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REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

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By
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Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology in a Low Dip Slope and Basin Reservoir in the Midway-Sunset Field, San Joaquin Basin, California

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Prepared for
U.S. Department of Energy
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Abstract

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

Cooperative Agreement No.: DE-FC22-95BC14937

A previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the upper Miocene Monarch Sand. However, the sand has a shallow dip (about 10°), thus inhibiting gravity drainage, lacks laterally continuous steam barriers within the pay interval, and has a thick water-saturated transition zone above the oil-water contact. These factors have required an innovative approach to steam flood production design that balances optimal total oil production against economically viable production rates and performance factors, such as OSR and OWR. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining recovery of heavy oils throughout the region.

In January 1997, the project entered its second and main phase with the purpose of demonstrating whether steam flood can be an effective mode of production of the heavy, viscous oils from the Monarch Sand reservoir. A steam flood pilot consisting of four 2 acre nine-spot patterns was developed in the center of the property and put on line. During 1998, ARCO Western Energy drilled 37 additional wells on the property outside of the steam flood pilot and began producing them by cyclic steam injection. In January 2000, the new operator of the property, Aera Energy LLC, converted all 37 cyclic wells into ten additional nine-spot steam flood patterns that flank the original DOE pilot on the south, west and north. To convert from cyclic to steam flood Aera Energy LLC drilled 10 additional injectors and three additional temperature observation wells on the property. The only portion of the property not now in steam flood is the very southeast corner where the Monarch Sand pay is less than 200 ft thick. The objective of the project is not just to produce oil from the Pru Fee property, but rather to test which operational strategies best optimize total oil recovery at economically acceptable rates of production and production costs.

As of June 2000, after 40 months of steam flood production of the four-pattern pilot and 21-24 months of cyclic/steam flood production of the surrounding 10 patterns, the total cumulative production of oil from the Monarch Sand stands at 735,700 bbls. During the year (July 1999-June 2000) production from just the upper Miocene sand reservoir had increased by 322,000 bbls, an amount nearly doubling all previous project production. The oil rate also doubled during the year and now stands at 1,280 bopd. Steam flood design principles developed and demonstrated for this project now have been adopted with dramatic oil recovery improvement in an adjacent lease in the southern Midway-Sunset field.

Executive Summary

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The Midway-Sunset field was discovered in 1894, however, it took nearly a decade for commercial production to begin. The original 13 wells drilled on the Pru Fee property in the early 1900's were operated in primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 MMBO was produced from the Pru property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru Fee property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 bopd in 1972, but by the time the property was shut-in it had dropped to less than 10 bopd. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-Sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aera Energy LLC until December 31, 1998, at which time operatorship passed to Aera Energy LLC.

In June 1995, the shut-in Pru Fee property was selected for a DOE Class 3 oil technology demonstration. The work to revitalize the property started in October 1995. Initially, this resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1. Pru 101 was cored, steam stimulated, then put into production. Several old wells in the center of the property were recompleted and put into cyclic production to evaluate the feasibility of thermal recovery at this marginal site. In January 1997 the project entered its second and principal phase with the purpose of demonstrating in an 8 acre four-pattern pilot whether steam flood can be an effective mode of production of the heavy, viscous oils from marginal, low-dip portions of the Monarch Sand reservoir where conventional cyclic steaming appeared, from prior experience, to be non-commercial.

The early production success of the pilot and the discovery of significant quantities of oil in the Pleistocene Tulare Formation during the preparation of the steam flood pilot lead AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Thirty-seven additional wells in the Monarch Sand surrounding the steam flood pilot were put on line in 1998 and early 1999. By mid-1999 these cyclic wells had reached oil rates in the range 363 to 381 bopd. In just a year, they had already produced an additional 129.7 MBO over and above production from the steam flood pilot. Upon acquiring the property in January 1999, Aera Energy LLC began modifications to the infrastructure at Pru Fee and all adjacent properties that a year later resulted in conversion of all new "300-series" cyclic wells to steam flood patterns.

As of June 2000, after 40 months of steam flood production of the four-pattern pilot and 21-24 months of cyclic/steam flood production of the surrounding 10 "300-series" patterns, the total cumulative production of oil from the Monarch Sand stands at 735,700 bbls. During the year (July 1999-June 2000) production from the upper Miocene reservoir had increased by 322,000 bbls, an amount nearly doubling all previous project production. The cumulative oil production from the 8 acre four-pattern steam flood pilot had reached 412.1 Mbbls, an increase of 128.1 Mbbls during the year. The cumulative oil production from the "300-series" wells had reached 323.6 Mbbls, an increase of 193.9 Mbbls during the year. During the year oil rates also doubled from 658.9 bopd in June 1999 to 1,280.3 bopd in June 2000. Even though the four-pattern pilot was already in its fourth year of operation and nearly half of the wells in the patterns are renovated older wells, the per well production for the year was greater in the steam flood pilot than in the "300-series" cyclic-steam flood wells, 6.1 Mbbls vs. 5.2 Mbbls, respectively.

Reservoir simulations with geostatistically generated data sets revealed that the initial fluid distribution in the reservoir had the most significant impact on the economics of the steam flood process. The production strategy adopted in the steam flood pilot involved steam injection within the upper third of the oil column, where the oil saturation (So) is greater than 50%, so as to avoid undue loss of heat to water. It was subsequently learned from examination of wells drilled for the "300-series" cyclic to steam flood conversion that the "initial" fluid distributions in the Monarch Sand are highly variable. Optimal production requires a more flexible strategy for completion of the injectors than that adopted for the pilot.

It is highly likely that without the incentives to ARCO Western Energy (AWE) to partner with the DOE Class Program in carrying out this oil technology demonstration, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was known to be a highly marginal property. Yet, in the four and a half years since the initiation of project the total production from this 40 acre shut-in tract has gone from zero to 1,280 bopd. In addition, the two operators, AWE and Aera Energy LLC, have invested, *without* a DOE matching contribution, in a total of 54 new producers external to the steam flood pilot, 10 new injectors increasing the number of steam flood patterns from 4 to 14, and three additional temperature observation wells. Total production from just the Monarch Sand reservoir at the Pre Fee property since the end of 1995 is 735.7 MBO.

Aera Energy LLC, observing the manner in which the injectors in the four-pattern Pru Fee pilot were completed, adopted the concept of a large stand-off from the OWC in injector workovers in the "low dip" portion of the Kendon lease immediately west of Pru Fee. The new perforations were placed in the uppermost one-third to one-half of the Monarch Sand, well above the OWC and the Sw transition zone, and deeper existing perforations sealed. It is reported that response from the injector workover using the recommended standoff from the OWC has been outstanding. Increases in oil rates in the renovated patterns average 25 bopd per well with a total increase being over 900 bopd. The OSR increased from 0.20 to 0.35 and the water cut improved.

During the past year the results of this project have been presented at 1) an AAPG-AMGP international research conference on mature field development in Veracruz, Mexico, 2) a Pacific region AAPG-SPE convention in Long Beach, California, and 3) a forum for independent producers on enhanced recovery methods sponsored by the Pacific Region of the Petroleum Technology Transfer Council (PTTC) in Los Angeles, California. All presentations were invited.

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This project has benefited immeasurably from the many contributions of past and current project team members. Although not necessarily authors this annual report, their efforts have advanced the goals of the project. The team members are:

Milind D. Deo and Craig Forster: *Petroleum Research Center, University of Utah*

K.M. Deets, Grahem Buksh, C.L. Mongold and L. S. Bultmann: *Aera Energy LLC*

Doug Sprinkel and Roger Bon: *Utah Geological Survey*

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GeoGraphix: *GeoGraphix Explorer*, *Prizm* and *ResEv* workstation modules

Biecep Inc.: *Heresim* geostatistical modeling tools

Computer Modeling Group Ltd.: *STARS* thermal reservoir simulator

Chapter 1

Introduction

General Statement

The 40 acre Pru Fee property is located south of Taft (Fig. 1-1) in the super-giant Midway-Sunset field and produces principally from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation. The Midway-Sunset field was discovered in 1894 (Kuespert, 1990), however, it took nearly a decade for commercial production to begin (Lennon, 1990). The original 13 wells drilled on the Pru Fee property in the early 1900's were operated in primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 MMBO was produced from the Pru Fee property (Schamel et al., 2000), 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru Fee property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 bopd in 1972, but by the time the property was shut-in it had dropped to less than 10 bopd. ARCO Western Energy (AWE) acquired the lease in 1988 along with various other producing properties in the Midway-Sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aera Energy LLC until December 31, 1998, at which time operatorship passed to Aera Energy LLC.

DOE Class 3 Oil Technology Demonstration

In June 1995, the shut-in Pru Fee property was selected for a DOE Class 3 oil technology demonstration. The work to revitalize the property started in October 1995. Initially, this resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1. Pru 101 was cored, steam stimulated, then put into production. Several old wells in the center of the property were recompleted and put into cyclic production to evaluate the feasibility of thermal recovery at this marginal site. In January 1997 the project entered its second and principal phase with the purpose of demonstrating in an 8 acre four-pattern pilot (Fig. 1-2) whether steam flood (Burger et al., 1985) can be an effective mode of production of the heavy, viscous oils from marginal, low-dip portions of the Monarch Sand reservoir where conventional cyclic steaming appeared, from prior experience, to be non-commercial.

The early production success of the pilot and the discovery of significant quantities of oil in the Pleistocene Tulare Formation during the preparation of the steam flood pilot lead AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Thirty-seven additional wells in the Monarch Sand surrounding the steam flood pilot were put on line in 1998 and early 1999. The wells initially were put into cyclic production because sufficient steam production to support steam flood was not available and to minimize the investment to AWE in new infrastructure immediately prior to the sale of the property to Aera Energy LLC. By mid-1999 these cyclic wells had reached oil rates in the range 363 to 381 bopd. In just a year, they had already produced an additional 129.7 MBO over and above production from the steam flood pilot. This number does not count the additional oil produced from the 20 new cyclic wells in the Tulare Formation in the southern half of the Pru Fee property that also came on line in 1998-99.

Upon acquiring the property in January 1999, Aera Energy LLC began modifications to the infrastructure at Pru Fee and all adjacent properties that a year later resulted in conversion of all new "300-series" cyclic wells to steam flood patterns. This DOE Class 3 oil technology demonstration was scheduled to end in March 2000, just one year into the cyclic production and before the performance of the "300-series" conversion of cyclic production to steam flood could be evaluated. In order to gain additional insight into optimal operational strategies at this site, the DOE National Office of Petroleum Technology approved a one-year no-cost extension of this project to allow a side-by-side comparison of cyclic and steam flood thermal recovery methods and the subsequent cyclic-steam flood conversion.

As of June 2000, after 40 months of steam flood production of the four-pattern pilot and 21-24 months of cyclic/steam flood production of the surrounding 10 "300-series" patterns, the total cumulative production of oil from the Monarch Sand stands at 735,700 bbls. During the year (July 1999-June 2000) production from the upper Miocene reservoir had increased by 322,000 bbls, an amount nearly doubling all previous project production. The cumulative oil production from the 8 acre four-pattern steam flood pilot had reached 412.1 Mbbls, an increase of 128.1 Mbbls during the year. The cumulative oil production from the "300-series" wells had reached 323.6 Mbbls, an increase of 193.9 Mbbls during the year. During the year oil rates also doubled from 658.9 bopd in June 1999 to 1,280.3 bopd in June 2000. Even though the four-pattern pilot was already in its fourth year of operation and nearly half of the wells in the patterns are renovated older wells, the per well production for the year was greater in the steam flood pilot than in the "300-series" cyclic-steam flood wells, 6.1 Mbbls vs. 5.2 Mbbls, respectively.

Drilling of the "300-series" wells revealed significant heavy (12° API) oil saturated sands at about 600 ft depth within the Pleistocene Tulare Formation. A total of 20 shallow wells subsequently were drilled in the southern half of the Pru Fee property to recover this oil by cyclic steaming. Although this production is not part of the present Class 3 oil technology demonstration, it does represent an added resource from the property developed as a consequence of the project. In just the first half of 2000, a total of 38.1 Mbbls of Tulare oil was produced. Oil rates appear to be increasing, rising from an average of 171.1 bopd in the first quarter of 2000 to 233.4 bopd in the second quarter. The Monarch wells are cased through the Tulare interval and none of the Tulare oil is commingled with the Monarch oil.

Monarch Sand Reservoir

Heavy oil production at the Pru pilot is from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation (Gregory, 1996). The pay interval is just 1100-1400 ft deep. Like other sand bodies within the Monterey Formation, it is a deep submarine channel or proximal fan deposit encased in diatomaceous mudstone (Link and Hall, 1990; Nilsen, 1996). The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault just 15 miles to the west of the site (Webb, 1981; Ryder and Thomson, 1989). The top of the Monarch Sand, actually a Pliocene/Miocene unconformity, dips at less than 10° to the southwest. The unconformity bevels downward at a very low angle to the northwest across the upper portion of the Monarch Sand body (Schamel, 1999). The net pay zone, which averages 220 ft at Pru, thins to the southeast as the top of the sand dips through the nearly horizontal oil-water contact (OWC). In the southeast half of the Pru property a thin wedge of Belridge Diatomite overlies the Monarch Sand beneath the Pliocene/Miocene unconformity providing a somewhat more effective steam barrier than the Pliocene Etchegoin Formation, a silty, sandy mudstone. However, it is the overlying Etchegoin Formation that forms the essential unconformity trap for the Monarch Sand reservoir in this part of the Midway-Sunset Field.

Average Monarch Sand reservoir characteristics derived from core and the log model developed for this project (Schamel et al., 1999) are 31% porosity and 2250 md permeability. The "initial" (1995) average oil saturation was estimated to be 59%. However, all wells have a relatively thick transition zone of downward decreasing oil saturation in the bottom half of the pay interval. The oil is both heavy and viscous, about 13° API gravity and 2070 cp at the initial (1995) reservoir temperature of 100° F. The Pru-101 core reveals a dominance of sand-on-sand contacts with only a few relatively thin intervals of diatomite and silt. The wire-line logs in wells penetrating up to 350 ft of the reservoir also suggest that the Monarch Sand at this site is essentially a single sand body with interspersed remnants of diatomite beds, rather than thin stacked sand bodies encased in diatomite.

Reservoir simulations with geostatistically generated data sets (Schamel, 1999) revealed that the initial fluid distribution in the reservoir had the most significant impact on the economics of the steam flood process. The initial fluid distribution was determined by the placement of the oil-water contact and the resulting transition zone in the reservoir. The production strategy adopted in the steam flood pilot involved steam injection within the upper third of the oil column, where the oil saturation (So) is greater than 50%, so as to avoid undue loss of heat to water. It was subsequently learned from examination of wells drilled for the "300-series" cyclic to steam flood conversion that the "initial" fluid distributions in the Monarch Sand are highly variable. Optimal production requires a more flexible strategy for completion of the injectors than that adopted for the pilot.

