MINUTE ITEM
This Calendar Item No. C72 was approved as Minute Item No. 72 by the California State Lands Commission by a vote of 3 to 0 at its 4-26-05 meeting.

CALENDAR ITEM
C72

A 54

S 27

04/26/05
W 17159
A. Reid

CONSIDER APPROVAL OF THE LONG BEACH UNIT PROGRAM PLAN (JULY 1, 2005 THROUGH JUNE 31, 2010) AND THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2005 THROUGH JUNE 30, 2006), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY

APPLICANT:

City of Long Beach
Attn.: Mr. Christopher J. Garner, Director
Department of Oil Properties
211 East Ocean Boulevard, Suite 500
Long Beach, CA 90802

BACKGROUND:

In accordance with Chapter 941 of the Statutes of 1991 (AB 227) and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, the Long Beach Unit Program Plan (July 1, 2005 through June 31, 2010) and the Long Beach Unit Annual Plan (July 1, 2005 - June 30, 2006) were submitted by the City of Long Beach (City) on March 21, 2005, to the California State Lands Commission (Commission).

At its meeting on March 8, 2005, the Long Beach City Council adopted the proposed Program Plan and Annual Plan, and authorized its submittal to the Commission for consideration and approval. The Commission has 45 days following formal submission of the Annual Plan to take action. If no action is taken, the Program Plan and Annual Plan will be deemed approved as submitted. The economic projections for the period July 1, 2005 through June 30, 2010 (as presented by the City) are shown below:

ALL FIGURES ARE IN MILLIONS OF DOLLARS			
PERIOD	**TOTAL REVENUE**	**EXPENDTURES**	**NET INCOME**
FY 05-06	345.8	272.0	73.8
FY 06-07	346.8	264.5	82.3
FY 07-08	282.4	205.7	76.7
FY 08-09	273.1	205.8	67.3
FY 09-10	268.1	205.7	62.4
TOTAL	**1,516.2**	**1,153.7**	**362.5**

As presented, the Long Beach Unit Program Plan includes anticipated rates of production, revenues, expenditures, and net profits for the Unit as projected by the City of Long Beach Department of Oil Properties. The City has estimated that the Unit net income from July 1, 2005 through June 30, 2010 will be $362.5 Million, after total Expenditures of $1153.7 Million. This income scenario is based on a forecasted oil price of $28.00 per barrel during Fiscal Years 2005/2006 and 2006/2007, and $23.00 per barrel for the last three years of the Program Plan period. This income will be generated primarily from oil revenues based on production forecasts ranging from 32,200 barrels per day (BOPD) in Fiscal Year 2005/2006 to 30,500 BOPD in Fiscal Year 2009/2010. These production rates are based on the assumption that development drilling will include a total 192 wells to be drilled or redrilled over the life of the Program Plan. The plan schedule is for 60 wells to be drilled per year for Fiscal Years 2005/2006 and 2006/2007, then 24 wells per year for fiscal Years 2007/2008, 2008/2009 and 2009/2010.

Commission staff has reviewed the Program Plan and Annual Plan as submitted by the City and believes that they provide an engineering framework to meet the objectives of the Optimized Waterflood Agreement and are based on all engineering, geologic, and economic information available at the time of preparation. Engineers representing the State, City, THUMS, and OXY agree that objectives will be met in all areas of interest, including those of good oil field practice, proper reservoir management, safety to employees and the public, and environmental protection, through active participation by all parties at Unit forums, Engineering Committee meetings, Voting Party Committee meetings, and during events as they occur in the field. Commission staff, through its participation in Engineering Committee, reviews all well proposals, and their bottom hole locations, and other unit expenditures, and votes on these expenditures at Voting Parties Meetings.

OTHER PERTINENT INFORMATION

1. Pursuant to the Commission's delegation of authority and the State CEQA Guidelines [Title 14, California Code of Regulations, section 15060(c)(3)], the staff has determined that this activity is not subject to the provisions of the CEQA because it is not a "project" as defined by the CEQA and the State CEQA Guidelines.

   Authority: Public Resources Code section 21065 and Title 14, California Code of Regulations, sections 15060 (c)(3) and 15378.

EXHIBITS:

A. Letter from the City of Long Beach submitting the Long Beach Unit Program Plan (July 1, 2005 through June 30, 2010) and Annual Plan (July 1, 2005 through June 30, 2006) to the California State Lands Commission.

B. Long Beach Unit Program Plan (July 1, 2005 – June 30, 2010)

C. Long Beach Unit Annual Plan (July 1, 2005 – June 30, 2006)

PERMIT STREAMLINING ACT DEADLINE:

N/A

RECOMMENDED ACTION:

IT IS RECOMMENDED THAT THE COMMISSION:

CEQA FINDING:

FIND THAT THE ACTIVITY IS NOT SUBJECT TO THE REQUIREMENTS OF THE CEQA PURSUANT TO TITLE 14, CALIFORNIA CODE OF REGULATIONS, SECTION 15060(c)(3) BECAUSE THE ACTIVITY IS NOT A PROJECT AS DEFINED BY PUBLIC RESOURCES CODE SECTION 21065 AND TITLE 14, CALIFORNIA CODE OF REGULATIONS, SECTION 15378.

AUTHORIZATION:

APPROVE THE LONG BEACH UNIT PROGRAM PLAN (JULY 1, 2005 THROUGH JUNE 30, 2010) AND ANNUAL PLAN (JULY 1, 2005 THROUGH JUNE 30, 2006), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY.

W 17159

Exhibit A

CITY OF LONG BEACH

DEPARTMENT OF OIL PROPERTIES

211 EAST OCEAN BOULEVARD, SUITE 500 • LONG BEACH, CALIFORNIA 90802 • (562) 570-3900 • FAX 570-3922

March 21, 2005

Mr. Paul B. Mount II, P.E.
Chief, Mineral Resources Management Division
California State Lands Commission
200 Oceangate, 12th Floor
Long Beach, CA 90802-4331

SUBJECT: **SUBMISSION OF THE LONG BEACH UNIT ANNUAL AND PROGRAM PLANS (JULY 1, 2005 - JUNE 30, 2010)**

Dear Mr. Mount:

The City of Long Beach, as Unit Operator of the Long Beach Unit, and in accordance with Chapter 138, Section 5, Chapter 941, Section 3, and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, Article 2, submits ten copies each of the Long Beach Unit Annual and Program Plans (July 1, 2005 - June 30, 2010).

