UNOCAL CORP
Form 10-Q
August 12, 2002

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2002

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______________ to ____________________

Commission file number 1-8483

UNOCAL CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	95-3825062
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2141 ROSECRANS AVENUE, SUITE 4000, EL SEGUNDO, CALIFORNIA 90245
(Address of principal executive offices)
(Zip Code)

(310) 726-7600
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No ______

Number of shares of Common Stock, $1 par value, outstanding as of July 31, 2002: 244,665,162

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GLOSSARY

Below are certain definitions of key terms that may be in use in this Form 10-Q report.

M	Thousand	Bbl	Barrels
MM	Million	Cf/d	Cubic feet per day
B	Billion	Cfe/d	Cubic feet of gas equivalent per day
CF	Cubic feet	Btu	British thermal units
BOE	Barrels of oil equivalent	DD&A	Depreciation, depletion and amortization
Liquids	Crude oil, condensate and NGLs	NGLs	Natural gas liquids
Bbl/d	Barrels per day		

- API Gravity is a measurement of the gravity (density) of crude oil and other liquid hydrocarbons by a system recommended by the American Petroleum Institute ("API"). The measuring scale is calibrated in terms of "API degrees." The higher the API gravity, the lighter the oil.
- Bilateral institution refers to a country specific institution, which lends funds primarily to promote the export of goods from that country. Examples of bilateral institutions are Ex-Im (U.S.), Hermes (Germany), SACE (Italy), COFACE (France), and JBIC (Japan).

- BOE A term used to quantify oil and natural gas amounts using the same measurement. Gas volumes are converted to barrels of oil on the basis of energy content, where the volume of natural gas that when burned produces the same amount of heat as a barrel of oil (6,000 cubic feet of gas equals one barrel of oil).
- British Thermal Units ("Btu") is a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.
- Delineation or appraisal well is a well drilled in an unproven area adjacent to a discovery well to define the boundaries of the reservoir.
- Development well is a well drilled within the proved area of an oil or natural gas reservoir to a depth of a stratigraphic horizon known to be productive.
- Dry hole is a well believed to be incapable of producing hydrocarbons in sufficient commercial quantities to justify future capital expenditures for completion and additional infrastructure.
- Economic interest method pursuant to production sharing contracts is a method by which the Company's share of the cost recovery revenue and the profit revenue is divided by year-end oil and gas prices and represents the volume that the Company is entitled to. The lower the commodity price, the higher the volume entitlement, and vice versa.
- Exploratory well is a well drilled to find and produce oil or natural gas reserves that is not a development well.
- Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in," while the interest transferred by the assignor is a "farm-out."
- Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.
- Floating Production Storage and Offloading ("FPSO") technology refers to the use of a vessel that is stationed above or near an offshore oil field. Produced fluids from subsea completion wells are brought by flowlines to the vessel where they are separated, treated, stored and then offloaded to another vessel for transportation.
- Gross acres or gross wells are the total acres or wells in which a working interest is owned.
- Hydrocarbons are organic compounds of hydrogen and carbon atoms that form the basis of all petroleum products.

- Lifting is the amount of liquids each working-interest partner takes physically. The liftings may actually be more or less than actual entitlements that are based on royalties, working interest percentages, and a number of other factors.
- Liquefied Natural Gas ("LNG") is a gas, mainly methane, which has been liquefied in a refrigeration and pressure process to facilitate storage and transportation.
- Liquefied Petroleum Gas ("LPG") is a mixture of butane, propane and other light hydrocarbons. At normal temperature it is a gas, but it can be cooled or subjected to pressure to facilitate storage and transportation.
- Multilateral institution refers to an institution with shareholders from multiple countries that lends money for specific development reasons. Examples of multilateral institutions are International Finance Corporation ("IFC"), European Bank for Reconstruction and Development ("EBRD"), and Asian Development Bank ("ADB").
- Natural Gas Liquids ("NGLs") are primarily ethane, propane, butane and natural gasolines which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower

temperature.

- Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by the Company's working interest percentage in the properties.
- Net pay is the amount of oil or gas saturated rock capable of producing oil or gas.
- Production Sharing Contract ("PSC") is a contractual agreement between the Company and a host government whereby the Company, acting as contractor, bears all exploration costs, development and production costs in return for an agreed upon share of production.
- Producible well is a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
- Prospective acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas.
- Proved acreage is acreage that is allocated to producing wells or wells capable of production or to acreage that is being developed.
- Reservoir is a porous and permeable underground formation containing oil and/or natural gas enclosed or surrounded by layers of less permeable rock and is individual and separate from other reservoirs.
- Subsea tieback is a well with the wellhead equipment located on the bottom of the ocean.
- Take-or-Pay is a type of contract clause where specific quantities of a product must be paid for, even if delivery is not taken. Normally, the purchaser has the right in following years to take product that had been paid for but not taken.
- Trend or Play is an area or region of concentrated activity with a group of related fields and prospects.
- Working interest is the percentage of ownership that the Company has in a joint venture, partnership or consortium.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONSOLIDATED EARNINGS (UNAUDITED)

