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CONSIDERATION OF THE LONG BEACH UNIT PROGRAM PLAN (JULY 1, 2011 THROUGH JUNE 30, 2016) AND ANNUAL PLAN (JULY 1, 2011 THROUGH JUNE 30, 2012), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY

APPLICANT:

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

BACKGROUND:

In accordance with Chapter 941 of the Statutes of 1991 (Chapter 941) and the Agreement for Implementation of an Optimized Waterflood Program (OWPA) for the Long Beach Unit (LBU), the City of Long Beach (City), as Unit Operator, submitted the LBU Program Plan (July 1, 2011 through June 30, 2016) and the LBU Annual Plan (July 1, 2011 – June 30, 2012) to the California State Lands Commission (Commission).

At its meeting on March 8, 2011, the Long Beach City Council approved the proposed Program Plan and Annual Plan and authorized formal submission of both Plans to the Commission for review. The Commission received the Plans on March 17, 2011. As provided by Chapter 941, the Commission has 45 days to review the Program Plan and the Annual Plan, otherwise the Plans are deemed to be reviewed and accepted.

The Program Plan and Annual Plan are requirements of the Optimized Waterflood Program Agreement (OWPA) pursuant to Chapter 941, and Chapter 138, Statutes of 1964, Extraordinary Session, respectively.

Pursuant to Section 3 of Chapter 941, the Program Plan as submitted is subject to review by the Commission for consistency with good oil field practices, the OWPA, the Long Beach Unit and Unit Operating agreements, and for environmental and safety concerns. The Commission's authority is limited to a review of whether the Program Plan:

1) is consistent with good oil field practice;
2) is consistent with the Optimized Waterflood Agreement;
3) is consistent with the Long Beach Unit and Unit Operating agreements; or
4) does not involve significant safety or environmental risks.

The Commission may revise the Program Plan to provide consistency with the categories identified above. Pursuant to the Optimized Waterflood Agreement, the changes ordered by the Commission must be in writing, fact driven, with the reasons set forth with specificity.

The Annual Plan must be consistent with the Program Plan.

LBU PROGRAM PLAN:

The proposed Program Plan is a five-year plan prepared by the City's Gas and Oil Department (LBGO) covering fiscal years 2011-12 through 2015-16. Preparation and submittal of Program Plans began in 1991 as required by Chapter 941 and the OWPA. The purpose of the Program Plan is to describe how the OWPA will be implemented during the five-year period. The Program Plan addresses reservoir management objectives, methods of continuing field development, results and performance of the prior year's development activities, economic projections, and anticipated drilling schedules for the five-year period. The Program Plan includes anticipated rates of production, revenues, expenditures, and net income as projected by the City. The Program Plan is prepared every two years and modified as necessary to reflect changes in actual field performance, economic factors, and reservoir management practices. Prior to the OWPA, only Annual Plans were prepared, but they were similar in detail to the current Program Plans.

LBU ANNUAL PLAN:

The proposed Annual Plan is a one-year plan submitted by the City covering fiscal year 2011-12. The Annual Plan is an itemized budget of anticipated expenditures needed to carry out Program Plan objectives. There are five expenditure categories in the Annual Plan – Development Drilling, Operating Expense, Facilities-Maintenance-Plant, Unit Field Labor and Administrative, and

Taxes-Permits-Overhead. For the 2011-12 Annual Plan, the total budgeted expenditure of $377.6 million for the five categories is consistent with the 2011-12 expenditure objectives in the Program Plan.

ECONOMIC PROJECTIONS IN PROGRAM PLAN:

For 2011-12 through 2015-16, the City estimates the LBU net income will be $188.5 million after total expenditures of $1,915.2 million. This net income projection is based on the City's crude oil price forecast of $45 per barrel (bbl) and a natural gas price of $4.50 per thousand cubic feet (mcf). Most of the net income will be from oil revenues. The City forecasts production to range from an average of 24,900 bbl/day in 2011-12 to 24,300 bbl/day in 2015-16. These rates assume the continuation of development activity to involve an average of 46 wells to be re-drilled from existing wellbores in each of the five years for a total of 231 wells over the Plan period. Expenditure levels and the types of development projects may be adjusted as necessary to respond to fluctuations in oil price and other economic conditions. Pursuant to Article 2, paragraph 2.07 of the OWPA the field contractor may exceed any budget category in the Plan budget up to 20%, without obtaining additional authority from the City and Commission.

OIL PRICE FORECAST:

In planning the expenditures needed to accomplish LBU objectives, and the revenues needed to fund those expenditures, the City has used a conservative crude oil price forecast of $45/bbl. The City takes this approach for planning purposes in order to ensure that revenues will be sufficient to pay for LBU proposed expenditures and still provide net income to the State and the City's field contractor, Occidental Long Beach, Inc. (OLBI) and its agent, THUMS Long Beach, Inc. (THUMS), and the other working interest owners. The severe and unanticipated drop in crude oil prices during 2008 and 2009 resulted in an over-projection of oil revenues in fiscal year 2008-09 leaving some of the City's budgeted spending categories under-funded. Exhibit E shows the volatility for oil prices. The City's budget projected a barrel price for 2008-09 going from $45 in the prior year to $85 -- only to see prices fall from over $128 a barrel to $25, with an average that year of less than $49.

The $45/bbl oil price basis in the proposed plans, which are low compared to the current actual price, yields a conservative projection of net income. It is, however, a factor relevant only for determining that the expenditures for the LBU can be met. Commission staff believes the expenditure levels proposed in the Program Plan and Annual Plan will satisfactorily provide for all LBU development objectives and is not in conflict with any of the four factors to be reviewed by the

Commission.

Estimates prepared by Commission staff for State revenue projections for fiscal year 2011-12 use an oil price forecast that better reflects the current commodity price environment. The price for LBU crude oil currently exceeds $110/bbl (week of April 18th). Staff projects that net income from the LBU during 2011-12 will be much greater than that projected in the Annual Plan. At an average oil price of $92/bbl, staff estimates the net income for fiscal year 2011-12 from the LBU to be $481 million. That level of profit under Chapter 941 would provide $282 million of non-tax revenue to the State of California. All net profits allocated to the State's share go directly to the State General Fund, with no monies directed to fund Commission staff expenses.

REVIEW OF PROGRAM AND ANNUAL PLANS:

Commission staff has reviewed the proposed Program Plan and Annual Plan submitted by the City and finds that the economic basis upon which the Plans were prepared will support and provide an engineering framework to meet the objectives of the OWPA and LBU objectives. Commission staff has concluded that the Program Plan is consistent with good oil field practice. The Plans are based on all engineering and geologic information available at the time of preparation. Further, to support the conclusion that the Program Plan was prepared to ensure good oil field practice, Commission staff maintains direct involvement in ongoing LBU development activities and the planning of future activities. Staff involvement includes, among other things, monthly meetings of an engineering committee, onsite inspector presence in the field, reservoir management consultation with the City and the field contractor, analysis of drilling safeguards involving blowout prevention equipment certification, oil spill prevention exercises, and subsidence monitoring and prevention.

In addition, Commission staff has concluded that the Program Plan is consistent with Articles in the OWPA, Unit Agreement, and Unit Operating Agreement pertaining to development and operations, subsidence prevention, preparation and submittal of plans of development and expenditures, re-pressuring operations, and drilling schedules. Commission staff also has concluded that the Annual Plan is consistent with the Program Plan.

Commission staff's ongoing participation in meetings, onsite inspections, and engineering review was the basis for staff to believe that operation of LBU was being conducted in a safe manner and the basis for recommending no changes to the Program Plan at the April 6, 2011 Commission meeting. Staff also

believes that the field contractor adheres to industry codes and standards, including the American Petroleum Institute (API) recommended practices, state oil and gas regulations, and safety and environmental regulations of all state and local governmental agencies having jurisdiction over LBU operations.

However, following a number of questions raised by the Lt. Governor's office and upon a more critical review of the Program Plan, staff believes that the Program Plan as a stand-alone document does not include sufficient detailed information on the safety and environmental programs for the LBU for Commission staff to make a recommendation that the Plan does not involve any significant environmental or safety risk. The LBU is one of the largest oil and gas production operations in the nation and is equivalent to six platforms or facilities in scope and complexity. Yet the discussion on safety and environmental programs in the Program Plan is less than a page in the Program's 48-page plan. For example, there is no detailed discussion on any injuries to workers and pollution events that may have taken place since the last Program Plan was reviewed, why such events occurred, what was the response, and what is being done to make sure that similar incidents do not occur again in the future. Further, there is no discussion of what programs are in place to ensure that latent defects in equipment or procedures that could lead to injuries or pollution events are intercepted before they occur.

A comprehensive safety audit was conducted by Commission staff as a condition of the Commission's approval of the field contractor assignment from ARCO to OLBI in 2002. That audit provided considerable enhancements to the LBU's safety systems and minimized further the risk of an offshore pipeline spill. Specifically, Commission staff found approximately 200 action items that posed a potential safety or environmental risk. Commission staff worked closely with the field contractor (OXY/THUMS) to resolve all of those items identified.

It has been almost ten years since that audit where the LBU was assessed for environmental and safety risks. Commission staff, therefore, recommends that the Commission order the Program Plan to be revised to include an updated environmental and safety review and assessment of the Long Beach Unit operations to be completed by staff within 15 months.

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

CEQA because it is not a "project" as defined by 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 LBU Program Plan and Annual Plan to the California State Lands Commission
B. LBU Program Plan (July 1, 2011 through June 30, 2016)
C. LBU Annual Plan (July 1, 2011 through June 30, 2012)
D. LBU Briefing Document
E. Oil Price Comparison Graph and Average Price Chart for 2007-2011

RECOMMENDED ACTION:

It is recommended that the Commission:

CEQA FINDING:

Find that the activity is not subject to the requirements of 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.

RECOMMENDED FINDINGS:

Pursuant to Section 3, Chapter 941, Statutes of 1991, order the Program Plan be revised to include an environmental and safety review and assessment of the Long Beach Unit operations. The Commission staff shall return to the Commission within 60 days with a detailed scope of the proposed environmental and safety review and assessment. Commission staff shall consult with the City of Long Beach and OLBI on the scope of the review and assessment. At a minimum, the scope of the review and assessment shall include an identification and analysis of environmental and safety risks that could lead to potential human injury, an adverse environmental impact, or significant property damage. The review and assessment shall also include recommendations to improve the operations and Program Plan to address any identified risks. The environmental and safety review and assessment shall be completed within 15 months.

Exhibit A

W 17165

CITY OF LONG BEACH
Gas & Oil
DEPARTMENT

CHRISTOPHER J. GARNER
DIRECTOR

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www.lbgo.org

March 15, 2011

Mr. Greg Scott
Chief, Mineral Resources Management
California State Lands Commission
200 Oceangate, 12th Floor
Long Beach, CA 90802-4331

SUBJECT: **SUBMISSION OF THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2011-JUNE 30, 2012) AND PROGRAM PLAN (JULY 2011-JUNE 2016)**

Dear Mr. Scott:

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 five copies of the Long Beach Unit Annual Plan (July 1, 2011-June 30, 2012) and Program Plan (July 2011-June 2016).

The Plans were approved by the Long Beach City Council on March 8, 2011. If you have any questions, please contact Mr. Kevin Tougas at (562) 570-3963.

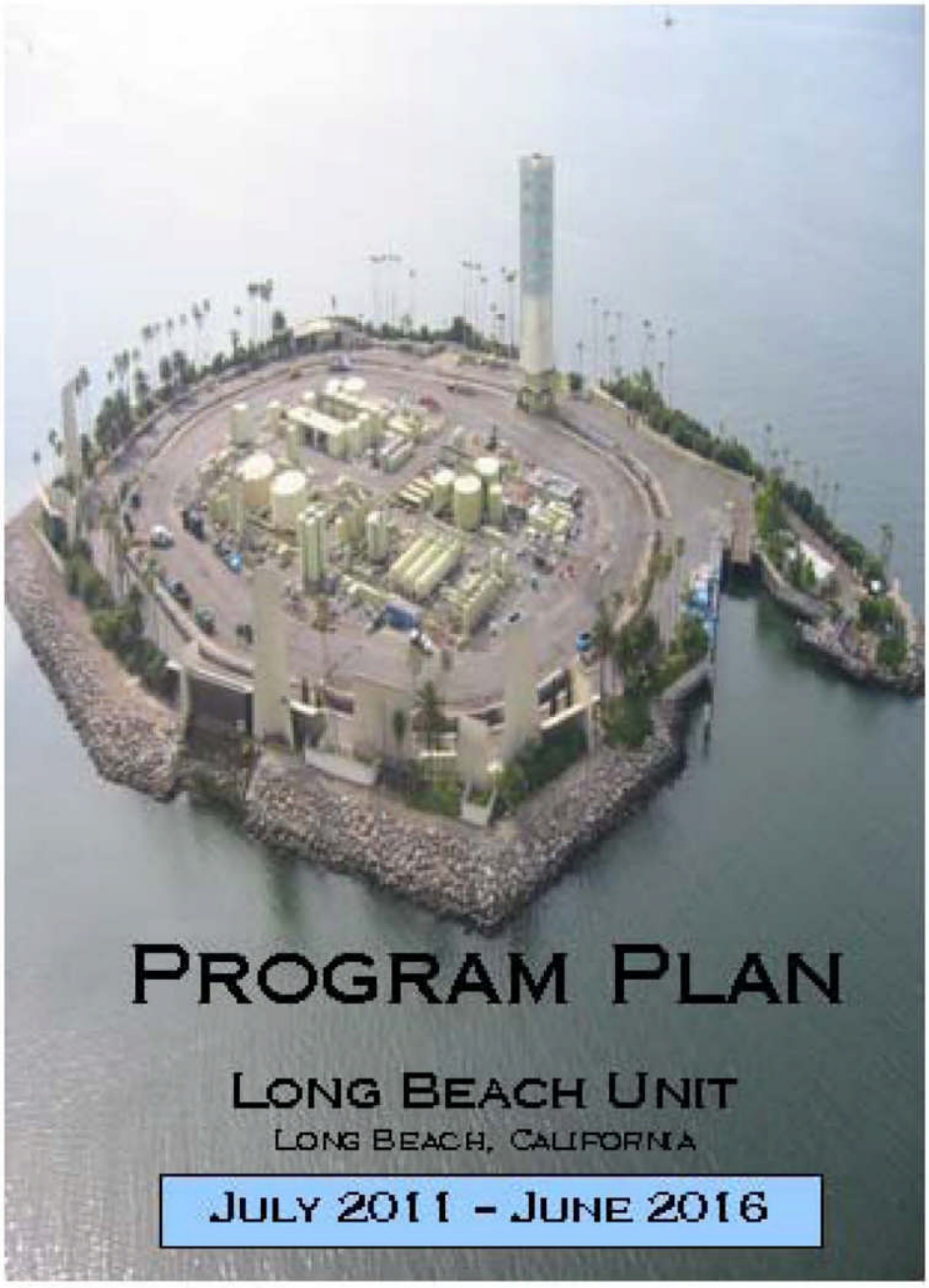
Sincerely,

CHRISTOPHER J. GARNER
Director, Long Beach Gas and Oil Department

CJG:kmt:tld

Enclosures

cc: Marina Voskanian, CSLC
Curtis L. Fossum, CSLC
Frank Komin, OLBI
Rich Anthony, CLB
J. Charles Parkin, CLB



PROGRAM PLAN

LONG BEACH UNIT

LONG BEACH, CALIFORNIA

JULY 2011 - JUNE 2016

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Executive Summary

This Program Plan covers the period from July 1, 2011 through June 30, 2016. 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 Long Beach Gas & Oil Department, 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 231 development and replacement wells over the life of the Program Plan. This schedule will result in a steady decline in oil production rate through the end of FY15/16. Unit production and injection rates are expected to average 24.9 Mbopd, 1,023.7 Mbwpd and 1,118.9 Mbwipd in FY11/12 and 24.6 Mbopd, 1,053.2 Mbwpd and 1,139.2 Mbwipd in FY12/13, 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, if needed, augmented with the use of other Unit rig assets, 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, continuous reservoir review, 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.

