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

Annual Report
March 30, 1995 to March 31, 1996

By
City of Long Beach

September 1997

Performed Under Contract No. DE-FC22-95BC14939

City of Long Beach
Long Beach, California

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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Increasing Heavy Oil Reserves In The Wilmington Oil Field Through Advanced Reservoir Characterization And Thermal Production Technologies

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Prepared for
BDM-Oklahoma/
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Jerry Casteel, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
City of Long Beach
Long Beach, CA

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ABSTRACT

The objective of this project is to increase heavy oil reserves in a portion of the Wilmington Oil Field, near Long Beach, California, by implementing advanced reservoir characterization and thermal production technologies. Based on the knowledge and experience gained with this project, these technologies are intended to be extended to other sections of the Wilmington Oil Field, and, through technology transfer, will be available to increase heavy oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves implementing thermal recovery in the southern half of the Fault Block II-A Tar zone. The existing steamflood in Fault Block II-A has been relatively inefficient due to several producibility problems which are common in SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and nonuniform distribution of remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios, and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

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

1. Developing three-dimensional (3-D) deterministic and stochastic geologic and reservoir simulation models.
2. Developing computerized 3-D visualizations of the geologic and reservoir simulation models to aid in analysis.
3. Performing detailed studies of the geochemical interactions between the injected steam and the formation rock and fluids.
4. Performing pilot tests of steam injection and production via new horizontal wells.
5. Performing pilot tests of hot water alternating steam (WAS) drive in the existing steam drive area to improve thermal efficiency.
6. Installing a 2100-ft insulated, subsurface harbor channel crossing to supply steam to an island location.
7. Testing a novel alkaline steam completion technique to control well sanding problems and fluid entry profiles.
8. Applying advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.

Key accomplishments during this reporting period include:

1. Developing a new three-dimensional deterministic geological model, after identifying and correcting previous data inconsistencies due to subsidence.

2. Installing four new horizontal wells (two injectors and two producers) in the desired strata using the new geological model and Measurement While Drilling (MWD) and Logging While Drilling (LWD) data.

3. Supplying steam to the island location of the new wells from the steam source on the mainland by installing a 2100-ft steam transmission line under a harbor channel.

4. Communicating the results of the work to date in numerous public presentations, publications and field tours.

EXECUTIVE SUMMARY

Introduction

The objective of this project is to increase heavy oil reserves in a portion of the Wilmington Oil Field, near Long Beach, California, by implementing advanced reservoir characterization and thermal production technologies. Based on the knowledge and experience gained with this project, these technologies are intended to be extended to other sections of the Wilmington Oil Field, and, through technology transfer, will be available to increase heavy oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves implementing thermal recovery in the southern half of the Fault Block II-A Tar zone. The existing steamflood in Fault Block II-A has been relatively inefficient due to several producibility problems which are common in SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and nonuniform distribution of remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios, and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves. A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery efficiency and reduce operating costs.

The first phase of the project begins with applying advanced reservoir characterization methods to enable improved design and application of thermal recovery methods. A deterministic geologic model of the reservoir has been completed and a stochastic model is being created. The geologic models will be used in reservoir simulators to optimize reservoir management and thermal recovery methods. Three pilot tests will be performed to evaluate different modes of thermal recovery, including steam drive via horizontal wells, cyclic steaming via horizontal wells, and hot water alternating steam (WAS) drive. A 2100-ft steam transmission line has been installed under the Cerritos Channel to supply steam to the new horizontal wells on Terminal Island. Two horizontal producers, two horizontal injectors, and five observation wells have been drilled during the first phase. The horizontal wells are being completed using a novel alkaline/steam injection treatment, which has been quite successful at reducing sanding problems and decreasing completion costs. The quality of injected steam will be controlled using a steam/hot water separator to provide operating flexibility for optimizing recovery efficiency.

In the second phase, a series of horizontal wells will be drilled to extend the thermal recovery project to the remainder of the D1 sand in the Fault Block II-A Tar zone, based on the results of the simulation studies and pilot tests. It is anticipated that four horizontal producers, four horizontal injectors, and three observation wells will be drilled during the second phase.

The overall project is expected to take over seven years to complete. The first phase began in the fourth quarter of 1994 and is expected to end during the first quarter of 1999. The second phase is expected to take place from 1999 through 2002.

The project is being implemented by a team including:

1. The City of Long Beach - the operator of the field as trustee of the State of California-granted tidelands;
2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in charge of implementing the project;
3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and
4. David K. Davies and Associates - consultants to the project regarding petrography, rock-based log modeling, and geochemistry of rock and fluid interactions.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach's and Tidelands Oil Production Company's development strategy for the field. The current thermal operations in the Wilmington Field are economical with today's oil prices due to the availability of inexpensive steam from an existing cogeneration plant. Such favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of this project.

Advanced Reservoir Characterization

A three-dimensional deterministic geologic model was completed and a stochastic geologic model is being created to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. Determining sand continuity is of particular importance for turbidite sands, because sand sequences in adjacent wells may look similar but in fact may not be connected because of the lobated nature of the stratified sands.

Data for the geologic models are being derived from existing logs from over 600 wells, detailed core studies, Measurement While Drilling (MWD) and Logging While Drilling (LWD) data from the installation of four new horizontal wells, open hole logs from five new observation wells and a tracer study. Conceptual geologic models are being developed using the EarthVision ™ three- dimensional imaging software by Dynamic Graphics, Inc. to facilitate future reservoir analysis and interpretation.

A working 3-D deterministic geological model was completed in June 1995 and used to place the initial wells. However, inconsistencies in geologic data resulting from errors in previously-used subsidence correction software were identified during the drilling of the observation wells. Differential compaction of unconsolidated sands during 64 years of hydrocarbon production has resulted in a subsidence bowl in the west Wilmington Field. Significant modifications to the data base were required due to inaccurate subsidence corrections in the original data set. Horizontal wells were laid out based on the revised data and the geological model was completely reconstructed. The success of the horizontal well drilling confirms the accuracy of the model. With as much as 15,900 stock tank barrels at risk for every foot the horizontal lateral is above the target horizon, it was imperative that the reservoir be characterized precisely.

A stochastic geologic model is being created to provide an improved understanding of the geologic controls on production and to address geologic uncertainties in reservoir simulation models. The work to create the stochastic model has just begun and will be discussed during the next reporting period.

Reservoir Simulation

Three-dimensional, thermal reservoir simulation models will be created based on the deterministic and stochastic geologic models. The simulation models will be used to improve reservoir management practices, addressing such issues as optimal well spacing, well completion strategies, and mode of thermal recovery. During the last year, major efforts were focused on bench mark testing of suitable hardware and commercially available software. Considerations were given to the selection of a suitable system that can handle fine grids, local grid refinement, and horizontal wells, and can provide accurate results based on simulation of test cases.

Reservoir Management

The key reservoir management activities during the first phase are connected with implementing three pilot tests of thermal recovery:

1. Cyclic steam stimulation through horizontal wells;

2. Steam drive through horizontal wells; and

3. Hot water alternating steam (WAS) drive.

The primary tasks to implement the pilot tests include:

1. Drilling two horizontal injectors and two horizontal producers;

2. Installing a steam transmission pipeline under a harbor channel to connect the mainland steam distribution system to the island location of the thermal recovery pilots;

3. Installing a steam separator on the mainland; and

4. Performing the three pilot tests.

Additional reservoir management tasks include analyzing petrophysical and geochemical interactions, evaluating steamdrive mechanisms and monitoring the response of the reservoir.

Under Channel Steam Transmission Line

A significant achievement was the successful installation of a 2100-ft steam transmission line under a harbor channel to supply steam from the mainland to the new horizontal wells on Terminal Island. Unusual design elements which had to be addressed in installing the under channel steam line include:

1. Designing for an exit point surface location below sea level;
2. Planning directional drilling to miss existing and abandoned vertical wellbores;
3. Designing a cementing program for 30-in. casing inside a 42-in. annulus;
4. Designing for eight ft of thermal expansion, both in the crossing and at the end connections
5. Designing the 14-in. steam line to be removable;
6. Preventing groundwater and moisture from entering the annular area between the 14-in. steam line and the 24-in. casing;
7. Designing the 30-in. outer casing for temperatures up to 300 F;
8. Electrically isolating the steam line from casings to facilitate cathodic protection;
9. Thermally insulating the steam line to minimize heat loss and casing temperature; and
10. Designing a support mechanism to allow longitudinal movement (thermal expansion) within the casing while protecting the insulation on the 14-in. steam line.

Pilot Tests

A four horizontal well pilot was implemented to evaluate the performance of thermal recovery using cyclic steam stimulation. Steam injection was initiated into the first two horizontal wells in mid-December 1995 at low rates of 300 cold water equivalent barrels per day (CWEB/D) each. The injection rates were increased to 1400-1500 CWEB/D after mechanically breaking down the perforations in both wells with high pressure water. The plan is to inject 2 cycles of 100,000 CWEB of steam into each well to consolidate the formation sands around the limited entry perforated completions and to stimulate initial oil production. Cyclic steam injection into the other two horizontal wells will begin when the first two wells are converted from injection to production.

Two of the four horizontal wells used in the cyclic steam stimulation pilot will be converted into permanent steam injectors for a steam drive pilot test. The pilot will be evaluated using conventional steam drive and WAS drive (hot water alternating steam drive). The horizontal steam drive wells will be operated based on a pseudo steam assisted gravity drainage (SAGD) technique, involving completing the last 600 ft of the horizontal wells in the updip section of the reservoir. The concept is to concentrate the steam updip to take advantage of steam gravity override of the steam in order to promote earlier development of a steam chest and to allow the oil and steam condensate to gravity drain downdip to the producers.

A WAS Drive pilot (Water Alternating System) will be implemented in the existing Tar II-A thermal recovery area as part of an effort to determine how to maximize oil recovery per unit energy input for the expansion of thermal operations throughout Fault Block II-A in the second phase of the project. Four vertical steam injection wells in the existing steam drive area were converted to hot water injection in March 1995. Injection rates per well ranged from 400-900 B/D of 300°F-400°F hot water. The hot water injection was suspended in April 1996 when the landowner required that the steam separator and hot water injection lines be moved. No production response has been observed to date. Tidelands will be installing a new and larger capacity vertical steam separator in September 1996 which will provide a higher volume hot water injection for the pilot.

Operational Management

Implementing thermal recovery in the Fault Block II-A Tar zone poses a variety of operational problems. Past thermal operations in the Wilmington Field have experienced premature well and downhole equipment failure due to early steam breakthrough and sanding problems. These problems are common in SBC reservoirs with heterogeneous geology and unconsolidated sands. In addition, the high reservoir pressure and associated high steam temperature in the Wilmington Field aggravate the wellbore and equipment problems associated with early steam breakthrough. A variety of approaches are being investigated to alleviate operational problems, thereby increasing the effectiveness and reducing the costs of thermal recovery operations.

The four horizontal wells are being completed by an alkaline hot water/steam injection technique for sand consolidation. This completion technique is believed to cause minor silica dissolution and precipitation, consolidating the formation sand grains and controlling sand movement into the wellbore. Experience with existing horizontal wells in Fault Block I Tar zone suggests that, if the perforations are too numerous or too large, then much higher steam rates and volumes are required to consolidate the sand. Accordingly, the new horizontal injectors will have eleven 0.29-in. perforations per well compared to seventy 0.50-in. perforations in the Fault Block I horizontal wells. The new horizontal producers will have thirty-five to forty-five 0.29-in. perforations per well. Sand consolidation in the producers will be performed in stages for a more iniform delivery of steam to the perforations more.

Carbonate scale formation in producing wells has been a significant problem in the past. Geochemical studies are being performed to understand the scaling mechanisms. Thin section, scanning electron microscope, and x-ray diffraction studies performed to date on fill samples from existing steamflood producers have identified the types of scale produced as calcites, dolomites, barites, anhydrites, and magnesium-silicates.

Expansion Program

Based on the results of reservoir characterization, reservoir simulation, and pilot testing in Phase 1, the thermal project will be expanded to the remainder of the D1 sand in the Fault Block II-A Tar zone in Phase 2 of this project. The expansion is scheduled to start in the second quarter of 1999 and proceed through 2002. It is anticipated that four horizontal producers, four horizontal injectors, and three observation wells will be installed during the second phase.

The expansion has a drainage area of approximately 83 acres and a net oil sand thickness of 75-ft. The remaining oil saturation after waterflooding is estimated to be 66%. The remaining oil in place is estimated to be 9,625,000 barrels of oil. Projected recovery from the expansion is estimated to be 5,100,000 barrels of oil. The total pilot and expansion projected cumulative oil production is estimated to be 7,117,000 barrels.

Technology Transfer

Technology transfer was achieved through a number of activities, in addition to preparing reports for the DOE. One highlight in particular is a multi-media CD-ROM being prepared to provide an overview of the project. In addition, experience and knowledge gained from specific aspects of the project have been communicated to other oil and gas operators in several presentations at professional society meetings and publications in technical and trade journals and newspapers.

ACKNOWLEDGMENTS

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

The City of Long Beach **310-570-6555**	Xen Colazas Don Clarke
Tidelands Oil Production Company **310-436-9918**	Jim Quay Mark Kapelke Scott Hara Chris Phillips Julius Mondragon Steve Siegwein Rick Cassinis
University of Southern California **213-740-2311**	Iraj Ershaghi Lyman Handy Linji An Zhengming Yang Yucel Akkutlu Linda Smith Herman Schaller Al Brown Shahed Meshkati B. Ghaffari Jon Bronson Jalal Torabzadeh
David K. Davies & Associates **310-426-5337**	David K. Davies Richard Vessel
Deloitte & Touche LLP **213-688-0800**	Robert Wunderlich Brenda Pontiff

1 INTRODUCTION

1.1 Report Overview

This is the first annual technical progress report for the project. Although the contract was awarded on March 30, 1995 and Pre-Award Approval was given on January 26, 1995, work was initiated on October 1, 1994. As such, this report summarizes the work performed from project inception to March 31, 1996.

The remainder of this chapter provides an overview of the project and the Wilmington Oil Field, in which the project is being implemented. Subsequent chapters summarize the objectives, status, and conclusions to date of the major activities of the project. The report concludes by describing technology transfer activities stemming from the project and providing a list of pertinent references.

1.2 Project Overview

The objective of this project is to increase heavy oil reserves in a portion of the Wilmington Oil Field, near Long Beach, California, by implementing advanced reservoir characterization and thermal production technologies. Based on the knowledge and experience gained with this project, these technologies are intended to be extended to other sections of the Wilmington Oil Field, and, through technology transfer, will be available to increase heavy oil reserves in other slope and basin clastic (SBC) reservoirs.

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A suite of advanced reservoir characterization and thermal production technologies were proposed for application during the project to improve oil recovery efficiency and reduce operating costs, including:

1. Development of three-dimensional (3-D) deterministic and stochastic geologic and reservoir simulation models.
2. Development of computerized 3-D visualizations of the geologic and reservoir simulation models to aid in analysis.
3. Detailed studies of the geochemical interactions between the steam and the formation rock and fluids.

4. Pilot tests of steam injection and production via new horizontal wells.

5. Pilot tests of a hot water alternating steam (WAS) drive in the existing steam drive area to improve thermal efficiency.

6. Installation of a 2100 ft insulated, subsurface harbor channel crossing to supply steam to an island location.

7. Testing a novel alkaline steam completion technique to control well sanding problems and fluid entry profiles.

8. Applying advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.

The project is being conducted in two phases. In the first phase, advanced reservoir characterization methods are being applied to enable improved design and application of thermal recovery methods. A deterministic geologic model of the reservoir has been completed and a stochastic model is being created. Data from the characterization studies come from combining existing data with new data obtained from the wells being installed in this project. A three-dimensional computerized visualization model was created to facilitate analysis of the geologic models. The geologic models will be used in reservoir simulators to optimize reservoir management and thermal recovery methods. Three pilot tests will be performed to evaluate different modes of thermal recovery, including steam drive via horizontal wells, cyclic steam stimulation via horizontal wells, and WAS drive. A 2100-ft steam transmission line has been installed under Cerritos Channel to supply steam to the new horizontal wells on Terminal Island. Two horizontal producers, two horizontal injectors, and five observation wells were drilled during the first year. The horizontal wells are being completed using a novel alkaline/steam injection treatment, which has been quite successful at reducing sanding problems and decreasing completion costs. The quality of injected steam will be controlled using a steam/hot water separator to provide operating flexibility to optimize recovery efficiency.

In the second phase, a series of horizontal wells will be drilled to extend the thermal recovery project to the remaining D1 sand of the Tar zone in Fault Block II-A, based on the results of the simulation studies and pilot tests. It is anticipated that four horizontal producers, four horizontal injectors, and three observation wells will be installed during the second phase.

The overall project is expected to take over seven years to complete. The first phase began in the fourth quarter of 1994 and is expected to end during the first quarter of 1999. The second phase is expected to take place from 1999 to 2002.

The project is being implemented in terms of a series of activities and associated tasks. The activities and the chapters in which they are discussed are listed below.

Chapter	Activity	Description
2	1	Compilation and Analysis of Existing Data - Compilation of production, injection, PVT, and log data
3	2	Advanced Reservoir Characterization - Analysis of existing and new reservoir data to develop deterministic and stochastic geologic models
4	3	Reservoir Simulation - Development of deterministic and stochastic thermal reservoir simulation models to assist reservoir management
5	4	Reservoir Management - Installation of wells and surface facilities, implementation of horizontal well, cyclic steam stimulation, steamdrive and WAS drive pilots, and reservoir surveillance
6	5	Operational Management - Development of techniques for sand control, horizontal well completion, scale minimization, and reducing temperature related operating problems
7	6	Expansion Program (scheduled to start in 1999)
8	7	Technology Transfer - Activities to communicate knowledge and experience gained from this project

This report emphasizes the three activities for which the greatest efforts and costs were devoted during this reporting period:

1. Developing a three-dimensional deterministic geologic model;
2. Installing four horizontal wells and five observation wells;
3. Installing a steam transmission line under a shipping channel to supply steam to an island location.

Of the total of $7.2 million (of which 50% was provided by the DOE cost sharing funds) expended during this reporting period, $3.4 million was devoted to installing the steam transmission line, $1.9 million was devoted to installing the four horizontal wells and associated well facilities, and $1.1 million was devoted to installing five observation wells, two of which were conventionally cored.

The project is being implemented by a team including:

1. The City of Long Beach - the operator of the field as trustee of the State of California-granted tidelands;
2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in charge of implementing the project;

3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and
4. David K. Davies and Associates - Consultants to the project regarding petrography, rock-based log modeling, and geochemistry of rock and fluid interactions.

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1.3 Development and Production History

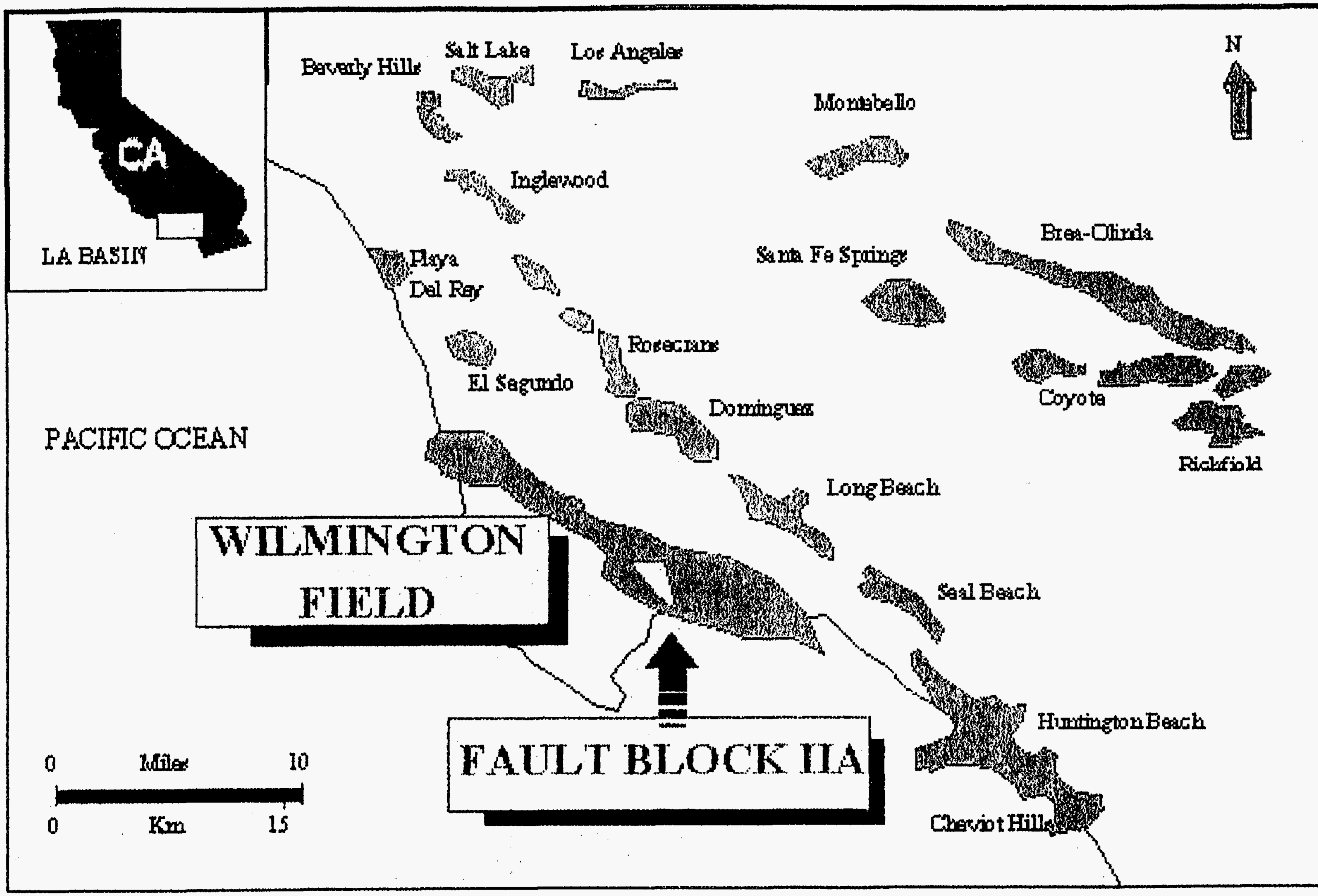
The Wilmington Oil Field is the third largest oil field in the United States, based on total oil recovered. Over 2.4 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion barrels.

The field is located in and around the City of Long Beach, in Southern California. A location map of the field is shown in Figure 1.1. The field is divided into ten fault blocks and seven major producing zones, as illustrated in Figures 1.2 and 1.3. Heavy oil occurs in the Tar, Ranger, and Upper Terminal zones. This project is being conducted in the Tar zone of Fault Block II-A.

Primary production from the field began in 1936. Waterflooding was introduced on a large scale during the 1950s to increase oil recovery and to control surface subsidence. Various tertiary recovery projects have been tried since 1960, but with limited success. For most of the producing zones, waterflooding remains the dominant form of economic oil recovery. The current water cut is approximately 96%. Recovery in the waterflooding and tertiary recovery projects has been hindered by poor sweep efficiency, as is typical of SBC reservoirs with heterogeneous turbidite geology.

The Tar zone in Fault Block II-A began producing in 1937. Unitization for reservoir pressure maintenance and secondary recovery (waterflood) operations took place in 1960 and water injection began in that year. Cumulative oil production through 1979, after 19 years of waterflooding, was 20 million barrels; equivalent to a recovery factor of only 20% of OOIP. This low recovery factor was due to an adverse mobility ratio and sand heterogeneity which resulted in low areal and vertical sweep efficiencies. Because of the poor performance of water flooding, it was decided to evaluate the economics of applying steam injection to improve recovery of this heavy (13° API) oil.