	For the Three Months Ended June 30,	
Millions of dollars except per share amounts	2002	2001
Revenues		
Sales and operating revenues	$ 1,349	$ 1,684
Interest, dividends and miscellaneous income	8	11
Gain (loss) on sales of assets	(1)	1
Total revenues	1,356	1,696
Costs and other deductions		
Crude oil, natural gas and product purchases	428	537
Operating expense	312	329
Administrative and general expense	37	27
Depreciation, depletion and amortization	255	245
Impairments	21	-
Dry hole costs	13	47
Exploration expense	61	55
Interest expense	43	48

Property and other operating taxes	18	20
Distributions on convertible preferred securities of subsidiary trust	8	8
Total costs and other deductions	1,196	1,316
Earnings from equity investments	51	49
Earnings from continuing operations before income taxes and minority interests	211	429
Income taxes	95	180
Minority interests	3	14
Earnings from continuing operations	113	235
Discontinued operations		
Refining, marketing and transportation		
Gain on disposal (net of tax)	1	12
Earnings from discontinued operations	1	12
Cumulative effect of accounting change	-	-
Net earnings	$ 114	$ 247
Basic earnings per share of common stock (a)		
Continuing operations	$ 0.46	$ 0.98
Net earnings	$ 0.46	$ 1.02
Diluted earnings per share of common stock (b)		
Continuing operations	$ 0.46	$ 0.95
Net earnings	$ 0.46	$ 0.99
Cash dividends declared per share of common stock	$ 0.20	$ 0.20

See Notes to the Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEET

	At June 30,
Millions of dollars	2002
Assets	
Current assets	
Cash and cash equivalents	$ 161
Accounts and notes receivable - net	837
Inventories	111
Deferred income taxes	138
Other current assets	23
Total current assets	1,270
Investments and long-term receivables - net	1,486
Properties - net (b)	7,741
Deferred income taxes	177
Other assets	119

Total assets	$ 10,793
Liabilities and Stockholders' Equity	
Current liabilities	
Accounts payable	$ 828
Taxes payable	245
Dividends payable	49
Interest payable	48
Current portion of environmental liabilities	116
Current portion of long-term debt and capital leases	8
Other current liabilities	147
Total current liabilities	1,441
Long-term debt and capital leases	3,111
Deferred income taxes	678
Accrued abandonment, restoration and environmental liabilities	587
Other deferred credits and liabilities	722
Subsidiary stock subject to repurchase	92
Minority interests	430
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	522
Common stock ($1 par value, shares authorized: 750,000,000 (c))	255
Capital in excess of par value	573
Unearned portion of restricted stock issued	(26
Retained earnings	2,926
Accumulated other comprehensive income	(66
Notes receivable - key employees	(41
Treasury stock - at cost (d)	(411
Total stockholders' equity	3,210
Total liabilities and stockholders' equity	$ 10,793

See Notes to the Consolidated Financial Statements.

CONSOLIDATED CASH FLOWS (UNAUDITED)

	F
Millions of dollars	2
Cash Flows from Operating Activities	
Net earnings	$
Adjustments to reconcile net earnings to net cash provided by operating activities	
Depreciation, depletion and amortization	
Impairments	
Dry hole costs	
Amortization of exploratory leasehold costs	
Deferred income taxes	
Gain on sales of assets (pre-tax)	
Gain on disposal of discontinued operations (pre-tax)	
Earnings applicable to minority interests	

Other	
Working capital and other changes related to operations	
Accounts and notes receivable	
Inventories	
Accounts payable	
Taxes payable	
Other	
Net cash provided by operating activities	
Cash Flows from Investing Activities	
Capital expenditures (includes dry hole costs)	(
Major acquisitions	
Proceeds from sales of assets	
Proceeds from sale of discontinued operations	
Net cash used in investing activities	(
Cash Flows from Financing Activities	
Long-term borrowings	
Reduction of long-term debt and capital lease obligations	(
Minority interests	
Proceeds from issuance of common stock	
Dividends paid on common stock	
Net cash provided by financing activities	
Net increase (decrease) in cash and cash equivalents	
Cash and cash equivalents at beginning of year	
Cash and cash equivalents at end of period	$

See Notes to the Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. General

The consolidated financial statements included in this report are unaudited and, in the opinion of management, include all adjustments necessary for a fair presentation of financial position and results of operations. All adjustments are of a normal recurring nature. Such financial statements are presented in accordance with the Securities and Exchange Commission's ("SEC") disclosure requirements for Form 10-Q.

These interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the related notes filed with the Commission in Unocal Corporation's 2001 Annual Report on Form 10-K.

For the purpose of this report, Unocal Corporation ("Unocal") and its consolidated subsidiaries, including Union Oil Company of California ("Union Oil"), are referred to as the "Company".

The consolidated financial statements of the Company include the accounts of subsidiaries in which a controlling interest is held. Investments in entities without a controlling interest are accounted for by the equity method or cost basis. Under the equity method, the investments are stated at cost plus the Company's equity in undistributed earnings and losses after acquisition. Income taxes estimated to be payable when earnings are distributed are included in deferred income taxes.

Results for the six months ended June 30, 2002, are not necessarily indicative of future financial results.

Certain items in the prior year financial statements have been reclassified to conform to the 2002 presentation.