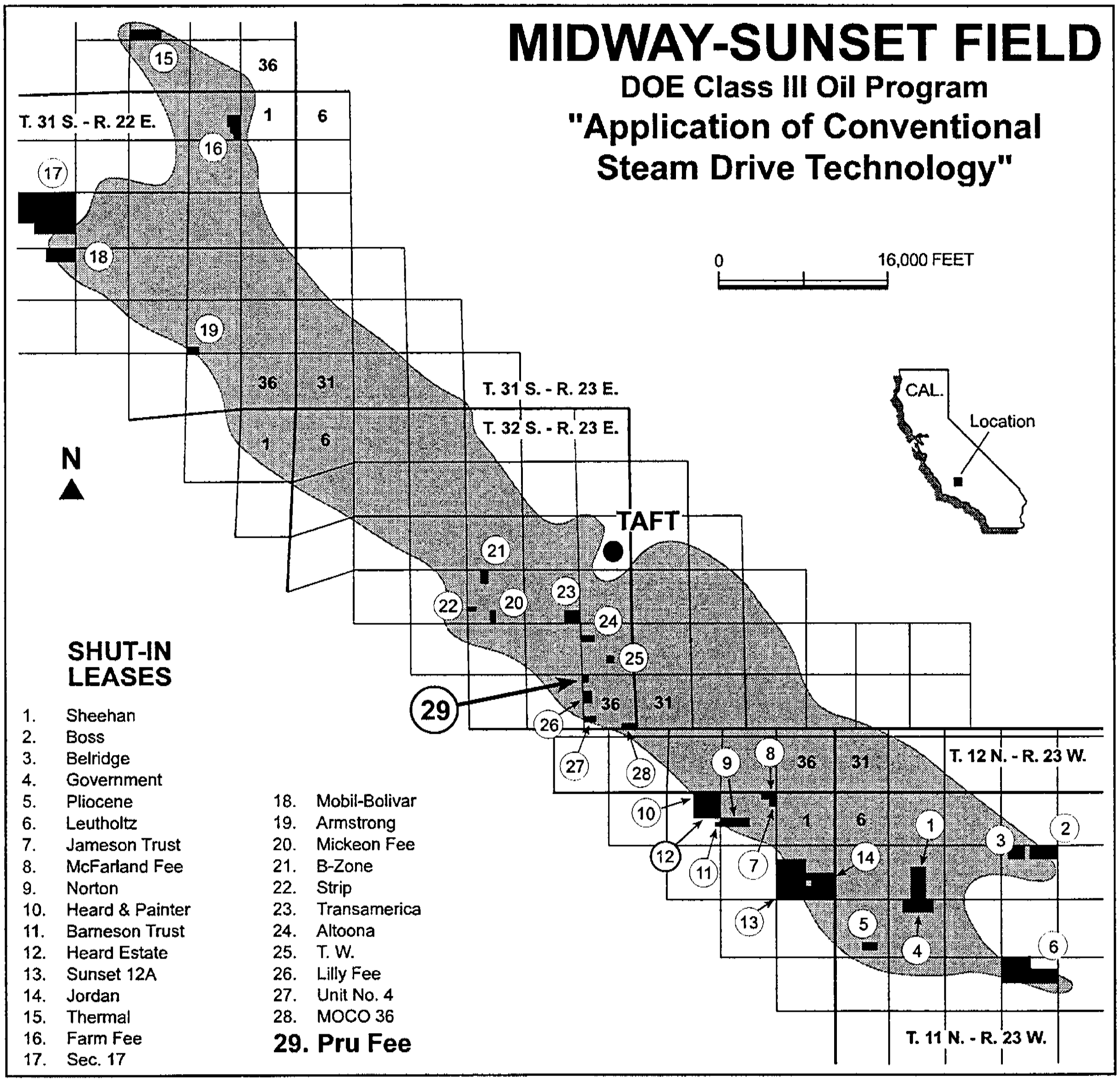

Figure 1-1: Index map of the Midway-Sunset field showing location of the Pru Fee property and other leases shut-in at the start of the project.

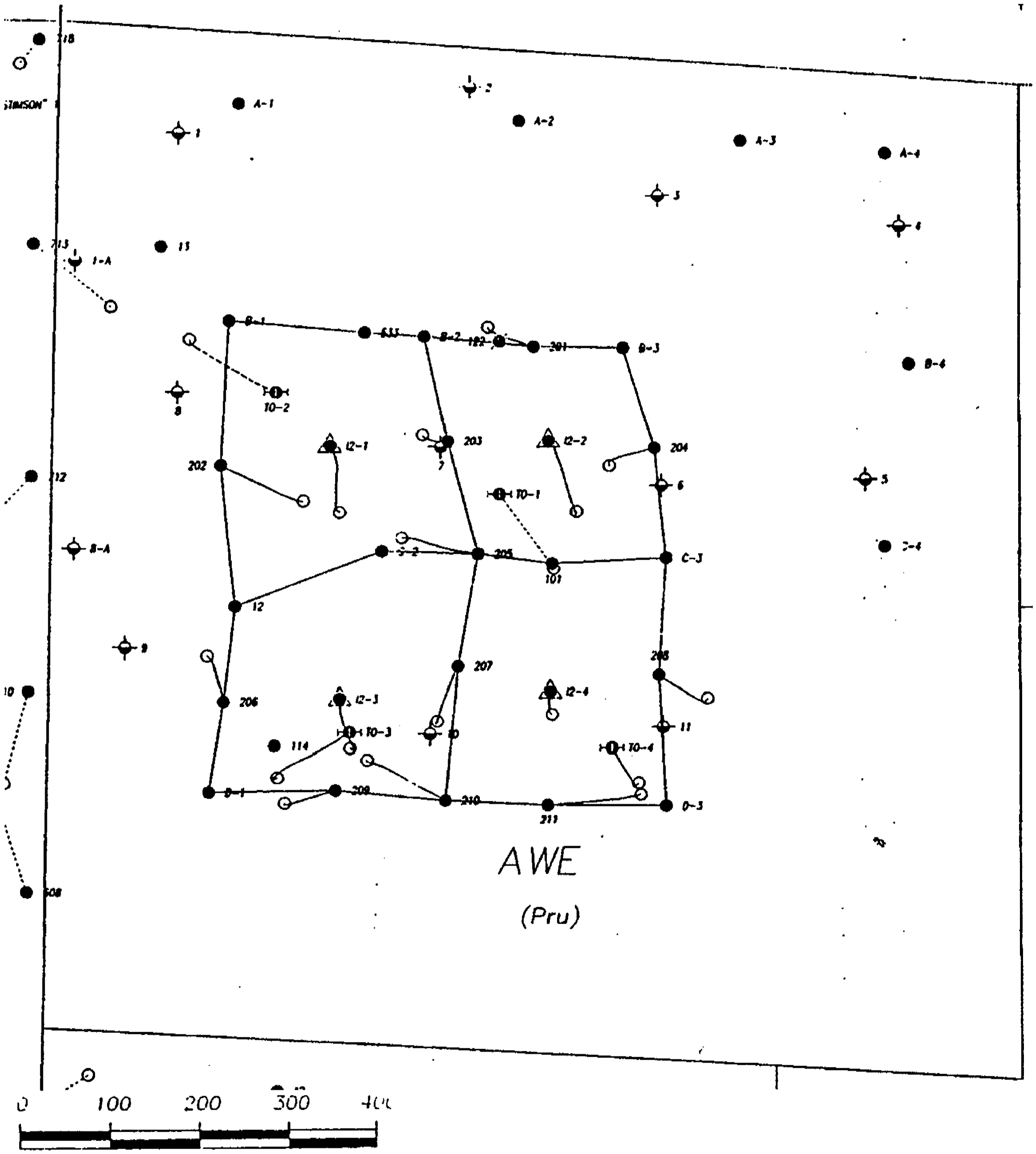

Figure 1-2: Map of the four-pattern, nine-spot steam flood array in the Pru Fee pilot.

Chapter 2

Conversion of "300-series" Cyclic Wells to Steam Flood

The 37 "300-series" wells drilled throughout 1998 surround the four-pattern steam flood pilot on the south, west, north and northeast (Fig. 2-1). Only the southeast corner of the 40 acre property, where the Monarch Sand pay is considerably less than 200 ft, was not drilled. The wells were drilled, completed, primed and put on line in cyclic mode in three phases: six wells in January, an additional six wells in May, and the remaining 25 wells in the period August through October. By January 1999, when Aera Energy LLC began operating the property, only 28 producers had been primed and were on line (Fig. 2-2). It was not until late spring-early summer that the entire group of "300-series" wells were producing.

In converting the "300-series" producers to steam flood, the wells were arranged into ten two-acre nine-spot patterns surrounding the four-pattern pilot in the center of the Pru Fee property (Fig. 2-3). The pilot patterns are numbered from *pattern 1* in the northwest corner to *pattern 4* in the southeast corner. The ten new patterns begin with *pattern 5* due south of *pattern 4* and proceed clockwise around the pilot patterns ending with *pattern 14* immediately east of *pattern 2.* There are no new patterns to the east and southeast of *pattern 4.* Otherwise, the entire property is covered with nine-spot patterns that on the whole mimic the configuration of the pilot patterns. All of the patterns are rough squares about 250-300 ft on a side. In forming the four patterns along the western edge of the property (patterns 7 through 10) it was necessary to incorporate 11 existing producers in the adjacent Kendon property, also operated by Aera Energy LLC. These Kendon wells are (from south to north) E-5, 608, 610, C-5, B-5, 712, 852, 713, 851, 718, and 716. All are within 50 ft of the Kendon-Pru boundary.

The "300-series" wells all had been completed as producers with slotted liner and gravel pack through the entire Monarch Sand pay zone. Therefore, in forming the new steam flood patterns it was necessary to drill and complete ten additional injectors. Each are positioned near the centers of their respective patterns and are numbered to reflect the pattern, Pru I2-5 through I2-14. Also three additional temperature observation wells were drilled. Pru TO-5 is situated in the southeast quadrant of *pattern 10* in the extreme northwest corner of the property. Pru TO-6 is in the southwest portion of the property near the join of *patterns 3, 6 and 7.* Pru TO-7 is in the northeast near the northern edge of *pattern 12* and immediately south of the Nevada lease. These three additional temperature observation wells complement the four existing wells within the pilot. The capital investment in the 13 new wells alone is about $889,000. Even though the new steam flood patterns will be incorporated into the overall oil demonstration project, Aera Energy LLC has made the investment alone without a DOE match.

In order to provide sufficient steam to the existing wells and the 10 new injectors, additional steam facilities were installed in December 1999. These consist of relocating an existing generator to the adjacent Kendon lease and running a steam line from Kendon to Pru Fee. New steam splitters with metering facilities were installed on Pru Fee to manage the increased steam. The capital cost of relocating the generator was budgeted at $182,000; the new steam line and steam splitters cost about $479,000. The total budgeted cost of the expansion of the steam flood production on the Pru Fee property is $1,550,000.

At the time the four-pattern steam flood pilot was designed and implemented, the price of San Joaquin heavy crude was considerably less than $15/bbl and the economics of the steam flood scheme was still untested. The injectors were completed such as to put the steam into the lower half of the zone of presumed highest oil saturation. Narrow (55-60 ft) injection intervals were adopted with an average stand off from the top of the Monarch Sand and the OWC of 48.8 ft and 166.8 ft, respectively. The steam injection flux was between 0.7 and 1.4 bspd/naf. This conservative strategy was intended to yield favorable oil rates while keeping operating costs to a minimum, as required by the then prevailing net present value (NPV) of the property.

Table 2-1: Steam Injection Intervals for Pru Steam Flood Patterns

Injector	# perfs	Top Monarch	Top perf	Base perf	OWC	Inj. Interval	Upper SO	Lower SO	Spacing
I2-1	6	1057.0	1104.0	1160.0	1365.0	56.0	47.0	205.0	9.3
I2-2	6	1088.0	1127.0	1174.0	1362.0	47.0	39.0	188.0	7.8
I2-3	6	1103.0	1149.0	1209.0	1358.0	60.0	46.0	149.0	10.0
I2-4	6	1087.0	1150.0	1206.0	1331.0	56.0	63.0	125.0	9.3
I2-5	5	1151.0	1164.0	1248.0	1352.5	84.0	13.0	104.5	16.8
I2-6	8	1136.5	1174.0	1324.0	1381.5	150.0	37.5	57.5	18.8
I2-7	6	1123.5	1154.0	1300.0	1388.5	146.0	30.5	88.5	24.3
I2-8	5	1105.0	1133.0	1308.0	1370.5	175.0	28.0	62.5	35.0
I2-9	11	1070.0	1086.0	1354.0	1392.0	268.0	16.0	38.0	24.4
I2-10	8	1097.0	1131.0	1344.0	1449.0	213.0	34.0	105.0	26.6
I2-11	11	1096.5	1107.0	1398.0	1429.0	291.0	10.5	31.0	26.5
I2-12	9	1068.0	1123.0	1305.0	1344.5	182.0	55.0	39.5	20.2
I2-13	10	1069.0	1078.0	1292.0	1331.5	214.0	9.0	39.5	21.4
I2-14	6	1084.0	1095.0	1282.0	1339.0	187.0	11.0	57.0	31.2

Note: All well depths are in feet down-hole, not TVD. *Injectors 1 - 4: Pru steam flood pilot; Injectors 5-14: 300-series patterns*

By the time of conversion of the "300-series" wells from cyclic to steam flood mode other factors governed optimal production. The principal factor was the sharp increase in the price of Midway-Sunset heavy crude to the upper teens and lower twenty's, and rising. Also the viability of steam flood as a successful production method in marginal, low dip portions of the Monarch Sand was proven. Furthermore, it was clear from the temperature observation wells that the steam was staying in the formation where injected, not rising into the overlying oil-free Etchegoin Formation. The very thin and apparently discontinuous diatomite lenses seemed to be partially effective in holding the steam within the sand reservoir. Therefore, the decision was made to adopt a less conservative strategy in placing the perforations in the ten new injectors. Although an effort would be made to avoid injecting steam into high Sw parts of the reservoir, there are shorter standoffs from the top of the Monarch Sand and the OWC, and the injection interval encompasses most of the pay interval (Table 2-1). The less than optimal placement of the injected steam will be offset by anticipated larger oil rates and total oil recovery, both desirable economic factors given the increased NPV of the Pru Fee crude.

