FOSSIL ENERGY

DOE/BC/14935-6
(DE98000466)

# FEASIBILITY OF OPTIMIZING RECOVERY AND RESERVES FROM A MATURE AND GEOLOGICAL COMPLEX MULTIPLE TURBIDITE OFFSHORE CALIFORNIA RESERVOIR THROUGH THE DRILLING AND COMPLETION OF A TRILATERAL HORIZONTAL WELL

Annual Report
September 1, 1995 - December 31, 1996

By
Steve Coombs
Ed Edwards
Will Fleckenstein
I. Ershaghi
F. Sobbi
Stanley Coombs

July 1998

Performed Under Contract No. DE-FC22-95BC14935

Pacific Operators Offshore
Santa Barbara, California

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

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield VA 22161

DOE/BC/14935-6
Distribution Category UC-122

# Feasibility Of Optimizing Recovery And Reserves From A Mature And Geological Complex Multiple Turbidite Offshore California Reservoir Through The Drilling And Completion Of A Trilateral Horizontal Well

By
Steve Coombs
Ed Edwards
Will Fleckenstein
I. Ershaghi
F. Sobbi
Stanley Coombs

July 1998

Work Performed Under Contract No. DE-FC22-95BC14935

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Chandra Nautiyal, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
Pacific Operators Offshore
205 E. Carrillo Street, Suite 200
Santa Barbara, CA   931001

# Table of Contents

## Abstract

The main objective of this project is to devise an effective re-development strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria Field. The lack of adequate reservoir characterization, high-water cut production, and scaling problems have in the past contributed to the field's low productivity.

To improve productivity and enhance recoverable reserves, the following specific goals were proposed:

- Develop an integrated database of all existing data from work done by the former ownership group.
- Expand reservoir drainage and reduce sand problems through horizontal well drilling and completion.
- Operate and validate reservoir's conceptual model by incorporating new data from the proposed trilateral well.
- Transfer methodologies employed in geologic modeling and drilling multilateral wells to other operators with similar reservoirs.

Pacific Operators Offshore, Inc. with the cooperation of its team members; the University of Southern California; Schlumberger; Baker Oil Tools; Halliburton Energy Services and Coombs and Associates undertook a comprehensive study to re-examine the reservoir conditions leading to the current field conditions and to devise methodologies to mitigate the producibility problems.

A computer based data retrieval system was developed to convert hard copy documents containing production, well completion and well log data into easily accessible on-line format. To ascertain the geological framework of the reservoir, a thorough geological modeling and subsurface mapping of the Carpinteria field was developed. The model is now used to examine the continuity of the sands, characteristics of the sub-zones, nature of water influx and transition intervals in individual major sands.

The geological model was then supplemented with a reservoir engineering study of spatial distribution of voidage in individual layers using the production statistics and pressure surveys. Efforts are continuing in selection of optimal location for drilling and completion of probing wells to obtain new data about reservoir pressure, in-situ saturation and merits of drilling a series of horizontal wells.

The probing re-drills and horizontal wells are scheduled for Budget period II.

Information generated on the characteristics of the geology and reservoir setting have been presented at various SPE Meetings and Tech Transfer workshops of PTTC. Oil and gas professionals from State and Federal agencies have visited POOI offices and have received briefings on the Carpinteria re-development progress.

## Executive Summary

Pacific Operators Offshore, a small independent operator, submitted a proposal under the Class III cost share program of U.S. Department of Energy and was granted support to pursue its study of the Carpinteria Field, Santa Barbara, California. The proposal called for improved and innovative drilling and completion strategies for the re-development of the field.

The reservoir in the Carpinteria field consists of thin to massive deep water sandstone's with intercalated siltstone and claystone. A total of 29 separate layers have been identified in the producing horizon. Major producibility problems in the field include high water cuts, sand production and poor wellbore mechanical conditions. The purpose of the proposal was to scrutinize all existing data about the field and develop a better description of the reservoir architecture, devise alternative drilling and completion strategies for redevelopment of the field and reduce the water cuts by pinpointing the source of the water.

A team consisting of the following entities assisting POOI in its field study submitted the proposal:

- The University of Southern California, experts in reservoir characterization and reservoir engineering;
- Coombs and Associates, experts in well log analysis;
- Schlumberger, a service company;
- Halliburton, a service company;
- and Baker Oil Tool, also a service company.

The database effort resulted in the design and implementation of a readily accessible production data system using the Production Analyst software. Well log interpretation work resulted in identification of the micro-lamina, oil water contacts and information about displacement across fault planes and a consistent approach to calculation of reservoir attributes such as porosity and saturation.

Basic reservoir engineering work generated estimates of by-passed oil and allocation to individual horizons. Analyses of water production pinpointed the sources of water and the role of the aquifers in maintaining reservoir pressure.

A number of target spots for drilling of new development wells have been identified. Computation of recovery from pilot horizontal wells has established the economic merit of drilling and completing such wells for draining the trapped oil.

With active participation in the workshops given by the Petroleum Technology Transfer Council, SPE meetings, tours and meetings, results of the studies have been disseminated to other producers. Additionally various presentations to both State and Federal agencies have been made.

## Acknowledgements

This study is co-sponsored by the U.S. Department of Energy under Class III Oil Program, Contract

No. DE-FC22-95BC14935. The Contracting Officer's Representative is Chandra Naytial with the DOE Bartlesville Office.

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

| | |
|---|---|
| Pacific Operators Offshore, Inc.<br>(805) 899-3144 | Steve Coombs<br>Ed Edwards<br>Will Fleckenstein |
| University of Southern California<br>(213) 740-0321 | I. Ershaghi<br>F. Sobbi |
| Coombs and Associates<br>(805) 642-6699 | Stanley Coombs |

# 1 Introduction

## 1.1 Report Overview

This report constitutes the first cumulative report on the project. Pacific Operators Offshore, Inc. received pre-award authorization for this project effective May 9,1995 and final approvals were obtained effective September 1, 1995 and as such began work on the database tasks set forth in the proposal. To date a significant amount of progress has been made on development of a database and reservoir characterization, which includes production data (project task 1.1.1), well log data (project task 1.1.2), well completion data (task 1.1.3) well test and PVT data (task 1.1.4), stratigraphy and micro lamination (task 1.2.1), reservoir performance (task 1.2.2), analysis of water production (task 1.2.3), management and administration (task 1.3.1) and tech transfer (task 1.4.1).

In this chapter an overview of the project is presented. A general description of the Carpinteria field is included .

## 1.2 Project Overview

The main objective of this project is to devise an effective re-development strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria Field. The lack of adequate reservoir characterization, high-water cut production, and scaling problems have in the past contributed to the field's low productivity.

To improve productivity and enhance recoverable reserves, the following specific goals were proposed:

- Development of an integrated database of all existing data from work done by the former ownership group.
- Expansion of reservoir drainage and reduction of sand problems through horizontal well drilling and completion.
- Operating and validating reservoir's conceptual model by incorporating new data from the proposed horizontal wells.
- Transferring methodologies employed in geologic modeling and drilling horizontal wells to other operators with similar reservoirs.

The project was proposed to be conducted in two phases. In the first phase, Budget Period I, we proposed to develop the field database, conduct reservoir analysis and field characterization, institute a modern reservoir management and surveillance system and transfer technology to other operators.

Drilling and completion of a series of horizontal wells , monitoring of production and updating of the geological and reservoir model for further field development planning were the items proposed for Budget period II. A major objective for this project and the pilot drilling is a formulation of a fieldwide development strategy. This is to follow after a careful analysis of results obtained from Budget period II.

The project is expected to take approximately 4 years to complete. The first budget period began in September 1995 and is expected to be phased out by summer 1998. The second budget period is planned to start in the last quarter of 1997.

Implementation of the budget period I portion of the project is monitored through a series of tasks proposed in the original proposal as listed below:

1. Task 1.1.1 - Database: Production Data

2. Task 1.1.2 - Database: Well Log Data

3. Task 1.1.3 - Database: Well Completion Data

4. Task 1.1.4 - Well Test / PVT

5. Task 1.2.1 - Stratigraphy and Micro Lamination

7. Task 1.2.2 - Reservoir Performance

8. Task 1.2.3 - Analysis of Water Production

9. Task 1.3.1 - Management and Administration

10. Task 1.4.1 - Tech Transfer

The team members of the project include:

Pacific Operators Offshore
University of Southern California
Coombs and Associates
Schlumberger Well Service
Halliburton Energy Service
Baker Oil Tools

## 1.3 The Carpinteria Field

### 1.3.1 Development and Production History

The Carpinteria Offshore Field was discovered by Chevron in 1964. It originally covered two State parcels and two Federal leases. State leases 3133, 3150 and 4000 were shut-in in 1992 and abandoned in 1996. The two Federal leases OCS P-0166 and OCS P-0240 are still producing. As of December 1996, total field production has been:

92 MMBO Oil, 174 MMBW Water and 84 BCF Gas

Pacific Operators operation is from OCS P-0166 and currently contributes 1400+ BOEPD (barrels oil and gas equivalent) to the total daily production of 2,800 BOEPD of the entire field. Cumulative oil production for lease OCS P-0166 as of December, 1996 is 45.69 MMbbls oil, 38.85 BCF gas and 60.54 MMbbls water.

Figure 1 shows water cut as a function of cumulative oil produced for lease OCS P-0166. High water production is evident from the early history of the field.

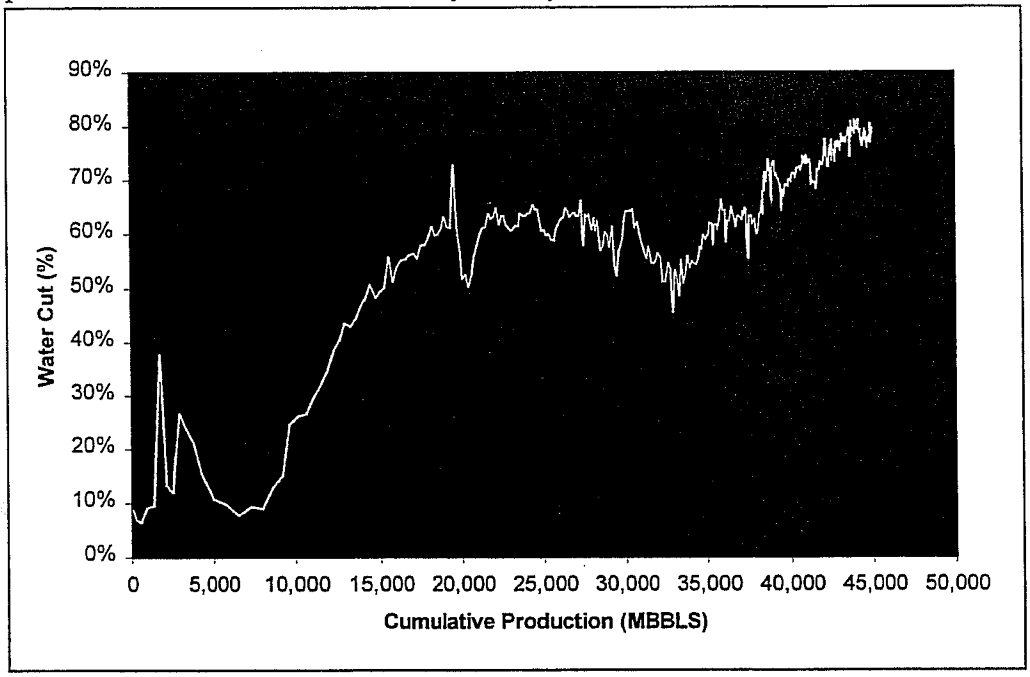



*Figure 1 - Water Cut vs. Cumulative Production Plot*

The State portion of the field was developed with a total of 77 wells originating from platforms HOPE and HEDI. These platforms were installed in 1965 and 1966 and were operated by Chevron until their abandonment in 1996. The Federal portion of the field has been developed with a total of 110 wells from three platforms, Hogan, Houchin and Henry. Fig. 2 Shows the chronological installation of the platforms for the Carpinteria field.

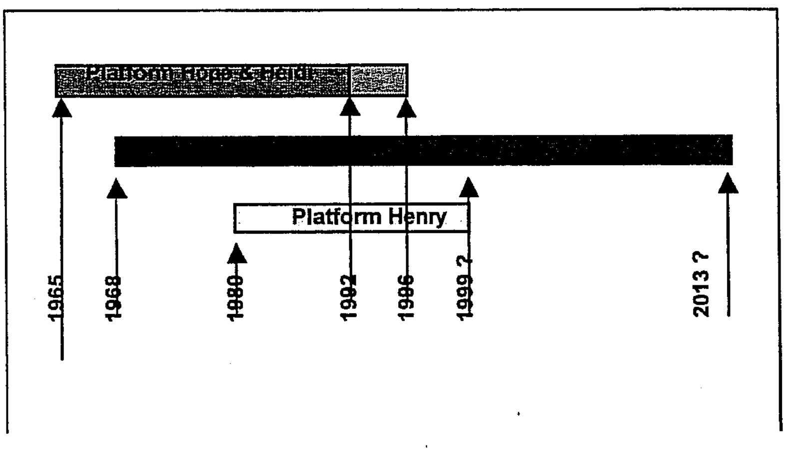



*Figure 2 - Platform Timeline*

### 1.3.2 Geologic Conditions

Carpinteria Field is located in the northern portion of the Ventura Basin. The producing formation is the multiple -zone Pliocene age Repetto. The trap is a faulted anticline with paytops ranging from 2500 to 5500 ft subsea. Formation dip range from 5 degrees to 15 degrees.

The Santa Barbara Channel, where the Carpinteria Offshore Field is located, is about eighty miles long and twenty-five miles wide. The Channel is a tectonic depression that extends east into Ventura Basin. These strata in the Channel have been subjected to major tectonic folding and complex faulting creating multiple hydrocarbon traps.

Carpinteia is the fourth of the five fields located along the "Rincon Trend", a structure that is the northerly limit of the Ventura Basin. All the fields are divided by a major thrust fault into two major reservoirs, one above the thrust fault and one below. All fields have numerous fault blocks created by transverse faulting as well as stratigraphic changes resulting in compartmentalized reservoirs.