2. Accounting Changes

Effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets". SFAS No. 142 addresses accounting for goodwill and identifiable intangible assets subsequent to their initial recognition, eliminates the amortization of goodwill and provides specific steps for testing the impairment of goodwill. Separable intangible assets that are not deemed to have an indefinite life will continue to be amortized over their useful lives. SFAS No. 142 also eliminates amortization of the excess of cost over the underlying equity in the net assets of an equity method investee that is recognized as goodwill. The adoption of the statement did not have a material effect on the Company's financial position and results of operations.

Effective January 1, 2002, the Company also adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of", and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations--Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". The adoption of SFAS No. 144 did not have a material effect on the Company's financial position and results of operations.

The Company has adopted SFAS No. 145, "Rescission of SFAS No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections." This Statement rescinds SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt", and an amendment of that Statement, SFAS No. 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements". This Statement also rescinds or amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The adoption of SFAS No. 145 did not have a material effect on the Company's financial position and results of operations.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". This statement provides guidance on the recognition and measurement of liabilities associated with disposal activities and is effective for the Company on January 1, 2003.

3. Other Financial Information

During the second quarters of 2002 and 2001, approximately 23 percent and 25 percent, respectively, of total sales and operating revenues were attributable to the resale of liquids and natural gas purchased from others in connection with marketing activities. For the six months ended June 30, 2002 and 2001, these percentages were approximately 22 percent and 32 percent, respectively. Related purchase costs are classified as expense in the crude oil, natural gas and product purchase category on the consolidated earnings statement. The current year percentage decreases were principally due to lower purchases of domestic crude oil from third parties for resale. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets.

Capitalized interest totaled $10 million and $6 million for the second quarters of 2002 and 2001, respectively, and $19 million and $11 million for the six months ended 2002 and 2001, respectively. The increase was primarily due to the capitalized interest related to the Mad Dog development project in the Gulf of Mexico and the West Seno oil and gas development project in the deepwater Kutei Basin, offshore East Kalimantan, Indonesia.

Exploration expense on the consolidated earnings statement consisted of the following:

	For the Three Months Ended June 30,		F
Millions of dollars	2002	2001	
Exploration operations	$ 25	$ 22	
Geological and geophysical	8	6	
Amortization of exploratory leases	23	23	
Leasehold rentals	5	4	
Exploration expense	$ 61	$ 55	

4. Restructuring

In June 2002, the Company adopted a restructuring plan that resulted in the accrual of a $19 million pre-tax restructuring charge. The charge included the estimated costs of terminating approximately 200 employees in the Company's Sugar Land, Texas, office and field locations. The restructuring plan involves organizational changes to eliminate unnecessary work processes in the Company's Gulf Region business unit, which is part of the U.S. Lower 48 operations in the Exploration and Production segment.

The restructuring charge was reflected in the operating expense line on the consolidated earnings statement and included approximately $14 million for termination costs to be paid to the employees over time, about $3 million for outplacement and other costs and about $2 million for benefit plan curtailment costs. All of the affected employees had been terminated or had received termination notices as of June 30, 2002.

5. Impairments

The Company, as part of its regular assessment, reviewed its developed and undeveloped oil and gas properties and other long-lived assets for possible impairment. In the second quarter of 2002, the Company recorded a pre-tax charge of $21 million, or $13 million after-tax, for the impairment of oil and gas fields in Alaska and the Gulf of Mexico region. The impairment in Alaska, which made up the majority of the amount recorded, was $18 million pre-tax, or $12 million after-tax.

6. Income Taxes

Income taxes on earnings from continuing operations for the second quarter and six months periods of 2002 were $95 million and $135 million, respectively, compared with $180 million and $370 million for the comparable periods of 2001. The effective income tax rates for the second quarter and six months periods of 2002 were 46 percent and 50 percent, respectively, compared with 43 percent and 41 percent for the comparable periods of 2001.

The higher effective income tax rates for the second quarter and the first six months of 2002, as compared with the same periods a year ago, reflect currency effects primarily in Thailand along with the effect of changes in the mix of domestic earnings in the prior year periods and losses in the current year periods coupled with foreign earnings for all periods reported, which are generally taxed at higher rates.

7. Earnings Per Share

The following are reconciliations of the numerators and denominators of the basic and diluted earnings per share ("EPS") computations for earnings from continuing operations for the second quarters and six months ended June 30, 2002 and 2001:

Millions except per share amounts	Earnings (Numerator)	S (Den
Three months ended June 30, 2002		
Earnings from continuing operations	$ 113	
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		
Diluted EPS	113	
Distributions on subsidiary trust preferred securities (after-tax)	7	
Antidilutive	$ 120	
Three months ended June 30, 2001		
Earnings from continuing operations	$ 235	
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		
	235	
Distributions on subsidiary trust preferred securities (after-tax)	7	
Diluted EPS	$ 242	

Not included in the computation of diluted EPS for the three months ended June 30, 2002 and 2001, were options outstanding to purchase approximately 1.9

million and 3.4 million shares, respectively, of common stock. These options were not included in the computation as the exercise prices were greater than average market prices of the common shares during the respective quarters.