The Plans were approved by the Long Beach City Council on March 8, 2005. If you have any questions, please contact Ms. Sue Schoij at (562) 570-3973.

Sincerely,

Christopher J. Garner
Director

CJG:scs

Enclosures

cc: M. Voskanian
P. D. Thayer
A. V. Hager
R. D. Nobles
F. Komin
J. Charles Parkin

FIN 312.006

W 17159

Exhibit B

PROGRAM PLAN

Long Beach Unit

July 2005 through June 2010

Prepared Jointly by:

Department of Oil Properties
City of Long Beach
(Unit Operator)

OXY Long Beach, Inc.
(Field Contractor)

THUMS Long Beach Company
(Agent for the Field Contractor)

February 2005

Table Of Contents

000370

CALENDAR PAGE

000716

MINUTE PAGE

Executive Summary

This Program Plan covers the period from July 1, 2005 through June 30, 2010. The purpose of the Plan is to describe key issues facing the Unit and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection. This Plan is the culmination of a cooperative effort by the Department of Oil Properties, City of Long Beach (Unit Operator), OXY Long Beach, Inc. (Field Contractor), and THUMS Long Beach Company (agent for the Field Contractor). The Program Plan meets requirements of Section 2.03 of the Optimized Waterflood Program Agreement ("OWPA").

The Program Plan describes the Unit reservoir management strategies to be implemented under the OWPA, including drilling plans and projected rates of production and injection. The Plan also includes a discussion of key issues facing the Unit, plans for major facility projects and initiatives to be implemented during the Plan period, and anticipated revenues and profits. The format is similar to the previous Program Plan.

The Plan includes expenses associated with drilling 192 development and replacement wells over the life of the Program Plan. This schedule will result in a reasonably stable production rate through the end of FY07/08 with an accelerated decline during the later stages of the Plan due to reduced development activities and continued field maturation. Unit production and injection rates are expected to average 32.2 Mbopd, 805 Mbwpd and 905 Mbwipd in FY05/06 and 30.5 Mbopd, 832 Mbwpd and 930 Mbwipd in FY09/10, respectively.

The anticipated development drilling activity is detailed in Exhibit B and the predicted rate curves are shown in Exhibits E and F. This drilling activity encompasses all locations: Pier J, and Islands Chaffee, Freeman, Grissom and White with the use of Unit rigs T-3, T-5 and T-9, augmented with use of other Unit rig assets, contract drilling rigs, workover rigs, and coiled tubing units. The purchase or rental of additional peripheral equipment to maintain safe and efficient operations may be required. It is possible that development results, improved Unit seismic data, and production history will yield additional new drilling candidates throughout the Plan period. Decisions regarding future drilling activity will be influenced by the quality of the projects identified and prevailing economic conditions.

The consummation of an agreement between stakeholders to develop shallow gas reserves is anticipated. This Plan includes funding for well drilling or recompletions and basic facility modifications associated with this project, as well as gas production and the associated revenue.

Several facility improvement projects are planned throughout the initial two to three years of the Plan. These improvements are focused on expanding current facility capacity limits to accommodate a full 2 and one half rig drilling program throughout all 5 years of the Program Plan period and could include projects such as installation of casing gas compression, and other investments that position the Unit for longevity. These investments result in enhancement of revenue streams, lower maintenance and operational costs, and improved safety and environmental performance.

Based on production from 60 development and replacement well projects planned for FY05/06 of the Program Plan and an average oil price of $28.00/bbl, total revenue, expenditures, and net profits are projected to be $345.8 million, $272.0 million, and $73.8 million, respectively. Over the five year Program Plan period, cumulative total revenue, expenditures, and net profit are expected to reach $1,516.2 million, $1,153.7 million, and $362.5 million, respectively. Economic results reflect a staged decline in oil prices through the 5 year Program Plan period. A schedule of projected revenue, expenditures, and net profits by year is given in Exhibit A. Expenditure levels and project mix will be adjusted as needed to respond to fluctuations in oil price and other economic conditions.

Overview

This Program Plan covers the period from July 1, 2005 through June 30, 2010. The purpose of this Plan is to describe key issues facing the Unit, and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection.

This Plan is divided into four major sections:

- The *Introduction* provides a brief summary of the Unit history.

- The *Unit Reservoir Management Plan* section outlines strategies to be employed in reservoir development and management. An overview of the field-wide goals and strategies is provided. Appendix 1 contains a more detailed Reservoir Management Plan for the five reservoir areas: Ranger West/Tar, Ranger East, Terminal, UP Ford, and 237 Zone.

- The *Unit Forecasts* section summarizes planned Unit drilling activity as well as projected production and injection rates during the Program Plan period.

- The *Major Issues and Projects* section describes the key issues facing the Unit. Key goals in the areas of people, safety, environmental protection, profitability, and subsidence control are described, as are plans for meeting those goals. Initiatives to manage costs through improved business and operating practices are described. Plans for maintaining and improving the field infrastructure, abandoning unusable wells, and managing external influences on the Unit are also described. This section also includes a brief discussion of the shallow gas development proposal and plans for managing electrical costs through operation of the newly constructed power generation plant.

- The *Economic Summary* section provides a forecast of Unit revenues, expenditures, and profits anticipated during the Plan period, assuming an oil price of $28.00/bbl during the first 2 years of the Program Plan period and $23.00 during the last 3 years of the Program Plan period. This section also includes the schedules that will be incorporated into the FY05/06 and FY06/07 Annual Plans.

Introduction

History

The Long Beach Unit ("Unit") commenced operation April 1, 1965. Since its inception, a major requirement of Unit operations has been to minimize the impact on the environment and to comply with all applicable environmental laws and regulations. No oil-related subsidence has occurred since the inception of the Unit, although minor positive and negative elevation fluctuations have been observed. An active subsidence monitoring system is in place and remedial measures would start immediately if significant subsidence was detected.

Development drilling began in July 1965. Initial development activity peaked with 20 rigs operating in 1968. This high level of drilling activity continued into early 1970. Drilling activity decreased to four rigs in 1973 and dropped to one rig in mid-1976. Full zone production and injection locations were emphasized. The pace of development accelerated in 1977, reaching a peak of nine rigs in 1982, when sub-zone development was initiated to improve oil recovery by completion of wells in sands with high remaining oil saturation. This level of activity was held until early 1986 when drilling activity again began to decline due to low oil price. Activity dropped to one rig in the summer of 1986. No drilling rig activity occurred from mid-March 1987 until August 1987, at which time one rig was re-activated. A second rig was started in January 1988, and a third in January 1990. Rig activity dropped to one rig again in 1994 and has fluctuated between a one and two rig pace until 2003 where it has remained at two rigs. The drilling pace is expected to remain at a two rig pace through the first two years of this Program Plan.

