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

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

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$700,000 (2000 Projected)
$199,957 (June 2000 YTD Actual)

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Objectives

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

Summary of Technical Progress

Through June 2000, 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 (Tar II-A) Zone. Work is continuing on improving core analysis techniques, final reservoir tracer work, operational work and research studies to prevent thermal-related formation compaction in the Tar II-A steamflood area, and operational work on the Tar V steamflood pilot and Tar II-A post steamflood project. Work was discontinued on the stochastic geologic model and developing a 3-D stochastic thermal reservoir simulation model of the Tar II-A Zone so the project team could use the 3-D deterministic reservoir simulation model to provide alternatives for the Tar II-A post steamflood operations and shale compaction studies.

The project team spent the third quarter 2000 revising the draft 1997-2000 Annual Report submitted last quarter, writing final reports on the research projects mentioned above, and operating the Tar II-A post-steamflood project and the Tar V horizontal well steamflood pilot.

Thermal-related formation compaction is a concern of the project team due to observed surface subsidence in the local area above the Tar II-A 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. An 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 has been to increase and subsequently maintain reservoir pressures at a level that would fill-up the steam chests in the "T" and "D" sands before they can collapse and cause formation compaction and to prevent the steam chests from reoccurring. A new 3-D deterministic thermal reservoir simulation model was used to provide operations with the necessary water injection rates and allowable production rates by well to minimize future surface subsidence and to accurately project reservoir steam chest fill-up by October 1999. A geomechanics study and a separate reservoir simulation study have been performed to determine the possible indicators of formation compaction, the temperatures at which specific indicators are affected and the projected temperature profiles in the over and underburden shales over a ten year period following steam injection. Further geomechanics work should be conducted.

It was believed that once steam chest fill-up occurred, the reservoir would act more like a waterflood and production and cold water injection could be operated at lower Injection to production ratios (I/P) and net injection rates. In mid-September 1999, net water injection was reduced substantially in the “D” sands following steam chest fill-up. 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 of 90% hydrostatic pressure by March 2000 and have been maintained through September 2000. When the “T” sands reached fill-up in October 1999, net “T” sand injection remained at a high rate through April 2000 and reservoir pressures stabilized at 98% hydrostatic pressure. The objective is to lower "T" sand pressure slowly to 90% hydrostatic. Net injection was reduced and "T" sand reservoir pressure was at 97% hydrostatic in September 2000. A more detailed discussion of the operational changes is in the Reservoir Management section of this report.

A reservoir pressure monitoring program was developed as part of the post-steamflood reservoir management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. The fluid levels have been calibrated for liquid and gas density gradients by comparing 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.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field, including the Tar V horizontal well pilot steamflood project, is a critical part of the City of Long Beach and Tidelands Oil Production Company’s development strategy for the field. The current thermal operations in the Wilmington Field are economical with low oil prices due to the availability of inexpensive steam from an existing 50 MMBTU/hr steam generator that can utilize non-commercial low Btu produced gas. Such 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.

Advanced Reservoir Characterization

With the shutdown of the steam injection process into the Tar II-A zone, further work on the 3-D stochastic reservoir modeling work has been limited to completing the core analysis and reservoir tracer work and finalizing the neural network log analyzer report. A preliminary report on the characterization of discontinuous shale bodies has been prepared that utilizes the available core analysis data and shows initial log-core correlation work and stochastic renderings of geologic models.

Past core analysis data had indicated inflated values for porosity and permeability when measuring unconsolidated sand formations. The project team evaluated several alternative procedures for analyzing conventional core data compared to the “routine porosity, permeability, and saturation techniques used by commercial core analysis companies. The most important and cost-effective procedural change is to measure reservoir characteristics with the core samples under original overburden-type stresses. The study also provides correlations to correct data measured using the previous “routine” core analysis method.

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 Gamma Ray logs. Sample stochastic grid block models were test run on the 3-D Earth-Vision™ 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 changes in the character of lithology logs in sand-shale sequences makes the visual correlation often a very difficult task. With over 600 penetrating well logs through an average of 280 ft of gross Tar II-A sands, the need for developing a neural network analyzer to expedite the stochastic geologic modeling was evident.