Millions except per share amounts	Earnings (Numerator)	S (Den
Six months ended June 30, 2002		
Earnings from continuing operations	$ 135	
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		
	135	
Distributions on subsidiary trust preferred securities (after-tax)	14	
Antidilutive	$ 149	
Six months ended June 30, 2001		
Earnings from continuing operations	$ 527	
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		
	527	
Distributions on subsidiary trust preferred securities (after-tax)	13	
Diluted EPS	$ 540	

The diluted EPS computation for the six months ended June 30, 2002 and 2001, did not include options outstanding to purchase approximately 3.3 million and 5.0 million shares, respectively, of common stock. These options were not included in the computation as the exercise prices were greater than the year-to-date average market price of the common shares.

Basic and diluted earnings per common share for discontinued operations were as follows:

	For the Three Months Ended June 30,		For E
Millions except per share amounts	2002	2001	
Basic earnings per share of common stock:			
Discontinued operations:			
Earnings from discontinued operations	$ 1	$ 12	

Weighted average common shares outstanding	244.6	243.5
Earnings from discontinued operations	$ -	$ 0.04
Dilutive earnings per share of common stock:		
Discontinued operations:		
Earnings from discontinued operations	$ 1	$ 12
Weighted average common shares outstanding	245.8	256.9
Earnings from discontinued operations	$ -	$ 0.04

8. Comprehensive Income

The Company's comprehensive income was:

Millions of dollars	For the Three Months Ended June 30, 2002	2001
Net earnings	$ 114	$ 247
Cumulative effect of change in accounting principle SFAS No. 133 adoption (a)	-	-
Change in unrealized loss on hedging instruments (b)	(1)	41
Reclassification adjustment for settled hedging contracts (c)	4	2
Unrealized foreign currency translation adjustments	35	15
Total comprehensive income	$ 152	$ 305

9. Cash and Cash Equivalents

Millions of dollars	At June 30, 2002	At Decem
Cash	$ 18	
Time deposits	97	
Restricted cash	6	
Marketable securities	40	
Cash and cash equivalents	$ 161	

10. Long Term Debt and Credit Agreements

During the first six months of 2002, the Company's consolidated debt, including the current portion, increased by $213 million. This net increase included $440 million in new commercial paper borrowings, the proceeds of which were used to refinance maturing debt and for general corporate purposes. The commercial paper had a weighted average interest rate of 2.23 percent at June 30, 2002. The Company retired $132 million of maturing medium-term notes during the first six months of 2002. In February 2002, the Company's Northrock Resources Ltd. subsidiary redeemed its $35 million "Series A" and $40 million "Series B" senior

U.S. dollar-denominated notes, which bore interest of 6.54 percent and 6.74 percent, respectively. The Company's Pure Resources, Inc. ("Pure") subsidiary reduced its long-term debt, included in the Company's consolidated debt, by $16 million principally due to a decrease in borrowing under its revolving credit facilities. Pure's debt was $571 million at June 30, 2002. Neither Unocal nor Union Oil guarantees any of Pure's debt.

11. Accrued Abandonment, Restoration and Environmental Liabilities

At June 30, 2002, the Company had accrued $472 million for the estimated future costs to abandon and remove wells and production facilities. The total costs for these abandonments are predominantly accrued on a unit-of-production basis and are estimated to be approximately $700 million. This estimate was derived in large part from abandonment cost studies performed by independent third party firms and is used to calculate the amount to be amortized. The Company's reserve for environmental remediation obligations at June 30, 2002 totaled $231 million, of which $116 million was included in current liabilities.

12. Commitments and Contingencies

The Company has contingent liabilities with respect to material existing or potential claims, lawsuits and other proceedings, including those involving environmental, tax and other matters, certain of which are discussed more specifically below. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date, the Company's estimates of the outcomes of these matters and its experience in contesting, litigating and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which could have a material effect on the Company's future results of operations and financial condition or liquidity.

Environmental matters

The Company is subject to loss contingencies pursuant to federal, state, local and foreign environmental laws and regulations. These include existing and possible future obligations to investigate the effects of the release or disposal of certain petroleum, chemical and mineral substances at various sites; to remediate or restore these sites; to compensate others for damage to property and natural resources, for remediation and restoration costs and for personal injuries; and to pay civil penalties and, in some cases, criminal penalties and punitive damages. These obligations relate to sites owned by the Company or others and are associated with past and present operations, including sites at which the Company has been identified as a potentially responsible party ("PRP") under the federal Superfund laws and comparable state laws. Liabilities are accrued when it is probable that future costs will be incurred and such costs can be reasonably estimated. However, in many cases, investigations are not yet at a stage where the Company is able to determine whether it is liable or, even if liability is determined to be probable, to quantify the liability or estimate a range of possible exposure. In such cases, the amounts of the Company's liabilities are indeterminate due to the potentially large number of claimants for any given site or exposure, the unknown magnitude of possible contamination, the imprecise and conflicting engineering evaluations and estimates of proper clean-up methods and costs, the unknown timing and extent of the corrective actions that may be required, the uncertainty attendant to the possible award of punitive damages, the recent judicial recognition of new causes of action, the present state of the law, which often imposes joint and several and retroactive liabilities on PRPs, the fact that the Company is usually just one of a number of companies identified as a PRP, or other reasons.