A successful steam injection pilot test, comprised of four inverted 5-acre five-spot patterns, was carried out in the Tar zone of Fault Block II-A from 1982-1989. The pilot recovered 1.1 million barrels of oil, for a recovery factor of 75% of the oil-in-place in a previously waterflooded area.[1]



CA
LA BASIN
N
Beverly Hills
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Montebello
Inglewood
Brea-Olinda
Santa Fe Springs
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Rosecrans
El Segundo
Coyote
Dominguez
Rickfield
PACIFIC OCEAN
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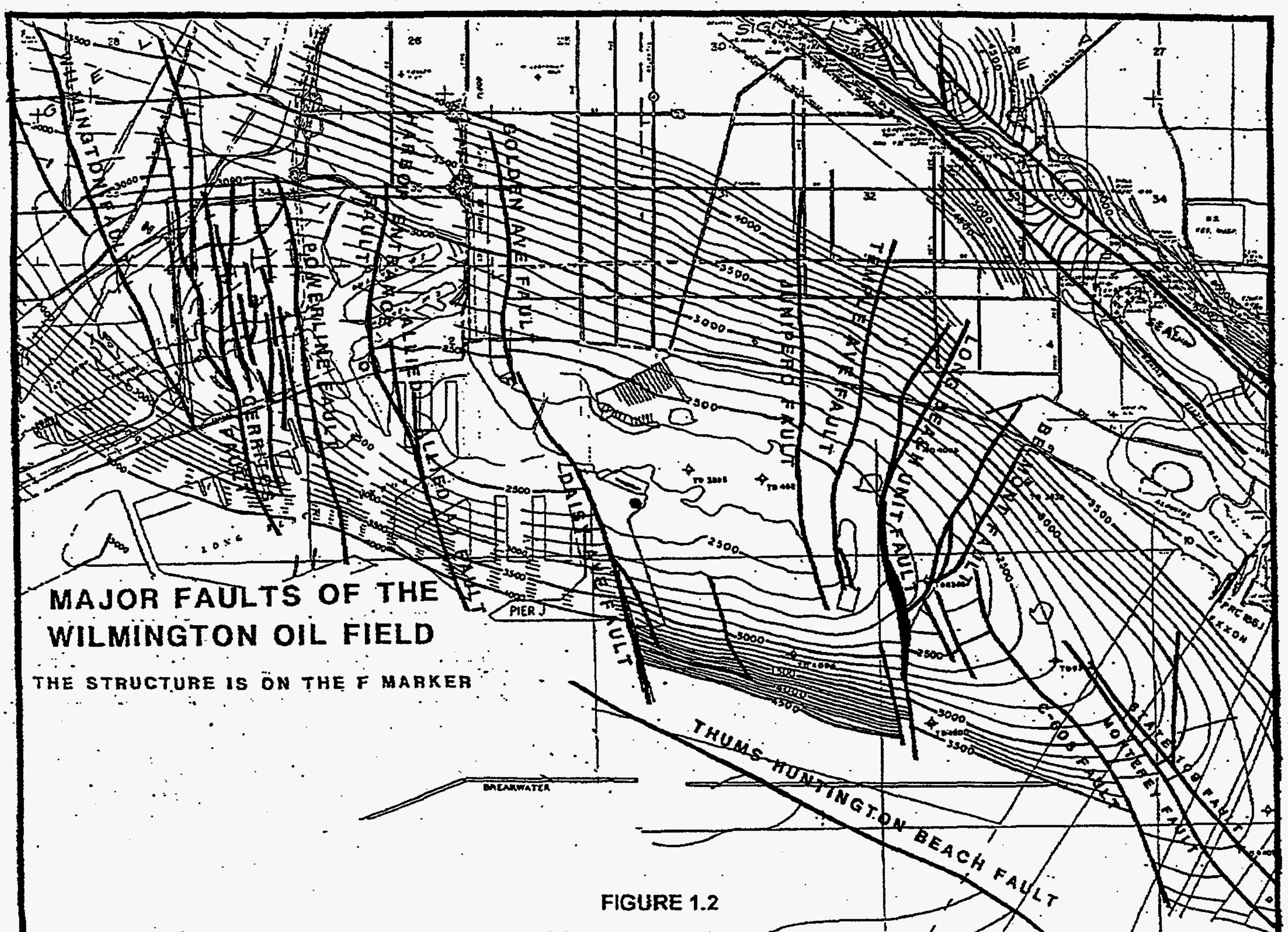
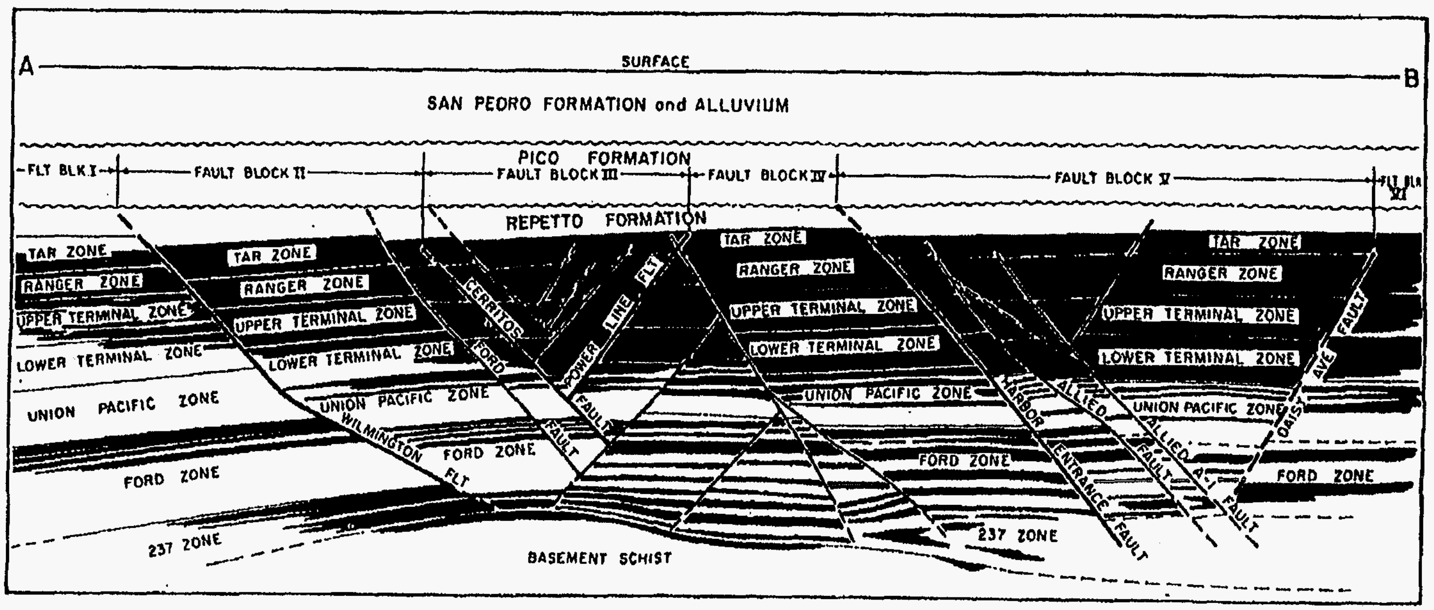


MAJOR FAULTS OF THE WILMINGTON OIL FIELD

THE STRUCTURE IS ON THE F MARKER

FIGURE 1.2



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

FIGURE 1.3

The pilot was expanded to 150 acres using an inverted 7-spot pattern throughout the northern half of the fault block in 1989, but the expansion has not met with the same degree of success as the pilot. As of March 1996, the steamflood was producing 2300 b/d of oil, 35,600 b/d of water, and 1000 mscf/d of low BTU gas from 57 wells. Steam injection was 29,300 b/d cold water equivalent into 40 injection wells. The cumulative steam:oil ratio is a high 8.0. Recovery efficiency has been relatively low due to poor sweep, high water cut, and early steam breakthrough. Operational problems have included scaling and premature equipment failure due to the high produced fluid temperatures accompanying steam breakthrough. Costly and inflexible completion practices were utilized to control sanding problems that have occurred elsewhere in the field. These are problems frequently encountered in the complex turbidite geology of SBC reservoirs such as the Tar zone.

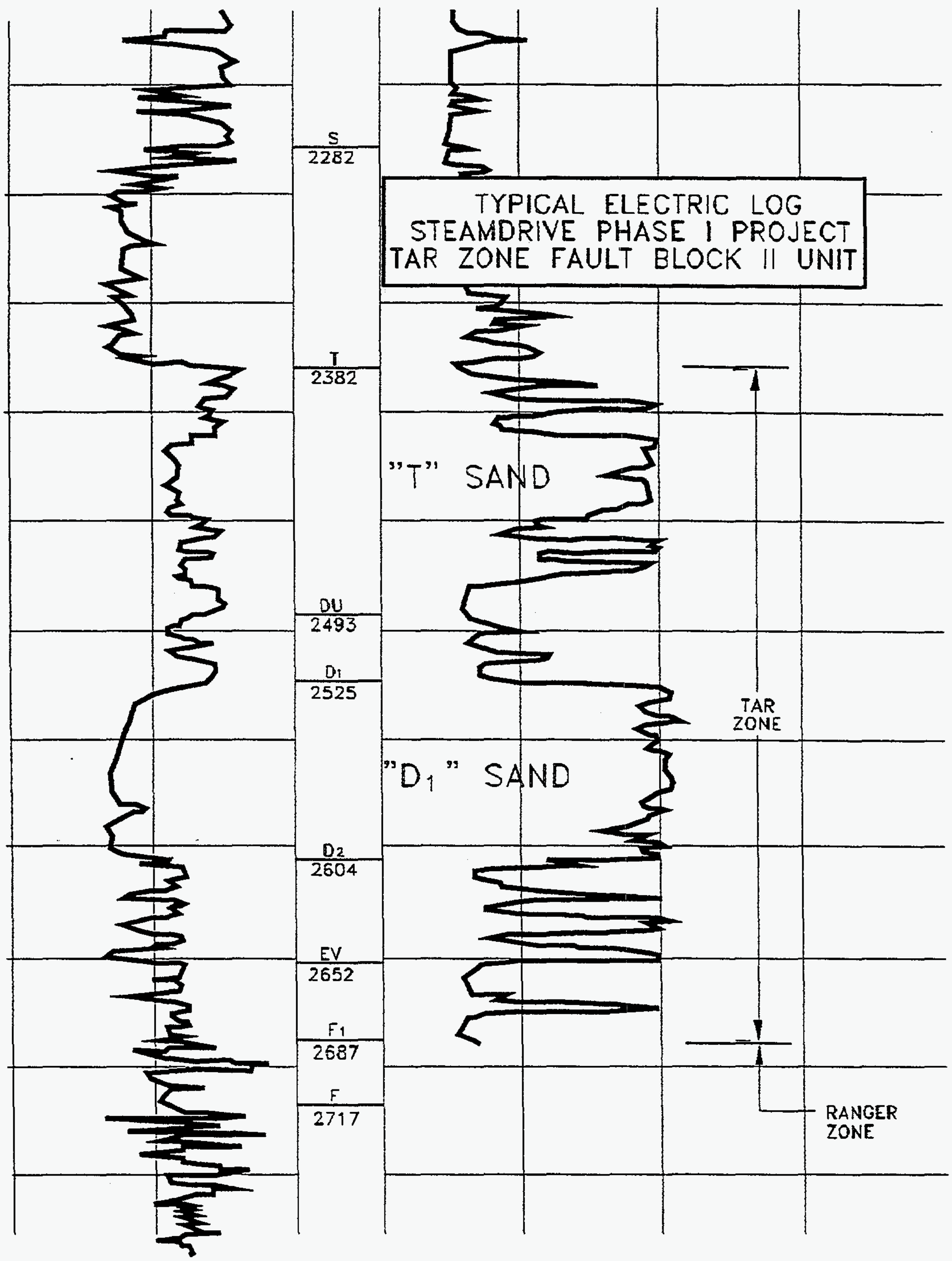
1.4 Geologic Setting

The Wilmington Oil Field is an asymmetrical anticline approximately eleven miles long and three miles wide, covering a productive area of approximately 13,500 acres. Fault Block II-A is located near the western edge of the field. It is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. The north and south limits of the fault block are governed by water-oil contacts within the individual sand members of the various zones. The seven zones within each fault block listed in order of increasing depth are: Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific Ford, and "237".

Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene and Upper Miocene age deposits. The Tar zone has the shallowest oil producing sands of the thick Miocene-Pliocene sequence. The Tar zone sands are lower Pliocene, middle Repetto formation lobe deposits.

The upper Miocene Puente and lower Pliocene Repetto formations within Fault Block II-A consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathayal, slope and base-of-slope deposits. The upper Miocene sands are intercalated with shales and siltstones in the form of widespread thin turbidites. The Pliocene section is dominated by large lobate fans.

The Tar zone in Fault Block II-A consists of four major producing intervals exhibiting typical California type alternation of sand and shale layers as illustrated by the type log in Figure 1.4. The Tar zone sands tend to be unconsolidated, friable, fine to medium-grained, and containing varying amounts of silt. Thicknesses of the sand layers vary from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale.


TYPICAL ELECTRIC LOG
STEAMDRIVE PHASE I PROJECT
TAR ZONE FAULT BLOCK II UNIT
S
2282
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2382
"T" SAND
DU
2493
D1
2525
"D1" SAND
D2
2604
EV
2652
F1
2687
F
2717
TAR
ZONE
RANGER
ZONE

FIGURE 1.4

The oil is of low gravity, ranging from 12-15° API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 30-35% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2330 ft in Fault Block II.

2 COMPILATION AND ANALYSIS OF EXISTING DATA

2.1 Introduction

Existing field data were compiled, evaluated for reliability, and analyzed in terms of production response and constraints to provide a foundation for creating geologic and reservoir simulation models. The production data was input into Production Analyst™ (PA), a computer-aided data retrieval system by Geoquest, to provide rapid access to performance data and diagnostic plots.

The following tasks have been completed:

1. Compilation of production and injection data for the Fault Block II-A Tar Zone from 1938 to the present.
2. Retrieval and review of historical reservoir engineering data.
3. Development of a database of available well logs.
4. Digitization and normalization of log data from 171 wells distributed throughout the fault block.

2.2 Data Compilation

A database of production and injection information for the Tar zone in Fault Block II-A from 1938 to the present has been completed. Historic reservoir engineering data available from the City of Long Beach or from Tidelands files were also retrieved and reviewed. The production and injection database and the historic reservoir engineering data are being used to support reservoir engineering for this project.

The database was more difficult to digitize than anticipated because of the volume and age of the hard copy data, and because of the difficulty in determining the correct historical allocation of production and injection to zones and sub-zones in commingled wells.

In addition to digitizing the data needed for this project, Tidelands has been digitizing historic production and injection data from all of its operated wells in Fault Blocks I through VI. The production and injection database in its entirety will be made publicly available when completed in mid-1997.

2.3 Log Digitization and Normalization

A preliminary database identifying all logs run in each well penetrating the Tar II-A zone was completed.

Log data from 171 wells distributed throughout the fault block were digitized, normalized and converted to Log ASCII Standard (LAS). The digitized logs, including electric or induction logs and spontaneous potential (SP) and/or gamma ray (GR) logs, will be used for basic reservoir engineering and for development of the deterministic and stochastic geologic models. Directional data for the wells were also digitized and included in the database.

The ten wells with Tar zone cores have additional logs, which were also digitized. These logs include the formation density, compensated neutron, dielectric, and, for a few wells, spectral gamma ray. These logs are being used for development of the rock-log model.

Logs from an additional 100 wells (from the more than 600 wells which penetrate the Tar zone in Fault Block II) will be digitized and normalized to serve as "confirmation" logs for testing the stochastic geologic model.

2.4 Conclusions

A computerized database of historic production and injection data was completed to aid in reservoir engineering. The database has provided the means of accessing individual well records on a digital and graphical basis.

The database contains valuable rock and fluid properties for performing correlation studies in similar SBC reservoirs in the Wilmington Field and other Los Angeles Basin oil fields.

3 ADVANCED RESERVOIR CHARACTERIZATION

3.1 Introduction

Reservoir characterization is considered to be a key element for improving oil recovery efficiency by allowing for optimum placement and completion of wells. Reservoir characterization supplies the input for the simulation models needed for effective design of thermal recovery projects. Reservoir characterization is also critical for reducing operating costs related to early breakthrough of steam.

A three-dimensional deterministic geologic model has been completed and a stochastic model is being created to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. These models will aid in delineating geological controls of reservoir dynamics, conceptualizing reservoir architecture, and identifying remaining oil.

The stochastic geologic model is expected to result in predicting the range of potential performance, a more realistic approach that what would be possible based on a deterministic model alone. Application of detailed, geologically realistic reservoir models based on stochastic concepts has increased in the petroleum engineering community in recent years. The main objective in constructing these models is to develop quantitative geologic models with arbitrary scales of resolution. Because the data from cores or well logs are only available at well locations, there is a need to assign flow properties to other unsampled locations. Geologic models should be able to match data measured at sampling points and resemble the significant reservoir properties at unsampled locations. This is the basis of using stochastic modeling techniques. Various levels of model creation may be employed to incorporate facies architecture, local flow properties, and distribution of discontinuous shales.

Data for the geologic models are being derived from various sources, including existing logs from over 600 wells in the Fault Block II-A Tar zone, detailed petrographic studies of cores, MWD data from the installation of four new horizontal wells, open hole logs from five observation wells, and a tracer study. Dynamic characteristics of the formation are being incorporated into the geologic models based on analysis of past performance data and the tracer and pilot tests to be performed during Phase I. The geologic models are being created using the EarthVision™ (by Dynamic Graphics, Inc.) three-dimensional imaging software to facilitate future reservoir analysis and interpretation.

Key tasks completed during this reporting period include:

1. Performing basic reservoir engineering studies;
2. Obtaining new reservoir characterization data;
3. Developing a new three-dimensional deterministic geological model; and
4. Successfully applying the new geological model to place four new horizontal wells in the desired strata.

3.2 Basic Reservoir Engineering

Basic reservoir engineering studies were performed to assemble pertinent data and maps and to begin data analysis for reservoir characterization and simulation. The Fault Block II-A Tar zone was arbitrarily divided into grid blocks and comparative studies were made on the basis of fault block, grid blocks and individual wells. Specific studies are summarized below.

The sealing nature of the faults forming the eastern and western boundaries of Fault Block II was investigated. One finding is that fault sealing cannot fully be explained by shale smear and the juxtaposition of permeable sandstone layers against the nonpermeable formations. In addition, the poorly sorted nature and compaction of fault gouge particles, containing high percentage of clay minerals, contribute to blockage within the faults. [2]

Well log studies indicated errors associated with the use of early logs due to the inability of the early well logs to accurately detect bed boundaries in sand-shale sequences. SP curves were found to be more consistent in bed boundary detection, but the varying influence of the wide range of muds used limits the effectiveness of SP logs for large scale correlation.

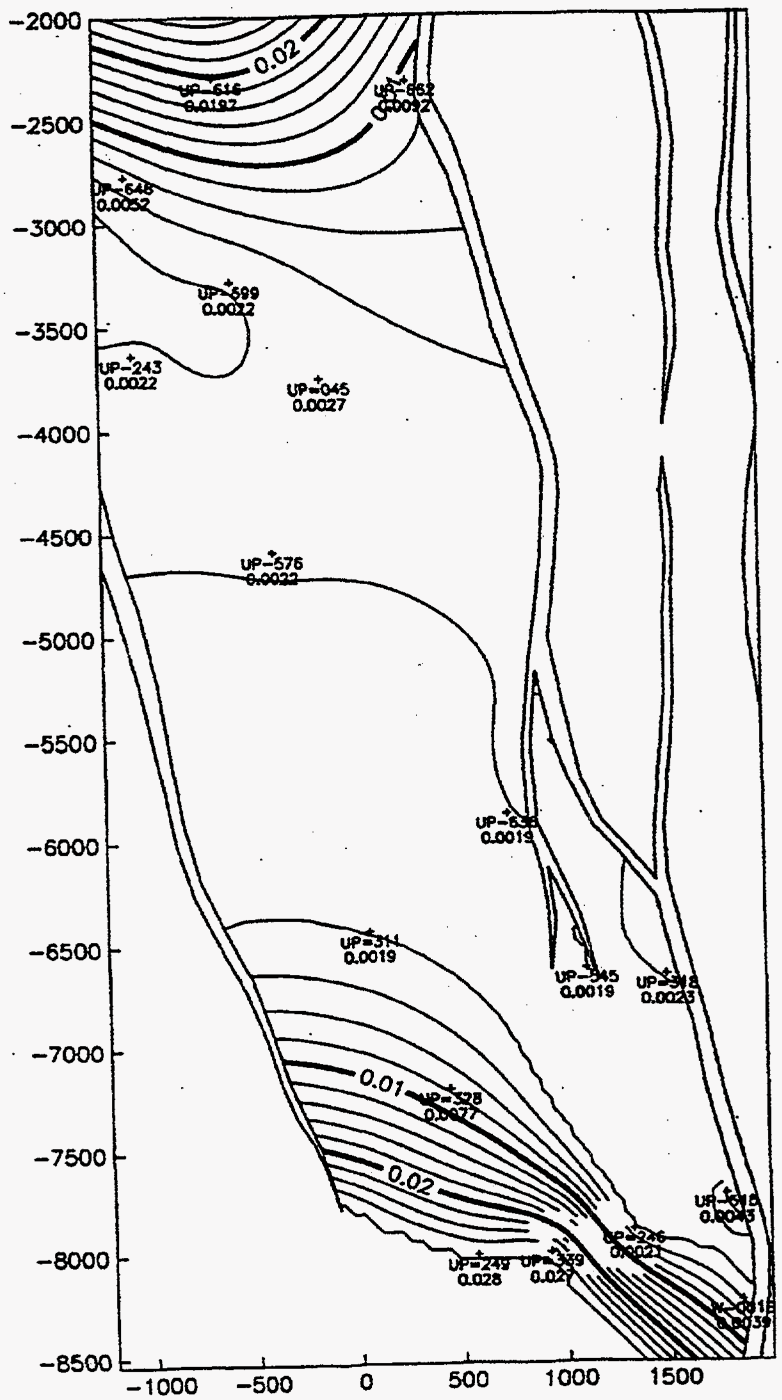
Composite permeability information was obtained by conducting a statistical study of individual well productivities using the Production Analyst database system. Applying the pseudo-steady state equation for flow and using the production data from wells with singular completions yielded the permeability contours shown in Figure 3.1. A field-wide set of gas/oil relative permeability curves was also derived from the individual well performance data for simulation purposes. This approach also helped in conditioning the initial fluid saturation estimated from log and core data.

3.2.1 Material Balance Studies

Conventional material balance studies were applied to estimate the initial oil in place. Using standard bulk volume computed from isopach maps for the Tar zone and estimated values of porosity and saturation from well logs and core data, the volumetric based initial oil in place was estimated at 92.5 MMSTB. Because of uncertainties associated with physical property measurements of unconsolidated sandstones, an independent approach was necessary for cross checking purposes. Using the cumulative gas produced from the field, we estimated an oil in place of 97 MMSTB. We also examined the application of a straight line material balance equation. With a pore volume compressibility of 113×10^{-6} vol/vol/psi, we estimated an initial oil in place of 92.5 MMSTB. This translates into a compaction drive recovery of approximately 12 MMSTB.

Recovery calculations indicate that prior to pressure maintenance by water injection, the cumulative production represented a recovery factor of 12%. During the water injection, the incremental recovery was about 13% to the initiation of the pilot steamflood. Steamflooding through the date of this report has contributed about 8% to the overall recovery factor of 33%.

Figure 3.1
Permeability Contours



3.2.2 Water Influx and Waterflood Response

Evidence of weak natural water influx was noted from the analysis of bubble maps as shown in Figure 3.2. Using the x-plot method[3], quantitative estimation of water influx indicated values in the range of 5-6 million barrels each from both the southern and the northern aquifers. These values are in agreement with those computed using a linear model of unsteady state Van Everdingen and Hurst influx calculations[4]. From the lumped parameter estimation method using the waterflood responses, field-wide oil-water relative permeability values were generated as shown in Figure 3.3. The corresponding average water saturation in the northern and southern portions of Fault Block II-A prior to waterflooding were estimated at 29-33%.

3.2.3 Steamflood Response

Analysis of the steamflood response is in progress and will be discussed in the next reporting period.

3.2.4 Productivity Problem Analysis

The work on individual well productivity characteristics is in progress.

3.2.5 Analysis of Injection Profile Surveys

An indirect method for mapping vertical permeability profiles using profile survey data was tested. The relatively few wells with profile survey data were examined in detail.[5] A major deficiency in the survey data was not allowing sufficient survey time, resulting in scarcity of R/A sampling intervals. A number of wells, however, were identified whose profile surveys will be used in a wellbore history matching process to estimate subzone permeabilities.

3.3 Obtaining New Characterization Data

New reservoir characterization data are being obtained to help understand lateral and vertical variations in reservoir properties and the relationship between the productivity of individual wells and their location and completion profile. Characterization techniques include obtaining MWD data during the installation of four new horizontal wells, performing a tracer study, characterizing water chemistry as a function of location and time performing oil fingerprinting studies, and installing observation wells.

3.3.1 Measurement While Drilling

Four horizontal wells were drilled by October 31, 1995. All MWD and LWD data for the four wells were good quality. The sub-sub-zone sands appeared continuous drilling west to east. A possible fault of small displacement was noted in well UP-956 and all the mapped faults were encountered very close to predicted location by the three-dimensional deterministic geological model. The horizontal well control was provided by Anadril's LWD and MWD integrated with cross sections and structure maps extracted from the three-dimensional geological model.

