeds of pelagic shale causes the T Sand reservoir to be strongly laminated (bedded). The Spontaneous Potential (SP), Gamma

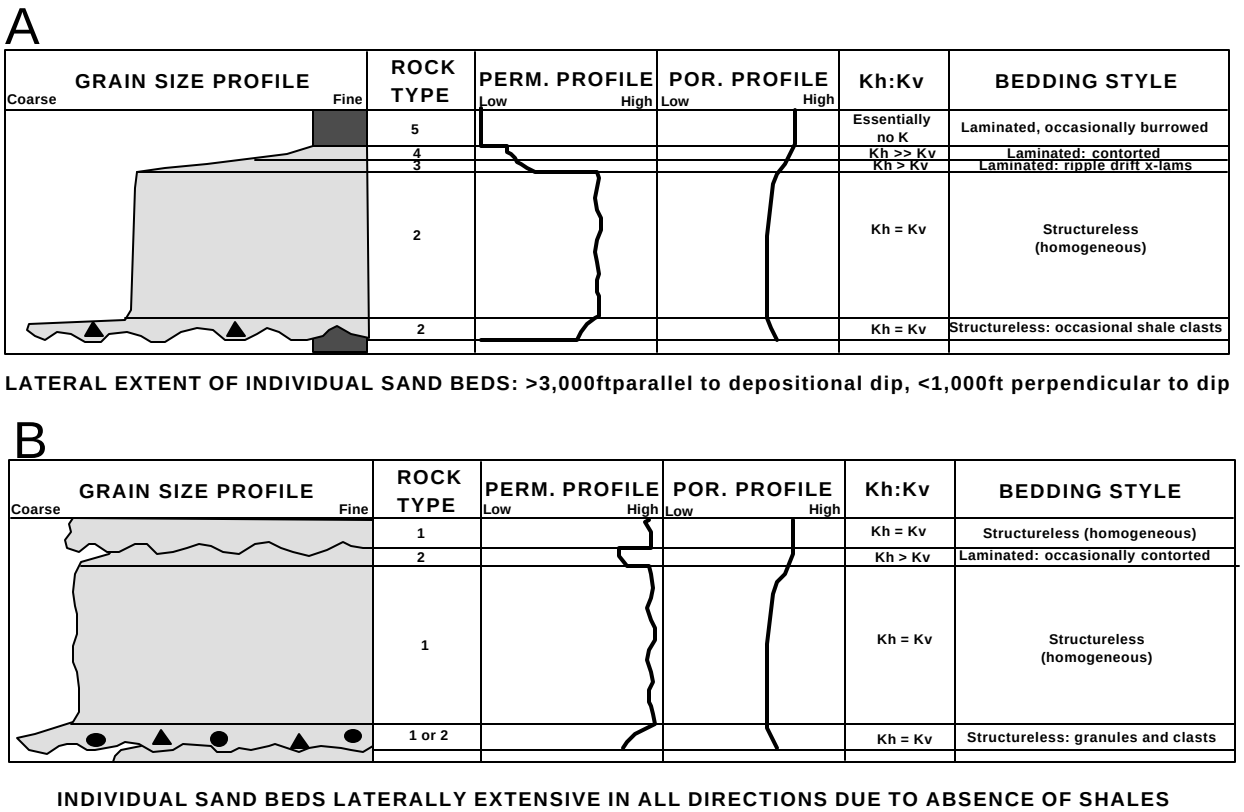


Figure 15: Geological and petrophysical characteristics of individual sand beds: A: T Sand interval; B: D Sand interval. (Not to scale).

Ray (GR) and true Resistivity (R_T) responses do not effectively reveal the highly laminated nature of this reservoir. On the other hand, the flushed zone resistivity (R_{XO}) response gives an improved indication of the high degree of reservoir lamination (Figure 14). High GR response in the T (and D) Sand is the result of the presence of abundant radioactive sand grains (orthoclase feldspar and micas).

A map of the gross thickness of the T Sand interval (Figure 16) reveals a characteristic NE-SW trending pattern of alternately thick and thin deposits. Long, narrow "thicks" (such as in the northern area of the field) are characterized by increased sand content (relative to shale), and they represent the locations of the outer fan submarine feeders that were the main avenue of transport of the sands to the distal lobes. In a general sense, these can be regarded as channels, but it is important to stress that they are not characterized by significant down cutting (basal incision). The system was strongly agradational: deposition dominated over erosion. While erosion surfaces are common at the base of most sand beds, the amount of vertical downcutting at the base of any sand bed is less than one or two inches. The sands do not completely erode the underlying shale beds. This fact is important because it means that the laminated nature of the reservoir is preserved even in areas where feeder channels are dominant. Sands were transported along the feeder channels (axes of the "thicks") into the basin. Overbank flow resulted in deposition of sands along the sides of the principal avenues of sand transport.

The map of the distribution of T interval thickness (Figure 16) displays the result of the growth and abandonment of several individual outer fan feeder channels and lobes during the sedimentation of the entire interval. This map shows the presence of a major feeder channel in the NW portion of the field, and the proximal portions of several lobes in the rest of the field. Not all of these channels and lobes were active at the same time. As a result, reservoir continuity is anisotropic. Individual sand beds are continuous in a NE-SW direction (>3,000ft) and discontinuous in a NW-SE direction (<1,000ft) based on a consideration of log responses and maps of sand distribution.

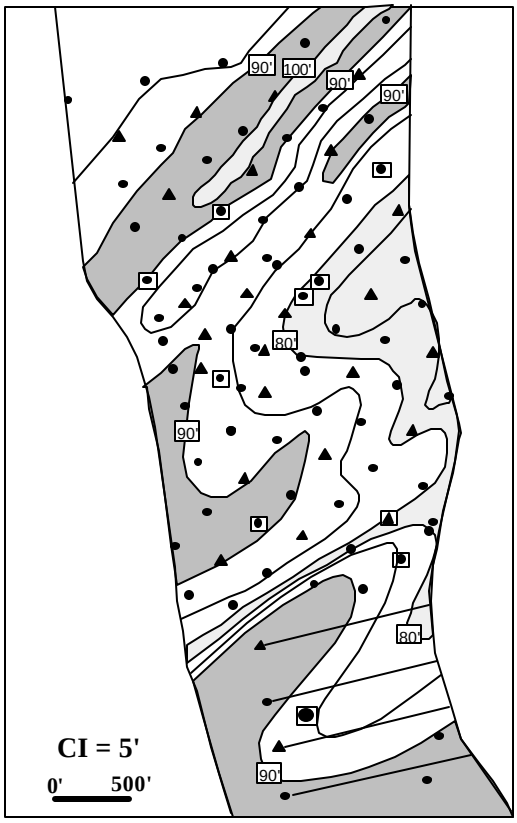


Figure 16: Isopach map of gross thickness, T Sand interval

D Sands

The D Sand interval is approximately 60ft thick. It was deposited in the Middle Fan (midfan) environment (Figure 13C) as indicated by the characteristics of the sand beds and the general absence of shale interbeds. Sand bed thickness is a function of relative position on the fan surface (Figures 17 and 18). Sand beds are thick in the proximal (inner) portion of the midfan and they thin gradually towards the distal portion of the midfan (outer midfan). Shale beds occur only in cores from the outer midfan sub-environment, where they are very thin (<0.2ft) and discontinuous due to minimal deposition and subsequent erosion of the thin shale beds during transportation and deposition of the overlying sand beds.

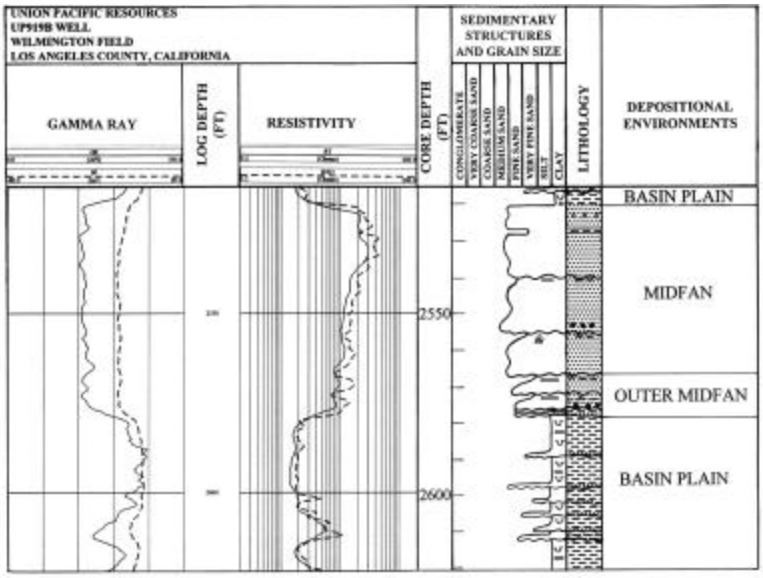


Figure 17: Log response and geological core description, central mid-fan environment, D Sand interval

The D Sand interval is characterized by a vertical stacking of numerous porous and permeable sand beds. In the outer portions of the midfan sub-environment, grain size fines upwards within individual

sand beds (Figure 18). Sand beds deposited in this environment have similar geological and petrophysical characteristics to those of the outer fan environment.

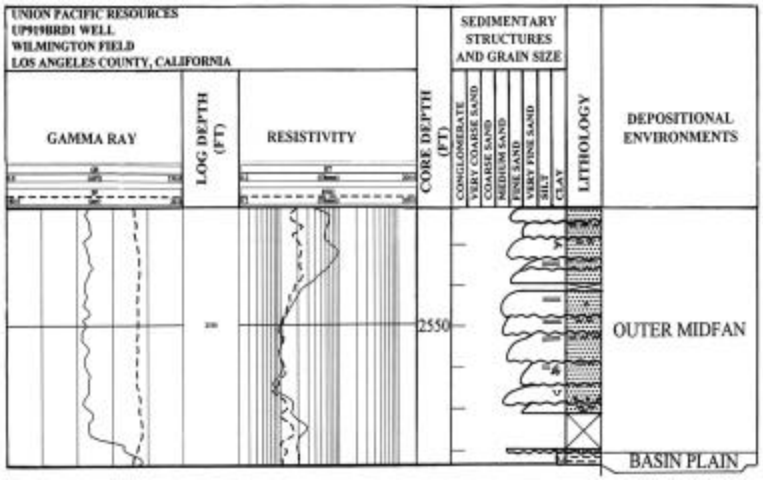


Figure 18: Log response and geological core description, outer mid-fan environment, D Sand interval.

Sand beds deposited in the central portion of the midfan environment exhibit no consistent vertical change in grain size (Figures 15B and 17) because here 1) deposition occurs from debris flows as well as from turbidity currents, and 2) bed contacts are erosive, sand-on-sand (shale interbeds are absent), making it difficult to separate deposits of individual gravity flows. The SP, GR and R_T responses do not effectively respond to the internal bedding characteristics of the D Sand interval. This is to be expected given the presence of sand-on-sand contacts between adjacent beds in this reservoir.

A map of the gross interval thickness of the D Sand interval (Figure 19) reveals that NE-SW trending areas that are alternately thick and thin dominate sediment distribution patterns. However, the rate of change of thickness is less pronounced than in the T Sand interval (compare Figures 16 and 19). These differences reflect the differences in detailed depositional environments between the two intervals. The D Sand interval was deposited in the center of a submarine fan system where rapid changes in sediment thickness are not common. The T Sand interval was deposited towards the outer edges of a submarine fan system where lateral changes in thickness and lithology (sand to shale) are common (Figures 13B and 13C).

In this field, the D Sand was deposited in a submarine fan system that received sediment along several, NE-SW oriented feeders (the apexes of the sand thicks, Figure 19. Sand quality in the D interval increases towards the northeast (towards the sediment source) along the directions of the feeders.

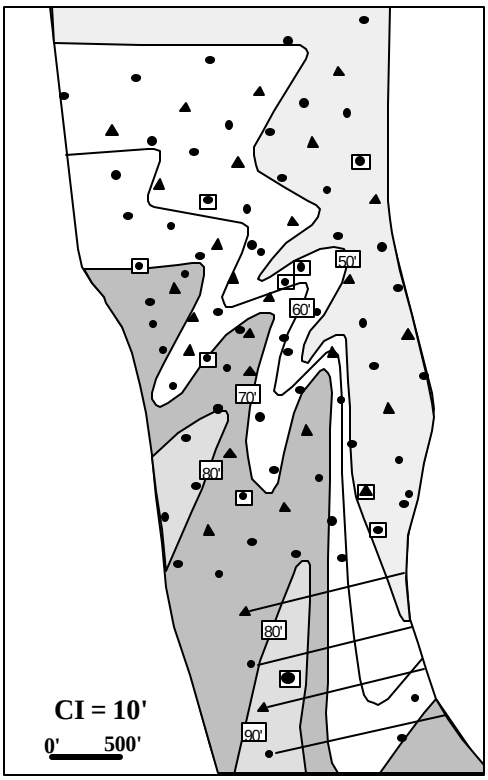


Figure 19: Isopach map of gross thickness, D Sand interval

Vertical permeability, vertical sweep efficiency and sand continuity are very high, as indicated by efficient oil displacement during steamflood operations. Finer grained portions of sand beds act only as permeability baffles, not as permeability barriers. The D Sand is the most homogeneous and most productive interval of the Tar Zone in Fault Block II.