As disclosed in note 11, at June 30, 2002, the Company had accrued $231 million for estimated future environmental assessment and remediation costs at various sites where liabilities for such costs are probable and reasonably estimable. The Company may also incur additional liabilities in the future at sites where remediation liabilities are probable but future environmental costs are not presently reasonably estimable because the sites have not been assessed or the assessments have not advanced to the stage where costs are reasonably estimable. At those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $255 million. The amount of such possible additional costs reflects the aggregate of the high ends of the ranges of costs of feasible alternatives identified by the Company for those sites with respect to which investigation or feasibility studies have advanced to the stage of analyzing such alternatives. However, such estimated possible additional costs are not an estimate of the total remediation costs beyond the amounts reserved, because there are sites where the Company is not yet in a position to estimate all, or in some cases any, possible additional costs. Both the amounts reserved and estimates of possible additional costs may change in the near term, and in some cases could change substantially, as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties.

The accrued costs and the possible additional costs are shown below in four categories of sites:

	At June 30, 2002	
Millions of dollars	Reserves	Possible Additional
Superfund and similar sites	$ 18	$ 11
Active company facilities	37	66
Company facilities sold with retained liabilities and former company-operated sites	97	71
Inactive or closed company facilities	79	107
Total reserves	$ 231	$ 255

The time frame over which the amounts included in the reserve may be paid extend from the near term to several years into the future. The sites included in the above categories are in various stages of investigation and remediation; therefore, the related payments against the existing reserve will be made in different future periods. Also, some of the work is dependent upon reaching agreements with regulatory agencies and/or other third parties on the scope of remediation work to be performed, who will perform the work, the timing of the work, who will pay for the work and other factors that may have an impact on the timing of the payments for amounts included in the reserve. For some sites, the remediation work will be performed by other parties, such as the current owners of the sites, and the Company has a contractual agreement to pay a share of the remediation costs. For these sites, the Company generally has less control over the timing of the work and consequently the timing of the associated payments. Based on available information, the Company estimates that the majority of the amounts included in the reserve will be paid within the next three to five years.

At the sites where the Company has a contractual agreement to share remediation costs with third parties, the reserve reflects the Company's estimated share of those costs. In many of the oil and gas sites, remediation cost sharing is included in joint venture agreements that were made with third parties during the original operation of the site. In many cases where the Company sold facilities or a business to a third party, sharing of remediation costs for those sites may be included in the sales agreement.

Contamination in the sites of the "Superfund and Similar Sites" category was the result of the disposal of substances at these sites by one or more PRPs. Contamination of these sites could be from many sources, of which the Company may be one. The Company has been notified that it is a PRP at the sites included in this category. At the sites where the Company has not denied liability, the Company's contribution to the contamination at these sites was primarily from waste from the current and former operations identified above.

The "Active Company Facilities" category includes oil and gas fields and mining operations. The sites are primarily contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at the active mining sites was principally the result of the impact of mined material on the groundwater and/or surface water at these sites.

The "Company Facilities Sold and Former Company-Operated Sites" and "Inactive or Closed Company Facilities" categories include former Company refineries, transportation and distribution facilities and service stations. The required remediation of these sites is mainly for petroleum hydrocarbon contamination as the result of leaking tanks or impoundments that were used in these operations. Also, included in these categories are former oil and gas fields that the company no longer operates. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at other sites in this category was the result of former industrial chemical and polymers manufacturing and distribution facilities, agricultural chemical retail businesses and ferromolybdenum production operations.

Superfund and similar sites - At June 30, 2002, Unocal had received notification from the U.S. Environmental Protection Agency ("EPA") that the Company may be a PRP at 30 sites and may share certain liabilities at these sites. Of the total, five sites are under investigation and/or litigation and the Company's potential liability is not presently determinable and for two sites the Company has denied responsibility. At one site, the Company's potential liability appears to be de minimis. Of the remaining 22 sites, where probable and to the extent costs can be reasonably estimated, reserves of $12 million have been established for future remediation and settlement costs.

Various state agencies and private parties had identified 23 other similar PRP sites. Two sites are under investigation and/or litigation and the Company's potential liability is not presently determinable. At three sites the Company's potential liability appears to be de minimis. At another site, the Company has made final settlement payments and is in the process of completing its involvement in the sites. The Company has denied responsibility at two sites. Where probable and to the extent costs can be reasonably estimated at the remaining 15 sites, reserves of $6 million have been established for future remediation and settlement costs.

In addition to the total of $18 million in reserves mentioned above, the Company has also estimated that additional costs of $11 million are possible for the "Superfund and Similar Sites" category.

Included in this category of sites are:

o The McColl site in Fullerton, California
o The Operating Industries site in Monterey Park, California
o The Casmalia Waste site in Casmalia, California

These 53 sites exclude 108 sites where the Company's liability has been settled, or where the Company has no evidence of liability and there has been no further indication of liability by government agencies or third parties for at least a 12-month period.

