

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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Anticipated Completion Date: March 29, 2001

DOE Award: \$5,573,165 (Cum Actual through June 1999)
\$700,000 (1999 Projected)
\$274,533 (1999 YTD Actual)

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Program Manager: Gary Walker - National Petroleum Technology Office

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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 March 1999, project work has been completed related to 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. Work is continuing on the stochastic geologic model, developing a 3-D stochastic thermal reservoir simulation model of the Fault Block II-A Tar (Tar II-A) Zone, and operational work and research studies to prevent thermal-related formation compaction.

Thermal-related formation compaction is a concern of the project team due to observed surface subsidence in the local area above the steamflood project. Last quarter on January 12, 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. Seven water injection wells were placed in service in November and December 1998 on the flanks of the Phase 1 steamflood area to pressure up the reservoir to fill up the existing steam chest. Intensive reservoir engineering and geomechanics studies are continuing to determine the best ways to shut down the steamflood operations in Fault Block II while minimizing any future surface subsidence. The new 3-D deterministic thermal reservoir simulator model is being used to provide sensitivity cases to optimize production, steam injection, future flank cold water injection and reservoir temperature and pressure. According to the model, reservoir fill up of the steam chest at the current injection rate of 28,000 BPD and gross and net oil production rates of 7,700 BPD and 750 BOPD (injection to production ratio of 4) will occur in October 1999. At that time, the reservoir should act more like a waterflood and production and cold water injection can be operated at lower net injection rates to be determined. Modeling runs developed this quarter found that varying individual well injection rates to meet added production and local pressure problems by sub-zone could reduce steam chest fill-up by up to one month.

Advanced Reservoir Characterization

The reservoir simulation and stochastic geologic models rely on good core porosity and permeability data in unconsolidated sands. Previous reports described the results of a

more accurate and cost-effective core analysis procedure than the "routine analysis" using the Dean Stark method on core plugs under minimum confinement stresses of 300 psi. The new procedure involved analyzing the core plugs with the Dean Stark method with the sample under an overburden pressure of 1800 psi and using liquid kerosene for permeability tests instead of air. The lab results showed that formation porosities at overburden pressures were about six porosity units lower than when using minimum confinement stresses. The permeabilities using liquid kerosene at overburden pressures were about 30% of the "routine" air permeabilities calculated under minimum confinement stresses. When the old core porosity data analyzed by the "routine analysis" was normalized using the overburden pressure data, good correlation could be observed with the corresponding density log porosity data. The tests showed that the "routine" core analysis procedure performed in the past can be significantly in error and that normalizing the past "routine" data can be useful in future reservoir studies.

Further special core analysis was run on fourteen unconsolidated sand samples and three shale samples from the pre-steamflood core in well OB2-3 with the objective of determining the calibration factors to use on old core analysis data where porosity and air permeability were measured at 300 psi overburden pressure. The selected sand samples were analyzed for porosity using the Dean Stark method and the shale samples were analyzed using cool solvent extraction method at 300 psi and 1800 psi overburden pressures. A well-defined correlation line could be drawn through the data points with the samples measured under 1800 psi having 85.72% of the porosity measured under 300 psi. The air permeabilities also had a well-defined correlation, with samples measured under 1800 psi having 41.57% of the permeabilities (in millidarcies) measured under 300 psi. A separate test was run only on the sand samples to compare the correlation between measured permeabilities under 1800 psi overburden pressure using air and liquid kerosene. Although a line can be drawn through the data set, the correlation is shaky. However, the air and liquid kerosene permeabilities can be bracketed within a definite range. The liquid permeabilities tend to be 7.5% to 18.5% of the measured air permeabilities.

Much of the stochastic geologic modeling centers on the continuity of the shales and the horizontal and vertical permeability of the sands and shales throughout the steamflood area. The objective is to understand the depositional history of the sand layers, quantify their flow characteristics, determine the effects of interbedded shales on the flow characteristics, and upscale this information into the reservoir model. Fortunately, there are about 80 wells with full suites of logs (density, neutron, gamma ray, SP and resistivity) in the steamflood project area, and eight of those wells were cored. The wells are a distance of 100 - 500 feet apart. Unfortunately, the cored wells show several thin discontinuous shales and silty shales from 0.1 - 0.4 ft thick that do not appear on the logs and therefore cannot be mapped. Most of the turbidite sequences appear to have similar lithotypes or depositional history with coarser sand grains at the bottom and fining-upwards. Many sequences are merged onto others due to unconformable erosion of the underlying beds. The objective of the stochastic model is to provide a better understanding of how reservoir heterogeneity can affect steam drive performance and production history

matching and prediction. Future quarterly reports will begin tying together the core work, the logs, the depositional history, the stochastic modeling of porosity, shaliness indicators, and permeability, the mapping of shale continuity, and upscaling issues.