Despite the overall homogeneity of this interval, production history reveals that the most productive wells occur along a northeast-southwest trend that parallels the depositional trend. Analyses of water salinity variations over time likewise reveal that the reservoir sweep has a preferred anisotropy in a NE-SW direction.

Geologic Modeling of Tar V

In 1995, five horizontal wells were drilled into the Fault Block V Tar zone as part of a steamflood pilot operation. The wells were drilled on average 1500 feet horizontally within the S_4 sand. Three-dimensional (3-D) geologic modeling and visualization were used from planning through completion of the wells. The modeling work was the subject of a paper by Clarke and Phillips entitled "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California."[A36]

Horizontal wells require precision placement to be effective. The studied areas required significant geological evaluation and characterization. The area was modeled with Dynamic Graphic's EarthVision™ software that provided 3-D visual displays of stratigraphic and structural relationships and also enabled excellent error checking of data and grids in 3-D space. The 3-D model provided a visual reference for well planning and communicating the spatial relationships contained within the reservoir.

The technologies developed in the Tar II-A steamflood project were applied to the Tar V steamflood project where five horizontal wells were drilled. The excellent accuracy of the 3-D geological model generated, and the usefulness of the computerized tools used to extract information from the model, greatly enhanced the success of the project.

As with the Tar II-A project, the 60+ year-old electric logs were reviewed and recorrelated dividing the Tar V zone into 14 sub-subzones. The log in Figure 12 shows a portion of the stratigraphic section from the probe hole drilled prior to the horizontal section in well FJ-204. The "S_4" sand has the highest resistivity (oil saturation) and is the most thick, continuous, and clean Tar V sand across the fault block. The FJ-204 probe hole verified the oil saturations and reservoir pressures in the individual Tar sands and confirmed the subsidence-corrected vertical depths used in generating the maps for horizontal well placement.

A deterministic geological model was created from which the maps and cross-sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than in the earlier Tar II-A project, as the lateral sections of

the horizontal wells are in unfaulted areas with relatively little structural relief (Figure 9). Customized 2-D and 3-D visualizations were used during drilling for interpreting the Logging-While-Drilling (LWD) resistivity, gamma ray and well survey data and for monitoring well progress. Map and section plots brought to the rig site allowed the drilling team to correlate real-time drilling to the geologic maps, thus providing a strong confidence factor that drilling operations were on target. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

The experience gained in the Tar II-A project and improvements to the EarthVision™ software made modeling even easier. Adding interpretive "ghost" points through the EarthVision 3-D viewer and then reconstructing the model controlled the mapped areas with "no data". This interpretative technique cut modeling time significantly.

During drilling, the LWD data provided near real-time data as the recorder was 60 ft behind the bit. This current data stream allowed the drilling team to adapt quickly when the penetrated formations did not correlate to the geologic maps. For example, one area of the geologic model indicated an anomalous structural low. The survey and log picks appeared to be correct for a well located in this "low" area. The datum point was honored and horizontal well J-201 was drilled into the area. It was apparent from the LWD curve separation and bed boundary intersections that the "T" shale below the "S_4" sand was shallower than the model indicated. The well course was changed during drilling of the horizontal section to point the bit up. Unfortunately, the new drilling course overcorrected for the problem and the well exited the top of the "S_4" sands for 200 ft before the reentering the sand. Still, the well course was placed into the "S_4" and "S_2" sands rather than in the "T" shale or below. Afterwards, the offending well datum was removed and the model was revised based on the multiple horizon picks from well J-201. Because this remodeling can now be done in almost real-time, the geologist can revise the model as drilling proceeds or after each new well is drilled.

The 3-D model in Figure 20 is "bench cut" and shows the five horizontal wells and their perforations. The goal was to keep the wells parallel to and within five feet above the top of the "T" shale to maximize recoverable reserves from the superjacent "S_4" sand. The maps, cross-sections and geological model were all used to place the horizontal wells accurately. Figure 21 shows the

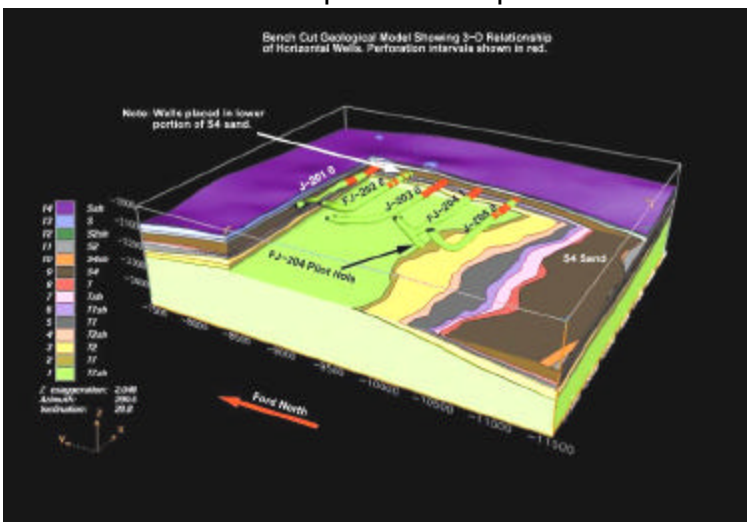


Figure 20: Three-dimensional bench cut of FB V Tar Zone showing steamflood project in S4 sand. "J" wells are producers and "FJ" wells are injectors. Well completions shown in red. This structurally flat area has 2X vertical exaggeration.

cross-section for well J-203, which was drilled near perfect along the bottom of the "S_4" sands.

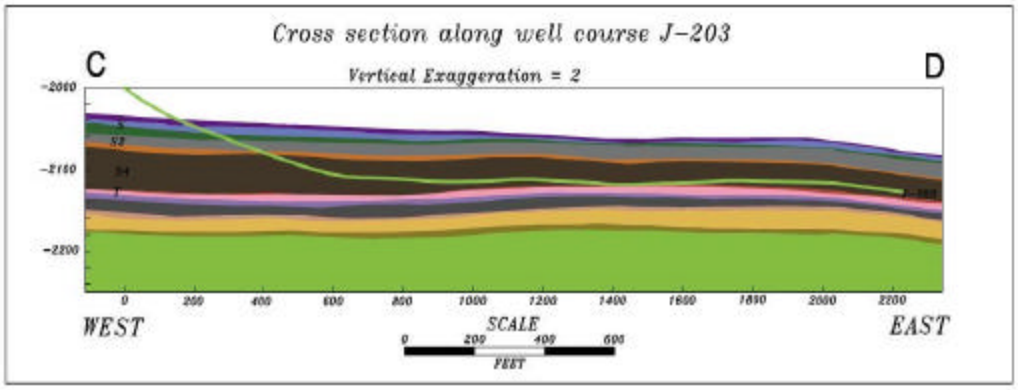


Figure 21: Cross-section along well course of J-203. Placing the well as close to the bottom of the S4 sand as possible to increase oil recovery.

Overall, the Tar V drilling project was a major technical and economic success. Based on what was learned in the Tar II-A project and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, only one pilot hole in FJ-204 was necessary. As a result, time and money were saved. Well J-203 took only six days from rig up to rig down to drill and case the 4,661 ft measured depth hole.

For the drilling team, having 2-D and 3-D visuals at the rig site stimulated better feedback and established a clearer understanding of how the geology affected drilling performance. Drilling efficiency was improved because 2-D and 3-D visuals provided the ability to see quickly what a particular directional tool set accomplished. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well drilling budget was based on the Tar II-A horizontal wells. The average savings per well was US$12,400 on directional costs and US$18,000 due to fewer drilling days. In total, US$152,000 was saved on the five horizontal wells drilled. The monetary savings and management's confidence in the 3-D model allowed all five laterals to be extended an extra 12%, on average, effectively increasing the producible area and adding 382, 000 stock tank barrels (STB) or 60,734 stock tank m^3 (STCM) of oil.

Geologic Model Conclusions

The geologist who can carefully characterize rock data and apply 3-D modeling and visualization techniques adds greatly to the horizontal well drilling team. The highly

accurate 3-D visualizations of the reservoir greatly increase the confidence factor of the team by reducing drilling risks and costs, thus enabling Wilmington Field oil reserves to be maximized.

To be effective, horizontal wells require precision placement. Three-dimensional models help isolate data inconsistencies, while 3-D viewers are good for adding data to correct the geological model. Once the final geological model is created, the drilling team can use the resulting 3-D visuals with confidence to improve drilling techniques and directional control. Post-well analysis of the LWD data also is facilitated using 3-D geological models.

The 3-D techniques contributed significantly to the economic success of the Tar Zone horizontal project. Assuming a 50% oil recovery factor, every foot the well is drilled above the target is equivalent to 15,876 STB (2,524 STCM) in lost reserves. [A37] At US$14/ bbl oil, being off as much as five feet vertically would equate to U.S.$1.1 million in lost revenue.

ACTIVITY 1 - COMPILATION AND ANALYSIS OF EXISTING DATA

Introduction

Existing field production and injection data for Tar II-A were compiled, evaluated for reliability, and analyzed in terms of production response and constraints to provide a foundation for creating geologic and reservoir simulation models. The data were incorporated into Production Analyst ™ (PA), a computer-aided data retrieval system by Schlumberger Geoquest, to facilitate simulation-based reservoir management. The PA database of monthly production and injection volumes is updated quarterly.

Historical Tar II-A reservoir engineering data such as pressure, volume, and temperature (PVT) test results on crude, annual isobaric data, water injection profile surveys, and past reservoir engineering studies were retrieved and analyzed to perform material balance calculations.

A database of available well logs was compiled. Digitization and normalization of log data from 178 wells distributed throughout the Fault Block II-A Tar Zone were completed for use in the 3-D deterministic and stochastic geologic models and rock-log models.

During the next year, the project team will update the Tar II-A 3-D thermal reservoir simulation model to compare its predictions to actual post-steamflood performance. Once the model is fine-tuned to match historical production, it will be used to evaluate multiple operational strategies for accelerating reservoir cooling to below 350°F while maximizing oil production and minimizing costs. Creation of a geologic model and a 3-D deterministic thermal reservoir simulation model for Tar V will be postponed until Budget Period 2. Reservoir temperature and pressure surveys are run periodically as described in Section 4.7 Reservoir Surveillance.

1.1. Data Compilation

Monthly production, injection, reservoir pressure, and reservoir fluid salinity data is compiled. Temperature surveys are run every six months to annually in selected observation wells.

1.2. Log Digitization and Normalization

No activity reported this period.

ACTIVITY 2 – ADVANCED RESERVOIR CHARACTERIZATION

2.1 Basic Reservoir Engineering

No activity reported this period.

2.2 Obtaining New Characterization Data

2.2.1 Measurement While Drilling Data

No activity reported this period.

2.2.2 Tracer Surveys

Introduction

A field pilot study demonstrated a low cost and operationally simple reservoir tracer alternative to obtain information about reservoir rock anisotropy from produced water chemistry data as written by Bronson, Ershaghi, Mondragon, and Hara in SPE Paper #54118 entitled "Reservoir Characterization in a Steamflood Using Produced Water Chemistry Data[A28]". Normally, reservoir tracer work is expensive and generally performed in one batch treatment that can lead to inconclusive results. This study periodically acquired inexpensive water chemistry data from producers to measure naturally existing cations and anions (salinity) in the produced formation water as affected by dilution from the condensed fresh water in the steam in the Tar II-a steamflood project. The project was conducted over a three-month period on two 7.5-acre inverted seven-spot well patterns with two steamflood injectors per pattern and ten producers. The correlation study showed that the reservoir sand connectivity or preferential permeability path of the steam condensate front trended in a northeast to southwest direction, which is consistent with the geological description of interpreted sand deposition.

Collection of water salinity data in the Tar II-A post-steamflood production wells resumed in October 2001 to monitor water breakthrough of the injected cold-water to the producers. In general, the structurally updip portion of the reservoir received more steam and therefore the formation waters there had lower salinities. Many of the structurally downdip producers near the flank injectors experienced higher water cuts and higher producing fluid levels from injection well response, hence, their produced fluids showed increased salinities with time that approach sea water or the normal waterflooded zone salinities of about 28,000 parts per million (ppm). Most of the structurally updip wells had salinities of about 3-16,000 ppm and the mid to downdip wells had salinities of 12-23,000 ppm. All of the mid and updip wells have experienced rising water salinities, especially after wells are sped up or repaired and after increasing gross fluid production. In general, salinity tracing has not shown anisotropic directional flow of the post steamflood injection water. The higher salinity water appears to be produced from the lowest structurally placed wells and the lowest salinity water from the higher structurally placed wells.

2.2.3 Water Composition Tests

No activity reported this period.

2.2.4 Oil Finger Printing

No activity reported this period.

2.2.5 Drill 3 Observation and 2 Core Hole / Observation Wells

No activity reported this period.

2.3 Deterministic 3-D Geologic Model

2.3.1 Three-Dimensional EarthVision™ Structure

No activity reported this period.

2.3.2 Core Based Log Model

No activity reported this period.

2.3.3 Porosity-Permeability Model

No activity reported this period.

2.3.4 Rock-Log Model

No activity reported this period.

2.3.5 V-Shale Model

No activity reported this period.