On January 1, 1992, ARCO Long Beach, Inc. ("ALBI") became the sole Field Contractor, having acquired interests from all previous Field Contractor companies. On the same date, the OWPA also took effect. On January 1, 1995, the term of the Contractors' Agreement was extended through the end of the Unit's economic life, in accordance with the OWPA. Consequently, THUMS Long Beach Company ("THUMS") will continue in its capacity as agent for the Field Contractor beyond the original contract term of April 1, 2000.

In April 2000, Occidental Petroleum Corporation bought all of Atlantic Richfield Company's stock in ALBI. As a result, the Field Contractor name was legally changed from ALBI to OXY Long Beach, Inc. (OLBI).

Unit Reservoir Management Plan

Goal

The goal of the Unit Reservoir Management Plan is to maximize the economic recovery of oil and gas from the Unit, while ensuring stable surface elevations, through the application of sound engineering practices. This will be achieved by utilizing existing Unit assets to maximize short and long term economic benefit, optimizing the Unit's waterflood depletion strategies, identifying investment opportunities, and delivering the expected results.

Reservoir Management Strategy

The Unit's Reservoir Management strategy consists of three elements:

1. Maximize economic production from existing assets by the use of sound waterflood practices. This effort is focused on waterflood surveillance activities including well monitoring, flood performance analysis, and voidage management for subsidence control.
2. Assess and deliver additional development investment opportunities via the drilling and investment wellwork programs. Development activities are currently focused on capturing bypassed, unswept oil and increasing waterflood throughput in immature areas.
3. Implement new technologies to decrease costs, improve efficiencies, and develop unproven reserves. The Unit's Technology Plan identifies technology needs, impacts, and implementation issues.

Each of these strategies is discussed in more detail below. Specific strategies and goals for each reservoir are included the Appendix.

Production and Surveillance

A major goal of the Unit's reservoir management plan is to ensure the value from production is maximized. The reservoir management strategies for accomplishing this goal include well monitoring, flood performance analysis, and voidage management for subsidence control.

- Well monitoring activities include monthly testing of production wells, daily monitoring of injection well pressures and volumes, acquiring injection well profiles at least once every two years, and obtaining well pressure surveys as required to assess formation pressures. This data forms the cornerstone for reservoir analysis of production trends. The Reservoir Engineering, Wellwork, and Operations Departments work jointly to ensure the needed data is obtained in the most cost-effective manner.
- Waterflood performance will be analyzed using standard industry techniques to differentiate between good and poor pattern performance and identify well enhancement opportunities. Techniques used will include decline curve analysis, material balance, volumetrics, bubble maps, waterflood sweep, hydrocarbon throughput analysis and streamline simulation. Based on the analysis results, development opportunities will be identified and evaluated including re-completions, profile modifications, new drill wells, and stimulations. In addition, as wells fail, the

analysis results will be used to justify well maintenance work such as liner replacements, wellbore repairs, and pump changes. The maintenance work program is managed and executed by the Wellwork group.

- The Unit is required to inject a total of 41.2 MBWPD in excess of gross production in designated voidage pools to ensure pressure maintenance and reduce the potential for subsidence. Reservoir engineers are responsible for insuring voidage targets are met for eleven separate voidage pools in the Tar, Ranger, and Terminal zones. This is accomplished by shutting-in producers, managing injection between pools, stimulating injectors, and/or performing well maintenance. The objective is to meet voidage targets, while minimizing expenses and the need to shut-in production.

Development Opportunities

The Unit has a strategy to invest to build oil production rate. To support this strategy, development activities have focused on:

- Drilling injection wells targeting increased throughput in the less mature sand layers and improving zonal injection control. Drilling results to date have shown good success from injection wells drilled to establish new injection patterns in the relatively underdeveloped areas of the field such as northern cut-recovery block 1 in Ranger West. Injection wells have been somewhat less effective in the more mature areas or when used as isolated infill injectors, but have still successfully advanced this strategy.
- Adding production wells: (1) where required to complete new injection patterns, (2) in areas of unswept oil (3) in lower productivity sands that cannot produce well in combination with higher productivity zones in long completions, (4) in areas of high oil saturations banked along sealing faults, and (5) in areas where improved injection warrants additional production capacity.
- Investing in wellwork projects that will increase the ultimate recovery of the field or require special planning and attention. Investment wellwork includes well conversions, recompletions, permanent profile modifications and hydraulic fracture stimulations. The Wellwork group handles projects considered more routine, like recompletions and conversions. Fracture stimulations, which are more complex and require special planning and expertise, are coordinated by the Drilling Group. The investment wellwork program is still one of the Unit's most successful programs, adding reserves at comparatively low cost. The investment wellwork program will continue at a healthy pace throughout the upcoming Plan period.

The Long Beach Unit has embarked on an effort to improve reservoir characterization across the Unit. This work started in the UP Ford where it is nearly complete. In that work, a petrophysical model was developed, the Unit horizons were subdivided in sand packages and a new reservoir description was created. This new description was used to update the UP Ford streamline simulation model. History matching will be complete in the near future. The model is already being used to screen drilling targets.

With the assistance of DeGoyler and MacNaughton, Oxy's Worldwide Reservoir Characterization Group, other outside consultants and local staff, this effort is now focused on Ranger East and the Terminal. Work is under way to build petrophysical models and subzone both areas. The target is to build a reservoir description and a streamline simulation model in Terminal East and Terminal West, and to update the description and streamline simulation in Ranger East.

In Ranger West, a working streamline simulation model of Ranger 7 is being used to manage that pool. Work is under way to build a streamline simulation model of Ranger 6. This work will be completed during this Program Plan.

Reprocessing of the 1995 3D Seismic data began in 2004. The work involves repositioning the receivers and reprocessing the data. The repositioning work is complete and results are encouraging. Data clarity has been improved over almost the entire field. Reprocessing work will begin in very late 2004 or early 2005. This work should be complete by the beginning of the Program Plan, at which point interpretation and use in identifying waterflood improvement projects will begin.