Tracer studies were conducted on characterizing the anisotropic nature of the formation. A study measuring naturally existing cations and anions in the produced water as affected by dilution of formation water by the condensed fresh water in the steam was completed and presented at the 1999 SPE Thermal Recovery Meeting in Bakersfield. The report has been upgraded and will be included in the 1997 - 2000 Annual Report.

The reservoir tracers, ammonium thiocyanate (AT) and lithium chloride (LC), were bulk injected on February 14 1997 into two hot water-alternating-steam pilot injectors. Sampling of produced fluids from first and second rows of producers were collected for analysis of the ammonium and lithium tracers. Very few tracer hits above background levels were recorded. The mixed signals were partly because the tracers break down in the very high temperature environment and in part because of operational changes dictated by the rapid conversion of steam injectors to hot water injectors. The tracer work included the issues related to tracer selection, concentrations and volumes and to field sampling, laboratory analyses and interpretation of the produced water results for tracer hits. In spite of its mixed results, the technology transfer value of the findings is substantial for other similar thermal operations and an upgraded report will be included in the 1997 - 2000 Annual Report.

Reservoir Simulation

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.

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. Reservoir pressures in the target area are affected by the following occurrences: mixing of the hot and cold fluids at the flank 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 post-steamflood reservoir simulation modeling study was the basis for a technical paper presented at the AAPG / SPE Western Regional Meeting in June 2000[1].

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 can effectively predict overall mass and heat balance of the injected and produced fluids, provided it is updated with actual data. The model cannot predict net oil production and did not provide the correct steam chest fill-up pressure or the short term I/P ratio following steam chest fill-up, but it did perform its primary function of setting injection and production rates and predicting when steam chest fill-up would occur. This model should be adapted for use on the Tar V steamflood pilot project.

Simulating Thermal Heating of Overburden and Underburden Shales

In the fourth quarter 1999, reservoir simulation modeling efforts were directed towards determining the amount of reservoir heat that is thermally conducted from the Fault Block II-A Tar Zone steamflood sands to the overburden and underburden shales. The model was based on a 1/12 of a seven-spot 5 x 5 x 81 grid (2025 grid blocks) using the CMG STARS™ thermal reservoir simulation software. The grid dimensions were 48 feet by 83 feet with the thickness of the vertical layers varying from 3 feet to 35 feet depending on whether the layer was part of a sand or shale. The model had 60 feet of non-steamflooded sands and shales below the steam zone and 200 feet of non-steamflooded sands and shales above the steam zone. The steam zone consisted of 50 feet of the “T” sands with three 3 foot interbedded shales and 50 feet of the “D” sands. There were 51 feet of non-steamflooded sands and shales between the “T” and the “D” sands. The model mimicked two injection wells (one for the “T” sand and one for the “D” sand) and one production well in a specific seven-spot pattern in the middle of the Tar Zone steamflood. The distance between the injection wells, 2AT-032 (“T” sand) and 2AT-033 (“D” sand), and the production well, UP-922 (“T” & “D” sands), was 384 feet. This is equivalent to an 8.8 acre pattern, although the average pattern size was 7.5 acres. The three wells were selected as the model pattern because observation well OB2-5 is located halfway between the injectors and the producer so reservoir temperatures in the model could be compared to actual data.

The first scenario was to inject 1,000 BPD of cold water equivalent steam (CWES) at 580°F and 80% quality into wells 2AT-032 and 2AT-033 and produce well UP-922 at 1200 B/D of gross production from June 1989 to January 1, 1999. The model’s predicted temperature profile of the steamflood zones and the adjacent non-steamflood layers in the observation well for January 1, 1999 was compared to an actual temperature profile in observation well OB2-5 for the same time period and had a very good match. The producer was shut-in on January 1, 1999. The injectors stopped injecting steam and started injecting only enough 500°F hot water to maintain reservoir pressures at 90% of the hydrostatic pressures, 930 psi in the “T” sand and 980 psi in the “D” sand. Without some form of injection, reservoir pressures would decline due to steam chest collapse from over and underburden heat losses and fluid losses to the lower pressured aquifers. In actuality, the reservoir pressures in the steamflood area are being maintained by flank cold water injection. Hydrostatic pressure is the pressure at a specific depth equivalent to the weight of a column of water from that specific depth to the surface. The model continued to run an additional ten years to determine the heating and cooling effects after steam injection. The heating and cooling data of the layers above and below the steam zone were recorded