2.3.6 Qualitative Conditioning

No activity reported this period.

2.3.7 Basin Modeling

No activity reported this period.

2.3.8 Updating

No activity reported this period.

2.4 Stochastic 3-D Geologic Modeling

No activity reported this period.

ACTIVITY 3 – ACTIVITY RESERVOIR SIMULATION

3.1 Deterministic 3-D Thermal Reservoir Modeling

Introduction

The original intent of the 3-D advanced reservoir modeling work was to address the lateral variations in rock geology using geostatistical correlation methods. Upon completion of the geostatistical work, the plan was to rebuild the 3-D deterministic geologic model and examine various stochastic realizations of reservoir conceptual models for simulation purposes. The STARS™ thermal reservoir simulation program by the Computer Modelling Group (CMG) of Calgary and the R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) were selected for the reservoir simulation modeling which began in October 1996. History matches covering the primary depletion, waterflood, and steamflood periods were completed for the 3-D deterministic thermal reservoir simulation model in June 1998.[A22, A25, A27]

The City of Long Beach modified the project priorities in the third quarter 1998 to address their concerns about steamflood-related surface subsidence and how to safely operate the Tar II-A wells during the post-steamflood phase. The 3-D deterministic reservoir simulation model was immediately used to optimize oil production while accelerating steam chest fill-up with flank water injection by measuring the mass fluid and heat balance effects as they pertained to reservoir pressure. Affecting reservoir pressures in the target area are the following four occurrences: (1) Mixing of the hot and cold fluids at the flank-water injection sites. (2) Continuous heat loss occurring in developed steamflood areas to the overburden and underburden formations. (3) Steam chest collapse and expansion in the structurally updip areas. (4) The movement and production of hot fluids throughout the steamflood project area. Taken together, these parameters make the prediction of reservoir pressures too difficult without a viable reservoir model. The post-steamflood reservoir simulation modeling study was the basis for a technical paper presented at the AAPG / SPE Western Regional Meeting in June 2000. [A34]

The real-time response capability of the reservoir simulation model has made it an indispensable tool for day-to-day reservoir management purposes. The model allowed the evaluation of several operating strategies and justified the flank cold water injection plan ultimately selected. Whereas the City's 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. The model can effectively predict overall mass and heat balance of the injected and produced fluids, provided it is updated with actual data.

This deterministic model has certain limitations. The model cannot predict net oil production from individual wells but can show oil saturation trends that can explain why certain wells have varying oil production rates over time. The model did not provide the correct steam chest fill-up pressure, as it required about 10% higher pressures than predicted to force the steam chest back into solution. However, once the reservoir approached steam chest fill-up pressures, reservoir pressures rose very rapidly. Therefore, the projected time for reaching steam chest fillup occurred during the same month as the actual fillup, even though more pressure was needed. One other shortcoming of the model was that it could not properly predict the short-term injection to production ratio to use following steam chest fillup. The model predicted that once steam chest fillup occurred, the reservoir would act similarly to a waterflooded reservoir and that typical injection to production (IP) ratios of about 1.05 to 1.10 would be enough to maintain reservoir pressures. In actuality, reservoir pressures dropped significantly and higher IP ratios of about 1.40 were needed to maintain pressures. These model weaknesses may require a stochastic 3-D model to correct the problems. Of course, more empirical production and injection data on the Tar II-A reservoirs may provide a better model when expanding to analogous reservoirs.

A study was performed to quantify the heating of over and underburden shales and sands in a typical Tar II steamflood pattern over a ten year period subsequent to steamflooding. The purpose was to determine the potential for thermal-related shale compaction over time. The CMG STARS thermal reservoir simulator was used to develop a 1/12 of a seven-spot, 2025 grid block (5 x 5 x 81 grids) model to determine how much, how far vertically, and for what length of time the reservoir heat is thermally conducted from the Fault Block II-A Tar Zone steamflood to the overburden and underburden sands and shales. The model mimicked an area in the middle of the steamflood project and had two injectors (one for the T Sand & one for the D Sand), one producer, and an observation well halfway between the injectors and the producer. Two basic scenarios were run, one with continual 500°F hot water injection and one with 135°F cold water injection. Injecting 500°F water for ten years after steam injection only cooled off the steam zone by 53 – 67°F while the shale layers above and below continued to heat up. Injecting 135°F cold water to maintain a 90% hydrostatic reservoir pressure in the T and D sands would cool the reservoirs to 135°F within five years after the steam was shut-in.

The five horizontal well steamflood pilot installed in the Tar V zone in late 1995 is based upon the three dimensional (3-D) deterministic geologic modeling and horizontal drilling technologies derived from the Tar II-A project. The Tar V steamflood pilot began operating in mid-1996 and has injected about 5.4 million barrels of steam and recovered about 763,000 barrels of oil from the S2 and S4 sands. Due to the Tar II-A production acceleration plan, modeling of the Tar V Zone will be performed during Budget Period 2.

Tar II-A Production Acceleration Plan

In March 2002, the City of Long Beach directed Tidelands to significantly accelerate Tar II-A cold water injection and production to minimize the thermal-related

shale compaction effects by reducing reservoir temperature. Previous studies suggest that shale compaction occurs at about 400°F. As predicted by the reservoir simulation model, the reservoir is still very hot and exceeds 400°F in many places. Since termination of steam injection in Jan 1999, peak reservoir temperatures in the upper D sands just below the problem shales have declined only about 30-40°F from 480+°F to about 440-450°F. These peak temperatures occur mostly at the steam injectors and in paths leading to the hot producers. In the meantime, the adjacent cooler areas have heated up from heat transfer, sometimes to temperatures exceeding 400°F.

An apparently simple solution is to inject cold water into the interior steamflood patterns, but this was not recommended because it could thermally shock the reservoir and cause immediate formation compaction. In April 2002, one interior "D" sand steamflood injector, well 2AT-33, was converted to cold water injection to test this hypothesis. Temperature, pressure and vertical casing movement in observation wells within the pattern (wells OB2-5 and 1F-10) are being monitored and preliminary results should be available by the end of Budget Period 1 in September 2003. As of March 2003, well 2AT-33 appears to have affected well UP-927 and possibly well UP-921. Both wells experienced higher produced fluid rates after April 2002 and are located structurally downdip of well 2AT-33, although their produced fluid temperatures were still relatively high. Injection response is more strongly suspected in UP-927 because produced fluid salinities increased from 12,500 ppm in June 2002 to 24,000 ppm during the first quarter 2003. No fluid salinities were taken in well UP-921, which only produced a short time from August 19 to September 23, 2002 at 2000 BGFPD and 2 BOPD. Previous production from UP-921 was 1100 BGFPD and 20 BOPD in November 1999, hence the suspicion that the well was watered out by 2AT-33,

The model is in the process of being updated to evaluate how well it history matched the post-steamflood operations to date. The last four years of production and injection data will be input into the model and pressure and temperature survey data will be compared with the model projections. Some differences are expected because of the accelerated cold water injection work performed since March 2002 which was not anticipated in the original model.

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. The second challenge 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. During the last four years, the City and Tidelands have disagreed on injection well placements within the main steamflood area and along the southerly flank that may be resolved by utilizing an updated model.

3.2 Stochastic 3-D Reservoir Modeling

No activity reported this period.

ACTIVITY 4 – RESERVOIR MANAGEMENT

4.1 Horizontal Wells and Surface Locations

No activity reported this period.

4.2 Horizontal Well Cyclic Steam Stimulation Pilot (4 Wells-2 Prod. & 2 Injection)

No activity reported this period.

4.3 Horizontal Well Steam Drive

Introduction

The original DOE horizontal well steamflood pilot, drilled and operated as an expansion phase within the Tar II-A steamflood project, included two producers and two injectors. Upon the cessation of Tar II-A steamflood injection in January 1999 because of loss of the steam source from Harbor Cogeneration Plant, the DOE approved continuing this segment of the project by replacing the Tar II-A pilot with the existing five-well horizontal steamflood pilot in Tar V in late 1998. The Tar II-A horizontal pilot wells are still active in the post-steamflood waterflood phase.

Tar II-A Horizontal Well Post-Steamflood Pilot

A workover was performed on horizontal producer well UP-955 in December 2002 to restore sand control and improve fluid productivity by installing an inner liner gravel-packed completion to back up the sand consolidation completion. The job on UP-955 was successful in restoring full productivity to the well (1668 BGFPD and 58 BOPD with 1920 ft of fluid over pump). The sand consolidation completion can fail if a well is pumped too hard because the high differential pressures pull the formation sands into the wellbore. Theoretically, wells like UP-955 could produce at 100 - 300% higher rates if pumped hard enough to draw the fluid levels down to the pump. The proposed inner liners were designed to allow the wells to be pumped at rates up to 3000 BGFPD, which is the limit for the pumping units. The goal is to increase oil production to over 125 BOPD per horizontal well. The well will be pumped harder, perhaps to about 2400 BGFPD, as a next step during the next reporting period. The sand consolidation completion in well UP-955 produced for thirty-one months at high gross fluid rates ranging from 1500 - 2400 BGFPD and high water cuts before sanding up, very good performance under the circumstances.

In October 2002, horizontal well UP-956 began sanding up after more than five years of service producing at high gross rates and high water cuts similar to UP-955. Well production dropped from 2123 BGFPD and 123 BOPD with 861 ft of fluid over the pump in October 2002 to 670 BGFPD and 56 BOPD with no fluid over the pump in January 2003. The plan is to keep pumping the well until it completely fails or oil production declines to uneconomic levels.

Tar V Steamflood Pilot Project

Cumulative pilot steamflood oil production from June 1996 through March 2003 is 757,137 barrels and oil production during the first quarter 2003 averaged 201 BOPD. Significant oil production has been recovered from three pre-steamflood vertical producers (wells A-186, A-195 and A-320) located within the steamflood area that have recovered 267,491 barrels of oil from June 1996 through March 2003 or 35% of the cumulative steamflood oil recovery. A fourth vertical producer, well A-194, was recompleted to the Tar V pilot area in February 2003. Peripheral water injection in March 2003 is from four wells: FRA-29, FRA-83, FL-337 and FR-111 (Figure 4.3-1). Figure 4.3-2 is a production and injection graph for the Tar V steamflood project from June 1996 through March 2003. Figure 4.3-2 is a type log of the Tar zone showing the "S" and "T" sands.

Pilot steamflood performance was excellent for the first two years as shown in Figure 4.3-2 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 original 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 until May 2002, when it was reactivated as a producer following the termination of hot water injection in April 2002. As mentioned previously, well A-194 was recompleted to the Tar zone in February 2003.

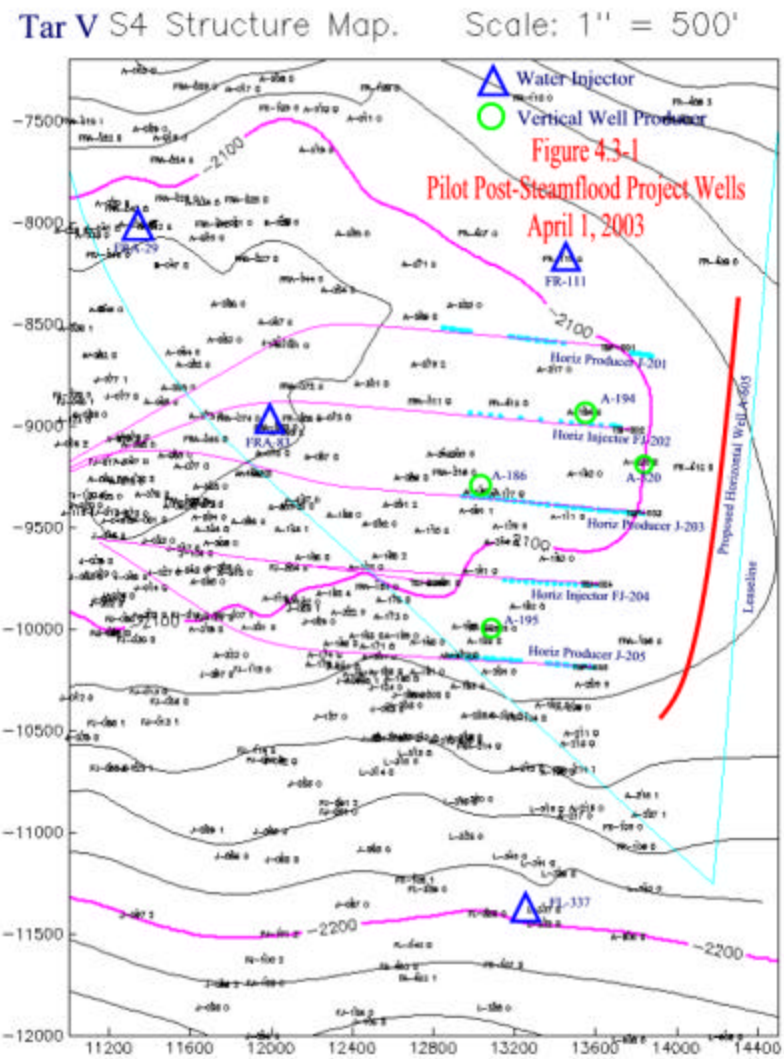


Figure 4.3-1: Tar V steamflood project wells as of March 31, 2003, including three horizontal producers (light blue "J" wells), two horizontal steam injectors (light blue "FJ" wells), four vertical infill producers (green circles) and four flank water injectors. (blue triangles)

