EXHIBIT B

W 17164

Long Beach Unit

THUMS Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2010 through June 30, 2011

ANNUAL PLAN

July 1, 2010 through June 30, 2011

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Part I

Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2010 through June 30, 2011 ("FY 2011"). 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 2010 – 2011 ($ Million)
Development Drilling	$ 68.0
Operating Expense	$101.2
Facilities, Maintenance, and Plant	$ 87.8
Unit Field Labor and Administrative	$ 54.2
Taxes, Permits, and Administrative Overhead	$ 42.2
Total	$353.4

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2009 through June 2014 and provides current estimates of volumes, drilling activity and expenditures for FY2011.

Volumes

Oil and gas production volumes in the Program Plan were predicted to average 24.9 Mbopd and 9.8 MMcfd, respectively, in FY2011. Oil and gas volumes and ranges have been revised from the Program Plan. Oil production is now expected to average 25.1 Mbopd within the Program Plan range of 24.1 to 25.4 Mbopd, and gas production is expected to average 9.4 MMcfd within the Program Plan range of 8.5 to 10.6 MMcfd. Water production and injection volumes have been revised from the Program Plan. Water production and injection volumes in the Program Plan were predicted to average 977 Mbwpd and 1,062 Mbwpd, respectively. Water production for the period is now expected to average 992 Mbwpd within the Program Plan range of 949 to 996 Mbwpd. Water injection is expected to average 1,068 Mbwpd within the Program Plan range of 1,032 to 1,083 Mbwpd.

The upward revision in oil production volumes is primarily a result of a shallower than expected decline in base production. Action plans implemented in FY2009 and FY2010 have helped to mitigate the steepening of the base decline by redistributing injection to areas of lower water-oil ratios.

The downward revision in gas production volumes is primarily driven by shallow gas production decline. Two shallow gas wells watered out sooner than anticipated.

Revenue and Expenses

Due to the observed strength in oil price for FY2010, the oil price assumption for FY2011 has been changed from $40.00/bbl in the Program Plan to $45.00/bbl in the Annual Plan. The gas price assumption remains unchanged. Revenues projected for FY2011 are $432.9 million, which is $47.6 million higher than anticipated in the Program Plan. Budgeted expenses of $353.4 million for FY2011 are in line with the Program Plan. Projected net profit in FY2011 is $79.5 million versus $31.9 million in the Program Plan.

The projected revenue increase in FY2011 is the result of higher forecasted oil prices ($40.00/bbl in the Program Plan) and higher expected oil rate. Overall forecasted expenses are in line with those forecasted in the Program Plan.

Other expenses consistent with strategies outlined in the Program Plan are also included but will be curtailed if revenues are not available to offset them. A comparison of revenue, expenditures, net income, and volumes is shown in Part II-C of this Plan.

Drilling

This Plan allows for drilling approximately 44 new and redrilled development and/or replacement wells. The plan is to use one and three quarters drilling rigs as compared to two in the Program Plan. The rig utilization could potentially increase if the realized oil price significantly exceeds the planning price. A workover rig will perform drilling preparation and completion work.

The location of production and injection wells to be drilled or redrilled are generally consistent with those given in the Program Plan (see attached Part II, Schedule 2B). Locations of anticipated drilling candidates have been better defined since the Program Plan was developed and are outlined in Revised Schedule 2B (attached). Significant variances include potential extension of a full time drilling rig on Island White.

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 FY11	BUDGET SECOND QUARTER FY11	BUDGET THIRD QUARTER FY11	BUDGET FOURTH QUARTER FY11	BUDGET TOTAL FY11
ESTIMATED REVENUE					
Oil Revenue	$105.4	$104.4	$101.3	$101.3	$412.4
Gas Revenue	$5.3	$5.2	$5.0	$5.0	$20.5
TOTAL REVENUE	$110.7	$109.6	$106.3	$106.3	$432.9
ESTIMATED EXPENDITURES					
Development Drilling	$17.0	$17.0	$17.0	$17.0	$68.0
Operating Expense	$25.3	$25.3	$25.3	$25.3	$101.2
Facilities & Maintenance	$22.1	$21.9	$21.9	$21.9	$87.8
Unit Field Labor & Administration	$13.4	$13.6	$13.6	$13.6	$54.2
Taxes, Permits & Overhead	$10.4	$10.6	$10.6	$10.6	$42.2
TOTAL EXPENDITURES	$88.2	$88.4	$88.4	$88.4	$353.4
NET PROFIT	$22.5	$21.2	$17.9	$17.9	$79.5