and analyzed. The normal reservoir temperature before steamflooding was 123°F. The model predicted that the average temperature of the steam zone cooled off from 523°F in January 1999 to 470°F by January 2009 at the injection wells, 520°F to 448°F at the observation well, and 515°F to 448°F at UP-922. The model showed that after steam injection the steam zone and shale immediately adjacent to the sands cooled off by 60-70 degrees while the remaining shale layers above and below continued to heat up slightly.

The second scenario was to restart the model on January 1, 1999 and inject only enough 135°F water into the injectors to maintain 90% hydrostatic reservoir pressures in the "T" and "D" sands. The producer was shut-in on January 1, 1999 and returned to production on October 1, 1999 following the model's projected reservoir steam chest fill-up. This simplified 1/12 of a seven-spot model predicted the same reservoir steam chest fill-up time as the full reservoir 3-D deterministic thermal model. The model continued to run an additional ten years and the heating and cooling data of the layers above and below the steamflood zone were recorded and analyzed. The model predicted that the steamflood zone cooled off from 523°F in January 1999 to 135°F by January 2009 at the injectors, 520°F to 160°F at the observation well, and 515°F to 214°F at the producer. Ten years after the steamflood was shut-in, the layers above and below the steamflood zone continued to heat up proportionally to how the steamflood zones were cooling off.

Reservoir Management

A post-steamflood operating plan was developed during the third quarter 1998 and implemented in the fourth quarter 1998 to mitigate problems associated with the January 1999 shutdown of steam injection and the probability of thermal-related surface subsidence from cooling and subsequent collapse of the steam chests in the "T" and "D" sands. A total of twelve water injection wells have been in service on the northern and southern flanks of the steamflood area, including two existing injectors (wells FW-101and FW-103), seven wells that were added in the fourth quarter 1998 (wells FW-88, 901-UP, 935-UP, 937-UP, 943-UP, 951-UP, and 2AT-56), two wells added in the second quarter 1999 (2AT-48 and 953-UP) and one well (2AT-20) added in the fourth quarter 1999. Their purpose has been to increase and subsequently maintain reservoir pressures in the "T" and "D" sands at a high enough level to eliminate and prevent the reoccurrence of any steam chest. Increasing reservoir pressure causes the steam vapor phase to go back into solution before it can cool through overburden heat loss and cause possible formation compaction. The flank water injection strategy increases reservoir pressure by "squeezing" the steamflood area along its structural downdip flank without introducing cold water into the interior of the mature steamflood area.

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. According to the model, reservoir fill up of the steam chests would occur in October 1999 at a constant injection rate of 28,000 BPD and gross fluid production rate of 7,700 BPD (I/P ratio of 3.6, net injection of 20,300 BPD). Actual operations followed the model's recommendations during the first six months of 1999, as water injection averaged 28,600 BPD and gross fluid production averaged 7,800 BPD. The number of active producers during the steam chest fill-up phase ranged from 8-11 wells, of which 6-8 were dual "T" and "D" completions, 1-2 were "D" completions and 0-1 was a "T" sand completion.

Further model runs found that varying individual well injection rates was better for addressing localized sub-zone pressure problems caused by added production and could reduce steam chest fill-up by up to one month. Based on this information, Tidelands increased water injection in July and August 1999 to an average of 36,000 BPD while only increasing gross fluid production to 9,500 BPD (I/P ratio of 3.8, net injection of 26,500 BPD). This operational change accelerated overall reservoir steam chest fill-up in the “D” sands to August 1999 because most of the increased net injection went to those sands. Reservoir pressures in the “D” sands at fill-up ranged from 960-1180 psi with a rough average of 1080 psi (89-106% hydrostatic pressure, 98% avg). Steam chest fill-up in the “D” sands was accompanied by steeply rising reservoir pressures, as would be expected in a fully liquid, relatively incompressible fluid situation.