Figure 3.2
Cumulative Water Production to 12/1959

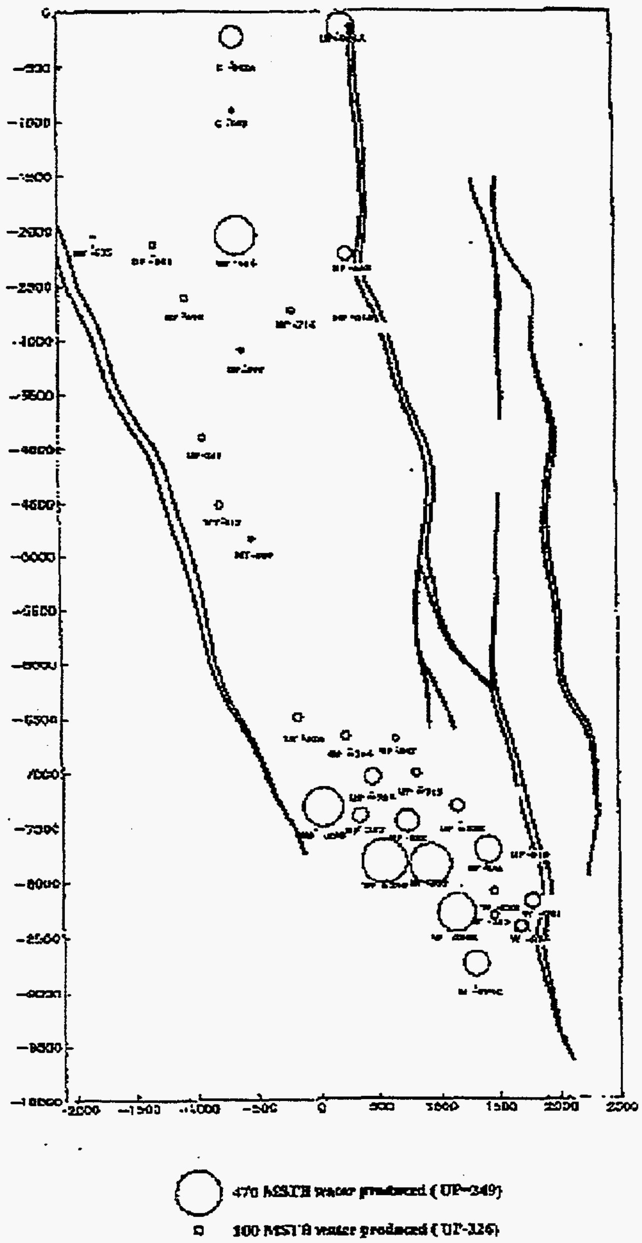
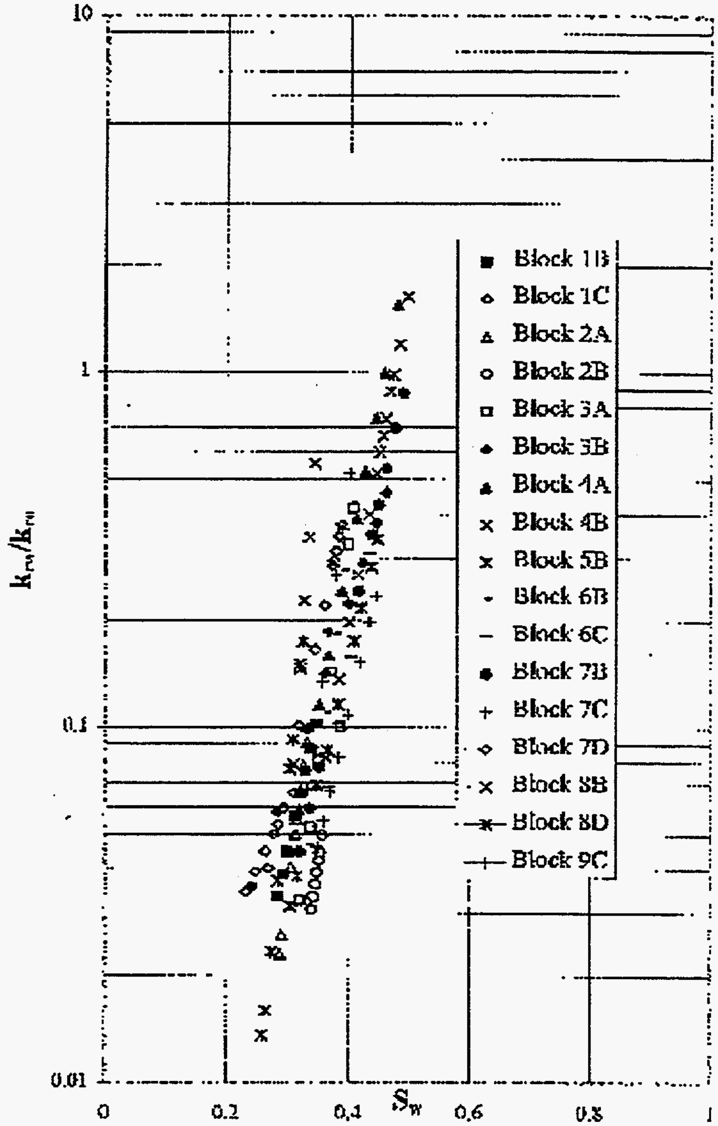


Figure 3.3
k_{rw}/k_{ro} Curves



3.3.2 Tracer Surveys

A tracer survey will be performed to identify cross zone communication, vertical permeability profile, and permeability anisotropy. Such information is crucial for accurate modeling and performance projection of the steamflood. The tracer survey has been designed but the test itself was postponed to the second year of this project due to operational problems.

Several laboratory tests were conducted to estimate tracer losses, thermal stability and adsorption at 500 ^{o}F. Two tracers were identified: ammonium thiocyanate and lithium chloride. The tracers, in a liquid form, will be blended with 500 ^{o}F injection water from the steam separator. One tracer will be injected into the "T" sand through injector 2AT-032 and the other will be injected into the "D" sand through injector 2AT-033. The responses will be monitored in the nine first line producers, six second line producers, and 12 third line producers, as shown in Figure 3.4. A computer model to interpret the tracer data has been developed and is currently being calibrated for non-unit mobility ratio cases.

3.3.3 Water Composition Tests

Water salinity tests are being performed on produced water from the Water Alternating Steam pilot in the existing steamflood. Because the injected steam and hot water are fresh, lower salinity in produced water is a qualitative indicator of steamflood or hot water response. No significant changes in salinity have been recorded to date.

3.3.4 Oil Finger Printing

Thirty samples of oil and chromatographs from 21 steamflood producers prior to start-up of this project have been located. Interpretations and correlations are in progress.

3.3.5 Observation Wells

Five observation wells, two of which were cored, were drilled by August 31, 1995. Four wells are used for monitoring reservoir temperatures in the horizontal well steam drive pilot area. A fifth well, OB2-5, was placed in the original pilot steam drive area to determine post-steam oil saturations and mineral alterations to the formation rocks.

Core recovery through the T and D sub-zones in wells OB2-3 and OB2-5 was excellent - over 99% of the planned core interval of 517 ft was recovered. A Repeat Formation Tester (RFT) run in observation well OB2-1 shows that the reservoir pressures within the D1 sub-sub-zones are in vertical hydrostatic pressure communication and are different from the sub-zones directly above and below. The D1 sub-zone is the steam drive interval for the horizontal wells. We are studying the reservoir pressure data obtained by the RFT to determine the validity of the data with respect to vertical pressure communication between sands by going around the tool through the mudcake.

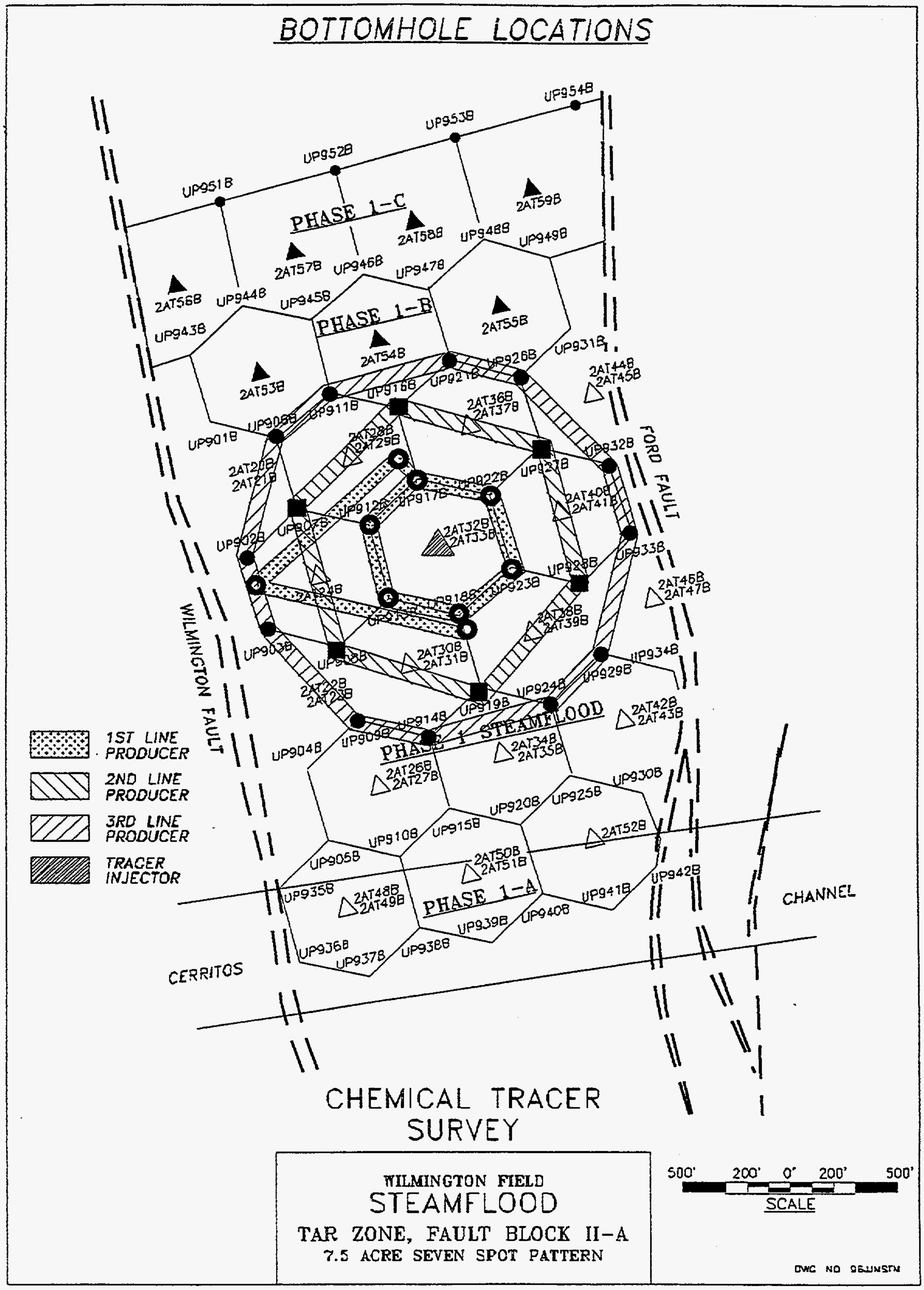


FIGURE 3.4

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Conventional porosity, permeability, and oil saturation measurements will be performed on the core plugs. A proposal has been completed for high temperature core work to investigate residual oil saturations at different steam temperatures, formation rock and fluid alterations caused by different steam temperatures, and the physical phenomena behind the successfully perforated well completions in unconsolidated sands when initially stimulated with steam.

With the exception of dielectric constant logs (EPT), good quality logs were acquired in the observation wells. The logs run are listed below:

Array Induction Logs	All wells
Gamma Ray and Spontaneous	Potential All wells
Litho Density + Compensated Neutron	All wells
Electromagnetic Propagation Log	All wells
Repeat Formation Tester	OB2-1 and OB2-5

3.4 Deterministic 3-D Geologic Model

The geological complexity of the Tar zone sand bodies in terms of lateral and vertical continuity is being characterized and incorporated into a deterministic geologic model. Many of the recovery problems in previous steamflooding of the Tar zone are attributed to a lack of understanding of geologic controls on flow through the reservoir. Determining sand continuity is of particular importance for turbidite sands, because sand sequences in adjacent wells may look similar but in fact may not be connected because of the lobated nature of the sand stratigraphy. In particular, an accurate three dimensional (3-D) deterministic geologic model is required for precise placement of horizontal wells within the heavy oil sands to facilitate gravity drainage via steam drive. The 3-D model will also provide the basis for a reservoir simulation model.

This work involves correlating Tar zone sequences using EarthVision™ (supplied by Dynamic Graphics, Inc.) geologic modeling software, developing a log-rock model of gamma ray response, creating a porosity-permeability model, creating a V-shale model, and placing the Tar zone geologic model within the context of an overall basin model.

3.4.1 Three-Dimensional Structure

A working 3-D deterministic geological model was completed in June 1995 and used to depict the location of the initial wells. In July 1995 the drilling program started and five observation wells were drilled. Data inconsistencies were revealed when core hole OB2-3 was drilled and cored. The inconsistencies were determined to result from errors in subsidence correction software (NEWILMA) that had been implemented by a previous operator. The software was modified and data were updated appropriately. Significant modifications to the data base were required due to inaccurate subsidence corrections in the original data set. Subsequent drilling verified the new data. Horizontal wells were then laid out based on the revised data and the geological model was completely reconstructed, as shown in Figure 3.5. Detailed cross sections extracted from the model were used for geosteering the horizontal wells. These cross sections proved to be highly accurate.

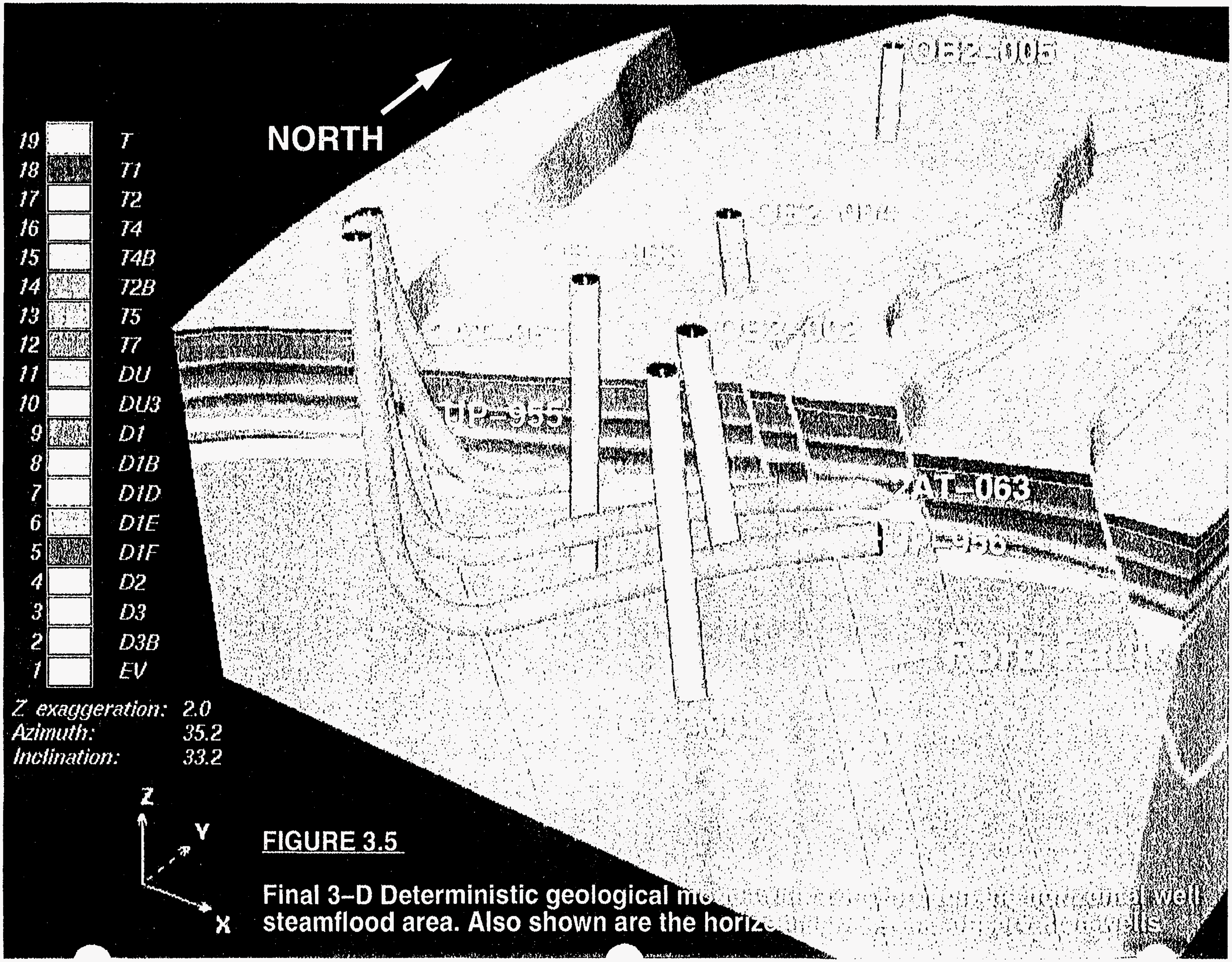


FIGURE 3.5

Final 3–D Deterministic geological mo[illegible] well steamflood area. Also shown are the horiz[illegible] wells.

Surface Subsidence Corrections

Surface subsidence in the project area caused by oil and water production ranges from 12-ft to 22-ft (see Figure 3.6). The electric log markers are uniquely located by Cartesian X, Y & Z coordinates interpolated from the directional well survey data. Initially, the Z location was modified by a subsidence correction program (NEWILMA) inherited from the previous operator.

After the second and third observation wells were drilled, it was noticed that the VSS depths for the stratigraphic markers appeared to be in error with respect to the initial geological model. It was confusing that the first well drilled, OB2-4, agreed within 1-ft, but subsequent wells were off by as much as 18-ft. When the old datum maps were compared with the 1995 maps, it became clear that the subsidence data were the problem. The NEWILMA subsidence adjustment was in error.

Three components to the subsidence correction were identified, as illustrated in Figure 3.7:

1. Individual survey stations require downward deflection based on subsidence occurring after a well was drilled. Survey location with reference to center of subsidence ellipsoid is also considered. The program assumes no subsidence since 1959, because actual surface elevation movement has been nominal with a maximum of 1.9-ft in specific locations.

2. Mat elevation datum should be adjusted (Operator dependent) due to artificial Kelly Bushing Elevation (KBE) raising based on subsidence that occurred before well was drilled.

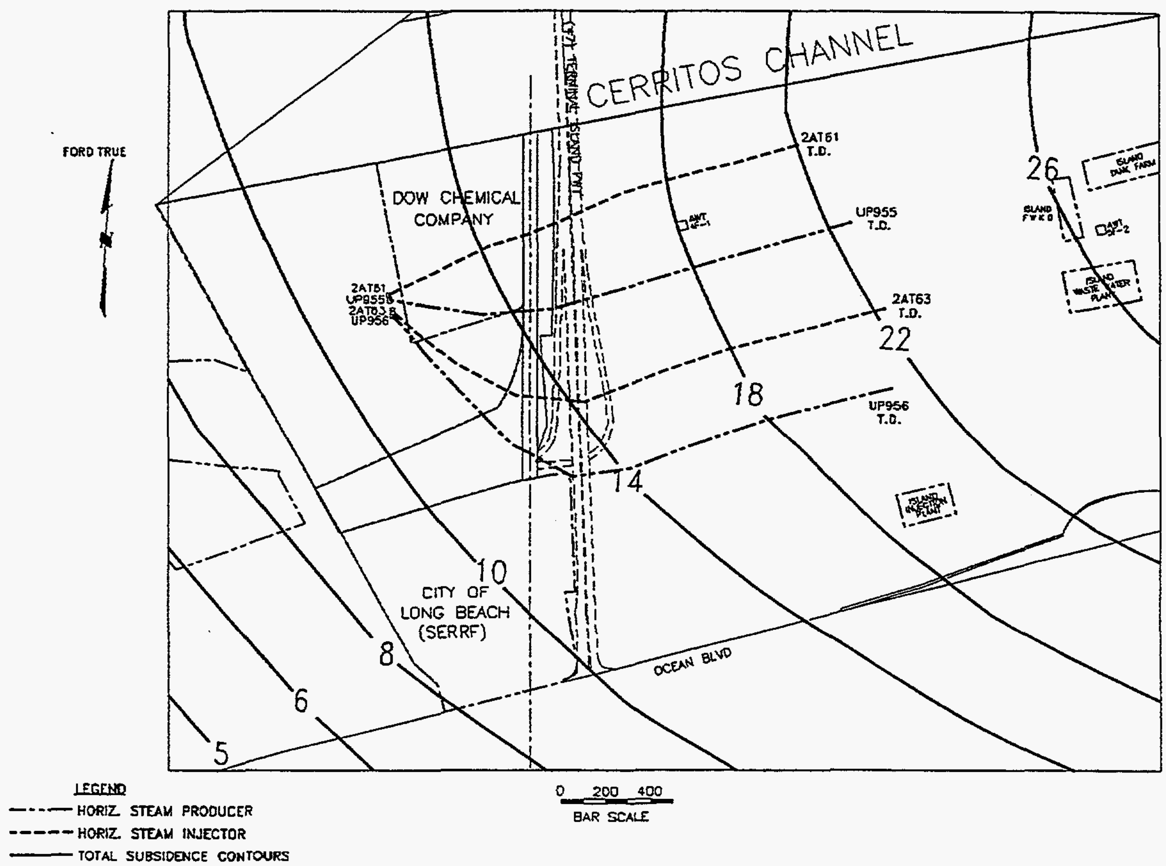
3. Compaction of overlying sands from fluid withdrawal should be accounted for, if significant.

A highly parameterized elliptical total subsidence model and a linear approximation was used to estimate the value of subsidence by year for the first and second corrections. The Tar zone is the top oil zone in Fault Block II so the third correction is negligible and was not included in the reprogramming of NEWILMA.

Correcting the data is vital for defining accurate structures in the Tar Zone, Fault Block II. Total subsidence of 12 to 22-ft affects the location and shape of the stratigraphic horizons. The D1 sand is about 60-ft thick in the producing intervals, so an error of 20 ft could be disastrous - either the zone would be missed, or 30% of the producing sands would be lost. Additional details regarding the subsidence error are reviewed by Phillips in Clarke, et al., 1996. [6]

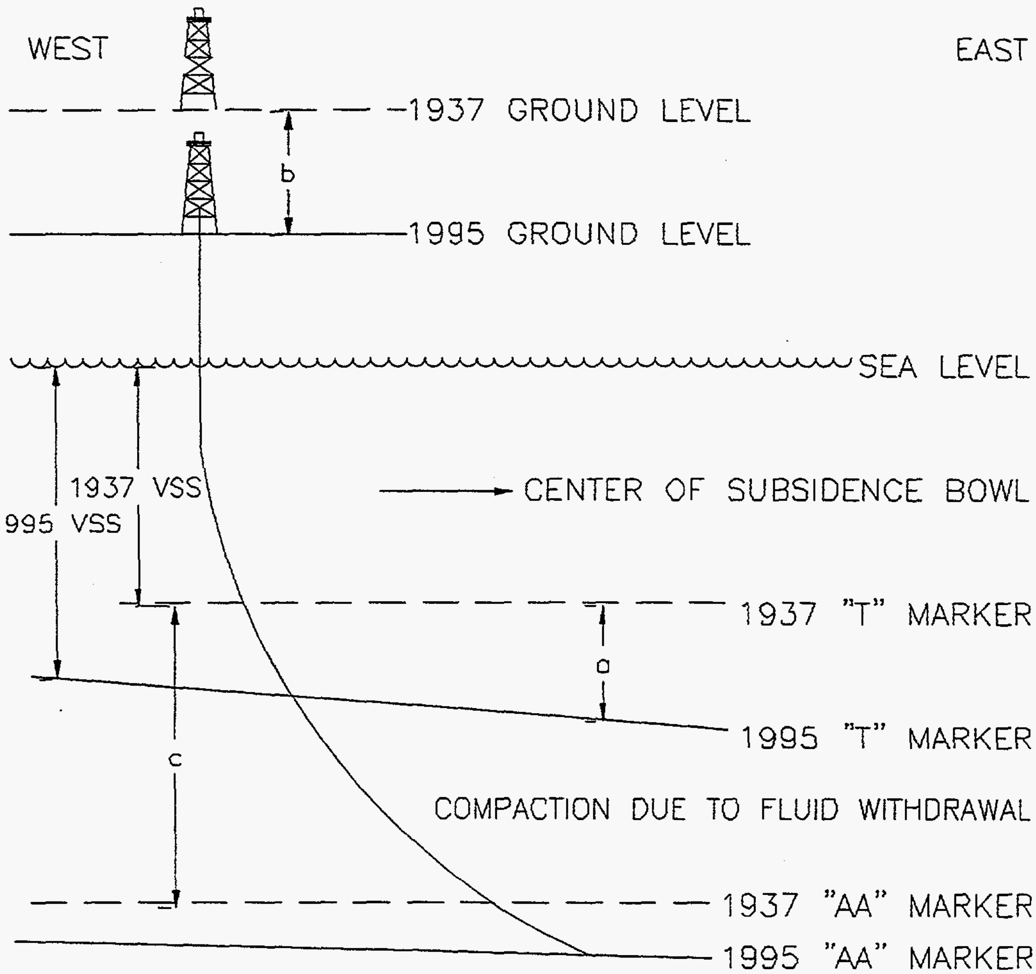
Although the data errors were catastrophic and a tight drilling rig schedule had to be managed, it was possible with available workstation technology to correct the data, build the 3-D model and create the necessary cross sections and structure maps in time to drill the first horizontal well.

The third component to the subsidence correction (compaction) will be integrated with NEWILMA as time permits. The compaction component affects the shape and structure of geological features significantly in the zones below the Tar Zone. A reservoir simulation study is planned to determine the effects of compaction.



Horizontal well paths are shown on top of total subsidence contours (in feet).
From 12 to 22 feet of total subsidence has occured in this area, and
the data used to define the structure spans 60 years.
FIGURE 3.6

THREE COMPONENTS TO SUBSIDENCE CORRECTION
FAULT BLOCK II PROJECT



a) DOWNHOLE ADJUSTMENT FOR SUBSIDENCE THAT OCCURED AFTER WELL REDRILLED X, Y DEPENDENT. DISTANCE BETWEEN 1937 MARKER AND 1995 MARKER INCREASED TOWARD CENTER OF SUBSIDENCE BOWL.

b) KB ELEVATION ADJUSTMENT--OPERATOR DEPENDENT ADJUSTMENT FOR SUBSIDENCE BEFORE WELL DRILLED. WELL HEAD DEPENDENT.

c) COMPACTION ADJUSTMENT OF OVERLYING SANDS.

Three components to subsidence correction. Fault Block II data corrected for the first two components only (a and b).

(NOT TO SCALE)

FIGURE 3.7

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Building The 3-D Deterministic Geological Model

A total of 18 horizons were defined through traditional reservoir characterization techniques. All the strata were successfully modeled, including the six normal faults, a paleochannel and onlapping sands. Maps and cross sections were extracted from the 3-D model and used for geosteering the horizontal wells. The model was extended vertically and laterally to facilitate studying the barrier characteristics of the faults.

A complicated turbidite distal/edge stratigraphy of the lower Pliocene, Repetto formation on a rising Wilmington anticline necessitated the construction of an electric log stratigraphic cross section grid. Nine north-south and eleven east-west sections were created. The 18 horizons were defined and the stratigraphy correlated in over 700 wells (see the type log in Figure 3.8 and stylized stratigraphic column in Figure 3.9). The T to EV interval (approximately 300 ft) was subdivided based on knowledge of California Pliocene and Miocene turbidite sequences and their producing characteristics, and applying seismic stratigraphic principles to interpret spontaneous potential (SP) curves as a wiggle trace.[7]

The primary correlation used the SP and induction curves from wells drilled between 1937 and 1995. The quality of the SP curves was good, even dating back to the 1930s, and, when combined with the shallow resistivity curve in oil saturated sands, provided excellent resolution of bed boundaries. Zero sand edge lines were drawn on base maps for both onlap pinchouts and paleochannel erosional banks (see Figure 3.10).

The method used to create the model on the workstation follows the sequence of the historical geological processes that occurred. Faults are defined as planar features and are used as the starting point. The data is parsed between the faults, and the horizons are gridded within each sub-block. The layers are then automatically sequentially placed within each fault sub-block as they would be deposited and stitched together beyond the fault extents. In the case of the paleochannel, the DU, T7, T5 and T2 layers are placed (deposited) and then mathematically cut (eroded) by the T4 channel. The zero sand edge lines for the onlap pinchouts and the paleochannel agreed well with the hand drawn base maps.