Technology

Advances in drilling and completion technology continue to be a significant factor in realizing development drilling opportunities. Key technologies being developed and applied include horizontal well placement, water shut-off techniques, special design and extended reach wells, cased hole completions including hydraulic fracturing and frac-n-pack completions, and low cost replacement wells. The Unit maintains a Technology Plan that identifies technology needs, impacts, and implementation issues. Operational and technological areas addressed by the Plan include wellwork and drilling (artificial lift, stimulation, corrosion, and scale prevention), facilities (automation, corrosion control, water quality), reservoir (profile control, fracture, behind-pipe-oil detection, conformance evaluation software tools, reservoir modeling software tools, 3D reservoir characterization), and Health, Environmental and Safety training.

Unit Forecasts

Drilling Schedule

The Program Plan projects development and replacement drilling to average 60 wells per year for FY05/06 and FY06/07. This schedule can be met with two Unit and one half drilling rigs running continuously. Workover rigs will continue to be used for new well completions to capitalize on improved completion quality control and to provide better drilling rig efficiency. As a result of facility constraints, the level of drilling will likely be reduced after FY06/07. At least a one rig drilling program is expected due to some facility limits but will continue with efforts to redrill failed wells and exploit growth opportunities that move probable and possible reserves into the proven reserve category.

Exhibit B shows the drilling plan by Unitized Formation for the Program Plan period, and the required Schedules 1B and 2B show the anticipated range of development and replacement wells to be drilled into each cut-recovery block during FY05/06 and FY06/07. This drilling plan reflects the current understanding of new development well economics. The drilling candidate list is updated annually by the reservoir development teams. Drilling projects are submitted to Voting Parties for approval at least 2-4 months ahead of the planned spud date. Individual well AFEs are submitted subsequently. The economics of each well are fully investigated at that time, and changes in key factors such as oil price, drilling cost, or candidate quantity and quality may result in changes to the overall plan.

Rate Forecasts

Exhibit C shows the Unit production forecasts for the Plan period, and the required Schedules 1A and 2A show the anticipated rates for FY05/06 and FY06/07. These forecasts were developed by combining a forecast of existing well performance with the expected results of the previously outlined development plan. The expected case injection forecast shown in Exhibit D was generated based on the gross fluid rates from the production forecast. A mandated excess water injection rate of 41.2 MBWPD over the gross fluid production rate is used in the Tar, Ranger and Terminal sands to preclude any possibility of subsidence. Graphs comparing historical and predicted field rate performance data are presented in Exhibits E and F. The plots clearly show the variability of historical rate data, necessitating the use of rate ranges to account for uncertainty in the rate projections.

The oil and water production forecast for the existing wells is based on a process that uses extrapolations of well groups within each Unitized Formation summed together to yield a forecast of the existing wells' production for the entire Unit. Each of these pools is comprised of the wells within a reservoir volume that is believed by the reservoir development teams to be acting as an independent waterflood area. These are generally comprised of either one or more cut-recovery blocks or a fault block. For each pool, the expected future oil and water rates are extrapolated from historical trends of oil and gross fluid rates vs. time and the trend of water-oil ratio vs. cumulative oil production using conventional decline curve techniques. For pools that reach the economic water-oil ratio before the approximate end of the Unit's expected economic life in 2020, production is ramped down over several years using Unit developed shut-in logic. While this evaluation is more sophisticated than a single Unit exponential decline evaluation, it more accurately models the Unit's reservoirs. The resulting prediction shows a near term exponential decline of about 12% per year. Longer term, the forecast follows a hyberbolic decline.

The incremental production contribution for new development wells is based on average rates for Unit wells, referred to as "type wells." The type wells are determined by reservoir (Ranger, Terminal and UP Ford) and completion type (conventional producer, frac producer, horizontal producer and injector) The producer type wells are based on average initial production rates and reserves of all Unit producers drilled between 1999 and early 2004. The injector type wells are based on average injection rates, peak offset oil and gross response measured in effected wells and reserves. The type well rates are combined with the development drilling schedule to generate the expected rate contribution for new development wells. The total Unit production forecast is the sum of the existing well and development well forecasts.

The Unit water production forecast was derived as the difference between the gross fluid and oil production rates.

The gas production forecast was calculated from the oil rate projections using a constant gas to oil ratio of 262 standard cubic feet per barrel of oil produced over the Plan period.

Major Issues and Projects

Several major issues must be considered when planning Unit strategies. These issues include consideration for people, safety, environmental protection, subsidence control, well abandonment, cost management, facility infrastructure adjustments, shallow gas development, electrical generation, make-up water, and property tax management. All can dramatically influence the success of the Unit, and as such, will be addressed with considerable effort and resources.

The most critical potential issues anticipated during the Program Plan period are discussed below. Actual operating practice will be adjusted in accordance with future economic circumstances, practical considerations, regulatory requirements, and any unforeseen situations that may arise.

People

The most important asset of the Unit is its employee resource and the ability of these employees to work together toward organizational goals. The Unit will strive to maintain a diverse workforce of employees who are positioned in the right job and who are well qualified to perform that job in a superior manner. Effective teamwork is expected of all Unit employees, as well as open communication, mutual respect, and individual accountability. Developing and enhancing job skills through training, education, and job experience will be emphasized through the Plan period.

Health and Safety

The Unit is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, contractors, and the public, and safeguards the environment in which it operates. Ensuring the safety of all personnel is crucial to the success of any enterprise and is a specific goal of the Unit. Operations are conducted in a manner to ensure compliance with applicable laws and regulations. The Health, Environment, and Safety (HES) Department is responsible for providing day to day health, environment, and safety support and service to the employees and contractors of the Unit.

The Safety and Environmental Steering Committee continues to be a key component in the ongoing health, environment, and safety improvement efforts for the Unit. The committee is made up of proven safety leaders within the organization and is designed to ensure participation by all employees. The committee will continue to be challenged to seek out new HES ideas and strategies from within and outside the industry that will take the Unit's safety performance to the next higher level.

Contractor Safety has been and will continue to be a primary focus at Thums. Contractors participate in many of the on-site safety meetings and also serve on many of the safety related teams and committees. Contractor performance is reviewed frequently to ensure that expectations are understood and are being met. Aggressive safety performance goals are set each year and are tracked to measure bottom line improvement.

Personnel awareness is essential for an effective safety program. Training will continue to be conducted routinely to meet regulatory requirements. Other safety awareness training will be conducted as areas of need are identified in health, environment, and safety practices.

The Unit is proud of the safety record attained by its employees and contractors. To ensure continued compliance, safety assessments are conducted periodically by Unit personnel and outside organizations.