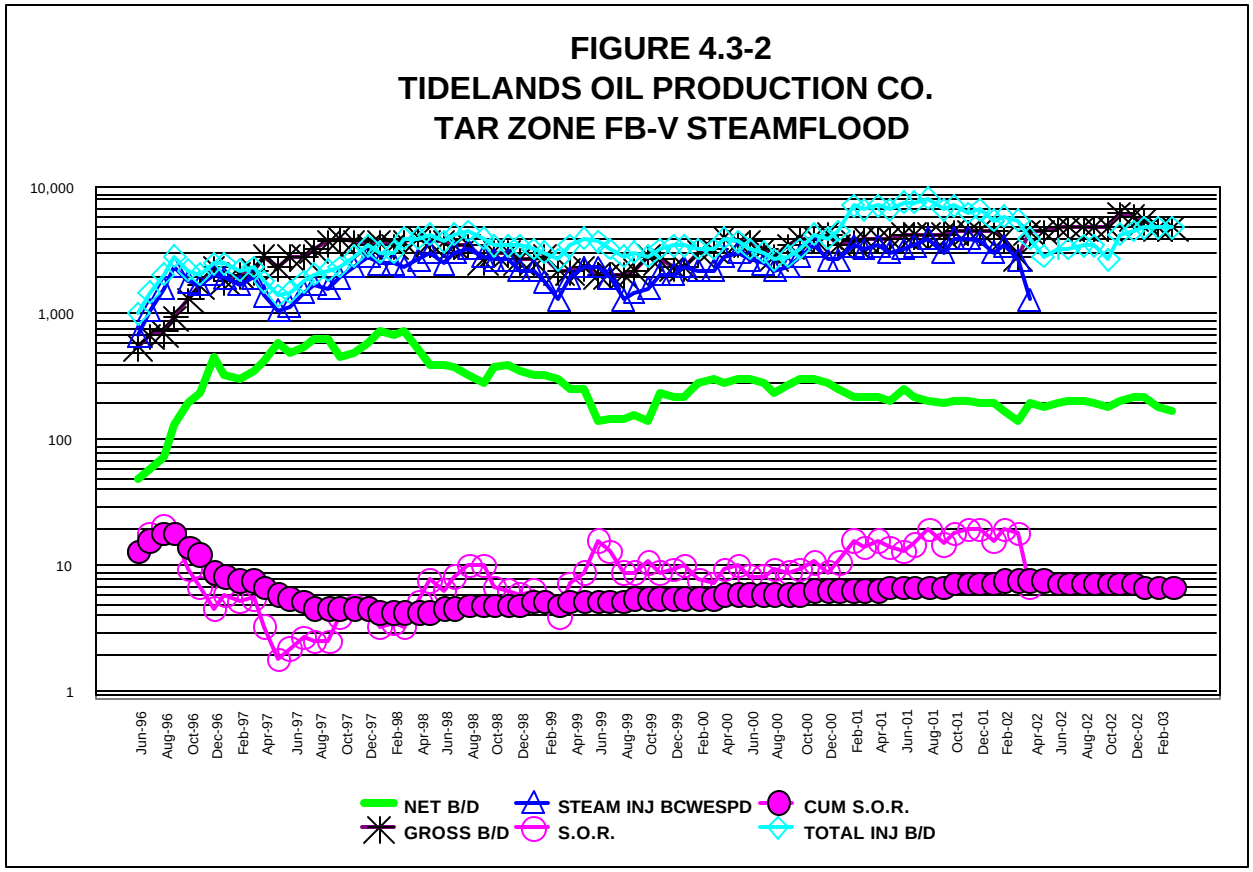


Table 4.3-1 lists the initial production date, the peak oil production rate, the date of peak oil production, and the cumulative oil production for the five horizontal and four vertical producing wells through March 2003.

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. 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.

As the Tar V fluid production temperatures began to exceed 350°F in the center horizontal production well J-203, a self-imposed temperature maximum limit was reached and the pilot steamflood was converted to a hot waterflood project in June 2001 to prevent overheating the overburden shales and causing formation compaction. Oil production declined to an average of 176 BOPD in the First Quarter 2002 despite continuing to speed

up pumping units and increasing gross fluid production rates. Oil production declined to a new low of 147 BOPD in March 2002 due to failing pumps in two horizontal wells that were replaced the same month. On April 19, 2002, hot waterflood injection was terminated and the pilot was converted to a post-steamflood operation with only cold water injection into the four peripheral vertical injectors and the two former horizontal steam injectors. The post-steamflood production performance in the Tar V pilot project has been below projections because of wellbore mechanical limitations. Horizontal well J-205 produced about 1685 BGFPD and 70BOPD until May 2002 when the well sanded up. A gravel-packed inner liner was installed in October 2002 to restore sand control, but the well completion experienced formation damage as the well has only produced 1500 BGFPD and 40 BOPD pumped off following the job and fluid production was declining through March 2003. A deeper zone producer well, L-337, was recompleted into the Tar zone and converted to water injection well FL-337 in November 2002 to supplement injection to enable higher horizontal well production rates and to support a new horizontal well, A-605, to be drilled in the second quarter 2003. Well FL-337 is located to the south of the pilot, provides more reservoir pressure support for surface subsidence control similar to the flank water injection in the Tar II-A project, and was injecting 2000 BWIPD at 1080 psi in March 2003. Another deeper zone producer, well A-194, was recompleted into the Tar zone with selected perforations and an inner liner gravel pack in February 2003. The well has severe formation damage and even after acid stimulating, it only produced 38 BGFPD and 6 BOPD in March 2003. The well is strategically located next to horizontal injection

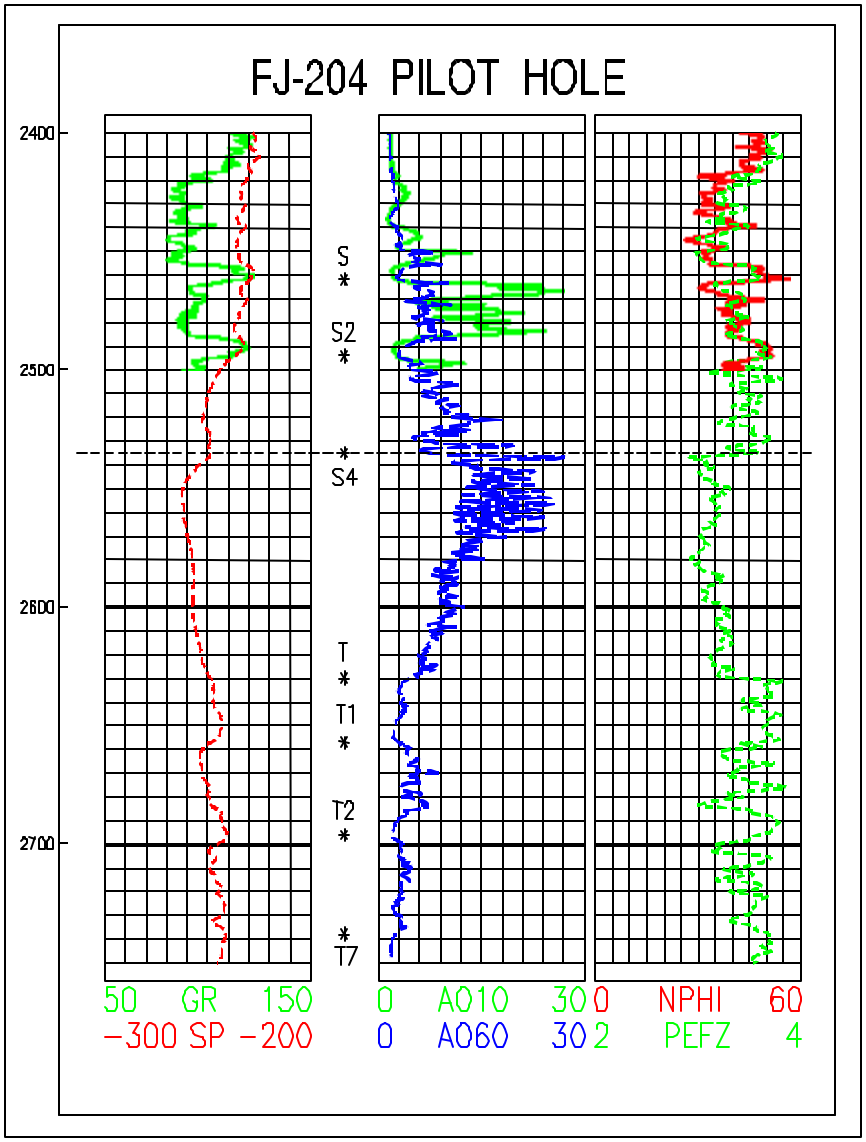


Figure 4.3-3: Type Log, Fault Block V Tar Zone, illustrating “S” and “T” sands.

well FJ-204 and was completed high in the S4 steamflood sands to take advantage of the remaining heat in the reservoir.

Table 4.3-1
Tar V Steamflood Pilot - Horizontal & Infill Wells

Well	Init Prod Date	Peak Prod, BOPD	Peak Prod Date	Cum Oil Prod Thru Mar 2003, 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	107.1
J-203 HW	Jun 97	267	Mar 98	184.4
J-201 HW	Oct 97	283	Jan 98	131.6
A-186	Prior Jun 96	83	Mar 00	100.0
A-195	Prior Jun 96	86	Nov 96	26.9
A-320	Prior Jun 96	145	Nov 97	139.4
A-194	Feb 2003	11	Feb 2003	0.2
Pilot Total	Jun 96	743	Jan 98	757.4

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

Plans have been approved to drill and complete well A-605 as a Tar V horizontal producer in the second quarter 2003. The well will be located along the north-south leaseline between Tidelands and Thums Long Beach Co. and perpendicular to the five horizontal wells to capture heated oil in the upper S4 sands (Figure 4.3-1).

Waterflood operations in 2003 still represent 75% of the oil production from the Tar V sands. Tar V oil production from April 2002 through March 2003 averaged 740 BOPD, of which pilot steamflood production was 186 BOPD or 25%. Tar V total water injection for the same period was 23,523 BWPD, whereas steam and hot water injection ceased as of April 19, 2002.

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 March 2003, the pilot has produced 757,137 barrels of oil and 8,713,948 barrels of gross fluid (91.3% average water cut) and injected 5,357,000 barrels of steam/hot water and 11,050,000 barrels of total steam and water for an overall I/P ratio of 1.27.

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. Water injection was increased to raise the cumulative steam + water 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. The additional water injection resulted in not being able to pump the horizontal wells down and their premature oil rate decline and water breakthrough. 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 first quarter 2002, the last full quarter hot water was injected, the pilot produced at an instantaneous steam-oil ratio of 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, despite the adverse changes made to the operation. 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%, an incremental difference of 107 BTU / lb of steam injected or 11% less heat transfer 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. The cumulative SOR through June 2001 was 6.9, marginal assuming steam costs based on market-priced fuel. However, if steam volumes are normalized based on heat transfer using 80% quality steam, the corrected SOR would be a much more reasonable 6.1. The 1,095,000 barrels of 330°F hot water injected is only 21% of the heat injected compared to an equivalent weight of water as 1600 psi 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. Using the ballpark heat input estimates of 60% quality steam and 330°F hot water compared to 80% quality steam, the adjusted pseudo-80% quality steam volume injected through March 2002 is 3,988,000 barrels instead of the 5,318,000 barrels of water actually injected or 75%. This results in a normalized cumulative steam-oil ratio of 5.85 instead of the 7.8 shown for the project using unadjusted barrels. The original project projections showed an SOR of 6.2 for the cumulative oil recovered.

The pilot project has potential for increasing thermal oil recovery. A new horizontal producer, well J-206, is planned to be drilled in a south to north direction along the THUMS / Tidelands leaseline to capture the remaining thermally-heated oil in the pilot area. Additional water injection on the south flank of the project is needed to support increasing production from the horizontal wells. The proposed producer and water injection conversion well are shown in Figure 4.3-1. In addition, new well and recomplete potential lies in the upper S4 sands, which were heated by steam but have no effective withdrawal points. The unsuccessful inner liner repair job recently performed on horizontal producer well J-205 and the unsuccessful recomplete performed on well A-194 need to be evaluated, as both have apparent formation damage problems.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. Thermal operations in the Wilmington Field were curtailed when the Tar V pilot hot waterflood was terminated in April 2002. Recent facility modifications to purify and sell the natural gas production will make future steam more expensive to generate from the existing 50 MMBTU/hr steam generator. Favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field and other SBC reservoirs will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of the project.

4.4 Hot Water Alternating Steam (WAS) Drive Pilot

See Section 4.7

4.5 Geochemistry of Rock / Fluid / Interactions

See Section 5.1

The project team completed developing laboratory research procedures to analyze the sand consolidation well completion technique and a contract was approved with the Stanford University Petroleum Engineering Department to initiate work effective January 6, 2003. By the end of March 2003, Stanford was preparing the laboratory equipment and cores for the experiments. The main objective of the research is to determine if the sand consolidation process can be duplicated in the laboratory. If so, then the objective will be to optimize and possibly commercialize the process. The sand

consolidation well completion technique has been field tested on an empirical basis on thirty-five wells and proven to be a superior method that offers higher productivity, more operating flexibility, and significantly lower costs than the conventional open-hole, gravel-packed, wire-wrapped screen completions used to control unconsolidated sands. No failures can be attributed to the sand consolidation process in the twenty-two jobs performed on vertical wells. Several of the vertical and horizontal wells have over six years of sand-free service as producers and/or injectors.