Reservoir Simulation

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 3-D deterministic reservoir simulation model was placed into immediate use to measure the mass fluid and heat balance effects as they relate to reservoir pressure. Mitigating thermal-related formation compaction has become a high priority for the project team. The model is necessary because predicting reservoir pressure changes resulting from the effects of steamflood production and cold water injection is too complex to perform intuitively. Reservoir pressures in the target area are affected by the 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.

In the third quarter 1998, reservoir simulation studies determined that cold water flank injection was better than cold water injection into the pattern steam injectors. The model predicted that reservoir fill-up would occur in February 1999 with 24,000 BWPD of cold water injection into the flanks of the steamflood area, 16,000 BWPD of 450_F hot water injection into the hot waterflood pilot area of the reservoir, and all production shut-in. However, the local reservoir pressure around the injectors was projected to rise above the reservoir fracture pressure, making the scenario undesirable. The flank water injection strategy was used to develop an operating plan by the end of the third quarter.

In the fourth quarter 1998, the reservoir simulation optimization scenarios mitigated the problem of local reservoir pressure around the injectors being above the fracture pressure. One scenario assumed 9,000 BPD of water injection into the hot waterflood area, 14,000 BPD of flank water injection and no production. This achieved reservoir fill up in August 1999, but generated undesirable temperatures and pressures. The second scenario assumed no production and a constant 20,000 BPD of flank water injection with an increasing number of flank injection wells to distribute the pressure. This predicted that reservoir fill-up would occur in September 1999.

In the first quarter 1999, the reservoir simulation modeling work predicted that steam chest fill-up would be achieved in mid-October 1999 with 7,700 B/D of gross (oil and water) production and 28,000 B/D of cold water injection. The water injection rates were 15,500

BPD in the north flank wells and 12,500 BPD in the south flank wells, which is consistent with the fact that most of the active production wells were near the north flank in the Phase 1-B area. Seven major scenarios were developed and run that varied gross fluid production from 0 - 7700 BPD and water injection rates from 20,000 - 28,000 BPD, keeping net injection (water injection less gross fluid production) between 19,000 - 20,000 BPD water. The model showed that steam chest fill-up was very dependent on specific injection well locations and rates relative to the locations of the active production wells and their completion intervals. Indiscriminately injecting 20,000 BPD of water more than gross fluid production did not necessarily achieve steam chest fill-up in a timely fashion, with some scenarios showing fill-up occurring over six months later than October 1999. The production and injection database was updated with actual volumes from July 1998 to February 13, 1999 and the data was history-matched by the model. After February 13, 1999, the production and injection rates for each well were set at pre-determined levels, depending upon the scenario, and held constant until reservoir steam chest fill-up was achieved. The T Sand was slightly over-pressured and the D Sand was under-pressured in the middle portion of the Phase 1 area. Late in the quarter, scenarios included water injection into three areas: the north flank, the south flank, and the west middle-side of the Phase 1 area by the Wilmington Fault.

In the second quarter 1999, a series of scenarios (1,2, & 3) were run to improve the steam chest fill-up time. The gross production was held constant at 7,700 B/D. The total cold water injection rate was held at 28,000 B/D. Individual injection well rates were varied from one scenario to the next scenario starting from February 13, 1999 until steam chest fill-up. The predicted reservoir steam chest fill-up time did not improve with the strategy of constant well injection rates. The predicted steam chest fill-up time varied from mid-October to mid-November 1999.

In the fourth scenario, a new injection strategy of changing individual well rates several times during the fill-up period was attempted. The injection rates were changed according to how the "T" and "D" sands were responding to the injection. Total gross fluid production and cold water injection were held constant at 7,700 gross B/D and 28,000 B/D, respectively. The north flank injection remained at 15,500 B/D with 44% being injected into the "T" Sand and 56% being injected into the "D" Sand starting on February 13, 1999. On August 1, 1999, the injection split was changed to 51% "T" Sand injection and 49% "D" Sand injection. The south flank injection remained at 12,500 B/D with 33% being injected into the "T" Sand and 67% being injected into the "D" Sand starting on February 13, 1999. On August 1, 1999, the injection split was changed to 48% "T" Sand injection and 52% "D" Sand injection. About 2,500 B/D of injection in the three most southerly injectors was shifted to the remaining south flank injectors because the interaction between Fault Blocks I and II-A was pressuring the Tar Zone in Fault Block I. The model predicted steam chest fill-up would occur in early October 1999.