It is very easy to identify erroneous data points in three dimensions. The software has the ability to display the faults and horizons along with the input data. Data busts are easily visualized. Where necessary, individual marker picks are checked and data base values are corrected, left alone or eliminated.

Once the 3-D model is constructed, cross sections and maps can be rapidly produced by extracting directly from the model. An example of a structure map and a cross section can be seen in Figures 3.11 and 3.12. The 3-D deterministic model is valuable for displaying detailed information about the structural geology, stratigraphy, trap types, reservoir boundaries and well locations.

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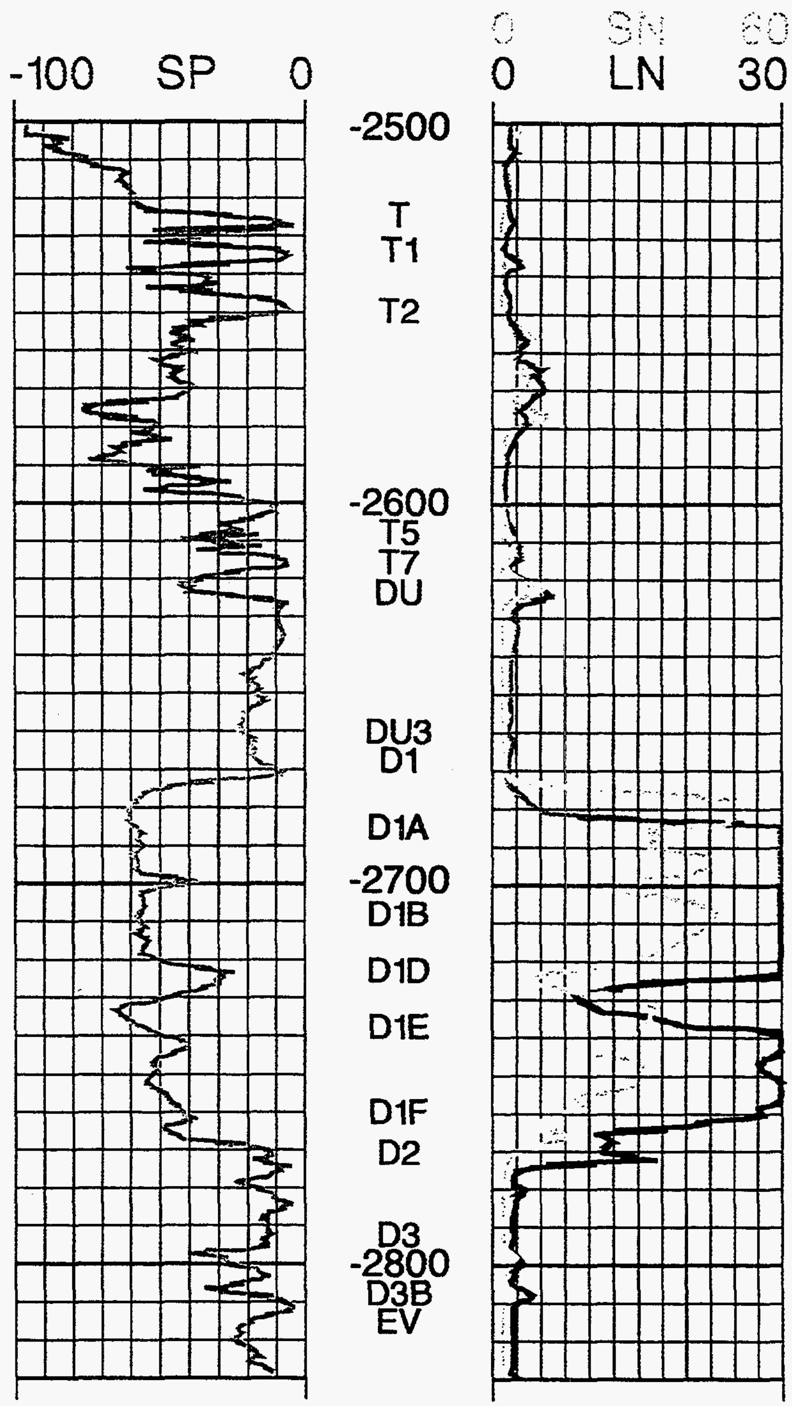

FIGURE 3.8

SP and Induction curves were used for detailed reservoir characterization work, as represented by this type section. The goal was to correlate flow units.

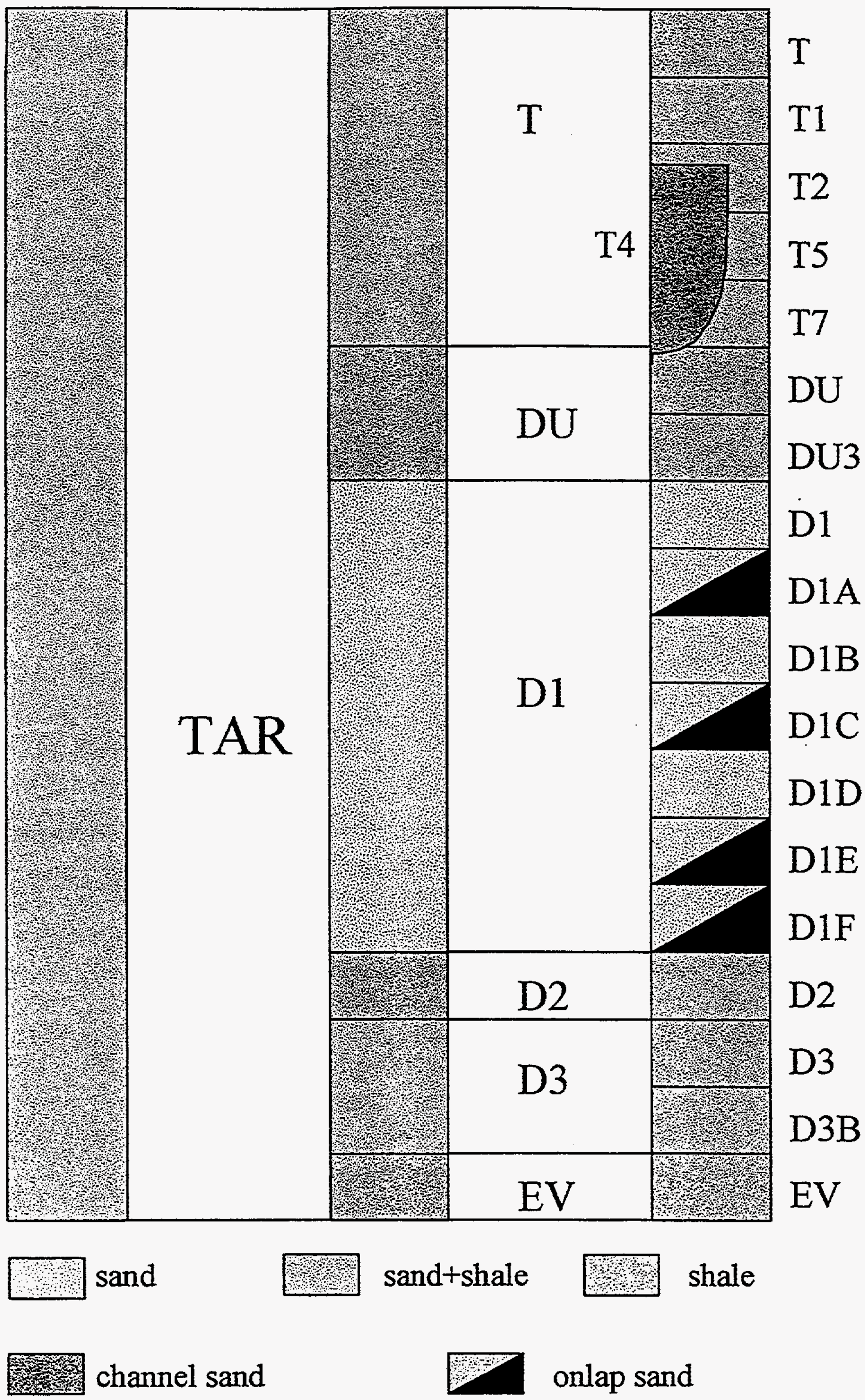

Figure 3.9 - Stylized Stratigraphic Column

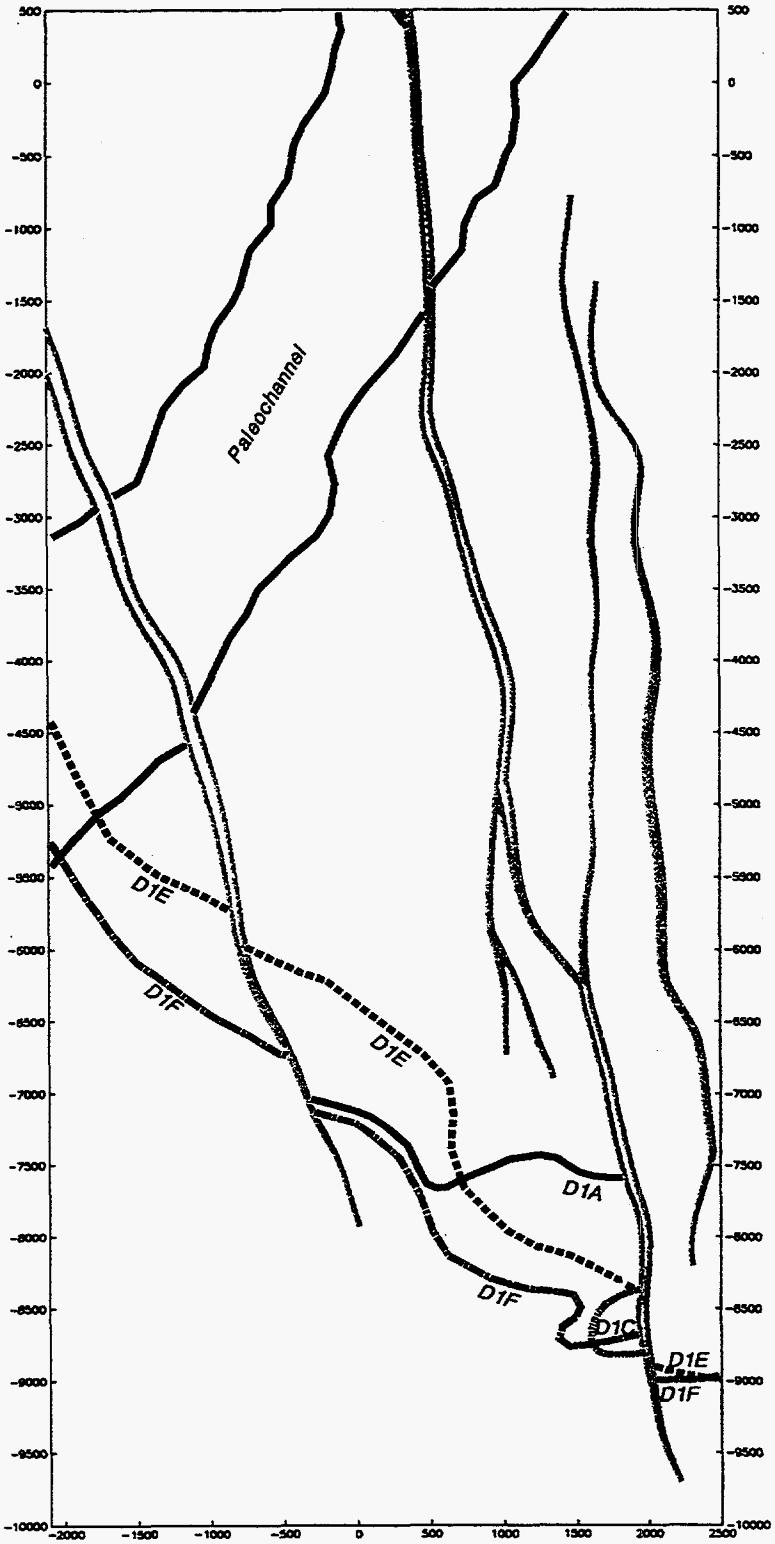

FIGURE 3.10

Sand pinch out map for the Tar Zone.

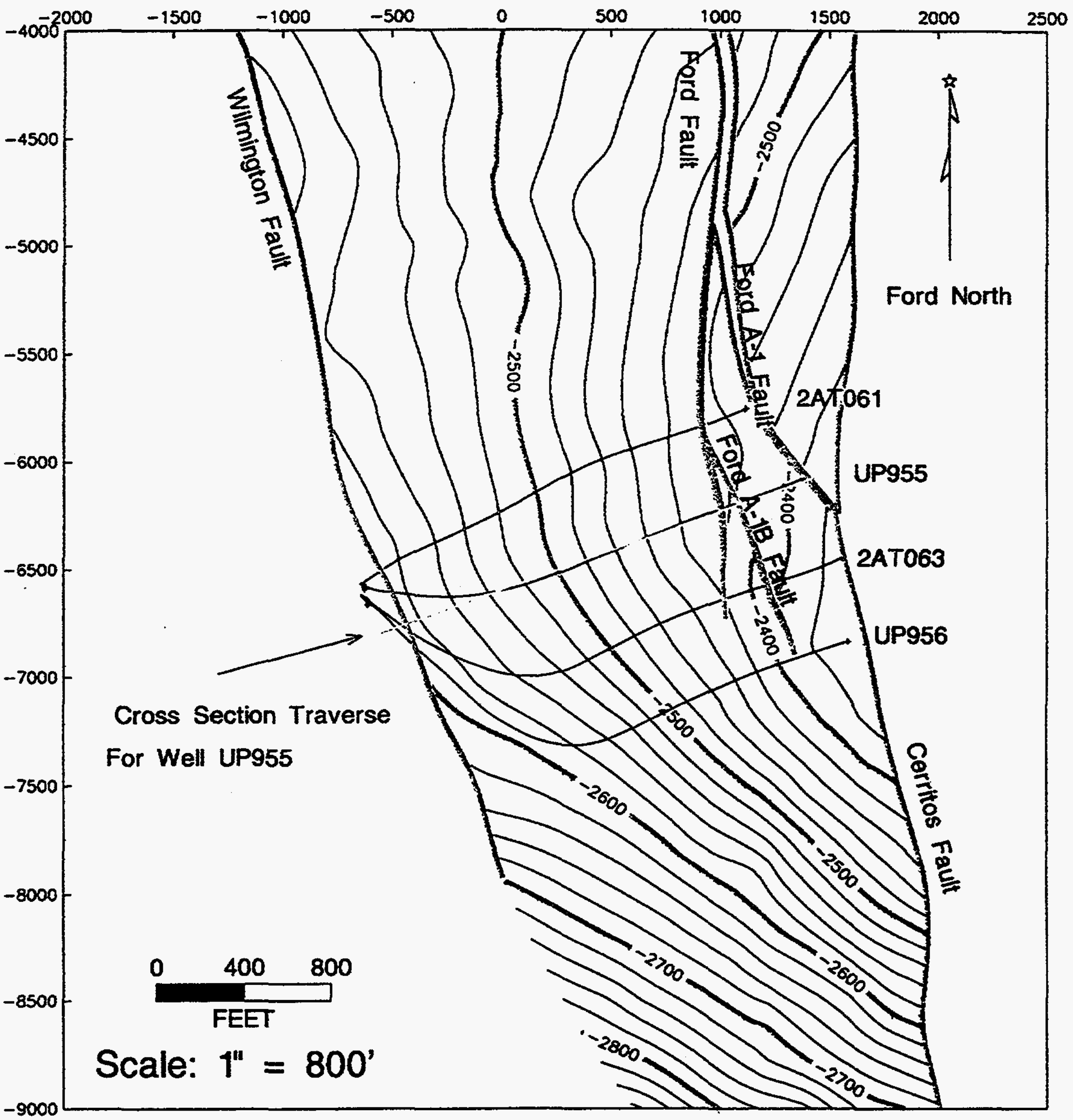

FIGURE 3.11

Structure Contour Map on top of the "D1" sand.

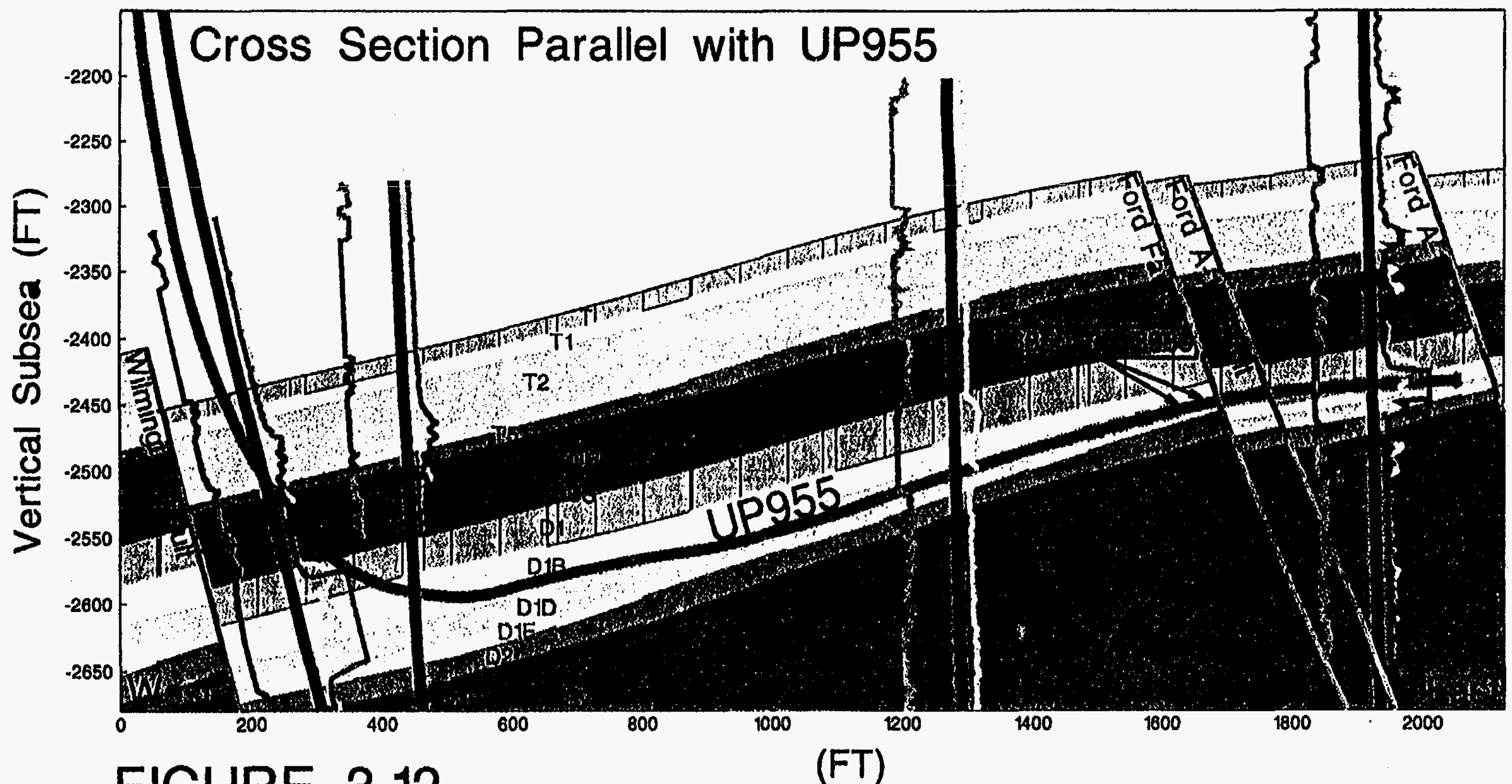
Cross Section Parallel with UP955
Vertical Subsea (FT)
-2200
-2250
-2300
-2350
-2400
-2450
-2500
-2550
-2600
-2650
T1
T2
D1B
D1D
D1E
UP955
Ford A
Ford A
0
200
400
600
800
1000
1200
1400
1600
1800
2000
(FT)

FIGURE 3.12

When more is learned about the rock types and problems are revealed from the stochastic modeling and reservoir simulations, the 3-D deterministic model will be scrutinized and modified as necessary. The 3-D model will also be used to construct Allan diagrams for the fault barrier characteristics study and to define oil water limits for future cross sections and models.

Planning the Horizontal Wells

Multiple cross sections were developed for each well using 3-D computerized modeling (EarthVision™) to facilitate planning the wells and monitoring drilling progress.

Two scenarios were considered for planning the wells:

1. The D1 sub-sands are separated by vertical permeability barriers, so that the horizontal lateral will need to be geosteered in a serpentine manner to connect the sub-sands. For example, D1B is a separate flow unit from D1D, so that the horizontal section will need to be divided between the two sands.

2. The D1 sub-sands behave as one flow unit and the horizontal lateral can be located above the basal shale to catch attic reserves as the steam chest expands downward.

The second scenario turned out to be true for the pilot area. This was verified by running a Repeat Formation Tester (RFT) in temperature observation well OB2-1. The results showed that the reservoir pressures within the D1 sub-zone were in vertical hydrostatic pressure communication and were different from the sub-zones directly above and below.

Geosteering the Horizontal Wells

Four horizontal wells were drilled (two producers: UP-955 and UP-956, and two steam injectors: 2AT-61 and 2AT-63) with the goal of placing the horizontal section near the base of the D1D sand (Fig. 3.12). The strata dip from 8 to 12 degrees to the west. Accordingly, the wells were drilled updip, perpendicular to strike at a 2-15 degree angle above horizontal, approximately 10- 15 ft above the bottom shale, in a pattern with 400 ft between laterals.

Logging While Drilling (LWD) and Measurement While Drilling (MWD) were used for directional/ geological control (geosteering). Dual resistivity gamma LWD provided sufficient real time data of approaching sand-shale boundaries (when approaching at a high angle of incidence), confirming location of the wellbore within the intended sand subzone. The compensated dual resistivity tool (CDR) was 32 ft behind the bit and the MWD was 62 ft behind the bit. The survey from the MWD was plotted on the geological cross section and bit position in the geological section was located by extrapolating 62 ft ahead of the survey points. Once bit position was known, the LWD resistivity and gamma ray values were compared to offset logs and cross sections to verify that the horizontal section was in the correct location.

The D2 shale is at the base of the D1D sand in the area where the horizontal wells were drilled. The offset logs from the new observation wells showed good 10 ohm-meter oil saturation at the base of the D1D sand. In the horizontal wells, the resistivity measurements appeared to be 1.2 times higher than that of similar sections in the observation wells. The resistivity curves in the horizontal wells separate as the logging sensors (CDR tool) detect a lithology change. The separation results from the different depths of investigation of the sensors. The depth of investigation for the deep resistivity (Rad) is approximately 43-in. at 10 ohm-m, while the depth of investigation for the phase shift shallow resistivity (Rps) is approximately 24-in. (see the Schlumberger chart (Schlumberger, Logging While Drilling, Schlumberger Educational Services, 42Houston, Texas, pp 5-10, 1993) in Figure 3.13. [8]

The well plan was adjusted to follow the base of the D1D sand. Theoretically, the lower in the D1D sand the well is located, the more recoverable reserves become available for gravity drainage. Assuming none of the reserves below the well bore are recoverable, every foot above the base of the D1D sand is equivalent to 15,876 STB lost reserves. [6]

The horizontal continuity was verified for the D1D sand by the consistent LWD readings. The fault sub-blocks are down dropped to the East in Fault Block II and the known faults were observed at their predicted locations. In well UP-956, a change in resistivity from 12-13 ohms to 19-20 ohms was unexpectedly observed approximately 850 ft from total depth. This suggests the hole is about 5 to 10 ft higher in the stratigraphic section and is believed to be an as yet unmapped fault of small displacement.

Although the goal of staying in the lower D1D sand was not achieved in well UP-955, the experience gained drilling the well enabled drilling horizontal well FJ-202 into a similar Tar zone sand in Fault Block V with great efficiency. In addition to achieving accurate stratigraphic control (within 5' of the lower shale), the well only took six days to drill. Maximum drilling rates were up to 600 ft per hour. Achieving these results required good communication between LWD/MWD operator, mud engineer, geologist and drilling supervisor.

An example of one problem encountered while drilling the Fault Block II horizontal wells occurred when the bit penetrated the D2 shale. Some of the shales in the Wilmington Field are composed of soluble clays which dissolve and release high ion concentrations that cause the low density solids to flocculate the mud. This greatly increases the viscosity of the mud. Telemetry problems were encountered when the viscous mud prevented the turbine in the power unit from spinning freely. The log and gravity tool face output was disabled. Without knowing which way the bottom hole assembly was pointing, it was difficult to direct the steerable assembly away from the shale. When the mud engineer saw an increase in low density solids or when there were telemetry problems due to drilling the D2 shale, operations slowed or ceased and the mud was conditioned before drilling resumed. The drilling approaches to mitigate these problems are described along with other details of well installation in Section 5.2, "Horizontal Wells and Surface Facilities."