Six of the thirteen sand-consolidated horizontally completed wells have sanded up for different reasons. To date, most of the wells with continual sand problems (wells J-201, J-205, J-17, A-113) are in the Tar V and Upper Terminal V zones and received their steam from the 50 MMBTU/hr steam generator on Parcel A. One possible explanation for the completion failures is that the steam generator was not outputting enough 80% quality steam because of operational problems related to using a fuel gas with variable BTU content. With the varying BTU gas fuel, a sudden flow of high BTU gas could cause the generator to create 90 - 100% quality steam before the controls could adapt, resulting in the generator to either shut down or the steam tubes to scale up. Therefore, the steam generator was operated to make an estimated 50 – 65% quality steam, which provided more operating flexibility. No doubt, the lower quality steam resulted in lower alkaline pH condensate that could have affected sandstone dissolution rates and volumes. A possible problem related to cyclic steam injection into the deeper Upper Terminal Zone well J-17 was that reservoir pressure was too high compared to the steam generator injection pressure (1200 psi compared to 1550 – 1600 psi) which resulted in too low an injection rate and a long drawn out injection cycle that probably experienced heavy heat losses. The sand consolidation process requires high steam injection rates to ensure each perforation in the well is being treated. When the rates are too low, only the sands with the highest permeability will get treated. The other two well failures occurred in wells SF-1 and UP-955. Well SF-1 was one of the first two horizontal wells in the field and was completed with a blank, uncemented liner, therefore the well had no way to isolate steam into perforations. A workover was performed on horizontal producer well UP-955 in December 2002 to restore sand control and improve fluid productivity by installing an inner liner gravel-packed completion to back up the sand consolidation completion. The job on UP-955 was successful in restoring full productivity to the well (1668 BGFPD and 58 BOPD with 1920 ft of fluid over pump). Prior to the workover, well UP-955 produced for thirty-one months at high gross fluid rates ranging from 1500 - 2400 BGFPD and high water cuts before sanding up, very good performance under the circumstances.

Four of the wells (J-201, J-205, J-17 and SF-1) were resteamed to reconsolidate the completions and all produced successfully for at least eighteen months. However, all except J-201 sanded up again. The completion failures will be evaluated to determine the weaknesses of the sand consolidation process and whether any completion or operating procedures can be changed to minimize the problem.

Thermal-related compaction of sands and shales in the Tar zone were studied in an effort to confirm one of the causes of surface subsidence in the Tar II-A steamflood

area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are planned to determine the critical maximum reservoir temperature that can be reached before appreciable shale compaction occurs. This information will help determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects.

Research will continue on the geochemical and petrophysical changes to the reservoir rock due to steam injection. Proposed research will be performed on the novel steam-induced sand consolidation well completion technique to see if the process can be duplicated in the laboratory and to confirm the mineralogy of the cement precipitates. If successful, the objective will be to optimize and possibly commercialize the process. The sand consolidation well completion technique has been field tested on an empirical basis on over two dozen wells and proven to be a superior method that offers higher productivity, more operating flexibility, and significantly lower costs than the conventional open-hole, gravel-packed, wire mesh screen completions used to control unconsolidated sands. Recent sanding problems will also be studied to determine the robustness of the completion. See Sections 5.1 and 5.2 for more details.

During the past two years, research has been performed on the thermal-related compaction of sands and shales in the Tar zone to confirm whether these are causes of observed surface subsidence in the Tar II-A steamflood area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are needed to determine the critical maximum reservoir temperature attainable before causing appreciable shale compaction. This information will determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects. See Section 5.5 for more details

4.6 Steam Drive Mechanisms

See Sections 4.3 and 4.7.

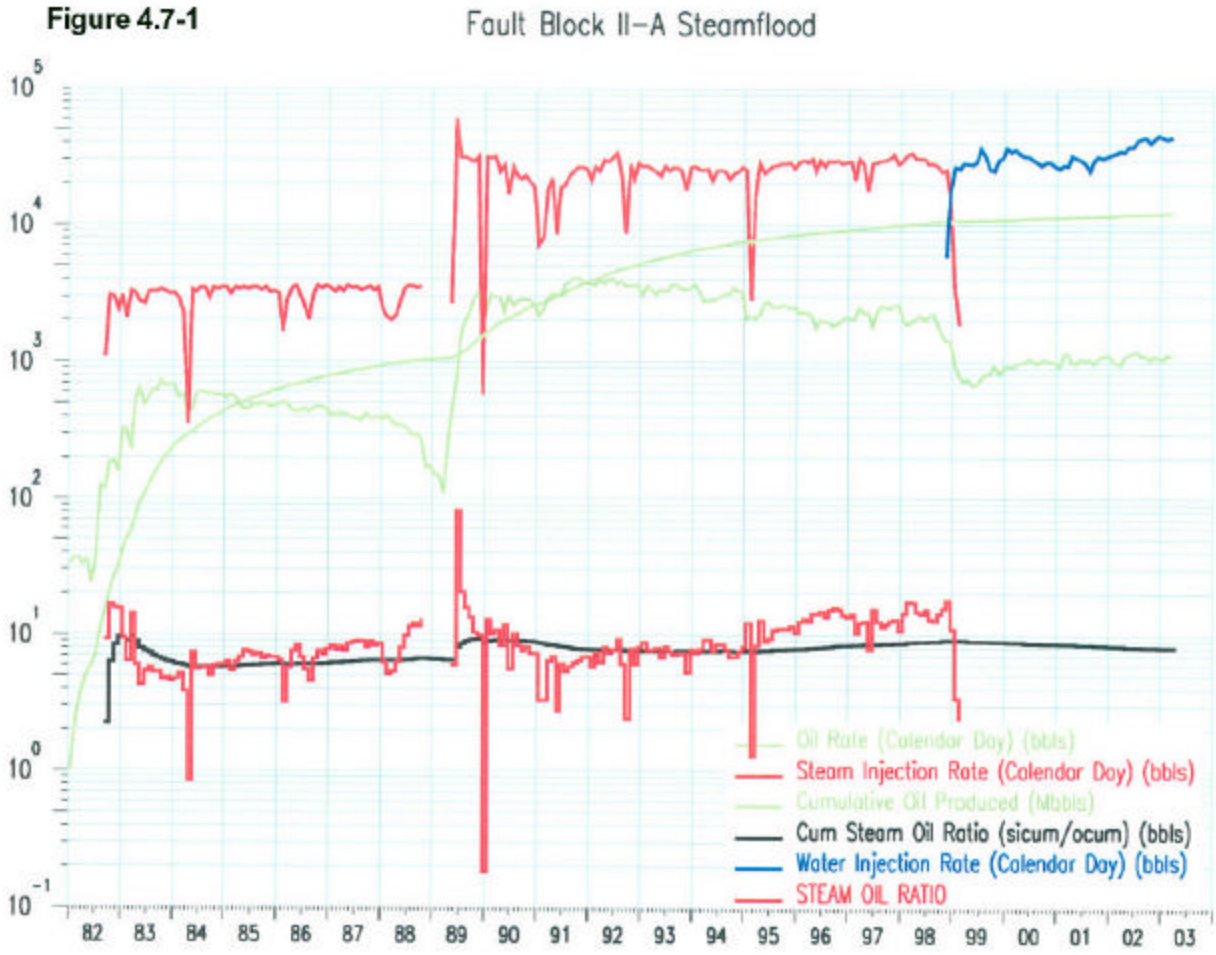
4.7 Reservoir Surveillance

Tar II-A Project

The Tar II-A post-steamflood operation started in February 1999 with flank cold water injection and steam chest fillup occurred in September - October 1999. The operational plan for flank water injection was based on a 3-D deterministic thermal reservoir simulation model. 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 monthly pressure monitoring program enacted at the start of the post-steamflood phase. The Tar II-A accelerated oil recovery and reservoir cooling plan began in March 2002 and oil production increased from 1009 BOPD in the first quarter to a peak of 1199 BOPD in June 2002. By January 2003, Tar II-A gross fluid

production increased almost 60% or 12,000 BGFPD since March 2002 whereas associated injection rates increased only about 26% or 9,000 BWIPD and oil production declined to 1059 BOPD with higher water cuts averaging 96.8%. The higher gross fluid production and water injection rates caused more frequent well failures from stressing the system and operating costs increased significantly. Reservoir pressures declined to 89% hydrostatic in the "T" sands and increased to 93% hydrostatic in the "D" sands in March 2003. Production during the current reporting year ending March 2003 averaged 1113 BOPD and 29,077 BGFPD (3.8%) with injection averaging 41,730 CWEBPD. The Tar II-A cumulative oil production through March 2003 is about 39 million barrels for a recovery factor of 39% OOIP. Figure 4.7-1 shows the post-steamflood wells active at the end of the reporting period as of April 1, 2003 compared to the original steamflood patterns.

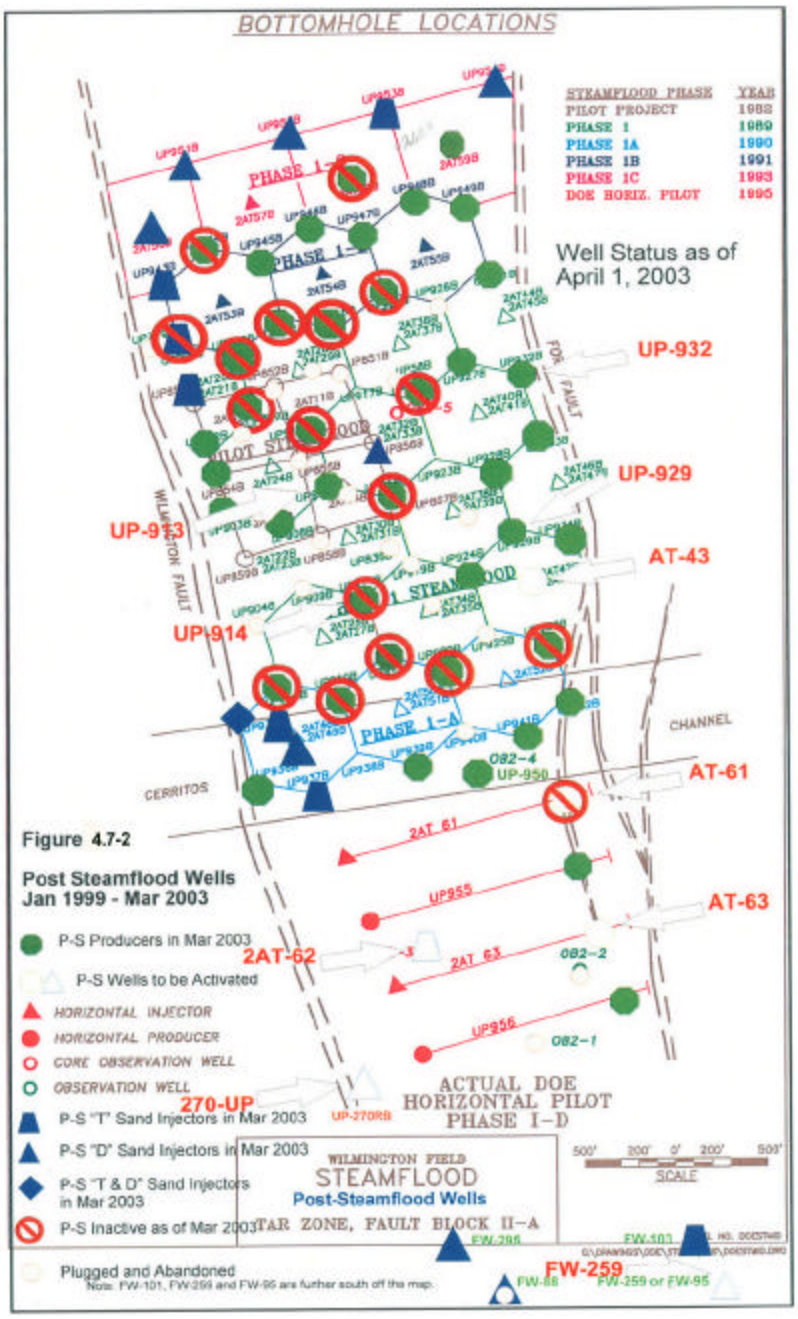
Figure 4.7-1



The Tar II-A post-steamflood operational plan was successful in filling the steam chests in the "T" and "D" sands and significantly reducing further surface subsidence in the steamflood area. Maintaining reservoir pressure is important to prevent steam chest reoccurrence. Following steam chest fillup 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. From 2000 to early 2002, most of the well work resulted in maintaining oil and gross fluid production and water injection rates.