Environmental Protection

The Unit is committed to the protection of the environment, and as such has identified this as a key goal. All operations are conducted to minimize environmental impacts and comply with all applicable laws, regulations, and policies.

Precautions to prevent uncontrolled discharges are a high priority. In the unlikely event such a situation does occur, trained personnel and emergency equipment are readily available for deployment. Each island has oil spill response booms and deployment equipment for rapid containment. Response drills are conducted regularly to continually improve the effectiveness of personnel and equipment, and to test coordination with other agencies. These assessments and drills will continue, and refinements to the response process and equipment will be made when necessary.

Personnel awareness is also essential for an effective Environmental Program. Training will be conducted routinely to meet all regulatory requirements and other environmental awareness training will be conducted as areas of need are identified.

The Unit is proud of the environmental record attained by its employees. To ensure continued compliance, environmental assessments are undertaken by Unit personnel and outside organizations.

Subsidence Control

A major goal during the operation and development of the Unit is the continued prevention of subsidence related to oil and gas production. Since the oil zones of the Wilmington Oil Field are susceptible to compaction, injection rates and reservoir pressures must be maintained to prevent subsidence.

Currently, injection-voidage targets are maintained in eleven reservoir pools in the Tar, Ranger and Terminal Zones to ensure pressure maintenance and reduce the potential for subsidence. In general, the injection must exceed gross production by an average of 41.2 MBWPD in these eleven pools, with each pool having specific injection requirements. A subsidence monitoring program is in operation and consists of eight permanent monitoring stations, semi-annual GPS elevation surveys, and continual monitoring of pressures and injection volumes. This plan has proven to be effective in preventing subsidence and no subsidence impact is anticipated.

Well Abandonment Plan

The Unit attempts to minimize the inventory of idle wells that have no further economic benefit. Each plugback of an idle well reduces the ultimate liability for that well to the cost of completing the surface abandonment. This prudently reduces overall future abandonment liability as well as the potential for detrimental in-zone cross flow.

Wells with no further economic use are fully abandoned to reduce the Unit's future abandonment liability. Abandonment also eliminates the costs of performing periodic pressure tests of long-term idle well casings mandated by the State Division of Oil, Gas and Geothermal Resources. Unit engineers regularly review idle wells and evaluate their potential value to the Unit. Those found to have little or no value are added to the queue of wells to be plugged or abandoned. The Unit plans provide funding for both in-zone and mud-line abandonments that will allow the Unit to reduce its abandonment liability.

Cost Management

The Unit continuously strives to be efficient in spending its operational funds. Emphasis is given to spending funds wisely, investing in opportunities with the best economic return, and continuing to look for ways to become more efficient in business operations. Employing effective cost management strategies will aid in achieving the Unit's goal of performing in the lowest cost per net barrel quartile for comparable operations. Cost management gains will be aggressively pursued during the term of this Plan. Some of the areas where the Unit plans to make substantial gains include the following:

Operations: The Facility Operations group is accountable for electricity usage, operation of oil, gas and water treating facilities, chemical usage, and make-up water. Process optimization, best operating practices, and operating cost reductions will be focus areas. Improvements in electrical efficiency, optimization of make-up water sources, maintaining water quality, enhanced well surveillance, and improved coordination between operations, wellwork, and facility maintenance are expected outcomes over the Program Plan period.

Waste Management: Operations at the slurrification well continue to save waste disposal costs associated with drill cuttings and other waste and reduce potential future liabilities for waste disposal. This Plan includes funding to maintain this beneficial project.

Maintenance Wellwork and Drilling Operations: In order to reduce overall Unit development costs, several challenges will be addressed during the Program Plan period. These include rig resource allocation, rig equipment, wellbore maintenance, high demand for quality labor and equipment, increased labor rates, improving safety performance, reducing well failures, and complex formation injection and pressure profile optimization projects. Several teams have been formed to focus on these areas of the business. Some of these include a well failure analysis team, a rig utilization team, a contracts/alliances team, and the Safety and Environmental Steering Committee.

Drilling/Wellwork Equipment: Future drilling activity can be accomplished on Pier J, and Islands Chaffee and Freeman with the use of Unit Rig T-9. Activity on Grissom can be accomplished with Unit Rig T-5. Activity on White can be accomplished with Unit Rig T-3. Additional drilling methods will be considered for lowering drilling costs on all locations. These include contract drilling rigs, workover rigs, top drive and coiled tubing units.

Expansion of Facility Capacity

Significant expansion of current facility processing capacity will be needed if the Unit were to continue with a full 2 and one half rig drilling program during the full course of the Program Plan period. Activities to help achieve capacity expansion include piping enhancement projects, pumps, motors and subsea pipeline optimization. This Plan includes funding to complete the upgrades needed to meet the drilling activity involved.

CO_2 Processing Plant

Unit produced gas has exceeded the contractual limits on CO_2 content and an Amine plant will be constructed to remove the excess. Engineering design and regulatory permitting are progressing. Starting February 1st 2005 until the amine facility is operational the Unit Power Plant will be running as much as possible to prevent loss of value to the Unit. An Interim Dry Gas Agreement was approved by the SLC in December 2004 that will price the gas so the plant will not run at a loss to the Unit. The amine facility is expected to be operational in May of 2006. While the plant is being constructed the Unit power plant will be used to dispose of the high CO_2 content gas. The Amine Plant is expected to require approximately $9 million in the first year of this Plan with approximately $1 million occurring in the second year.

Shallow and Deep Gas Development

An agreement between the State of California, City of Long Beach, and OLBI regarding the development of shallow and deep gas reserves is expected to be finalized prior to this Program Plan start date. This Plan contains funding necessary for wellwork associated with producing these reserves, basic facility modifications necessary for production operations, and the gas production associated with the project.

Electricity Generation

Electricity is the single largest cost element for the Unit. Currently the Unit consumes approximately 550 million kWh per year, and is one of the largest single-site users of electricity in Southern California Edison's territory. Any change in the electrical rates or availability of electricity supply significantly affects the profitability of Unit operations.

The Unit has constructed a 47MW power generation plant in an effort to increase the California in-state generation supply, as well as insulate the Unit from the risks of electricity supply disruptions and escalating wholesale electric costs. The plant commenced operations in FY02/03.

The power plant was converted into a cogeneration facility in FY04/05 to provide heat to a neighboring wallboard manufacturing facility, reducing their reliance on natural gas. As a result, the Unit receives revenue from heat sales and favorable treatment regarding departing load charges that may be assessed for leaving Southern California Edison's electricity grid.