It was believed that once steam chest fill-up occurred, 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. The City and Tidelands decided to maintain reservoir pressures at about 90%±5% hydrostatic as ideal in the short term and to possibly lower reservoir pressures to 80% hydrostatic over time provided no steam chest development reoccurred. The model predicted steam chest fill-up at about 78% hydrostatic pressure. The City and Tidelands felt that production rates could be increased as long as water injection rates were kept at relatively high injection to production ratios (I/P).

Beginning in September 1999, “D” sand gross fluid production was increased from 6200 BPD to 7800 BPD and water injection was reduced substantially from 24,200 BPD to 14,500 BPD (net injection from 18,000 BPD to 6700 BPD). Injection was increased slightly in the “T” sands from 10,700 BPD to 12,700 BPD (net injection from 7100 BPD to 9000 BPD). The “T” sands reached steam chest fill-up on schedule in mid-October 1999 with reservoir pressures ranging from 930-1070 psi with an average of 980 psi (91-103% hydrostatic pressure, 95% avg). Following steam chest fill-up of the "T" sands in October 1999, gross fluid production was increased from 10,500 BPD in September to 14,500 BPD in November. In September and October, nine production wells were activated for a total of 19 producers, of which 15 were dual "T" and "D" completions, three were "D" completions and one was a “T” sand completion. The number of active producers thereafter through September 2000 has ranged from 16-19 wells, with high water cut wells being idled to allow for the activation and testing of other wells. Two of the best oil producing wells were idled in November 1999 to accommodate the surface owner for a possible 12 - 18 months.

The significant decrease in “D” sand net injection rates caused reservoir pressures to plummet about 100 psi to an average of 980 psi and 89% hydrostatic pressure (range 930-1050 psi) within six weeks. This happened even though the I/P was 1.85. Starting in late-October, gross fluid production in the “D” sands was further increased to 8800 BPD, but net injection was increased to 10,200 BPD to an I/P of 2.20. “D” sand reservoir pressures stabilized by the end of December to an average of 960 psi and 88% hydrostatic pressure (890-1030 psi range). Following “T” sand fill-up in October, gross fluid production was increased from 3700 BPD to 5600 BPD and net injection was lowered only slightly to 7400 BPD (I/P of 2.33) by activating an additional four "T" only completions. “T” sand reservoir pressures stabilized by December 1999 to an average of 1010 psi and 98% hydrostatic pressure (950-1060 psi range).

In the first quarter 2000, the plan was to reach 90% hydrostatic pressure in both the “T” and “D” sands by increasing net injection rates in the “D” sands and by carefully lowering net injection rates in the “T” sands. The number of active producers remained at

19, but the number of “T” sand completions rose to five and the number of “D” sand completions was reduced to two. The “D” sand gross fluid production rates were decreased to 8200 BPD and net injection was increased to 12,300 BPD for an I/P of 2.5. By the end of the quarter, the average “D” sand reservoir pressure increased to 1020 psi and 91% hydrostatic pressure (940-1090 psi range). The “T sand gross fluid production rates were increased to 8400 BPD and net injection was lowered slightly to 6700 BPD for an I/P of 1.80. By the end of the quarter, the “T” sand reservoir pressures essentially stayed constant at 1020 psi and 98% hydrostatic pressure (980-1070 psi range). Injection well profile logs run during the quarter showed that two “D” sand injectors were partially injecting into the “T” sands at an average rate of 3000 BPD, of which about 2000 BPD was entering the DU3 thief sand. By adjusting the “D” and “T” sand injection totals to reflect net effective injection, the “D” sands had a net injection of 9,300 BPD and I/P of 2.1, slightly lower than fourth quarter rates, and the “T” sands net injection actually increased to 7700 BPD and I/P of 1.92. The high net injection rate into the “D” sands was still adequate to increase reservoir pressure to the desired level. The higher net injection into the “T” sands explains why the reservoir pressures slightly increased.