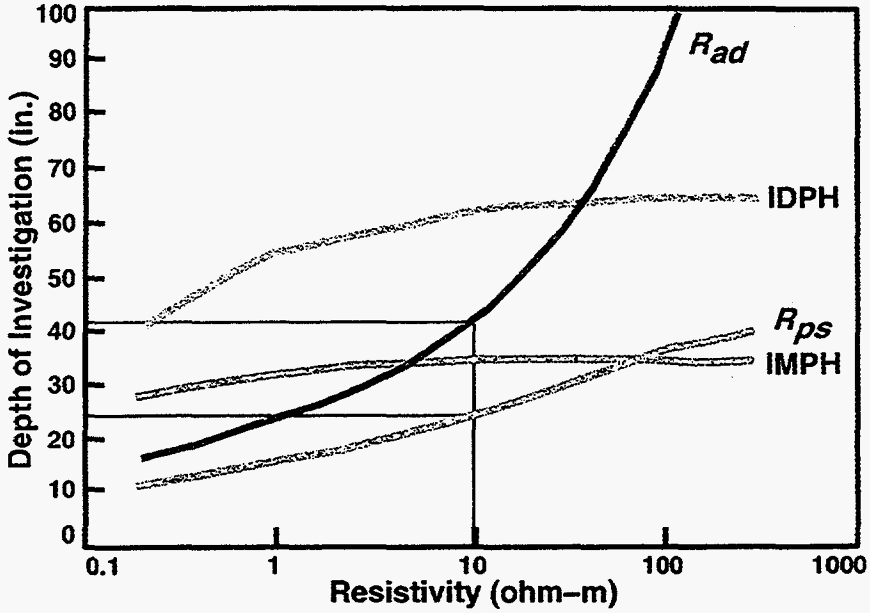

FIGURE 3.13

Comparison of Rps and Rad at 10 ohm–meters resistivity (Schlumberger, 1993)

Correlating the Horizontal Wells

Correlating the logs for these horizontal wells was a significant challenge. Vertical movements of the bit within the D1 sand package is hard to detect using the gamma ray log. The log signature for the D1 consistently reads around 75 gamma ray API units, as illustrated in Figure 3.14. The bit moved vertically 140 ft, laterally 1300 ft, crossed two faults and moved 30 ft vertically within the D1 sand and the gamma ray reading still remained 75 gamma ray units. Therefore one has to rely on the curve separation of the induction curves, accuracy of the surveys and the 3-D model to enable accurate log correlation. The faults were noted by a very slight increase in the GR count and a change in the resistivity from one side of the fault to the other. The plot in the cross section gives the best information on spatial relationship of the bit.

The cross sections proved to be highly useful for planning and accurately geosteering the horizontal wells. The rough location for five more horizontal wells has been determined for the southern expansion. The knowledge gained from the recent drilling gives us confidence in the 3-D model and proceeding with plans for future wells. The actual location of the expansion wells will be determined after completion of the 3-D stochastic geological model.

3.4.2 Core-Based Log Model and Porosity-Permeability Model

A rock-log model is being created based on detailed petrographic analysis of reservoir cores to provide a consistent log data set for identifying rock types in cored and non-cored wells. This work is ongoing and includes:

1. Sedimentologic core description, including identification of depositional environment, rock diagenesis, rock types, and pore geometry characteristics.

2. Developing a porosity-permeability model based on the various rock types present in the formation.

3. Laboratory core analysis, including:
   a) Porosity, permeability and saturation;
   b) Thin sections;
   c) X-ray diffraction;
   d) Scanning electron microscopy;
   e) Relative permeability and capillary pressure; and
   f) Electrical and cementation properties (m and n).

4. Developing a rock-log model to interpret rock types and lithologies from log response.

5. Developing a model to relate rock type and log porosity to permeability.

An initial core-based log model has been developed and is being reviewed by the project partners. Facies of the Fault Block II-A Tar zone sands were studied based on macroscopic core descriptions performed in Long Beach during May 15-19, 1995, on frozen preserved and unpreserved conventional cores from nine Fault Block II-A Tar zone wells. Prior core work on the nine wells was evaluated including core plug analyses for porosity, permeability, and oil saturation data and core photographs, and petrographic reports. The core-based log model identifies five distinct petrophysical rock types. The rock types are based on thin section, scanning electron microscope, and x-ray diffraction analyses of the cores and log-derived formulas using the dual induction, gamma ray (GR), SP, formation density, and compensated neutron logs to correlate porosity, permeability, grain density, and V-shale for each rock type.

An initial porosity-permeability model has been developed and is being reviewed by the project partners. The core permeabilities range over several orders of magnitude for any given value of porosity. This dispersion of porosity-permeability data reflects changes in the volumetric distribution of pore types within the reservoirs. Coherent porosity-permeability relationships were developed for the five petrographic rock types identified in the core-based log model. All of the rock types had high average porosities ranging from 31%-36%. Only three of the rock types are potential reservoir rocks, as the other two have high shale content and low permeabilities.

An initial rock-log model has also been developed. Three potentially productive rock types occur in sandstone and two rock types contain non-reservoir rocks containing silty sands/shales and shales. The different sandstone rock types are discriminated on the basis of pore geometry, specifically the size of pore bodies and pore throats as measured in a scanning electron microscope. Algorithms have been developed for the prediction of permeability from well log determined values of porosity and rock type. This allows for the prediction of rock type and permeability in all wells with a modern log suite (dual induction, GR, formation density, and compensated neutron).

3.4.3 V-Shale Model

An initial V-shale model has been developed and is being reviewed by the project partners. Log shale indicators were calibrated with actual measured values of V-shale (thin sections). Results indicate that traditional log analysis can significantly overestimate V-shale, particularly in the "T" sand, due to thin bed effects on the logs. Rock-calibrated V-shale relationships that have been developed in this phase of the study allow for more accurate determination of V-shale from logs. In addition, an alternative V-shale model for reservoir mapping is being developed, which will be completed in the next report period.

3.4.4 Quantitative Conditioning

This task is in progress.

3.4.5 Basin Modeling

This activity will be addressed during the second year.

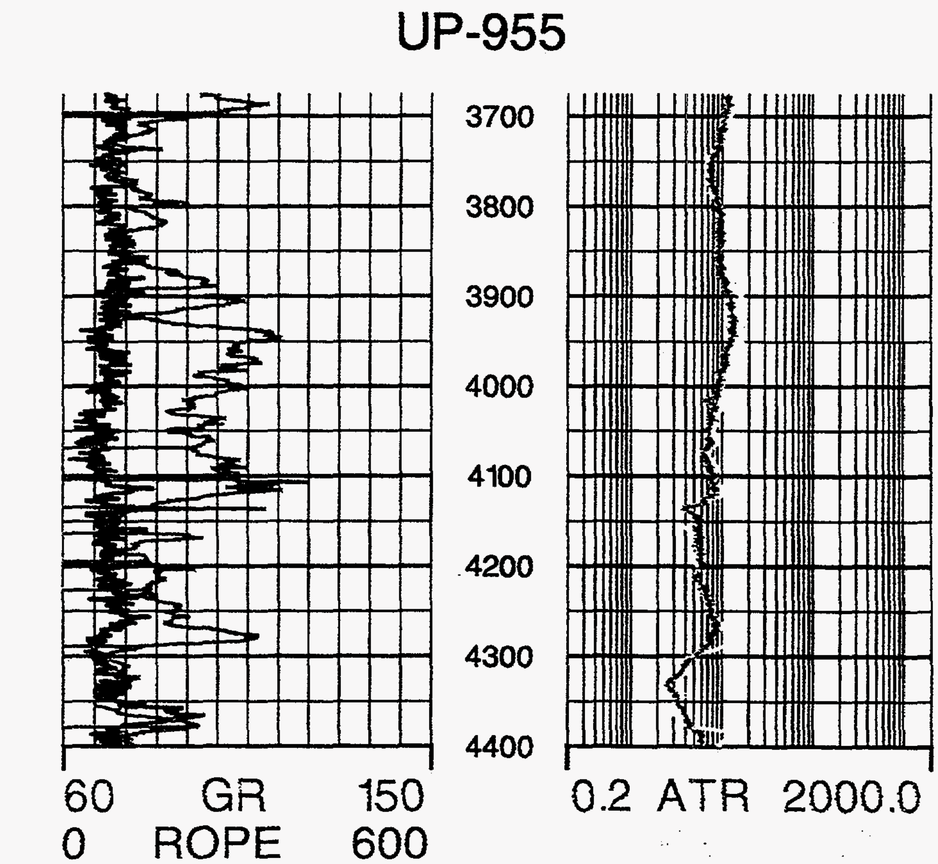

FIGURE 3.14

Logging while drilling logs from Well UP955, including Rate of Penetration (ROPE). Note separation of induction curves suggesting less than 5 feet proximity to basal shale.

3.4.6 Updating

This task will start during the next several months after other new measurement data have been interpreted for integration into the reservoir image model.

3.5 Stochastic 3-D Geologic Modeling

Stochastic geologic models provide improved understanding of the geologic controls on production and offer more realistic representation of the reservoir for simulation purposes. Flow simulation on layered reservoirs assuming constant permeability within each layer often results in poor history matching and unreliable recovery forecasts. Stochastic modeling provides an alternative approach in which various realizations of the geological framework and associated petrophysical properties are incorporated in the geologic and simulation models. These stochastic images offer multiple realizations of the geology and can help in improved history matches. From these models, small scale lateral continuity of the reservoir and the high uncertainty of interwell permeability fields can be accounted for in a stochastic manner.

The stochastic geologic model will be implemented based on data from logs, new MWD data obtained during the drilling of four new horizontal wells, log data from five new observation wells, a tracer study now scheduled for the next report period, and other sources of information regarding vertical and lateral variations in reservoir properties.

The work to create the stochastic model has just begun and will be discussed during the next reporting period.

3.6 Conclusions

Reservoir Engineering

Basic reservoir engineering methods, including volumetric and material balance calculations, cross-plots, decline analysis and bubble mapping provided baseline estimates of initial oil in place, field wide oil/water and oil/gas relative permeability ratios, and a rough conceptualization of the permeability structure of the field. Further characterization work using tracer surveys and neural network based mapping of sand body heterogeneities are underway to improve the representation of the reservoir architecture for simulation purposes.

The basic reservoir computations assisted in delineating the features required for a suitable reservoir simulation code. We recognized that to accurately represent the combined effects of water influx, compaction drive, and subsequent rebound resulting from water injection, the simulation model should be able to account for the geomechanics of the field including potential hysteresis in compressibility-pressure relationship. Furthermore, because of the uneven concentration of well locations and the need to accurately model horizontal wells, local grid refinement must be supported by the simulation code.

Performance data from individual wells were found to indicate commingled production. As such, allocating cumulative production to individual sands is not possible using zero dimensional models as commonly applied in basic reservoir engineering. The bookkeeping of individual layers production and remaining reserves will be accomplished using hybrid deterministic and stochastic reservoir models.

Geological Models

Reservoir compaction and antiquated data were found to have resulted in significant errors in the reservoir geologic model. A subsidence bowl is impressed on the structural horizons in the west Wilmington Field from differential compaction of unconsolidated sands during 64 years of hydrocarbon production. With as much as 29 ft of total subsidence, defining geological features depends on the ability to correct directional well survey data through time. Once the data are normalized, accurate geological structures can be defined with the precision necessary to geosteer horizontal wells.

The 3-D geologic model was valuable in discriminating faulty data and for providing visualization of the paleochannel, onlap sands and fault features. Cross sections extracted from the model, coupled with LWD and MWD data, were successfully used for placing the horizontal wells. Dual resistivity LWD provided sufficient real time data of approaching sand-shale boundaries (when approaching at a high angle of incidence), and confirming location of the wellbore within the intended sand subzone. The induction curves in the horizontal wells separate as the logging sensors (CDR tool) detect a lithology change due to the different depths of investigation of the sensors.

The success of the horizontal well drilling confirms the accuracy of the geological model. With as much as 15,900 stock tank barrels at risk for every foot the horizontal lateral is above the target horizon, it was imperative that the reservoir be characterized precisely.

Petrophysical Models

Four preliminary petrophysical models were created with key findings as summarized below:

Core-log model	Five petrophysical rock types were identified.
Porosity-permeability model	Three of five rock types are potential reservoir rocks. Average porosities ranged from 31% to 36%. Coherent porosity-permeability relationships were developed for the rock types.
Rock-log model	Sandstone rock types were discriminated by pore geometry. Algorithms were developed for prediction of permeability using modern log suites.
V-shale model	Traditional log analysis overestimates V-shale, particularly in the T sand.

4 RESERVOIR SIMULATION

4.1 Introduction

Three-dimensional, thermal reservoir simulation models will be created based on the deterministic and stochastic geologic models. The simulation models will be used to improve reservoir management practices, addressing such issues as optimal well spacing, well completion strategies, and mode of thermal recovery. Reservoir simulation is considered to be one of the key tools of effective reservoir management to be applied throughout the lifetime of the project. Reservoir simulation is essential for making best use of the data provided by reservoir characterization and in interpreting production data as the project proceeds.

4.2 Deterministic Reservoir Modeling

Tasks under this activity have just started. During the last year, major efforts were focused on bench mark testing of suitable hardware and commercially available software. Considerations were given to the selection of a suitable system that can handle fine grids, local grid refinement, horizontal wells, compositional changes of in-situ fluids geomechanics of compaction, and can provide accurate results based on simulation of test cases.

4.3 Stochastic 3-D Reservoir Modeling

Most of the work associated with stochastic modeling will start during the next reporting period. During this period, techniques were developed for incorporation of waterflood response data in the conditioning of stochastic images of the reservoir. [9]

5 RESERVOIR MANAGEMENT

5.1 Introduction

During this project, thermal recovery will be extended throughout the southern half of the Fault Block II-A Tar zone. The project is being managed in two phases. The first phase involves developing geologic and reservoir simulation models, and implementing three pilot tests of thermal recovery using horizontal wells to determine the most effective mode of thermal recovery. In the second phase, thermal recovery will be expanded throughout the southern half of the Fault Block II-A Tar zone, based on the results of the pilot tests and with guidance provided by the geologic and simulation models.

Chapters 3 and 4 described the geologic and simulation models. This chapter describes the reservoir management aspects of implementing Phase 1.

The three pilot tests to be implemented in the first phase are:

1. Cyclic steam stimulation through horizontal wells;

2. Steam drive through horizontal wells; and

3. Hot water alternating steam (WAS) drive.

The primary tasks to implement the pilot tests include:

1. Drilling two horizontal injectors and two horizontal producers;

2. Installing a steam transmission pipeline under a harbor channel to connect the mainland to the island location of the thermal recovery pilots;

3. Installing a steam separator on the mainland; and

4. Performing the three pilot tests.

Additional tasks related to evaluating production response include analyzing petrophysical and geochemical interactions, evaluating steamdrive mechanisms and monitoring the response of the reservoir.

5.2 Horizontal Wells and Surface Facilities

Injecting and producing steam through horizontal wells is expected to reduce production constraints associated with heterogeneity, poor sweep efficiency, and high water cut. Horizontal wells are also expected to reduce drilling capital costs, because the installation of one horizontal well is expected to result in the equivalent production response of three or more vertical wells.

5.2.1 Horizontal Wells

Four new horizontal wells (two producers: UP-955 and UP-956, and two injectors: 2AT-61 and 2AT-63) were drilled on Terminal Island to continue reservoir development of the Tar zone in Block II-A. Previously, all the steamflood wells had been drilled as straight or normal directional wells, positioned in an inverted five or seven spot pattern. This project's original development plans called for drilling a total of 12 horizontal wells to develop the remaining southern portion of the reservoir. The first four wells were proposed as long radius wells with a 800-ft horizontal lateral (see Figure 5.1). The original directional well plans were modified to maximize the horizontal section of the wells and reduce the total number of wells ultimately needed to develop the reservoir (see Figure 5.2). These medium radius wells were drilled to a total measured depth of 4380-ft to 4820-ft (approximately 2400-ft TVD) with horizontal laterals of between 1450-ft and 1700-ft in 9.5 to 10.5 days.

Multiple cross sections were developed for each well using 3-D computerized modeling (EarthVision TM) to facilitate planning the wells and monitoring drilling progress. Dual resistivity gamma ray Logging While Drilling (LWD) and Measurement While Drilling (MWD) provided real time data of approaching sand-shale boundaries and confirmed location of the wellbore within the intended sand subzone. Using geological models to plan and geosteer the horizontal wells is described in Section 3.4.1, "Three-Dimensional EarthVision™ Structure." This section describes the mechanical aspects of installing the horizontal wells.

The four horizontal wells were drilled from west to east from a restricted surface site of approximately two acres. The goal was to place the horizontal section near the base of the D1D sand. The strata dip from 8 to 12 degrees to the west. Accordingly, the wells were drilled updip (92-105°), perpendicular to strike, approximately 10-15 ft above the bottom shale, in a pattern with 400 ft between laterals.

An example of one problem encountered while drilling the Fault Block II horizontal wells occurred when the bit penetrated the D2 shale. Some of the shales in the Wilmington Field are composed of soluble clays which dissolve and release high ion concentrations that cause the low density solids to flocculate the mud. This greatly increases the viscosity of the mud. Telemetry problems were encountered when the viscous mud prevented the turbine in the power unit from spinning freely. The log and gravity tool face output was disabled. Without knowing which way the bottom hole assembly was pointing, it was difficult to direct the steerable assembly away from the shale. When the mud engineer saw an increase in low density solids or when there were telemetry problems due to drilling the D2 shale, operations slowed or ceased and the mud was conditioned before drilling resumed.

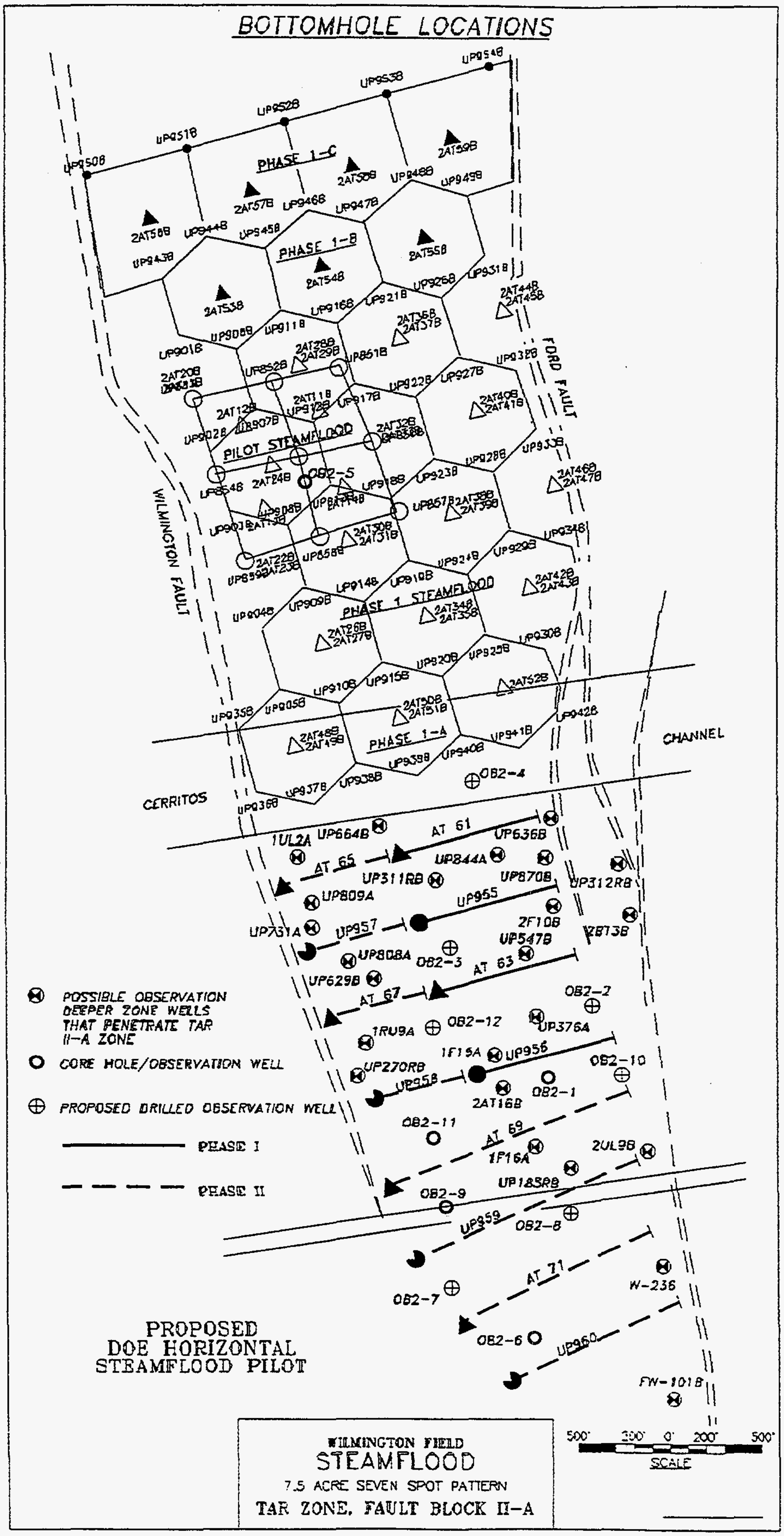
BOTTOMHOLE LOCATIONS
PHASE 1-C
PHASE 1-B
PILOT STEAMFLOOD
PHASE 1 STEAMFLOOD
PHASE 1-A
WILMINGTON FAULT
FORD FAULT
CERRITOS
CHANNEL
POSSIBLE OBSERVATION DEEPER ZONE WELLS THAT PENETRATE TAR II-A ZONE
CORE HOLE/OBSERVATION WELL
PROPOSED DRILLED OBSERVATION WELL
PHASE I
PHASE II
PROPOSED DOE HORIZONTAL STEAMFLOOD PILOT
WILMINGTON FIELD
STEAMFLOOD
7.5 ACRE SEVEN SPOT PATTERN
TAR ZONE, FAULT BLOCK II-A
SCALE

FIGURE 5.1

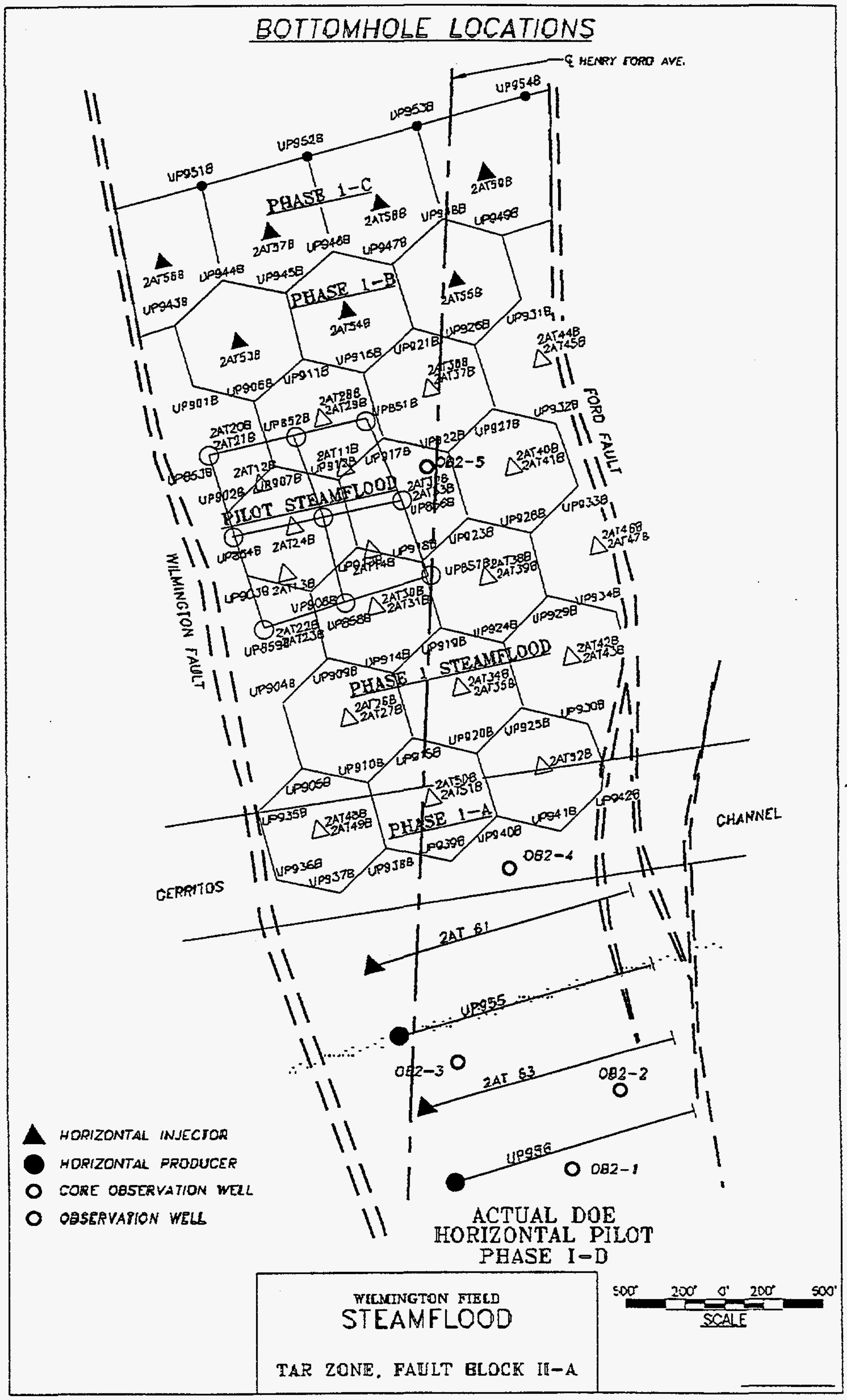
BOTTOMHOLE LOCATIONS
℄ HENRY FORD AVE.
PHASE 1-C
PHASE 1-B
PILOT STEAMFLOOD
PHASE 1 STEAMFLOOD
PHASE 1-A
FORD FAULT
WILMINGTON FAULT
CERRITOS
CHANNEL
2AT 61
UP955
2AT 63
UP956
OB2-1
OB2-2
OB2-3
OB2-4
OB2-5
HORIZONTAL INJECTOR
HORIZONTAL PRODUCER
CORE OBSERVATION WELL
OBSERVATION WELL
ACTUAL DOE
HORIZONTAL PILOT
PHASE I-D
WILMINGTON FIELD
STEAMFLOOD
TAR ZONE, FAULT BLOCK II-A
500' 200' 0' 200' 500'
SCALE

FIGURE 5.2

The following approaches were taken to mitigate the drilling problems:

1. Reducing the "rake" or fin angle of the power turbine to eliminate excessive voltages shutting off telemetry power.

2. Installing Anadrill's 7-in. extra high flow configuration to lower turbine velocity.

3. Using bits with a center jet and larger jets on the outside to eliminate wash out in the build section of the hole.

4. Using correctly sized stabilizers so that the steerable system could be rotated with predictable results.

5. Establishing optimal pressure on the bit over the off bottom circulation pressure, enabling achieving maximum instantaneous drilling rates of 600 ft per hour.