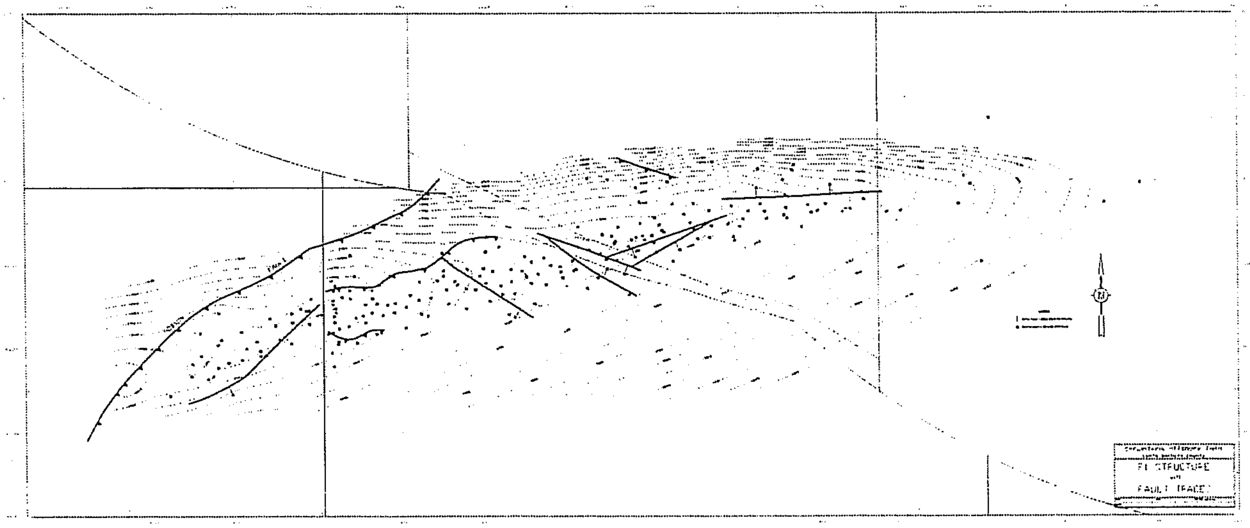


*Figure 3 - F-1 Structure Map with Current Fault Interpretation*

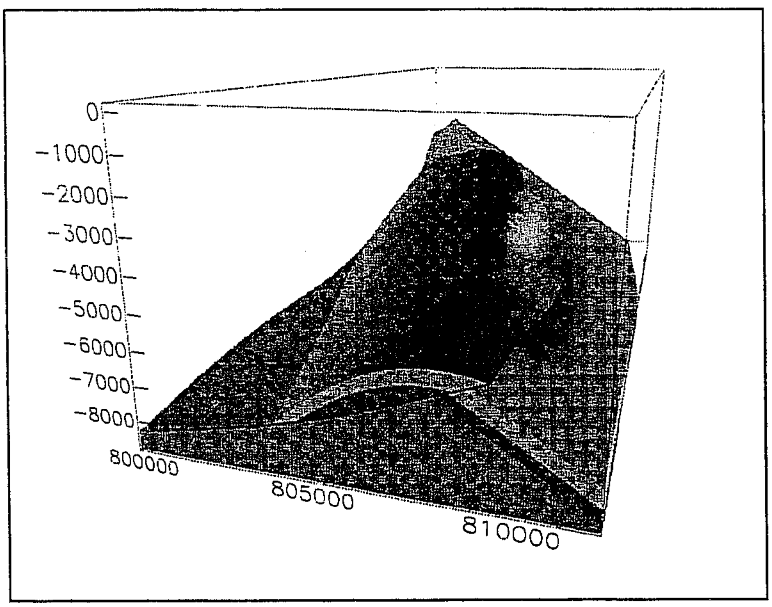



*Figure 4 - EarthVision block diagram looking west showing overthrusting of G-zones along Hobson Fault*

The Carpinteria field extends from approximately two miles offshore in State waters to 3.3 miles further on to Federal parcels P-0166 and P-0240. It is less than one mile wide at its widest point. The structure of the field and the current fault model is shown in Figure 3. Major producing horizons within the field are the sands identified as E-1 through E-4, F-1 through F-5 and G-1 through G-7a above the Hobson fault and G-1 through G-7 below the fault. A 3-D block diagram showing the displacement of the Hobson thrust fault is shown in Figure 4.

The E-1 sands are generally highly porous, friable and with high permeabilities. The F-1 sand is 100-150 ft thick with medium to fine grained sand, moderate to well compacted with some microlamination limiting the vertical permeability. The F-3 sand is up to 125 ft thick and is comprised of several sequences with intervening silt and shaly layers.

## 2 Database Development

### 2.1 Introduction

Information available on Carpinteria Field were primarily in hard copy format. Besides the monthly production data, important reservoir engineering data existed in a number of studies and reports by the previous working -interest owners. A significant effort was devoted to distill information for populating the database.

### 2.2 Production Data

For the purpose of computerizing the performance data, we employed production history management software called Production Analyst or "PA". This software, developed by OGCI (Oil and Gas Consultants International), allows production history by individual wells to be easily combined and grouped to prepare diagnostic plots for analysis of reservoir behavior. The software was installed and all of the historical production history on a well by well basis were imported.

Because all the wells on the lease are drilled from one of two platforms (platform Hogan or Houchin), an X-Y coordinate system was used to show the reference datum well spots on the location map. This map interface accompanies the PA program. The datum used was the F1 sand.

The quality of the production history database was carefully compared with historical hard copy reports and production history database available from the regulatory agency, the Minerals Management Service. Each of these databases contains a huge number of monthly oil, gas and water production values. In order to compare the two databases a computer program was written to compare the data on a well by well, month by month basis. The differences then were checked with the hard copy and corrections were made where appropriate.

### 2.3 Well Log Data

A considerable amount of progress has been made on the well log database. Much of this work was initiated prior to the pre-award date. The well log processing system being used for this task is LOGCALC II, by Scientific Software, running on a DEC Micro-VAX II system.

Calculations of all petrophysical attributes is complete for all wells with useable data. All computed data were exported to the Stratigraphic Geocellular Model. Later, the SGM model was replaced with the EarthVision 3-D modeling package by Dynamic Graphics, Inc.

Using annotated computed logs and the marker data, oil water contact picks were re-evaluated with sections representing true vertical depth logs. Quality control consisted of use of the data in EarthVision, comparing the data with top and bottom picks and plotting a number of computer cross sections, which included the oil water contacts. The computer cross sections were also used to scrutinize the effect of production in the key areas. For these areas, studies have been started to assess the effect of production on logs for mapping swept and unswept oil, and to evaluate remaining reserves. Several potential remaining productive areas have been identified and additional evaluation is in progress.

Well log processing efforts have resulted in some calculated parameters that are currently undergoing quality control checks. A series of calculated log parameter maps has been created for each zone. These maps were developed by contouring each calculated parameter with a computer contouring package. Each map, for each layer or zone is compared to validate the calculated results.

Core data from four wells, A-9, B-15, B-35 and B-45, was used to develop a correlation for correcting lab permeability data for overburden pressure. This correlation was developed by using experimental compaction test data. Table 1 shows the core permeability and porosity data for all of the cored wells.

**Table 1**
**Corrected Permeability and Porosity**

| Well | Formation | Corr k | Porosity |
|---|---|---|---|
| A-9 | E-1 | 847.09 | 31.52 |
| A-9 | F-1 | 389.09 | 29.44 |
| A-9 | G-2 | 283.07 | 27.11 |
| A-9 | G-6BST | 45.14 | 22.71 |
| Avg. | | 391.10 | 27.70 |
| | | | |
| B-15 | F-1 | 229.96 | 27.73 |
| B-15 | F-2 | 427.95 | 29.43 |
| B-15 | G-1 | 199.26 | 28.56 |
| B-15 | G-1B | 125.49 | 25.33 |
| B-15 | G-3 | 157.96 | 25.92 |
| B-15 | G-3B | 153.40 | 25.60 |
| Avg. | | 215.67 | 27.10 |
| | | | |
| B-35 | G-1 | 94.72 | 24.43 |
| B-35 | G-3 | 214.20 | 26.89 |
| Avg. | | 154.46 | 25.66 |
| | | | |
| B-45 | E-1 | 396.79 | 35.21 |
| B-45 | E-1A | 546.34 | 36.30 |
| B-45 | F-1 | 318.13 | 36.80 |
| B-45 | F-4 | 482.14 | 34.38 |
| B-45 | G-1 | 332.75 | 32.14 |
| Avg. | | 415.20 | 34.97 |

**Table 2**
**Comparison of Core Permeability and Porosity by Zone**

| Well | Formation | Corrected k | Porosity |
|---|---|---|---|
| A-9 | E-1 | 847.09 | 31.52 |
| B-45 | E-1 | 396.79 | 35.21 |
| B-45 | E-1A | 546.34 | 36.3 |
| | | | |
| A-9 | F-1 | 389.09 | 29.44 |
| B-15 | F-1 | 229.96 | 27.73 |
| B-45 | F-1 | 318.13 | 36.8 |
| | | | |
| B-15 | F-2 | 427.95 | 29.43 |
| | | | |
| B-45 | F-4 | 482.14 | 34.38 |
| | | | |
| B-15 | G-1 | 199.26 | 28.56 |
| B-35 | G-1 | 94.72 | 24.43 |
| B-45 | G-1 | 332.75 | 32.14 |
| | | | |
| B-15 | G-1B | 125.49 | 25.33 |
| | | | |
| A-9 | G-2 | 283.07 | 27.11 |
| | | | |
| B-15 | G-3 | 157.96 | 25.92 |
| B-35 | G-3 | 214.2 | 26.89 |
| | | | |
| B-15 | G-3B | 153.4 | 25.6 |
| | | | |
| A-9 | G-6BST | 45.14 | 22.71 |

Table 2 shows the same data but organized by producing zone. Although the data is somewhat sporadic there is a trend of decreasing permeability with depth as might be expected.

Special core analysis data including water-oil relative permeability, gas-oil relative permeability and air-water capillary pressure data have been digitized. Reservoir water-oil capillary pressure data has been derived from air-water capillary pressures. A complete set of reservoir data has been compiled for a reservoir simulation study.

## 2.4 Well Completion Database

Well completion design in Carpinteria lease OCS P-0166 allows artificially assisted production from individual zones to commingle. A well completion database containing the completion history of all of the wells was created. This information is maintained in a MS-Access database.

## 2.5 Well Test /PVT Data

A total of 39 pressure buildup tests were analyzed which include 17 drill stem tests. Results of analysis from DST No. 3, 4 and 5, which had surface flow rates, are believed to produce the most reliable permeability values for the sub-thrust G-7 and the supra thrust G-1 and F-1 layers respectively in the drainage areas encountered during the tests.

### 2.5.1 PVT Data

A total of five oil samples were taken from lease OCS P-0166 for PVT analysis. The first oil sample was prepared from recombining a sample of separator liquid with a synthesized separator gas in order to obtain a fluid having a bubble point equal to the original reservoir pressure of 1545 psig at 110 °F. This sample was taken on November 28, 1967 prior to start of lease production. Although the synthesized gas was not exact in its physical properties, it was felt to be within the practical limits for the recombination. The saturation pressure of the recombined sample was measured to be 1546 psig at a reservoir temperature of 110 °F. During differential pressure depletion at 110 °F the fluid evolved 223 SCF/STB. The viscosity of the liquid varied from a minimum of 14.4 centipoise at saturation pressure to a maximum of 46.5 centipoise at atmospheric pressure. The gravity of the residual oil was 22.0 °API at 60 °F.

The second recombined sample was taken early in the producing life of the lease on July 12, 1968 from well A-4. The well was opened to the E, F and G zones. The separator gas oil ratio (GOR) was 436 SCF/STB. PVT analysis of this sample resulted in 460 SCF/STB of gas in solution at a saturation pressure of 2528 psig and reservoir temperature of 122 °F. It is worth noting that this pressure is approximately 400 psi higher than the hydrostatic pressure at the deepest oil bearing point in the well (4630 ft. subsea). The gravity of the residual oil was 26.2 °API at 60 °F.

The third sample is a subsurface sample taken from Well A-7 on Sept. 28, 1968 from the F zone. This sample established a saturation pressure of 2155 psig at a reservoir temperature of 122 °F and a solution GOR of 336 SCF/STB. The gravity of the residual oil was 25.2 °API at 60 °F.

Subsurface samples 4 and 5 were taken April 24, 1969 during Drill Stem Test No. 1 (DST No. 1) on Well B-2A. The producing interval during the test was 5090-5115 ft. MD which corresponds to the G-5A sub-thrust sand. DST No.2 on the same well sampled the G-3A sand from a producing interval 3785-3805 ft. MD. These samples exhibited saturation pressures of 974 psig at 145 °F and 1271 psig at 126 °F with solution GORs of 273 and 212 SCF/STB respectively. The gravity of the residual oil samples were 32.4 and 25.8 °API at 60 °F respectively.

All available gas analysis data have been digitized. Also the historical API gravity measurements have been digitized. Chronological drop of API gravity's are attributed to the loss of the light components during the solution gas drive process and variable contribution from individual layers.

All available gas analysis data have been digitized. Table 3 shows a typical gas analysis data set. Also the historical API gravity measurements have been digitized.

**TABLE 3**
**TYPICAL GAS ANALYSIS**

| Well No.: A-6 , Sample # 1, Date : 7-25-68 | |
|---|---|
| Component | Mole per cent |
| He | < .01 |
| CO2 | 3.28 |
| N | 0.06 |
| CH4 | 84.34 |
| C2H6 | 2.67 |
| Propane | 4.1 |
| I-Butane | 0.84 |
| N-Butane | 1.81 |
| I-Pentane | 0.82 |
| N-Pentane | 0.74 |
| Hexane | 0.52 |
| Heptanes and Heavier | 0.82 |
| | |
| Specific Gravity | 0.7487 |
| Heating Value | |
| Dry | 1237 |
| Wet | 1215 |

## 2.6 Conclusions

Conversion of hard copy format report on production, pressure, PVT and production test into a computer based data retrieval system has been completed. The system allows real time access of the data for reservoir analysis.

# 3 Reservoir Characterization

## 3.1 Introduction

Implementation of a successful re-development program requires an understanding of the reservoir setting with respect to the following areas:

- Characterization of the structural nature of the reservoir
- Delineation of the sratigraphic nature of the reservoir
- Location and exact orientation of transverse faults
- Mapping of facies changes
- Relative contribution of individual sands to the commingled production
- Nature of the drive mechanisms of the wet sands
- Petrophysical properties of reservoir rock
- Quality of available reservoir pressure data
- The interplay of existing well completion with the stratigraphy of the field.

We have made progress in understanding some of these issues by implementing an integrated reservoir characterization method.

## 3.2 Stratigraphy and Microlamination

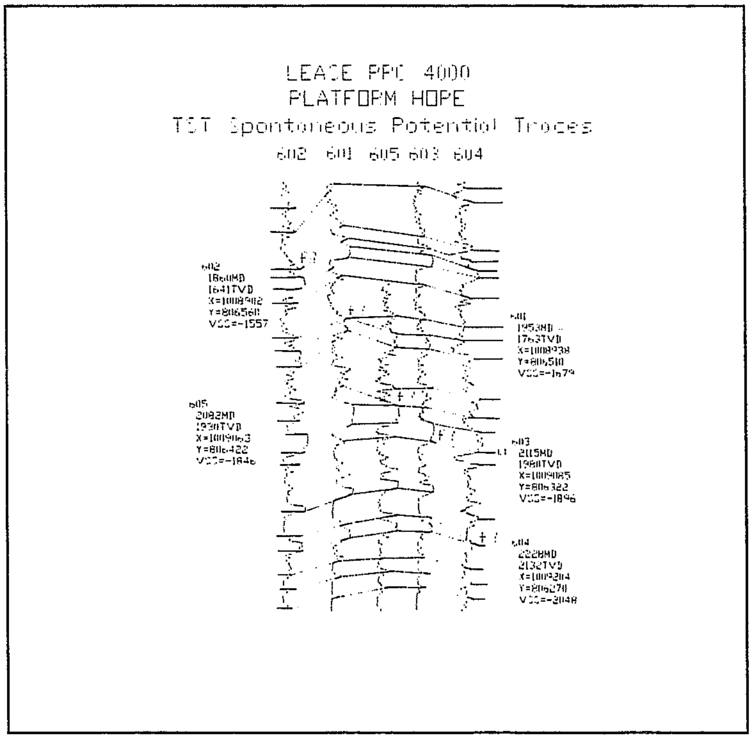



*Figure 5 - Typical TST correlation panel created in AutoCAD showing section thickness anomalies indicative of faulting*

Based on the well log correlation's a total of 29 sub-layers have been identified. These sub-layers were identified using an onscreen correlation approach. A typical correlation panel of SP log traces is shown in Figure 5. These correlation panels were created by using the calculated True Stratigraphic Thickness (TST) logs and then displaying the traces in Autocad for correlation.