As of February 2002, there were sixteen active producers and eleven active injectors. During the First Quarter 2002, the project team developed a plan to accelerate oil recovery and reservoir cooling within the most mature and hottest Tar II-A 7-spot steamflood patterns and began implementing the proposed well work in March 2002. The plan included converting a number of wells to flank water injection and activating several producers that had been idle since post-steamflood operations began in January 1999. The plan also included injecting water into an interior pattern injection well in the "D" sands, well 2AT-33, to observe whether the formation can withstand the extreme temperature changes without serious compaction problems in the sands or shales. Activating idle producers to test them hurt production results because better wells had to be idled to meet injection / production ratios and many of the activated wells tested at very high water cuts. Twenty producers and five injectors were activated or worked over from March 2002 through March 2003. The Tar II-A project averaged 1,102 BOPD (3.45% oil cut and 27.4 WOR) with 43,836 BPD water injection during the First Quarter 2003. Several producers have experienced water breakthrough and high water cuts from the increased water injection and were idled. As of March 2003, there were twenty-five active producers and fourteen active injectors. Figure 4.7-2 shows the 26 producers and 14 injectors that were active in the Tar II-A



post-steamflood area as of April 1, 2003 compared to the original steamflood pattern wells. Eighteen wells have been activated during the post-steamflood period and later idled.

The oil recovery and water injection acceleration plan included major well work on three producers. Horizontal well UP-955 was activated after installing a gravel-packed inner liner for sand control (in original plan). Recent well tests show UP-955 successfully producing 1754 BGFPD and 70 BOPD with 1864 feet of fluid over the pump. Well AT-59 was recompleted to the upper “D1” sands after watering out in the lower “D1” and “D3" sands. AT-59 initially produced at a disappointing rate of 1775 BGFPD and 29 BOPD with 1552 feet of fluid over the pump. Production decreased to 863 BGFPD and 10 BOPD and fluid was at the pump, which indicates a scale problem and premature water coning. The well is scheduled for an acid stimulation job. Well UP-927 (in original plan) was activated and sanded up. The well required installation of an inner liner after which it produced 1322 BGFPD and 41 BOPD in March 2003.

		TABLE 4.7-1				
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**
Dec-02	**930**	**90**		**Dec-02**	**1007**	**91**
Mar-03	**920**	**89**		**Mar-03**	**1027**	**93**

The project team is continuing to activate and repair wells to accelerate oil recovery and reservoir cooling. 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, still

high compared to the 1.05 in most of the other Wilmington waterflood projects. Reservoir modeling currently being performed will provide guidance on when water injection can be reduced safely. It is believed that once good reservoir pressure control is maintained in both the "T" and "D" sands at 90% ±5% for a few years and reservoir temperatures cool adequately, reservoir pressures can be reduced gradually at a decline rate of about 2% hydrostatic pressure per year until overall reservoir pressures approach the 80% hydrostatic pressure level, as this is the pressure theoretically necessary to keep the saturated steam in the reservoir in solution (approximately 900 psi steam is at 532°F). It may be possible to reduce reservoir pressures even below 80% hydrostatic. Table 4.7-1 lists the "T" and "D" sand average reservoir pressures before the post-steamflood phase began in February 1999 and thereafter in quarterly periods.

The Tar II-A steamflood reservoirs have been operated over three years at relatively stable pressures, due in large part to the bimonthly pressure-monitoring program enacted at the start of the post-steamflood phase. The 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 program utilizes old technology, sonic fluid levels and wireline Amerada temperature and pressure bombs, and is relatively low cost compared to other pressure and temperature survey methods. The program not only provides the efficiency of the well pumping equipment, it also provides indications of reservoir connectivity between producers and injectors. The fluid levels have been calibrated for liquid and gas density gradients by comparing a number of them with 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.

The Tar II-A steamflood project has an ongoing temperature survey program to monitor reservoir temperatures. The temperature observation wells may or may not be completed in the Tar sands and consist of both injectors and producers, the latter having tubing without rods. Two types of wireline temperature surveys are run, contact temperature surveys, which have a pad assembly to force the tool against the wellbore and provide continuous temperature readings, and Amerada bomb temperature surveys, which float freely in the wellbore and take temperature measurements at predetermined stops. The Amerada temperature surveys are lower cost and are generally run in combination with Amerada pressure surveys, but contact temperature surveys appear to be more accurate. Surveys are run every six months to annually in about thirty wells. Reservoir temperatures in the T and D sands were originally at 120-130°F and currently range from 135-480°F. Reservoir temperatures in the hot wells such as well OB2-5 are cooling about 10°F per year. The City of Long Beach would like to see reservoir temperatures ultimately cool to below 300°F before abandonment of the project.

Reservoir formation water salinity data is gathered monthly from all active production wells to monitor water breakthrough of the injected cold-water to the producers. See Section 2.2.2 for more details on this surveillance method.

ACTIVITY 5 – OPERATIONAL MANAGEMENT

5.1 Alkaline Water/ Steam Injection Sand Control

The project team completed developing laboratory research procedures to analyze the sand consolidation well completion technique and a contract was approved with the Stanford University Petroleum Engineering Department. Project work was initiated in January 2003. The project team will 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. See Section 4.5 for a historical discussion of the process.

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.

Experimental Design: Multiple cells

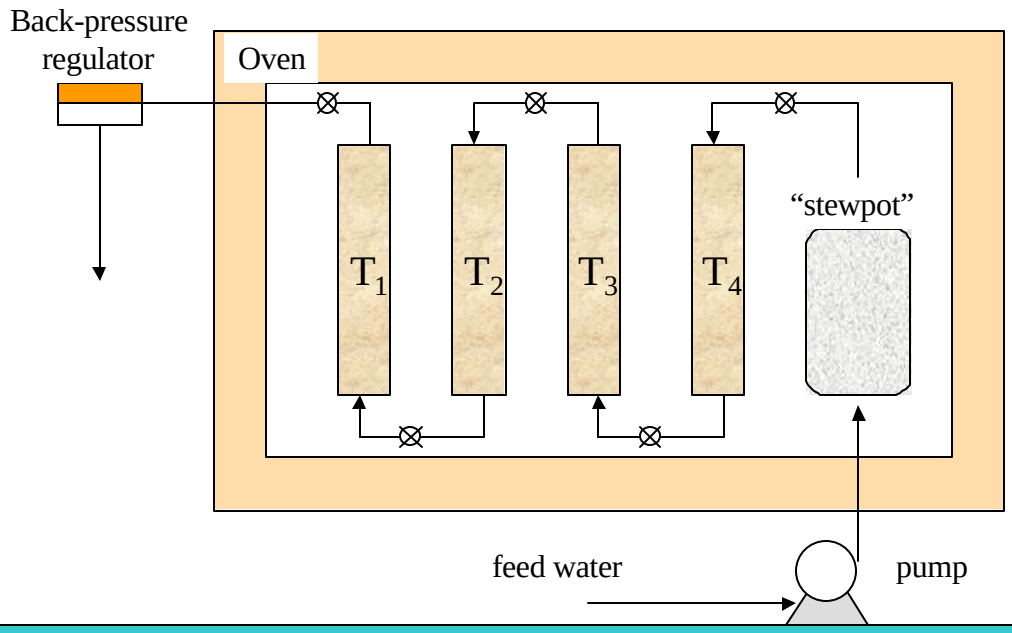


Figure 5.1-1: Conceptual design of test apparatus to create geochemical stew and precipitate it onto gravel samples.

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. Figure 5.1-1 shows the conceptual design of the apparatus, with hot alkaline water going into the stew pot and the soup with the dissolved minerals exiting the stew pot and entering a series of sand packs to observe what precipitates out at different temperatures. A backpressure regulator controls the pressure drops throughout the system.

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.

5.2 Horizontal Well Completion Techniques

Tidelands has been applying two well completion technologies for horizontal wells including the sand consolidation process and a new gravel-packed, slotted-liner completion procedure that has been successful to date in Tar V wells L-232 and L-233 (Tidelands' DOE Class 3 near-term 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.

Workovers were performed on two horizontal producers, one in the Tar II-A (UP-955) and one in the Tar V (J-205) to restore sand control and improve fluid productivity by installing inner liner gravel-packed completions to back up the current sand consolidation completions. The job on UP-955 has been successful in restoring full productivity to the well (1668 BGFPD and 58 BOPD with 1920 ft of fluid over pump), but J-205 experienced severe formation damage (1270 BGFPD and 37 BOPD with fluid at the pump) and requires an acid job or other stimulation technique to restore full productivity. The sand consolidation completions can fail if the wells are pumped too hard because the high differential pressures pull the formation sands into the wellbores. Theoretically, the wells like UP-955 could produce at 100 - 300% higher rates if pumped hard enough to draw the fluid levels down to the pump. The proposed inner liners were designed to allow the wells to be pumped at rates up to 3000 BGFPD, which is the limit

for the pumping units. The goal is to increase oil production to over 125 BOPD per horizontal well.

Recent new horizontal wells (L-232 and L-233) drilled by Tidelands in the Wilmington Field were completed either as a cased-through well with selective perforations and inner liner gravel pack completion (L-232) or as an open-hole, slotted-liner, gravel-packed completion for sand control (L-233). The wells were drilled through the completion intervals with measurement while drilling and logging while drilling (MWD/LWD) tools and a sized calcium carbonate polymer mud system to minimize water loss. After reaching total depth, well L-232 had 7-5/8" casing cemented to total depth, selectively perforated, and completed with a gravel-packed 4-1/2 " wire wrapped screen. Well L-233 had 7-5/8" casing cemented to the Tar zone T sands and the completion interval was drilled with a 6-3/4" bit and opened with a 6-3/4" bull-nosed pilot hole reamer and a 4-1/2" wire wrapped screen was set inside. The 20-40 mesh gravel was packed at a concentration of 0.4 – 1.0 pounds per gallon (ppg) with filtered 9.0 ppg NaCl brine water through the top of the liner. When the gravel packed off prematurely, the tubing was connected to the GPC shoe at the bottom of the liner and gravel was packed through the bottom of the well. Well L-232 has produced since April 2001 and experienced some sand inflow that has caused a few pump failures. Well L-233 has produced problem free since December 2001. Both wells are producing from sands that have not been adequately waterflooded and therefore have relatively low gross fluid rates ranging from 175 to 600 BGFPD and high oil cuts of 20-40%. Although the initial production rates are encouraging, the new completion type is not experiencing high gross fluid rates and water cuts and more time is needed to evaluate its performance.

5.3 Profile Control in Horizontal Injectors

No activity this period.

5.4 Minimize Carbonate Scale Problems

With the steam chest filled and reservoir pressured stabilized at about 90% hydrostatic or higher for over a year, the plan is to increase well work activity to increase production and injection. Acid stimulation jobs have been successful and are planned on selected producers to remove wellbore scale and increase oil cuts.

5.5 Determine Temperature Limits to Minimize Operating Problems

Thermal-related compaction of sands and shales in the Tar zone were studied in an effort to confirm one of the causes of surface subsidence in the Tar II-A steamflood area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are planned to determine the critical maximum reservoir temperature that can be reached before causing appreciable shale compaction. This information will help determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects. No activity this period.

ACTIVITY 6 – EXPANSION PROGRAM

Recent thermal recovery methods in the Wilmington Field have been expanded from the Tar II-A steamflood project to include a pilot steamflood in the Tar V "S" sands and cyclic steam injection into the Ranger V zone, the Upper Terminal V zone and other areas of the Tar V zone. Some of the Ranger V and Upper Terminal V cyclic steam injection work were included in the DOE Class III Short-term Wilmington Field Waterflood Project under contract #DE-FC22-95BC14934. Cyclic steam jobs applied to the wells gave them sand-consolidated, limited-entry perforated completions and provided a boost to initial oil production rates by reducing the oil viscosity in the near-wellbore region.

Future thermal recovery work at Wilmington must consider potential oil rates and reserves, the cost-effectiveness of the sand consolidation or other completions over the life of the wells, and the sensitivity of the sands and shales to thermal-related formation compaction.

The Budget Period 2 plan will utilize the technologies developed in Budget Period 1 to improve thermal and heavy oil recovery from the Tar zones in the Wilmington Field. These technologies include steamflooding, hot waterflooding and post-steamflooding the Tar II-A and Tar V steamflood projects, horizontal well drilling and completion technology, reservoir characterization, pilot testing, geologic and reservoir modeling, and reservoir management techniques. The first part of the plan includes obtaining current reservoir oil saturation data through reservoir simulation modeling, new cased hole logs, or drilling vertical wells penetrating all of the Tar subzones to obtain new open hole logs. This information will determine which sands have bypassed oil in the steamfloods and adjacent waterfloods. Projected well work includes well conversions from injection to production and vice-versa, plugback and selected liner isolation jobs to avoid watered out sands, well recompletions with selective perforations and one or more horizontal wells. New vertical wells will be selectively perforated with either gravel-packed inner liners or sand consolidation completions to increase oil production where existing wells have "watered out" and to replace failed wells. Horizontal wells will be drilled in structurally updip and stratigraphically high locations to improve Tar zone oil recovery in a post-steamflood setting and accelerate reservoir cooling.

The original Budget Period 2 plan to expand the Tar II-A steamflood project was revised because of the loss of the Tar II-A steam source from the Harbor Cogeneration Plant. Steam needed in Tar II-A, if any, would be supplied through a leased portable steam generator. The only anticipated steam needed in Tar II-A would be for sand consolidating new well completions. The Tar V steam generator is currently idle, but can be made operational when needed to service Tar V wells.