The fifth scenario was similar to the fourth scenario with the exception of the injection splits. The north flank injection rates remained at 15,500 B/D with 38% being injected into the "T" Sand and 62% being injected into the "D" Sand starting on February

13, 1999. On August 1, 1999, the injection split was changed to 51% "T" Sand injection and 49% "D" Sand injection. The south flank injection remained at 12,500 B/D with 33% being injected into the "T" Sand and 67% being injected into the "D" Sand starting on February 13, 1999. On August 1, 1999, the injection split was changed to 41% "T" Sand injection and 59% "D" Sand injection. The model predicted reservoir steam chest fill-up would occur in mid-September 1999.

Before running the sixth scenario, the production and injection database and model were updated with actuals from February 1999 through April 1999. All future scenarios were restarted on May 1, 1999. The injection strategy to have three areas of injection (the north flank, the south flank, and the west middle side of the reservoir by the Wilmington Fault) was stopped because of adverse reservoir cooling. Future scenarios will only have cold water injection in the north and south flanks.

The sixth scenario applied the updated database and estimated May 1, 1999 production and injection rates. On June 1, 1999, two production wells were activated and two wells were converted to cold water injection, one in the north flank and one in the south flank. The May 1, 1999 gross production rate was 6,800 B/D, which was increased on June 1, 1999 to 8,100 B/D. The May 1, 1999 north flank cold water injection rate was 14,350 B/D, which was increased on June 1, 1999 to 17,850 B/D (26% "T" Sand & 74% "D" Sand). The May 1, 1999 south flank injection rate was 14,370 B/D, which was increased on June 1, 1999 to 15,970 B/D (51% "T" Sand & 49% "D" Sand). The model predicted reservoir steam chest fill-up would occur in mid-September 1999 in the "D" Sand and in October 1999 in the "T" Sand.

The seventh scenario evaluated how reservoir pressure would be affected by reducing the injection to production ratio (I/P ratio) from approximately 4.2 to 1.07 following reservoir steam chest fill-up in the sixth scenario. This scenario was similar to the sixth scenario except that on September 15, 1999 the I/P ratio was reduced to 1.07. The gross production rate was held constant at 8,100 B/D. The north flank injection was reduced to 5,000 B/D (30% "T" Sand & 70% "D" Sand) and the south flank injection was reduced to 3,600 B/D (39% "T" Sand & 61% "D" Sand) for a total injection of 8,600 B/D. The model predicted that the steam chest in the "T" Sand reestablished itself and reservoir steam chest fill-up was delayed from October 1999 to October 2004 because of inadequate "T" Sand injection volumes. Injection rate changes must be scheduled to follow predicted reservoir steam chest fill-up in both the "T" and "D" Sands. Drastic injection rate changes should be avoided to prevent reestablishment of the steam chests in localized areas.

The eighth scenario started with May 1, 1999 gross production of 6,800 B/D and increased it on June 1, 1999 to 8,100 B/D. Gross production was reduced to 5,900 B/D from August 1, 1999 to February 1, 2001 to account for two producers being temporarily idled to accommodate the surface owner. The May 1, 1999 north flank cold water injection rate was 14,350 B/D, which was increased on June 1, 1999 to 18,500 B/D (38% "T" Sand & 62% "D" Sand). The May 1, 1999 south flank injection rate was 14,370 B/D, which was increased on June 1, 1999 to 15,420 B/D (49% "T" Sand & 51% "D" Sand). The model

predicted reservoir steam chest fill-up in both the "T" and "D" Sands in early October 1999.