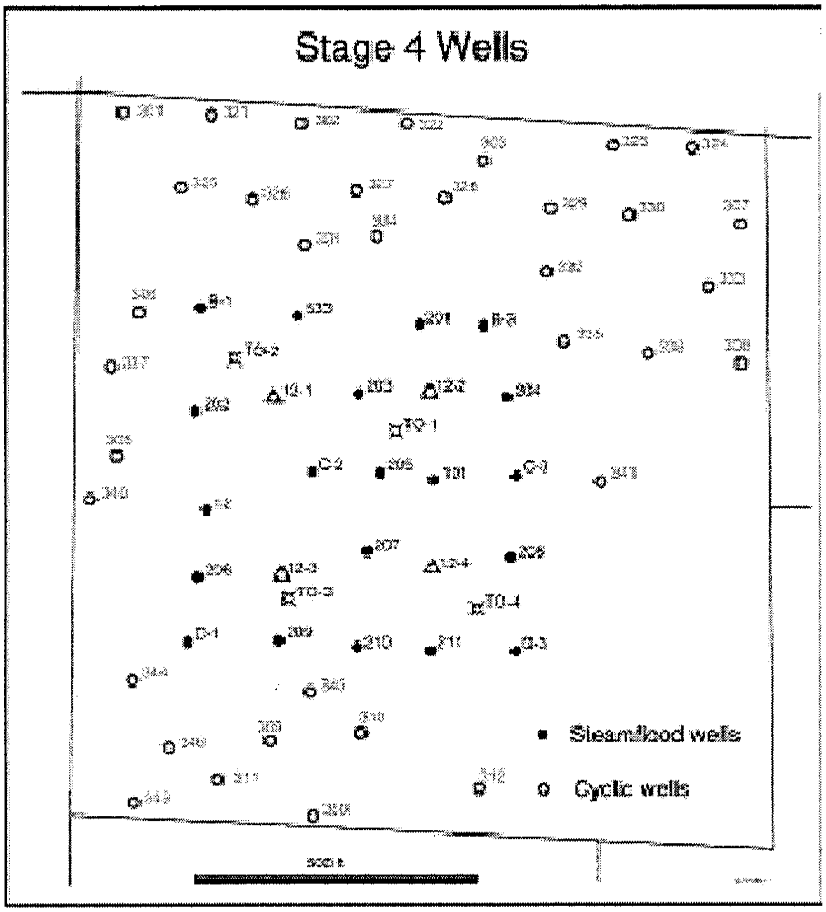

Figure 2-1: Location of new cyclic Pru 300-series producers drilled by AWE in 1998 (open circles). The preexisting 4-pattern steam flood pilot wells are shown in the center of the Pru Fee property as closed circles (producers) and triangles (injectors). The TO wells are for temperature observation only.

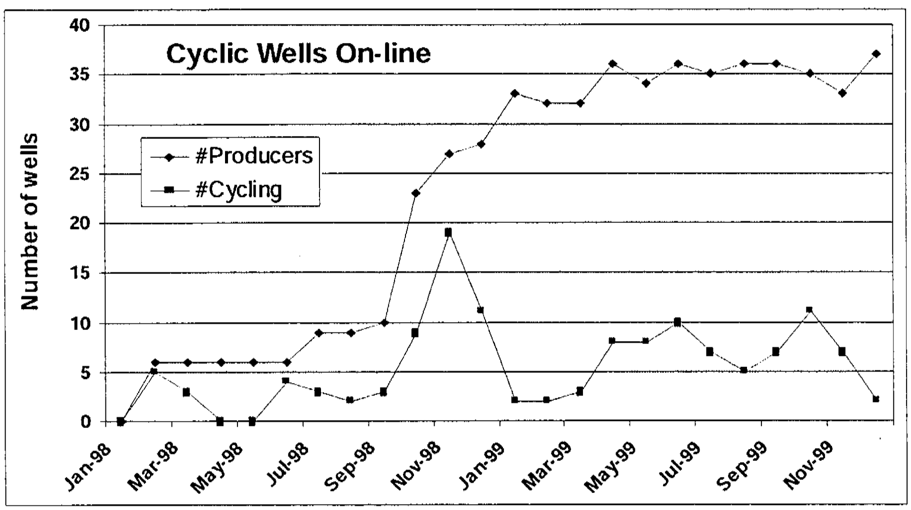

Figure 2-2: Plot of "300-series" wells being cycled and subsequently put on line during 1998-1999.

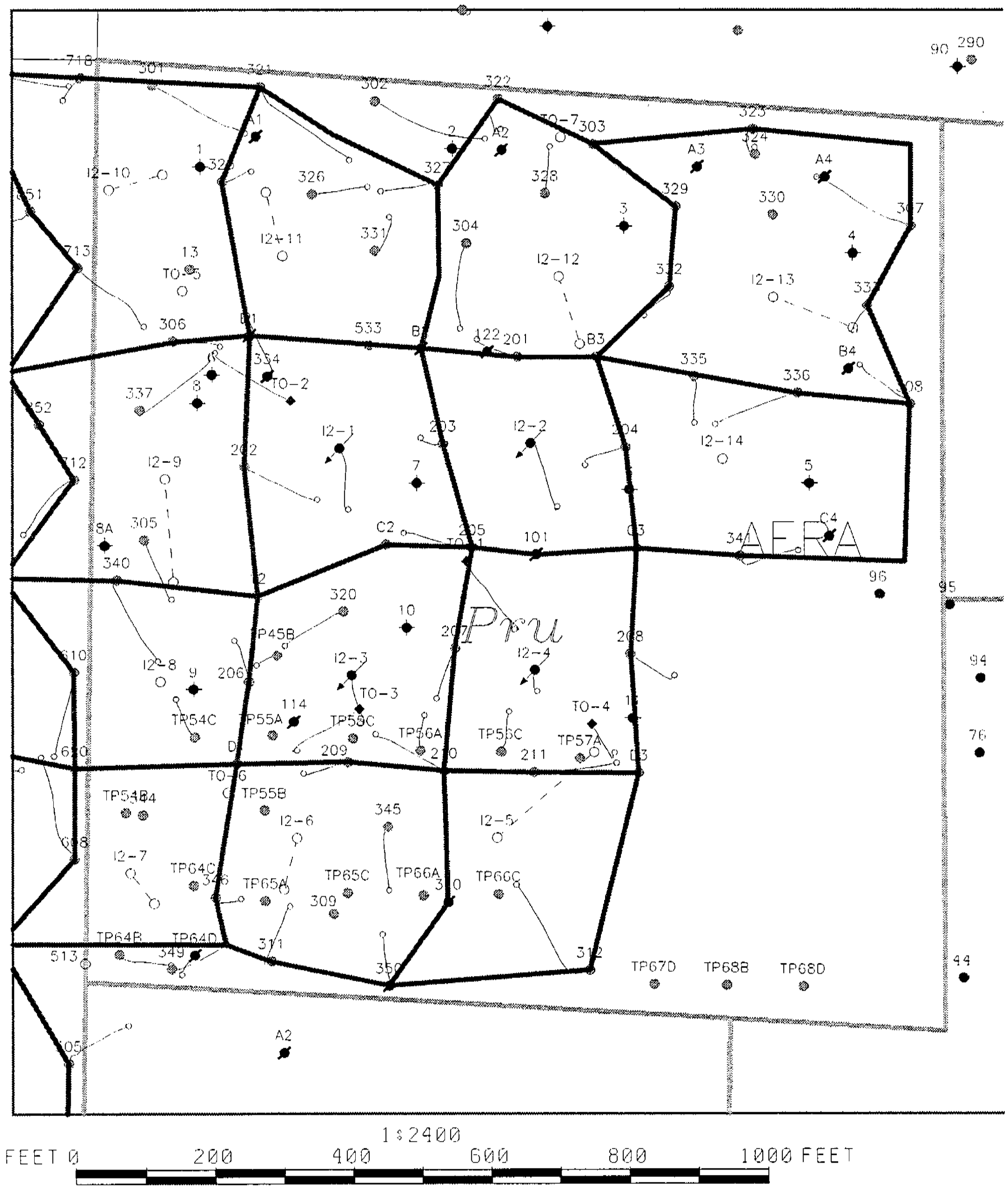

Figure 2-3: Array of ten new inverted nine-spot steam flood patterns developed using the 37 existing "300-series" cyclic wells. These new patterns surround the older four-pattern Pru Fee pilot at the center of the property that has been operating in steam flood since early 1997.

Chapter 3

Production Performance

Production performance for the steam flood pilot and the "300-series" wells are described separately in this section. The comparison and significance of the production numbers is discussed in Chapter 6.

Performance of the Steam Flood Pilot

The production rates of fluids from the 8 acre four-pattern steam flood pilot (Table 3-1) is shown in Figure 3-1. During the initial phase of evaluation of the project from late 1995 through early 1997, oil rates from mainly renovated cyclic wells averaged 65 BOPD. Soon after the steam flood pilot began in February-March 1997, oil rates rose dramatically reaching a maximum of 424 BOPD in July 1997. Since then, the oil rates have fallen back slightly to maintain a general range of 300 to 370 BOPD through the latter half of 1997 and all of 1998. However, production rates fell below 300 BOPD at the time of transfer of operatorship and for all of 1999 and the first two months of 2000 they were in the general range 250 to 310 BOPD.

The drop in oil rates is a consequence of infrastructure improvements to the site undertaken by Aera Energy LLC. The new construction, in part, brought additional steam to Pru Fee from the adjacent Kendon lease so as to cycle the new "300-series" wells more rapidly and bring up reservoir temperature in the Monarch Sand across the entire property more quickly. During this period, fluids from Pru Fee were being routed to processing facilities on the MOCO property. There they were commingled with fluids from all adjacent leases, then metered. By late February 2000, a new dedicated metering system for the Pru Fee property was operational. Immediately oil rates increased dramatically from 285.6 bopd in February to 444.2 bopd in March. In as much as no other changes in production were occurring at Pru, the increase is attributed to inacrecurate metering during the year prior to March 2000.

Although, in general, water rates had been rising gradually during the entire period of steam flood, in the year 1999-2000 the rates dropped sharply from 2,433 bwpd in June 1999 to 1,366 bwpd in June 2000 (Fig. 3-1). Yet during this period the steam rates were at an all time high (Fig. 3-1), especially during the second half of 1999. The target injection rate for the four-pattern pilot is 1,000-1,200 bspd. Temperature monitoring at the pilot indicates that full steam flood production had begun late in 1997. Nevertheless, the steam chest apparently is still building, albeit slowly. The entire volume of the pilot had not reached maximum temperature as of the beginning of 2000, when the temperature observation wells were last logged.

By the end of the end of June 2000, the cumulative oil production from the 8 acre steam flood pilot alone stood at 412.1 MBO (Table 3-1; Fig. 3-2). Cumulative water production was at 2,335.6 Mbbls. A total of 1,841.9 Mbbls of steam had been injected on site to produce these fluids.

The steam flood performance factors, the oil-steam (OSR) and oil-water (OWR) ratios, have been favorable through the duration of the steam flood, except in 1999 when the actual oil production may have been under-reported (Fig. 3-3). Both measures of performance have greatly improved since March 2000. The OSR and OWR ratios determined from the cumulative volumes produced may give a more accurate picture of project performance (Fig. 3-4). Here we have an OSR of about 0.23, except for the dip in 1999, and OWR in the range 0.17-0.19.

Table 3-1: Monthly average production at the Pru steam flood pilot June 1999-June 2000

	Average Daily Rate			*Cumulative Volumes by Month*		
Month	**Oil** bopd	**Water** bwpd	**Steam** bspd	**Oil** Mbbls	**Water** Mbbls	**Steam** Mbbls
June	284	2,433	1,184	284	1,640	1,301
July	281	2,222	1,593	293	1,708	1,350
August	254	2,151	2,285	301	1,775	1,421
September	281	2,097	1,811	309	1,838	1,475
October	236	1,969	1,578	317	1,899	1,524
November	283	2,198	2,114	325	1,965	1,588
December	308	2,239	1,268	335	2,034	1,627
January	292.8	1,844.4	964.5	344.1	2,091.2	1,656.9
February	285.6	1,611.1	906.6	352.4	2,137.9	1,711.2
March	444.2	1,617.5	923.0	366.1	2,188.0	1,745.9
April	510.7	1,769.3	1,152.1	381.4	2,241.1	1,780.4
May	528.9	1,725.9	949.0	397.8	2,294.6	1,809.8
June	475.6	1,366.4	1,068.5	412.1	2,335.6	1,841.9

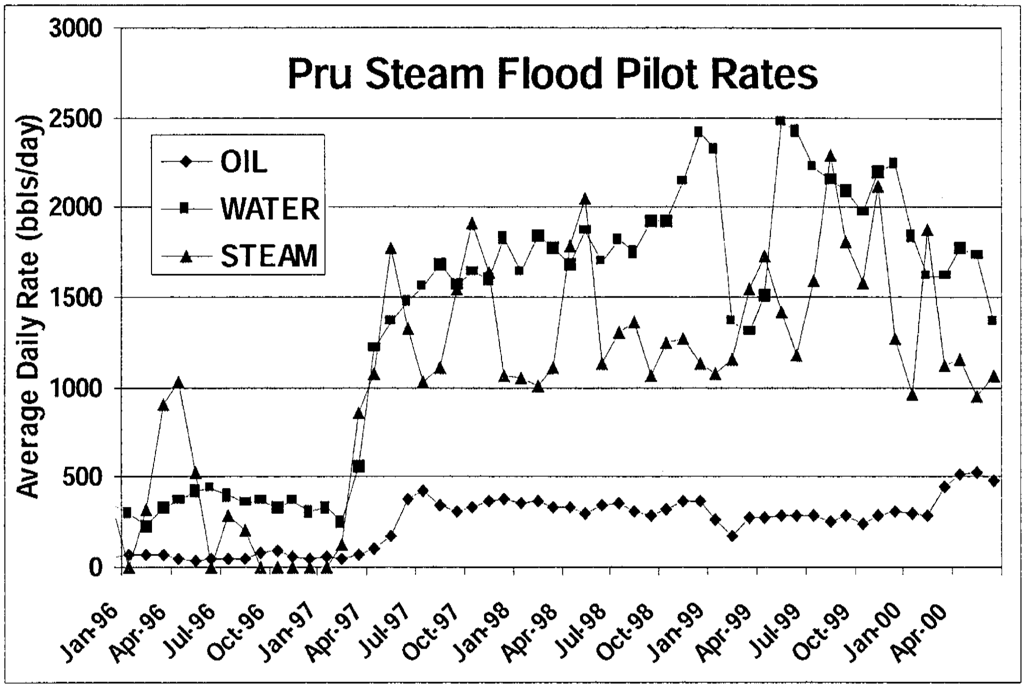

Figure 3-1: Production and steam injection rates for the four-pattern Pru Fee pilot through June 2000. The steam flood demonstration began early in 1997.