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY11	BUDGET SECOND QUARTER FY11	BUDGET THIRD QUARTER FY11	BUDGET FOURTH QUARTER FY11	BUDGET TOTAL FY11
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,341	2,321	2,250	2,252	9,164
(AVERAGE B/D)	25,447	25,225	25,005	24,747	25,108
GAS PRODUCTION					
PRODUCED (1000 MCF)	872	865	840	841	3,418
(AVERAGE MCF/D)	9,480	9,406	9,329	9,244	9,365
WATER PRODUCTION					
PRODUCED (1000 BBL)	90,171	91,296	89,852	90,736	362,055
(AVERAGE B/D)	980,120	992,353	998,351	997,099	991,932
WATER INJECTION					
INJECTED (1000 BBL)	97,108	98,224	96,591	97,476	389,398
(AVERAGE B/D)	1,055,524	1,067,648	1,073,229	1,071,160	1,066,844
OIL PRICE ($/BBL)	$45.0	$45.0	$45.0	$45.0	$45.0
GAS PRICE ($/MCF)	$ 6.0	$ 6.0	$ 6.0	$ 6.0	$ 6.0

Part II

Program Plan Schedules

Schedule 2 A

Range of Production and Injection
FY 2011
Long Beach Unit Program Plan, July 2009-June 2014

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2010-11	24.1 - 25.4	949 - 996	8.5 - 10.6	1032 - 1083

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2010-11	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B

Anticipated New and Redrilled Wells
Fiscal Year 10/11
Long Beach Unit Program Plan, July 2009-June 2014

Reservoir	CRB	Producers Grissom Min - Max	Producers White Min - Max	Producers Chaffee Min - Max	Producers Freeman Min - Max	Producers Pier J Min - Max	Injectors Grissom Min - Max	Injectors White Min - Max	Injectors Chaffee Min - Max	Injectors Freeman Min - Max	Injectors Pier J Min - Max
Tar		0 - 3	0 - 0			0 - 0	0 - 2				0 - 0
SG		0 - 2	0 - 2								
Ranger West	1	0 - 1	0 -				0 - 1				
	2	0 - 3	1				1 - 2				
	3	0 - 3	0 - 1			0 - 1	0 - 1				0 - 0
	4	0 - 5	0 - 1		0 - 0	0 - 1	0 - 1	0 - 0		0 - 0	1 - 3
	5	0 - 2			0 - 0	0 - 1				0 - 0	2 - 4
	7				0 - 0	0 - 1				0 - 0	1 - 2
	8				0 - 0					0 - 0	
	9		0 - 1		0 - 0			0 - 1		0 - 0	
	10		0 - 1				0 - 2	0 - 1			
	11		0 - 1				0 - 2	0 - 1			
	12		0 - 1					0 - 1			
	13		0 - 1					0 - 1			
	36		0 - 0		0 - 0	1 - 2		0 - 0		0 - 1	0 - 2
	37				0 - 0					0 - 0	
Ranger East	14		0 - 1					0 - 0			
	15		0 - 1		0 - 1			0 - 0		0 - 0	
	16		0 - 1	0 - 1	0 - 0			0 - 0	0 - 1	0 - 0	
	17			0 - 1					0 - 1		
	18			0 - 1					1 - 1		
	20			0 - 1					0 - 1		
	21			1 - 1					0 - 1		
	22			0 - 1					0 - 1		
	33			0 - 1					0 - 1	0 - 0	
Terminal	24	0 - 1	0 - 0			0 - 1	0 - 1				0 - 0
	38	1 - 2	0 - 0		0 - 0	1 - 3	1 - 2	0 - 1		0 - 0	0 - 2
	39	1 - 2	0 - 0		0 - 1		1 - 2	0 - 1		0 - 0	
	40		0 - 0		0 - 0			0 - 0		0 - 0	
	41	1 - 2									0 - 2
	42			0 - 1					0 - 2		
	43			0 - 1	0 - 0				0 - 0	0 - 0	
	47										
UP Ford	26		0 - 0		0 - 0			0 - 1		0 - 0	
	27		0 - 0		0 - 0			0 - 1		0 - 0	
	30	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 1	0 - 0	0 - 1
	31		2 - 4	0 - 0	0 - 0			0 - 0	0 - 0	0 - 0	
	44		0 - 0	1 - 1	0 - 0			0 - 0	0 - 0	0 - 0	
	45		0 - 0	1 - 1	0 - 0			0 - 0	0 - 1	0 - 0	
	46			1 - 2							
237	30	0 - 0		0 - 3	0 - 0						
		Total					Total				
		11 - 72					8 - 55				

Schedule 2 B - Revised

Anticipated New and Redrilled Wells
Fiscal Year 10/11
Long Beach Unit Program Plan, July 2009-June 2014