The ninth scenario started when reservoir steam chest fill-up occurred in the eighth scenario in October 1999. The gross production was 5,900 B/D on October 1, 1999 and increased to 8,100 B/D on February 1, 2001 when the two temporarily idled wells were returned to production. A series of water injection scenarios were run where the volumes, rates, and times to change the well rates were varied to minimize the injection volumes needed to keep the steam chest from reestablishing itself by maintaining relatively constant reservoir pressures. The best injection scenario started with a north flank injection rate of 7,800 B/D and south flank injection rate of 2,525 B/D for a total of 9,325 B/D and I/P ratio of 1.6. In November 1999, injection rates were reduced to 4,800 B/D in the north flank and 2,300 B/D in the south flank for a total of 7,100 B/D and I/P ratio of 1.2. In April 2000, injection rates reduced to 4,400 B/D in the north flank and remained at 2,300 B/D in the south flank for a total of 6,700 B/D and I/P ratio of 1.4. In February 2001, the injection rates were increased to 4,800 B/D in the north flank and 4,000 B/D in the south flank to a total of 8,800 B/D and I/P ratio of 1.09 to offset the increase in production. The model ran to the year 2006 without the steam chest reestablishing itself while maintaining constant reservoir pressure.

Next quarter, the project team will continue to update the model with the most current production and injection field rates and optimize injection and production ratios and operational strategies to maximize oil production.

Reservoir Management

A post-steamflood operating plan was developed during the third quarter 1998 to mitigate problems associated with the January 1999 shutdown of steam injection and the probability of thermal-related surface subsidence. The plan concept is to prevent post-steamflood surface subsidence by injecting high net rates of cold water into the northern and southern flanks of the mature steamflood to increase reservoir pressures in the AT® and AD® sands. The flank water injection will fill up the steam chests that exist without introducing cold water into the interior of the mature steamflood area. Once fill-up occurs, it is hoped the reservoirs can be operated more like a waterflood. Reservoir pressures in the mature Phase 1 area have been increasing for the last year. The average AT® sand pressure has gone from 818 psi in June 1997, to 889 psi in March 1999, and to 926 psi in June 1999. The average AD® sand pressure has gone from 594 psi in May 1996, to 748 psi in August 1998, to 874 psi in March 1999, and to 1004 psi in June 1999. The "D" sand pressures started increasing dramatically in April in selected wells and is showing signs of achieving steam chest fill-up during the next quarter. The "T" sand pressures are still increasing slowly, indicating gas compression in the reservoir. At first, it was postulated that reservoir pressures only needed to reach an estimated 800 - 1000 psi to collapse the steam chests based on the saturated steam pressure - temperature relationship. It appears from field experience that higher reservoir pressures above 1000 psi are needed to actually achieve reservoir fill-up.

With reservoir pressures increasing quickly in the "D" sands, gross fluid production has increased due to higher differential pressures in the wellbore from 6145 barrels of gross fluid per day (BGFPD) and 725 barrels of oil per day (BOPD) in March 1999 to 8435 BGFPD and 690 BOPD in June. Water injection rates in June were increased to 29,400 BPD from the previous rate of 28,000 BPD to compensate for the increased production levels. With the imminent achievement of steam chest fill-up in the AD@ and AT@ sands, the project team is developing plans to activate more production wells and convert additional flank wells to cold water injection service to increase injection rates and to achieve a more even distribution of injection in the AT@ and AD@ Sands.

Pressure data is being retrieved approximately once a month from each idle well using sonic fluid levels and Amerada bombs. This is different from the previous manner of reading the instantaneous shut-in gauge pressure of the steam injection wells and therefore the initial fluid level pressures are occasionally different from the steam gauge pressure readings. The Amerada pressure bomb readings taken from wireline provide more accurate pressure readings than the sonic fluid levels and are being run within a few days of the sonic fluid level shots in the same wells. The Amerada bombs were specially tested to correct pressure readings for temperature in the wellbore as higher temperatures will expand the bomb and show higher pressures than actual. The Amerada bomb has a temperature probe attached that measures the highest temperature in the wellbore. The highest temperature is assumed to exist only across the completion interval and extrapolated up to 2000 feet vertical subsea (VSS) depth where temperature is assumed to be 120° F. The temperature from 2000 feet VSS to the surface is assumed to be 120° F. The plan is to evaluate whether the fluid level data can be calibrated to the Amerada bomb readings once we get enough paired pressure readings to provide a statistically valid data set. The exact steam chest collapse pressures will become evident upon reservoir fill up as the reservoir pressures should increase rapidly with the high net water injection rate.