The Company does not consider the number of sites for which it has been named a PRP as a relevant measure of liability. Although the liability of a PRP is generally joint and several, the Company is usually just one of numerous companies designated as a PRP. The Company's ultimate share of the remediation costs at those sites often is not determinable due to many unknown factors. The solvency of other responsible parties and disputes regarding responsibilities may also impact the Company's ultimate costs.

Active Company facilities - The Company has a reserve of $37 million for estimated future costs of remedial orders, corrective actions and other investigation, remediation and monitoring obligations at certain operating facilities and producing oil and gas fields. Included in this category are:

o The Molycorp molybdenum mine in Questa, New Mexico
o The Molycorp lanthanide facility in Mountain Pass, California
o Alaska oil and gas properties

The company estimates that it may incur possible additional costs of $67 million for this group of sites.

Company facilities sold with retained liabilities and former Company-operated sites - Company facilities sold with retained liabilities include:

o West Coast refining, marketing and transportation sites o Auto/truckstop facilities throughout the U.S. o Industrial chemical and polymer sites in the South, Midwest and California o Agricultural chemical sites in the West and Midwest.

In each sale, the Company retained a contractual remediation or indemnification obligation and is responsible only for certain environmental problems associated with its past operations. The reserves represent estimated future costs for remediation work: identified prior to the sale of these sites; included in negotiated agreements with the buyers of these sites where the Company retained certain levels of remediation liabilities; and/or identified in subsequent claims made by buyers of the properties. Former Company-

operated sites include service stations, distribution facilities and oil and gas fields that were previously operated but not owned by the Company. The Company has an aggregate reserve of $97 million and additional costs of $72 million are possible for this category. The possible additional costs are primarily related to service station and distribution facilities and oil and gas properties.

Inactive or closed Company facilities - Reserves of $79 million have been established for these types of facilities. The major sites in this category are: o The Guadalupe oil field on the central California coast o The Molycorp

Washington and York facilities in Pennsylvania o The Beaumont Refinery in Texas.

These sites also have possible additional costs of $95 million associated with them.

The Company is subject to federal, state and local environmental laws and regulations, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended, the Resource Conservation and Recovery Act ("RCRA") and laws governing low level radioactive materials. Under these laws, the Company is subject to possible obligations to remove or mitigate the environmental effects of the disposal or release of certain chemical, petroleum and radioactive substances at various sites. Corrective investigations and actions pursuant to RCRA and other federal, state and local environmental laws are being performed at the Company's Beaumont, Texas, facility, a former agricultural chemical facility in Corcoran, California, and Molycorp's Washington, Pennsylvania, facility. In addition, Molycorp is required to decommission its Washington and York facilities in Pennsylvania pursuant to the terms of their respective radioactive source materials licenses and decommissioning plans.

The Company also must provide financial assurance for future closure and post-closure costs of its RCRA-permitted facilities and for decommissioning costs at facilities that are under radioactive source materials licenses. Pursuant to a 1998 settlement agreement between the Company and the State of California and the subsequent stipulated judgment entered by the Superior Court, the Company must provide financial assurance for anticipated costs of remediation activities at its inactive Guadalupe oil field. Also, pursuant to a 1995 settlement agreement between Molycorp and the California Department of Toxic Substances Control (and subsequent final judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of disposing of certain wastes, as well as closing facilities associated with the handling of those wastes, at Molycorp's Mountain Pass, California, facility. Although these costs are likely to be incurred at different times and over a period of many years, the Company believes that these obligations could have a material adverse effect on the Company's results of operations but are not expected to be material to the Company's consolidated financial condition or liquidity.

The total environmental remediation reserves recorded on the consolidated balance sheet represent the Company's estimates of assessment and remediation costs based on currently available facts, existing technology and presently enacted laws and regulations. The remediation cost estimates, in many cases, are based on plans recommended to the regulatory agencies for approval and are subject to future revisions. The ultimate costs to be incurred could exceed the total amounts reserved. The reserve will be adjusted as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties. Therefore, amounts reserved may change substantially in the near term.

The Company maintains insurance coverage intended to reimburse the cost of damages and remediation related to environmental contamination resulting from sudden and accidental incidents under current operations. The purchased coverages contain specified and varying levels of deductibles and payment limits. Although certain of the Company's contingent legal exposures enumerated above are uninsurable due either to insurance policy limitations, public policy or market conditions, management believes that its current insurance program significantly reduces the possibility of an incident causing a material adverse financial impact to the Company.

Certain Litigation and Claims

City of Santa Monica MTBE Lawsuit: In June 2000, the City of Santa Monica (the "City") sued Shell Oil Company and other oil companies, including the Company, for contamination with methyl tertiary butyl ether ("MTBE") and a related chemical of water pumped from its Charnock wellfield (City of Santa Monica v Shell Oil Company et al, California Superior Court, Orange County, Case No. 01CC04331). In August 2001, Shell filed a cross-complaint against the Company and other oil companies, seeking the recovery of the funds it has expended to respond to the contamination. Further proceedings on this cross-complaint remain stayed.