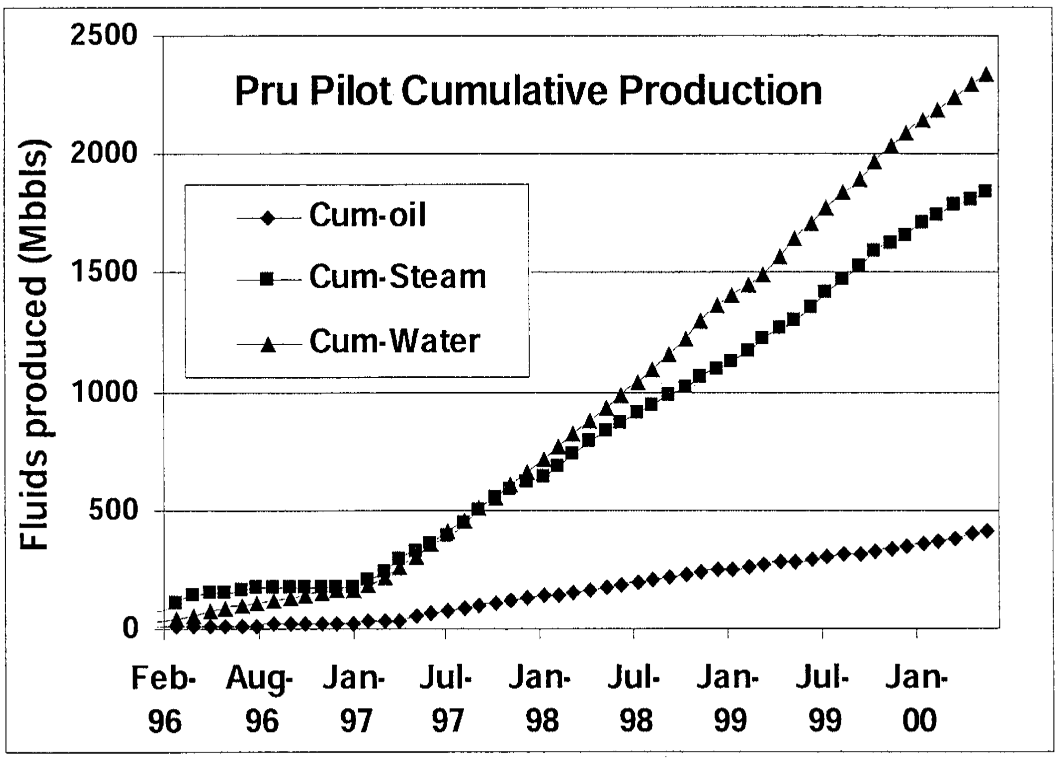

Figure 3-2: Cumulative production and steam injection for the four-pattern Pru Fee pilot through June 2000.

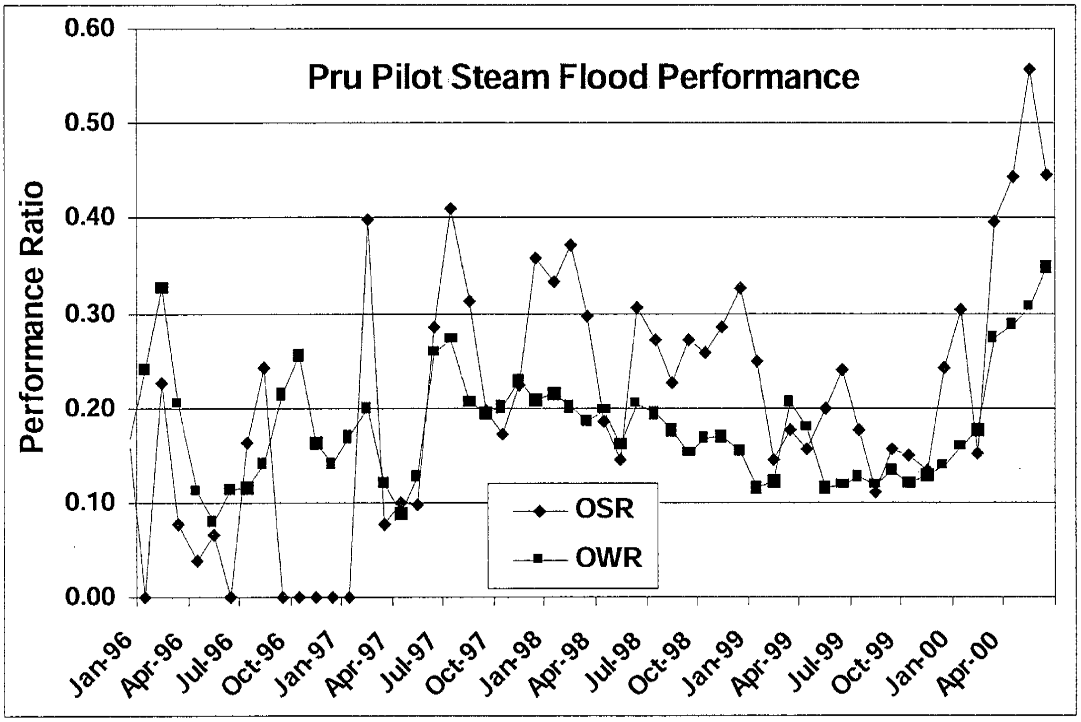

Figure 3-3: Performance factors for the four-pattern Pru Fee pilot through June 2000. OSR is the "oil-steam ratio" and OWR is the "water-steam ratio".

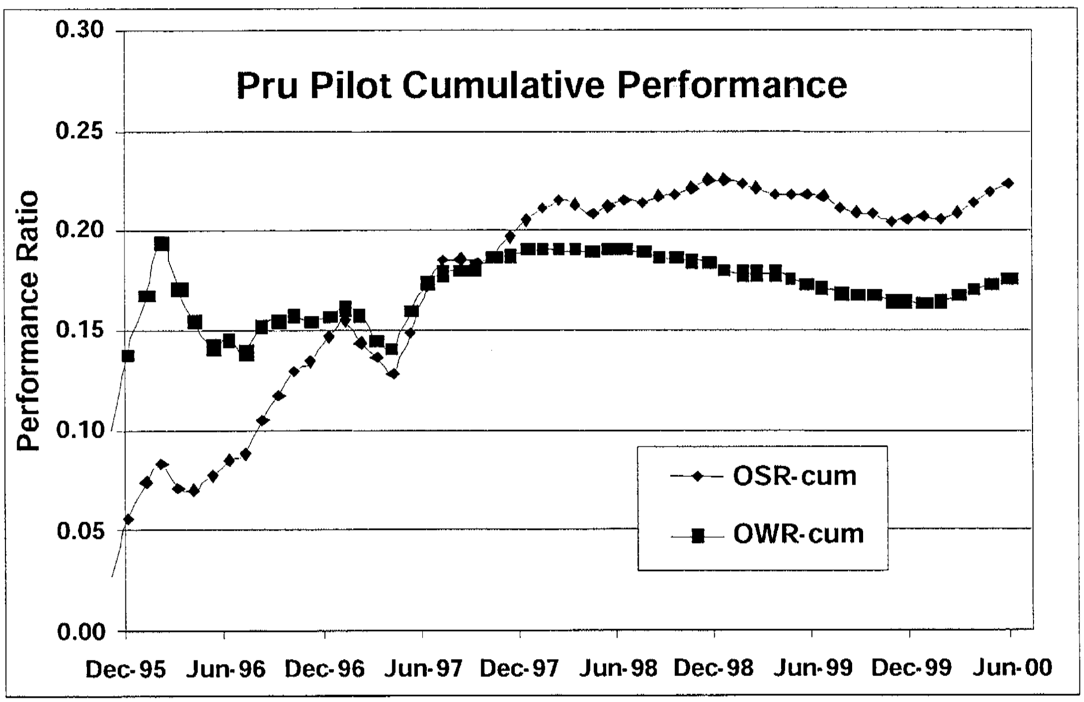

Figure 3-4: Performance factors determined from cumulative production/injection volumes through June 2000 for the Pru Fee pilot.

Performance of the "300-series" Wells

The 37 "300-series" wells drilled on the Pru Fee property in 1998 represented a substantial investment in enhanced heavy oil recovery. Already by mid-year 2000 this investment was having a remarkable payback (Table 3-2; Fig. 3-5). During the year 1999-2000 the oil rate from these wells had more than doubled from 374.9 bopd in June 1999 to 804.7 bopd in June 2000. The increase in water rate was gradual, but proportionally smaller. In the third quarter of 1999 the water rate averaged 2,030 bwpd, but by the second quarter of 2000 it was just 2,555 bwpd, only a 26% increase. The rates of steam injection, which in cyclic mode had been less than 2,000 bspd for the entire group of producers, increased substantially when the wells were converted to steam flood. The steam rate in May 2000 was 7,055 bspd.

In terms of cumulative volumes (Table 3-2; Fig. 3-6), oil production increased 150% in the year from June 1999 to June 2000 ending the year at 323.6 MBO. The cumulative water production at year's end was 1,376.5 Mbbls. A total of 1,718.3 Mbbls of steam was injected, in both cyclic and steam flood modes, to produce these fluids.

Table 3-2: Monthly production from the Pru "300-series" wells June 1999-June, 2000

	Average Daily Rate			*Cumulative Volumes by Month*		
Month	Oil bopd	Water bwpd	Steam bspd	Oil Mbbls	Water Mbbls	Steam Mbbls
June	374.9	1,871.2	1,689.1	129.7	591.1	572.2
July	372.2	1,766.5	1,731.6	141.2	645.9	625.9
August	384.8	2,129.4	1,047.1	153.1	711.9	658.3
September	473.6	2,195.4	1,338.1	167.3	777.7	698.5
October	395.2	1,982.4	1,950.5	179.6	839.2	758.9
November	406.0	2,270.6	970.8	191.8	907.3	788.1
December	458.3	1,888.1	282.1	206.0	965.8	796.8
January	424.0	1,572.5	2,090.6	219.1	1,014.6	861.6
February	434.6	1,891.9	4,349.4	231.7	1,069.5	987.8
March	759.4	2,403.5	5,512.8	255.3	1,144.0	1,158.7
April	728.9	2,600.8	5,076.0	277.1	1,222.0	1,311.0
May	719.2	2,555.7	7,055.4	299.4	1,301.2	1,529.7
June	804.7	2,508.1	6,287.2	323.6	1,376.5	1,718.3

The OSR performance ratio (Fig. 3-7), which had been relatively favorable during the cyclic production in the range 0.20-0.25, has been dropping steadily during steam flood. This is seen as a temporary reduction in production efficiency as heat builds in the new steam flood patterns. The OWR performance ratio has remained in the range 0.23-0.24 since early 1999 when the entire group of "300-series" wells were fully operational.

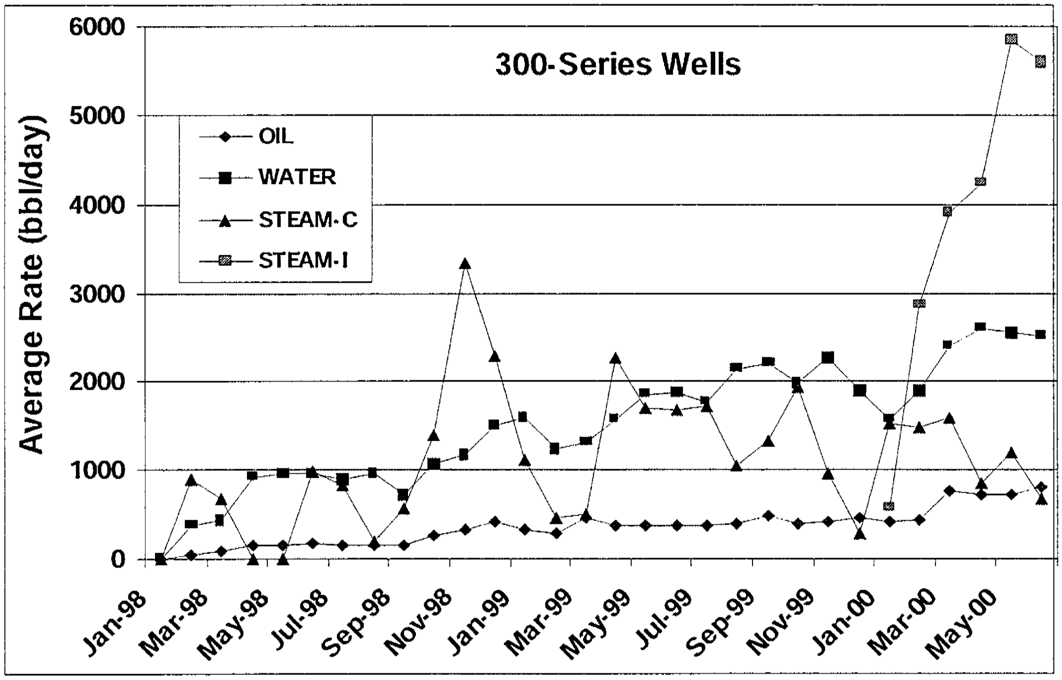

Figure 3-5: Production and steam injection rates for the Pru Fee "300-series" wells through June 2000. Cyclic production in these wells began in 1998; conversion to steam flood occurred in January-February 2000.

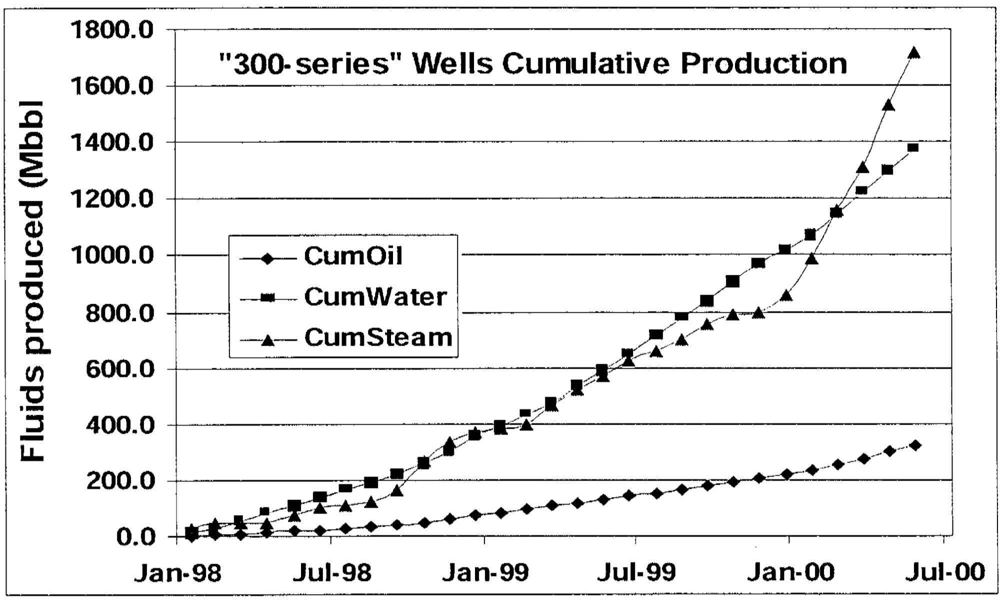

Figure 3-6: Cumulative production and injection in the Pru Fee "300-series" wells.