In the second quarter 2000, the plan was to increase production in both the “T” and “D” sands equally and to reduce total and net water injection slowly to maintain reservoir pressure in the “D” sands and reduce pressure in the “T” sands. A profitable higher water cut “T” and “D” producer was activated and one “D” sand producer was idled as uneconomic. Gross fluid production in the “T” and “D” sands averaged 10,500 BPD each. Effective water injection into the “D” sands was 16,200 BPD for an I/P of 1.54 and net effective injection of 5,700 BPD and effective water injection into the “T” sands was 14,800 BPD for an I/P of 1.41 and net effective water injection of 4,300 BPD. By the end of the quarter, the average “D” sand reservoir pressure decreased slightly to 1000 psi and 90% hydrostatic pressure (960-1060 psi range) which was right on plan. The “T” sand reservoir pressures essentially stayed constant again at 1020 psi and 98% hydrostatic pressure (960-1070 psi range).

The third quarter 2000 plan was to maintain pressure in the “D” sands and slowly reduce pressure in the “T” sands while decreasing net water injection in the process. During the quarter, one “T” well and one “T” and “D” well were idled to allow the two best producers that were idled the previous November 1999 to accommodate the surface owner to be activated. The “D” sand production averaged 10,800 BPD and effective water injection was decreased to 14,200 BPD for an I/P of 1.32 and net effective injection of 3400 BPD. By the end of the quarter, the average “D” sand reservoir pressure decreased slightly to 990 psi and 90% hydrostatic pressure (940-1070 psi range) which again was right on plan. The “T” sand production was decreased to 9,600 BPD and effective water injection averaged 11,900 BPD for an I/P of 1.24 and net effective injection of 2300 BPD. By the end of the quarter, the average “T” sand reservoir pressure decreased slightly to 1000 psi and 97% hydrostatic pressure (960-1090 psi range) which was right on plan.

In summary, reservoir pressures in the mature Phase 1 area have increased during the last three years to eliminate the steam chests in the “T” and “D” sands. The current objective is to gradually lower the “T” sand pressure to about 920 psi±50 psi or 90%±5% hydrostatic pressure and to maintain the "D" sand pressure at about 1000 psi±50 psi or 90%±5% hydrostatic pressure. The average “T” sand pressure has risen from 818 psi in June 1997, to 889 psi in March 1999, to 979 psi in September 1999, to 1020 psi in June 2000, and to 1000 psi or 97% hydrostatic pressure in September 2000. The average “D” sand pressure has gone from 594 psi in May 1996, to 748 psi in August 1998, to 874 psi in March 1999, to 1080 psi in September 1999, to 960 psi in December 1999 and has been

maintained at about 1000 psi or 90% hydrostatic pressure from March to September 2000.

At first, it was postulated that reservoir pressures only needed to reach an estimated 800 psi to fill the steam chests based on the saturated steam pressure - temperature relationship. Field experience shows that higher reservoir pressures above 900 psi are needed to achieve steam chest fill-up throughout the reservoir, which means that certain areas in the steamflood have maximum reservoir temperatures exceeding 530°F.

Reservoir pressure data were continued to be retrieved approximately once a month from each idle well using sonic fluid levels and Amerada bombs as explained previously.

Operational Management

Operational management is focused on the apparent steamflood-related surface subsidence for the Tar II-A project due to shale compaction above the “D” sands. A study has been 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.

Expanding the project to the Tar V steamflood has allowed the project team to continue ongoing thermal operations in a pilot horizontal well steamflood that was based on the Tar II-A horizontal well pilot. Two of the three Tar V horizontal producers (wells J-205 and J-201) had experienced sand inflow problems and required the well completions to be re-treated with steam to reconsolidate the formation sands. Both jobs were recently completed and the wells have been on production with no further sand problems. Well J-205 began producing in September 1999 at low rates, was sped up in November 1999 to a stabilized rate of 90 BOPD and 800 BWPD, and started to experience pump problems in the second quarter 2000 with 47 BOPD and 780 BWPD. The well was pulled in mid-September 2000 and initial tests showed 57 BOPD, 1572 barrels of gross fluid per day (BGFPD), and 1340 feet of fluid over the pump. The well should produce over 100 BOPD when production stabilizes. Well J-201 began producing in March 2000 at low rates and was sped up during the second quarter 2000 to about 65 BOPD and 1150 BWPD. These rates have been maintained through September 2000 and the well still appears to have a high fluid level of over 1500 feet over the pump. Flank well A-29 has been approved to be converted to water injection as well FRA-29. This well will supplement the injection to production ratio for surface subsidence control and allow increased production from the horizontal wells by pumping off the high fluid levels. This well will also provide more reservoir pressure support from outside the pilot area to improve well productivity similar to the flank water injection in the Tar II-A project.