The objective of the proposed Budget Period 2 project work is to increase oil production and improve the water cuts and operating cost structure for the Tar II-A and Tar V projects, thereby extending the lives of the projects and increasing oil reserves by an estimated 2-3 million barrels.

Future thermal recovery work at Wilmington must consider potential oil rates and reserves, the cost-effectiveness of the sand consolidation or other completions over the life of the wells, and the sensitivity of the sands and shales to thermal-related formation compaction. The work remaining in Budget Period 1 addresses these concerns and proposed work in Budget Period 2 will utilize the technologies learned from Budget Period 1 and carry them forward.

ACTIVITY 7 – TECHNOLOGY TRANSFER

Introduction

The project team wrote one white paper this reporting period and continues to transfer technology to interested operators.

7.1 DOE Reports

The project team is current on quarterly and annual reports from project inception on March 30, 1995 through March 31, 2003, which total 32 quarterly reports and six annual reports[E34-38]. The five prior "annual" reports cover the periods 1995-96, 1996-97, 1997-2000, 2000-01 and 2001-02. This "annual report" covers the period from April 1, 2002 to March 31, 2003.

7.2 Publications

Project team publications or publications by others that are related to project team work which were written during the reporting period have been categorized by professional society, DOE, or other organizations.

7.2.1 Professional Societies

Don Clarke of the City of Long Beach and Chris Phillips of Tidelands wrote a white paper entitled "Three-dimensional Geologic Modeling and Horizontal Drilling Bring More Oil Out of the Wilmington Oil Field of Southern California" which was published in a new 2003 AAPG book entitled "*Horizontal Wells: Focus on the Reservoir*"[A38].

The project attracted interest from two organizations in Trinidad / Tobago. Several papers of interest related to the sand consolidation well completion and formation geochemistry were emailed.

7.2.2 Industry Trade Journals and Newspapers

No activity reported this period.

7.2.3 DOE Symposium Proceedings

No activity reported this period.

7.2.4 Professional Society Newsletters / Mailing List

No activity reported this period.

7.2.5 Database Files

No activity reported this period.

7.3 Presentations

Presentations on project-related technical work given during the current reporting period are categorized by PTTC, professional society, DOE, or other organizations.

7.3.1 Professional Societies

SPE/AAPG-organized Oral Presentations

No activity reported this period.

7.3.2 Industry Organizations

No activity reported this period.

7.3.3 Non-oil Industry Organizations

No activity reported this period.

7.4 Technology Awards

No activity reported this period.

7.5 Web Site and CD-ROM Projects

A home page on the USC service provider has been set up in conjunction with the existing account for the Petroleum Engineering Program at USC. The ongoing DOE projects on the West Coast are comprehensively summarized and can be accessed at: http://www.usc.edu/dept/peteng/topko.html

The web site is also linked to a significant number of petroleum related sites both in industry and in academia, which includes the national PTTC site.

A CD-ROM of the project has been completed and was presented at the DOE and PTTC exhibit booths at the 1997 SPE Western Regional Meeting. The CD-ROM is

available on IBM PC format and is distributed free to interested operators and organizations by contacting Scott Hara by phone at 562-436-9918 or through email at scott.hara@tidelandsoil.com. The CD-ROM project is essentially a collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project.

7.6 Field Tours

No activity reported this period.

ACTIVITY 8 – PROJECT MANAGEMENT

Executive Committee and Steering Committee

The Executive and Steering Committees are active in supporting the operation of the Tar II-A and Tar V thermal projects and committing to the technology transfer aspects of this DOE project. In fact, as of the end of the reporting period, the Project Team partners have published more original papers and given more presentations to industry and non-industry groups than any other DOE Class Project.

REFERENCES

References in “A”, “B”, and “E” below provide all of the papers and publications of original technical work completed throughout the project or in progress. References in “C” below are poster and oral presentations that were given throughout the current reporting period only. References in “D” below were cited in this report, but were not specifically part of this project. References in “F”, “G” and “H” were cited in current or former annual reports within the sections of the report noted.

A. Papers, Articles, Reports, CD-ROMs, Web Sites, and Other Original Technical Work Generated by DOE Project Team

A1 Sameer Joshi, L.M. Castanier and W.E. Brigham (Stanford University), Mike C. Wood (Union Pacific Resources Co.), ”Steamflooding a Waterflooded Reservoir - Performance Evaluation Prediction”, SPE Paper 29669 presented at the 1995 Western Regional Meeting of the Society of Petroleum Engineers in Bakersfield, CA, 8-10 March 1995.

A2 Mike C. Wood, Bruce Laughlin, Doug Fuller and Robert Fickes (Tidelands Oil Production), “The Use of Downhole Submersible Pumps in a High Temperature Steamflood”, SPE paper 29507, presented at the 1995 Society of Petroleum Engineers Production Operations Symposium in Tulsa, OK, April 1995.

A3 David Crane, William R. Barry II (Digital Petrophysics Inc.), ”Database preparation for Wilmington Field, Fault Block II-A - Tar Zone” dated 15 June 1995.

A4 Herman E. Schaller, ”Study of Water Injection Surveys, Tar Zone, Fault Block II, Wilmington Field” dated 8 November 1995.

A5 David Crane (Digital Petrophysics Inc.), report dated 12 March 1996 detailing list of well data that had undergone checking and processing.

A6 David K. Davies, Richard K. Vessel (David K. Davies and Associates), ”Nature, Origin, Treatment and Control of Well-Bore Scales in an Active Steamflood, Wilmington Field, California”, SPE Paper No. 35418, 1996 Society of Petroleum Engineers/Department of Energy Tenth Symposium on Improved Oil Recovery in Tulsa, OK, 21-14 April.

A7 Donald Clarke (City of Long Beach), Chris Phillips (Tidelands Oil production), “Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin”, field trip and guidebook of 14 papers, given at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996. The guidebook was revised for a tour given at the 1997 Western Regional Meeting of the Society of Petroleum Engineers and subsequently reprised each year for industry professionals and public school teachers.

[A8] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), and Linji An (University of Southern California), ”3-D Modeling, Horizontal Drilling... Give New Life to Aging Fields”, *American Oil & Gas Reporter*, September 1996 issue, pages 106-115.

[A9] Iraj Ershaghi, M. Hassibi (University of Southern California), ”A Neural Network Approach for Correlation Studies in a Complex Turbidite Sequence”, SPE Paper No. 36720, 1996 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Denver, CO, 6-9th October.

[A10] Rick Cassinis (Tidelands Oil Production), “2100-foot, 14-inch Steam Line Under a Ship Channel”, SPE Paper No. 37530, 1997 SPE International Thermal Operations and Heavy Oil Symposium in Bakersfield, CA, 10-12 February 1997.

[A11] Al-Qahtani, M., Ershaghi, I., University of Southern California: "Characterization and Estimation of Permeability Correlation Structure from Performance Data", Paper presented at Fourth International Reservoir Characterization Technical Conference sponsored by DOE, BDM, and AAPG, 2-4 March 1997.

[A12] Iraj Ershaghi, Lyman L. Handy, Yucel I. Akkutlu (University of Southern California), Julius J. Mondragon III (Tidelands Oil Production), ”Conceptual Model of Fault Block II-A, Wilmington Field, from Field Performance Data”, SPE Paper No. 38309, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A13] Iraj Ershaghi, Pouya Amili (University of Southern California), ”Correlations for Prediction of Steamflood Oil Recovery in Steam-Assisted Gravity Drainage (SAGD) Process Using Horizontal Injectors and Producers”, SPE Paper No. 38297, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A14] Walt Whitaker II (Tidelands Oil Production), ”7-ppm No. 50 MM BTU/hr Oilfield Steam Generator Operating on Low-Btu Produced Gas”, SPE Paper No. 38277, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A15] F. Scott Walker (Tidelands Oil Production), ”Locating and Producing Bypassed Oil: A DOE Project Update”, SPE Paper No. 38283, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June. This DOE waterflood project for Wilmington describes new application of well completion technology using steam to consolidate sand developed in this project.

[A16] Richard Cassinis (Tidelands Oil Production), William A. Farone (Applied Power Concepts, Inc.), ”Improved H_2S Caustic Scrubber”, SPE Paper No. 38273, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A17] David K. Davies, Richard K. Vessel (David K. Davies and Associates), ”Improved Prediction of Permeability and Reservoir Quality through Integrated Analysis of Pore

Geometry and Open-hole Logs: Tar Zone, Wilmington Field, California", SPE Paper No. 38262, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A18] Donald Clarke, (City of Long Beach), Chris Phillips, (Tidelands Oil Production Company), "Horizontal Drilling for Thermal Recovery in the Wilmington Field, California", Article for Summer 1997 edition of U. S. DOE *The Class Act*.

[A19] David K. Davies (David K. Davies and Associates), Julius J. Mondragon III, P. Scott Hara (Tidelands Oil Production), "A Novel Low-Cost Well Completion Technique Using Steam for Formations with Unconsolidated Sands, Wilmington Field, California", SPE Paper No. 38793, 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

[A20] David K. Davies, John Aumon, Richard K. Vessel (David K. Davies and Associates), "Improved Prediction of Reservoir Behavior through Integration of Quantitative Geological and Petrophysical Data", SPE Paper No. 38914, 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

[A21] Iraj Ershaghi, Chang-An Du, Linji An (University of Southern California), "A Three Stage Conditioning Process for Scrutinizing Stochastic Representation of a Turbidite Sequence in a Densely Drilled Formation", SPE Paper No. 38681, not done in 1997 as planned.

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[A23] Montgomery, Scott (Consultant Technical Writer), "Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part I: Reservoir Characterization to Identify By-passed Oil", *AAPG Bulletin*, March 1998, pages 367-385.

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[A25] Yang, Zhengming and Ershaghi, Iraj, (University of Southern California), Mondragon, Julius III and Hara, Scott, (Tidelands Oil Production Co.), "Method for Handling the Complexities Associated with History Matching the Performance of a Highly Stress-Sensitive Formation", SPE Paper #49314, 1998 SPE Annual Technical Conference, New Orleans, LA, Sept. 27-30.

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[A29] Hassibi, Mahnaz, (USC), "A Method For Automating Delineation of Reservoir Compartments and Lateral Connectivity From Subsurface Geophysical Logs", Doctoral Thesis, USC Department of Chemical Engineering - Petroleum Engineering Program, May 1999.

[A30] Hara, P. Scott and Mondragon, Julius J. III, (Tidelands), Davies, David K., (DKD), "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam", 1999 DOE Oil and Gas Conference, Dallas, TX, June 28-30.

[A31] Davies, David K., (DKD), Davies, John P., (Chevron), "Stress-Dependent Permeability: Characterization and Modeling", SPE Paper #56813, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

[A32] Davies, David K., (DKD), Hara, P. Scott and Mondragon, Julius J. III, (Tidelands), "Geometry, Internal Heterogeneity and Permeability Distribution in Turbidite Reservoirs, Pliocene California", SPE Paper #56819, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

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[A35.] Changan Du, Iraj Ershaghi, (USC), "Reservoir Characterization and Stochastic Modeling of Fault Block II-A Turbidite Sand Formation of Wilmington Oil Field, Long Beach, California", technical report, USC Department of Chemical Engineering –

Petroleum Engineering Program, December 1998. Revised by Julius Mondragon III, (City of Long Beach), May 2001.

A36. Donald D. Clarke, City of Long Beach, Christopher C. Phillips, Tidelands, "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California," GCSSEPM Foundation 20th Annual Research Conference – Deep-Water Reservoirs of the World, Houston, TX, December 3-6, 2000

A37. Christopher C. Phillips, Tidelands, "Enhanced Thermal Recovery and Reservoir Characterization", in Field Guide prepared by Don D. Clarke, City of Long Beach George E. Otott, Jr., THUMS, and Christopher C. Phillips, "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin: Pacific Section AAPG, 1996 AAPG Annual Meeting, May 18-22, p. 65-82.

A38. Clarke, Don, City of Long Beach, Phillips, Chris, Tidelands Oil Production Co., "Three-dimensional Geologic Modeling and Horizontal Drilling Bring More Oil Out of the Wilmington Oil Field of Southern California", published by AAPG in the book, "*Horizontal Wells: Focus on the Reservoir", 2003, pages 27-47, Tulsa, OK.*

B. Publications Related to Original DOE Project Technical Work and Articles of Interest

B1 Steve Bell, "Extraction Technologies May Increase Recoverable Reserves by Billions", Hart's *Petroleum Engineer*, Tech Trends, page 9, March 1995.

B2 Donald D. Clarke, Xen Colazas (City of Long Beach), Janet Wiscombe (Los Angeles Times), "Drilling in Disguise", *Los Angeles Times*, Metro Section, page B2, 15 November 1996.

B3 Chris C. Phillips (Tidelands Oil Production), Pat Prince Rose (Los Angeles Times), "In Geological Time, He's Ancient", *Los Angeles Times*, Business Section, Trends, page D5, 9 December 1996.

B4 Iraj Ershaghi (University of Southern California), Frank Clifford (Los Angeles Times), "A New Oil Boom", *Los Angeles Times*, Metro Section, Next L.A., page B2, 24 December 1996.