All available conventional core analysis from whole core and sidewall plugs from 6 core holes and 5 development wells were digitized. In addition, screen or sieve analysis, where available, were also used in the micro lamination study. Core analysis data was used to map silt stones and shales in wells. A correlation for correcting laboratory permeability data for overburden pressure was developed by using experimental compaction test data. For material balance studies, a database was developed to relate cumulative production of oil and water to various sub-categories of producing horizons.

This data will be used for the microlamination study. In addition, screen or sieve analysis, where available, will also be studied in detail. A general trend of east to west permeability decrease was observed from core data and analysis of initial oil production.

Lithology of cored sections has been investigated. A detailed study of thin shales and silt stones in cored wells is in progress. This study will include comparisons of resistivity logs, continuity of thin

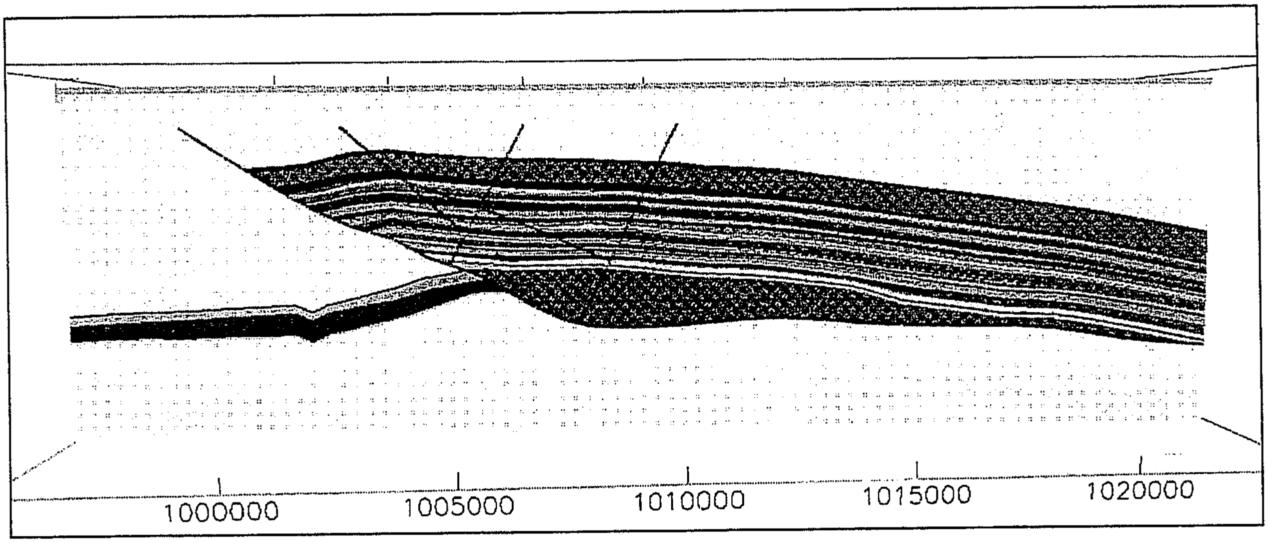



*Figure 6 - East-west cross-section through EarthVision model showing producing zones and faults.*

shales and silts tones and their effect on past production. The 3-D visualization model, EarthVision (Dynamic Graphics Software) is now being used for visualization, comparison and posting data. A east-west cross section created in EarthVision is shown in Figure 6.

A general trend of east to west permeability decrease was observed from core data and analysis of initial oil production.

Special core analysis data including water-oil relative permeability, gas-oil relative permeability and air-water capillary pressure data have been digitized. Reservoir water-oil capillary pressure data has been derived from air-water capillary pressures. A complete set of reservoir data for preliminary reservoir simulation study has been prepared.

### 3.3 Basic Reservoir Engineering

The reservoir engineering efforts completed so far have focused on three primary issues: (1) Estimating original oil in place (OOIP), using both volumetric and material balance techniques;

(2) Estimating oil produced by well and by zone; and (3) Estimating the productivity of horizontal wells that will be drilled in the field.

This effort incorporated the results of recent geological and petrophysical interpretations. The study was hampered by limited pressure and core data, commingled production, heterogeneous reservoir fluids and incomplete geological and petrophysical evaluations of the subthrust reservoirs.

### 3.3.1 Original Oil in Place

Original oil in place (OOIP) for P-0166 is estimated to be 157 MMSTB by volumetric method and 166 MMSTB by material balance (MB) calculations. A second phase 3-D EarthVision model will result in more refined volumetric estimates of OOIP. Following is a discussion for the basis of our current OOIP calculations:

#### 3.3.1.2 Volumetric method: P-0166

Our current 3-D EarthVision model only includes detailed reservoir attributes for the supra-thrust sands, series C through G5. Therefore, our 3-D model is only helpful in determining volumetrics for these zones. The determination of the productive areas in sands G6, G7 and the subthrust for the P-0166, as well as for the rest of the field, is still in progress. In this report, for the sake of completeness, previously determined reservoir data was used to complete the estimation of OOIP for G6, G7 and the subthrust. These estimates will be revised when new well attributes and net pay volumes become available. Net average thickness and thickness weighted average porosity and water saturation of each sand are used in the estimation of OOIP. The limits and cut-offs of reservoir parameters are shown in Table 4. An average oil formation volume factor of 1.15 bbl/STB is used in the volumetric calculations.

The original oil in place for P-0166 is presented by layer in Table 5. That table shows the E1, F1, G1 and G3 sands to have the largest oil accumulations in the lease. Statistical analysis of OOIP was performed by utilizing a Monte Carlo simulation using triangular distributions for area and net sand thickness. The mean value of reserves depicted there is 157 MMSTB with a 75% certainty of reserves between 144 MMSTB and 174 MMSTB.

**TABLE 4**
**CUT OFFS OF RESERVOIR PARAMETERS**

| | |
|---|---|
| Shale cut off | 35 % |
| Net pay total porosity cut off | 15 % |
| Net pay total water saturation cut off | 70 % |
| Effective porosity cut off | 12 % |
| Effective water saturation cut off | 60 % |

## TABLE 5
## OOIP FOR P-0166 BY VOLUMETRIC METHOD

| Sand | Productive area acres | Net thickness Feet | Ave. $\phi_e$ | Ave. Sw | OOIP, MSTB |
|---|---|---|---|---|---|
| C1 | 0.0 | 3.6 | 0.2920 | 0.5003 | 0 |
| D1A | 47.8 | 8.8 | 0.2403 | 0.4965 | 345 |
| E1 | 281.3 | 37.9 | 0.2642 | 0.3754 | 11,857 |
| E1A | 207.9 | 31.2 | 0.2585 | 0.4462 | 6,255 |
| E2 | 13.3 | 7.1 | 0.2293 | 0.5189 | 71 |
| E3 | 3.7 | 2.6 | 0.2583 | 0.5206 | 8 |
| E4 | 63.0 | 13.1 | 0.2715 | 0.4942 | 763 |
| F1 | 475.2 | 116.5 | 0.2263 | 0.3681 | 53,387 |
| F2 | 220.1 | 33.6 | 0.2348 | 0.4514 | 6,431 |
| F2A | 108.4 | 18.8 | 0.2110 | 0.4979 | 1,454 |
| F3 | 255.3 | 30.3 | 0.2093 | 0.4465 | 6,049 |
| F4 | 268.6 | 33.0 | 0.2157 | 0.4115 | 7,589 |
| F5 | 111.2 | 18.1 | 0.2198 | 0.4662 | 1,589 |
| F6 | 69.3 | 13.3 | 0.2098 | 0.5053 | 647 |
| G1 | 253.6 | 44.5 | 0.2190 | 0.3445 | 10,938 |
| G1B | 176.6 | 23.4 | 0.2109 | 0.3320 | 3,921 |
| G2 | 281.3 | 13.0 | 0.2055 | 0.3900 | 3,103 |
| G3 | 238.0 | 68.8 | 0.2155 | 0.3361 | 15,794 |
| G3A | 119.4 | 10.9 | 0.2067 | 0.4581 | 987 |
| G3B | 88.9 | 23.6 | 0.2251 | 0.3501 | 2,069 |
| G4 | 98.6 | 7.8 | 0.2010 | 0.4502 | 572 |
| G5 | 75.6 | 6.5 | 0.1818 | 0.5111 | 294 |
| G5A | 67.7 | 9.5 | 0.2084 | 0.4668 | 484 |
| G5B | 31.6 | 5.2 | 0.2053 | 0.5325 | 106 |
| G5C | 22.5 | 3.2 | 0.1957 | 0.5369 | 45 |
| G6 | 23.7 | 12.0 | 0.2077 | 0.4767 | 208 |
| G6A | 29.2 | 4.6 | 0.2080 | 0.4955 | 95 |
| G6B | 44.9 | 16.5 | 0.1989 | 0.4563 | 541 |
| G6C | 35.5 | 4.6 | 0.1819 | 0.4697 | 107 |
| G7 | 87.5 | 20.4 | 0.1907 | 0.4211 | 1,332 |
| ST | 558.0 | 43.0 | 0.2100 | 0.4200 | 19,715 |
| | | | | Total OOIP | 156,754 |

### 3.3.1.2 Material Balance Methods

Based on the reservoir pressure database, the initial reservoir pressure on lease OCS P-0166 was calculated to be 1500 psig at a datum of 3300 ft subsea. In the basic material balance study of field, the combined effects of reservoir compressibility, depletion and water influx was examined.

Indications are that the reservoir pressure from its initial value of 1500 psig dropped to 870 psig in a matter of 3 years. Following this initial drop in pressure, a period of pressure stabilization indicates potential water influx. Cumulative production from various segments of the lease indicate considerable production of water. From diagnostic plots of water cut versus cumulative production, indications are that high water production is from commingled production from oil and wet sands and aquifer influx.

Two different approaches of the material balance equation (MBE) were considered for the estimation of original oil in place for lease P-0166. First the general material balance equation was examined using a water influx model as described by Ershaghi and Abdassah (JPT, Oct. 1984) in the form of X-plot. We also applied then a simplified form of the material balance equation. The general material balance equation for a reservoir incorporating the combined effects of aquifer support, formation compaction and the solution gas drive mechanism may be written as follows:

$$Z = a \times E + b \times I$$

where Z is the total reservoir withdrawal, A is the unknown OOIP, E is the unit of expansion, B is the unknown water influx constant and I is the influx function which will be calculated by the assumed water influx model. The MB equation was solved by the least square method. The OOIP was estimated 159 MM STB

The X-plot method has been found useful in obtaining an estimate of water influx in Carpinteria field lease P-0166. An example X-plot is shown in Figure 7. The water encroachment which is a mixture of bottom and edge water influx may be calculated using the following equation:

$$W_e = \frac{B_{oi}}{m f_w (1.0 - f_w)}$$

where $W_e$ is water influx in barrels, m is the slope of the X-plot in 1/bbls ( $1.0372 \times 10^{-7}$ ), $B_{oi}$ is the initial oil formation volume factor.

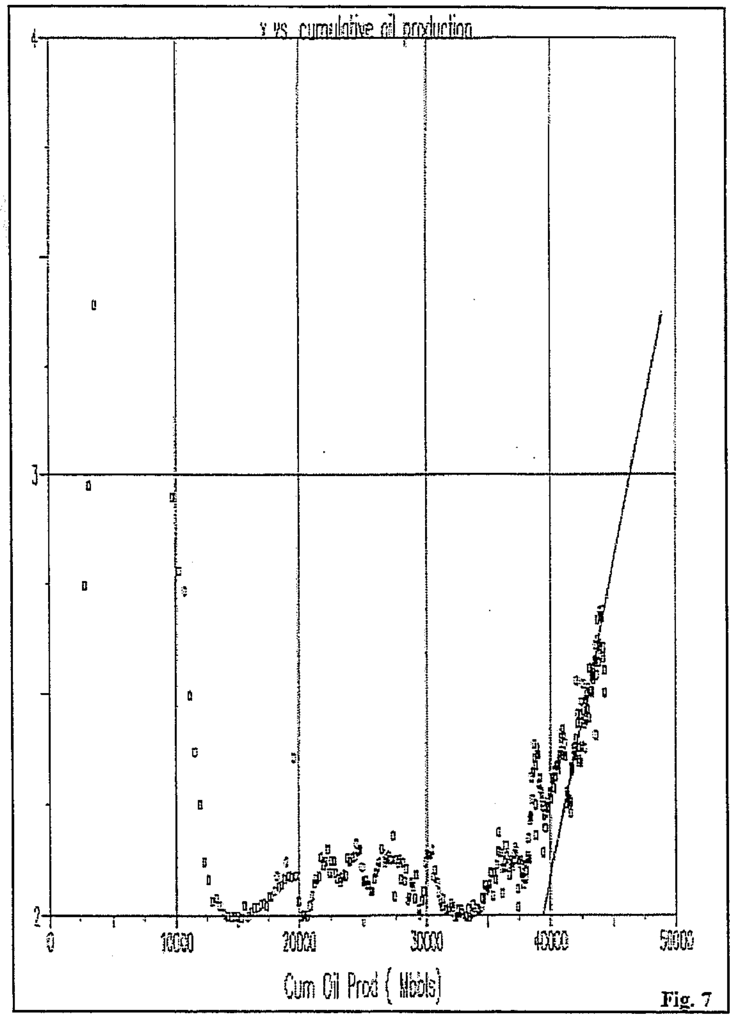


Fig. 7

*Figure 7 - Xplot of Carpinteria production showing water influx.*

A Monte Carlo Simulation approach was devised to estimate OOIP in lease OCS P-0166. The material balance equation was rearranged in the following form:

$$Ni = a \times Npi + b$$

where $N_i$ is an apparent estimate of initial oil in place at different time steps, i , assuming no water influx, $Np_i$ is cumulative oil production at different time steps and a and b are constants. For a reservoir with water influx, $N_i$ tends to show mono-tonically increasing linear correlation with $Np_i$. The true value of original oil in place may be obtained by plotting $N_i$ versus $Np_i$ and extrapolating the straight line to $Np_i = 0$ . Early time, data during which the reservoir was not fully developed, were excluded. Monte Carlo Simulation results in a mean of 168 MM STB, median of 162 MMSTB with a standard deviation of 42 MM STB.