		Producers					Injectors				
Reservoir	CRB	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 - 1	0 - 0			0 - 0	0 - 1				0 - 0
SG		0 - 1	0 - 2								
Ranger	1	0 - 2	0 -				0 - 2				
West	2	0 - 2	0 - 1				0 - 1				
	3	0 - 2	1 - 2			0 - 1	0 - 2				0 - 0
	4	0 - 2	1 - 3		0 - 0	0 - 1	0 - 1	0 - 2		0 - 0	0 - 1
	5	0 - 1			0 - 0	0 - 1				0 - 0	0 - 1
	7							0 - 1			
	8		0 - 1					0 - 1			
	9		0 - 2		0 - 0			0 - 2		0 - 0	
	10		0 - 4					0 - 3			
	11		0 - 2					0 - 2			
	12		0 - 1					0 - 1			
	13		0 - 1					0 - 1			
	36				0 - 1	0 - 2				0 - 1	0 - 2
	37				0 - 1					0 - 1	
Ranger	14		0 - 1					0 - 1			
East	15		0 - 1		0 - 1			0 - 1		0 - 0	
	16			0 - 1	0 - 0				0 - 1	0 - 0	
	17			0 - 1					0 - 1		
	18			0 - 1					0 - 1		
	20			0 - 1					0 - 3		
	21			1 - 2					0 - 2		
	22			0 - 1					0 - 1		
	32			0 - 1					0 - 1		
	33			0 - 1					0 - 1		
Terminal	24		0 - 1	0 - 1	0 - 1			0 - 1	0 - 1	0 - 1	
	38	0 - 2	0 - 0		0 - 0	0 - 2	1 - 2	0 - 1		0 - 0	0 - 1
	39	0 - 2	0 - 1		0 - 1	0 - 1	0 - 1	0 - 1		0 - 0	0 - 1
	40		0 - 1		0 - 0			0 - 1		0 - 0	
	41	1 - 2					0 - 1				0 - 1
	42			0 - 1					1 - 2		
	43			0 - 1	0 - 0				0 - 1	0 - 0	
	47										
UP Ford	26		0 - 0		0 - 0			0 - 1		0 - 0	
	27		0 - 1		0 - 0			0 - 1		0 - 0	
	30	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 1	0 - 0	0 - 1
	31		0 - 1	0 - 0	0 - 0			0 - 0	0 - 0	0 - 0	
	44		0 - 0	1 - 1	0 - 0			0 - 0	0 - 0	0 - 0	
	45		0 - 0	1 - 1	0 - 0			0 - 0	0 - 2	0 - 0	
	46			1 - 2							
237	30	0 - 0		0 - 3	0 - 0						
		Total					Total				
		7 - 76					2 - 63				

TABLE 1C
COMPARISON OF PROGRAM PLAN TO FISCAL YEAR 2010/11

	Program Plan	Annual Plan	Variance	
			Over / (Under)	%
Drilling - Total Wells	50	44	(6.0)	-12%
Oil Production (MBBL)	9,094	9,164	70	1%
Oil Production (MBOPD)	24.9	25.1	0.2	1%
Water Production (MBBL)	356,605	362,055	5,450	2%
Water Production (MBWPD)	977	992	15	2%
Water Injection (MBBL)	387,630	389,398	1,768	0%
Water Injection (MBWPD)	1,062	1,067	5	0%
Total Revenue	$385.3	$432.9	$47.6	12%
Total Expenditure	$353.4	$353.4	$0.0	0%
Profit	$31.9	$79.5	$47.6	149%
Oil Price ($/BBL)	$40.0	$45.0	$5.0	13%
Gas Price ($/MCF)	$6.0	$6.0	$0.0	0%

C. Comparison to Program Plan

Drilling Variance: Drilling activity is forecasted to reduce by quarter of a rig as compared to the Program Plan. The reduction is primarily based on the forecast, which builds upon the activity planned for the remainder of FY2010. Currently the Unit is employing one and a half drilling rigs, which is half a rig less than that one projected in FY2010 Annual Plan. Rig utilization for the Unit drilling will be adjusted as needed to respond to fluctuations in oil price and other economic conditions.

Oil Production Variance: Net oil production is forecast to be one percent higher than forecasted in the Program Plan primarily due to shallower than expected base decline rates.

Revenue Variance: The revenue variance from the Program Plan is due to higher oil price assumption and higher forecasted oil rate.

Part III

Itemized Budget of Expenditures

A. Development Drilling $68,000,000

The Development Drilling category of expenditures encompasses all new well and replacement well drilling activity, as well as maintenance and replacement of drilling equipment within the Unit. Funds for development drilling are based on the assumption that 44 wells will be developed and/or replaced during the Plan year, using approximately one and three quarters drilling rigs and a workover rig.

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

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

B. Operating Expense $101,200,000

The Operating Expense category of expenditures encompasses the ongoing costs of day-to-day well production and injection operations necessary for producing, processing, and delivering crude oil and gas, and for all electric power charges. Expenses for this category are based on estimated oil production of 25.1 Mbopd, estimated gas production of 9.4 MMcfpd, water injection requirement of 1,067 Mbwpd, and water production of 992 Mbwpd. Anticipated operating expenses were based on operating three and a half workover rigs per month for servicing an average active well count of 861 producers and 490 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 38 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 58 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 695,483,000 kwh at an average rate of $0.084/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 $87,800,000

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

Approximately 45 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 55 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 $54,200,000

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

Funding for Unit personnel includes costs of salaries, wages, benefits, training, and expenses of all THUMS employees. These costs represent approximately 74 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 $42,200,000

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

Funding is provided for taxes levied on personal property, mining rights, and oil production; for the Petroleum and Gas Fund Assessment; annual well permits and renewals; Conservation Committee of California Oil and Gas Producers Assessment; California Oil Spill Response, Prevention, and Administration fee; land leases; and pipeline right-of-way costs. These costs represent approximately 67 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, 2011 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY11 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 FY11 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.