The City's first amended complaint, filed in May 2002, alleges causes of action for strict liability (gasoline containing MTBE as a defective product designed, manufactured and sold without adequate warnings), negligence, trespass, public and private nuisance, declaratory relief and unfair competition. The City seeks damages, a declaration that the defendants are liable for all remedial actions, abatement of nuisance and injunctive relief. The City alleges that releases from sites of units of Shell, ChevronTexaco Corporation and ExxonMobil Corporation were the releases which caused the wellfield to be shut down. Releases from Company sites allegedly impacted the wellfield subsequently.

In July 2002, the City, ChevronTexaco and ExxonMobil announced a proposed settlement, under which the two companies would pay the City $30 million and construct and operate a water treatment plant. Future settlement and/or judgment amounts paid to the City from other defendants would go in part into an operating account, from which the two companies could be reimbursed for part or all of their treatment plant costs, as well as certain other costs. The Company, Tosco Corporation (now a unit of Phillips Petroleum Company) and other defendants, but not the Shell defendants, have been invited to participate in this settlement. The Company is evaluating its position with regard to participation, which would involve its paying the City $7.5 million and contributing to the costs of the treatment plant. However, based on a rigorous technical analysis of the data, the Company believes it has strong defenses to the allegations in the complaint, including the lack of evidence that its former service stations or activities are responsible for any contamination that has reached or threatens the wellfield. The Company also believes it has certain available defenses that the settling defendants and others may not have due to tolling agreements they entered into with the City; and, unlike the Shell defendants and the settling defendants, the Company is neither the object of punitive damages claims nor a cause of the wellfield's being originally shut down. The Company is also subject to potential partial responsibility for liabilities arising from its former gasoline marketing business that was sold to Tosco in 1997. The Company's current analysis does not indicate any such liabilities are likely to be significant.

For several years prior to the City's suit, the EPA and the California Regional Water Quality Control Board have asserted jurisdiction over contamination of groundwater potentially affecting the wellfield, and these agencies have issued a number of orders under RCRA and state law to the Shell defendants and the other defendant oil companies, including the Company, with respect to both investigation of individual facilities and regional contamination, and requiring replacement of water lost to the City, which Shell is currently providing. The impact of the proposed settlement in the City's lawsuit on future government agency actions is uncertain. The Company has submitted to these agencies several technical analyses, which it believes demonstrate that its sites are not a part of any regional contamination problem, but, rather, present, at the most, localized issues which the Company, under agency oversight, has been successfully resolving.

Agrium Litigation: In June 2002, a lawsuit was filed against the Company by Agrium Inc., a Canadian corporation, and a U. S. subsidiary in the California Superior Court, Los Angeles County (Agrium U.S. Inc. and Agrium Inc. v. Union Oil Company of California, Case No. BC275407). The Company subsequently removed the case to the U.S. District Court for the Central District of California (Case No. 02-04769 Nm).

The Agrium entities ("Agrium") allege numerous causes of action relating to their purchase from the Company of a nitrogen-based fertilizer plant on the Kenai Peninsula, Alaska, in September 2000. The primary allegations involve the Company's obligation to supply natural gas to the plant pursuant to a Gas Purchase and Sale Agreement (the "GPSA") between the parties. Agrium alleges that the Company misrepresented the amount of gas reserves available for sale to the plant as of the closing of the transaction and that the Company has failed to develop additional reserves for sale to the plant. Agrium also alleges that

the Company misrepresented the condition of the general effluent sewer at the plant and made misrepresentations regarding other environmental matters.

Agrium seeks damages in an unspecified amount for breach of such representations and warranties, as well as for alleged misconduct by the Company in operating and managing certain oil and gas leases and other facilities. Agrium also seeks declaratory relief concerning the base price of gas under the GPSA, as well as for the calculation of payments under a "Retained Earnout" covenant that entitles the Company to certain contingent payments based on the price of ammonia subsequent to the September 2000 closing. The complaint includes demands for punitive damages and attorneys' fees.

Also in June 2002, the Company filed a lawsuit against Agrium in the U.S. District Court for the Central District of California (Union Oil Company of California v. Agrium Inc. and Agrium U.S. Inc., Case No. 02-04518 Nm(Ctx)). The Company seeks declaratory relief in its favor against the allegations of Agrium set forth above and for judgment on the Retained Earnout in the amount of $16.6 million, together with interest accrued subsequent to May 31, 2002.

The Company believes that certain portions of its disputes with Agrium are subject to binding arbitration under the terms of the GPSA, and has initiated arbitration respecting the gas supply available under that agreement. Agrium claims the dispute resolution provisions of the agreement for the sale of the plant (the "PSA") supersede the arbitration provisions of the GPSA. Agrium has filed motions to stay the Company's lawsuit, to enjoin implementation of the arbitration and for Agrium's lawsuit to be remanded to the state court. A hearing on these motions is set for September 2002. The federal court recently denied a motion by Agrium to temporarily restrain implementation of the arbitration.

The GPSA contains a contractual limit on liquidated damages of $25 million per year, not to exceed a total of $50 million over the life of the agreement. In addition, the PSA contains a limit on damages of $50 million. The Company believes it has a meritorious defense to each of the Agrium claims, but that in any event its exposure to damages for all disputes is limited by the agreements. Agrium alleges that it is entitled to recover damages in excess of those amounts.