### 3.3.2 Production Allocation

The majority of the wells in lease P-0166 were completed in multiple sands. As a first step in determining the remaining oil in each sand, a computer based back allocation algorithm was developed. The log derived net productive intervals with pertinent average effective porosity and water saturation, well completion data, core analysis and production data were used. The original oil in place (OOIP) in the supra-thrust reservoirs for each sand was calculated. The production allocation procedure was used to calculate cumulative oil production from each well and from each sand. The remaining oil in each sand was found by subtracting the amount of oil produced by each well from each individual sand from the original oil in place.

Due to the heterogeneous nature of reservoir fluids in lease P-0166 and large contrasts in individual layer pressures caused by differential depletion, an effort was began to develop new methods for production allocation to individual layers utilizing commingled well production. The allocated production data will be used to calculate initial oil in place in the three main sands as well as the sub-thrust reservoirs.

In order to allocate oil production to each producing sand, the total perforation interval and the effective time duration for each perforation were determined for each well. Cumulative oil production for each time interval was calculated using the actual well production data. The oil transmissibility of individual perforation intervals are calculated utilizing formation average water saturation and the pertinent sands oil and rock properties. The total effective transmissibility for each well at each time interval is obtained by adding the active perforation transmissibilities during that time interval. The oil produced from the sand during each time interval for each well is obtained by multiplying the oil produced from the time interval by the effective formation transmissibility and dividing the product by the total effective well transmissibility. Finally oil production from each sand is calculated by adding the oil produced during each time interval. The allocation program was modified to take into account reservoir pressure history and changes in fluid saturations. Reservoir pressure history was used to estimate the pressure at the end of each producing month. The water saturation at the end of each time interval was updated by replacing produced oil by water. The drainage volumes for individual wells in each sand were also updated at the end of a given time step. It was assumed that the drainage volumes of the wells in each sand are directly proportional to the well's cumulative oil production and inversely proportional to the initial hydrocarbon column.

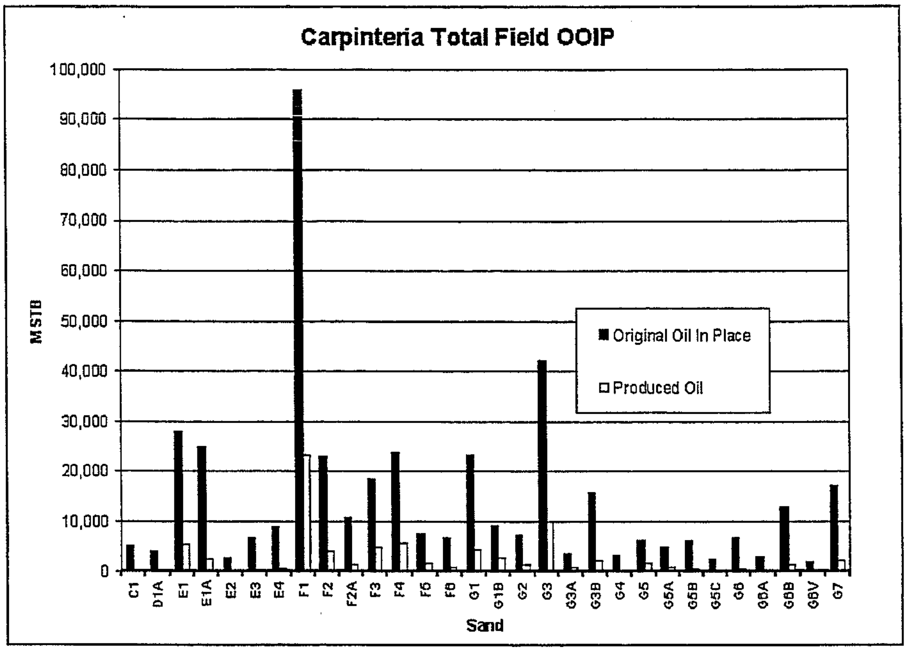



Figure 8 is a bar graph depicting the original oil in place and the remaining oil on a sand by sand basis.

### 3.3.3. Productivity of Horizontal Wells

A preliminary study of the expected productivity of horizontal wells producing from E-1, F-1 and F-3 sands in the Carpinteria offshore field, using pseudo steady state method presented by Babu and

*Figure 8 - Bar chart showing distribution of OOIP and cumulative oil produced by zone*

Odeh (SPERE Nov. 1989, p.417-421), has been completed. Reservoir and fluid parameters utilized in this study are given in Table 6. Figure 9 shows the effect of well length on the productivity index, PI, for the three sands. Other effects, such as oil viscosity, horizontal permeability and permeability ratio were also analyzed. In general, for the range of applicable reservoir data, the proposed horizontal drilling can substantially increase the productivity of new wells in the Carpinteria sands.

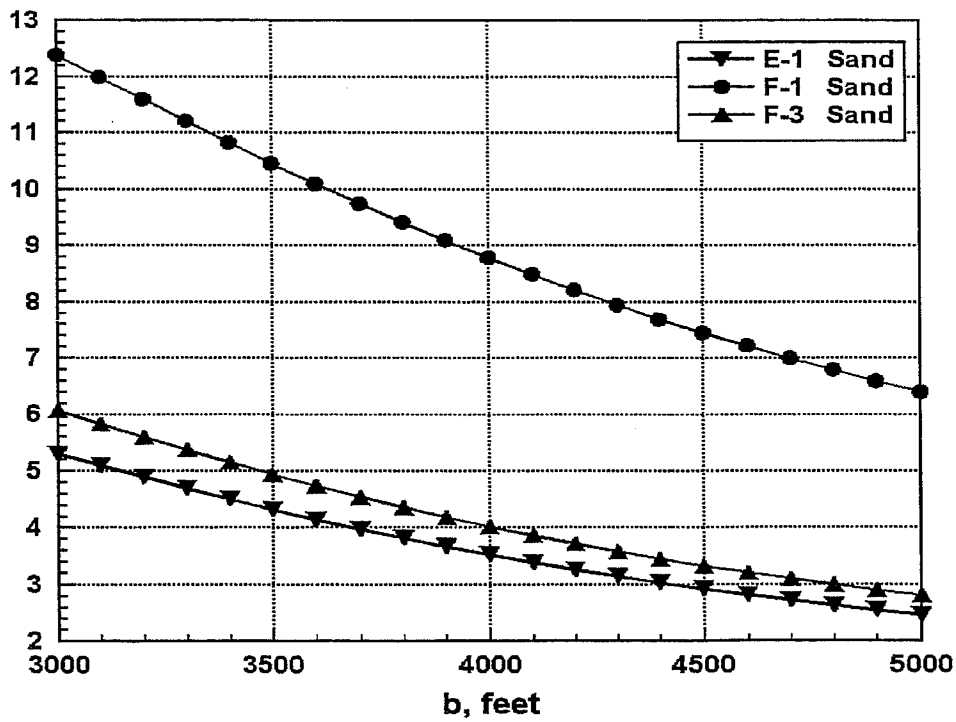



*Figure 9 – Productivity of horizontal well versus length*

**TABLE 6**
**Reservoir and Fluid Properties**

| Parameter | E-1 sand | F-1 sand | F-3 sand |
|---|---|---|---|
| Well length, feet | 1500 | 1500 | 1500 |
| Sand Width, a, feet | 2000 | 2000 | 2000 |
| Sand Length, b, feet | 3000 | 3000 | 3000 |
| Sand thickness, h, feet | 45.60 | 107 | 42 |
| Wellbore radius, $r_w$, feet | 0.25 | 0.25 | 0.25 |
| Oil viscosity, cp | 20.0 | 8.5 | 8.5 |
| Oil formation volume factor, bbl/STB | 1.065 | 1.07 | 1.07 |
| Permeability in x direction, md | 425 | 223 | 223 |
| Permeability in y direction, md | 425 | 223 | 223 |
| Permeability in z direction, md | 340 | 178.4 | 178.4 |
| $x_0$, feet | 1000 | 1000 | 1000 |
| $z_0$, feet | 41.04 | 96.3 | 37.8 |
| $y_1$, feet | 500 | 500 | 500 |
| $y_2$, feet | 2000 | 2000 | 2000 |
| Skin factor | 0 | 0 | 0 |

## 3.4 Analysis of Reservoir Performance

Well Test Data – All pressure data for Lease OCS P-0166 has been analyzed. A total of 39 pressure buildup test were analyzed which include 17 DST test. The results of these DST tests are show in Table 7. Results of analysis from DST No. 3, 4 and 5, which had surface flow rates, are believed to produce the most reliable permeability values for the sub-thrust G-7 and the supra thrust G-1 and F-1 layers respectively in the drainage areas encountered during the tests.

## TABLE 7
## Analysis of Drill Stem Tests

| Well No. | Fluid | Date | Type | Zones | Ref. Depth | $P^*$, psig | k, md |
|---|---|---|---|---|---|---|---|
| CH#6 | 38 BOPD<br>12 BWPD | 4/26/67 | DST#3 | G-7ST | -4944 | 2243.5 | ko 1.43<br>kw 0.11 |
| CH#6 | 348 BOPD | 4/29/67 | DST#4 | G-1 | -3436 | 1594 | 45.9 |
| CH#6 | 555 BOPD | 4/30/67 | DST#5 | F-1 | -2854 | 1277 | 386.5 |
| A-1 | 60% OIL<br>40%W | 5/24/68 | DST#1 | G-6 | -4254 | 1880 | 2.3<br>2FP 3.8 |
| A-1 | WATER | 5/25/68 | DST#2 | F-4 | -3467 | 1548.5 | 81.2 |
| A-1 | 90% OIL | 5/27/68 | DST#3 | F-4 | -3467 | 1556 | 56.6 |
| A-1 | WATER | 5/28/68 | DST#4 | E-1 | -2641 | 1200.9 | 42.3 |
| A-1 | OIL | 6/2/68 | DST#5 | E-1 | -2641 | 1193.5 | 110.8 |
| A-2 | WATER | 5/19/68 | DST#1 | F-4 | -3496 | 1534 | 307 |
| A-2 | OIL | 5/20/68 | DST#2 | F-1 | -3170 | 1373 | 104.7 |
| A-2 | OIL | 5/21/68 | DST#3 | E-2 | -2785 | 1230 | 132.6 |
| A-7 | OIL | 9/26/68 | DST#1 | F-1 | -3077 | 1206 | 124.5 |
| A-12 | OIL | 7/30/68 | DST#1 | G-7ST | -5120 | 2351 | 13.8 |
| A-12 | OIL | 8/1/68 | DST#2 | G-6ST | -4829 | 2156 | 36 |
| A-12 | GAS | 8/2/68 | DST#3 | G-5ST | -4741 | - | 0.3 |
| B-2A | Oil | 4/24/69 | DST#1 | G-5AST | -4818 | 2173 | 9.6 |
| B-2A | Oil | 4/25/69 | DST#2 | G-3B | -3485 | 1557 | 234 |

PVT Data - Further analysis of PVT data results in the data shown in Table 8 which presents a comparison between the properties of the reservoir fluids. Figure 10 shows a linear relationship of methane content with saturation pressure of the reservoir fluids.

## TABLE 8
**Comparison between Reservoir Fluids**

| No. | Type of Sample | Formation | Temp. °F | $P_b$ , psig | $R_s$ , SCF/STB @ $P_b$ and Res. Temperature |
|---|---|---|---|---|---|
| 1 | Rec. Well CH-6 | - | 110 | 1546 | 223 |
| 2 | Rec. Well # 40 | E-1 zone | 124 | 1218 | 173 |
| 3 | BH sample A-7 | F zone | 122 | 2155 | 336 |
| 4 | BH sample B-2A | G-3A zone | 126 | 1271 | 212 |
| 5 | BH sample B-2A | G-5A ST | 145 | 974 | 273 |

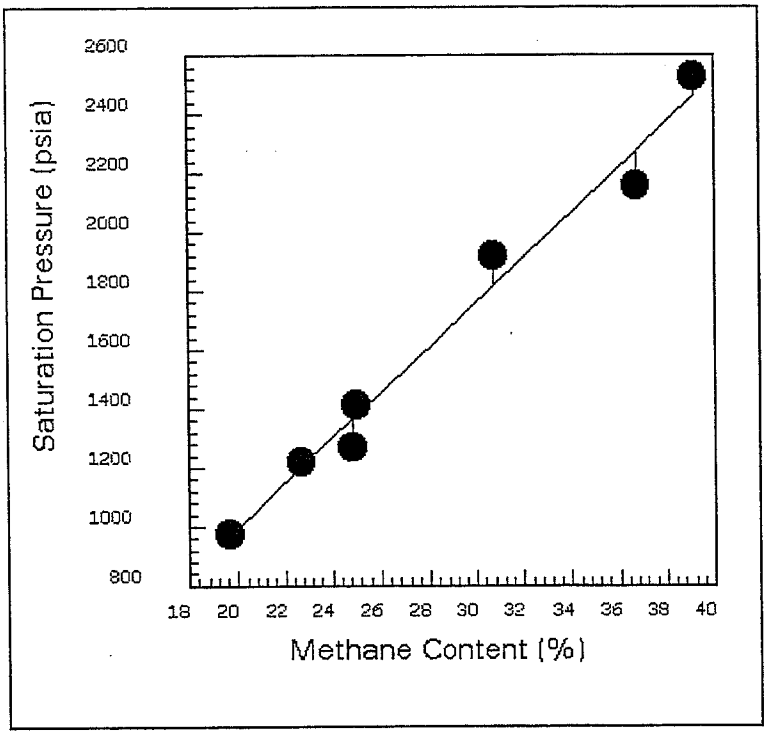



*Figure 10 - Saturation pressure vs. methane content*

Reservoir Pressure - In addition to the static pressure data, a flowing bottom hole pressure database has been developed from fluid level measurements from the last 5 years of operations. Figure 11 presents flowing bottom hole pressure versus time from the fluid level data.

In the basic material balance study of the field, the combined effects of reservoir compressibility, depletion and water influx need to be examined. From the review of the database, indications are that the reservoir pressure from its initial value of 1500 psig dropped to 870 psig in a matter of 3 years. Following this initial drop in pressure, a period of pressure stabilization indicates potential water influx. Cumulative production from various segments of the lease indicate considerable production of water. From diagnostic plots of water cut versus cumulative production, indications are that high water production may be caused from commingled production from oil and wet sands and aquifer influx. In order to better understand field producibility problems a transmissivity map representing the heterogeneity of the field will be created. A qualitative distribution of remaining oil in the four most important layers, namely E-1, F-1, and F-3 using the above procedure was determined.