6. Monitoring low density solids and conditioning the mud if telemetry problems occurred.

Several challenging design criteria had to be met with the drilling of these wells, including

1. Isolating zones within the horizontal lateral to control the steam injection profile;

2. Being able to selectively determine the production interval; and

3. Providing a continuous conduit external to the casing for the installation of a fiber optic cable.

Casing design was based in part on recent experience by an offset operator. The operator found that good penetration and directional control was possible in a 9-7/8-in. hole and that 7-5/8-in. collared casing was large enough to accommodate the intended rod pump, yet small enough to be run in a 9- 7/8-in. hole. Based on this experience, it was determined that 7-5/8-in. casing be run to total depth and cemented to surface, instead of running 9-5/8-in. casing to the top of the completion interval and then landing a 7-in. liner as originally proposed (see Figures 5.3 and 5.4).

Zonal isolation would require a good cement job, but it was apparent that casing rotation or reciprocation would be impossible once cement reached the shoe. Instead, the quality of the cement job would rely on the cement slurry properties and casing centralization plan. The slurry was designed for zero free water and zero water loss. Normal cementing equipment and the fracture gradient of the reservoir dictated that turbulent flow could not be achieved with the cement slurry. Even though the centralizer placement program recommended only one centralizer per joint for the normally accepted standoff percentage, two tandem rise centralizers per joint were run to increase the standoff to 93%. These centralizers were selected due to their ability to withstand high lateral forces and yet minimize drag in horizontal applications. Additionally, a flotation collar was used to reduce string weight and thereby reduce drag in the horizontal section.

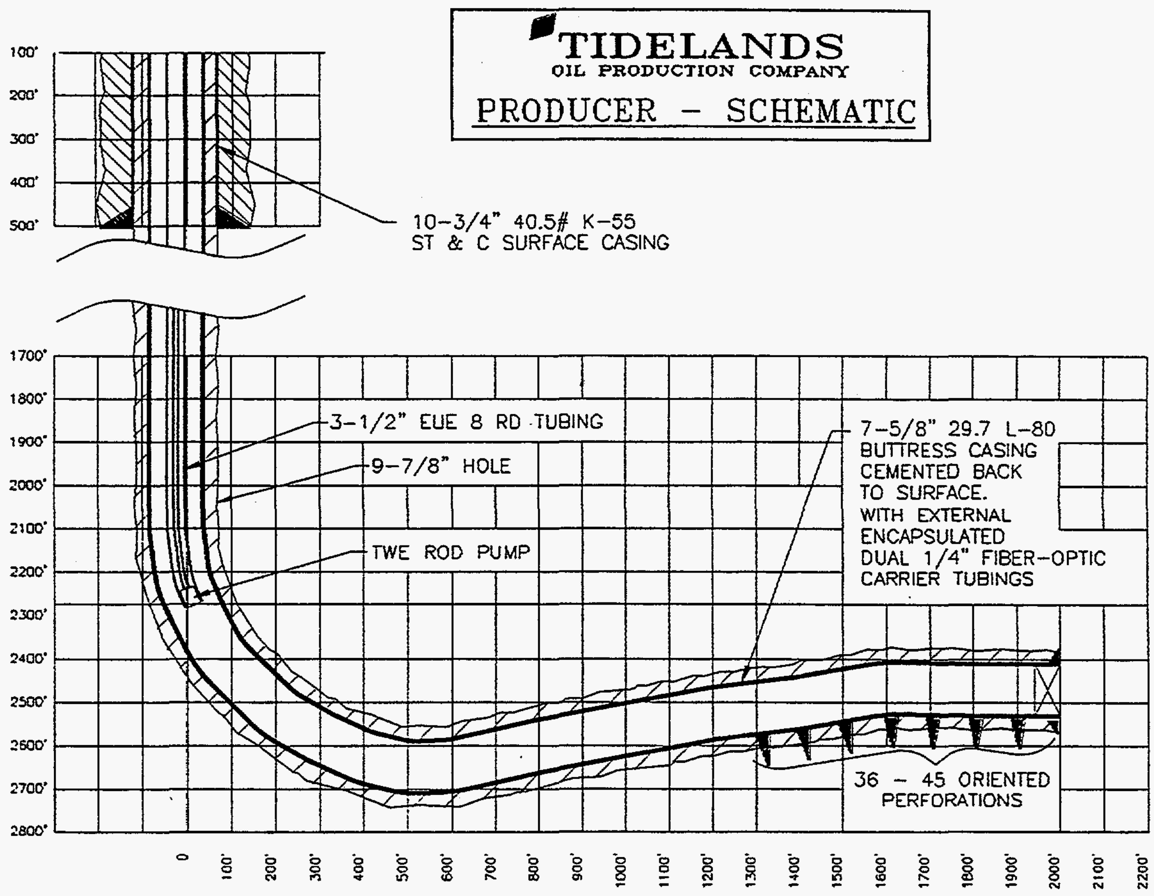

FIGURE 5.3

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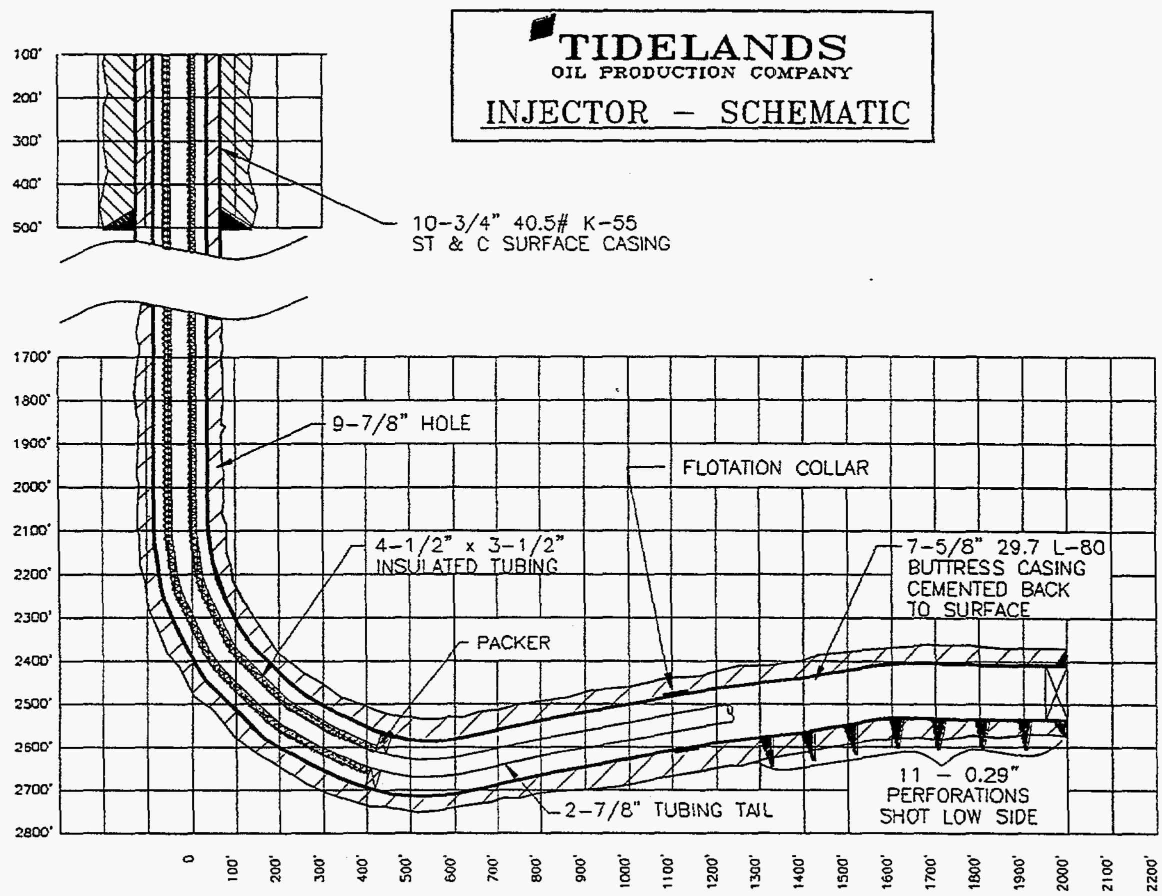

FIGURE 5.4

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This well design facilitated the installation of an external carrier tube for a fiber optic cable. The 7- 5/8-in. casing strings on the two producers were run with an externally mounted, plastic encapsulated, 0.25-in. stainless steel U-tube from the float collar to surface. The U-tube was attached using six 1- 1/2-in. wide stainless steel bands per joint. Stop collars were welded to the tandem rise centralizers and used to attach the centralizers to the casing and to eliminate longitudinal or rotational movement. Strips of steel approximately 3-in. long by 1.5-in. wide by 3/8-in. thick were welded to the casing adjacent to the U-tube every 4 to 5 joints as future aids to locating the U-tube. Modification of the wellhead equipment was required to thread the 0.25-in. tubings through the slip housing and packoff assembly. Significant rig time (2-3 days) was saved by not running an intermediate casing string. The use of two tandem rise semi-rigid centralizers per joint and a flotation collar to trap air within the lower 900 to 1300-ft of casing reduced drag and facilitated the running of all four casing strings to bottom without incident through doglegs approaching 20 $_o$/100-ft. The casings were completely cemented from total depth to surface to achieve total zonal isolation.

The successful completion of the injectors would depend on the ability to evenly inject steam over the entire completion interval, while the success of the producers would depend on maintaining sand control. Limited entry perforations were selected as the means to control the injection profile, while sand control would be accomplished by hot alkaline water/steam injection-induced consolidation.

As of March 31, 1996, the two injectors have been selectively perforated and completed for steam injection. The wells were tubing conveyed, perforated low-side with eleven (11) 0.29-in. diameter perforations over a 330-ft to 465-ft interval at the end of the lateral. Depth control and perforation orientation were achieved independently using pump down gamma ray and gyro logging tools. The initial steam injection rates were considered low at 300-400 cold water equivalent barrels per day (CWEBPD) with 1250 psi tubing pressure. After approximately one month of low injectivity, well 2AT-061 was shut-in and allowed to cool before water was injected at high rates (15 barrels per minute) in an attempt to open perforations and increase injectivity. Subsequent injection rates rapidly increased from 600 to 1500 CWEBPD over a three week period. Well 2AT-063 showed similar but not as dramatic results.

The producers had not been completed as of March 31, 1996. A Cement Bond Log and Ultrasonic Imaging Tool are scheduled to be run in the two producers to locate the position of the exterior fiber optic tubing and, at the same time, verify the cement quality.

5.2.1 Under Channel Steam Transmission Line

The steam source for the new injectors drilled on Terminal Island comes from the existing (70%- 80% steam quality, 1600 psig, 600°F) steam transmission line located on the mainland. To get the steam to the new wells, a 2100-ft steam line was installed underneath a ship channel, providing sufficient depth clearance at each shoreline to allow the Port of Los Angeles to develop ship berths with deep pilings. The crossing has been in service since December 1995, with no problems to date.

Some of the unusual design elements which had to be addressed in installing the underwater steam line include:

1. Designing for an exit point surface location below sea level;
2. Planning directional drilling to miss existing and abandoned vertical wellbores;
3. Designing a cementing program for 30-in. outer casing inside a 42-in. annulus;
4. Designing for eight ft of thermal expansion, both in the crossing and at the end connections;
5. Designing the 14-in. steam line to be removable;
6. Preventing groundwater and moisture from entering the annular area between the 14-in. steam line and the 24-in. inner casing;
7. Designing the 30-in. outer casing for temperatures up to 300°F;
8. Electrically isolating the steam line from the inner and outer casings to facilitate cathodic protection;
9. Thermally insulating the steam line to minimize heat loss and casing temperature; and
10. Designing a support mechanism to allow longitudinal movement (thermal expansion) within the casing while protecting the insulation on the 14-in. steam line.

Installing the steam line was one of the most significant accomplishments of this report period, both in terms of level of effort and cost. The design and construction of the steam line is described in detail below.

Engineering Approach

The casing for the steam line would be installed by conventional directional drilling for pipeline installation drilling to a maximum depth of 150 feet below sea level. The crossing would consist of long arcs on each side (3,000-ft radius) and a straight section in the center of the crossing. There would be no bends in the casing from one side to the other, other than these long deflections. In heating up from 60° F to 600° F, the steam line would freely expand longitudinally 8-ft in its 2100-ft crossing length. Because it is not possible to fully restrain the line during heat-up without exceeding the allowable stress limits, the steam line would be installed within a welded steel casing and be free to grow as the temperature increased.

Initial analysis considered a single 30-in. diameter casing. The design evolved to include a 24- in. diameter inner casing and 30-in. outer casing.

Steam Hydraulics

A simulation of the two phase steam flow was performed to assess slugging and liquid holdup in the channel crossing. A maximum future flow rate of 465,000 lb/hr was considered, equivalent to the full output from the cogeneration plant. Flow rates of approximately 10%, 20%, 65%, and 100% of maximum were considered with respect to slugging and liquid holdup.

The anticipated flow rate to the first two wells to be drilled on Terminal Island is 50,000 lb/hr, equivalent to 3,000 barrels per day (BPD) of water. At this rate, the flow in the downward sloping pipe is stratified, with the liquid flowing down the bottom of the pipe. At higher rates, flow in this downward section is a combination of annular and slug flow, or slug annular transitional flow. Liquid holdup is lower at the lower flow rates in the downward sloping section, and varies from approximately 2% up to 9%.

As would be expected, the liquid holdup is higher at the lower flow rates in the upward sloping section. At 50,000 and 100,000 lb/hr, the flow is intermittent slugging, with liquid holdup 28% and 15%, respectively. The slugging at these rates is not expected to cause any problem, however, because the slug volumes will be relatively small and the velocity is quite low (4-9 ft/sec). Even at 300,000 lb/hr, the flow is still intermittent slugging, with the velocity of the gas phase up to 28 ft per second. The increased velocity is offset by a reduction in the liquid holdup to 9%, which reduces the potential size of the slugs. At the maximum future rate of 465,000 lb/hr, the flow in the upward sloping section is slug annular transitional flow, and slug sizes are expected to be relatively small.

A steam separator may be required downstream of the crossing to handle higher flow rates in the future. For the current 50,000 lb/hr operation, the slugs flatten out in a horizontal run of 14-in. pipe at the surface, and a reduced size outlet on the bottom combines the steam and condensate fairly uniformly prior to flowing to the injection wells.

Anchoring

The crossing had to be anchored for seismic forces and for friction due to thermal expansion. Because all friction due to thermal expansion occurs between the 14-in. steam line and the 30-in. outer casing, it was logical to anchor the steam line to the casing. The soil provides a natural anchor for the cemented outer casing for seismic forces, so no additional anchors were required for the system.

In many steam piping systems, the piping is anchored at the middle of a run in order to balance the friction loads during thermal expansion and to split the growth in two directions. For this system, the steam line was anchored to the casing at one end, and all the expansion taken at the other end. The downstream, or Terminal Island, side of the crossing was anchored, eliminating the need for an expansion loop at the end, where slugging of condensate from the crossing would have the greatest effect. Because the corrosion protection method (discussed later) dictated that the steam line be electrically isolated from the casing, standard high temperature insulating flange materials were used to bolt the steam line to the casing. An oversized 14-in. anchor flange was fabricated, machined to match the 24-in. flange on the casing, and welded into the steam line.

Expansion Loop

An expansion loop was installed at the upstream, or mainland, side of the crossing, sufficient to accommodate 8 ft of longitudinal expansion upon startup. The use of ball joints was considered, but rejected because: (1) it would require a larger size ball joint than any that were known to operate at this temperature and pressure; (2) the ball joints would require maintenance; and (3) the system could be economically designed using welded steel pipe without the ball joints.

A tight loop was designed which would minimize the movement due to slugs. The hair pin shaped loop was sloped to match the angle of the drilled crossing, and supports were likewise sloped such that the growth was all absorbed in the same plane. A single guide was provided outside the end of the cased crossing to act as a guide and hold-down. Six diameter bends (7-ft radius) were used in the loop to minimize stress, soften the effects of slugging, and increase the stiffness of the loop.

Thermal Shock

When steam is first introduced into the line, a significant amount of water will condense as the line heats up and accumulate in the crossing. The minimum steam pressure to push out the water is 60 PSIG, which corresponds to a steam temperature of 310 °F. The insulation system therefore had to be capable of absorbing a thermal shock of at least 250 °F without damage. The steam pipe material is not damaged by thermal shock at these temperatures, but some types of insulation are affected and the steam line may tend to bow if the top section is significantly hotter than the bottom. Slow, controlled heat-up is therefore preferred to minimize the effects on insulation and the increased friction that bowing could produce. The steam line support system had to consider the potential bowing by preventing the pipe insulation from contacting the top of the casing and providing additional load capacity at each support.

Heat Transfer and Insulation

The base case assumption required that the 30-in. casing be kept at a reasonably low temperature in order to use proven external coatings to prevent corrosion. Coatings with temperature ratings up to 240°F were reviewed and some alternatives for up to 300° F were suggested. From the beginning, it was assumed that the 14 in. steam line would be insulated with 3 to 3- ½-in. of thermal insulation, and installed within a welded 30 in. steel casing. The 24-in. steel inner casing was added to the design later. The integrity of the insulation system would have to be assured under all conditions, and pipe supports would have to be clamped to the steam line over high density insulation (calcium silicate) in order to minimize overall and localized heat transfer to the casing.

The insulated supports required some method of minimizing friction between the support shoes and the inside of the 30-in. casing. Standard support shoe pads, like polyethylene lining, could not withstand the high temperature. Graphite could not withstand shock during installation and could accelerate corrosion, and other materials required the casing to be internally coated to provide a slide surface.

Casing heat loss to the surrounding soil was analyzed to determine its affect on casing temperature. Virtually all of the crossing is below the water table. Although the soil will be saturated with water, it is still a relatively good insulator due to its thickness (depth of casing).

The pipeline was to be installed to a depth of approximately 135 ft. Although it would not be this depth for its entire length (shallower near the ends, and not as deep in the middle relative to the bottom of the 50-ft deep channel), the average thickness of cover is approximately 65 ft deep. Even with this thickness of soil, 3 inches of thermal insulation on the steam line, and insulated pipe supports, the casing temperature would vary between 240°-350°F which is too high for coatings.

Other insulation systems were considered which might reduce heat loss through the insulation and keep the casing cooler. Reflective surfaces outside of the insulation and inside of the casing would help, and a vacuum in the space would probably work, but these all seemed impractical and more subject to failure.

Air cooling systems were considered to supplement the insulation systems. Cooling methods considered included blowing air through the casing or using a refrigerant in a cooling tube which would vaporize underground and be condensed in a fan cooler above ground, with gravity providing cross flow. All of the options required maintenance and were subject to failure.

The base case assumption was re-evaluated and it was concluded that all of the steps listed above were not necessary to protect the coating of the outer casing. The maintenance of any type of cooling system would be expensive, and any malfunction or hot spot in the insulation could cause failure of the casing coating. It was decided that the casing be installed bare and protected adequately with impressed current cathodic protection. This solved many problems and reduced project costs, including:

1. Elimination of cost to coat the outer casing.

2. Elimination of expensive and more fragile insulated supports, in favor of stronger clamps capable of accommodating higher loads;

3. Elimination of cooling system for the outer casing.

4. Reduction of heat loss from the steam line under the crossing (compared to cooling the casing).

The primary disadvantage is that the casing may be more susceptible to corrosion than it would be with a good coating system and cathodic protection. However, any coating which is overheated and disbonded from the casing may shield the pipe and impede cathodic protection. An uncoated casing requires more cathodic protection at a higher capital and expense cost, but is more desirable than having disbonded coating.

Casing Integrity

The effects of thermal expansion were reviewed for assurance that the casing would not buckle in a manner which is detrimental to the life of the crossing. Depending on the assumed thermal conductivity of the soil, the amount of insulation that is installed on the steam pipe, and the depth of the casing, the temperature of the casing may vary from 240° F up to 400° F (with the use of uninsulated pipe supports).

The 30-in. casing was to be installed through a drilled and reamed opening approximately 42 in. in diameter. The annular space between the casing and the opening would be full of drilling mud and the casing could potentially be on the top, bottom, or somewhere in the middle of the opening, depending on the buoyancy of the casing string in the mud and other forces and factors involved in the pulling process.

It was anticipated that over time the soil around the opening would settle to exert external pressure and more friction on the casing, and that the casing would develop virtual anchors at some distance from the ends. A virtual anchor is the point at which the sum of the friction forces along the casing, beginning at a free end, total the force generated by the temperature increase of a fully restrained casing. At this point, there will be no longitudinal movement of the casing due to thermal expansion. The soil is less compacted near the ends than it is in the deeper, middle section of the crossing. Under the worst case scenario, it might be possible for the casing to be anchored about 300-500 ft from the ends and not be restrained laterally within the 42-in. opening in between those anchors (for some unknown period of operation). It is this case that was considered for the buckling analysis.

The analysis of alternative buckling modes with this pipeline anchored 300-ft from each end provided the following results:

1. Unless restrained laterally within the 42-in. opening, the casing would buckle at elevated temperature in an unacceptable manner (the casing will be non-linear and may fail).

2. If the casing is supported laterally with sufficient force, the casing will yield, but will do so somewhat uniformly and concentrically, such that the integrity of the casing and steam pipe will not be compromised.

The analysis confirms the intuitive assessment that the casing had to be cemented into the opening, or otherwise reliably restrained laterally, prior to heating up the steam line. With lateral restraint provided by the cement, thermal expansion of the casing and associated deformation would be controlled in a manner which is acceptable.

In order to cement the casing, drilling mud had to be displaced with cement, while maintaining the pumping pressure below casing collapse levels. Although the best method for displacing the mud was uncertain, the following approach was adopted. Surplus 3-in. steel tubing was to be installed along the outside of the casing, with perforations at the middle of the string. After completion of the pulling of the casing, cement was injected into the two ends of the tubing to displace drilling mud from the center of the crossing to the two ends.

Corrosion

A cathodic protection system was designed to protect the bare casing from corrosion. The system consists of two deep well anode beds, one on each side of the crossing, and impressed current from a rectifier.

The cementing of the 30-in. outer casing into the surrounding soil presented a potential corrosion problem. Sections of the casing would still be in contact with mud or soil, and the concern was that local corrosion cells might accelerate corrosion of the casing which was not covered with cement. Alternatives to cementing were reviewed, such as adding a substance to cause the drilling mud to set up, but were not deemed to be practical. A second 24-in. inner casing was included to allow for the possible shortened life of the outer casing and to facilitate installation of the steam line.

Cathodic protection of the 30-in. casing dictated that the above ground steam piping be electrically isolated from the casing. The above ground steam line is electrically bonded to virtually all of the wells throughout the production field, and it would be impractical to protect it all. The use of insulating flanges in the steam line on both sides of the crossing was undesirable, so the steam line was isolated from the casing for its entire length. Custom refractory sheet material (¼-in. thick) which is typically used in fired heaters and boilers was manufactured and installed between the steam line and the clamp-on support shoes. The aluminum jacketing over the steam line insulation was kept isolated from the steam line at the ends of the crossing. Internal corrosion of the casing and steam appurtenances is expected to be minimal, as the ends of the line will be installed to keep water out of the casing, and one end is tightly sealed so there will be minimal circulation of air.

Inner Casing

Although cathodic protection will extend the life of the 30-in. casing, the casing could still develop localized corrosion at some time in the future, which would allow water to enter the casing. The presence of a 24-in. inner casing provides assurance that the steam line insulation will not be damaged by water which could contact it through an outer casing leak. The effect of such a leak is unpredictable, and the inner casing provides contingency protection for this possibility. The 24 in. inner casing will allow the steam line to continue in operation for some period if a leak is noted, while the situation is analyzed and alternatives are developed. Water that leaks through the outer casing will vaporize and move to the open end of the casing, where it will condense in the steel shroud around the end. Water will drip out, indicating the leakage. The inner casing provides a secondary barrier to assure the integrity of the steam line and insulation system.

The inner casing also facilitated the installation of the steam line. There was some risk that the insulated steam line would get stuck during the pipe pull. To circumvent this, the 24-in. casing was pulled into the 30-in. casing with the insulated pipe inside it, protecting the insulation and providing more alternatives if it had become stuck.

The inner casing can expand, differentially relative to the steam line and outer casing, and is welded to the 30-in. outer casing near the steam line anchor.

Support System

Supports between the 14-in. steam line and the 24-in. inner casing were designed to clamp onto the steam line over a ¼-in. thick material which provides electrical isolation between the support and the pipe. The ¼-in. thick refractory sheet was provided in two halves and held in place by the support. Disc springs were provided at each bolt to help accommodate any differential thermal expansion between the steam line and the support clamp.

Steel runners were provided around the supports so orientation of the steam line within the casing was not critical and guiding was provided horizontally and vertically. The clearance between the support runners and the inner casing is approximately one inch.