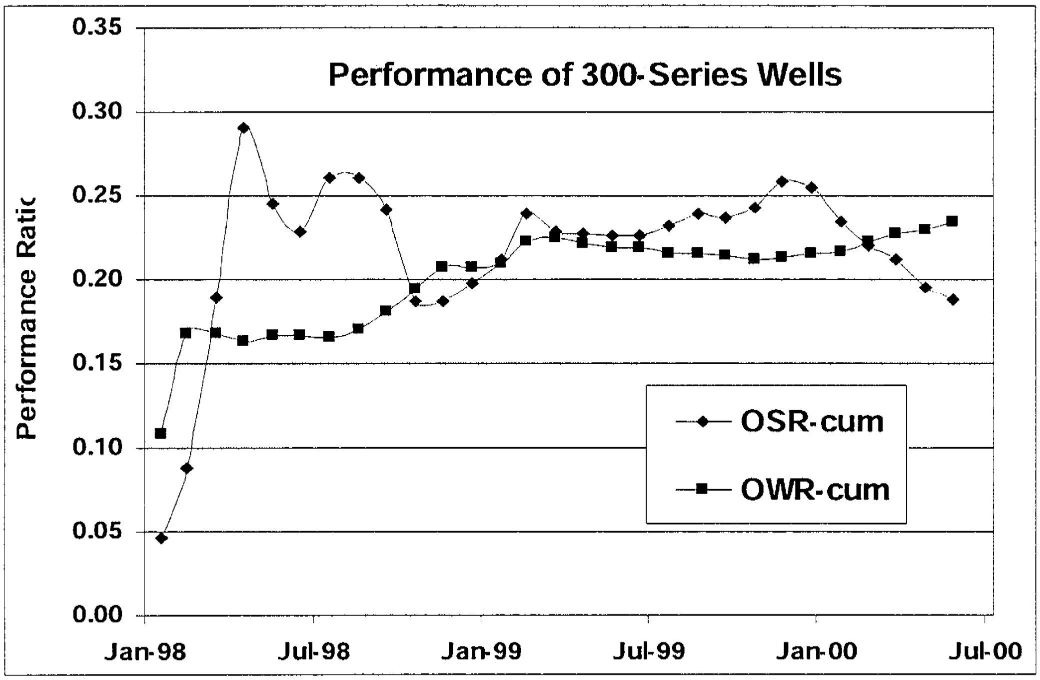

Figure 3-7: Performance factors for the Pru Fee "300-series" wells through June 2000. Ratios shown are those calculated from cumulative fluid volumes. Ratios determined from the monthly volumes are extremely variable.

Chapter 4

Temperature Distribution in Monarch Sand Reservoir

The progressive buildup of heat within the Monarch Sand reservoir is monitored by two means: 1) a series of temperature observation wells interspersed within the array of injectors and producers and 2) the temperature of produced fluids. Four temperature observation wells were installed in early 1997 at the time of startup of the four-pattern steam flood pilot. These wells have been logged just eight times during the period June 1997 through January 2000. At the time of conversion of the "300-series" cyclic producers to steam flood patterns three additional temperature observation wells were installed, one each in the southwest, northwest and north-central portions of the 40 acre Pru Fee property. These wells have been logged just once, in December 1999, before the steam flood patterns became operational.

Heat Buildup in Steam Flood Pilot

During the first two years of operation of the steam flood pilot, the four temperature observation wells were logged on a regular basis to track the buildup of heat within the Monarch Sand reservoir. However, in the period of transfer of ownership between ARCO Western Energy and Aera Energy LLC, this activity was suspended. Thus, a nine-month gap in temperature logging exists between September 10, 1998 and June 15, 1999.

The progressive buildup of heat in the four temperature observation wells since the onset of the steam flood operation in the spring of 1997 is displayed in Figures 4-1 through 4-4. The depths in the wells are expressed as elevations relative to sealevel. It is important to note that during the entire period of temperature record, the points of steam injection had not been altered. Eacreh injector well is a solid pipe perforated at six points about 10 ft apart. The lowest perforation has a standoff from the OWC in excess of 100 ft. Also, it should be noted that the ambient reservoir temperature prior to steam injection was close to 100° F. This ambient reservoir temperature is preserved in the deeper parts of the Monarch Sand.

Table 4-1 provides information about the distances of each temperature observation well from the nearest injector, the elevations of the top of the Monarch Sand reservoir and the OWC, and the distance/elevation, relative to the top of the reservoir and OWC, of the top and bottom of the injection interval in the nearest injector. It is obvious that the initial thermal response to steam injection recorded in each temperature observation well is approximately proportional to its proximity to an injector well. However, the specific pattern of reservoir heating implicit in the temperature logs varies greatly.

The strategy for optimizing steam flood production in the pilot is to put the heat into the upper part of the Monarch Sand reservoir where the oil saturations are observed to be highest (greater than 50-60%), and avoid heating the lower half of the pay interval where water saturations generally exceed 50%. The heat capacity of water is more than twice that of crude oil (Burger et al., 1985) so that heat is lost disproportionately to formation water. The temperature observation logs provide critical data for knowing if the reservoir heating objectives are being reached.

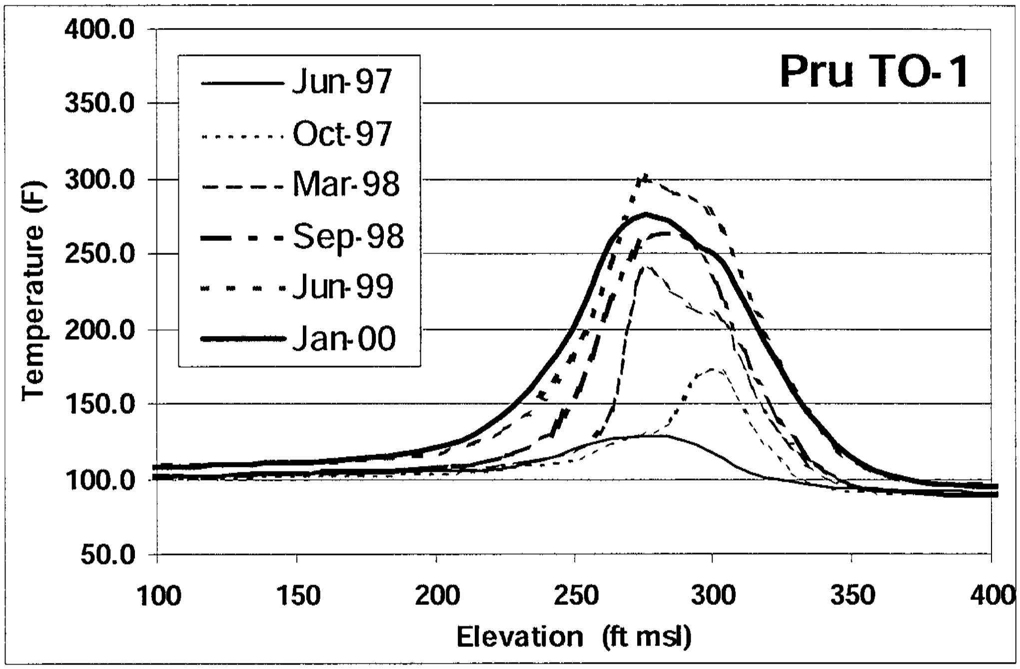

Figure 4-1: Stacked temperature logs for the Pru TO-1 well, which is 100 ft from the nearest injector well. Top of Monarch Sand = 300 ft; OWC = 30.5 ft.

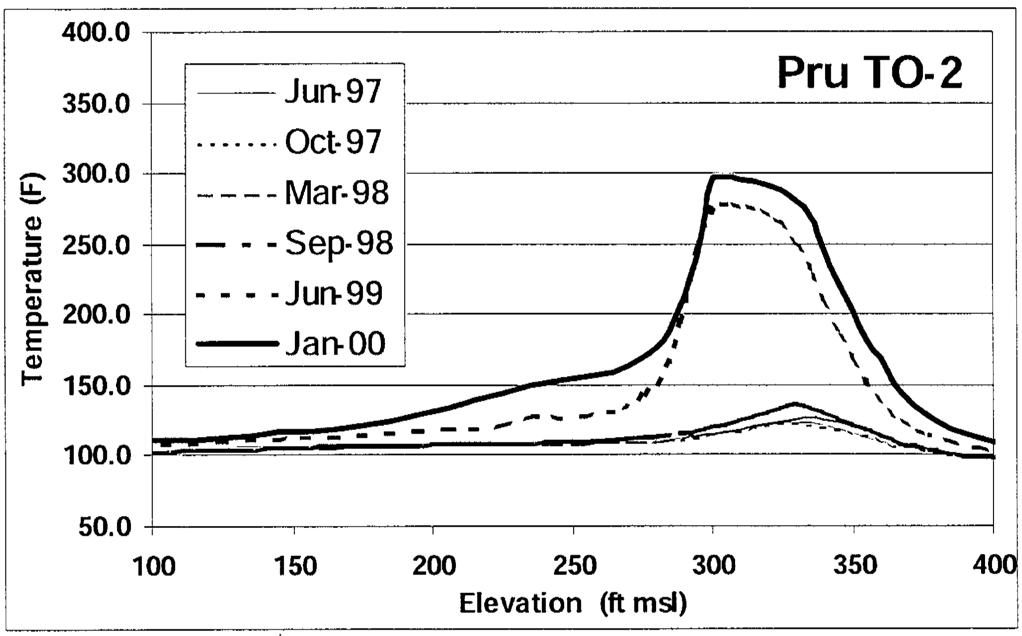

Figure 4-2: Stacked temperature logs for the Pru TO-2 well, which is 90 ft from the nearest injector well. Top of Monarch Sand = 350 ft; OWC = 31.8 ft.

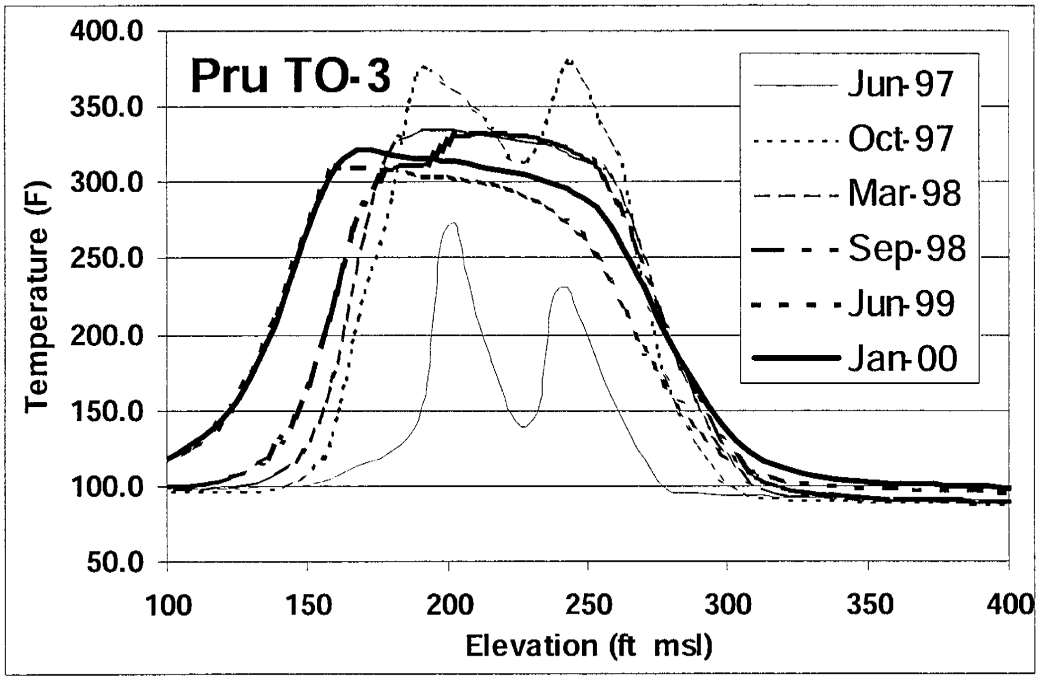

Figure 4-3: Stacked temperature logs for the Pru TO-3 well, which is 45 ft from the nearest injector well. Top of Monarch Sand = 278.5 ft; OWC = 32.8 ft.

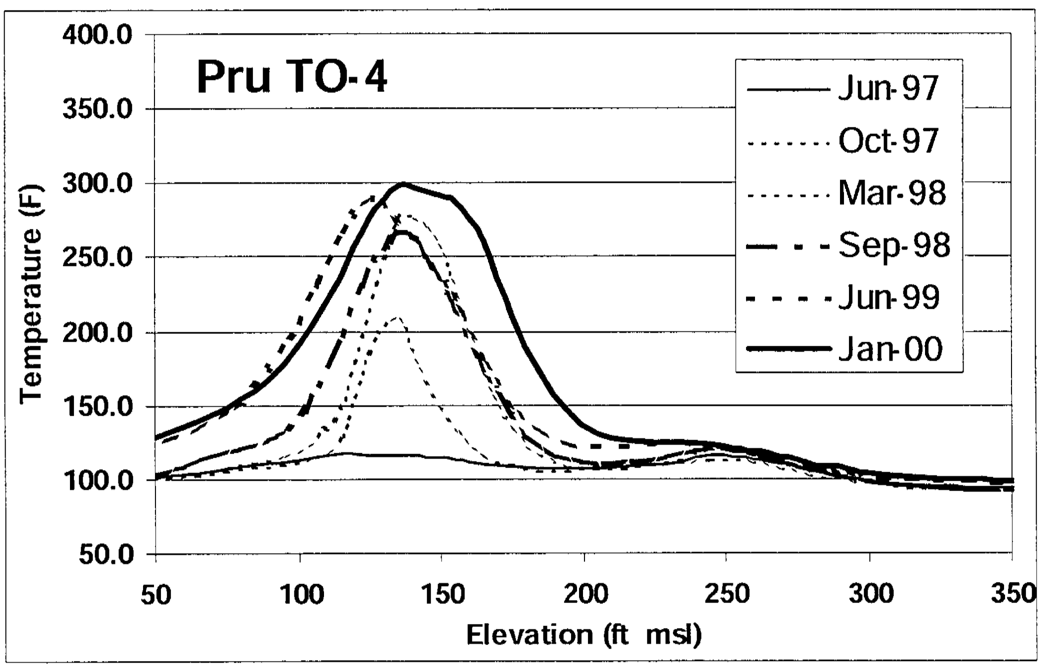

Figure 4-4: Stacked temperature logs for the Pru TO-4 well, which is 110 ft from the nearest injector well. Top of Monarch Sand = 222.6 ft; OWC = 25.9 ft.

Table 4-1: Information related to Temperature Observation Wells

	TO-1 well	TO-2 well	TO-3 well	TO-4 well
Nearest injector	I2-2	I2-1	I2-3	I2-4
Distance/direction to injector	100 ft/NE	90 ft/SE	45 ft/NNW	110 ft/NW
Elevation top reservoir	300 ft	350 ft	278.5 ft	222.6 ft
Elevation of OWC	30.5 ft	31.8 ft	32.8 ft	25.9 ft
Thickness of zone >200° F	68 ft	67 ft	139 ft	74 ft
Elevation interval > 200° F	318/250 ft	350/283 ft	278/139 ft	178/104 ft
Nearest injector				
Elevation top/base perf.	262/206 ft	290/243 ft	233/173 ft	209/153 ft
Offset - top perforation	47 ft	39 ft	47 ft	44 ft
Offset – base perforation	103 ft	86 ft	107 ft	100 ft
Offset base from OWC	202 ft	187 ft	161 ft	131 ft

Note: The viscosity of the Pru Fee crude oil at 200° F is measured as 37 cp.