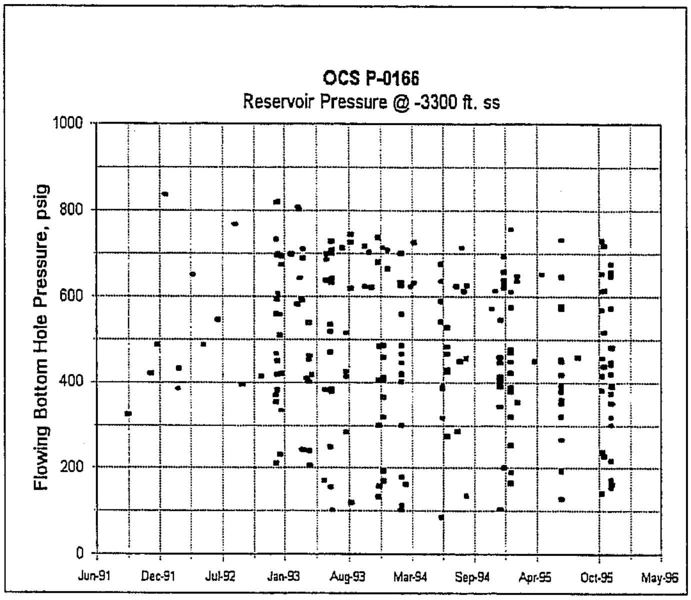



*Figure 11 - Reservoir pressure interpreted from Fluid level information*

### 3.5 Analysis of Water Production

Efforts are under way to construct the x-plots of individual wells for prediction of anticipated production under water influx. Water chemistry data are being compiled for finger-printing of the source of water and variation of water composition across the field and in individual sands. All available water chemistry data have been digitized. Table 9 shows a typical water analysis. Efforts are under way for fingerprinting of the source of water and variation of water composition across the field and in individual sands. Water oil ratio versus cumulative oil production of individual wells were used to study the source of water production.

**TABLE 9**
**Typical Water Analysis Data**

| WELL NO. : A-11 | DATE: 5-23-69 | | | |
|---|---|---|---|---|
| | Milligrams per liter | Milliequivalent per liter | Parts per million | Percent |
| Sodium | 7905 | 343.85 | 7781 | 35.9 |
| Calcium | 20 | 1 | 20 | 0.09 |
| Magnesium | 41 | 3.37 | 40 | 0.19 |
| Barium | 0 | 0 | 0 | 0 |
| Iron, Dissolved | | | | |
| Iron, Total | 0.4 | | 0.4 | 0 |
| | | | | |
| Hydroxide | 0 | 0 | 0 | 0 |
| Carbonate | 84 | 2.8 | 83 | 0.38 |
| Bicarbonate | 4111 | 67.42 | 4047 | 18.67 |
| Chloride | 9858 | 278 | 9704 | 44.77 |
| Sulfate | 0 | 0 | 0 | 0 |
| | | | | |
| Total Dissolved Solids (Sum.) | 22019 | | 21675 | 100 |
| | | | | |
| pH When Sampled | | | | |
| pH in Lab | 8.2 | | | |
| Resistivity, Ohm-meters at 77 °F | 0.326 | | | |
| Specific Gravity 60 / 60 °F | 1.0159 | | | |

### 3.6 Conclusions

During budget period I we have accomplished a large portion of our reservoir characterization objectives spelled out in the statement of work, which are summarized as follows:

Verified the original oil in place by two material balance methods and by volumetric analysis

Developed a system to allocate production by well and by layers and hence remaining reserves in each zone

Looked at the feasibility of horizontal wells which included a series of horizontal wells vs. one trilateral well.

## 4 Management and Administration

Monthly meetings of the steering committee continue to be held in POOI's Ventura office or at USC to monitor the progress of the individual tasks.

# 5 Technology Transfer

## 5.1 Publications and Reports

During this period we completed the following activities:

Bi weekly meeting at USC on the geology and production issues related to slope and basin reservoirs.

2. March 1, 1996: Pacific Operators hosted a tour of their offshore Platforms including a presentation on the field recovery potential to representatives from the DOE and the local congresswoman, Rep. Andrea Seastrand.

3. March 13, 1996: Made a presentation on the Carpinteria Redevelopment project at the API Energy Day

4. July 8, 1996: Presentation to regulatory agencies (Minerals Management Service and California State Lands Commission) on recovery potential of the Carpinteria field using convention reservoir engineering techniques.

5. August 21, 1996: Review of geology, drilling problems and reservoir issues presented New York investment community visiting in Santa Barbara.

6. June - September, 1996: Provided internship to three college students who received supervised instructing relating to the project.

7. August - Present: Developed a Pacific Operators maintained web site for online reporting on the progress of the Class III project. The address for this web site is: http://www.pacops.com

8. Attended Tech Transfer planning meeting with other Class III project in Valencia, CA.

9. Participated in brain-storming sessions related to the initial formation of the west coast PTTC.

10. Conducted sessions with the CSLC to demonstrate that the State portion of field has significant remaining reserves and that it should be included in the Class III study for potential drilling.

11. Pacific Operators was invited to contribute its reservoir database as an example of slope and basin reservoir as a part of the on-line database under development between USC and LLNL.

# 6 Budget Period II

## 6.1 Introduction

Our current plans are to proceed to budget period II during the third quarter of 1997. Our plans are to drill horizontal wellbores as called for in our SOW, however due to the remaining uncertainties in our understanding of the reservoir we will most likely drill the three wellbores by redrilling two existing wells and drilling one longer reach horizontal well. Figure 12 is a vertical section view of a updip horizontal well that would be drilled from Platform Hogan.

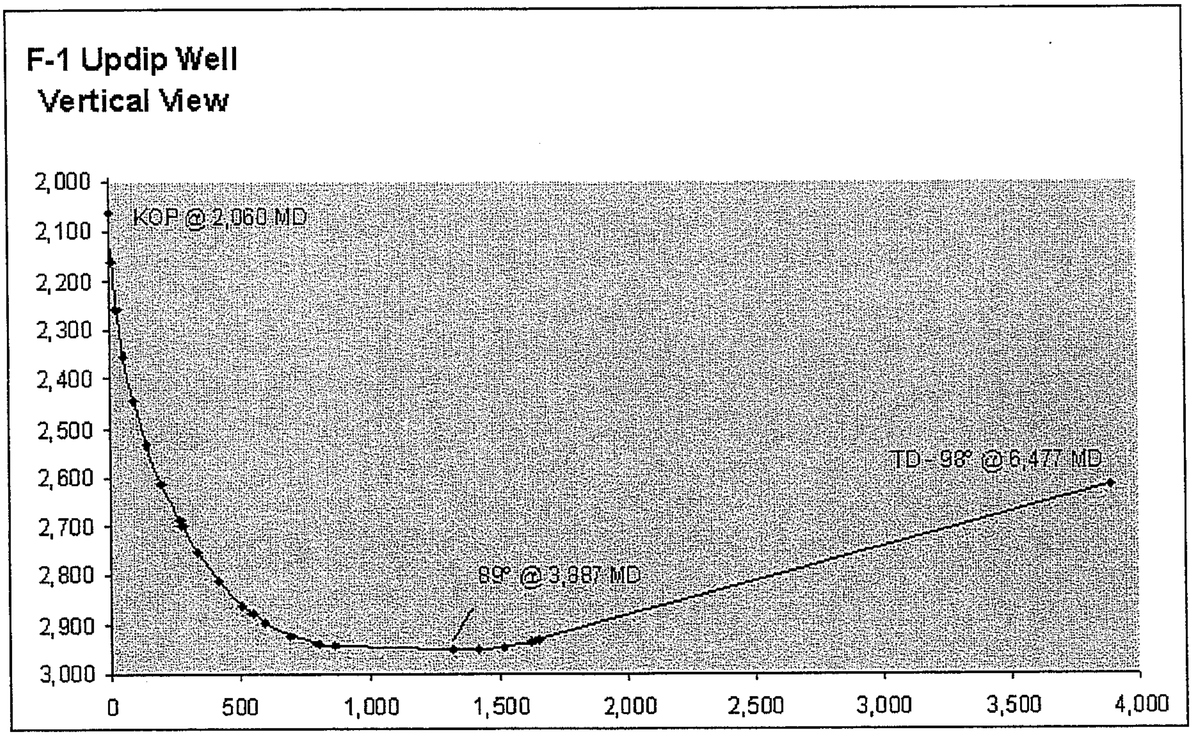



*Figure 12 – Vertical section view of a planned updip horizontal well*

# ADDENDUM

# to

## Feasibility of Optimizing Recovery and Reserves From a Mature and Geologically Complex Multiple Turbidite Offshore California Reservoir Through The Drilling And Completion of a Trilateral Horizontal Well

DOE Contract No. DE-FC22-95BC14935

Feasibility of Optimizing Recovery and Reserves
from a Mature and Geologically Complex Multiple
Turbidite Offshore California Reservoir
Through the Drilling and Completion
of a Trilateral Horizontal Well

# PROJECT EVALUATION REPORT

## Table of Contents

## Abstract

The budget period I objectives set forth in the Statement of Work were successfully met in this project. In fact additional time and effort was directed toward an expansion of the budget period I tasks by including a larger study area that had originally been proposed in our SOW. We realized early on in our study that in order for us to gain the most complete understanding of our lease area that we needed to include the adjacent leases in the field in the study project. This included 3 leases to the north of OCS P-0166 that were recently acquired by the Pacific Operators group and one lease to the south currently operated by Torch Energy (formerly Unocal).

A significant conclusion of the budget period I study was that after fully evaluating the available data for the Carpinteria field, significant uncertainty remained on the state of current depletion on an individual zone by zone basis. This is primarily due to the fact that the field was produced in a commingled fashion from inception. A great deal of attention and effort was placed on allocation of production history on a by well by zone basis. While we feel we have a good estimate, this remaining uncertainty would add risk to drilling a new (grass roots) tri-lateral well in three separate horizons. Instead, we intensely evaluated creating several laterals from existing vertical wells by redrilling the wells. A monte carlo model was developed that allowed us to model the potential affects of this modification to budget period II.

Budget period I activities are recapped in the following discussion:

## Executive Summary

During Budget period I of this project a considerable amount of reservoir and geologic study of the field was accomplished. Further, we were fortunate to be able to gain insight and results from a complementing reservoir simulation study that was being developed concurrent with this study. During this budget period we accomplished the following:

- Created a digital production database for all wells in the field which included an extensive effort to quality check the data and verify its integrity.

- Performed petrophyiscal analysis on 198 wells in the suprathrust and 51 wells in the subthrust. All the calculated well log attributes were transferred into a 3-D modeling package called EarthVision.

- 39 pressure buildup tests and 17 drill stem tests were examined and analyzed.

- PVT data was analyzed from 5 original samples taken early in the life of the field.

- Available core data in the field was analyzed. A compaction correction to the core permeability was applied and the results compared to the results from the well test analysis.

- A geologic model consisting of 29 reservoirs along with the Hobson thrust fault and five normal faults was constructed using a 3-D geological modeling package called EarthVision.

- Since all zones in the field were produced in a comingled fashion, a significant effort was required to allocate production back to the individual zones on a well by well basis. The remaining oil in each sand was found by subtracting the amount of oil produced from each sand in each well from the original oil in place.

- An estimate of the productivity of a horizontal well was made by applying a pseudo steady state method, Babu and Odeh.

- Both the volumetric and material balance method were applied to estimate original oil in place on lease OCS P-0166. A monte carlo model for each method was developed.

- A considerable effort was made toward planning for budget period II, the drilling phase of this project. We determined that the best way to proceed in BPII was to drill several laterals from existing wellbores (redrills) as opposed to drilling a new tri-lateral well. This approach will allow for a greater amount of information and knowledge to be obtained from the reservoir.

## Database Activities

Production Data

Our project employed production history management software called Production Analyst or "PA". This software, developed by OGCI (Oil and Gas Consultants International), allowed production history by individual wells to be easily combined and grouped to prepare diagnostic plots for analysis of reservoir behavior.

Cumulative oil production for lease OCS-P-0166 as of August, 1995 is 44.96 MMbbls oil, 39.46 BCF gas and 58.01 MMbbls.

Because all the wells on the lease are drilled from one of two platforms (platform Hogan or Houchin), an X-Y coordinate system was used to show the reference datum well spots on the location map. This map interface accompanies the PA program. The datum used was the F1 sand.

A minor amount of programming was required to modify Pacific Operators existing production history database system into an ASCII format for loading into PA. During the investigation period, production history updates were loaded into the program using this same method (ASCII data import).

Further, the quality of the production history database was carefully compared with historical hard copy reports and production history database available from the regulatory agency, the Minerals Management Service. Each of these databases contains a huge number of monthly oil, gas and water production values. In order to compare the two databases a computer program was written to compare the data on a well by well, month by month basis. The differences then were checked with the hard copy and corrections were made where appropriate.

Well Log Data

Prior to the start of the project, a considerable amount of work had been accomplished on the well log database. The well log processing system that was used for this task is LOGCALC II, by Scientific Software, running on a DEC Micro-VAX II system.

During the log processing cycle, a considerable effort was directed toward quality control checking. A series of calculated log parameter maps were created for each zone. These maps were developed by contouring each calculated parameter with a computer contouring package. Each map, for each layer or zone was compared to validate the calculated results.

Once the calculation of the petrophysical attributes were completed, they were formatted into ASCII files and transferred to the 3-D modeling package (originally Stratamodel and later EarthVision)

A considerable effort was made to determine the oil / water contacts of each sand in each well. This was accomplished by using annotated computed logs and the marker data. For the purpose of computer aided mapping, estimation of depth corresponding to the oil water contact within each layer for individual wells was prepared.

Quality control consisted of use of the data in EarthVision, comparing the data with top and bottom picks and plotting a number of computer cross sections which included the oil water contacts. The computer cross sections were also used to scrutinize the effect of production in the key areas. For these areas, studies have been started to assess the effect of production on logs for mapping swept and unswept oil, and to evaluate remaining reserves. Several potential remaining productive areas were identified.

The original efforts of the log study focused on the supra-thrust portion of the field. Later efforts included the subthrust portion of the field and the integration of the oil/water contacts into the geological model.

Toward the end of the study effort, a program to re-process many of the well logs in the field was initiated. This was necessary for two reasons: 1) Our prior 3-D geologic modeling efforts used a log data set that contained cut-offs applied by the log calculation package. Because of the way the 3-D modeling program works (EarthVision) it is more desirable to apply parameter cut-offs in the 3-D package. 2) Because of some additional water analysis data we recently obtained on the Chevron portion of the field we were able apply a much better water salinity relationship in the intervals below the G7.

Concentration on wells which had poorer response and less cumulative oil production than would have been anticipated by the operators suggests the following.

(1) Wells which had a substantial amount of net pay in the "F" sands and which did not have good pay in the "G" sands depleted early did not have high water cumulative water production. This suggests that water support and/or oil and water migration did not occur in these wells. Attempts to further define the conditions points to the need for additional fault modeling based on these premises.

(2) Examination of the logs, both open hole from the late drilling program and some of the cased hole logs of about the same vintage suggest that the "G" sands do tend to show changing oil water contacts. The "F-1" sand in particular shows some desaturation with time, but not clearly a change in the water surface. Since the "F-1" is the biggest single sand and may still contain the most potential oil we should consider the F-1 as a candidate for some flank support with water injection, perhaps following some additional measurement of zone pressures in these weak areas.