Facility improvement projects envisioned during the Plan include completion of Pier J infrastructure and piping projects that will upgrade and ensure continued, efficient, production processing. Other work will focus on electrical infrastructure improvements to provide additional well capacity required to support the planned development program. These improvements are focused on right-sizing facility capacity limits to accommodate the forecast drilling program throughout all 5 years of the Program Plan period. These investments result in enhancement of revenue streams, lower maintenance and operational costs, and improved safety and environmental performance. The first year of the Program Plan also includes funds to design and install replacement pipe from Pier 3 through J4 and J5 to reduce facility risk. These lines were identified as high priority in the Pier J Piping Risk Assessment.

Based on production from 46 development and replacement well projects planned for FY11/12 of the Program Plan and an average oil price of $45.00/bbl, total revenue, expenditures, and net profits are projected to be $429.3 million, $377.6 million, and $51.7 million, respectively. Over the five-year Program Plan period, cumulative total

revenue, expenditures, and net profit are expected to reach $2,103.7 million, $1,915.2 million, and $188.5 million, respectively. 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, 2011 through June 30, 2016. 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 six reservoir areas: Ranger West/Tar, Ranger East, Terminal, UP Ford, Shallow gas zone 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.

- The *Economic Summary* section provides a forecast of Unit revenues, expenditures, and profits anticipated during the Plan period, assuming an oil price of $45.00/bbl during the Program Plan period and gas price of $4.50/mcf. This section also includes the schedules that will be incorporated into the FY11/12 and FY12/13 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, fluctuated between a one and two rig pace until 2003 where it remained at two rigs until 2005. In September 2005 a third rig was contracted to capitalize on the high oil price environment. A review was made in 2007 to determine optimal drilling pace and Unit Stakeholders made the decision to move from a three to a two rig drilling program effective November, 2007. For the remainder of the FY07/08 fiscal year the drilling program was executed using two Unit rigs. In November 2008 a third rig was contracted to execute accelerated drilling pace due to 237 zone exploration wells and to support the activities from the Injection Balance and Optimization Team (IBOT) efforts. The Unit continued drilling operations with three rigs until January 2009 when the contract rig was demobilized. Drilling is expected to be at an approximately two-rig pace through the FY15/16

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. In third quarter of FY 07/08, an "Injection Balance and Optimization Team" (IBOT) was formed to execute such strategy through a structured and detailed process.
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. Enhanced oil recovery applications will be considered for implementation if economically and technically viable.

Each of these strategies is discussed in more detail below. Specific strategies and goals for each reservoir are included in 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. THUMS Development and Operations Divisions 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 and other reservoir simulation methodologies. 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 was formerly 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. Since July 2006, the LBGO Subsidence and Geology Division, along with the Thums RMT and Well Surveillance Leaders have been periodically modifying the voidage accounting rules to ensure stable ground elevations (subsidence and dilation), while providing prudent operational flexibility to improve waterflood management. A collaborative effort is used on the methodology for the voidage account, and to identify key wells to survey for bottomhole pressures to support semi-annual ground elevation measurements.

Development Opportunities

The Unit has a strategy to invest and minimize the decline of the LBU's 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 re-establish injection patterns in the relatively underdeveloped areas of the field.
- Adding production wells: (1) in areas of unswept oil (2) in lower productivity sands that cannot produce well in combination with higher productivity zones in long completions, (3) in areas of high oil saturations banked along sealing faults, and (4) 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. Although most work is considered routine, fracture stimulations which are more complex, require special planning. 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. With the assistance of Oxy's Worldwide Reservoir Characterization Group, other outside consultants and local staff, the Long Beach Unit continues to assess, understand and refine its knowledge of the reservoir and develop new production opportunities.

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. Enhanced oil recovery applications will be considered for implementation if economically and technically viable.

Unit Forecasts

Drilling Schedule

The Program Plan projects development and replacement drilling to average approximately 46 wells per year in both FY11/12 and FY12/13. This schedule can be met with approximately 2 Unit 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.

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 FY11/12 and FY12/13. 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 FY11/12 and FY12/13. 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. 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 an extrapolation of wells within each Unitized Formation summed together to yield a forecast of the existing wells' production for the entire Unit. For each well, 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. The resulting prediction shows a near term exponential decline of about 11% per year for the existing wells.

The incremental production contribution for new development wells is calculated by adding together type wells. The type wells are determined by reservoir area and completion type (conventional producer, frac producer, horizontal producer and injector). The engineers managing individual reservoir pools determine type wells for their areas based on historical performance. Depending on available data, type wells are built by reservoir, by pool, or by cut-recovery block. The producer type wells are based on recent development wells determining an average initial production rate and decline rate. 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.

Major Issues and Projects

Several major issues must be considered when planning Unit strategies. These issues include consideration for people, health and safety, environmental protection, subsidence control, well abandonment, cost management, expansion of production infrastructure, shallow and deep gas development, electrical generation, taxes and make-up water sources. 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.

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

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.

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. 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. 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 continues to strive to improve the environmental record attained by its employees and is proud of it's accomplishments, including the Wildlife Habitat Council Certification of all four Thums Islands. To ensure continued compliance, environmental assessments are undertaken by Unit personnel and outside organizations.

Regulatory Environment

The regulatory and permitting outlook is an area of growing concern and could lead to unknown and potentially significant development, cost and production impacts in future years. In 2010, significant delays in well permitting became an issue that impacted drilling schedules. It also resulted in increased voidage management challenges resulting in production losses to maintain voidage conformance. As of this time, there is no resolution to the delays in well permitting. Other issues that could impact operations include severance tax proposals and similar tax/fee proposals related to the California budget situation.

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 must be managed 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. Current injection rules require net injection to exceed gross production by an average of 41.8 MBWPD in the eleven voidage pools with each pool having specific injection requirements. Since July 2006, the LBGO Subsidence and Geology Division, along with the Thums RMT and Well Surveillance Leaders, have been periodically modifying the voidage accounting rules to ensure stable ground elevations, while providing prudent operational flexibility to improve waterflood management. A collaborative effort is used on the methodology for the voidage account, and to identify key wells to survey for bottomhole pressures to support semi-annual ground elevation measurements.

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 acquisition of make-up water. Amine Plant operations, used to reduce produced-gas CO2 levels, will be optimized in conjunction with Power Plant operations. 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 operating and maintenance costs for 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 and a contracts/alliances team.

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 Island White can be accomplished with Unit Rig T-3. Additional drilling methods or equipment will be considered for lowering drilling

costs on all locations. These additional equipment could include contract drilling rigs, workover rigs and coiled tubing units and the use of top drive components.

Expansion of Pier J Electrical Infrastructure

Expansion of current electrical facility will be needed to provide electrical capacity for the field development during the Program Plan period at the Pier J facilities. The existing electrical service capacity is sufficient to handle our current load but will not be able to handle future development. Activities to help achieve capacity expansion include new SCE 66KV service substation, transformers, electrical switchgears, motor control centers, and conduits. The planned expansion will also optimize system reliability by providing back-up service to minimize production downtime in the event of a primary electrical service failure. This Plan includes funding to complete the upgrades needed to meet the anticipated drilling activity.

Shallow and Deep Gas Development

Currently the Shallow Gas accumulation under Grissom and White has been produced. However, Shallow Gas production was shut down from the middle of July to mid December 2010 for repairs and maintenance on subsea lines. White Shallow Gas production has been added through well B403, while four producers (A271, A301, A310 and A313) on Grissom make up for the majority of production. As the wells water out, shallower gas sands will be added to continue the production of Shallow Gas.

Electricity Generation

Electricity is the single largest cost element for the Unit. Currently the Unit consumes approximately 700 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 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, and depending on demand from the wallboard facility, 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.

Taxes

The County of Los Angeles has significantly increased the assessed value of the Unit. Estimation of taxes for the Plan period assume an annual 3% increase, although determination of actual tax levies will be based on assessor valuation, again driven by oil price.

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 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 Tidelands 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.

THUMS is working closely with Tidelands to anticipate water needs and sources to satisfy the injection needs in the Unit.

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 $2,103.7 million, based on a $45.00/bbl oil price and $4.50/mcf gas price, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY11/12 is expected to be $429.3 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY11/12 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 Program Plan period are expected to be $1,915.2 million. The projected expenditures for FY11/12 are $377.6 million. Costs in future years will be refined upon completion of ongoing studies and projects and also be affected by changes and adjustments that may result from the economic conditions.

Profit Forecast

Based on the above revenue and cost forecasts, Unit profit during the Program Plan period is projected to be $188.5 million. Unit profit for FY11/12 is expected to be $51.7 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY12/13 will be established based on actual results and additional insights gained during FY11/12.

Table 1
SUMMARY OF PRODUCTION AND INJECTION
AS OF OCTOBER 2010
JULY 2011 – JUNE 2016 PROGRAM PLAN, LONG BEACH UNIT

		Active Well Count		Average Rates for October 2010				Average Well Rates	
Reservoir	CRB	Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/ Well	BIPD/ Well
SG	65	0	0	0	0	0	0.00%	-	-
	66	0	0	0	0	0		-	-
Tar	35	5	1	72	817	1,962	92%	14	1,962
Ranger	1	41	28	1,349	65,818	75,620	98%	33	2,701
West	2	28	16	1,034	39,991	44,851	97%	38	2,894
	3	39	28	1,510	77,799	90,199	98%	39	3,221
	4	58	28	2,210	107,413	102,594	98%	38	3,664
	5	32	25	1,368	71,999	81,719	98%	43	3,269
	7	18	8	498	19,899	21,351	98%	28	2,847
	8	12	8	329	18,049	18,099	98%	27	2,413
	9	7	6	330	6,389	9,074	95%	47	1,512
	10	23	18	939	30,325	37,799	97%	42	2,100
	11	11	5	838	10,418	10,169	93%	80	2,034
	12	6	4	254	6,656	6,944	96%	42	1,736
	13	6	5	247	11,341	9,445	98%	41	1,889
	36	21	17	688	35,537	45,436	98%	33	2,754
	37	7	9	282	13,858	21,909	98%	40	2,434
	Total	**311**	**204**	**11,950**	**516,311**	**577,171**	**97.74%**	**38**	**2,829**
Ranger	14	16	17	589	21,705	33,707	97.36%	37	2,043
East	15	38	22	1,194	50,674	51,669	97.70%	31	2,403
	16	18	9	587	17,628	15,621	96.78%	33	1,736
	17	24	12	741	17,115	18,628	95.85%	32	1,552
	18	16	13	382	19,524	30,752	98.08%	24	2,366
	20	11	5	290	9,387	9,518	97.00%	26	1,904
	32	2	2	34	1,356	2,141	98%	17	1,070
	33	30	18	960	42,864	43,624	98%	32	2,424
	21	33	23	1,274	44,259	48,604	97%	39	2,113
	22	18	6	498	15,307	12,834	97%	28	2,139
	Total	**206**	**126**	**6,549**	**239,818**	**267,098**	**97.34%**	**32**	**2,120**
Terminal	24	29	18	817	19,413	25,092	96%	28	1,394
	38	37	20	1,100	54,657	61,245	98%	30	3,062
	39	30	13	908	28,021	29,548	97%	30	2,273
	40	7	6	100	3,335	6,223	97%	14	1,037
	41	4	2	189	3,480	3,253	95%	47	1,626
	42	10	5	290	12,752	9,875	98%	29	1,975
	43	35	18	1,026	29,565	30,393	97%	29	1,688
	47	4	1	15	580	-	98%	4	-
	Total	**156**	**83**	**4,446**	**151,802**	**165,628**	**97.15%**	**29**	**1,996**
UP/Ford	26	0	2	-	-	2,001	0%	-	1,000
	27	17	16	625	14,002	17,341	96%	37	1,084
	31	10	5	143	4,892	4,902	97%	14	980
	44	4	6	66	2,594	7,099	98%	16	1,183
	45	23	14	677	18,343	14,168	96%	29	1,049
	46	27	18	959	21,846	23,294	96%	36	1,331
	Total	**81**	**60**	**2,470**	**61,678**	**68,804**	**96.15%**	**30**	**1,147**
237	30	2	0	389	2957	0	0.00%	-	-
	LBU Total	761	474	25,875	973,383	1,080,662	97.41%	34	2,280