Shale Compaction Study:

While steam injection can improve the recovery of heavy oil from a reservoir, it can also potentially affect the composition and physical properties of the reservoir rock and surrounding shales. Of particular interest in this regard is the effect of steam injection on the compactional properties of shales occurring within and surrounding the Tar II-A reservoir. Changes in shale volume in response to steaming could impact surface subsidence.

David K. Davies and Associates, Inc analyzed both the pre-steam cores from well OB2-3 and the pre- and post-steam cores from wells OB2-5 and UP-908. DKD concluded that the most serious shale compaction is occurring in a six foot interval above the D1 sands as was conjectured. Lesser forms of shale compaction are occurring above and throughout the T2 sand, the thickest of the T sands, and in the interbedded shales within the upper D1 sands above the apparent steam / oil interface as delineated by the density - neutron log crossovers in the post-steam wells.

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.

Using the seven compaction indicators given in the report, late stage shale compaction occurred in well OB2-5 from 2412.5 - 2440.15 ft (above and throughout T2 sand), from 2531.5 - 2534.8 ft (above D1 sand) and in the interbedded shales within the D1 sands to a depth of 2542 ft which is above the steam / oil contact. The most impacted samples were above the D1 sands. According to the density-neutron log, the steam chest (log separation) in the T2 sand extended throughout the sand from 2417-2446 ft and the D1 sand steam chest also extended throughout the sand from 2535-2587 ft with a major log separation from 2535-2550 ft. In UP-908, the shales exhibited late stage compaction from 2558.25 - 2561.75 ft (above D1 sand). The ReSpec core sample that was heated to 550°F also experienced late stage shale compaction. Early stage compaction was observed in most of the shales that experienced reservoir heating and in the ReSpec core sample that was heated to 275°F. Recent Thermal-Decay-Time logs run in wells UP-800 and 1F-10 only show noticeable compaction in the twelve foot interval above the D1 sands and none in the “T” sands or interbedded shales in the “D1” sands, even when comparing total gross sub-zone thicknesses with the original logs.

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. The ReSpec core sample that was heated to 135°C or 275°F experienced clay dewatering but not late stage compaction symptoms. 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. Yet as mentioned above, the crude oil tends to coke at approximately 285°C or 545°F and epidotes 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.

With respect to the ReSpec "open-system" high temperature compaction tests on sands and shales, where fluids were allowed to bleed off to maintain constant pressures, the tests on the shales were probably closer to a "semi-closed" system because of the lack of vertical permeability in the samples. During the shale tests at 275°F and 550°F, both samples were allowed to bleed fluids out of the system to maintain constant pressure in the test vessel. However, the rate of fluid expulsion was not recorded and therefore it cannot be determined when, if at all, the pore pressures exceeded critical lithostatic pressures and a resultant sudden release of pore fluids occurred. The sample heated to 550°F appears to have microfractures whereas the sample heated to 275°F did not. The test procedure also ramped up whole core temperatures within an hour, which may not have allowed the "whole core-size" shale samples to heat up uniformly and to "gradually" bleed off pressure to adjacent interbedded sands as would happen in the field. In the ReSpec shale test at 275°F, compaction was based on early stage compaction symptoms or mostly through dehydration of the clays. The ReSpec shale test at 550°F underwent late stage compaction symptoms such as microfracturing, color changes, and mica realignment. Further shale tests at ReSpec should measure the rate of fluid expulsion from the core samples and ramp up temperatures more gradually to allow the large shale samples to heat up more uniformly

Technical Transfer

No presentations or papers were given during the third quarter 2000. The project team anticipates submitting papers to the Society of Petroleum Engineers regarding our research on cost effective procedures to improve core analysis techniques in unconsolidated sands and on cost effective reservoir temperature and pressure surveillance methods for steamflood projects.

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

References and Notes

1. Mondragon, J.J. III, Ershaghi, I., and Yang, Z., USC, “Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California”, SPE Paper #62571, 2000 AAPG / SPE Western Regional Meeting, Long Beach, CA, June 19-22.