B5 Richard Cassinis, Sean Massey (Tidelands Oil Production), Stuart M. Heisler (TJ Cross Engineers Inc.), for the Sulfatreat Company "The Story Behind Lo~CoST^{SM}", *Oil, Gas and Petrochem Equipment* Magazine, back cover page, March 1997. Advertisement by the Sulfatreat Company on product developed through the DOE project work related to "Improved H_2S Caustic Scrubber" technology. Also refer to, http://www.ingersoll-rand.com/compair

[B6] Iraj Ershaghi (University of Southern California), Herb Tiderman (DOE), Gail Dutton (Compressed Air Magazine), ”Coaxing Crude From The Ground”, *Compressed* Air Magazine, pages 22-26, March 1997.

[B7] Jeff Schwalm (Dynamic Graphics Inc.), Chris C. Phillips (Tidelands Oil Production), ”Earth Vision Software Solutions for Structurally Consistent 3-D Geologic Modeling, 3-D Well Placement Planning”, Advertisement Mailer sent to the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting attendees, conducted 7-9 April 1997. Mailer contains copy of “3-D Modeling, Horizontal Drilling... Gives New Life to Aging Fields”, Wilmington DOE projects featured in Dynamic Graphics’ exhibit booth at convention and in Internet homepages: (info@dgi.com and http://www.dgi.com/topko.html)

[B8] University of Southern California, West Coast DOE projects comprehensively summarized and can be accessed at: http://www.usc.edu/dept/peteng/doe.html. Summarized content of the previous year’s annual report is located at: http://www.usc.edu/dept/peteng/topko.html

[B9] University of Southern California, A collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project on CD-ROM.

[B10] Davies, David K., David K. Davies and Assoc. Inc., Mondragon, Julius J. III and Hara, P. Scott, Tidelands Oil Production Co., SPE Paper #38793 "Well-Completion Technique Using Steam For Formations With Unconsolidated Sands", *SPE Journal of Petroleum Technology*, September 1998, pages 46-52, an abridged version of the paper.

[B11] Clark, Donald D., City of Long Beach, Phillips, Christopher C., Tidelands Oil Production Company, “Successful Horizontal Well Program In Wilmington Field”, *DGInsider, the EarthVision Newsletter*, First Quarter 1999.

[B12] Davies, David K., Vessel, Richard K., Aumon, John P., DKD, “An Improved Prediction of Reservoir Behavior Through Integration of Quantitative Geological and Petrophysical Data”, SPE Paper #38914 peer-reviewed and assigned SPE Paper #55881, *SPE Reservoir Evaluation and Engineering* Magazine, April 1999.

[B13] Davies, David K., DKD, Davies, John P., Chevron wrote an article entitled “Stress-dependent Permeability in Unconsolidated Sand Reservoirs”, *Offshore Magazine*, February 2000, pp 82-84, a summary of SPE Paper 56813, “Stress-Dependent Permeability: Characterization and Modeling” in ref. A31 above.

[B14] Ron Bowman (Case Engineering and Laboratory, Inc.), L. C. Gramms (Separ Systems and Research Ltd.), R. R. Craycraft (Union Pacific Resources Inc.), “High-Silica Waters in Steamflood Operations”, SPE Paper #37528 peer-reviewed and

assigned SPE #63015, *SPE Production and Facility Engineering Magazine* (pages 123-125) May 2000.

B15 D. D. Mamora, F. E. Moreno, Guillemette R. (Texas A&M University), "Sand Consolidation Using High-Temperature Alkaline Solution", SPE Paper #62943, 2000 SPE Annual Technical Conference and Exhibition, Dallas, TX, October 1-3.

B16 F. E. Moreno, D. D. Mamora, (Texas A&M University), "Sand Consolidation Using High-Temperature Alkaline Solution – Analysis of Reaction Parameters", SPE Paper #68847, 2001 SPE Western Regional Meeting, Bakersfield, CA, March 26-30.

C. Presentations, Poster Sessions, Tours, and Other Activities from which No New Reference Materials were Generated

C1 Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Horizontal Wells in a Clastic Oil Field with Intraformational Compaction", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

C2 Iraj Ershaghi, Linji An (University of Southern California), Donald D. Clarke (City of Long Beach), Chris Phillips (Tidelands Oil Production), "Sealing Behavior of Normal Faults in Fault Block II, Wilmington Oil Field, California", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

C3 Jeff Schwalm, John Perry (Dynamic Graphics Inc.), :"3-D Geologic Modeling: Theory and Application", a half day workshop sponsored by the PTTC at USC Campus, Los Angeles, CA on 2 May 1997. Presentation utilizes 3-D Deterministic Geologic Model from this project to explain fundamentals of 3-D Geologic Modeling.

C4 Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Tertiary Development of Heavy Oil Sands through Thermal Recovery in the Wilmington Oil Field, California: An Update and Some New Challenges", Oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, on 14-16 May.

C5 Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Reservoir Characterization Using Advanced 3-D Computer Modeling Technology: A Case Study of the Fault Block II in Wilmington Field, California", Electronic poster session at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

[C6] M. Hassibi, Iraj Ershaghi (University of Southern California), “Characterization of Lithological Log Responses in Turbidite Series using Neural Networks”, oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May 1997.

[C7] David K. Davies, Richard K. Vessel (David K. Davies and Associates), ”Geological Controls on Permeability Distribution and Sand Distribution: Tar Zone, Fault Block II-A, Wilmington Field”, oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

[C8] Donald D. Clarke (City of Long Beach): Project status presentation for DOE/BDM conference regarding status of all DOE contracted projects, Houston, TX, 16-20 June 1997.

[C9] Julius Mondragon III, Scott Hara (Tidelands Oil Production), ”Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in the Tar Zone, Wilmington Field”, SPE GEM Presentation WR GEM 29, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C10] Chris Phillips, Scott Hara (Tidelands Oil Production), ”Three-Dimensional Geological Modeling as a Cost-Effective Tool for Horizontal Drilling”, SPE GEM Presentation WR GEM 6, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C11] Mark Kapelke (Tidelands Oil Production), “How to Work With the DOE” and “Multimedia and Technical Transfer”, National Petroleum Technology Resource Center sponsored by the DOE, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C12] Du, C., University of Southern California, West Coast PTTC staff, organized short course entitled "GOCAD^{++} Training" and made a presentation during the course, November 14, 1997 at USC campus.

[C13] Hara, S., Tidelands Oil Production Company, reprised sand consolidation well completion presentation - SPE paper 38793, SPE Los Angeles Basin Section New Technology and Environmental Forum meeting, November 19, 1997, Long Beach Petroleum Club.

[C14] Ershaghi, I., University of Southern California, Clarke, D., City of Long Beach, West Coast PTTC staff: Organized geologic short course and field trip on "Turbidite Reservoirs in California", November 24, 1997, Ventura, CA.

[C15] Tidelands Oil Production Company gave a short presentation of the two Wilmington Class III projects to Guido DeHoratiis of the DOE on December 4, 1997 in Tidelands' office.

[C16] Clark, D., City of Long Beach, Phillips, C., Tidelands Oil Production Company, "Subsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technologies Solutions from the Wilmington Oil Field, California, USA", 3rd AAPG / EAGE Joint Research Conference on Developing and Managing Turbidite Reservoirs: Case Histories and Experiences, Almeria, Spain, 4-9 October 1998.

[C17] Scott Hara gave an oral presentation entitled "Steamflooding Recovery of a Class 3 Reservoir – DOE's Cooperative Efforts with Independent Producers to Enhance Production While Maintaining Safe and Environmentally Compatible Operations" at the Technology Assessment & Research Program's Technology Seminar held on May 19, 1999 at the office of the U. S. Minerals Management Service in Camarillo, CA.

[C18] Same as (C18), but given at 1999 EAGE Conference and Technical Exhibition, Helsinki, Finland, June 7-11.

[C19] Same as (C18), but given at 1999 AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13.

[C20] Clarke, Donald D., City of Long Beach, "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field", 1999 AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13.

[C21] Scott Hara reprised his presentation entitled "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam" at two West Coast Petroleum Technology Transfer Council (PTTC) workshops on "Sand Control for California Oilfield Operations" given in Long Beach, CA on November 18, 1999 and in Bakersfield, CA on November 19, 1999.

[C22] Scott Hara made an oral presentation summarizing this DOE project's achievements related to reservoir and operational management and technical transfer of steamflood experience to the Wilmington Fault Block V Tar zone. The presentation was given at the West Coast PTTC Annual Forum held on the USC campus on December 10, 1999.

[C23] Scott Hara, Tidelands, reprised presentation "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam", 2000 IPAA Mid-year Meeting, San Francisco, CA, May 18-20.

[C24] Don Clarke, City of Long Beach, reprised oral presentation "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field", 2000 Pacific Section AAPG/SPE Western Regional Meeting, Long Beach, CA, June 19-22.

[C25] Scott Hara nominated and helped prepare application for the 2001 Pacific Section AAPG Teacher of the Year Award Winner, Mr. John Jackson, of Monterey Highlands

Elementary School, Monterey Park, CA. Mr. Jackson was presented the award at the 2001 PSAAPG Annual Meeting, Universal City, CA, April 10.

[C26] Hara, Scott, Tidelands Oil Production Company, "Applying New Technology to an Old Field", California Conservation Committee of Oil and Gas Producers, Long Beach, CA, 19 September 2001.

[C27] Hara, Scott, Tidelands Oil Production Company, "Applying New Technology to an Old Field", Stanford University Petroleum Engineering Dept., Stanford University, CA, 2 November 2001.

[C28] Hara, Scott, Tidelands Oil Production Company, "World Oil and Gas Reserves and Recovery Methods", Geology classes, Long Beach Polytechnic High School, Long Beach, CA, 13 March 2002.

D. Outside References Cited in Report

[D1] Small, G.P., Shell California Production Inc. "Steam-Injection Profile Control Using Limited-Entry Perforations", SPE Paper 13607, presented at the 1985 California Regional Meeting in Bakersfield, CA, March 27-29 1985.

[D2] R.M. Butler, "Gravity Drainage to Horizontal Wells", *Journal of Canadian Petroleum Technology*, Volume 31, No. 4, pages 31-37, April 1992.

[D3] F.H. Lim, W.B. Saner and W.H. Stillwell (Union Pacific Resources Co.) and J.T. Patton (New Mexico State University), "Steamflood Pilot Test in Waterflooded, 2500 ft. Tar Zone Reservoir, Fault Block II Unit, Wilmington Field, California", presented at the 1993 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Houston, TX, 3-6 October 1993.

[D4] R.M. Butler, *"Horizontal Wells for the Recovery of Oil, Gas and Bitumen; Monograph 2"*, Petroleum Society of CIM, Calgary 1994.

[D5] M. Polikar, D.A. Redford, "Evolution of Steam-Based Technology for the Recovery of Canadian Heavy Oil Reservoirs", *Journal of Petroleum Technology*, Volume 34, No. 5, pages 33-40, May 1995.

[D6] Ershaghi, I., Omoregie, O., University of Southern California, "A Method for Extrapolation of Cut Vs. Recovery Curves," *Journal of Petroleum Technology*, pages 203-04, February 1978.

[D7] Ershaghi, I., Abdassah, D., University of Southern California, "A Prediction Technique for Immiscible Processes Using Field Performance Data," *Journal of Petroleum Technology*, pages 664-70, April 1984.

[D8] George E. Ottot, Tom F. Norton, Thums Long Beach Company, "The Stratigraphy of the Wilmington Field", Pacific Section American Association of Petroleum Geologists, Field Guide Book entitled "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin"[A7], 1996 AAPG Annual Meeting, San Diego, CA, May 18-22

[D9] M. N. Mayuga, City of Long Beach, "Geology and Development of California's Giant - Wilmington Oil Field", American Association of Petroleum Geologists Memoir No. 14, 1970.

E. Required Reports Generated for the Department of Energy

[E1] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (30 March 1995 - 30 June 1995).

[E2] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1995 - 30 September 1995).

[E3] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1995 - 31 December 1995).

[E4] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 1996 - 31 March 1996).

[E5] Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (30 March 1995 - 31 March 1996).

[E6] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1996 - 30 June 1996).

[E7] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1996 - 30 September 1996).

[E8] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 October 1996 - 31 December 1996).

[E9] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 January 1997 - 31 March 1997).

[E10] Project Team, Annual Report entitled “Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 April 1996 - 31 March 1997).

[E11] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 April 1997 - 30 June 1997).

[E12] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 July 1997 - 30 September 1997).

[E13] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 October 1997 - 31 December 1997).

[E14] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 January 1998 - 31 March 1998).

[E15] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (1 April 1998 - 30 June 1998).

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[E17] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil

Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1998 - 31 December 1998).

[E18] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 1999 - 31 March 1999).

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[E20] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1999 - 30 September 1999).

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[E23] Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1997 - 31 March 2000).

[E24] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 2000 - 30 June 2000).

[E25] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 2000 - 30 September 2000).

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[E27] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 2001 - 31 March 2001).

[E28] Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 2000 - 31 March 2001).

[E29] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 2001 - 30 June 2001).

[E30] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 2001 - 30 September 2001).

[E31] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 2001 - 31 December 2001).

[E32] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 2002 - 31 March 2002).

[E33] Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 2001 - 31 March 2002).

[E34] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 2002 - 30 June 2002).

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[E36] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil

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