Operational Management

The project team decided to perform more detailed shale alteration analysis of the post-steamflooded cores and the cores that were heated and compacted in the lab. The objectives of the proposed work will be to determine the lithology, mineralogy, and microstructure of the AT@ and AD@ shales, to identify the geological controls that influence shale compaction and subsidence, and to determine the temperature at which significant changes in shale mineralogy and microstructure occur. The proposed work will include the following: 1) a petrographic analysis of over 70 thin sections of shale samples to determine grain sizes, grain size distribution, grain orientation, depositional environment, and other textural and compositional characteristics; 2) x-ray diffraction analysis of 47 shale samples for mineral composition; 3) scanning electron microscope analysis to observe clays, pore throats, and mineral alterations; 4) measure the velocity of shear and compressional waves in the plug samples to determine the Poisson's Ratio and Young's Modulus elastic

properties of the shales; 5) perform a micro-probe analysis on several shale samples to identify any diagenetic minerals that require minimum or maximum temperature conditions to create them; 6) evaluate the core photos to analyze the differences or similarities between bedding styles, laminations and burrows; and 7) perform a geochemical analysis on four shale samples to determine the effects of steamflooding on organic matter. This study should be completed by the third quarter 1999.

Technical Transfer

Hart's Oil and Gas World Magazine honored Tidelands with the Best Field Improvement Project award in their Best of the Pacific contest in April 1999. This award was for the design and implementation of a lower-cost H₂S scrubber as part of the DOE thermal project. Our project partners were T. J. Cross Engineers and the Sulfa Treat Company¹.

Mahnaz Hassibi of USC completed her Doctoral Thesis entitled A Method For Automating Delineation of Reservoir Compartments and Lateral Connectivity From Subsurface Geophysical Logs in May 1999 in partial fulfillment of her requirements for the degree of Doctor of Philosophy, Petroleum Engineering².

Scott Hara gave an oral presentation entitled A 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.

David Davies, Richard Vessel, and John Aumon of DKD had their SPE Paper #38914 entitled A Improved Prediction of Reservoir Behavior Through Integration of Quantitative Geological and Petrophysical Data peer-reviewed and published in the prestigious SPE Reservoir Evaluation and Engineering Magazine in April 1999. The peer reviewed paper was assigned SPE Paper #55881³.

David Davies of DKD will present two papers at the 1999 SPE Annual Technical Conference and Exhibition (ATCE) to be held in Houston, TX from October 3-6. One abstract is SPE Paper #56813 entitled A Stress-Dependent Permeability: Characterization and Modeling and his co-author is J. P. Davies of Chevron⁴. The other abstract is SPE Paper #56819 entitled A Geometry, Internal Heterogeneity and Permeability Distribution in Turbidite Reservoirs, Pliocene California and his co-authors are Scott Hara and Julius Mondragon of Tidelands⁵.

Iraj Ershaghi and Mahnaz Hassibi of USC will present a paper entitled A Reservoir Heterogeneity Mapping Using an Artificial Intelligence Approach (SPE Paper #56818) at the 1999 SPE Annual Technical Conference and Exhibition (ATCE) to be held in Houston,

TX from October 3-6⁶.

Don Clarke of the City has been invited to make two oral presentations entitled "Subsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technological Solutions from the Wilmington Oil Field, California, USA" and "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field" at the 1999 AAPG/SPWLA Hedberg Research Symposium in The Woodlands, TX from October 10-13^{7,8}.

A project homepage can be viewed on the Internet at <http://www.usc.edu/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 - tidelands@95net.com.

References and Notes

1. Cassinis, R.B., Tidelands, Farone, W.A., Applied Power Concepts, Inc., "Improved H₂S Caustic Scrubber", SPE Paper #38273, 1997 SPE Western Regional Meeting, Long Beach, CA, June 25-27.
2. Hassibi, M., USC, Doctoral Thesis entitled "A Method For Automating Delineation of Reservoir Compartments and Lateral Connectivity From Subsurface Geophysical Logs", USC Department of Chemical Engineering - Petroleum Engineering Program, May 1999.
3. Davies, D.K., Vessel, R.K., Aumon, J.P., DKD, "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.
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5. Davies, D. K., DKD, Hara, P.S. and Mondragon, J.J. Tidelands, "Geometry, Internal Heterogeneity and Permeability Distribution in Turbidite Reservoirs, Pliocene California", SPE Paper #56819, 1999 SPE Annual Technical Conference and Exhibition (ATCE) to be held in Houston, TX , October 3-6.
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7. Clarke, D.O., City of Long Beach, Phillips, C.C., Tidelands, ASubsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technological Solutions from the Wilmington Oil Field, California, USA@, 1999 AAPG/SPWLA Hedberg Research Symposium to be held in The Woodlands, TX, October 10-13.
8. Clarke, D.O., City of Long Beach, AAt 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field@, 1999 AAPG/SPWLA Hedberg Research Symposium to be held in The Woodlands, TX, October 10-13.