Exhibit A

ECONOMIC PROJECTIONS
July 1, 2011 through June 30, 2016 Program Plan
(Million Dollars)

	Fiscal 2011/12	Fiscal 2012/13	Fiscal 2013/14	Fiscal 2014/15	Fiscal 2015/16	Program Plan Period
Estimated Revenue						
Oil Revenue	$410.8	$403.2	$400.8	$399.5	$399.8	$2,014.0
Gas Revenue	$18.5	$17.6	$17.6	$17.8	$17.9	$89.6
Total Estimated Revenue	$429.3	$420.9	$418.5	$417.3	$417.7	$2,103.7
Estimated Expenditures	$377.6	$387.2	$385.6	$382.8	$382.0	$1,915.2
Net Income	$51.7	$33.7	$32.9	$34.5	$35.7	$188.5

Exhibit B

Anticipated Drilling Schedule

July 1, 2011 through June 30, 2016

FISCAL YEAR	RANGER WEST	RANGER EAST	TERMINAL	U.P. FORD/ 237	TOTAL WELLS
2011/12	25	10	7	4	46
2012/13	25	10	6	5	46
2013/14	25	5	11	6	47
2014/15	17	11	8	9	45
2015/16	17	11	6	13	47

* See text for a description of the process that will be used to identify and approve all new locations
** Development drilling of proven, risked probable and possible replacement wells

Exhibit C

Range of Production Rates

July 2011-June 2016 Program Plan

Long Beach Unit

FISCAL YEAR	EXPECTED RANGE			EXPECTED RATE		
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	OIL MBOPD	WATER MBWPD	GAS MMCFPD
2011/12	23.7 - 26.2	973 - 1,075	10.7 - 11.8	24.9	1,024	11.2
2012/13	23.3 - 25.8	1,001 - 1,106	10.2 - 11.3	24.5	1,053	10.7
2013/14	23.2 - 25.6	1,041 - 1,150	10.3 - 11.4	24.4	1,095	10.8
2014/15	23.1 - 25.5	1,077 - 1,191	10.3 - 11.4	24.3	1,134	10.8
2015/16	23.1 - 25.5	1,111 - 1,228	10.4 - 11.4	24.3	1,170	10.9

Exhibit D

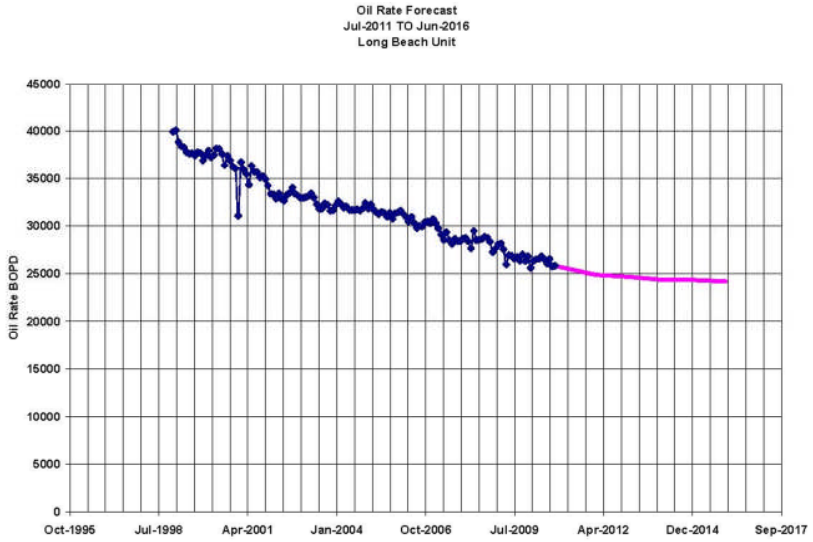
Range of Injection Rates

July 2011-June 2016 Program Plan

Long Beach Unit

FISCAL YEAR	WATER INJECTION RATE		RANGE OF INJECTION PRESSURES			
	RANGE MBWPD	EXPECTED MBWPD	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2011/12	1,056 - 1,167	1,119	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2012/13	1,085 - 1,200	1,139	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2013/14	1,128 - 1,246	1,184	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2014/15	1,167 - 1,289	1,224	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2015/16	1,202 - 1,329	1,262	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Exhibit E


Oil Rate Forecast
Jul-2011 TO Jun-2016
Long Beach Unit
Oil Rate BOPD
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
Oct-1995
Jul-1998
Apr-2001
Jan-2004
Oct-2006
Jul-2009
Apr-2012
Dec-2014
Sep-2017

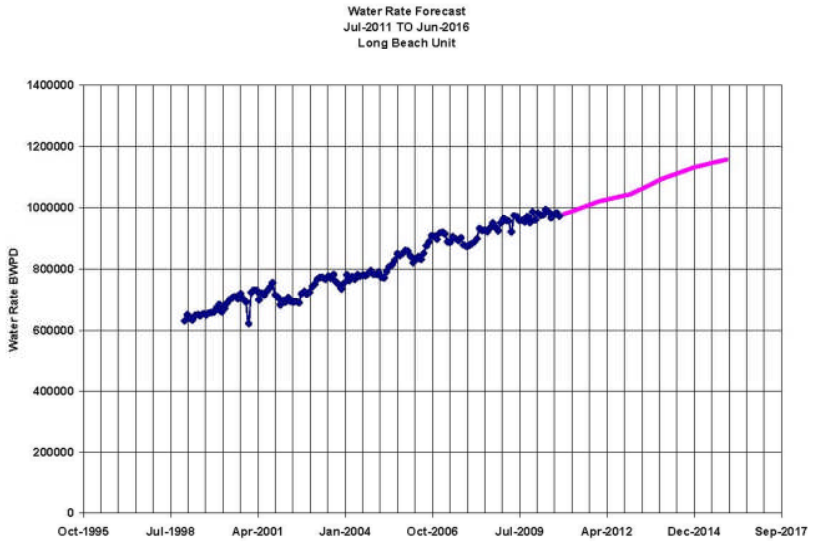

Water Rate Forecast
Jul-2011 TO Jun-2016
Long Beach Unit
Water Rate BWPD
1400000
1200000
1000000
800000
600000
400000
200000
0
Oct-1995
Jul-1998
Apr-2001
Jan-2004
Oct-2006
Jul-2009
Apr-2012
Dec-2014
Sep-2017

Exhibit F


Gas Rate Forecast
Jul-2011 TO Jun-2016
Long Beach Unit
Gas Rate MCFD
16000
14000
12000
10000
8000
6000
4000
2000
0
Oct-1995
Jul-1998
Apr-2001
Jan-2004
Oct-2006
Jul-2009
Apr-2012
Dec-2014
Sep-2017

Schedule 1 A

Range of Production and Injection

FY 2011/12

Long Beach Unit Program Plan, July 2011-June 2016

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2011/12	23.7 - 26.2	973 - 1,075	10.7 - 11.8	1,056 - 1,167

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2011/12	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 1 B

Anticipated Development and Replacement Locations

Fiscal Year 11/12

Long Beach Unit Program Plan, July 2011-June 2016

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		0 - 2	0 - 2				0 - 1	0 - 1			
SG		0 - 1	0 - 1								
Ranger West	1	0 - 3					0 - 2				
	2	1 - 3	0 - 1				1 - 1	0 - 1			
	3	0 - 3	0 - 1				0 - 1	0 - 1			0 - 1
	4	1 - 3	0 - 1		0 - 1	0 - 1	1 - 2	0 - 1		0 - 1	0 - 1
	5	0 - 1			0 - 1	0 - 1	0 - 1			0 - 1	0 - 1
	7				0 - 1					0 - 1	
	8							0 - 1			
	9		0 - 1					0 - 1			
	10		0 - 1					0 - 2			
	11		0 - 1					0 - 1			
	12		0 - 1					0 - 1			
	13		0 - 1					0 - 1		0 - 1	
	36				0 - 1	0 - 1				0 - 1	0 - 1
	37				0 - 1					0 - 1	
Ranger East	14		0 - 1					0 - 1			
	15		0 - 1		0 - 1			0 - 1		0 - 1	
	16								0 - 1		
	17			1 - 2					0 - 1		
	18			1 - 1					0 - 1		
	20			0 - 1					0 - 3		
	21			1 - 2					1 - 2		
	22			0 - 1					0 - 1		
	33			0 - 1					0 - 1		
Terminal	24		0 - 1					0 - 1			
	38	0 - 1				0 - 1	0 - 1				0 - 1
	39	0 - 1	0 - 1				0 - 1			0 - 1	
	40		0 - 1								
	41	0 - 1				0 - 1	0 - 1				0 - 1
	42			0 - 1					0 - 1		
	43			0 - 1	0 - 1				0 - 1	0 - 1	
	47										
UP Ford	26				0 - 1					0 - 1	
	27		0 - 2		0 - 1			0 - 1		0 - 1	
	30			0 - 2	0 - 1						
	31	0 - 1	0 - 1		0 - 1	0 - 1	0 - 1	0 - 1		0 - 1	0 - 1
	44			0 - 2					0 - 1		
	45			0 - 1				0 - 1	0 - 1		
	46			0 - 1	0 - 1				0 - 1	0 - 1	
237	30	0 - 1		0 - 2	0 - 2						
		Total					Total				
		5 - 78					3 - 64				

Schedule 2 A

Range of Production and Injection

FY 2012/13

Long Beach Unit Program Plan, July 2011-June 2016

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2012/13	23.3 - 25.8	1,001 - 1,106	10.2 - 11.3	1,085 - 1,200

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2012/13	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B

Anticipated Development and Replacement Locations

Fiscal Year 12/13

Long Beach Unit Program Plan, July 2011-June 2016

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		0 - 2	0 - 2				0 - 1	0 - 2			
SG		0 - 1	0 - 2	0 - 1			0 - 1				
Ranger West	1	0 - 1					0 - 9				
	2	1 - 4	0 - 1				0 - 2	0 - 1			
	3	1 - 5	0 - 1				0 - 1	0 - 1			0 - 1
	4	1 - 3	0 - 1		0 - 1	0 - 2	0 -	0 - 1		0 - 1	0 - 1
	5	0 - 1			0 - 1	0 - 2	0 -			0 - 1	0 - 1
	7				0 - 1					0 - 1	
	8										
	9		0 - 1					0 - 1			
	10		0 - 1					0 - 1			
	11		0 - 1					0 - 1			
	12		0 - 1					0 - 1			
	13		0 - 1					0 - 1		0 - 1	
	36				0 - 1	0 - 2				0 - 1	0 - 1
	37				0 - 1					0 - 1	
Ranger East	14		0 - 1					0 - 1			
	15		0 - 1		0 - 1			0 - 1		0 - 1	
	16		0 - 1					0 - 1	0 - 1		
	17			0 - 1					0 - 1		
	18			0 - 1					0 - 1		
	20			0 - 1					1 - 1		
	21			1 - 2					1 - 1		
	22			0 - 1					0 - 1		
	33			0 - 1					0 - 1		
Terminal	24		0 - 1				0 -	0 - 1			
	38	0 - 1				0 - 2	0 - 1				0 - 1
	39	0 - 1	0 - 1				0			0 - 1	
	40		0 - 1								
	41	0 - 1				0 - 2	0				0 - 1
	42			0 - 1					0 - 1		
	43			0 - 1	0 - 1				0 - 1	0 - 1	
	47										
UP Ford	26				0 - 1					0 - 1	
	27		0 - 1		0 - 1			0 - 1		0 - 1	
	30			0 - 1	0 - 1		0 -				
	31	0 - 1	0 - 1		0 - 1	0 - 2		0 - 1		0 - 1	0 - 1
	44			0 - 1					0 - 1		
	45			0 - 2				0 - 1	0 - 1		
	46		0 - 1	0 - 1	0 - 1				0 - 1	0 - 1	
237	30	0 - 1		0 - 2	0 - 2						
		Total					Total				
		4 - 86					2 - 64				

Appendix 1

Ranger West / Tar
Reservoir Management Plan

History

The Ranger West reservoirs are comprised of the Ranger 6 and Ranger 7 fault blocks. Ranger West is the largest pool in the Unit with 1.5 billion barrels of original oil in place (OOIP). The first pool developed at field startup in late 1965, Ranger West contains a contrasting mix of mature and under-developed blocks. The crestal and southern blocks are generally more mature than the northern blocks in the Ranger West area. In the more mature crestal and southern blocks, waterflood recovery is generally high (30-40% OOIP) with water-oil ratios (WOR's) approaching 40. In the less mature northern blocks, oil recoveries range from 26-30% and WOR's range from 27-31.

The Ranger West waterflood was originally implemented using a 3-1 staggered line drive (SLD) pattern containing three rows of producers for each row of injectors. There are twelve cut-recovery blocks (CRB's) still using this pattern framework. The only exceptions are CRB-8, which lies between 2 faults on the crest, and CRB's 1 and 10, which were re-configured through development drilling as injector-centered patterns (1992-1994). In 1986, 70 offset row producers were shut-in because of high water cuts and high operating costs. This left only the center row producers in some blocks, converting these patterns to a classic line drive with exaggerated spacing between producers and injectors. This skewed pattern provides a slow rate of recovery at a reduced, but still relatively high, theoretical areal sweep efficiency. The SLD pattern makes pattern balancing difficult with less than optimal areal sweep due to reservoir heterogeneity.

The Ranger West pool is also peripherally flooded from the north and south aquifers. The southern aquifer appears to be bounded allowing peripheral injection to be effective in supporting up-dip producers. The northern aquifer appears to be unbounded providing less effective support from aquifer injection (based on production performance, pressure histories, and full-field reservoir simulation studies).