Efforts will also focus on electrical production equipment efficiency. Injection pumps will utilize power monitoring devices to identify opportunities for improving their electrical efficiency. Work will also continue with the Unit's submersible pump supplier to identify opportunities for reducing power usage on submersible pumps.

Funding for the power plant was through a 10 year capital lease. If oil and gas prices continue to be strong, the Unit will accelerate the principal payments on this lease by approximately $10 million in each of the first two years of this Plan. The accelerated payments will shorten the remaining life of the capital lease, reduce Unit interest expense, and improve the long term cost structure of the Unit.

Belmont Offshore – PRC 186

The offset lease PRC 186, Belmont Offshore will be drilling its initial phase of wells in during first year of the Plan. Belmont is not part of the Unit but the drilling affects the Unit through a facilities sharing agreement. Belmont will use Unit drilling and processing facilities in exchange for various financial considerations. The effect on the Unit will be to distribute fixed costs over a larger asset base and improve Unit profitability over the long term.

Make-up Water Sources

A reliable source of water to be used for injection is vital to the success of the Unit. Water injected into the formations serves two purposes: 1) controlling subsidence; and 2) enhancing oil recovery. In order to meet voidage targets, make-up water is purchased from sources outside the Unit. The Unit's primary make-up water sources include Tidelands Oil Production Company (TOPKO) produced water and Long Beach Water Department (LBWD) reclaimed water. Due to cost and environmental considerations, the Unit will use fresh potable water from LBWD only when necessary as a back-up supply.

The Unit evaluated the usage of reclaimed water because of quality issues related to the TOPKO water and the high cost and potential for interruptions in supply of the LBWD fresh water. This evaluation resulted in the Unit installing facilities to utilize reclaimed water supplied by the LBWD. Reclaimed water provides a long-term source of make-up water at a lower cost than fresh potable water.

The Unit continues to investigate options for improving the injection water quality by minimizing the negative impacts that occur when make-up water is mixed with Unit production water.

Property Tax Management

During FY02/03, a settlement regarding over-valuation of the Unit for property tax purposes was reached with Los Angeles County for tax years 1996 through 1999. In FY04/05 a settlement was reached on the exemption status of the Nonoperating Contractors' interest from 1995 through the economic limit of the field. Outstanding items include the impact on Prop 13 base year value resulting from the Oxy change of ownership in 2000 and the subsequent years' property valuation. Efforts will continue as needed to resolve these issues during the Plan period.

Economic Summary

Revenue Forecast

Unit Revenue will be generated from the sale of oil and gas from six producing formations: Lower Pliocene shallow gas sands, Tar, Ranger West, Ranger East, Terminal, and UP Ford/237. The projected revenue during the Program Plan period is $1,516.2 million, based on a $28.00/bbl oil price and $5.50/mcf gas price during FY05/06, $28.00/bbl oil price and $4.50/mcf gas price during FY06/07, $23.00/bbl oil price and $4.00/mcf gas price during the last 3 years of the Plan period, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY05/06 is expected to be $345.8 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY05/06 Annual Plan. Costs in subsequent years are projected by establishing a relationship between current costs and the variables believed to be principally responsible for driving future costs by category. The most leveraging cost drivers overall are the levels of gross fluid production and injection, discretionary activity levels (e.g., drilling, abandonment, and major projects), and the number of wells and facilities that are active at a given time.

Based on the projected production rates, injection rates and activity levels, total expenditures during the Plan period are expected to be $1,153.7 million. The projected expenditures for FY05/06 are $272.0 million. Costs in future years will be refined upon completion of ongoing studies and projects.

Profit Forecast

Based on the above revenue and cost forecasts, Unit profit during the Program Plan period is projected to be $362.5 million. Unit profit for FY05/06 is expected to be $73.8 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY06/07 will be established based on actual results and additional insights gained during FY05/06.

Exhibits

W 17159

Exhibit C

Long Beach Unit

Thums Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2005 through June 30, 2006

000387
CALENDAR PAGE

000733
MINUTE PAGE

ANNUAL PLAN

July 1, 2005 through June 30, 2006

Table of Contents

Part I

Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2005 through June 30, 2006 ("FY05/06"). It is being submitted as required by Section 5(a) of Chapter 138, Statutes of 1964, First Extraordinary Session, and as revised by passage of Assembly Bill 227 (Chapter 941) and the Optimized Waterflood Program Agreement approved by the State of California, the City of Long Beach, and Atlantic Richfield Company, whose interest has been assigned to Occidental Petroleum Corporation.

This Plan provides for drilling, producing, water injection, and other associated activities from offshore and onshore locations. The budget for these activities is grouped into the following five major categories:

Plan Category	Fiscal Year 2005 – 2006 ($ Million)
Development Drilling	$ 70.0
Operating Expense	$ 96.3
Facilities, Maintenance, and Plant	$ 46.8
Unit Field Labor and Administrative	$ 37.9
Taxes, Permits, and Administrative Overhead	$ 21.0
Total	$272.0

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2005 through June 2010 and provides current estimates of volumes, drilling activity and expenditures for FY05/06.

Volumes

Oil production for FY05/06 is expected to average 32.2 Mbopd within a range of 29.0 to 33.8 Mbopd. Gas production is expected to average 8.4 MMcfd within a range of 7.6 to 8.9 MMcfd. Water production for the period is expected to average 805 Mbwpd within a range of 724 to 845 Mbwpd. Water injection is expected to average 905 Mbwpd within a range of 815 to 950 Mbwpd.

Revenue and Expenses

A projected oil price of $28.00/bbl and gas price of $5.50/mcf will result in revenues of $345.8 million. Based on a budgeted expense level of $272.0 million, this will result in a net profit of $73.8 million.

Drilling

This Plan allows for drilling approximately 60 new and redrilled development and/or replacement wells. It is expected that this will be accomplished by using the T-9 drilling rig at Island Chaffee, Freeman and Pier J, the T-3 drilling rig at Island White, and the T-5 drilling rig at Island Grissom during the Annual Plan term. A workover rig will do drilling preparation and completion work. Locations of production and injection wells to be drilled or redrilled are presented in Part II, Schedule 1B of this Plan.

Maintenance

Most of the major facility projects anticipated during the Plan period are required to maintain current equipment capabilities or to enhance operations. Other projects will be necessary to take advantage of improvement opportunities and to address changes in the oil field operating environment.

Many projects will be undertaken to repair or replace equipment that has outlived its useful life. Items needing to be repaired or replaced include facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Unit facilities in safe operating condition.