Also, we made a determination of oil/water contacts in the wells penetrating the subthrust, and subsequent calculation of vertical depths and coordinates of water in wet zones, depths of oil in oil filled zones and verification graphically of all picks and calculations. This was done along with the re-verification of all markers from both the 51 wells in the subthrust, and the 198 wells in the suprathrust sections. Toward the end of the petrophysics study we revisited some of the earlier markers picks. Missing from this work are a number of log markers from the wells on the P-240 lease and digitized logs from the state 3133 parcel, both of which are considered of lesser importance to the study due to fault separation and short term potential economic value. Marker data from the subthrust was supplied to the geology group for mapping.

Continuing feedback and evaluation of information from an ongoing workover program in the field and the potential redrill program, along with the refinement of the fault picks by the geologists, verified some of the previously suspected relationships between log calculations and production results. This information allowed the construction of a new 3-D model that better represents the reservoir.

One unconfirmed point in the observation of the logs is the fact that most of the wells which have oil saturation in a particular sand or layer in the subthrust interval generally do not have any saturation in that sand in the suprathrust interval. This is true particularly on the P-0166 and in part of the SACS-3150 areas and has not been examined on the P-240 and the 3133 leases. It is anticipated that the construction of the next generation 3-D model will expand this understanding and define the areas over which this may apply, and provide an estimate of the potential for a horizontal well in the subthrust area.

In the reprocessing of logs in the subthrust of the 3150 (7911) lease, and in the light of the now available raw data for all the wells, it is noted that a high incidence of incorrectly digitized data, or data which had not been checked by the prior operator, is present on the wells drilled during the period from 1979 to 1984. At least five of these wells have data that did not agree with the raw data, and required some additional digitizing.

Well Completion Database

A well completion database containing the completion history of all of the current producing wells was created prior to the start of the Class III project. This information was maintained in a Paradox database and was made available to the Class III project. Following creating of that database, the company made a switch to MS-Access database and imported the data into an Access table. Additional information was added to the database, such as perforation information, marker information etc.

Well Test Data

A total of 25 pressure buildup tests from wells A-1(3), A-3(3), A-4(1), A-6(4), A-9(2), A-15(2), A-16A(1), A-18(2), A-23(2), A-25(2), A-38(1) and B-28(2) with pertinent data necessary for pressure transient analysis were digitized, and put in ASCII format files.

Additional pressure data was collected and prepared in a standardized ASCII format. A total of 39 pressure buildup test were analyzed which include 17 drill stem tests (DST's). The results of these DST tests are shown in table 1. Results of analysis from DST No. 3, 4 and 5, which had surface flow rates, are believed to produce the most reliable permeability values for the sub-thrust G-7 and the supra thrust G-1 and F-1 layers respectively in the drainage areas encountered during the tests.

**TABLE 1**
**Analysis of Drill Stem Tests**

| Well No. | Fluid | Date | Type | Zones | Ref. Depth | P*, psig | k, md |
|---|---|---|---|---|---|---|---|
| CH#6 | 38 BOPD<br>12 BWPD | 4/26/67 | DST#3 | G-7ST | -4944 | 2243.5 | ko 1.43<br>kw 0.11 |
| CH#6 | 348 BOPD | 4/29/67 | DST#4 | G-1 | -3436 | 1594 | 45.9 |
| CH#6 | 555 BOPD | 4/30/67 | DST#5 | F-1 | -2854 | 1277 | 386.5 |
| A-1 | 60% OIL<br>40%W | 5/24/68 | DST#1 | G-6 | -4254 | 1880 | 2.3<br>2FP 3.8 |
| A-1 | WATER | 5/25/68 | DST#2 | F-4 | -3467 | 1548.5 | 81.2 |
| A-1 | 90% OIL | 5/27/68 | DST#3 | F-4 | -3467 | 1556 | 56.6 |
| A-1 | WATER | 5/28/68 | DST#4 | E-1 | -2641 | 1200.9 | 42.3 |
| A-1 | OIL | 6/2/68 | DST#5 | E-1 | -2641 | 1193.5 | 110.8 |
| A-2 | WATER | 5/19/68 | DST#1 | F-4 | -3496 | 1534 | 307 |
| A-2 | OIL | 5/20/68 | DST#2 | F-1 | -3170 | 1373 | 104.7 |
| A-2 | OIL | 5/21/68 | DST#3 | E-2 | -2785 | 1230 | 132.6 |
| A-7 | OIL | 9/26/68 | DST#1 | F-1 | -3077 | 1206 | 124.5 |
| A-12 | OIL | 7/30/68 | DST#1 | G-7ST | -5120 | 2351 | 13.8 |
| A-12 | OIL | 8/1/68 | DST#2 | G-6ST | -4829 | 2156 | 36 |
| A-12 | GAS | 8/2/68 | DST#3 | G-5ST | -4741 | - | 0.3 |
| B-2A | Oil | 4/24/69 | DST#1 | G-5AST | -4818 | 2173 | 9.6 |
| B-2A | Oil | 4/25/69 | DST#2 | G-3B | -3485 | 1557 | 234 |

<u>PVT Data</u>

A total of five oil samples were taken from lease OCS P-0166 for PVT analysis. The first oil sample was prepared from recombining a sample of separator liquid with a synthesized separator gas in order to obtain a fluid having a bubble point equal to the original reservoir pressure of 1545 psig at 110 °F. This sample was taken on November 28, 1967 prior to start of lease production. Although the synthesized gas was not exact in its physical properties, it was felt to be within the practical limits for the recombination. The saturation pressure of the recombined sample was measured to be 1546 psig at a reservoir temperature of 110 °F. During differential pressure depletion at 110 °F the fluid evolved 223 SCF/STB. The viscosity of the liquid varied from a minimum of 14.4 centipoise at saturation pressure to a maximum of 46.5 centipoise at atmospheric pressure. The gravity of the residual oil was 22.0 °API at 60 °F.

The second recombined sample was taken early in the producing life of the lease on July 12, 1968 from well A-4. The well was opened to the E, F and G zones. The separator gas oil ratio (GOR) was 436 SCF/STB. PVT analysis of this sample resulted in 460 SCF/STB of gas in solution at a saturation pressure of 2528 psig and reservoir temperature of 122 °F. It is worth noting that this pressure is approximately 400 psi higher than the hydrostatic pressure at the deepest oil bearing point in the well (4630 ft. subsea). The gravity of the residual oil was 26.2 °API at 60 °F.

The third sample is a subsurface sample taken from Well A-7 on Sept. 28, 1968 from the F zone. This sample established a saturation pressure of 2155 psig at a reservoir temperature of 122 °F and a solution GOR of 336 SCF/STB. The gravity of the residual oil was 25.2 °API at 60 °F.

Subsurface samples 4 and 5 were taken April 24, 1969 during Drill Stem Test No. 1 (DST No. 1) on Well B-2A. The producing interval during the test was 5090-5115 ft. MD which corresponds to the G-5A sub-thrust sand. DST No.2 on the same well sampled the G-3A sand from a producing interval 3785-3805 ft. MD. These samples exhibited saturation pressures of 974 psig at 145 °F and 1271 psig at 126 °F with solution GORs of 273 and 212 SCF/STB respectively. The gravity of the residual oil samples were 32.4 and 25.8 °API at 60 °F respectively.

Further analysis of PVT data results in the data shown in Table 2 which presents a comparison between the properties of the reservoir fluids.

**TABLE 2**
**Comparison Between Reservoir Fluids**

| No. | Type of Sample | Formation | Temp. °F | $P_b$ , psig | $R_s$ , SCF/STB @ $P_b$ and Res. Temperature |
|---|---|---|---|---|---|
| 1 | Rec. Well CH-6 | - | 110 | 1546 | 223 |
| 2 | Rec. Well # 40 | E-1 zone | 124 | 1218 | 173 |
| 3 | BH sample A-7 | F zone | 122 | 2155 | 336 |
| 4 | BH sample B-2A | G-3A zone | 126 | 1271 | 212 |
| 5 | BH sample B-2A | G-5A ST | 145 | 974 | 273 |

<u>Reservoir Pressure</u>

The initial reservoir pressure on lease OCS P-0166 was calculated to be 1500 psig at a datum of 3300 ft subsea. A reservoir pressure database was developed. During the last 8-10 years of operations very few reservoir pressure measurements were made, however fluid level measurements that were equated to reservoir pressure from the last 5-7 years of operations were updated in the database. Further, some static reservoir pressures have been taken over the last year in conjunction with an ongoing workover program in the field.

All available gas analysis data was digitized. Table 3 shows a typical gas analysis data set. Also the historical API gravity measurements were also digitized and analyzed. A chronological drop of API gravities are attributed to the loss of the light components during the solution gas drive process.

**TABLE 3**
**Typical Gas Analysis**

| Well No.: A-6 , Sample # 1, Date : 7-25-68 | |
|---|---|
| Component | Mole per cent |
| He | <.01 |
| CO2 | 3.28 |
| N | 0.06 |
| CH4 | 84.34 |
| C2H6 | 2.67 |
| Propane | 4.1 |
| I-Butane | 0.84 |
| N-Butane | 1.81 |
| I-Pentane | 0.82 |
| N-Pentane | 0.74 |
| Hexane | 0.52 |
| Heptanes and Heavier | 0.82 |
| | |
| Specific Gravity | 0.7487 |
| Heating Value | |
| Dry | 1237 |
| Wet | 1215 |

## Stratigraphy and Micro-lamination Study

Based on the well log correlations completed prior to the date of this project a total of 29 sub-layers were identified. For material balance studies, a database was developed to relate cumulative production of oil and water to various sub-categories of producing horizons. All available conventional core analysis from whole core and sidewall plugs were digitized. This data was used in a microlamination study. In addition, screen or sieve analysis data, where available, was also studied. A general trend of east to west permeability decrease was observed from core data and analysis of initial oil production. Table 4 shows the wells on lease P-0166 that were cored.

# TABLE 4
## OCS P-0166 Core Material

| Date Cored | Well | Zones Cored |
|---|---|---|
| August, 1968 | A-9 | E-1, F-1, G-2, G-6B, Subthrust |
| August, 1969 | B-15 | F-1, F-2, F-4, G-1, G-1B, G-3 |
| August, 1978 | A-49 | E-1 |
| May, 1979 | B-35 | G-1, G-3 + Sidewall Cores |
| October, 1980 | B-45 | E1, E1A, F1, F4, G1 |

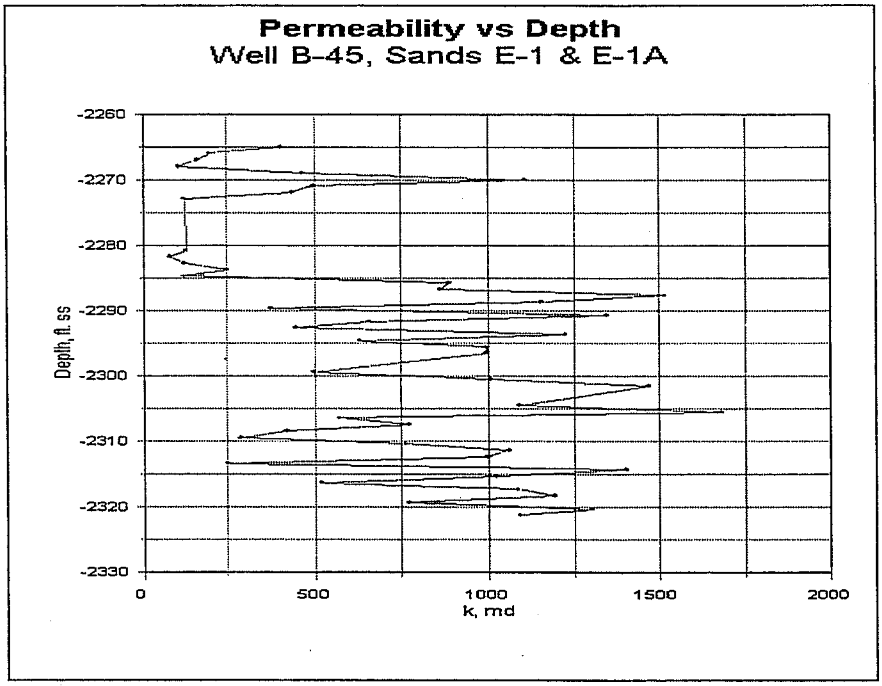



Figure 1

Core data from four wells, A-9, B-15, B-35 and B-45, was used to develop a correlation for correcting lab permeability data for overburden pressure. This correlation was developed by using experimental compaction test data. Compaction corrected permeability data for well B-45 (E sand) is plotted versus depth and shown in figure 1. In addition, table 5 shows the core permeability and porosity data for all of the cored wells.

## TABLE 5
## Comparison of Core Permeability And Porosity by Zone

| Well | Formation | Corrected k | Porosity |
|---|---|---|---|
| A-9 | E-1 | 847.09 | 31.52 |
| B-45 | E-1 | 396.79 | 35.21 |
| B-45 | E-1A | 546.34 | 36.3 |
| | | | |
| A-9 | F-1 | 389.09 | 29.44 |
| B-15 | F-1 | 229.96 | 27.73 |
| B-45 | F-1 | 318.13 | 36.8 |
| | | | |
| B-15 | F-2 | 427.95 | 29.43 |
| | | | |
| B-45 | F-4 | 482.14 | 34.38 |
| | | | |
| B-15 | G-1 | 199.26 | 28.56 |
| B-35 | G-1 | 94.72 | 24.43 |
| B-45 | G-1 | 332.75 | 32.14 |
| | | | |
| B-15 | G-1B | 125.49 | 25.33 |
| | | | |
| A-9 | G-2 | 283.07 | 27.11 |
| | | | |
| B-15 | G-3 | 157.96 | 25.92 |
| B-35 | G-3 | 214.2 | 26.89 |
| | | | |
| B-15 | G-3B | 153.4 | 25.6 |
| | | | |
| A-9 | G-6BST | 45.14 | 22.71 |

Although the data is somewhat sporadic there is a trend of decreasing permeability with depth as might be expected.

Special core analysis data including water-oil relative permeability, gas-oil relative permeability and air-water capillary pressure data were digitized. Reservoir water-oil capillary pressure data was derived from air-water capillary pressures. Finally, a complete set of reservoir data was compiled for a reservoir simulation study that POOI plans to conduct in the future outside of the scope of the Class III project.

Lithology of cored sections was investigated. A study of thin shales and silt stones in cored wells included comparisons of resistivity logs, continuity of thin shales and silts tones and their effect on past production. The three dimensional visual model, Earth vision (Dynamic Graphics Software) was used for visualization, comparison and posting data.

Geology
A geologic model of 29 reservoirs along with the Hobson thrust fault and five normal faults was constructed using a 3-D geological modeling package called EarthVision. Further, the distribution of log calculated attributes was populated in the 3-D model.

An intensive effort to verify faults continued nearly up to the end of the budget period I study. One of the techniques used to identify some of the smaller faults was accomplished by mapping the oil water contacts in each reservoir. This effort lead to the relocation of some existing faults (some of the five normal faults mentioned above) and the discovery of some additional faults. This work was used to find additional, but previously overlooked, fault intersections with the wellbores. Depending on the direction of fault movement, horizontal, vertical or a combination of both, indications are that hydraulic isolation of some layers could occur with little or no vertical offset or displacement on a log, with interruption of the depositional sequence.