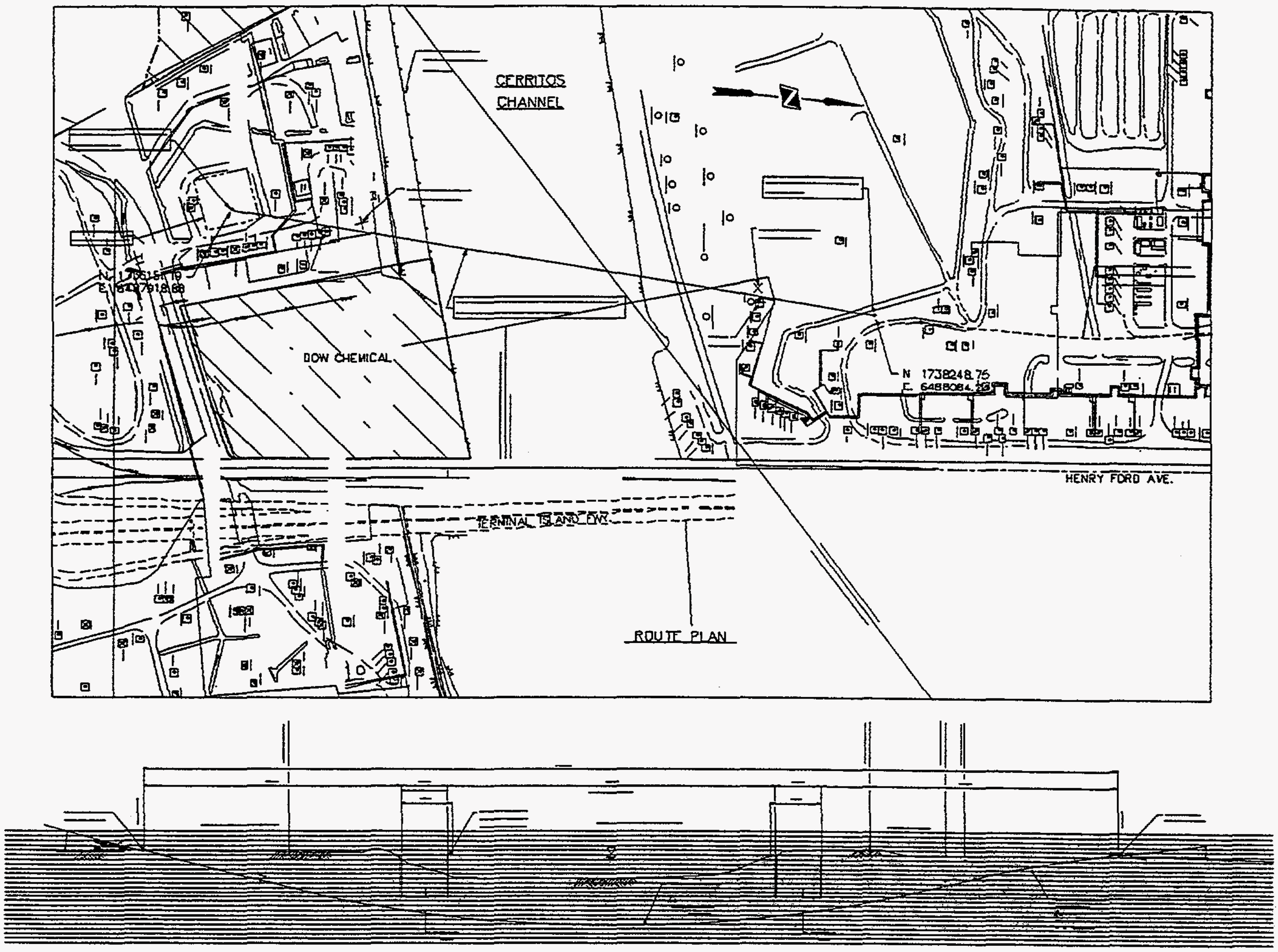
Construction

Geotechnical Investigation

Geotechnical tests were performed to evaluate soil conditions. The tests consisted of boring four holes, two on each side of the channel, to a depth of 181-ft, 30-ft deeper then the maximum expected channel crossing depth. This would give the drilling contractors a reasonable indication of the risks involved with making the drill. An additional geotechnical test was done on the actual drill site to give the drilling contractors the soils conditions under their rig (see Figure 5.5).

Pipeline and Well Clearances

Pipelines, surface equipment, and both existing and abandoned oil wells were identified on drawings and verified in the field. An 80-ft wide pipeline corridor was needed by the drilling contractor to minimize interference to their steering system and allow enough spacing for a planned future crossing. This requirement was met by moving the crossing location westerly and angling it slightly, as illustrated in Figure 5.5.



PROFILE FOR DIRECTIONAL DRILLING OF CROSSINGS

FIGURE 5.5

Building Exit Pad

The drill's initial exit location on the mainland was below sea level and 8 ft below the entrance elevation on Terminal Island. The exit point was built up to equal the entrance's elevation. Elevating the exit point helped in two ways. First it improved the ability to circulate mud to both entrance and exit locations during the drilling operations. Second, a water zone connected to the ocean was located near the bottom of the borehole. Drilling through the water zone with the exit hole below sea level could have created surfacing problems.

Layout Area for Steam Line and Casing Prior to Pipe Pull

Prior to pulling the pipe and casing into the channel crossing, a 2100-ft long layout area was established on the mainland. The area had to be located on the exit end of the drilling rig. The right-of-way was cleared, lease roads were closed and temporary access roads were used.

Fabrication of 14-in. Steam Line

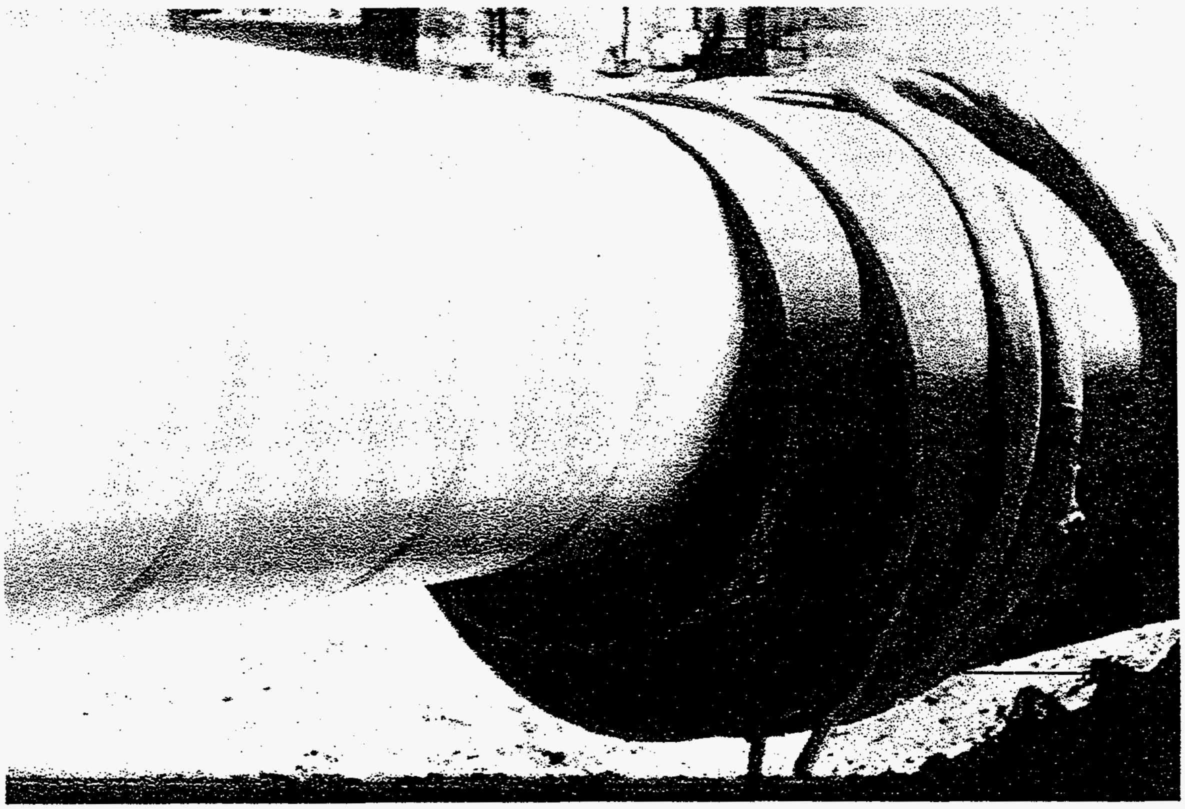
With the layout area established, the 14-in. (0.937-in. wall thickness) steam line was strung out on skids and welded together. Rig welders using 6010 5 P plus rod welded the pipe together. Each weld required about 16 passes with the 3/16-in. rod, taking two welders working together an average of two hours. After the welding process, the welds were X-rayed to ASME B31.3 piping code, stress relieved, and then the entire line successfully held a 4000 psig hydrostatic test.

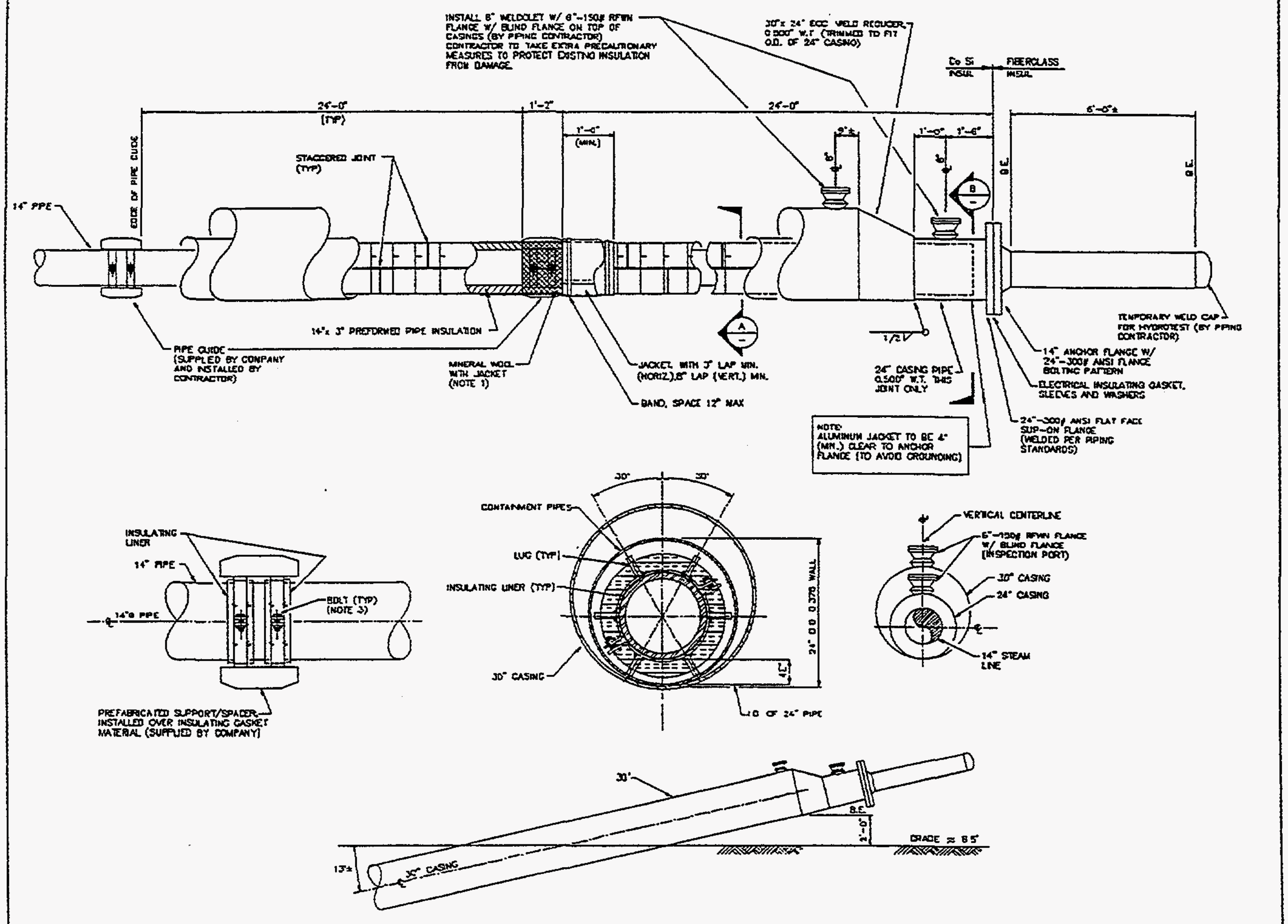
The completed steam line was lifted from the pipe skids and placed on rollers. Pipe spacers, with refractory sheets used to electrically isolate the steam line from the pipe spacers, were bolted on every 25 ft. Three-in. of calcium silicate insulation was tied to the steam line and loose mineral wool was placed around the pipe spacers. An aluminum jacket was banded over the insulation for protection, as illustrated in Figures 5.6 and 5.7.

Fabrication of 24 and 30-in. Casing Pipe

At this point the drilling contractor made a decision to pull the 30-in. casing separately, and then on a second pull to get the 24-in. casing with the 14-in. steam line inside. This would require sliding the 24-in. casing over the completed steam line in the limited area allowed for pipe layout. To accomplish this the 24-in. casing was welded into 120-ft joints. With the steam line sitting on rollers, the first joint of casing pipe was slid over the insulated steam line, then another 120 ft joint was welded on the end and slid further on to the steam line. This was done until a 720-ft casing section was welded together, this section was then slid to the front of the 2100 ft steam line. Then a second and third casing section was fabricated similar to the first. With the three sections in place, two welds were needed to join all three sections together. To do this, the last two welds were made with the insulated steam line inside, exposing the aluminum jacketing to the hot weld splatter. To protect the aluminum jacket, a heat resistant sheet was wrapped around the insulated pipe., The two welds were made and then the 24-in. casing was pneumatically tested to 100 psig with the 14-in. steam line inside.

Figure 5.6
Photograph of Steam Line with Aluminum Jacket over Insulation





Pipe, Casing and Anchor Details

FIGURE 5.7

The 30-in. casing was strung out on skids, welded together along side of the 14-in. steam line and pneumatically tested to 100 psig. After installing the steam line inside the 24-in. casing, the bundle was remove from the rollers. The rollers were repositioned and the 30-in. casing was set on the rollers. The 30-in. casing was now in position for the drilling rig to pull it into the channel crossing.

Directional Drilling

Pilot Hole

The first stage of directional drilling was to successfully complete the pilot hole. The pilot hole was drilled with a 5-in. drill string and spud jet. A tensor wire line steering tool with Tru Tracker was used to locate direction and depth of the drill. The pilot hole took five days to drill, with one crew working a 12 hour shift. Occasionally during drilling, it was necessary to pull the drill bit back and redirect the drilling. The pilot hole came out within 5-ft of the planned exit point, which was within design limits. The exit angle was at 7 degrees, 1 degree higher than the contractor desired. The exit angle of the bore is critical because the higher the angle the larger the lifting equipment needed to guide the casing pipe into the hole. The contractor reviewed their equipment capabilities and agreed to work with the 7 degree angle (see Figure 5.8, Stage 1).

Reaming

Reaming was the second stage of directional drilling. A second crew was added, so the drill rig could operate 24 hours per day. With the drill string (wash over pipe) left in the pilot hole, the spud jet and steering tool were removed. A 36-in. fly reamer was attached to the wash over pipe on the exit side. Drilling mud was pumped from the exit side of the hole though the wash over pipe back to the fly reamer. The fly reamer was then rotated and pulled back toward the drilling rig. As the fly reamer was pulled back, wash over pipe was added to the fly reamer on the exit side. Once the 36-in. fly reamer was pulled completely through the hole, the reaming operation was repeated with a 42-in. fly reamer. In general, the hole was reamed at least 12-in. larger then the diameter of the pipe to be pulled through it in order to reduce the risk of getting the pipe stuck (see Figure 5.8, Stage 2).

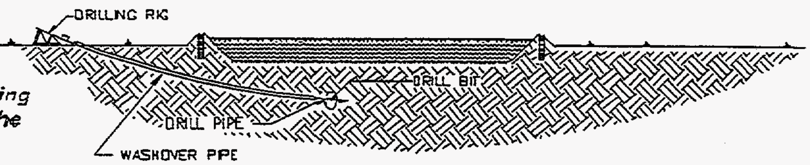
30-in. Casing Pull Back

The wash over pipe remained in the hole after the reaming was completed. A barrel reamer and swivel joint were attached to a pulling head which was welded to the 30-in. casing. Mud was circulated through the rotating barrel reamer. Cranes and side booms lifted the casing pipe with sling rollers to help guide it into the hole. Pulling the 30-in. casing through the channel crossing took about 18 hours. With half of the casing through, pulling tensions were increasing. The pulling operation was stopped, so water could be pumped inside the casing to equalize the buoyancy. Because of buoyancy the pipe will cut into the top of the bored hole, making it very difficult to pull. The water reduced the pulling tension and the pull back operation continued until the casing was

STEAMLINE CHANNEL CROSSING

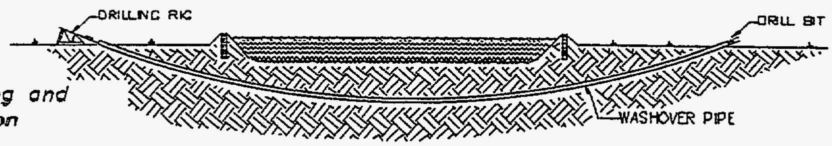
Stage 1 – Pilot Hole

Pilot hole drilled by advancing the drill string and overdrilling with the washover pipe.
Length= 2100 ft.
Depth= 155 ft.



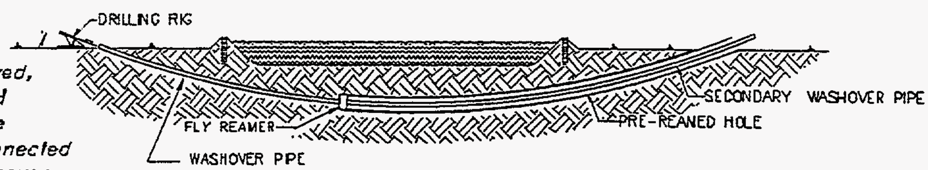
Pilot Hole

Pilot hole completed when both drill string and washover pipe exit on opposite bank



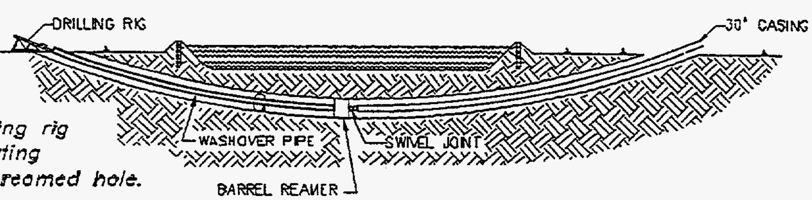
Stage 2 – Reaming

Drill pipe was removed, fly reamer connected to the washover pipe which in turn is connected to a secondary washover pipe. The hole was reamed to 36" on the first pass and then to 48" on the second pass.



Stage 3 – Casing Pipe Pull Back

The barrel reamer was positioned, pulled back and rotated by the drilling rig positioning the non-rotating 30" casing into the pre-reamed hole.



Stage 4 – Steamline Pipe Pull Back

With 30" casing in place. Washover pipe repositioned in 30" casing to pull 24" casing and 14" steamline together.

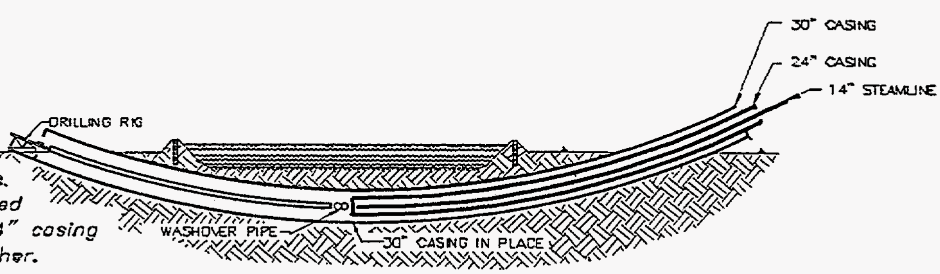


FIGURE 5.8

pulled into place. The water placed in the casing was pigged out prior to pulling the 24-in. casing (see Figure 5.8, Stage 3).

Grouting the 30-in. Casing

A 3-1/2-in. grout line was pulled with the 30-in. casing. The grout line was on the outside of the 30-in. casing. A single 30-ft joint was slotted in the middle of the string. This design allowed grout to be pumped down the grout line to enter at the bottom of the drill. The grout started to displace the mud in the annulus between the casing and the 42-in. drilled hole and eventually worked its way up the outside of the casing to the surface.

Although grouting was to start immediately, there were several delays. First, the barrel reamer and swivel joint were removed. The drilling rig had shifted while pulling the 30-in. casing. Consequently, the rig was unable to pull the casing out of the ground. The area had to be excavated, the pulling head cut off and an additional 30-ft of casing was welded on. The drilling crew then connected to the grout line with their mud circulating equipment and started pumping mud. Because of the excavation, the hole was compacted and the contractor was unable to regain circulation on the entrance side. Additional excavation and movement of the grout line was attempted but circulation could not be achieved. The grouting procedure was finally attempted 36 hours after the 30-in. casing was pulled into place.

This procedure displaced, approximately one-fourth of the theoretical volume of mud in the crossing, less than the volume of mud desired. Approximately half of the theoretical mud volume was displaced on the upstream exit hole before the cement surfaced and only an eighth of the theoretical mud volume was displaced on the downstream exit hole before the cement surfaced. Heavy equipment working over the downstream exit hole probably collapsed the hole around the casing, causing the cement to flow toward the upstream exit hole. The cementing job was considered successful for only half of the crossing.

24-in. Casing With Steam Line Pull Back

With the grouting completed, the drilling rig ran a pulling string back into the 30-in. casing. The pulling string was attached to a pulling head welded onto the 24-in. casing. The drilling rig then pulled the 24-in. casing, with the 14-in. steam line inside, into the 30-in. casing. This procedure took about 8 hours to complete. The channel crossing was now finished. The crossing was successfully put into service in December 1995 and remains in service to this date (see Figure 5.8, Stage 4).

Application to other Pipeline Installations

Design features of the steam pipeline have a number of benefits which could be useful in other pipeline installations. Some of the benefits of this type of installation include:

1. It accommodates a long, linear (or near linear) installation of a hot pipeline, where the differential temperature is so high that the pipeline would be over-stressed if not allowed to

grow longitudinally.

2. It provides anchoring to one end of a continuous steel casing, eliminating the need for any other anchors, and accommodating very high loads.

3. It works with a conventional directionally drilled crossing or with a long buried installation where intermediate expansion loops are not practical.

4. For lower temperature applications, better insulating material can reduce heat transfer and casing temperature, such that the casing can be externally coated.

5. The length of the installation can be very long, limited by construction issues and the cumulative friction between the steam line and casing (i.e., 5000 ft may not be unreasonable for smaller lines).

6. The double casing offers secondary protection and assurance that any problems with the outer casing do not threaten the valuable inner casing, steam line, and insulation system.

Other conclusions that may be useful when considering related projects are summarized below:

1. The ground surrounding a buried high pressure steam line can be hot for a considerable distance from the line. This could affect any other facilities being planned for the area. For example, power lines in a buried conduit parallel to the pipeline could become too hot, as the ground might serve as a heater, rather than a heat sink, for the conductors.

2. Piping which is subject to large differential temperature often requires installation of expansion loops. Such piping installed in a casing can reduce the number of expansion loops required, which is particularly advantageous when the piping must be below ground.

3. Directional drilling for steam lines is feasible when condensate in the low point is acceptable or can be overcome by installation of a low point drain line outside, or inside, of the carrier pipe.

Some of the benefits of this type of crossing have already been applied to two other drilled crossings installed by Tidelands. A 2200-ft insulated oil production gathering line (designed for 325° F) was installed as part of a bundle with four other lines, in a directionally drilled crossing. The hot oil pipe was factory insulated and covered with a hard polypropylene jacket, and slid inside an externally coated casing during field fabrication. The line was anchored to one end of the casing. The jacket slid easily in the casing, and the low friction would allow this system to be used for much longer crossings.

5.3 Horizontal Well Cyclic Steam Stimulation Pilot

A four horizontal well pilot was implemented to evaluate the performance of thermal recovery using cyclic steam stimulation. Each well will be stimulated twice with approximately 100,000 barrels of cold water equivalent (CWE) 80 % quality steam per cycle.

Steam injection was initiated into the two horizontal injectors 2AT-061 and 2AT-063 in mid-December 1995, at low rates of 300 CWE B/D each. The injection rates were increased to 1400 - 1500 CWE B/D after mechanically breaking down the perforations in both wells with high pressure water. The plan is to perform 100,000 CWE bbl. of steam injection cycles on each well to consolidate the formation sands around the limited entry perforated completions and to stimulate initial oil production. Cyclic steam injection into the two horizontal producers UP-955 and UP-956 will begin when 2AT-061 and 2AT-063 are converted to production wells in July 1996. Wells 2AT-061 and 2AT-063 will be converted to permanent steam drive injectors either after the post cycle production becomes uneconomic or after four months. The original proposal called for two cycles per well. Based on the poor production performance from cyclic steam injection from the Fault Block I horizontal steam wells, the plan may be changed to cycle the injectors once before converting to permanent steam drive injection. This change in plan will be implemented if the cumulative oil production response to cyclic steam stimulation is below 15,000 barrels. The producers will be cycled as necessary to induce steam response from the steam injectors.

5.4 Horizontal Well Steam Drive Pilot

The steam drive pilot will convert two of the four horizontal wells used in the cyclic steam stimulation pilot into permanent steam injectors. The pilot will be evaluated using conventional steam drive criteria. Each injector will inject about 1500 CWE B/D of 80 % quality steam. The horizontal well steam drive pilot will commence after the cyclic steam pilot is completed. The horizontal steam drive wells will be operated based on a pseudo steam assisted gravity drainage (SAGD) technique. The SAGD technique was designed by Butler [1,2] and has been tested extensively in the heavy oil fields in Canada. The pseudo SAGD technique to be employed involves completing the last 600 ft of the horizontal wells in the updip section of the reservoir.

The horizontal lateral sections of the wells ranged between 1500 ft to 1900 ft and were drilled updip perpendicular to the structural strike of the formation at a 2-15° angle above horizontal, approximately 10-15 ft above the bottom shale, in a parallel pattern with 400 ft between laterals. The concept is to concentrate the steam updip to take advantage of steam gravity override of the steam in order to promote earlier development of a steam chest and allow the oil and steam condensate to gravity drain downdip to the producer. As the steam chest grows to envelop the producer's completion interval, updip perforations that are producing the steam chest will be plugged off and more perforations will be opened downdip. The pseudo SAGD technique is preferred over a conventional SAGD technique because the Tar zone has more mobile oil (14° API gravity) than the bitumen in Canada and has very mobile free water located primarily downdip and along the bottom of the sands caused by prior waterflooding. Applying the concepts to this process entailed extending the horizontal laterals of the wells from the planned 800 ft to 1500-1900-ft This effectively eliminated the need for up to three horizontal wells originally proposed to the west of the subject wells (see Figure 5.2).