There are three main completion intervals in Ranger West: the F0, the F-X, and X-HX1 (Lower Ranger). Over the majority of the Ranger West pool, the F0 is the thickest and most dominant sand package. Original wells used full-zone, open-hole gravel packs across all three intervals. The more permeable F0 sand received the majority of the injected water through point exits resulting in bypassed oil within the F0 and throughout the lower zones. The Subzone Redevelopment Program, from 1980-1984, was successful in diverting injection and production to the F-X and Lower Ranger intervals by selectively completing only those subzones. Ranger West production increased 4,000 BOPD during 1980-1984 from this effort. Pockets of bypassed oil throughout the Ranger West area continue to be the target of horizontal wells, injection realignment/conversions, and selective, cased-hole recompletions.

Since 1992, a successful development drilling program in CRB-1 has resulted in increased water throughput and oil production. CRB-1 oil production increased from a low of 2690 BOPD in April 1992 to a high of 6350 BOPD in September 1994. Additional development is needed to further optimize the waterflood patterns in CRB-1.

Status

The Ranger West/Tar production rates in October 2010 were 11.9 MBOPD and 515.5 MBWPD (97.75% water cut) from 299 producers. October 2010 injection averaged 575.3 MBWPD from 281 injectors. Average active well rates were 40 BOPD and 2047 BWPD for producers and 2697 BWPD for injectors.

Ranger West currently has 55 inactive wells that have not been plugged in zone. 40 of these wells are being evaluated for repair and/or conversion. Additionally there are 40 wells that have previously been plugged in zone and are currently inactive.

Recovery through October 2010 was 492.5 MMBO (31.8% OOIP). While the base production in Ranger West reservoir has been declining at around 13% per year, the active development program in 2009-2010 resulted in a 0% decline in total rate for the January to mid-November 2010 period. Additional information concerning the development drilling and wellwork activities can be found in the Calendar Year 2009-2010 Activities and Results section.

Calendar Years 2009 and 2010 Activities and Results

Since publication of the last Program Plan, 27 producers (9 horizontal, 16 conventional, and 2 cased-hole completions) and 2 injectors (2 dual string vertical cased injectors) have been drilled and completed in the Ranger West pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger West Pool is 103 BOPD with initial rates ranging from 17 BOPD to 271 BOPD. This rate is better than the anticipated average rate of 93 BOPD. The average initial stabilized production rate is 110 BOPD for the horizontal completions, 95 BOPD for the conventional completions and 39 BOPD for the cased-hole completions. The injection wells drilled during the 2009-20010 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. All the injection wells met injectivity expectations with an average injection rate of 2423 BWPD.

During the 2009-2010 Plan period, a total of 12 development (investment) wellwork jobs were also completed (5 producers and 6 injectors). Three of the producer development projects were selective recompletions/add pay projects and two were recompletions to the Ranger zone targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 27 BOPD/job at a cost of $357,303 per job. The injector development wellwork projects included three convert to injectors and 3 profile modifications and add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 2975 bpd of injection per well at an average cost of about $202,802 per job.

Maintenance wellwork continues to play a major role in maximizing Ranger West base production. During 2009-2010, approximately 171 producer maintenance wellwork projects at a cost of about $89,196/job were performed. 535 injector maintenance projects were also completed at an average cost of about $18,824/job.

Reservoir Management Objectives

The primary reservoir management objective is to maximize the profitability of the Ranger West pool. Maximum profitability will be achieved by increasing recovery in underdeveloped blocks through identifying optimal locations for development drilling/investment wellwork combined with the right placement of injection water. Throughput objectives are to reach an HPVI target of at least 6.0 for each sand in all CRB's. As of November 2010, HPVIs range from 1 to more than 10 on an individual sand basis. As a result, oil recoveries range from values as low as 26% in some CRB's up to 40% in other CRB's. By ensuring that each sand reaches an HPVI target of at least 6.0, oil recoveries for individual sands should reach a minimum of 30-33% for an overall recovery in excess of 37% for the Ranger West sand. In the more mature blocks, maximum profitability will be achieved through minimizing the volume of low value water cycling, directing water to the remaining economic reservoir targets and targeting by-passed oil pockets with development drilling and investment wellwork projects. In the absence of economic options, idle wells will be abandoned to reduce future abandonment liabilities and reservoir crossflow. Risk of subsidence will be minimized in all reservoir management actions.

Strategies

The Ranger West development plan includes drilling an additional 21 development wells and performing 5 investment wellwork projects in FY11/12. The development plan will be implemented under the guidance of the reservoir management objectives discussed above. The best new drilling and investment wellwork locations will be evaluated and selected for inclusion in the drilling and wellwork programs based on a combination of economic and strategic criteria. Projects will be reviewed carefully to ensure that only projects that will be profitable even in low price environments are executed. Pool reviews/reservoir studies, conducted on an ongoing basis, will be used as the foundation for identifying the best drilling and wellwork opportunities and to monitor progress towards achieving reservoir management goals.

Key reservoir management strategies have been developed for each of the CRB's in Ranger West. In summary, waterflood optimization of the more mature crestal and south flanking blocks will be achieved through injector and producer profile control, pattern realignment, and capturing bypassed pockets of oil through horizontal drilling and cased-hole recompletions. In the less mature northern blocks, waterflood optimization will be achieved through (1) infill drilling and recompletions to improve pattern throughput, and (2) injector profile modifications to better balance injection between high permeability and low permeability sands.

Critical Issues

Key areas of focus for the Program Plan period include the following:

- Continue throughput optimization in under-injected sands; generally the lower sands (Mn thru G6).
- Optimize the Ranger West waterflood through subzoning into upper and lower floods where it economically effective.
- Continue application of horizontal well technology including additional infill Fo horizontals in blocks 3, 4, and 5, the crestal area of Ranger 7, and look for horizontal

well opportunities in lower Fo lobes (F01 & F02) in all areas. In addition utilize slant wells as another way to optimize depletion from these sands.

- Evaluate the completion methods to deliver optimum productivity including continued improvement of open hole gravel packed slotted liners and cased hole selective completions including fracture stimulations.
- Implement low cost replacement drilling options for failed wells, particularly for injectors with poor conformance and limited repair options.
- Update the geologic and reservoir description in Tar V and develop a depletion plan.
- Continue to update and optimize streamline reservoir models to evaluate depletion optimization in Ranger West. Update the geologic model in Petrel.

Ranger East
Reservoir Management Plan

History

The Ranger East area is comprised of the three major fault blocks east of the Long Beach Unit fault: Ranger 8A/8B, Ranger 90N, and Ranger 90S. To facilitate reservoir analysis, the fault blocks are further broken down into cut-recovery blocks (CRB's) along injection rows or significant faults, as appropriate.

Production from Ranger East began in April 1967. However, several initial wells encountered relatively low reservoir pressures, and full production was delayed until enough pressure support was established to reduce the high producing gas-oil ratios. The waterflood program was initiated immediately, based primarily on peripheral injection. Line drive injectors were subsequently added in some areas, primarily along the crest of the structure. Early efforts to inject into and produce from full-zone completions were not fully effective, as flow was dominated by well-developed and high permeability F0, F, or M1 sand units high in the vertical section. A subzoning program in the early 1980's significantly improved the flood by decreasing the amount of interval open in each well, and substantially enhanced the response in the Lower Ranger sands.

This development strategy has been effective along the southern flank and the structural crest of the reservoir. The aquifer along the southern flank is effectively bounded, and the adjacent CRB-21 area has seen good pressure support and sweep from the peripheral injectors. Similarly, the crestal areas have benefited from a combination of downdip support from the aquifer injectors along the southern flank and direct support from line drive injectors. Pressure support and recovery efficiencies in crestal CRB's 15, 22, 32, and 33 are expected to be high, though somewhat lower than in CRB-21 due to complex faulting and reduced sweep efficiency.

Although peripheral injection along the northern flank provides a row of back-up injection, this injection has been less effective because the aquifer is not well bounded and communicates with the Seal Beach field downstructure. A significant portion of the peripheral injection in CRB's 14, 16, 17, and 18 has been lost to the aquifer, particularly during the early field life when withdrawal from the Seal Beach field was higher. Pressure support has thus been limited in these areas, and both the current and projected recoveries are relatively low. The remaining reserves in these areas constitute the major redevelopment target in Ranger East.

Status

As of October 2010, Ranger East production is 6548 BOPD and 239,819 BWPD from 204 active producers. Total water injection was 267,097 BWPD into 124 active injectors. Average active well rates were 33 BOPD and 1211 BWPD for producers and 1950 BWPD for injectors.

Ranger East currently has 18 wells that are mechanically idle but are capable of reactivation with further investment. The team is currently evaluating the repair and/or conversion options for these wells. Additionally, there are 7 wells that have been identified as "uneconomic to repair" that have yet to be plugged in zone.

Cumulative oil production as of October 2010 is 243.9 MMBO (29.2% OOIP).Since the last reporting period in December 2008, oil production, the base production has declined at 8.1% per year. With development in the past year, total production is approximately flat for the period of January – mid-November 2010.

Calendar Years 2009 and 2010 Activities and Results

Since publication of the last Program Plan, 11 producers (1 horizontal, 9 conventional, and 1 cased-hole completion) and 8 injectors (1 single string vertical cased injector and 7 dual string vertical cased injectors) have been drilled and completed in the Ranger East pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger East Pool is 63 BOPD with initial rates ranging from 14 BOPD to 136 BOPD. This expected rate is as an average rate of 63 BOPD. The average initial stabilized production rate is 52 BOPD for the horizontal completion and 65 BOPD for the conventional completions. The injection wells drilled during the 2009-20010 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. All the injection wells met injectivity expectations with an average injection rate of 2285 BWPD.

During the 2009-2010 Plan period, a total of 7 development (investment) wellwork jobs were also completed (5 producers and 2 injectors). All of the producer development projects were selective recompletions/add pay projects targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 33 BOPD/job at a cost of $250,577 per job. The injector development wellwork projects included one convert to injectors and one profile modifications and add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 2336 bpd of injection per well at an average cost of about $195,758 per job.

Maintenance wellwork continues to play a major role in maximizing Ranger East base production. During 2009-2010, approximately 94 producer maintenance wellwork projects at a cost of about $74,241/job were performed. 247 injector maintenance projects were also completed at an average cost of about $14,082/job.

Reservoir Management Objectives

The primary goal of the reservoir management plan is to maximize the profitability and economic oil recovery from the Ranger East pool. This can be accomplished by developing proper waterflood pattern closure, providing adequate injection throughput into all the individual sand intervals in each pattern, reducing water cycling in swept zones where possible, and maximizing well productivity. Current WOR in the three major fault blocks averages 36.6. The injection target volume is greater than 6.0 hydrocarbon pore volumes into each sand before reaching a producing WOR of 70. Injection throughput has been challenged by the difficulty of maintaining good vertical profile control. Another challenge is the optimal placement of injectors in the highly

faulted Ranger East pool. Producer to injector conversions and injector recompletions have been done to improve sweep efficiency.

Production rates are maximized by selective acidization of active wells, or in conjunction with other wellwork. In addition, increasing pump size and using variable speed drives to increase well drawdown assure that maximum productivity is achieved from the wells. Finally, producers are recompleted when economic quantities of unswept oil are identified.

Strategies

The Ranger East development plan includes drilling an additional thirteen development wells and performing several investment wellwork projects in FY11/12. These projects will target insufficiently swept pay.

An update of the Ranger East geologic description and streamline reservoir model was completed in 2007. The geologic study was undertaken to improve the reservoir characterization of Ranger East, to improve the estimate of net pay and OOIP and to provide the framework for the simulation model. The goals of the simulation model are to understand flux into or out of the Unit, identify hydrocarbon hot spots, manage waterflooding, optimize the Ranger East depletion plan and assist with well planning. The low ultimate recovery indicates a greater amount of study is needed to maximize recovery in Ranger East. Updating and fine-tuning of the streamline reservoir model is continuing on a regular basis.

The profitability of the development plan will be maximized by reducing costs where possible and prudent. The focus will be on using existing wellbores, correcting injection profiles with workovers or remedial wellwork where possible, returning idle producers to production, shutting in high WOR producers and potentially adding or stimulating non-productive intervals. Existing wells will continue to be redrilled when warranted. A successful wellwork program will continue to be critical to Ranger East success. Strong communications between individuals in operations and engineering will be maintained through joint involvement in block reviews and joint review of wellwork opportunities and priorities.

Critical Issues

Redevelopment of the Ranger East area is continuing. The primary development goals for the Plan period include:

- Continue to refine and update the existing Ranger East streamline model.
- Complete depletion studies by CRB for Ranger 90N/90S and R8A/B.
- Develop proper waterflood pattern closure and improve the injection throughput into under-injected sands by prudent application of acid stimulation, wellwork, and drilling.
- Select the optimal injector drilling locations by utilizing the results of the improved streamline simulation model.
- Continue selective fracturing of mid and lower Ranger zones to improve productivity and ultimately reserves.

- Evaluate the feasibility of high-angle slant wells in the M1 in the eastern part of the pool similar to the Belmont Upper completions.
- Redevelop bypassed areas down-dip

Terminal Zone
Reservoir Management Plan

History

The Terminal zone is about 1000 feet thick and its productive limits cover an area about four miles long and two miles wide within the Unit. The LBU fault divides the Terminal into the Upper and Lower Terminal zones on the west side of the field from the Terminal East zone on the east side.

The Terminal Zone was first developed in 1965 on the west side of the LBU fault in Upper Terminal VI (UT6). Water injection commenced with initial production utilizing a peripheral injection flood configuration. Early injectors were drilled in the aquifer, down structure from the productive limits of the oil column. Development of Terminal East began in 1967, and the last block to be flooded was Upper Terminal VII (UT7) starting in 1985.

Wells on the west side of the field have generally been completed in Upper Terminal sands, in either the HX1-Y4 or Y4-AA intervals; however, a few wells include the less prolific Lower Terminal AA-AD sands.

Terminal East wells are completed in either the upper Y-AA or AA-AE intervals. In the middle 1980's, some Terminal East wells were completed as dedicated sub-zone producers and injectors in the AC-AD interval. The sub-zone development program targeted reserves in these deeper interbedded sands. AC-AD zone reserves were not fully recovered in the original full-zone completions due to competition from the upper, more prolific intervals.