Because of the small throws on most of the faults in the field we needed to do additional work to verify fault plane angles. This was accomplished by creating on the oil/water contact summary maps. These maps show the configuration of the oil/water contact surface overlaid with isopachs of gross saturated interval. Well data points are posted with symbols displaying the saturation state of individual zone penetrations, i.e., fully oil saturated, wet, or containing an oil/water contact. Only the early well set was used in the preparation of these maps so that the results represent a depiction of the original oil saturation of the reservoir. Preliminary fault patterns from well correlation work have also been overlaid for comparison with the saturation patterns. These maps were completed for zones E4 through G3B on Leases P-0166.

These maps depict our best estimate of the original reservoir saturation distribution for each zone and frequently show concentrations of hydrocarbon saturation along the plunge of the structure which must be due to some sort of migration barrier, probably faulting. On Lease P-0166 two of these areas correspond to the positions of the West Hogan and West Boundary faults, respectively, which had previously been mapped based on well correlation data. A third anomaly appeared in the area of Platform Houchin which seems to imply a previously unrecognized fault which we are calling Houchin-1 or HOU1) for present. The distribution of wells on the OWC/saturation maps sets limits on the possible locations of the faults which are considered to cause the saturation anomalies, and these limits have been quantified and entered into an Excel spreadsheet.

The presence of congruent saturation anomalies in vertically separated zones provides a third dimension for fault location. These data were entered into EarthVision and examined with the 3-D viewer. After data conflicts were resolved, contouring was performed and .2grd and .plt files prepared in EarthVision. These fault planes were extended over the model space and checked for consistency with well data.

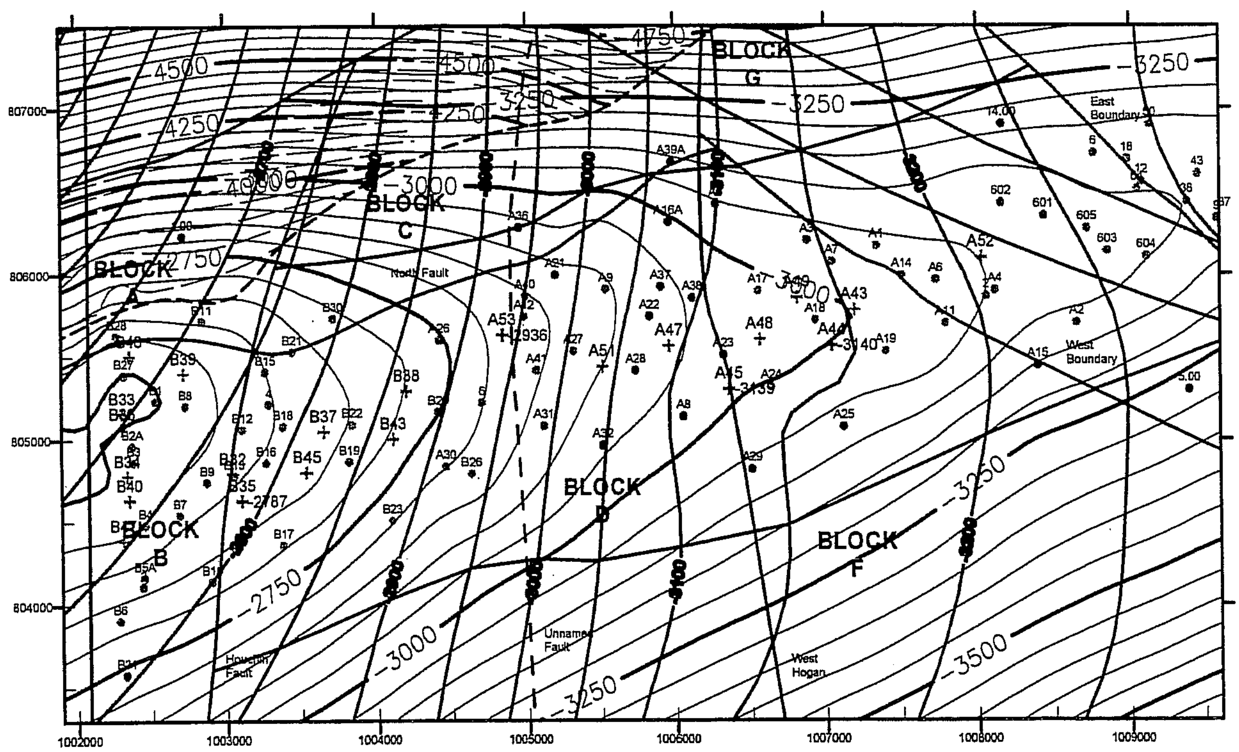
Similar to the suprathrust, zone top and base contact picking was also completed for the subthrust wells on leases P-0166 and PRC 3150. These picks were entered into an Access database for matching with X/Y location data, and contour maps of each subthrust horizon were prepared to produce quick mapping results for quality control purposes before entering the subthrust data into the 3-D model. Isochore maps of the subthrust stratigraphic intervals between zone G3 and the

Miocene were prepared in Surfer in support of quality control review of log picks previously made.

A final 3-D geologic model included a total of 6 faults; the East Boundary Fault, the West Boundary Fault, the West Hogan Fault, the newly recognized Houchin Fault, the North Fault and the Hobson Fault. The current fault interpretation has integrated the well log fault intercept picks made early in the project with results from the oil-water contact/fluid type/structure contour map overlays which were made in May and June, 1997. The resulting interpretation shows those faults that have a demonstrated effect on the distribution of reservoir fluids. EarthVision grid files were generated for these faults, and extended over the project area. From these, faces files were prepared which can be displayed in the EV 3-D viewer with the intercept data points, which allowed fine tuning of the fault plane orientation to obtain the best fit to all of the available data.

Figure 2 shows a 2-D map of the field with the six faults mentioned above.

WELLS, FAULT PATTERNS and STRUCTURE CONTOURS
Zone F1, Lease P-0166




OWC's in red, wet wells in blue, oil wells in green
OWC contours in cyan
Wells drilled after 1976 shown as crosses
Current fault pattern in magenta
EarthVision structure contours in black/green
Production limit from post-1976 wells in bold black
Lease lines in blue

Figure 2

## Reservoir Performance

In the basic material balance study of field, the combined effects of reservoir compressibility, depletion and water influx needed to be examined. From the review of the database, indications were that the reservoir pressure from its initial value of 1500 psig dropped to 870 psig in a matter of 3 years. Following this initial drop in pressure, a period of pressure stabilization indicates potential water influx. Cumulative production from various segments of the lease indicate considerable production of water. From diagnostic plots of water cut versus cumulative production, indications were that high water production may be caused from commingled production from oil and wet sands and aquifer influx. In order to better understand field producibility problems a transmissivity map representing the heterogeneity of the field was created.

Production Allocation

The majority of the wells in lease P-0166 were completed in multiple sands. As a first step in determining the remaining oil in each sand, we assumed a 5-acre drainage area for each well. The log derived net productive intervals with pertinent average effective porosity and water saturation were used to calculate the original oil in place (OOIP). A production allocation procedure was used to calculate cumulative oil produced from each zone (sand) in each well. The remaining oil in each sand was found by subtracting the amount of oil produced from each sand in each well from the original oil in place.

Well completion data was used to define a datum for each sand. According to completion information, the E-1 sand is the main producer in the E sand group, therefore an average value of -2500 ft. ss (feet subsea) was calculated from 92 wells. In the F sand group, the F-1 to F-4 sands are opened to most of the wells, therefore, the top of F-3 sand was selected as the datum for this group with an average value of -3000 ft. ss. The middle of the G sand group with an average value of -4000 ft. ss from 71 wells and the top of G-6 sand in the sub-thrust at a datum of -5000 ft. ss were selected for the G and sub-thrust (ST) groups respectively.

Average datum pressures of 1000 psig, 1200 psig, 1600 psig and 2000 psig were assumed for the E, F, G and ST sands respectively. Average oil properties for each sand at the prescribed pressure has been obtained from differential fluid analysis of surface and subsurface fluid samples taken from individual sands in the early life of the lease. The average core permeabilities were also corrected for the confining pressures at the datum planes.

In order to allocate oil production to each producing sand, the total perforation interval and the effective time duration for each perforation were determined for each well. Cumulative oil production for each time interval was calculated using the actual well production data. The oil transmissibilities of individual perforation intervals are calculated utilizing average formation water saturation and the pertinent sands oil and rock properties. The total effective transmissibility for each well at each time interval is obtained by adding the active perforation transmissibilities during that time interval. The oil produced from the sand during each time interval for each well is obtained by multiplying the oil produced from the time interval by the effective formation transmissibility and dividing the product by the total effective well transmissibility. Finally oil production from each sand is calculated by adding the oil produced during each time interval.

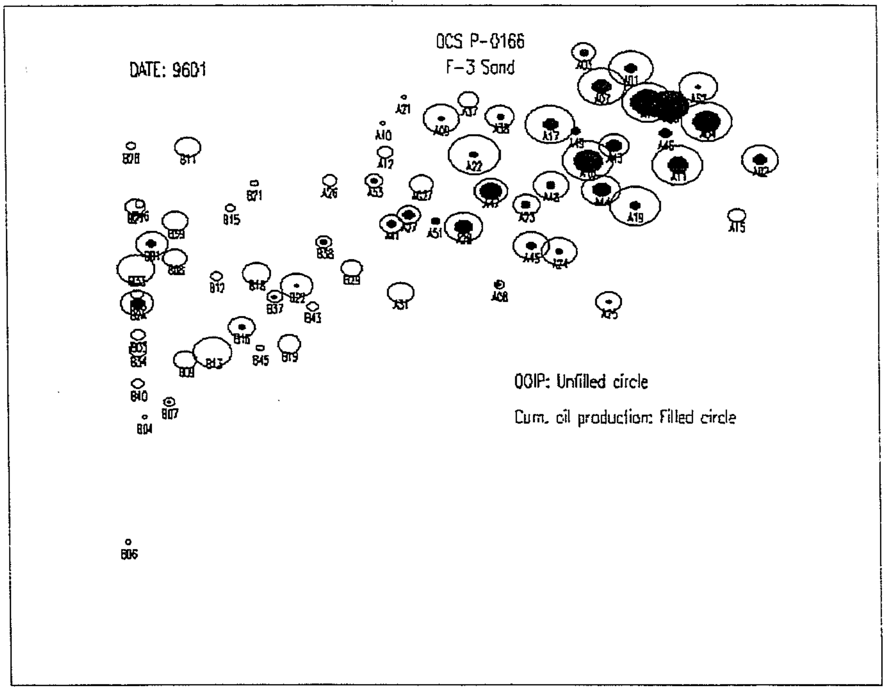


Figure 3

A qualitative distribution of remaining oil in the four most important layers, namely E-1, F-1, and F-3 using the above procedure was determined. Figure 3 is an example of a bubble map showing the remaining oil distribution in the F-3 sand. Later, three modifications were incorporated in the production allocation program: (1) reservoir pressure history was used to estimate the pressure at the end of each producing month; (2) the water saturation at the end of each time interval was updated by replacing produced oil by water; and (3) the drainage volumes for individual wells in each sand were updated at the end of a given time step. It was assumed that the drainage volumes of the wells in each sand are directly proportional to the well's cumulative oil production and inversely proportional to the initial hydrocarbon column. Some individual isolated zone tests were available to check the accuracy of the allocation results. Table 6 shows one such example.

**TABLE 6**
**Comparison of Allocation Program Results with Flow Tests by Zone - Well B-37**

| ZONE | FLOW TEST 12/7-20/1979 | ALLOCATION RESULTS JAN, 1980 |
|---|---|---|
| E | - | 4.9 % |
| F | 38.4 % | 32.1 % |
| G | 26.5 % | 22.6 % |
| Subthrust | 35.1 % | 40.4 % |

Productivity of Horizontal Wells

A preliminary study of the expected productivity of horizontal wells producing from E-1, F-1 and F-3 sands in the Carpinteria offshore field, using pseudo steady state method presented by Babu and Odeh (SPERE Nov. 1989, p.417-421), was completed. The horizontal permeability in the X and Y direction were assumed to be equal. The vertical to horizontal permeability ratio is assumed to be 80 percent in all cases. The result of this study shows that in general, for the range of applicable reservoir data, the proposed horizontal drilling can substantially increase the productivity of new wells in the Carpinteria sands.

Original Oil in Place - Material Balance

A Monte Carlo Simulation approach was devised to estimate OOIP in lease OCS P-0166. The material balance equation was rearranged in the following form:

$$N_i = a \times N_{pi} + b$$

where $N_i$ is an apparent estimate of initial oil in place at different time steps, i . Assuming no water influx, $Np_i$ is cumulative oil production at different time steps and a and b are constants. For a reservoir with water influx, $N_i$ tends to show mono-tonically increasing linear correlation with $Np_i$. The true value of original oil in place may be obtained by plotting $N_i$ versus $Np_i$ and extrapolating the straight line to $Np_i = 0$ . In this study a least squares approach was used to calculate the intercept of the straight line. Early time, data during which the reservoir was fully developed, were excluded. A correlation was used to calculate the PVT data. Average initial fluid parameters have been assumed to produce bubble point pressure very close to initial reservoir pressure. Average porosity of normal distribution with a mean of 24.75 % and standard deviation of 2.48 was assumed. Also an average connate water saturation of normal distribution with a mean of 40 % and standard deviation of 3 was assumed. Initial reservoir pressure of triangular distribution with a most likely value of 1500 psig was assumed with a minimum and a maximum values of 1440 and 1560 psig respectively. Further triangular distribution of pressure values was made to cover a range of 95 to 125% of those shown in Table 7. Assumptions were also made for cumulative gas production to cover a minimum range of 80 to 90 % of those values given in Table 7 and a maximum range of 111 to 125%. Cumulative water and gas injection data is given in Table 8.

Monte Carlo Simulation results are given as follows. Also, the OOIP distribution and estimates are shown in Figures 4.