5.5 Hot Water Alternating Steam (WAS) Drive Pilot

A WAS drive pilot was implemented in the existing Tar II-A thermal recovery area as part of an effort to determine how to maximize oil recovery per unit energy input for the expansion of thermal operations throughout Fault Block II-A in the second phase of the project. In particular, the methodology for alternating hot water and steam injection will be pilot tested as a means of healing steam breakthrough, promoting better sweep efficiency, and increasing efficient use of available heat (see Figure 5.9).

Four vertical steam injection wells in the existing steam drive area were converted to hot water injection in March 1995. Injection rates per well ranged from 400-900 B/D of 300°F-400°F hot water. The hot water injection was suspended in April 1996 when the landowner required that the steam separator and hot water injection lines be moved. No production response has been observed to date. Tidelands will be installing a new and larger capacity vertical steam separator in October 1996 which will provide a higher volume hot water injection for the pilot. Hot water injection will resume at that time.

5.6 Petrophysical and Geochemical Rock/Fluid Interactions

Petrophysical and geochemical analyses of the interaction between reservoir rock, reservoir fluids, and steam will be performed to investigate the effects of thermal recovery on silica dissolution and precipitation, permeability degradation, and scale plugging. This work will allow for the development of detailed geochemical models to predict reservoir reactions in the presence of steam. These models will be used to design means of mitigating potential reservoir operating constraints.

Three families of wellbore scale occurring in steamflood producers have been identified. Carbonate scale is the most abundant and is soluble in acid Sulfate scale is next abundant and is not soluble in acid, but can be removed with a wire brush. Silicate scale is not soluble in acid, is hard and well consolidated. Carbonate scales are characterized by significant substitution of Mg for Ca in the crystal lattice of calcite. Ca-rich calcite is precipitated at higher temperatures than Mg-rich calcite. Carbonate scale is precipitated at higher temperatures than sulfate and silicate scale. Carbonate and sulfate scales originate from interaction of injected hot fluid and formation fluids (connate water and seawater injected during an earlier waterflood). Scales that result from interactions of hot fluid with the formation (silicates) are not volumetrically significant at this time, but may become increasingly important with continued steam operations. It is necessary to determine the temperatures and pressures at which each variety of scale is stable. This will be investigated both theoretically and in laboratory flow-through tests using actual reservoir cores and fluids at reservoir conditions. It is anticipated that results will allow the design of long-term strategies to minimize or prevent scale precipitation.[10]

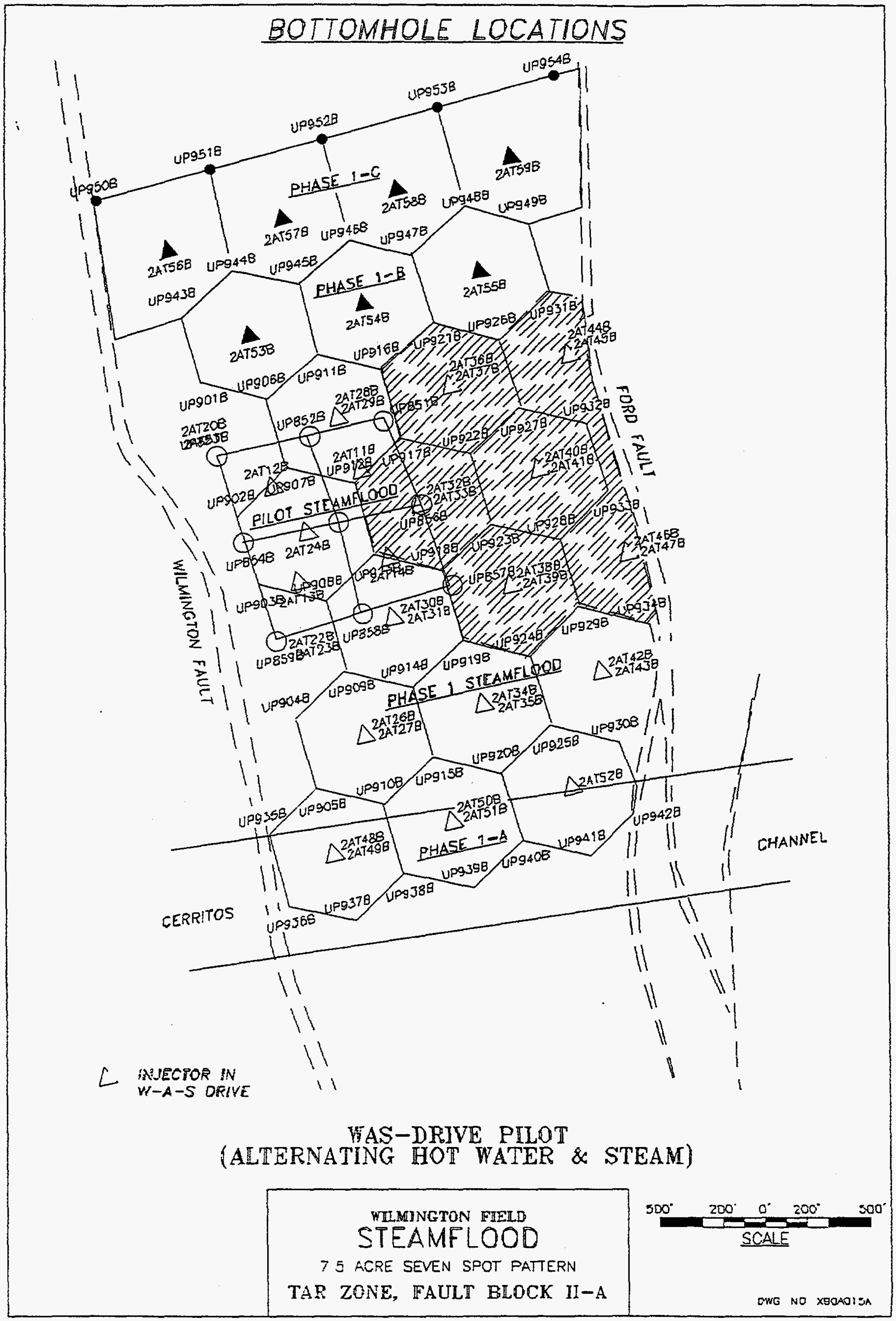

BOTTOMHOLE LOCATIONS
PHASE 1-C
PHASE 1-B
PILOT STEAMFLOOD
PHASE 1 STEAMFLOOD
PHASE 1-A
FORD FAULT
WILMINGTON FAULT
CHANNEL
CERRITOS
INJECTOR IN
W-A-S DRIVE
WAS-DRIVE PILOT
(ALTERNATING HOT WATER & STEAM)
WILMINGTON FIELD
STEAMFLOOD
7.5 ACRE SEVEN SPOT PATTERN
TAR ZONE, FAULT BLOCK II-A
500' 200' 0' 200' 500'
SCALE
DWG NO XBOA015A

FIGURE 5.9

Design of high temperature laboratory testing on pre-steam cores from the Tar II-A Zone D1 sub-zone cored in August 1995 was completed December 1995. The high temperature laboratory testing will be performed beginning in the fourth quarter 1996.

5.7 Laboratory Evaluation of Steamdrive Mechanisms

Laboratory evaluation of steamdrive mechanisms will be performed to aid in optimizing reservoir management. In particular, we will analyze the effects of steam on crude oil characteristics to evaluate the importance of various steam drive mechanisms in recovering Wilmington Tar Zone crude oil. The steam drive mechanisms to be investigated include: viscosity reduction of oil; thermal expansion of oil; steam distillation of oil; gas stripping of oil; oil phase miscible drive mechanism; solution gas drive from associated gas, and formation generated CO_2; and emulsion drive mechanisms. This work is scheduled for November 1996.

5.8 Reservoir Surveillance

Reservoir surveillance is crucial for supplying the information needed for good reservoir management. Monitoring the response of the reservoir is essential to evaluate the technologies being applied, to effectively manage the pilot projects, and to design the planned expansion of the project and future thermal recovery operations.

Production and injection rates, pressures, and temperatures are being collected by a Foxboro computerized monitoring system and input into Production Analyst on a monthly basis for evaluating steamflood performance.

Thirty samples of oil and chromatographs from 21 steamflood producers prior to start-up of this project have been located. Interpretations and correlations are in progress. As of this report, no oil samples have been extracted for chromatographic analysis from the OB2-3 core, drilled in August 1995.

Water salinity tests are being performed on produced water from the WAS drive pilot in the existing steamflood. Since the injected steam and hot water are fresh, lower salinity in produced water is a qualitative indicator of steamflood or hot water response. No significant changes in salinity have been recorded to date.

Contact temperature surveys have been run in observation wells in both the existing and the horizontal well pilot steamflood area. Surveys in the existing steamflood reveal the vertical distribution of heat in that area. Optical fiber temperature surveys will be made after the installation of the optical fiber in the two horizontal producers.

Radioactive steam injection surveys have not been made due to vendor equipment problems. A new vendor has been awarded the bid for these surveys and should start in October 1996.

5.9 Conclusions

Four horizontal wells were successfully installed, allowing for:

1. Isolating zones within the horizontal lateral to control the steam injection profile;
2. Being selective in determining the production interval; and
3. Providing a continuous conduit external to the casing for the installation of a fiber optic cable.

Zonal isolation was accomplished by completely cementing the well casings from total depth to surface. The good cement job required for zonal isolation was achieved by utilizing a zero free water, zero water loss cement slurry, and running two tandem rise centralizers per joint to increase the standoff to 93%.

Steam injection profile was controlled by using limited entry perforations. Injectivity in two horizontal injectors significantly improved after injecting water at high rates to open perforations. Sand control in the horizontal wells is being accomplished by hot alkaline water/steam injection-induced consolidation.

A steam transmission line was successfully installed under a harbor channel to supply steam from the mainland to the new horizontal wells on Terminal Island. The underwater line was constructed by: (1) directionally drilling a horizontal pilot hole using a slant rig; (2) underreaming the hole to 42-in.; (3) pulling a 30-in. casing through the drilled ; (4) sliding a 24-in. casing over the 14 in. insulated steam line in several sections and welding into a single 2100-ft string; and (5) pulling the dual concentric string through the 30 in. casing.

A WAS drive pilot was implemented in the existing Tar II-A thermal recovery area in March 1995. The pilot was suspended in April 1996 so that the steam separator and hot water injection lines could be moved. A new vertical steam separator will be installed in September/October 1996.

6 OPERATIONAL MANAGEMENT

6.1 Introduction

Implementing thermal recovery in the Fault Block II-A Tar zone poses a variety of operational problems. Past thermal operations in the Wilmington Field have experienced premature well and downhole equipment failure due to early steam breakthrough and sanding problems. These problems are common in SBC reservoirs with heterogeneous geology and unconsolidated sands. In addition, the high reservoir pressure and associated high steam temperature in the Wilmington Field aggravate the wellbore and equipment problems associated with early steam breakthrough.

As part of the overall objective of increasing the effectiveness and reducing the costs of thermal recovery operations, this project will apply the following approaches to alleviate operational problems:

1. Controlling sanding in producing wells by alkaline hot water/steam injection;
2. Investigating improved horizontal well completion techniques;
3. Improving profile control in horizontal injectors by limited entry perforation;
4. Investigating the geochemical origins of carbonate scale problems; and
5. Determining temperature limits to minimize operating problems.

6.2 Alkaline Hot Water/Steam Injection For Sand Control

The four horizontal wells are being completed by alkaline hot water/steam injection technique for sand consolidation. This completion technique causes minor silica dissolution which bonds the formation sand grains and controls sand movement into the wellbore.

The alkaline hot water/steam injection process for controlling sand production in perforated wells has been field tested successfully in six vertical producers, five vertical injectors, and two horizontal wells that were selectively perforated. Approximately 750 CWE barrels of steam were injected per perforation.

The conventional completion cost for a slotted liner with a gravel pack in a vertical well is approximately $ 120,000. The alkaline hot water/steam injection process with selective perforations, insulated tubing, thermal packer and expansion joint, and cost of steam is approximately $30,000, for a well cost savings of $90,000.

The sand consolidation process was applied to UP-932, a steam producer with enlarged slots in its liner causing sand production. Approximately 41,000 CWE bbls of eighty percent quality steam was injected into the enlarged slots. The well has been on production for over a year without any sand production. We believe that the hot alkaline water in the eighty percent quality steam causes silica dissolution, which bonds the sand grains and controls sand movement into the wellbore.

In addition, the steam aids in creating a secondary porosity and permeability equal to the original porosity and permeability. Laboratory tests are being designed to determine the geochemistry occurring in the formation around the wellbore and volumes of hot water and steam needed to optimize the process.

6.3 Horizontal Well Completion Techniques

Traditional means of establishing a quality completion for sand control in a vertical well cannot always be technically or economically applied to horizontal wells. Cementing and gravel packing operations are problematic, tending to leave gaps and voids on the top of the hole and liner. The relatively long length of the completion interval in a horizontal well requires a completion technique which is effective yet inexpensive on a dollar per foot basis. Productive capacity should be increased by a factor of five to ten. Finding the proper balance between effective technique and cost is essential. Cemented casing which is perforated in the low-side and treated with hot alkaline water/steam injection appears to be the best hope of attaining this objective.

Two existing horizontal wells in Fault Block I Tar Zone have experienced sand problems after applying the sand consolidation the first time. A second application of steam was applied in stages, 200-ft sections at a time. This treatment helped one well, but the other is shut-in with a sand problem. The problem is attributed to too many and too large perforations which would have required much higher steam rates and volumes to consolidate the sand. The new horizontal injectors will have eleven 0.29-in. perforations per well compared to seventy 0.50-in. perforations in the Fault Block I horizontal wells. The new horizontal producers will have thirty-five to forty-five 0.29-in. perforations per well and the sand consolidation will be done in stages.

6.4 Profile Control In Horizontal Injectors

Profile control in horizontal injectors is achieved either through the mechanical use of packers and steam chemical foam diverters or by the limited entry perforating technique. The mechanical use of packers and steam diverters is expensive and highly problematic because of the high steam temperatures which can vulcanize the packer seals and breakdown the chemical diverters. Perforating horizontal injectors without using the limited entry technique has been tried in horizontal steam injectors. In order to achieve any kind of profile control the well had to be steamed in stages, steaming only several hundred feet at a time in order to achieve a sand consolidation completion. This method was only fifty percent effective, was labor intensive and wasted steam energy. Limited entry perforating has been very successful in vertical injection wells, where profile control is obtained by the number and size of the perforations and the injection and reservoir pressure. Limited entry perforating will be used to control steam distribution across the lateral section of the horizontal injectors.

6.5 Minimize Carbonate Scale Problems

The presence of carbonate scale in producing wells is a significant problem. To date, we have experienced significant wellbore formation damage which required eight wells to be redrilled. The formation damage was caused by high steam temperatures over 550 °F which created carbonate scale in the gravel pack completion that cemented the gravel pack to the liner. In addition, cooling off the well during a workover has resulted in parting the liner. We are also experiencing a less severe form of wellbore scaling which occurs when hot reservoir fluids flash in the wellbore. However, this problem is recurrent and requires hydrochloric acid jobs. We believe it is important to understand the mechanisms which are causing these problems so we can adjust our operations to reduce or eliminate their occurrence.

Samples of fill (sand, scale, gravel pack) from existing steamflood producers were analyzed to determine possible reasons for formation damage and liner plugging in wells. Detailed thin section, scanning electron microscope, and x-ray diffraction work were performed on the samples. The types of scale identified were calcites, dolomites, barites, anhydrites, and magnesium-silicates. Additional discussion of scaling is provided in Section 5.6, "Petrophysical and Geochemical Rock/Fluid Interactions".

6.6 Determine Temperature Limits To Minimize Operating Problems

A laboratory and theoretical study will be performed to determine the temperatures and pressures at which each variety of scale is stable. This will be investigated both theoretically and in laboratory flow-through tests using actual reservoir cores and fluids at reservoir conditions. It is anticipated that results will allow the design of long-term strategies to minimize or prevent scale precipitation.

In addition, we are field testing high temperature packing in the stuffing box on rod pumping wells and high temperature downhole electric submersible pumps (ESP).

6.7 Conclusions

The four horizontal wells are being completed by alkaline hot water/steam injection technique for sand consolidation. This completion technique causes minor silica dissolution and precipitation, consolidating the formation sand grains and controlling sand movement into the wellbore. Experience with existing horizontal wells in Fault Block I Tar zone suggests that, if the perforations are too numerous or too large, then much higher steam rates and volumes are required to consolidate the sand. Accordingly, the new horizontal injectors will have eleven 0.29- in. perforations per well compared to seventy 0.50-in. perforations in the Fault Block I horizontal wells. The new horizontal producers will have thirty-five to forty-five 0.29-in. perforations per well and the sand consolidation will be done in stages.

Carbonate scale in producing wells has been a significant problem in the past. Formation damage was caused by high steam temperatures over 550° F which created carbonate scales in the gravel pack completions cementing the gravel pack to the liner. Cooling off the well during a workover resulted in parting the liner. A less severe form of wellbore scaling also occurred as a result of hot reservoir fluids flashing in the wellbore. This problem is recurrent and requires hydrochloric acid jobs. In order to mitigate these problems, laboratory studies are being performed to understand the mechanisms responsible for scale formation. Thin section, scanning electron microscope, and x-ray diffraction studies performed to date on fill samples from existing steamflood producers have identified the types of scale produced as calcites, dolomites, barites, anhydrites, and magnesium-silicates.

7 PROJECT EXPANSION

The thermal project will be expanded to the remainder of the D1 sand in the Fault Block II-A Tar zone in Phase 2 of this project, based on the results of reservoir characterization, reservoir simulation, and pilot testing in Phase 1. It is anticipated that four horizontal producers, four horizontal injectors, and three observation wells will be installed during the second phase.

The expansion has a drainage area of approximately 83 acres and a net oil sand thickness of 75-ft. The remaining oil saturation after waterflooding is estimated to be 66%. The remaining oil in place is estimated to be 9,625,000 barrels of oil. Projected recovery from the expansion is estimated to be 5,100,000 barrels of oil. The total pilot and expansion projected cumulative oil production is estimated to be 7,117,000 barrels.

The overall project is expected to take seven years to complete. The expansion is scheduled to start in the first quarter of 1999 and proceed through 2002.

8 TECHNOLOGY TRANSFER

8.1 Introduction

Technology transfer was achieved through a number of activities, in addition to preparing reports for the DOE. One highlight is a multi-media CD-ROM being prepared to provide an overview of the project. In addition, experience and knowledge gained from specific aspects of the project have been communicated in several presentations at professional society meetings and publications in technical and trade journals and newspapers.

8.2 CD-ROM Development

The USC Petroleum Engineering Program and Tidelands are working with the USC Integrated Media System Center to develop a CD-ROM summarizing the project. The first draft of the CD- ROM will be completed in the fourth quarter of 1996. Upon review and approval, the first version of the CD-ROM will be produced. The CD-ROM will include video, audio, animation, photographic and text presentations for technology transfer and education on the Wilmington Field and the two Wilmington DOE Class III projects. The first version will emphasize the steamflood project. The CD-ROM is expected to be ready for alpha and beta testing shortly, with a goal for widespread distribution at the Western Regional Meeting of SPE in Long Beach during June 1997.

8.3 Poster Presentations, Presentations, & Meetings

The following presentations or meetings focused upon on-going activities at the Wilmington Field:

1. October 1, 1994 - Don Clarke from the City of Long Beach gave a presentation on and field tour of Wilmington to the Los Angeles Trade and Technology College and Compton College.

2. October 19, 1994 - Julius Mondragon from Tidelands made a presentation on "Novel Perforated Thermal Well Completions in Unconsolidated Sands" at the monthly SPE Los Angeles Basin Section Environmental and Study Group Forum in Long Beach.

3. October 19, 1994 - Steve Siegwein from Tidelands made a presentation on "Drilling , Completion, and Production From Two Recent Horizontal Thermal Wells in the Tar Zone" at the monthly SPE Los Angles Basin Section Environmental and Study Group Forum in Long Beach.

4. December 5, 1994 - Don Clarke from the City of Long Beach gave a presentation on and field tour of Wilmington to the Interstate Oil and Gas Compact Commission.

5. January 18, 1995 - Dave Stepp from Tidelands made a presentation on "Treating Produced Water To Meet Water Injection Requirements Without the Use of Filters an Dispersed Gas

Flotation Units at the Wilmington Field" at the monthly SPE Los Angeles Basin Section Environmental and Study Group Forum in Long Beach.

6. January 18, 1995 - Robert Fickes from Tidelands made a presentation on "Is 'the Average Cost Per KWH' a Valid Way to Evaluate Adding or Reducing Electric Loads?" at the monthly SPE Los Angeles Basin Section Environmental and Study Group Forum in Long Beach.

7. Monthly, 1995-1996 - USC held a monthly seminar series at the campus during the 1995-96 school year. Many of the seminars had subjects related to Slope and Basin Clastic Reservoirs.

8. February 23-24, 1995 - Don Clarke, Jeff Blessener, and Henry Sun from the City of Long Beach gave a two day presentation on and field tour of Wilmington to a delegation from China .

9. March 15, 1995 - Rick Cassinis from Tidelands made a presentation on the "Harbor Cogeneration Steam Plant" at the monthly Los Angeles Section of the Desk and Derrick Club in Long Beach.

10. March 18, 1995 - Don Clarke from the City of Long Beach gave a presentation on and field tour of Wilmington to the Los Angeles Trade Technology College and Compton College.

11. April 6, 1995 - Don Clarke from the City of Long Beach made a presentation on Wilmington to the Long Beach Realtor Association.

12. April 19, 1995 - Mark Shemaria from Tidelands made a presentation on "Oil Spill and Response" at the monthly SPE Los Angeles Basin Section Environmental and Study Group Forum in Long Beach.

13. April 1995 - Mike C. Wood, Bruce Laughlin, Doug Fuller, Robert Fickes from Tidelands presented an SPE paper entitled "The Use of Downhole Submersible Pumps in a High Temperature Steamflood."

14. May 4, 1995 - Christopher Phillips from Tidelands gave a presentation entitled "Application of Advanced Reservoir Characterization to Increase the Efficiency of a Thermal Steam Drive in the Wilmington Oil Field" to the AAPG Pacific Section in San Francisco.

15. May 3-5, 1995 - Don Clarke from the City of Long Beach chaired a technical session at the 1995 AAPG Pacific Section Meeting in San Francisco.

16. May 15, 1995 - Personnel from Tidelands, the City of Long Beach, USC, and David K. Davies & Associates met to promote opportunities to present DOE Class III papers at the

1996 AAPG National Meeting, the 1997 SPE Western Regional Meeting, and the 1998 Joint SPE Western Regional/AAPG Pacific Basin Section Meeting.

17. June 1, 1995 - Don Clarke from the City of Long Beach gave a presentation on and field tour of Wilmington to the California State University of Long Beach Physics Department.

18. July 10, 1995 - Don Clarke from the City of Long Beach gave a presentation on and a field tour of the Wilmington Field to the Thai Minister of Mineral Resources and Long Beach City Manager's Office.

19. July 11, 1995 - Don Clarke from the City of Long Beach gave a presentation on and field tour of Wilmington to the Salvation Army Volunteers.

20. November 30, 1995 - Scott Hara from Tidelands and Dr. Iraj Ershaghi from USC organized a Basic Internet workshop at USC campus and made plans to hold two more workshops on June 25, 1996 and August 6, 1996.

21. January -June 1996 - Don Clarke from the City of Long Beach conducted eight field tours of the Wilmington Field for students, geologists, engineers, public officials, civic groups and senior groups.

22. May 1996 - David K. Davies presented a poster session to the AAPG entitled "Novel Sand Consolidation Completion Technique Using Alkaline Steam Injection in the Tar Zone, Wilmington Field, California" in San Diego.

8.4 Publications

1. October 10, 1994, *Long Beach Press - Telegram* newspaper, "Grants to help L.B. extract more oil from its fields" by George Cunningham, Staff Writer

2. October, 1994, *SPE Los Angeles Basin Section Newsletter*, "$9.7 Million in Federal Funds Awarded for Application of Advanced Technology in the Wilmington Field" by Robert Wunderlich, Deloitte & Touche LLP, consultant to Tidelands.

3. December, 1994, *World Oil* magazine, "What's Happening in Production" by David E. LeLeux.

4. March 1995, *Petroleum Engineer International* magazine, "Extraction Techniques May Increase Recoverable Reserves By Billions" by Steve Bell, Engineering Editor.

5. May 18, 1996 "Old Oil Fields and New Life: A Visit To The Giants of the Los Angeles Basin" Pacific Section, AAPG

9. REFERENCES

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[2] Linji An, et al "Sealing Property of External Faults in the Wilmington Field, Ca," Report Prepared for the DOE Class III project.

[3] I. Ershaghi, L.L. Handy, and M. Hamdi, "Application of the x-plot Technique to the Study of Water Influx in the Sidi el-itayem Reservoir, Tunisia,' Journal of Petroleum Technology, September 1987.

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[5] H. Schaller, "Study of Water Injection Surveys, Tar Zone, FB IIA Wilmington Field", Report Prepared for the DOE/Tidelands/USC Class III Project.

[6] C.C. Phillips, "Enhanced Thermal Recovery and Reservoir Characterization", in D.D. Clarke, G.E. Otott, and C.C. Phillips, eds., *Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin*, Guidebook 74, Division of Environmental Geology, Pacific Section, American Association of Petroleum Geologists and the Society of Petroleum Engineers, 1996.

[7] Gulf Research and Development Corporation, Report #442A1032, *Recognition of Sand Depositional Environments from Well Logs*, by Syed Ali, 1977

[8] *Logging While Drilling*, Schlumberger Educational Services, Houston, Texas.

[9] Al-Qahtany and I. Ershaghi, "Improvements in Conditioning of Stochastic Images using Field Performance Data",. Paper presented at the Western Regional Meeting of SPE in Bakersfield, CA, 1995.

[10] D.K. Davies, et al., "Nature, Origin, Treatment, and Control of Well-Bore Scales in an Active Steamflood, Wilmington Field, California", SPE paper 35418 presented at the 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, OK, April 1996.