Abandonments

Wells and facilities with no further economic use will be abandoned to reduce current and future Unit liability. This Plan provides funds for both in-zone plugs and conditional abandonments with approximately $1.5 million in spending for the Plan period.

Safety, Environmental, and Regulatory Compliance

Projects relating to safety and environmental issues and others necessary for meeting compliance with code, permit, or regulatory requirements will continue to be undertaken.

Economic Review

Project expenditures during the Plan period are subject to economic review through the Determination and Authority for Expenditure processes.

All existing wells are frequently reviewed in light of changing crude prices to determine if they are economic to operate. Well servicing work is justified both on economics and conditions consistent with good engineering, business, and operating practices.

B. Economic Projections

(Data in Millions of Dollars)

	BUDGET FIRST QUARTER FY05/06	BUDGET SECOND QUARTER FY05/06	BUDGET THIRD QUARTER FY05/06	BUDGET FOURTH QUARTER FY05/06	BUDGET TOTAL FY05/06
ESTIMATED REVENUE					
Oil Revenue	$82.4	$82.9	$81.5	$82.1	$328.9
Gas Revenue	$4.2	$4.3	$4.2	$4.2	$16.9
TOTAL REVENUE	$86.6	$87.2	$85.7	$86.3	$345.8
ESTIMATED EXPENDITURES					
Development Drilling	$17.5	$17.5	$17.5	$17.5	$70.0
Operating Expense	$21.9	$32.4	$20.9	$21.1	$96.3
Facilities & Maintenance	$11.4	$10.9	$12.0	$12.5	$46.8
Unit Field Labor & Administration	$9.2	$9.2	$10.2	$9.3	$37.9
Taxes, Permits & Overhead	$5.1	$5.6	$5.2	$5.1	$21.0
TOTAL EXPENDITURES	$65.1	$75.6	$65.8	$65.5	$272.0
NET PROFIT	$21.5	$11.6	$19.9	$20.8	$73.8

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY05/06	BUDGET SECOND QUARTER FY05/06	BUDGET THIRD QUARTER FY05/06	BUDGET FOURTH QUARTER FY05/06	BUDGET TOTAL FY05/06
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,943	2,960	2,910	2,933	11,746
(AVERAGE B/D)	31,988	32,174	32,339	32,227	32,181
GAS PRODUCTION					
PRODUCED (1000 MCF)	771	776	763	768	3,078
(AVERAGE MCF/D)	8,383	8,430	8,472	8,443	8,432
WATER PRODUCTION					
PRODUCED (1000 BBL)	72,635	72,602	73,133	73,558	291,928
(AVERAGE B/D)	789,513	789,154	812,586	808,327	804,557
WATER INJECTION					
INJECTED (1000 BBL)	81,942	82,913	82,008	83,539	330,402
(AVERAGE B/D)	890,667	901,230	911,202	918,012	905,211
OIL PRICE ($/BBL)	$28.00	$28.00	$28.00	$28.00	$28.00
GAS PRICE ($/MCF)	$ 5.50	$ 5.50	$ 5.50	$ 5.50	$ 5.50

Part II

Program Plan Schedules

Schedule 1 A

Range of Production and Injection
FY 2005/06
Long Beach Unit Program Plan, July 2005-June 2010

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	**WATER MBWPD**	**GAS MMCFPD**	**INJECTION MBWPD**
2005-06	29.0 - 33.8	724 - 845	7.6 - 8.9	815 - 950

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	TAR PSI	**RANGER PSI**	**TERMINAL PSI**	**U. P./FORD PSI**
2005-06	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

SCHEDULE 1B

ANTICIPATED NEW AND REDRILLED WELLS
FISCAL YEAR 2005-06

LONG BEACH UNIT PROGRAM PLAN, JULY 2005 – JUNE 2010

Reservoir	CRB	PRODUCERS					INJECTORS				
		GRISSOM MIN MAX	WHITE MIN MAX	CHAFFEE MIN MAX	FREEMAN MIN MAX	PIER-J MIN MAX	GRISSOM MIN MAX	WHITE MIN MAX	CHAFFEE MIN MAX	FREEMAN MIN MAX	PIER-J MIN MAX
Tar	Sc	0 - 0				0 - 0	0 - 0				0 - 0
Ranger West	1	0 - 0	0 - 0				2 - 7				
	2	2 - 7					1 - 2				
	3	3 - 9	0 - 0			0 - 0	1 - 2				0 - 0
	4	0 - 0	0 - 1		0 - 0	1 - 3	0 - 0	0 - 1		0 - 0	0 - 0
	5	0 - 0			0 - 0	1 - 3				0 - 0	0 - 1
	36				0 - 0	0 - 1				0 - 0	0 - 0
	7				0 - 0					0 - 0	
	8		0 - 0		0 - 0			0 - 0		0 - 0	
	9		0 - 1					0 - 0			
	10		0 - 0					0 - 0			
	11		0 - 1					0 - 0			
	12		0 - 0					0 - 0			
	13		0 - 0		0 - 0			0 - 0		0 - 1	
	37				0 - 0					0 - 0	
Ranger East	14		0 - 0					0 - 0			
	15		0 - 1		0 - 1			0 - 0		0 - 0	
	16		0 - 0	0 - 0	0 - 0			0 - 0	0 - 0	0 - 0	
	17			0 - 0					0 - 1		
	18			0 - 0					0 - 0		
	32			0 - 0					0 - 0		
	33			0 - 0					0 - 0		
	20			0 - 0					0 - 0		
	21			0 - 0	0 - 0				0 - 0	0 - 0	
	22			0 - 0	0 - 0				0 - 0	0 - 0	
Terminal	38	1 - 4				1 - 2	0 - 0				0 - 0
	39	0 - 0	0 - 0		0 - 0	0 - 0	1 - 3	0 - 0		0 - 0	0 - 0
	40		0 - 1		0 - 0			0 - 0		0 - 0	
	24		0 - 0		0 - 1			0 - 0		0 - 1	
	41										
	42			0 - 0					0 - 0		
	43			1 - 2	1 - 2				0 - 0	1 - 2	
UP Ford	26		0 - 1		0 - 0			0 - 0		0 - 0	
	27		0 - 0		0 - 2			0 - 2		0 - 0	
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44		0 - 0	0 - 1	0 - 0			0 - 0	0 - 0	0 - 0	
	45		0 - 0	1 - 2	0 - 0			0 - 0	0 - 0	0 - 0	
	46		0 - 0	0 - 0	0 - 0			0 - 0	1 - 2	1 - 3	
237	30	0 - 0		0 - 1	0 - 0						
		TOTAL					TOTAL				
		12 - 47					8 - 28				

000395

CALENDAR PAGE

0007[illegible]

MINUTE PAGE

Part III

Itemized Budget of Expenditures

A. Development Drilling $70,000,000

The Development Drilling category of expenditures encompasses all new well and replacement well drilling activity, as well as maintenance and replacement of drilling equipment within the Unit. Funds for development drilling are based on the assumption that 60 wells will be developed and/or replaced during the Plan year, using two and one half drilling rigs, and one part-time completion rig.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 93 percent of the funding provided in this category. Included in these activities is funding for rig move-in, drilling and casing, completion activities, drilling rig in-zone plugs and conditional abandonments, and unscheduled activity (fishing operations, cement squeezing, special logging, contract drilling services).