Early wells were completed with gravel packed slotted liners and water zones were excluded with cemented blank liner sections. Water exclusion and selective injection became more important as the waterflood matured and the more permeable reservoir sands watered out. In the early 1980's cased hole completions were utilized to improve water exclusion and sand control. The current cased hole completion program typically includes conventional perforating and wire-wrapped screens or the use of frac technology.

Status

As of October 2010, the total production from the Terminal zone is 4,446 BOPD and 151,802 MBWPD resulting in an average WOR of 34.1. There are currently 156 active producers. Terminal zone injection for October 2010 is 165,627 BWPD from 79 wells. Average active well rates were 29 BOPD and 992 BWPD for producers and 2,208 BWPD for injectors.

Sixteen Terminal wells are currently mechanically idle and capable of being reactivated with further investment. Evaluation of repair and/or conversion options is underway for these wells. There are currently no idle wells slated to be plugged in zone. Additionally there are five wells that have previously been plugged in zone and are currently inactive.

Cumulative production through October 2010 totaled 145.4 MMBO (33.2% OOIP). Successful infill drilling and well work activities have partially offset the underlying Terminal zone oil production decline rate of 15.5%/year. Additional information concerning the development drilling and wellwork activities can be found in the Calendar Year 2009-2010 Activities and Results section.

Calendar Years 2009 and 2010 Activities and Results

Since publication of the last Program Plan, 2 producers (2 cased-hole completions) and 1 injector (1 single string vertical cased injector) have been drilled and completed in the Terminal pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger East Pool is 71 BOPD with initial rates ranging from 53 BOPD to 90 BOPD. This expected rate is as an average rate of 83 BOPD. The injection well drilled during the 2009-20010 period was selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. The average initial injection rate is 2065 BWPD.

During the 2009-2010 Plan period, a total of 5 development (investment) wellwork jobs were also completed (4 producers and 1 injectors). Two of the producer development projects were selective recompletions/add pay projects and two were completions to new zone targeting bypassed oil sands. Overall, the producer development wellwork has returned average of about 32 BOPD/job at a cost of $325,898 per job. The injector development wellwork projects included one convert to injectors and one profile modifications and add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 4,756 bpd of injection per well at an average cost of about $267,202 per job.

Maintenance wellwork continues to play a major role in maximizing Terminal base production. During 2009-2010, approximately 82 producer maintenance wellwork projects at a cost of about $74,750/job were performed. 199 injector maintenance projects were also completed at an average cost of about $8,123/job.

Reservoir Management Objectives

Future plans for development and management of the reservoir are guided by the objective of maximizing profitability while ensuring stable surface elevations. Development will be driven by identifying the best new well locations and by optimizing the placement of injected water within voidage constraints while minimizing uneconomic water cycling.

In 2004 and 2005, a reservoir study was conducted to improve the geological and reservoir description of the Terminal Zones and better define the estimation of OOIP. This project resulted in the creation of a streamline reservoir simulation model for the Terminal East area and a second model for Terminal West. These models are and will continue to be used as a directional tool to identify opportunities to maximize recovery from the reservoir.

Production and injection infill well locations will be identified and drilled to recover oil banked near faults, to improve areal sweep efficiency and to increase reservoir

throughput. Profile modification will be attempted to reduce thief intervals and improve vertical conformance. Recovery from existing wells will be optimized to ensure maximum economic value. Completion techniques will be modified to increase injectivity, minimize reservoir damage, and reduce high decline rates.

Strategies

The Terminal Zone development plan for FY 11/12 assumes six drilling projects and several investment workover projects. These objectives will be met by utilizing the various Unit programs currently in-place. The best new production and injection infill well candidates will be evaluated and selected for inclusion in the drilling schedule based on economic and strategic development criteria. Pool reviews will be conducted regularly to identify well work, conversion, and infill opportunities. Reservoir studies are being performed to develop long term depletion plans and to reliably forecast future reservoir performance.

Key reservoir management strategies have been formulated for each Terminal reservoir pool. The focus strategy for UT6 CRB-38 is to improve vertical conformance due to the block's waterflood maturity and highly layered system. In addition, a highly selective drilling program will be conducted to target bypassed oil. The reservoir management goal for UT6 CRB-39 is to increase the overall level of development through infill drilling in this less mature block. Increased throughput and optimization of vertical and areal conformance will also be focus areas for the block. The development strategy for UT7 includes crestal injection to augment the current peripheral injection configuration due to the area's highly faulted nature. Terminal 8A development will include additional injection projects to achieve throughput targets. Finally, injection in Fault Block 90 will continue to be tailored to the improved understanding of fault compartmentalization.

Reservoir studies incorporating updated volumetric analyses, based on additional geologic interpretation, will help fine tune future drilling requirements. Throughput analyses will be performed in those areas with the greatest development potential to quantify injection requirements. The streamline models will be used to optimize the waterflood and generate development projects for depletion planning. Detailed review of existing well histories and performance during pool reviews will help identify candidates for well work to improve management of the reservoir. Special logs including Formation Mirco Image, Density-Neutron and 3-Resistivity will be run to better understand the thin bed potential.

In order to optimize well performance, completion techniques will continue to include larger perforating guns, gravel pack and frac and pack technology. Fracture stimulation technology in the lower sands of the Terminal zone will continue to be applied on a case by case basis to provide sand control and improve well deliverability in sensitive, low permeability formations. The team will actively seek out and advocate cost reduction strategies while meeting reservoir objectives.

Critical Issues

The following key points summarize the development goals for the Program Plan period:

- Update the Terminal East and West streamline models with the latest production, completion and log data. In addition, update the Terminal East fault model.
- Improve vertical conformance in UT6 CRB-38 through selective drilling of a limited number of new cased hole producers, profile modification workovers of existing wells, and drilling of a limited number of injectors.
- Identify areas of bypassed oil and drill high angle producers to exploit in Terminal Blocks 38 and 39.
- Strategically develop thinly bedded Lower Terminal East sands independently of more permeable zones characterized by higher water saturations.
- Optimize crestal injection in UT7 to augment the current peripheral injection configuration.
- Increase reservoir throughput in Terminal 8A through injection well drilling and conversions.
- Identify up-hole add-pay potential in Terminal 8A and increase development of upper Terminal zones
- Optimize waterflood pattern development in Terminal 90N by incorporating detailed reservoir fault analysis stream tube model development.

UP-Ford

Reservoir Management Plan

History

The UP-Ford Zone has produced 103.4 MMSTB oil to date and current active well counts are 80 producers and 59 injectors. Much of the historical production is attributable to natural water drive from the AX sand, which watered-out over almost the entire field by the early 1980's. Sands above the AX have been historically less prolific owing to several factors, including: lower formation permeability, thin-bedded discontinuous shaly sands which are prone to formation damage owing to a high clay content, a lack of adequate injection support and damaging completion and workover techniques.

The UP-Ford reservoir is complex from both reservoir and operational perspectives. Since it underlies the Ranger and Terminal zones, new wells are more expensive to drill because of the depth and the pressure difference in Ranger and Terminal sands. In addition, higher reservoir temperatures and lower total fluid production rates shorten pump run times relative to the other reservoirs of the Unit. Non-damaging fluids are required during drilling and workover operations owing to the sensitive nature of the formation, and fracture stimulation is often required to yield economically successful wells.

From the late 1990's, success in pattern waterflood development in the Tract II area was achieved through adoption of non-damaging drilling and completion techniques, and the fracture stimulation program. As a result, UP-Ford oil production rate reached a 20-year high (6978 STB/D oil) during early 1998. During the early 2000's, attempts to further exploit these strategies in the upper UP-Ford sands were not successful because of the lack of adequate injection support. During a two year development break, the reservoir description was completely redone and completion techniques were reviewed. New Petrel geological model and Frontsim reservoir simulation model were built and history-matched in 2005. The drilling and workover program is continuing with many benefits being realized from hydraulic fracturing completion techniques.

Status

The UP Ford production rates in October 2010 were 2,469 BOPD and 61,678 BWPD (96.1% water cut) from 80 producers. October 2010 injection averaged 68,804 BWPD from 59 injectors. Average active well rates were 32 BOPD and 801 BWPD for producers and 1,186 BWPD for injectors.

UP Ford currently has 14 wells that are currently mechanically idle and capable of being reactivated with further investment. These wells are being evaluated for repair and/or conversion. Additionally there are 43 wells that have previously been plugged in zone and are currently inactive.

Recovery through October 2010 was 103.4 MMBO (18.7% OOIP). The base production in UP Ford reservoir has been declining at around 11% per year for the January to mid-November 2010 period. Additional information concerning the development drilling and

wellwork activities can be found in the Calendar Year 2009-2010 Activities and Results section.

Calendar Years 2009 and 2010 Activities and Results

Since publication of the last Program Plan, 3 producers (3 cased-hole completions) have been drilled and completed in the UP Ford pool.

The average initial stabilized rate (3 month average) for the producers drilled in the UP Ford Pool is 48 BOPD with initial rates ranging from 13 BOPD to 98 BOPD. This rate is less than the anticipated average initial rate of 85 BOPD.

During the 2009-2010 Plan period, a total of 1 development (investment) wellwork jobs was also completed (1 injectors). The injector development wellwork project was a convert to injector project. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 961 bpd of injection per well at a cost of $87,874.

Maintenance wellwork continues to play a major role in maximizing UP Ford base production. During 2009-2010, approximately 44 producer maintenance wellwork projects at a cost of about $114,327/job were performed. 85 injector maintenance projects were also completed at an average cost of about $17,732/job.

Reservoir Management Objectives

The goal of the UP-Ford Reservoir Management Plan is to maximize the profitability of the reservoir. As the recovery mechanism is waterflood, we have to increase the waterflood efficiency by increasing throughput ratio, injection efficiency and volumetric sweep. There are three areas of focus with respect to attaining this goal. First is to maintain the base production and injection rates in existing wells through reactive and proactive wellwork. The second objective is to effectively stimulate and waterflood sands above the AU through selective completion and stimulation techniques. Most of the remaining oil is in these thinner, lower permeability sands, which will only achieve economic production rates if their deliverability can be enhanced through fracture stimulation or horizontal/slant completion and their pressures be increased through waterflooding. The third area of focus is to enhance the producer-injector conformance which will improve sweep efficiency.

Reservoir simulation models will be used to confirm infill locations. Production and injection infill well locations will be identified and drilled to recover oil banked near faults and oil bypassed between producer rows. Profile modifications will be attempted to improve vertical conformance. Completion techniques will be modified to increase injectivity, minimize reservoir damage, and reduce sanding.

Strategies

The development plan for UP-Ford in FY11/12 includes continued activity in this reservoir. The various Unit programs currently in place will be utilized to help achieve the development objectives stated above. Potential new production and injection infill well candidates will be evaluated and the best selected for inclusion in the drilling

schedule based on economic and strategic development criteria. Reservoir studies are ongoing to develop long term depletion plans and to reliably forecast future reservoir performance.

The key strategy for realizing optimal development of the UP-Ford zone is understanding its complex reservoir description. Geologic studies addressing sand quality, continuity and distribution, as well as reservoir faulting and stratigraphy, are critical to this effort. Reservoir models combining the best reservoir description and well performance data will help identify regions of high remaining oil saturation as well as regions with sub-optimal waterflood. Logs such as 3-D resistivity image logs will be run to better understand the thin bedded sands.

UP-Ford 8 and 90 fault blocks have a reservoir flow model but additional work needs to be performed to calibrate it better so the results from the development forecast could be used with confidence. In FY11/12 the model will be further upgraded based on most recent understanding of the geological framework and properties. A depletion study for UP Ford CRB 44 was completed in 2010 due to its low recovery factor and development opportunities have been identified and will be implemented. The UP-Ford 98 block needs further study utilizing seismic, well log, core and production performance data to quantify future development opportunities as its recovery factor is low. Reservoir description studies will be performed to locate and map the most likely areas of sand development.

The in-zone injection program will expand to improve flood performance in the upper, less mature, tight reservoir sands. Fracture stimulation techniques will continue to be refined in an attempt to reduce treatment costs while maintaining or improving effectiveness. Horizontal/slant wells will be drilled as an alternative to fracture stimulation to reduce costs and variable performance.

Critical Issues

To refine the development plans, focus will be on the following key issues during the Program Plan period:

- Develop CRB 44 with infill wells to improve low recovery factor.
- Further exploit alternatives for increasing infill well deliverability primarily through hydraulic fracturing as well as high angle and horizontal completions.
- Horizontal/slant wells are drilled in AK1 sands currently and will be further tested in AE, AF, AI, AM, A0, AR sands in the future.
- Continue to refine non-damaging procedures to complete and work over wells and determine injection water quality requirements.
- Increase pressure support in the upper reservoir sands utilizing in-zone injectors and conformance improvement projects for existing injection wells through stimulation and mechanical methods.
- Continue to delineate the Northern down-dip extent of UP-Ford CRB 44 and CRB 45.

- Evaluate the development potential of the Horst block along the LBU Fault in CRBs 27.
- Evaluate the development potential of the deep sands AU2 through AZ .
- Evaluate the potential of “central” UP-Ford 98.

237 Shale Zone
Reservoir Management Plan

History

The 237 Zone underlies the UP Ford Zone and comprises two distinct sub-zones, an upper clastic interval and a lower shale interval. The lower 237 Zone shale is further subdivided into the Hot Shale and Basal Shale members.

The Hot Shale member of the Lower 237 Zone Is a world-class oil source rock. It is correlative with the Nodular Shale of the western Los Angeles Basin. It probably contributed most of the oil trapped within the Long Beach Unit. The Hot Shale contains a poorly developed foraminite facies, but this has not been specifically targeted to date.

The Basal Shale is also a good, but lesser quality source rock. It has numerous thin dolomitic interbeds and thin quartz cemented sandstones. This facies tends to have higher fracture density than the Hot Shale and has been more productive. It is extremely thick in the eastern LBU where it is determined from 3D seismic to be up to 1600 feet thick. This is ten times thicker than the average thickness found across the western Los Angeles Basin.