Monte Carlo simulation results:

| **Statistics:** | Value |
|---|---|
| Mean | 167,000,000 |
| Median | 162,000,000 |
| Standard Deviation | 41,994,564 |
| Range Minimum | 63,218,309 |
| Range Maximum | 322,749,981 |
| Range Width | 259,531,672 |

**TABLE 7**
**Production Data For Material Balance**

| Date | Pressure | Cum. Oil | Cum. Gas | Cum. Water |
|---|---|---|---|---|
| YYMM | psig | MSTB | MMSCF | Mbbls |
| 6912 | 1400.00 | 8850.15 | 5984.34 | 1224.79 |
| 7012 | 1150.00 | 14003.43 | 10545.15 | 3691.13 |
| 7112 | 840.00 | 17354.14 | 12914.52 | 7259.29 |
| 7212 | 800.00 | 19915.88 | 14515.57 | 11105.35 |
| 7312 | 790.00 | 22105.33 | 15989.57 | 14145.24 |
| 7412 | 775.00 | 23976.40 | 17264.05 | 17337.19 |
| 7512 | 765.00 | 25737.86 | 18226.75 | 20727.54 |
| 7612 | 757.50 | 27468.60 | 19154.33 | 23943.15 |
| 7712 | 750.00 | 28983.75 | 19907.36 | 26577.11 |
| 7812 | 742.50 | 30715.08 | 20913.56 | 29132.08 |
| 7912 | 735.00 | 32417.00 | 22296.50 | 31731.50 |
| 8012 | 727.50 | 34139.78 | 23888.16 | 33729.06 |
| 8112 | 720.00 | 35598.79 | 25383.18 | 35550.60 |
| 8212 | 712.50 | 36696.60 | 26784.73 | 37341.10 |
| 8312 | 705.00 | 37682.64 | 28063.91 | 39049.33 |
| 8412 | 697.50 | 38557.88 | 29083.95 | 40571.84 |
| 8512 | 690.00 | 39330.80 | 29685.85 | 42010.80 |
| 8612 | 682.50 | 39970.74 | 30154.10 | 43396.42 |
| 8712 | 675.00 | 40730.16 | 30737.70 | 44999.30 |
| 8812 | 667.50 | 41446.96 | 31576.55 | 46792.03 |
| 8912 | 660.00 | 42072.58 | 32552.92 | 48486.41 |
| 9012 | 652.50 | 42704.62 | 34102.98 | 50033.71 |
| 9112 | 645.00 | 43310.57 | 35891.20 | 51946.43 |
| 9212 | 637.50 | 43808.62 | 36791.94 | 53650.30 |
| 9312 | 630.00 | 44317.74 | 37428.98 | 55423.29 |
| 9412 | 622.50 | 44787.88 | 38023.90 | 57215.68 |
| 9512 | 615.00 | 45241.29 | 38505.80 | 58907.88 |

**TABLE 8**
**Injection Data For Material Balance**

| Date | Water Injection | Gas Injection |
|---|---|---|
| YYMM | Mbbls | MMSCF |
| 6912 | 0.00 | 0.00 |
| 7012 | 0.00 | 0.00 |
| 7112 | 0.00 | 0.00 |
| 7212 | 0.00 | 0.00 |
| 7312 | 849.87 | 0.00 |
| 7412 | 2931.02 | 0.00 |
| 7512 | 6323.57 | 0.00 |
| 7612 | 9542.62 | 0.00 |
| 7712 | 12196.97 | 0.00 |
| 7812 | 12686.91 | 27.99 |
| 7912 | 12686.91 | 614.73 |
| 8012 | 12686.91 | 1162.53 |
| 8112 | 12686.91 | 1856.20 |
| 8212 | 12746.62 | 2694.61 |
| 8312 | 13139.91 | 3390.49 |
| 8412 | 13531.81 | 3854.32 |
| 8512 | 13818.95 | 3908.56 |
| 8612 | 14088.52 | 3921.19 |
| 8712 | 14327.30 | 4102.28 |
| 8812 | 14557.83 | 4546.91 |
| 8912 | 14779.69 | 5133.10 |
| 9012 | 15074.59 | 6344.21 |
| 9112 | 15103.12 | 7536.29 |
| 9212 | 15103.12 | 7670.01 |
| 9312 | 15103.12 | 7685.87 |
| 9412 | 15103.12 | 7710.05 |
| 9512 | 15103.12 | 7738.92 |

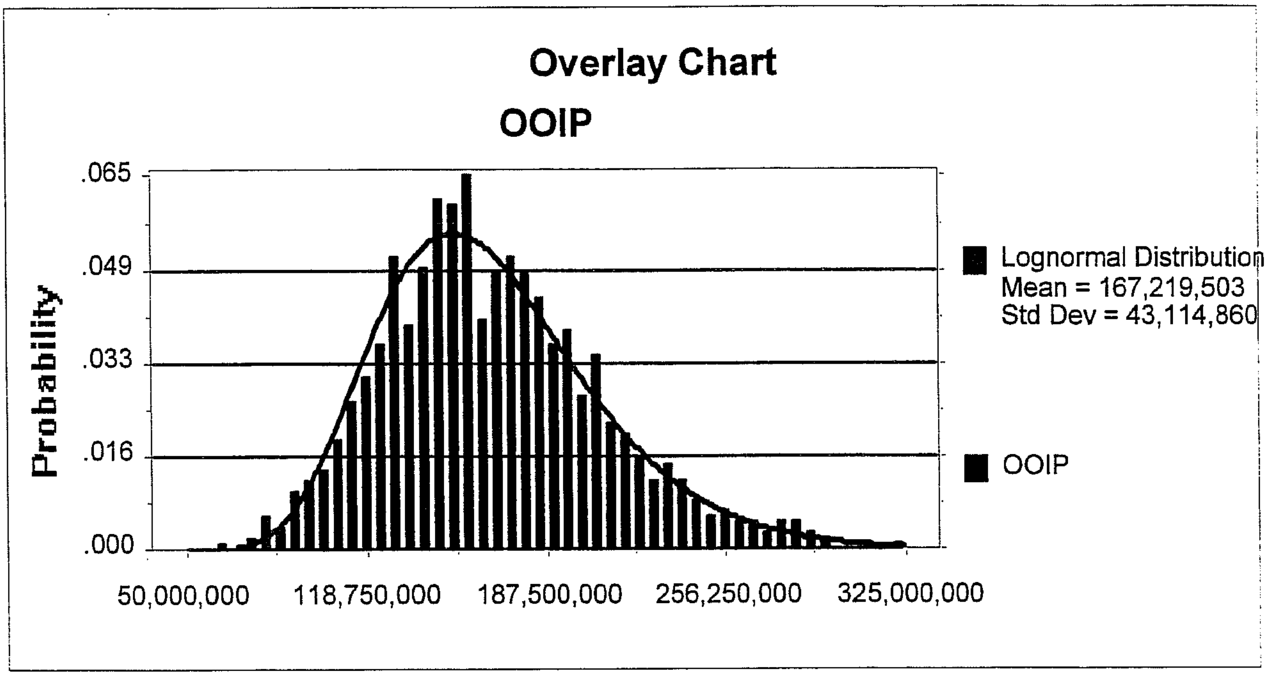



Figure 4

OOIP - Volumetrics

The areal extent of the productive layers (supra thrust, sand C to G7 and the subthrust) for lease P-0166 has been identified using the 3-D geologic model. Net average thickness and thickness weighted average porosity and water saturation of each sand are used in the estimation of OOIP. An average oil formation volume factor of 1.15 bbl/STB is used in the volumetric calculations. The original oil in place for lease P-0166 by layer is given in Table 9.

## TABLE 9
## Original Oil in Place for Lease P-0166 by Volumetric Method

| Sand | Productive area acres | Net thickness ft. | Ave. $\phi$ | Ave. Sw | OOIP, MSTB |
|---|---|---|---|---|---|
| C1 | 0.00 | 3.64 | 0.2920 | 0.5003 | 0 |
| D1A | 47.83 | 8.83 | 0.2403 | 0.4965 | 345 |
| E1 | 281.28 | 37.87 | 0.2642 | 0.3754 | 11,857 |
| E1A | 207.85 | 31.16 | 0.2585 | 0.4462 | 6,255 |
| E2 | 13.31 | 7.14 | 0.2293 | 0.5189 | 71 |
| E3 | 3.66 | 2.59 | 0.2583 | 0.5206 | 8 |
| E4 | 63.04 | 13.06 | 0.2715 | 0.4942 | 763 |
| F1 | 475.24 | 116.45 | 0.2263 | 0.3681 | 53,387 |
| F2 | 220.14 | 33.62 | 0.2348 | 0.4514 | 6,431 |
| F2A | 108.39 | 18.77 | 0.2110 | 0.4979 | 1,454 |
| F3 | 255.25 | 30.33 | 0.2093 | 0.4465 | 6,049 |
| F4 | 268.56 | 33.00 | 0.2157 | 0.4115 | 7,589 |
| F5 | 111.17 | 18.06 | 0.2198 | 0.4662 | 1,589 |
| F6 | 69.33 | 13.32 | 0.2098 | 0.5053 | 647 |
| G1 | 253.64 | 44.53 | 0.2190 | 0.3445 | 10,938 |
| G1B | 176.55 | 23.37 | 0.2109 | 0.3320 | 3,921 |
| G2 | 281.28 | 13.05 | 0.2055 | 0.3900 | 3,103 |
| G3 | 238.00 | 68.76 | 0.2155 | 0.3361 | 15,794 |
| G3A | 119.40 | 10.94 | 0.2067 | 0.4581 | 987 |
| G3B | 88.93 | 23.57 | 0.2251 | 0.3501 | 2,069 |
| G4 | 98.59 | 7.79 | 0.2010 | 0.4502 | 572 |
| G5 | 75.62 | 6.49 | 0.1818 | 0.5111 | 294 |
| G5A | 67.72 | 9.53 | 0.2084 | 0.4668 | 484 |
| G5B | 31.60 | 5.16 | 0.2053 | 0.5325 | 106 |
| G5C | 22.53 | 3.24 | 0.1957 | 0.5369 | 45 |
| G6 | 23.70 | 11.99 | 0.2077 | 0.4767 | 208 |
| G6A | 29.20 | 4.58 | 0.2080 | 0.4955 | 95 |
| G6B | 44.90 | 16.50 | 0.1989 | 0.4563 | 541 |
| G6C | 35.50 | 4.64 | 0.1819 | 0.4697 | 107 |
| G7 | 87.50 | 20.45 | 0.1907 | 0.4211 | 1,332 |
| ST | 558.00 | 43.00 | 0.2100 | 0.4200 | 19,715 |
| Total OOIP, MSTB | | | | | 156,754 |

## Planning for Budget Period II

Drilling Engineering

A study was initiated to determine the cost feasibility and potential economic benefit of re-drilling existing P-0166 wells as opposed to drilling new multi-lateral wells. The concept was to evaluate recompleting selected existing wells by cutting a window in the existing casing above the top perfs and re-drilling the completion interval. Based on our study results, and on the findings from an ongoing workover program (several wells with partially collapsed casing in the uppermost perforated interval) we determined that it would be advantageous to do a small re-drill program (6 to 8 wells) prior to drilling multilateral wells in the field. The big disadvantage of grass roots tri-lateral well in the Carpinteria field (at this time) is the remaining uncertainty of how individual reservoirs will produce. As previously mentioned in this report, there are over 29 producing sands that have been identified and mapped in the field. Since most of the production was commingled, this adds a component of risk as to exactly how a single individual sand will produce given the current state of depletion in the field. In the case of a tri-lateral well, we would drill three separate laterals from one main wellbore into these sands. Some laterals may produce well, others may not. The difficulty comes when we attempt to isolate the laterals. This would have the advantage of obtaining current saturations in the targeted horizontal zones and increase production at the same time.

Based on our evaluation for budget period II, we propose to redrill existing vertical wells to a horizontal configuration. This would be accomplished by cementing off the existing vertical completion (a cement plug across the existing perforated interval) and then cutting a window and drilling a short horizontal section, estimated to be approximately 500 ft. in length. The result of this modification to budget period 2 will allow us to test multiple areas of the reservoir, without the same financial risk as a single tri-lateral well.

Permitting Activities

An important aspect of preparing to drill wells during budget period II was completing the permitting tasks with the various agencies that oversee operations in the Carpinteria field. Among the more important of these are Santa Barbara County Air Pollution Control District (SBAPCD), and the U.S Department of Interior, Minerals Management Service (MMS). Several meeting were held with the MMS to discuss our planned activities. In addition, we prepared a project scope document that detailed the planned development activities. As a result of these meetings and a review of our scope document, the MMS concluded that our proposed re-drill program only required a sundry notice approval (MMS form 123) by the Camarillo District Supervisor. These sundry notices will be submitted approximately 60 days prior to initiation of drilling operations, now expected for February-March, 1998. With regard to the SBAPCD, our planned drilling activities all fall completely within our existing Permit to Operate (PTO) and therefore no additional permitting with that agency is required.

**Tech Transfer**

A summary of the tech transfer activities completed during budget period I are listed as follows:

1. Bi-weekly meeting at USC on the geology and production issues related to slope and basin reservoirs.

2. March, 1996: Pacific Operators hosted a tour of their offshore Platforms including a presentation on the field recovery potential to representatives from the DOE and the local congresswoman, Rep. Andrea Seastrand.

3. March, 1996: Made a presentation on the Carpinteria Redevelopment project at the API Energy Day

4. July, 1996: Presentation to regulatory agencies (Minerals Management Service and California State Lands Commission) on recovery potential of the Carpinteria field using convention reservoir engineering techniques.

5. August, 1996: Review of geology, drilling problems and reservoir issues presented New York investment community visiting in Santa Barbara.

6. June - September, 1996: Provided internship to three college students who received supervised instructing relating to the project.

7. August, 1996 - Present: Developed a Pacific Operators maintained web site for online reporting on the progress of the Class III project. The address for this web site is: http://www.pacops.com

8. Attended Tech Transfer planning meeting with other Class III project in Valencia, CA.

9. Participated in brain-storming sessions related to the initial formation of the west coast PTTC.

10. Conducted sessions with the CSLC to demonstrate that the State portion of field has significant remaining reserves and that it should be included in the Class III study for potential drilling.

11. Pacific Operators was invited to contribute its reservoir database as an example of slope and basin reservoir as a part of the on-line database under development between USC and LLNL.

12. November, 1996: Pacific Operators became a member of the producers advisory group, known as PAG, that advises PTTC and works with CIPA.

13. October, 1996: POOI participated in the planning committee for the design of the California Comprehensive database system.

14. November, 1996: POOI co-sponsored the PTTC exhibit at the Pacific Coast Oil and Gas Show in Bakersfield, in Bakersfield, Ca.

15. November, 1996: POOI co-Sponsored the West Coast PTTC Problem Identification workshop in Ventura, Ca.

16. November, 1996: Steve Coombs presented a talk at the West Coast PTTC Problem Identification workshop titled "Problems and A Potential Solution to Excess Water Production From The Turbidite Sands, The Carpinteria Field".

17. December, 1996: Co-sponsored the West Coast PTTC opening ceremonies and provided exhibits demonstrating progress on the Class III project.

18. December, 1996: Provide data from the Carpinteria Class III project for the California reservoir database which will be exhibited on the ACTI database via the Internet.

19. Sponsored the PTTC West Coast Workshop on "California Geology With and Without Computer Graphics" on Jan. 15, 1997. We also presented a paper on the geological modeling of the Carpinteria field.

20. Attended the DOE Reservoir Characterization Conference and participated in the discussion regarding geological modeling.

21. Sponsored a field trip for 19 students from University of Southern California who visited the offshore platforms.

22. Sponsored a field trip for 6 students from University of California Santa Barbara who visited the offshore platforms.

23. Sponsored a field trip for 2 students from California State College at Northridge who visited the offshore platforms.

24. June, 1997 - Presented SPE paper at the SPE Western Regional Meeting, Long Beach, CA.

## LIST OF TABLES