The dip of strata within the Monarch Sand at the four-pattern pilot is 10° to the southeast. At this dip, the strata would be expected to drop about 18 ft for every 100 ft of horizontal distance to the southeast. Two of the temperature observation wells (TO-3, TO-4) are situated to the southeast, downdip, of their nearest injector (Fig. 1-2). The TO-2 well is updip and the TO-1 well is on strike to the southwest (Table 4-1). If indeed the steam remained confined within the strata in which it was injected, we could expect that the "hot" interval in the temperature observation wells, designated for convenience as that over 200° F (Table 4-1), would be of similar thickness and elevation as the perforation interval within the nearest injectors. Yet this is not entirely what is observed. In two instances (TO-1, TO-2), the steam rises about 50 ft, somewhat more than can be explained by the inclination of the strata. In another case (TO-3), it spreads upward and downward about 40 ft in each direction. Only in the last instance (TO-4) does the steam appear to be constrained by stratigraphic barriers. In the first three wells, it is clear that the top of the steam chest is constrained principally by the overlying less permeable silts and shales of the Etchegoin Formation.

The major features in eacreh of temperature observation well logs are described below:

TO-1 well: The temperature logs (Fig. 4-1) record a very regular heating of the Monarch Sand reservoir through time and a relatively tight zone of heating within the upper 50 ft interval of the reservoir. The maximum temperature recorded is 296.7° F reached in June 1999 after 27 months of steam injection in the I2-2 well 100 ft to the northeast. In the subsequent six months to January 2000 the well has cooled slightly to a maximum temperature of 275.2° F. The interval of temperatures greater than 200° F extends about 18 ft into the overlying Etchegoin Formation, probably due to conduction.

TO-2 well: Curiously this well (Fig. 4-2) in the northwest quadrant, only 90 ft from the nearest injector, showed very sluggish build up of heat in the Monarch Sand reservoir. In the nearly two years of steam injection through September 1998 the maximum temperature had risen only about 30° and was virtually static. However, in the next 9 months of record, the maximum temperature jumped about 150° F to stand at 280° F. In the subsequent 6-month interval to January 2000 the maximum temperature rose to 296.8° F and the "hot" interval broadened slightly to span the upper 67 ft of the Monarch Sand. It is probable that the late thermal pulse is not from the injector, but rather from the Pru-334 well just 60 ft to the northeast (Fig. 2-3) that was primed with 8,976 bbls of steam in November-December 1998 and 14,723 bbls of steam in May-June 1999. The relatively flat bottom recorded in the recent temperature curves (Fig. 4-2) coincides with a 7 ft diatomite-rich interval within the otherwise rather massive Monarch Sand.

TO-3 well: This well in the southwest quadrant (Fig. 4-3), which is only 45 ft away from its nearest injector, has shown a bizarre history of reservoir heating. Whereas all of the other temperature records indicate slow progressive heating of the reservoir with time, the steam reaching this well rapidly "fingered" along specific strata. Maximum temperature of about 380° F was recorded in October 1997, only 7 months after steam injection began. Since then the temperature profile has broadened and has cooled back to a maximum 321° F (January 2000). The interval of elevated (>200°) temperature is 139 ft thick, twice that in the other temperature observation wells.

TO-4 well: This well in the southeast quadrant is the most distant, 110 ft, from its nearest injector. The temperature logs record the gradual heating of the reservoir, which stabilized around 280° F in mid-1998 and has increased only slightly to about 300° F since then. The "hot" interval, as recorded in January 2000, has broadened slightly over the last year and is now 74 ft thick. However, in contrast to the other three temperature observation wells, this "hot" interval is 45 ft below the top of the Monarch Sand, which is the standoff interval of the top of the injection points in the nearby injector well (Pru I2-4). In May 2000 this injector received a workover to seal the lower four existing perforations and raise the injection interval by 66 ft.

It is interesting to observe that the temperature peaks for all wells, except TO-4, tend to shift downward through time. This suggests that the steam chest, once having been restricted by the less permeable strata overlying the Monarch Sand, then builds downward.

The temperature observation wells record two separate aspects of the build up of heat within the Monarch Sand reservoir: (1) variations as a function of distance outward from the injector and (2) spatial variations in the capacity of the reservoir to transmit steam and advective heat. In terms of heating at the site of the temperature observation wells, the wells fall into two groups. The TO-3 well, just 45 ft away from an injector, reaches maximum temperature quickly through fingering of steam along stratal intervals and cools slightly as heat is transmitted into surrounding strata. For the wells more distant from the nearest injector, the heat builds rather slowly. If there are stratal controls on steam transport, they are secondary factors

In as much as the normal distance between injector and producer is in the range 150 to 200 ft, it would be reasonable to conclude that as of the time of the last temperature logging in January 2000 the "steam chest" for the steam flood pilot was not yet fully developed. This slow building of the region of elevated temperature is very likely inhibiting the production potential of the steam flood pilot.

An additional method for monitoring the ambient temperature of the Monarch Sand reservoir is to track the temperature of produced fluids. These fluid temperatures for the Pru Fee pilot through the entire duration of the project are plotted in Figure 4-6.

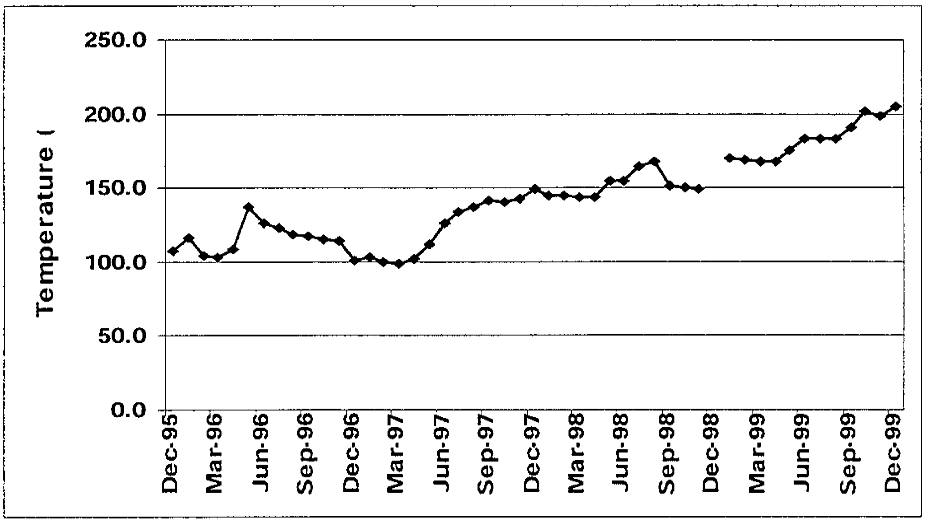

Figure 4-6: Temperature of produced fluids (water and oil) from the four-pattern steam flood pilot showing the gradual increase in reservoir temperature since the onset of the steam flood operation in the second quarter of 1997. The break in December 1998 is related to the change of operator and installation of a different metering line.

The first temperature spike in produced fluids relates to cyclic production of a group of renovated wells serving as a general baseline for subsequent steam flood production. Once the entire steam flood array came on line in Spring 1997, there has been a steady increase in the temperature of produced fluids. The temporary plateaus relate to times when steam injection rates were dropped back to a baselevel 1200-1300 BSPD rate. The surge in temperature observed in the last two quarters of 1999 relates to the considerably higher steam injection rates (up to 2,285 BSPD) being used in the pilot with the intention of more quickly driving up the reservoir temperature. These produced fluid temperatures were not reported for the first two quarters of 2000. In as much as the fluids experience some cooling rising up the well, the temperatures will be somewhat less than the average in situ reservoir temperature. However, they do confirm that through the end of 1999 the reservoir temperature is continuing to rise.

Ambient Temperatures in the New Steam Flood Patterns

The three new temperature observation wells, drilled and logged in December 1999, record the ambient reservoir temperature prior to the initiation of steam flood, but after nearby producers had been cycled for over a year. The temperature logs (Fig. 4-6) illustrate the importance of prior thermal recovery activity in the design of a steam flood project. The TO-6 well in the southwest corner of the Pru Fee property shows only slight heating in the upper part of the Monarch Sand. In contrast, the two temperature observations wells along the upper edge of the property, adjacent to the active Nevada lease, record thick intervals where the temperatures exceed 200° F. At the location of the TO-5 well near the northwest corner of the property, the upper 130 ft of the Monarch Sand is hotter than 200° F and the maximum temperature recorded is 262.7° F. The TO-7 well in the extreme north-central portion of the property (pattern 12) records temperatures in excess of 200° F in the top 215 ft of the Monarch Sand. There are two temperature maxima at 57 ft and 189 ft below the top of the Monarch Sand, 255.6° F and 258.6° F, respectively. The multiple temperature peaks recorded in both of the northern temperature observation wells suggests that "fingering" of steam within discrete strata-bound zones continues to control heat within the reservoir. The thick injection interval in the Nevada lease injectors to the north is an important factor in the thick steam chest observed. These portions of the Monarch Sand reservoir appear to be deeper stratigraphic intervals than those penetrated by wells in the four-pattern pilot.

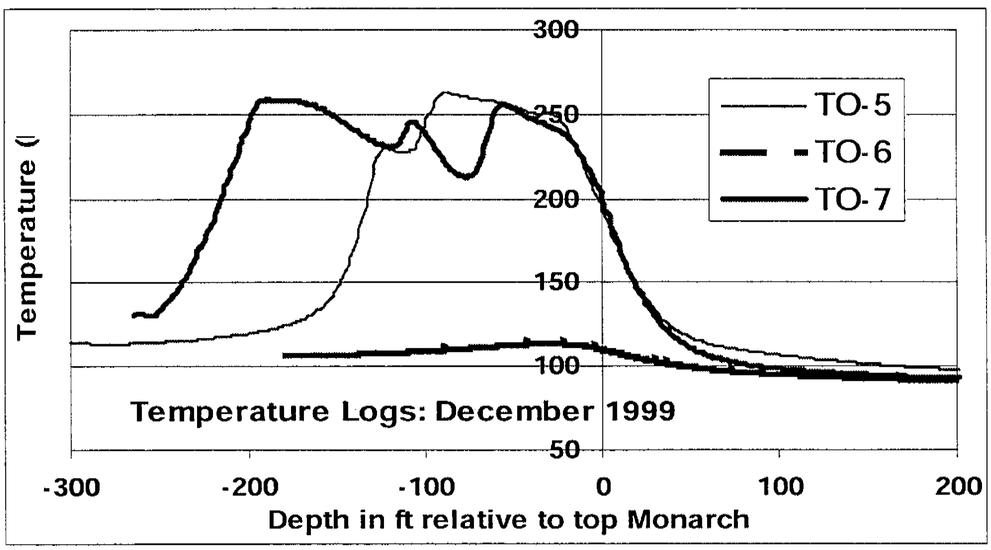

Figure 4-6: Temperature logs for the new temperature observation wells on the Pru Fee property.

Chapter 5

Patterns of Water Saturation in the Monarch Sand Reservoir

The strategy for completion of the four injector wells in the Pru Fee pilot was strongly influenced by the water saturation (Sw) profile observed in the Pru-101 test well (Fig. 5-1) drilled and cored as part of the feasibility study for the project. This profile exhibited a progressive upward decrease in Sw over a span of about 125 ft from values in the 80-90% range immediately above the oil-water contact (OWC). Relatively stable Sw values of 25-30% are observed in a 150 ft thick interval in the upper half of the well. The uppermost 30 ft of the Monarch Sand, referred to in earlier reports as the "oil depleted zone" again had high Sw values. The strategy followed in completing the pilot injectors involved placing the six perforations per well in a 60-80 ft interval near the lower part of the zone of lowest Sw. A standoff of 130-200 ft for the injection interval was maintained from the OWC; standoff from the top of the Monarch Sand reservoir was 40-50 ft (Table 4-1).

The thirteen additional wells drilled by Aera Energy LLC in converting the "300-series" cyclic wells to steam flood provided valuable data for assessing water saturation (Sw) distributions in the Monarch Sand across most of the property. The new wells show extreme variations in Sw not previously recognized. Less extreme variations previously observed in several of the "300-series" wells where thought to be a consequence of poor quality log data. The Sw vertical profile is definitely not uniform from one small portion of the property to the next, as sampled by the array of the 40 new wells logged for this demonstration project. However, certain areas exhibit larger variation from the "ideal" Sw curve than others.

In contrast to the Pru-101 Sw profile, many have nearly constant Sw values throughout their length, varying little from the 50-60% range (Fig. 5-2). A few profiles exhibit bizarre configurations in which the entire upper half, or even middle half (Fig. 5-3), of the Monarch pay interval has values of Sw very close to 100%. One also will notice in these figures that within any short interval the variation in Sw values can be very large. There is a half-foot resolution to the Sw values, which is about the same as bed thickness throughout much of the Monarch Sand. The sand texture of discrete beds or parts of graded beds appears to have some degree of control on the fluid saturations.

To better capture the coarser-scale variation in Sw, profiles were constructed representing 5 ft moving averages of the half-foot spaced Sw values calculated from log data. By nesting the profiles for clusters of wells, it is relatively easy to see the magnitude of spatial variation in Sw, or more importantly So, oil saturation. The four two-acre patterns that form the Pru Fee pilot are located in the portion of the property where oil saturations in the upper half of the pay interval are largest (Fig. 5-4) and where the "ideal" Sw profile demonstrated in the Pru-101 core and log is best represented. In contrast, the group of four patterns along the western edge of the property (Fig. 5-5), adjacent to the produced

Kendon lease, show substantially lower oil saturations in the upper half of the pay interval and less vertical variation in saturations in general.

It is the four patterns along the northern edge of the Pru property (Fig. 5-6) that are the most different from the others. Several of the Sw profiles for wells in these patterns exhibit nearly complete depletion of oil within the upper half of the Monarch Sand reservoir. These patterns are adjacent to the Aera Energy LLC Nevada lease, which has been in intensive cyclic production for many years. The effects of this production are being noticed within the adjacent portions of Pru Fee, as is evidenced by the very high reservoir temperatures recorded (Fig. 4-6) even prior to the onset of steam flood.

The spatial variations in the Sw profiles appear to relate solely to prior oil production activity in the different parts of the Pru Fee property. Before the present DOE-sponsored steam flood project demonstration project began in 1995 there is record of nearly 2 million bbls of oil having been produced from the property, most of that in primary. To date, this project has thermally extracted an additional 0.75 million barrels.