About 2.87 MMBO has been produced from the fractured shales of both 237 Zone shale members from six commercial wells within the LBU. Acoustic basement underlies the 237 Zone shales. These rocks include the Miocene San Onofre Breccia and Cretaceous/Jurassic Catalina Schist basement. These fractured reservoirs have contributed an additional 1.35 MMBO from two LBU wells, one of which had a flowing IP of 1800 BOPD.

The first 237 Zone well was completed in 1968 at an initial rate of 1050 BOPD. Eighteen more wells were completed in the LBU, the last one in 2009. All wells reported oil and gas shows while drilling through the lower 237 Zone. Six of the wells were economic, one was marginally economic, eleven were uneconomic and one is still being evaluated. One of the wells was a mechanical failure and did not properly evaluate the lower 237 Zone. The uneconomic wells may have been damaged during drilling or lacked sufficient fracture systems to be productive. Through November 2010 cumulative production from the 237 Zone/acoustic basement is 4.22 MMBO with two active wells in the pool.

In 2006 a 237 team was formed to re-evaluate the fractured shale play. Using seismic coherency mapping and fracture trend measurements taken at local outcrops, Well C-250 was proposed. This was the first 237 zone well drilled in the LBU in over 11 years. C-250 targeted the Hot Shale and Basal Shale with acoustic basement as a secondary target. It was completed in December 2007 and flowed for seven months at rates between 750 and 300 BOPD with only a 2 percent water cut. A pump was installed in July 2008 and the well made 1240 BOPD. Water cut has been rising and at the end of November the rates were 274 BOPD and 668 BWPD. Oil production through the end of October 2010 from Well C-250 is 48.4 MSTB.

In FY08/09, two additional 237 zone wells were drilled from Island Freeman. These were ranked 3rd and 4th out of five proposed wells to build on the commercial C-250 discovery. They were drilled early in the program owing to cost savings related to rig

moves. They targeted a previously drilled structure high thought to have remaining potential. Well D-720A made 1,440 BWPD and 15 BOPD from the original completion of the lower part of the Basal Shale. It was recompleted in the upper part of the Basal Shale and became a 320 BOPD well.

D-562A was a non-commercial well, it having only produced 40 barrels of oil before dying. Multiple acid treatments failed to establish production. This well probably lacks a meaningful fracture network.

Our most recent well, C-355, was drilled in FY09/10 as our first 237 zone completion through cemented liner. It was plagued by drilling and mechanical issues and a side track was necessary. The sidetrack was approximately 850 feet short of planned TD when the drill string became irrevocably stuck. Good oil shows were encountered in both well bores, but we have had difficulty keeping this well producing as the pump rather quickly draws down the fluid level. We are continuing to work this issue.

Two additional wells are planned from Island Chaffee in calendar year 2011 as step-outs to the commercial C-250 well. Each of these wells will include new play elements including a previously untested stratigraphic interval or a new position on structure.

Critical Issues

- To fully understand the 237 reservoir and to refine future development plans, the focus will be on key reservoir issues during the current phase of exploratory/delineation drilling:
- Evaluation of open hole log and mud-log data acquired during drilling to better refine our completion design.
- Continued integration of reservoir performance, stress-field analysis, and geological understanding to high-grade future drilling targets.
- Core the first of the next two wells to determine if the reservoir is a single or dual porosity system and to evaluate the reservoir potential of the thin sands interbedded in the Basal Shale member.

Shallow Gas
Reservoir Management Plan

History

An agreement between the State of California, City of Long Beach, and OLBI regarding the development of shallow and deep gas reserves was finalized in 2006. 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.

The bulk of the Shallow Gas reserves reside below Island Grissom with additional proven undeveloped reserves accessible from Island White. Gas shows have been found in wellbores originating on Island Chaffee and Pier J. Development of Shallow Gas reserves began from Island Grissom due to the availability of commercially identifiable reserves for development from this location. Shallow Gas production commenced May 18, 2006 from one well. To date five wells have been recompleted as Shallow Gas producers and one horizontal well has been drilled.

A separate production train was installed that collects, measures, and processes gas for sale to Long Beach Energy.

Status

The Shallow Gas reservoirs consist of 5 primary sand bodies: A10, A14, A16, A18 and A20. The Grissom Gas is currently the main Shallow Gas accumulation being produced, with the majority of the current production coming from the A14 sand. To date four of the six wells have been completed in the A16, and one in each of the A20 and A14, respectively. With four wells producing out of the A16 sand a stabilized production rate was maintained at 5,000 mcfd. This rate was maintained until June 2008 when Well A-268 watered out. Well A-260 followed and watered out as forecasted in September 2008. In January of 2009, well A-271 watered out. From this point, production rate for Grissom Shallow Gas production was averaging 4,200 mcfd, with production from two active producers, Well A-301 (horizontal in A16 sand) and Well A-313 (A14 sand completion) which was recently returned to production after an inner liner was installed. In February of 2009, Well A310 completed in the A20 sands was successfully stimulated after a year of non-production. Shallow Gas production sharply declined in October of 2009 when horizontal well A-301 watered out; this event was shortly followed by the recompletion of well A-271 in the A14 sand. From October of 2009 to February of 2010, Grissom Gas production averaged 2500 mscf/d.

In February of 2010, B-403 was recompleted in the A-20 sands as the first step in the development of the White Shallow Gas accumulation with positive results early on. However, higher CO2 content in the White Shallow Gas stream forced Facilities department to reduce/curtail the White Gas rate out of concern for subsea lines. In April of 2010, Well A-268 was recompleted in the A14 sand. During the February 2010 - July 2010, average the total Shallow Gas rate was averaging 2300 mscf/d until subsea line

repairs and facility maintenance forced the shut down the Shallow Gas production. Upon completion of the repairs and maintenance work, near term wellwork projects are to recomplete the Grissom watered out wells up-hole into the A14 sand. Daily rate by sand and cumulative production can be seen in Figure 1.

Additional White Gas development is planned. The original two well development plan has been initiated with the recompletion of well B403, producing from the A20 sand and which will be recompleted up hole as the sands water out. A second well will be completed in the A10 sand. Produced gas is shipped to Grissom for dehydration and processing where it commingles with Grissom Shallow Gas.

Cumulative Grissom production through July 2009 totals 4.571 BCFG (62.1% OGIP) in excess of initially estimated ultimate recovery expected to reach 4.33 BCFG (61.0% OGIP) in 2011 for the Grissom Gas reservoir. To date, White Gas cumulative production does not contribute significantly to the total of Shallow Gas. Including White Gas production the ultimate recovery was expected to reach 6.344 BCFG (61.0% OGIP including both Grissom and White accumulations) by 2015. Underlying aquifer support within the reservoir will affect total gas recovered. However, Grissom OGIP will most likely be revised upward, pending results of petrophysical analysis.

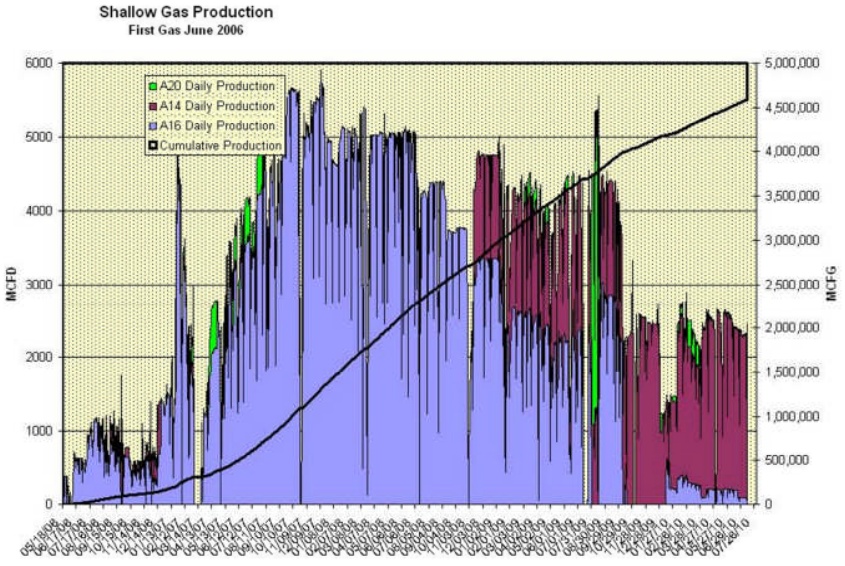


Figure 1: Shallow Gas production by sand

Reservoir Management Objectives

The overriding goal of the Shallow Gas Reservoir Management Plan is to maximize the profitability of the reservoir. Three objectives must be attained to achieve this goal. The first is to understand long-term reservoir energy support through monitoring of aquifer influx and pressure measurement. Understanding the rate of withdrawal to pressure change in the reservoir is fundamental to quantifying recoverable reserves. Through P/Z vs. Cum production analysis and a Fetkovich water influx simulation, production rate at or exceeding 3500 mcfd is required to best outpace the aquifer in the A16 sand. Secondly, all small gas "stringers" should be tested for viable productivity, which will add to development opportunities and increase the reserves volume if they are commercially productive. Lastly, we must focus on utilizing the most ideally situated idle wellbores for Shallow Gas development to maintain a low cost development and maximize recovery through existing assets.

It has been found that sand control is needed in order to maintain the require production rates. Sand control has been installed on previously sanded wells. With the success of Well A-301 horizontal drill well, additional opportunities must be evaluated to optimize the economic success of Shallow Gas expansion through recompletions vs. drill project.

Strategies

The development plan consists in the recompletion of four Grissom gas wells in FY 11/12, mostly in the A14 sands, and one recompletion in the A10 sand in the White Gas accumulation. Reservoir studies will be done on the Pier J and Chaffee gas to better understand the connectivity of the shows and extent of the gas in place. These studies will utilize seismic, well log, and cased hole reservoir sampling data to quantify extensional development opportunities. However, lower gas prices have pushed most of those studies back.

The key strategy for realizing optimal development of the Shallow Gas reservoir is understanding the lateral continuity of the smaller sand sequences. Geologic studies addressing structural uncertainty, continuity and distribution, as well as reservoir faulting and stratigraphy, are critical to this effort. Reservoir studies combining the best reservoir description and well performance data will help identify regions of high remaining hydrocarbon saturation. Geologic model and reservoir simulation tool are under construction to aid in optimizing ultimate recovery through optimal well recompletions, draw down rates and water influx.

Exhibit C

Long Beach Unit

THUMS Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2011 through June 30, 2012

ANNUAL PLAN

July 1, 2011 through June 30, 2012

Table of Contents

Part I

Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2011 through June 30, 2012 ("FY12"). 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, Statutes of 1991) 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 2011 – 2012 ($ Million)
Development Drilling	$ 86.8
Operating Expense	$ 97.3
Facilities, Maintenance, and Plant	$ 91.3
Unit Field Labor and Administrative	$ 59.0
Taxes, Permits, and Administrative Overhead	$ 43.1
Total	$377.6

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2011 through June 2016 and provides current estimates of volumes, drilling activity and expenditures for FY12.

Volumes

Oil and gas production volumes are predicted to average 24.9 Mbopd and 11.2 MMcfd, respectively, in FY12. Water production for the period is expected to average 1,023 Mbwpd and water injection is expected to average 1,118 Mbwpd.

Revenue and Expenses

A projected oil price of $45.00/bbl Wilmington and gas price of $4.50/mcf will result in revenues of $429 million. Budgeted expenses for FY12 total $378 million. Projected net profit in FY12 is $52 million.

Drilling

This Plan allows for drilling approximately 46 new and redrilled development and/or replacement wells. The plan is to use two drilling rigs as noted in the Program Plan. The rig utilization could potentially change due to variations in oil price. A workover rig(s) will perform drilling preparation and completion work. Locations of production and injection wells to be drilled or redrilled are given 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, but are not limited to, facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Unit facilities in safe operating condition.

Abandonment

Wells and facilities with no further economic use will be abandoned to reduce current and future Unit liability. This Plan provides funds for plugging wells to surface, in-zone, and conditional abandonments.

Safety, Environmental, and Regulatory Compliance

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. Projects relating to safety, environmental issues, or other situations necessary for meeting compliance with code, permit, or regulatory requirements will continue to be implemented under this Plan in accordance with all Unit agreements. In addition, THUMS will be placing additional emphasis on risk and system reviews and operational safeguards to assure reliable and compliant environmental performance.

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 on economics and other conditions consistent with good engineering, business, and operating practices.