Exact specifications regarding the distribution of wells, bottom hole locations, and completion intervals will be determined by OXY Long Beach, Inc. (OLBI). These decisions will be influenced by contributions from reservoir engineering personnel, results from ongoing engineering studies, and new well performance. This information will be reviewed in regularly scheduled Unit forums.

B. Operating Expense $96,300,000

The Operating Expense category of expenditures encompasses the ongoing costs of day-to-day well production and injection operations necessary for producing, processing, and delivering crude oil and gas, and for all electric power charges. Expenses for this category are based on estimated oil production of 32.2 Mbopd, estimated gas production of 8.4 MMcfpd, water injection requirement of 905 Mbwpd, and water production of 805 Mbwpd. Anticipated operating expenses were based on operating 4-1/2 workover rigs per month for servicing an active well count of 680 producers and 400 injectors, and up to 1/5 rig for abandonment activity. Abandonment well count will be determined as a function of drilling activity and the number of idle wells with no future use identified.

The day-to-day costs for production and injection well subsurface operations represent approximately 29 percent of the funding provided in this category. Included are funds for acidizing, fracturing, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 63 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 555,903,000 kwh at an average rate of $0.09/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases. Funds for a partial accelerated pay down of the power plant lease of $10.4 million are also included in the budget.

C. Facilities, Maintenance, and Plant $46,800,000

The Facilities, Maintenance, and Plant category of expenditures encompasses costs for maintenance, repairs, upgrades, additions of surface facilities and pipelines, and costs for general field services.

Approximately 52 percent of the funding in this category is for general field and operating costs. This includes, but is not limited to, charges for general labor, equipment rentals, and materials for general maintenance (painting, welding, electrical, etc.) of all Unit systems, such as oil gathering, treating, storage, and transfer; gas gathering and treating; scale and corrosion control; produced water handling; waste disposal; leasehold improvements; electrical system; fresh water system; fire protection and safety; marine operations; and automotive equipment. Funds are also provided for chemical purchases and laboratory-related charges for chemical treatment of produced and injected fluids; gas processing charges; make-up water; security; transportation; small tools; and other miscellaneous field activities.

Approximately 48 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects include spending for pipeline replacements, facility repair projects, and other infrastructure related investments that position the Unit for longevity. Also included are funds for the installation of a CO_2 plant ($9 million) and investments to increase facility production capacity limits ($3 million) to accommodate a full two rig drilling program throughout the full life of the Program Plan.

D. Unit Field Labor and Administrative $37,900,000

The Unit Field Labor and Administrative category of expenditures encompasses costs for Unit personnel and other Unit support activities.

Funding for Unit personnel includes costs of salaries, wages, benefits, training, and expenses of all Thums employees. These costs represent approximately 74% of the category total.

Funding for Unit support activities includes, but is not limited to, costs for professional and temporary services necessary for the completion of support activities; charges for data processing; computer hardware and software; communications; office rent; general office equipment and materials; Unit Operator billable costs; OLBI billable costs; drafting and reprographic services; Department of Transportation drug and alcohol testing; special management projects; and other miscellaneous support charges.

E. Taxes, Permits, and Administrative Overhead $21,000,000

The Taxes, Permits, and Administrative Overhead category of expenditures includes funds for specific taxes, permits, licenses, land leases, and all administrative overhead costs for the Unit.

Funding is provided for taxes levied on personal property, mining rights, and oil production; for the Petroleum and Gas Fund Assessment; annual well permits and renewals; Conservation Committee of California Oil and Gas Producers Assessment; California Oil Spill Response, Prevention, and Administration fee; land leases; and pipeline right-of-way costs. These costs represent approximately 58 percent of the Category total.

Funding is also provided in this Category for all Administrative Overhead as called for in Exhibit F of the Unit Operating Agreement.

PART IV

Definitions

This Annual Plan may be Modified or Supplemented after review by the State Lands Commission for consistency with the current Program Plan. All Modifications and Supplements to this plan will be presented by the Department of Oil Properties, City of Long Beach, acting with the consent of OLBI, to the State Lands Commission in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

In addition, on or before October 1, 2006, the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY05/06 Annual Plan, in accordance with the provision in Section 10 of Chapter 138.

A. Modifications

The City of Long Beach, acting with the consent of OLBI, has the authority to cause the expenditures of funds for Unit Operations in excess of the amount set forth in the budget included in the Annual Plan, provided, however, that no such expenditure shall be incurred that would result in any category of expenditures set forth in the budget to exceed 120 percent of the budgeted amount for that category. A budget modification would be required for any expenditure which would cause a budget category to exceed its budgeted amount by 120 percent.

Any transfer of funds between budget categories or an augmentation or decrease of the entire budget may be accomplished by a budget modification in accordance with section 5(g) of Chapter 138 and Article 2.06 of the Optimized Waterflood Program Agreement.

Investment, facilities, and management expense projects commenced in prior budget periods, which are to be continued during the current budget period, may be added to this budget by a modification in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

B. Supplements

This Annual Plan contains all the investment and expense projects reasonably anticipated at the time the Plan was drafted and for which adequate detailed studies existed. Any significant and uncommon expenses not originally contemplated may be added to this budget or transferred by a supplement in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

The amount of the supplement shall include sufficient funds to complete the projects.

C. Final Report and Closing Statement

The final report and closing statement for FY05/06 shall contain a reconciliation by category as finally modified and the actual accomplishments, including:

1. New wells and redrills by zone.

2. Facilities and capital projects.

3. Production by zone.

4. Injection by zone.