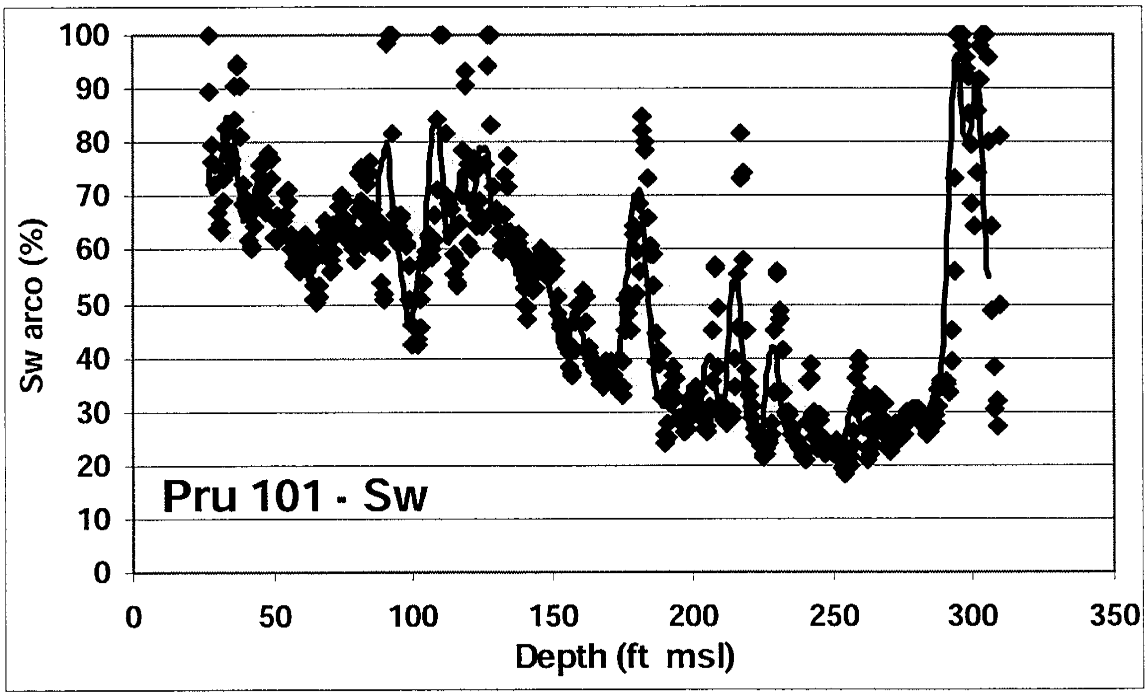

Figure 5-1: Sw values in the Monarch Sand reservoir calculated from the Pru-101 well log plotted by elevation msl. The fitted heavy curve is the 5 ft moving average.

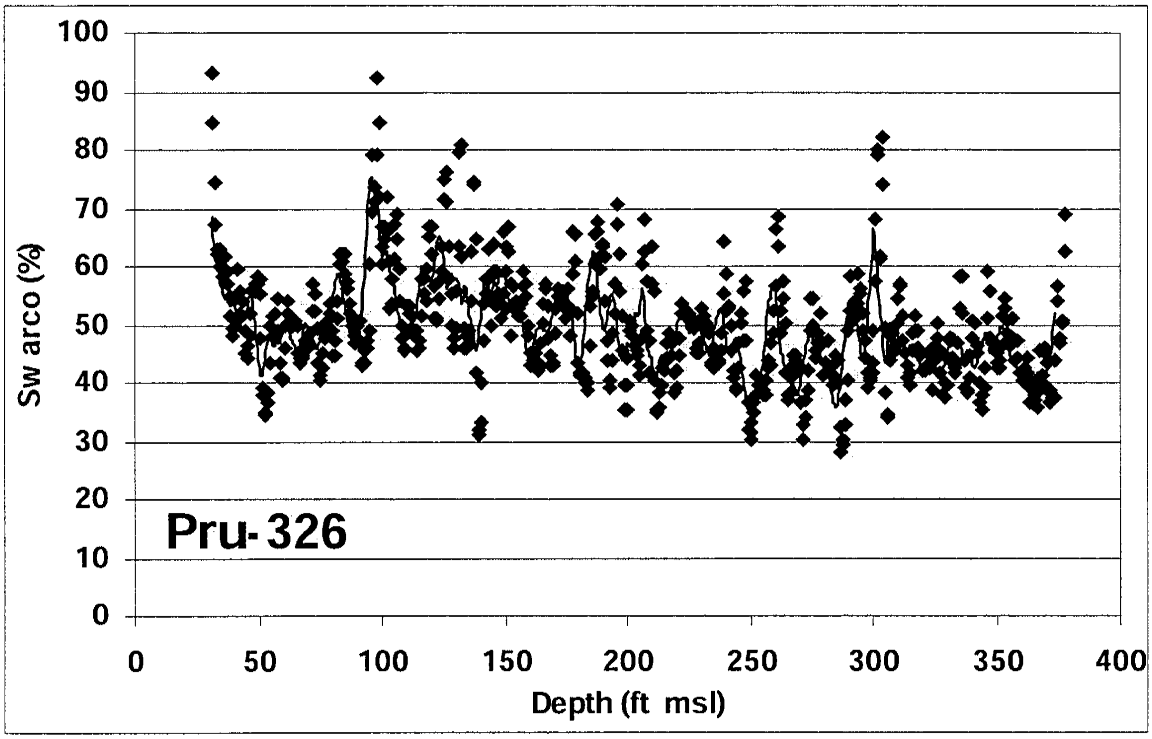

Figure 5-2: Sw values in the Monarch Sand reservoir calculated from the Pru-326 well log plotted by elevation msl. The fitted heavy curve is the 5 ft moving average.

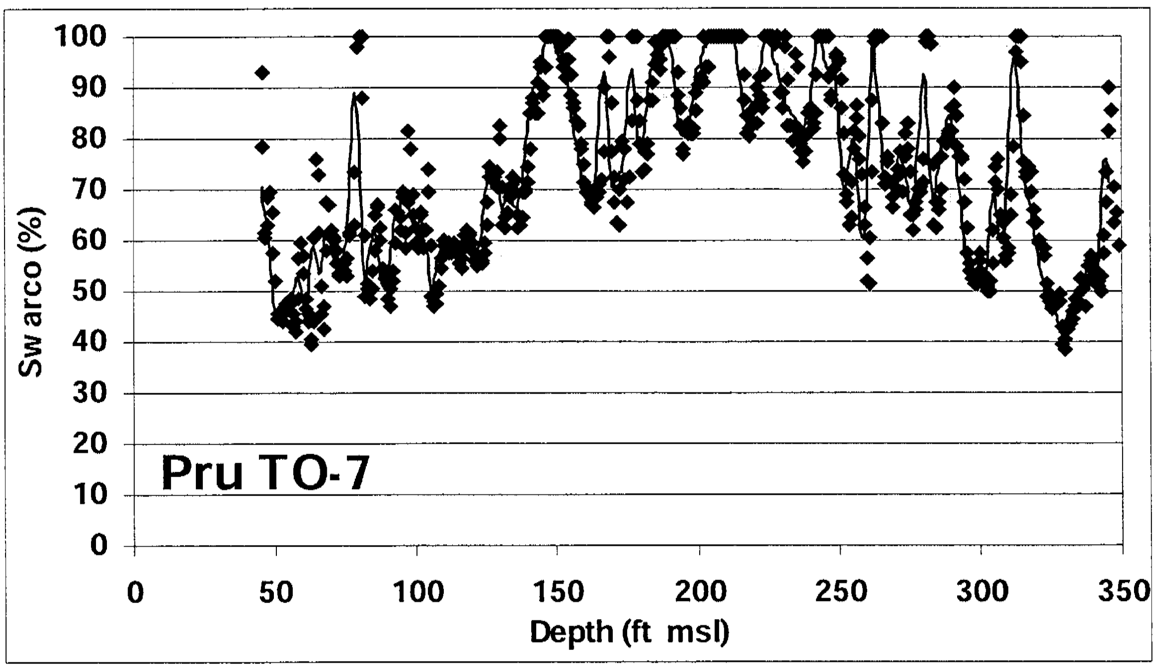

Figure 5-3: Sw values in the Monarch Sand reservoir calculated from the Pru TO-5 well log plotted by elevation msl. The fitted heavy curve is the 5 ft moving average.

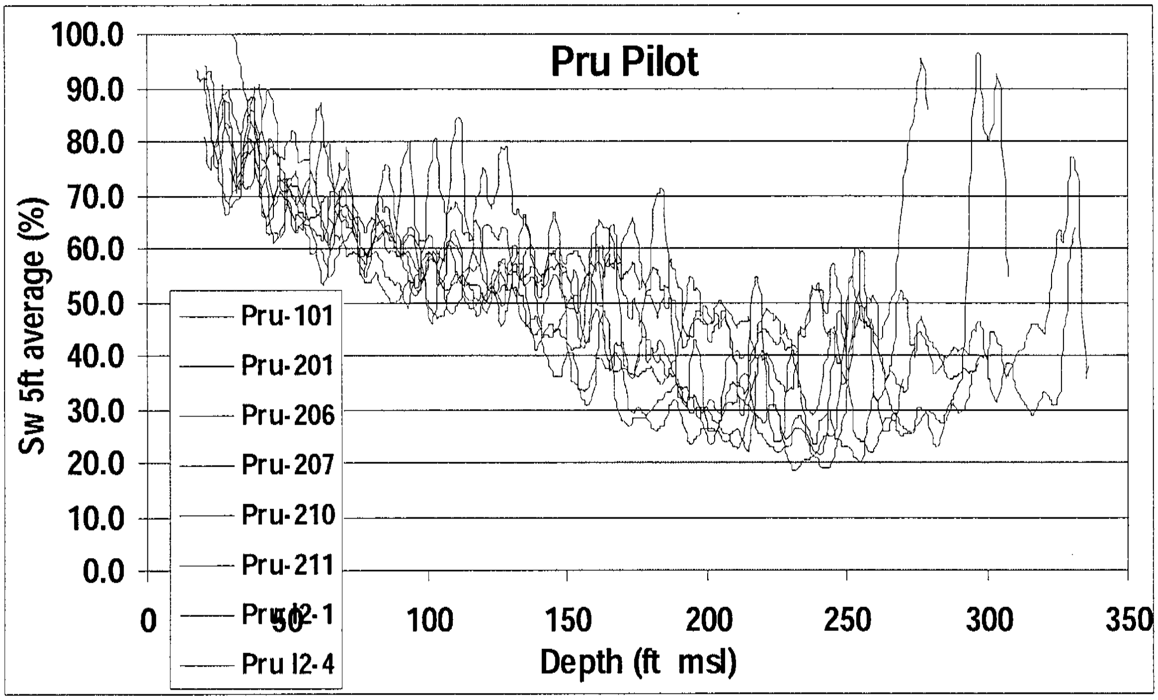

Figure 5-4: Nested 5-ft moving average Sw curves for a selection of wells within the 8 acre Pru Fee steam flood pilot at the center of the 40 acre property.

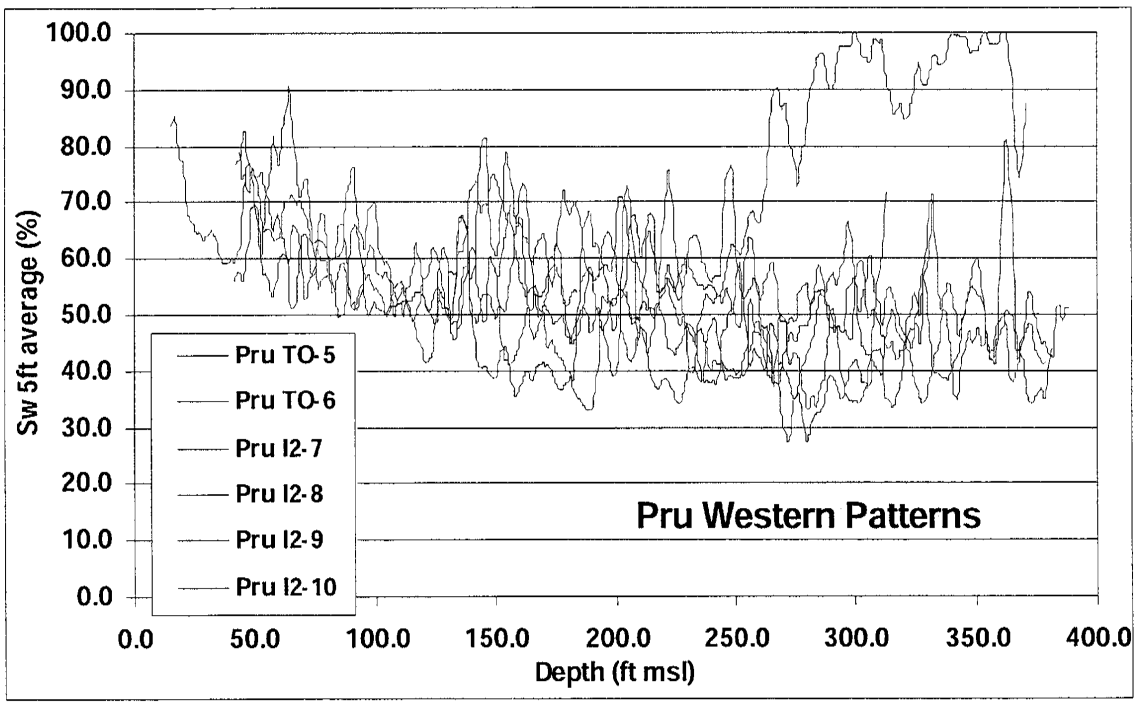

Figure 5-5: Nested 5-ft moving average Sw curves for a selection of wells within the four steam flood patterns along the western margin of the Pru Fee property and bordering the producing Kendon lease.

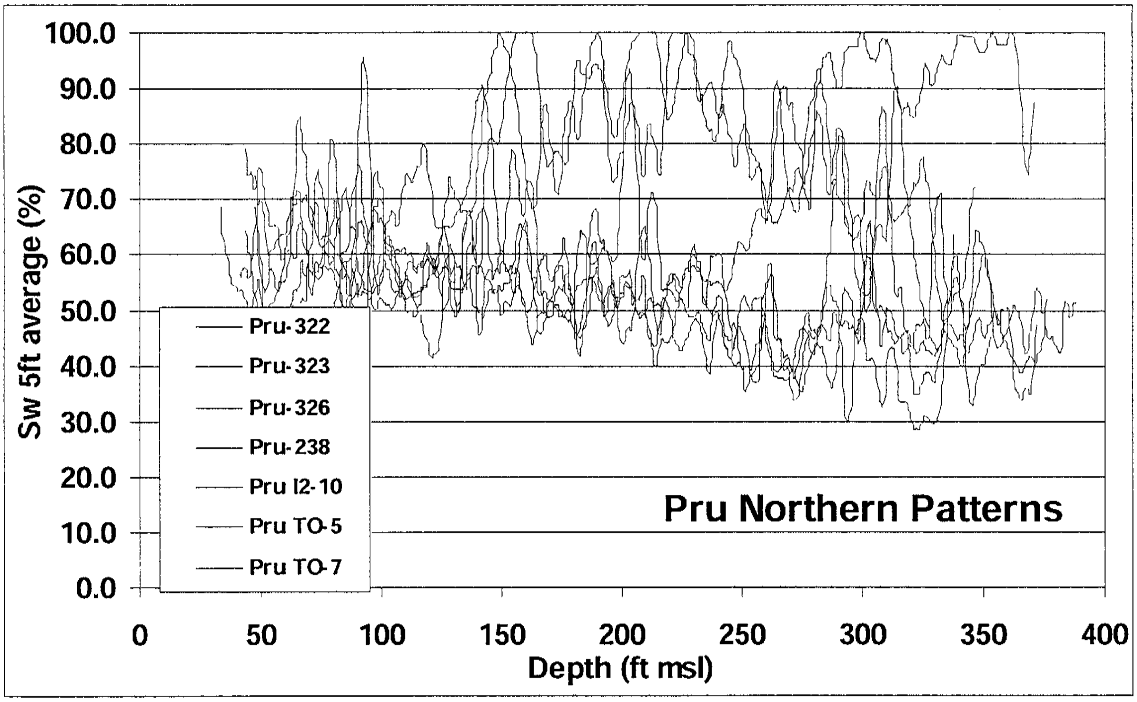

Figure 5-6: Nested 5-ft moving average Sw curves for a selection of wells within the four steam flood patterns along the northern margin of the Pru Fee property and bordering the producing Nevada lease.