B. Economic Projections

(Data in Millions of Dollars)

	BUDGET FIRST QUARTER FY12	BUDGET SECOND QUARTER FY12	BUDGET THIRD QUARTER FY12	BUDGET FOURTH QUARTER FY12	BUDGET TOTAL FY12
ESTIMATED REVENUE					
Oil Revenue	$104.3	$103.6	$101.8	$101.1	$410.8
Gas Revenue	$4.5	$4.7	$4.7	$4.6	$18.5
TOTAL REVENUE	$108.9	$108.3	$106.4	$105.7	$429.3
ESTIMATED EXPENDITURES					
Development Drilling	$21.7	$21.7	$21.7	$21.7	$86.8
Operating Expense	$24.6	$23.5	$23.9	$25.3	$97.3
Facilities & Maintenance	$22.8	$22.8	$22.9	$22.9	$91.3
Unit Field Labor & Administration	$14.7	$14.7	$14.7	$14.7	$59.0
Taxes, Permits & Overhead	$10.8	$10.8	$10.8	$10.8	$43.1
TOTAL EXPENDITURES	$94.6	$93.5	$94.0	$95.4	$377.6
NET PROFIT	$14.3	$14.8	$12.4	$10.3	$51.7

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY12	BUDGET SECOND QUARTER FY12	BUDGET THIRD QUARTER FY12	BUDGET FOURTH QUARTER FY12	BUDGET TOTAL FY12
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,319	2,303	2,261	2,246	9,128
(AVERAGE B/D)	25,205	25,027	24,851	24,677	24,941
GAS PRODUCTION					
PRODUCED (1000 MCF)	1,007	1,038	1,033	1,027	4,106
(AVERAGE MCF/D)	10,947	11,282	11,356	11,290	11,218
WATER PRODUCTION					
PRODUCED (1000 BBL)	92,693	93,683	93,651	94,646	374,673
(AVERAGE B/D)	1,007,530	1,018,295	1,029,128	1,040,068	1,023,696
WATER INJECTION					
INJECTED (1000 BBL)	101,774	102,551	102,207	102,984	409,516
(AVERAGE B/D)	1,106,243	1,114,682	1,123,154	1,131,690	1,118,896
OIL PRICE ($/BBL)	$45.00	$45.00	$45.00	$45.00	$45.00
GAS PRICE ($/MCF)	$4.50	$4.50	$4.50	$4.50	$4.50

Part II

Program Plan Schedules

Schedule 2 A
Range of Production and Injection
FY 2012
Long Beach Unit Program Plan, July 2011-June 2016

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2011/12	23.7 - 26.2	973 - 1,075	10.7 - 11.8	1,056 - 1,167

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2011/12	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B
Anticipated New and Redrilled Wells
Fiscal Year 11/12
Long Beach Unit Program Plan, July 2011-June 2016

Reservoir	CRB	Producers					Injectors				
		Grissom	White	Chaffee	Freeman	Pier J	Grissom	White	Chaffee	Freeman	Pier J
		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max
Tar		0 - 2	0 - 2				0 - 1	0 - 1			
SG		0 - 1	0 - 1								
Ranger	1	0 - 3					0 - 2				
West	2	1 - 3	0 - 1				1 - 1	0 - 1			
	3	0 - 3	0 - 1				0 - 1	0 - 1			0 - 1
	4	1 - 3	0 - 1		0 - 1	0 - 1	1 - 2	0 - 1		0 - 1	0 - 1
	5	0 - 1			0 - 1	0 - 1	0 - 1			0 - 1	0 - 1
	7				0 - 1					0 - 1	
	8							0 - 1			
	9		0 - 1					0 - 1			
	10		0 - 1					0 - 2			
	11		0 - 1					0 - 1			
	12		0 - 1					0 - 1			
	13		0 - 1					0 - 1		0 - 1	
	36				0 - 1	0 - 1				0 - 1	0 - 1
	37				0 - 1					0 - 1	
Ranger	14		0 - 1					0 - 1			
East	15		0 - 1		0 - 1			0 - 1		0 - 1	
	16								0 - 1		
	17			1 - 2					0 - 1		
	18			1 - 1					0 - 1		
	20			0 - 1					0 - 3		
	21			1 - 2					1 - 2		
	22			0 - 1					0 - 1		
	33			0 - 1					0 - 1		
Terminal	24		0 - 1					0 - 1			
	38	0 - 1				0 - 1	0 - 1				0 - 1
	39	0 - 1	0 - 1				0 - 1			0 - 1	
	40		0 - 1								
	41	0 - 1				0 - 1	0 - 1				0 - 1
	42			0 - 1					0 - 1		
	43			0 - 1	0 - 1				0 - 1	0 - 1	
	47										
UP Ford	26				0 - 1					0 - 1	
	27		0 - 2		0 - 1			0 - 1		0 - 1	
	30			0 - 2	0 - 1						
	31	0 - 1	0 - 1		0 - 1	0 - 1	0 - 1	0 - 1		0 - 1	0 - 1
	44			0 - 2					0 - 1		
	45			0 - 1				0 - 1	0 - 1		
	46			0 - 1	0 - 1				0 - 1	0 - 1	
237	30	0 - 1		0 - 2	0 - 2						
		Total					Total				
		5 - 78					3 - 64				

Part III

Itemized Budget of Expenditures

A. Development Drilling $86.8MM

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 46 wells will be developed and/or replaced during the Plan year, using approximately two drilling rigs and one and a half workover rigs.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 91 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 and approved in accordance with Unit Agreements during regularly scheduled Unit forums.

B. Operating Expense $97.3MM

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 24.9 Mbopd, estimated gas production of 11.2 MMcfpd, water injection requirement of 1,118 Mbwpd, and water production of 1,023 Mbwpd. Anticipated operating expenses were based on operating two and a half workover rigs per month for servicing an average active well count of 731 producers and 461 injectors. 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 40 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 56 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 704,181,000 kwh at an average rate of $0.077/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases.

C. Facilities, Maintenance, and Plant $91.3MM

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 46 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 54 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects include spending for the construction of the polarity treaters, Pier J pipeline replacements, and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $59.0MM

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 75 percent 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 $43.1MM

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 68 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 Long Beach Gas and Oil Department, 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, 2012 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY12 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 expenditures 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 FY12 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.

EXHIBIT D

W 17165

LONG BEACH UNIT

Briefing Document

Prepared by Staff of the
Mineral Resources Management Division
California State Lands Commission
April 2011

CONTENTS

LONG BEACH UNIT

Briefing Document to Supplement Calendar Item 62 from CSLC's April 6, 2011 Meeting

Tidelands Grants

Between 1911 through 1935, the State of California (State) granted to the City of Long Beach (City) all of the tidelands within its city limits, from the mean high tide line to three miles offshore. The City received these properties from the State in trust, for the purposes of developing commerce, navigation, fisheries, and recreation.

Wilmington Field Discovery

The giant Wilmington Oil Field was discovered in 1932. It is one of the largest fields in North America and includes an onshore portion and an offshore portion, the latter extending through the tidelands area of the City. In Long Beach, the field is divided into the West Wilmington Field, which covers the City's harbor area first developed more than 70 years ago, and the East Wilmington Field, which covers the offshore area not developed until the mid-1960s. (See Figures 1 and 2 at end of this document).

West Wilmington

In 1939, the City's Harbor Department created a petroleum division and drilled the first well under the tidelands. The Long Beach Oil Development Company (LBOD), a consortium of oil companies, was selected as the City's first oil contractor. As development progressed during the 1940s and 1950s, the ground surface in the harbor area began to subside. The rate of subsidence exceeded two feet per year in 1951, and by 1958 the "subsidence bowl" reached 29 feet deep at its center and affected 20 square miles. The City and State joined to pass legislation that forced unitization of the subsided areas, and through the newly created units, waterflooding operations were initiated to halt subsidence and to increase oil production.

East Wilmington

With subsidence under control in the West Wilmington Field, the City explored the area east of the harbor with eight core holes in 1961 and confirmed that the oil field extended offshore. In 1962, City voters approved a referendum for offshore development of the East Wilmington Field. In 1964, Chapter 138 was enacted by the State Legislature to settle disputes between the City and the State, such as the boundary between the Tidelands and uplands, and the sharing the revenues to be derived from tidelands oil production in the East Wilmington Field.

Chapter 138

Chapter 138 provided for the formation of the Long Beach Unit (LBU) as the mechanism for developing the oil reserves beneath the offshore area, with the City being designated the unit operator with control over day-to-day operations. The State would have control over budgetary matters. Chapter 138 provided the City would receive a small share of Tidelands oil revenue each year, which would gradually decrease over the years to a minimum of $1 million per year in the late 1980s. The State would receive the remainder of the oil revenue, which was by far the greatest portion, and all revenue derived from dry gas sales.

Long Beach Unit

The LBU was officially formed in 1965. The City selected THUMS, a consortium of oil companies consisting of Texaco, Humble, Union, Mobil, and Shell, as the contractor. The contract would run for 35 years, and enable the City, as trustee for the State, to retain approximately 96% of the net profits attributable to the unit. The LBU provides for the operation of both publicly-owned tidelands and privately-owned uplands as a single producing entity, and consists of three major areas. Tract 1 includes tidelands granted in trust to the City and comprises about 87% of the unit. Tract 2, comprising about 3%, is the parcel of Alamitos Beach Park Lands where the State owns the mineral interest. The remaining 10% is the upland area known as the Townlot and owned by numerous individuals.

Due to restrictions imposed by the City, development of the LBU had to be done from offshore drilling islands, and only with a pressure maintenance program to prevent subsidence of the land surface. The four man-made drilling islands built in the mid-1960s are now familiar landmarks along the City shoreline. Each island is about 10 acres in size and landscaped with palms and other vegetation, water falls, sound-blocking sculptures, and decorative lighting to obscure the oil operations. (See Figure 3). The islands are named in honor of four astronauts – Grissom, White, Chaffee, and Freeman – who perished in the early years of the U.S. space program.

Development of the LBU was rapid between 1965 and 1970. In mid-1967, twenty drill rigs were in operation with wells being drilled at the rate of one well every 3-1/2 days! Oil production peaked at 148,495 barrels per day in August 1969 before beginning an inevitable decline. During 1982 to 1986, a redevelopment program was undertaken to improve the effectiveness of the waterflood and increase oil recovery. Approximately 480 wells were drilled or redrilled and completed with shorter productive intervals. The shorter intervals isolated zones that contained oil that was by-passed in wells with long completion intervals. The sub-zone development effort increased oil production from 60,000 to 73,000 barrels per day.

Geology

The geologic structure beneath the LBU is a plunging anticline consisting of alternating sands and shales deposited during the Miocene to Pliocene ages. The major oil-bearing sands include the Tar, Ranger, Terminal, UP-Ford, and 237 zones. A shallow gas-bearing zone has also been

encountered in some portions of the unit. These sedimentary rocks are underlain by basement rock composed of metamorphic schist of Jurassic age, which can also contain oil where fractured. The uppermost zone occurs at a depth of about 2,000 feet subsea, while the basement is about 7,500 feet subsea. However, most wellbores are substantially greater in length because they must be drilled directionally at very high angles, and in some cases horizontally, to reach the reservoir target from the five drilling sites. The anticline is cut by large, normal faults that create multiple oil-bearing reservoirs in each zone. The Ranger zone accounts for nearly 70% of production.

Optimized Waterflood Program Agreement

The LBU was operated under the terms of Chapter 138 until 1992. In 1990, ARCO Long Beach, Inc. (ALBI, which had purchased the interests of the five original owners of THUMS to become the field contractor for the City), approached the City and State with a proposal to fund and implement a program to optimize waterflood operations in exchange for a share of the incremental tidelands revenue. In 1991, the State enacted Chapter 941 authorizing the City, State, and ALBI to enter into an "Optimized Waterflood Program Agreement" (OWPA), which became effective in 1992. The OWPA redefined the revenue split among the State, City, and ALBI for Tract 1 and the State and ALBI for Tract 2.

ALBI offered to invest at least $100 million for the application of state-of-the-art technology to locate and produce additional recoverable oil from the LBU. To provide an incentive for ALBI to undertake the financial risk, the City and the State agreed to a projection of expected oil rate decline in the absence of the OWPA. The projected oil was defined in the OWPA as the "Base Production". ALBI would continue to pay the original percentage of net profits on the Base Production, but would be allowed to keep a larger percentage of the net profits attributable to produced oil that exceeded the Base Production, or "Incremental Production." Incremental revenue was to be divided as follows – 49% to ALBI, 42.5% to the State, and 8.5% to the City. The OWPA extended the term of the operating contract for as long as the LBU could economically produce oil and gas. The City remained as unit operator but ALBI was given more authority over the development planning and implementation.

In 2000, ALBI's interests were assigned to Occidental Long Beach Inc. (OLBI). OLBI is now the City's field contractor, while THUMS Long Beach Co. still exists as the agent for OLBI. In 2006, OLBI acquired interests in the West Wilmington field and is now the City's contractor there too.

Current LBU Operations

The LBU is a mature waterflood with an average water cut of 97%. This means that out of every 100 barrels of fluid produced, 97 of barrels are water, and only 3 barrels are oil. Current production rates for the LBU are roughly 28,000 barrels per day oil, 1,000,000 barrels per day water, and 10,000,000 cubic feet gas per day. The water injection rate is 1,100,000 barrels per day. There are nearly 1,400 wells in the LBU – roughly 900 producers and 500 injectors. At present, the cumulative oil production is approximately 997 million barrels. The milestone one-billionth barrel from the LBU should be produced later this year!

Revenue to State

Since its inception in 1965, the LBU has yielded approximately $5 billion in net profits revenue to the State of California. The State expects to receive $277 million from the LBU for the current fiscal year. Expected revenue for future years is discussed later in this document.

Safety and Environmental Protection Standards

Several programs are conducted to assure that a high standard of safety and environmental protection is maintained at LBU facilities. In 2000, when the operator interests were assigned to OLBI, a comprehensive Safety Audit was conducted by CSLC engineers that covered all LBU facilities. The audit found that the corporate Process Risk Management program that OLBI had put into practice was comparable to programs used by other major producers, and was fully compliant with industry Process Safety Management standards and Federal OSHA regulations. The audit also resulted in major upgrades to several safety systems. At the direction of CSLC staff, automatic shutdown valves were installed on all outgoing subsea crude oil pipelines, and have since been installed on all the dry gas pipelines. The substantial funding OLBI spent to resolve the action items identified in the safety audit demonstrate its commitment to safety and spill prevention.

LBU Program Plan and Annual Plan

The LBU *Program Plan* is a five-year plan that outlines the strategies for maximizing profitability and maintaining excellence in safety and environmental protection. The Program Plan describes the reservoir management strategies to be implemented under the OWPA. The Program Plan proposed for July 2011 through June 2016 estimates total costs of $1.9 billion and, with a conservative oil price assumption of $45 per barrel, total revenue of $2.1 billion, resulting in a total profit of $188.5 million over five years.

The LBU *Annual Plan* proposed for July 2011 through June 2012 outlines in detail the cost outlays in five major categories – Development Drilling, Operating Expense, Facilities-Maintenance-Plant, Unit Field Labor and Administrative, Taxes-Permits-Overhead. In addition to the financial aspects of the budget, these plans include strategies to be employed in reservoir development and management, major issues facing the unit, and key goals in the areas of people, safety, and environmental protection.

The Annual Plan estimates that costs for the fiscal year will total $377.6 million. The LBU is projected to produce 9.1 million barrels of oil, or 24,900 barrels per day. This production will generate $410.8 million in revenue at the assumed conservative oil price of $45 per barrel. This will result in $51.7 million in net profit. However, oil prices have increased dramatically in recent months and are now above $100 per barrel. If these conditions hold through next year the profit from the unit will be much higher than the Annual Plan predicts. See Figure 4 for a comparison of the estimated revenue, costs, and net profit at both a $45 and a $100 per barrel oil price. Note that at the $100 oil price net profit increases to about $554 million, or more than ten times

the figure estimated in the Annual Plan. This shows the significant roll oil price has when looking at the economics of the LBU.

The State has an influence on the development of both plans through the regular communication that occurs between staff of the CSLC and the City and OLBI on economic issues and the progress and success of individual projects. This communication has proved essential when projects or objectives require change, as it supports the overall operation of the LBU and ensures that it is as efficient as possible. Further, it is through this direct involvement that future program and annual plans are developed. Successful project models tested in the previous year form the framework for next year's plan. The efforts of staff helps ensure the LBU employs the best engineering practices available, which promotes efficient recovery, and a culture of safety and environmental protection.

Direct CSLC Staff Involvement in LBU

Engineering Committee and Voting Parties

CSLC staff engineers participate in monthly "Engineering Committee" and "Voting Parties" meetings with the City and OLBI. Engineering Committee meetings are where LBU projects involving major expenditures are reviewed and discussed. The proposed projects include well drilling, redrilling, investment well work (such as adding productive interval, installing inner liners, cleaning out, stimulating producing wells), and facility replacement, upgrade, or repair. The Engineering Committee meetings provide a forum for participants to discuss project goals and economic justification, as well as analysis of post-project performance. Budget goals are often discussed during the meetings. Voting Parties meetings are where individual projects are voted upon by for approval by the State, City and OLBI. The approvals result in OLBI preparing Authority for Expenditures (AFE's) which are needed to authorize and account for the funding of projects.

Review of Program Plans and Annual Plans

The Program Plan (or Five-Year Plan) is submitted to the State for approval every other year. The Program Plan is first sent to CSLC staff in draft form for review, so that questions and comments can be considered prior to its formal submittal. Once formally submitted, the CSLC has 45 days to complete its review and approve the plan. If no changes are ordered within the 45-day review period the plan is deemed to be reviewed and accepted by the CSLC. The Annual Plan is submitted to the CSLC in the same manner as the Program Plan except it is reviewed every year for consistency with the current Program Plan. Any Program Plan may be amended, supplemented or modified when necessary. These amendments are subject to CSLC review and approval. The CSLC has 30 days to review amendments.

Engineering Oversight

CSLC staff regularly oversees and monitors the LBU performance, particularly reservoir performance, facility issues, oil prices, revenue, expenses, and profit. This oversight ensures that a high standard of safety and environmental protection is maintained at LBU facilities. It also ensures that the best engineering practices are applied to all operations so that resource recovery from the unit is maximized. The daily involvement of CSLC staff also helps in

forecasting future revenue as accurately as possible and in responding to requests for information from management and all levels of government.

Accounting and Financial Review

CSLC accounting and finance staff reviews statements prepared by the City which show the State's share of LBU profits for each month to verify the statement figures agree with the monthly wire transfer payment amount sent to our Sacramento office. Additionally, each month's OWPA statement calculations are checked and verified for consistency with other statements. On a yearly basis, staff also reviews information supplied by an independent CPA firm hired by the City to verify that the State received revenue based on the correct oil prices during the year. Staff also conducts annual financial audits of key LBU parameters, including oil production totals, revenues, expenses, net profits, and the accuracy of the profit-sharing calculations.

Field Inspection

CSLC staff inspectors monitor LBU operations on a daily basis. Among their duties are formal monthly inspections of island safety and pollution prevention systems, witnessing oil sales meter calibrations, producing oil sales run-tickets, and verifying water cut and API oil gravity measurements. While performing these duties, CSLC inspectors also conduct daily surveillance of island operations for evidence of pollution. Daily reports generated by the inspectors keep staff engineers abreast of production and sales volumes, rig and facility operations, and accident or pollution issues. Staff inspectors also participate in annual in oil spill drills conducted for the LBU.

Subsidence Monitoring

CSLC staff engineers participate in the review of twice-annual measurement of ground elevations in and around the LBU to detect surface subsidence. Maps of elevation changes and reports that relate elevation changes to a balance of fluid withdrawal and injection are also reviewed. The City, as LBU operator, is responsible for monitoring and arresting subsidence attributable to oil production operations pursuant to Chapter 138. CSLC staff work with the City to prepare an annual budget for that subsidence monitoring. The budget is submitted to the CSLC for approval, while the twice-annual reports are submitted to CSLC for informational purposes.

Annual Management Review

Once per year the CSLC staff calls for a meeting of the management of all LBU participants – State, City, and OLBI – for a formal review of the previous year's performance and discussion of proposals for the coming year. The review covers all aspects of unit activity, from safety and environmental issues, project performance and reservoir monitoring, to future planning and goals.

Figure 1 – Location of Wilmington Oil Field

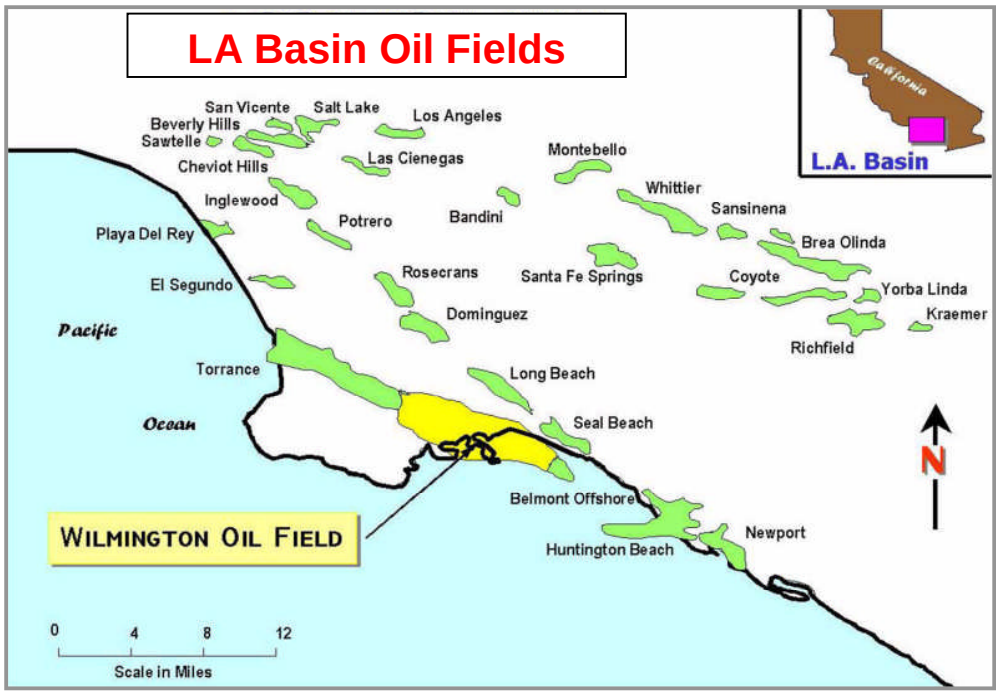


Figure 2 – West Wilmington and East Wilmington (LBU)

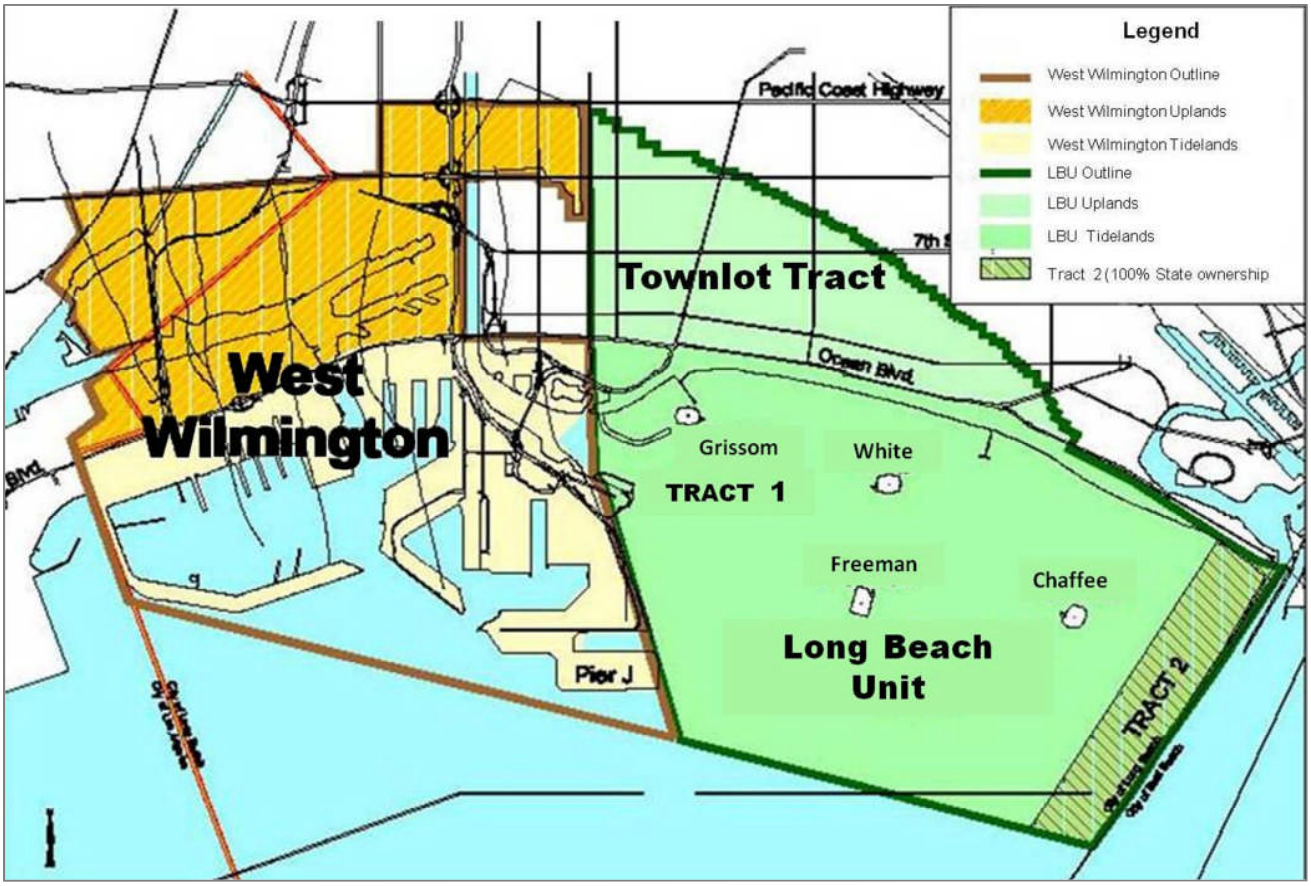
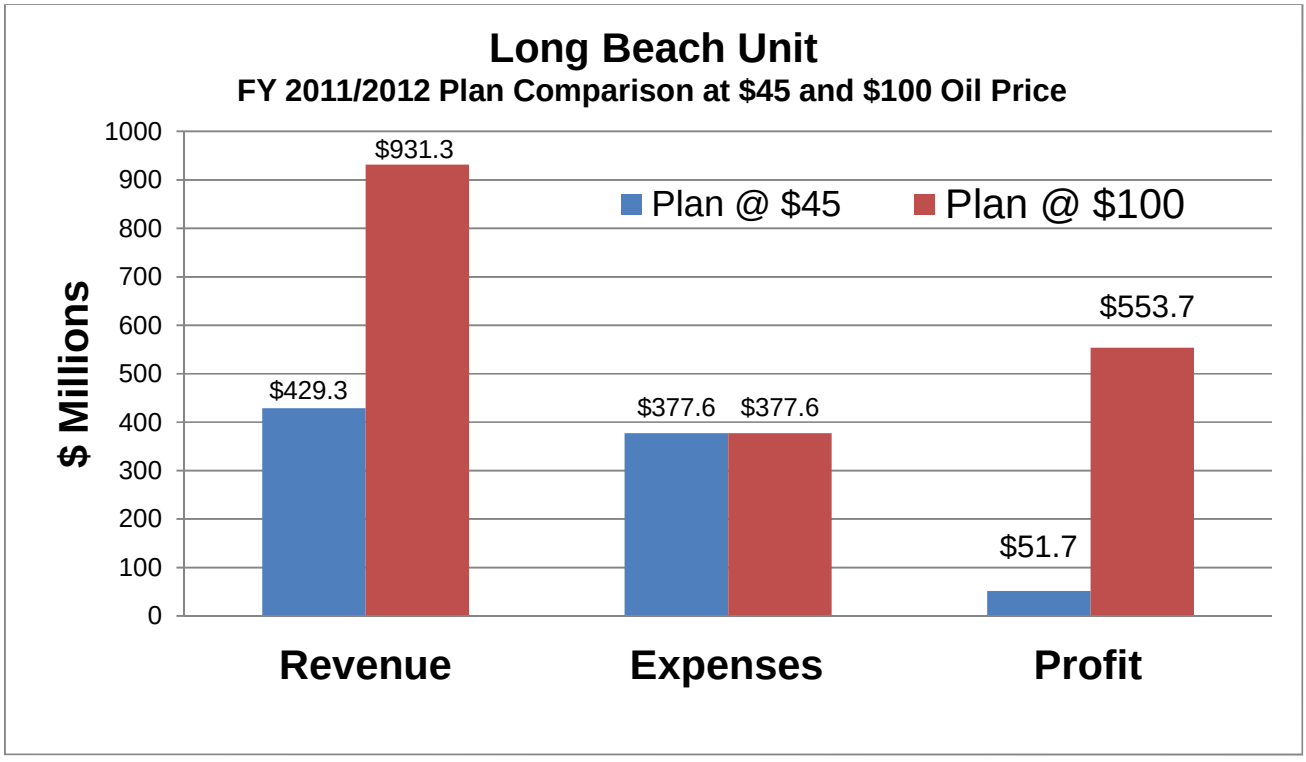


Figure 3 – Island White, one of four man-made islands in LBU

Figure 4 – Comparison of estimated revenue, costs, and profit at $45 and $100/bbl



Oil Price Comparison

LONG BEACH GAS & OIL DEPARTMENT - GAS & OIL OPERATIONS BUREAU