Chapter 6

Summary of Monarch Sand Production Performance

It is highly likely that without the incentives to ARCO Western Energy (AWE) to partner with the DOE Class Program in carrying out this oil technology demonstration, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was known to be a highly marginal property. Yet, in the four and a half years since the initiation of project the total production from this 40 acre shut-in tract has gone from zero to 1,280 bopd (Fig. 6-1). In addition, the two operators, AWE and Aera Energy LLC, have invested, *without* a DOE matching contribution, in a total of 54 new producers external to the steam flood pilot, 10 new injectors increasing the number of steam flood patterns from 4 to 14, and three additional temperature observation wells. Total production from just the Monarch Sand reservoir at the Pre Fee property since the end of 1995 is 735.7 MBO.

Within the steam flood pilot wells, it was observed that oil saturations increased in a very regular pattern upward from the oil-water contact (OWC). In the interval immediately above the OWC the oil saturations were about 20%, a value thought to represent the irreducible oil saturation in this highly porous and permeable Monarch Sand reservoir. The oil saturations increase very gradually upward over an interval of 150 to 200 ft, finally reaching a maximum value in the range 60-70% through an interval approximately 100 ft thick near the top of the sand body. The production strategy adopted in the steam flood pilot is to restrict steam injection to the upper one-third of the pay zone, that portion where oil saturations exceed 50%. Any steam injected below this interval would loose large quantities of heat to water and result in unfavorable steam-oil and water-oil ratios.

The performance for both the pilot and the 300-series patterns is very good (Table 6-1). The average oil-steam ratio (OSR) for the second quarter of 2000 is 0.48 and 0.20, respectively. The average oil-water ratio (OWR) for the second quarter is 0.31 and 0.23, respectively. The lower per pattern oil rates and OSR values for the newer patterns may be attributed to the fact that they have been operating in steam flood for less than a half-year and are still warming.

Table 6-1: Pru steam flood pattern performance for June 2000

Performance facretor	Pru pilot	300-series
Average oil rate per pattern	118.9 bopd	80.5 bopd
Average water cut per pattern	0.78	0.76
Average OSR per pattern	0.45	0.13

As of June 2000, after 40 months of steamflood production of the four-pattern pilot and 21-24 months of cyclic/steam flood production of the surrounding 10 patterns, the total

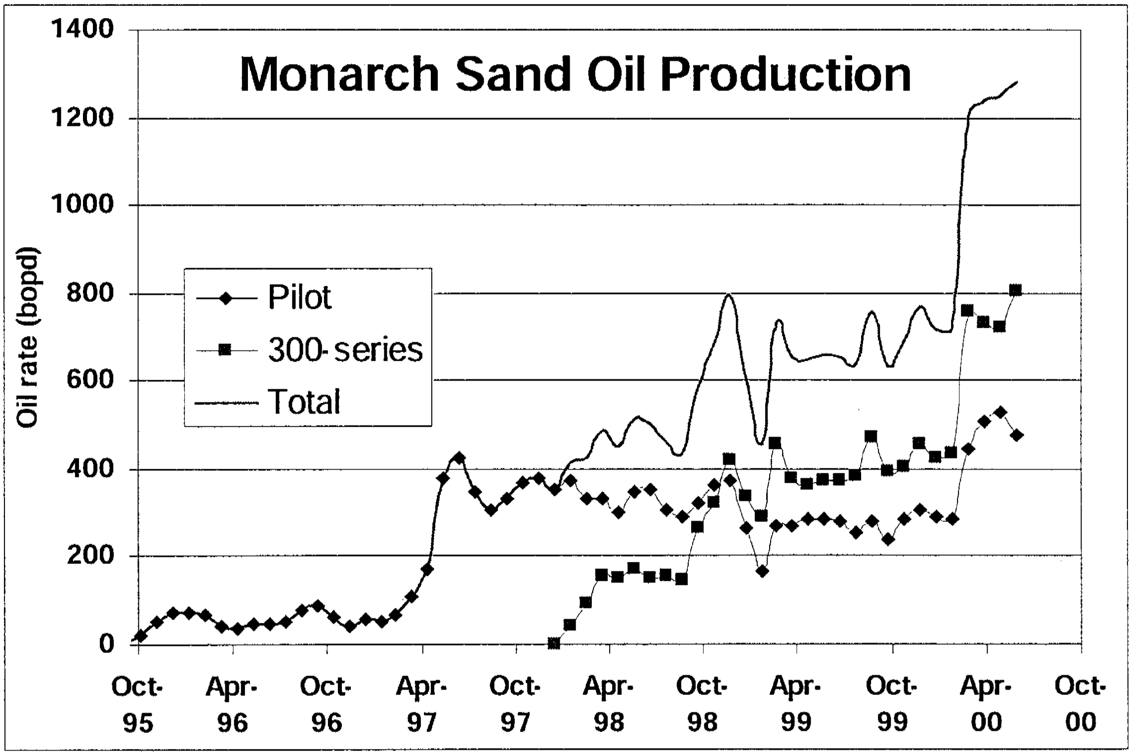

Figure 6-1: Average daily oil rates for the four-pattern Pru pilot producers and the ten-pattern "300-series" producers. The pilot steam flood began in February-April 1997. The "300-series" wells began producing in cyclic mode early in 1998 and were converted to steam flood in January-February 2000.

cumulative production of oil from the Monarch Sand stands at 735,700 bbls (Table 6-2). During the year (July 1999-June 2000) production from the upper Miocene at the Pru Fee property had increased by 322,000 bbls, an amount nearly doubling all previous project production. The cumulative oil production (Fig. 2) from the 8 acre four-pattern steam flood pilot had reached 412.1 Mbbls, an increase of 128.1 Mbbls during the year. The cumulative oil production from the "300-series" wells had reached 323.6 Mbbls, an increase of 193.9 Mbbls during the year.

Table 6-2: Total Monarch Sand cumulative production (Mbbls) - June 2000

	Oil	Water	Steam	OSR	OWR
Pru pilot:	412.1	2,335.6	1,841.9	0.22	0.18
300-series:	323.6	1,376.5	1,718.3	0.19	0.24
Total Pru:	**735.7**	**3,712.1**	**3,560.2**	**0.21**	**0.20**

Even a casual examination of the production curves (Fig. 6-1) shows that the oil rate experienced a sharp decline starting at the time of transfer of operatorship of the property in the last quarter of 1998 and continuing until February-March 2000 when the rates suddenly rebounded. The reported production rates (Table 6-3) during this period are not an accurate measure of well performance, but rather are strongly influenced by the management of the property during this period of major infrastructure improvements. The operational factors affecting the lower rates require explanation:

- During the period prior to the end of 1998, when Pru was operated by ARCO Western Energy, all Pru Fee production was going through the adjacent Kendon lease for metering and processing. By the last quarter of that year, the Pru Fee four-pattern steam flood pilot was fully operational, nearly all of the new Monarch Sand wells had come on-line in cyclic production, and the new Tulare cyclic wells also were contributing to production from the property. During the quarter the number of producing Monarch cyclic wells increased from 10 to 34 resulting in a spike in production rates from about 500 bopd to nearly 800 bopd. These rates exceeded the capacity of the Kendon facilities. As a consequence, when Aera Energy LLC took over the operations in January 1999, about 20 of the Pru Fee producers were temporarily shut-in while preparations were being made to shunt all production from Pru Fee and adjacent leases to the larger facilities at MOCO already operated by Aera Energy LLC. This is responsible for the sharp drop in production during the first quarter of 1999.

- For all of 1999 and the first two months of 2000 Pru Fee production was commingled with that of all adjacent Aera Energy properties, except the Kendon lease. This was a temporary arrangement necessitated by the consolidation of a large tract of producing properties previously operated by three separate companies. During this period it appears as though the production allocated back to Pru Fee was substantially less than actual production. The problems can be attributed to both inadequate metering of individual producers and the methods of allocation. Attempts to reconstruct a more accurate picture of Pru Fee production rates for this period, as of yet, has been unsuccessful. However, the relative rates between Pru Fee producers are probably reliable. The steam rates, of course, are unaffected by the commingling of production at MOCO.

- By February-March 2000 the construction of new facilities for on-site metering and processing of the Pru Fee production as part of the overall upgrading of steam generation and fluid handling capacity was complete. With metering once again restored on-site the total oil rates for Pru jumped 65%. Although some of the increase can be attributed to the fact that the previous cyclic wells had been converted to 10 new steam flood patterns, this alone cannot explain the dramatic increase in oil and water rates. Interestingly, the water rate increased only 13% from February to March (Fig. 6-2), suggesting that the previous problems with allocation of commingled production could be related to the handling of the water cut. The oil and water rates reported for Pru since February 2000 are considered to be accurate.

The actual cumulative production from the Monarch Sand at the Pru Fee property could be greater than what is reported here.

Table 6-3: Averaged oil rates (bopd) through transfer of operatorship

	Sept-Dec'98	Jan-Apr'99	June-Sept'99	Nov'99-Feb'00	Mar-Jun'00
Pru pilot:	337	244	275	292	490
300 series:	288	377	402	431	753

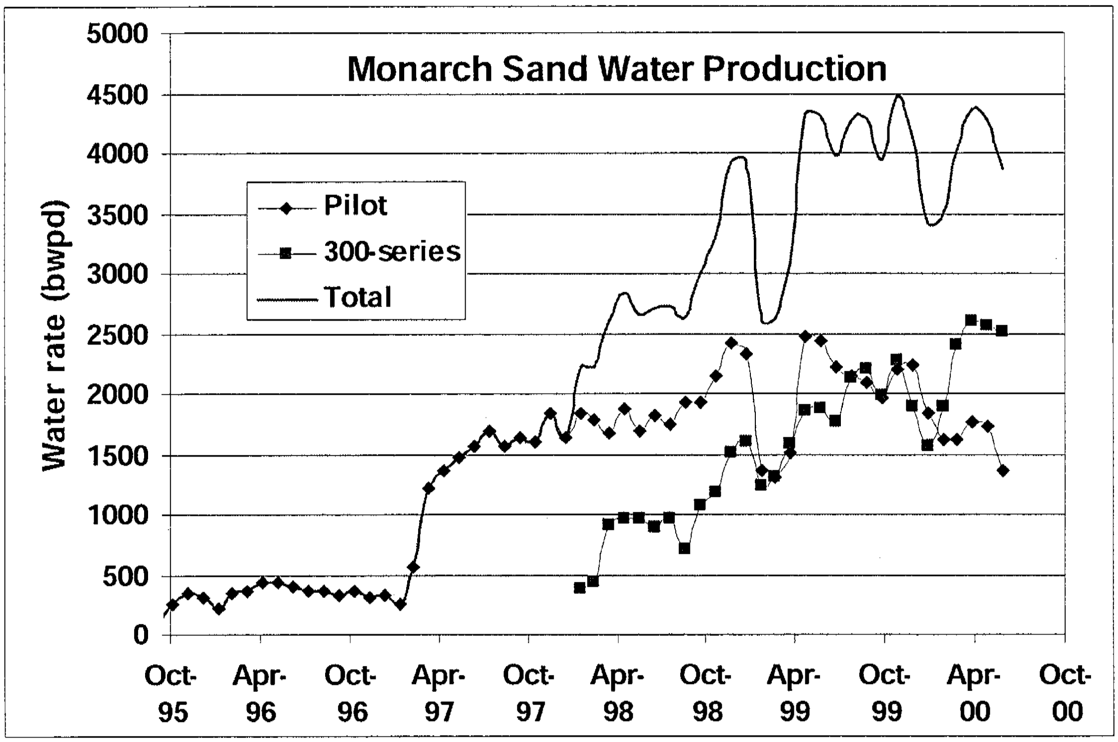

Figure 6-2: Average daily oil rates for the four-pattern Pru Fee pilot producers and the ten-pattern "300-series" producers. The pilot steam flood began in February-April 1997. The "300-series" wells began producing in cyclic mode early in 1998 and were converted to steam flood in January-February 2000.

Chapter 7

Technology Transfer

From the beginning of the project, there have been two technology transfer goals. The immediate goal has been to communicate on a regular basis to operators in California and elsewhere the ongoing developments related to the project and its success in bringing the shut-in Pru Fee property back into commercial production. This has been done through many presentations at professional meetings and publications. More recently, there have been invitations to speak in workshops and technical sessions aimed specifically at the heavy oil producers in California, or groups engaged in old field renovation.

Our second and more important goal is encouraging operators in California to use methods proven successful at Pru in putting idle or underdeveloped properties into full production. Here, for the first time since the project began, we can point to a specific example of this practical type of technology transfer.

Aera Energy LLC, seeing the manner in which the injectors in the four-pattern Pru Fee pilot were completed, adopted the concept of a stand-off from the OWC in injector workovers in the "low dip" portion of the Kendon lease immediately west of Pru Fee. The new perforations were placed in the uppermost one-third to one-half of the Monarch Sand, well above the OWC and the Sw transition zone, and the deeper existing perforations sealed. It is reported that response from the injector workover using the recommended large standoff from the OWC has been outstanding. Increases in oil rates average 25 bopd per well with a total increase being over 900 bopd. The OSR has increased from 0.20 to 0.35 and the water cut improved.

During the year there were three invited papers summarizing the significant results of the project delivered at professional meetings:

S. Schamel and M. Deo, Strategies for optimal enhanced recovery of heavy oil by thermal methods, Midway-Sunset Field, southern San Joaquin Basin, California. Revitalizacreion de Provincias Petroliferas Maduras, joint AMGP/AAPG Research Conference, Veracreruz, Mexico, October 10-13, 1999.

S. Schamel, Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology Midway-Sunset Field, southern San Joaquin Basin, California. Petroleum Technology Transfer Council (Pacific Region) forum on enhanced oil recovery methods for independent California producers, University of Southern California, Los Angeles, CA, December 10, 1999.

S. Schamel and M. Deo, Strategies for optimal enhanced recovery of heavy oil by thermal methods, Midway-Sunset Field, southern San Joaquin Basin, California Joint AAPG Pacific Section Convention and SPE Western Regional Meeting, Long Beach, CA June 19-22, 2000.

In addition, two informal seminars on the project were given to the Department of Chemical and Fuels Engineering, University of Utah, and Wascana Energy, Calgary, Alberta.

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Schamel, S., 1999b, Reactivation of an idle lease to increase heavy oil recovery through application of conventional steam Drive technology in a low dip slope and basin reservoir in the Midway-Sunset Field, San Joaquin Basin, California: Annual Report for 1997-1998. DOE National Petroleum Technology Office, DOE/BC/14937-9, 54 p.

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