Petrobangla Claim: In July 2002, the Company's subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. (which was acquired in 1999 from Occidental Petroleum Corporation and, prior to the recent completion of Bangladesh name-change formalities, was still known in Bangladesh as Occidental of

Bangladesh Ltd.) ("OBL"), received from the Bangladesh Oil, Gas & Mineral Corporation ("Petrobangla") a letter claiming, on behalf of the Bangladesh government and Petrobangla, compensation allegedly due in the amount of $685 million for 246 BCF of recoverable natural gas allegedly "lost and damaged" in a 1997 blowout and ensuing fire during the drilling by OBL, as operator, of the Moulavi Bazar #1 ("MB #1") exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout.

Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractors' operations. Even if some form of compensation were due, the Company and OBL believe that settlement compensation for the blowout was fully addressed in a 1998 Supplemental Agreement to the PSC, which, among other matters, waived OBL's then 50-percent contractor's share (as well as the then 50-percent contractor's share held by the Company's Unocal Bangladesh, Ltd., subsidiary) of entitlement to the recovery of costs incurred in the blowout, waived their right to invoke force majeure in connection with the blowout, and reduced by five percentage points their contractors' profit share (with a concomitant increase in Petrobangla's profit share) of future production from the sands encountered by the MB #1 well to a drill depth of 840 meters or, if the blowout sand reservoir were not deemed commercial, from other commercial fields in the Moulavi Bazar "ring-fenced" area of Block 14. Consequently, the Company and OBL consider the matter closed and OBL has advised Petrobangla that no additional compensation is warranted.

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Tax matters

The company believes it has adequately provided in its accounts for tax items and issues not yet resolved. Several prior material tax issues are unresolved. Resolution of these tax issues impact not only the year in which the items arose, but also the company's tax situation in other tax years. With respect to 1979-1984 taxable years, all issues raised for these years have now been settled, with the exception of the effect of the carryback of a 1993 net operating loss ("NOL") to tax year 1984 and resultant credit adjustments. The 1985-1990 taxable years are before the Appeals division of the Internal Revenue Service. All issues raised with respect to those years have now been settled, with the exception of the effect of the 1993 NOL carryback and resultant adjustments. The Joint Committee on Taxation of the U.S. Congress has reviewed the settled issues with respect to 1979-1990 taxable years and no additional issues have been raised. While all tax issues for the 1979-1990 taxable years have been agreed and reviewed by the Joint Committee, these taxable years will remain open due to the 1993 NOL carryback. The 1993 NOL results from certain specified liability losses, which occurred during 1993, and which resulted in a tax refund of $73 million. Consequently, these tax years will remain open until the specified liability loss, which gave rise to the 1993 NOL, is finally determined by the Internal Revenue Service and is either agreed to with the IRS or otherwise concluded in the Tax Court proceeding. In 1999, the United States Tax Court granted Unocal's motion to amend the pleadings in its Tax Court cases to place the 1993 NOL carryback in issue. The 1991-1994 taxable years are now before the Appeals division of the Internal Revenue Service. The 1995-1997 taxable years are under examination by the Internal Revenue Service.

Pure Resources, Inc. Employment and Severance Agreements

Under circumstances specified in the employment and/or severance agreements entered into between the Company's Pure subsidiary and its officers, each covered officer will have the right to require Pure to purchase its common shares currently held or subsequently obtained by the exercise of any option held by the officer at a calculated "net asset value" per share. The circumstances under which certain officers may exercise this right include the termination of the officer without cause prior to May 25, 2003, termination for any reason after May 24, 2003, a change in control of either Pure or Unocal and other events specified in the agreements. The net asset value per share is calculated by reference to each common share's pro rata amount of the present value of Pure's proved reserves discounted at 10 percent, as defined, times 110 percent, less funded debt, as defined. At June 30, 2002, Pure estimated that the amount it may have to repurchase under these agreements was approximately $92 million, which is reflected as subsidiary stock subject to repurchase on the consolidated balance sheet. The repurchase amount will fluctuate with changes in the net asset value per share. At December 31, 2001, the repurchase amount under these agreements was approximately $70 million.

Other matters

The Company has a lease agreement relating to its Discoverer Spirit deepwater drillship, with a remaining term of approximately three years and three months at June 30, 2002. In 2001, the Company signed a sublease agreement with a third party for a minimum period of 200 days. The completion of the sublease period is currently estimated to be in September 2002. Under the provisions of the agreement, the third party assumed all of the lease payments to the lessor during the sublease period, which began in December 2001. The drillship has a minimum daily rate of approximately $219,000. The future remaining minimum lease payment obligation, excluding the remaining sublease period, was approximately $240 million at June 30, 2002.

In the normal course of business, the Company has performance obligations which are secured by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions but are funded by the Company if exercised. At June 30, 2002, the Company, including its Pure subsidiary, had obtained various surety bonds for approximately $350 million. These surety bonds primarily consisted of bonds for the Company's mining operation discussed in the following paragraph and a bond for $99 million securing the Company's performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten year period that began in January of 1999 and will end in December of 2008. The Company also had obtained approximately $64 million in standby letters of credit at June 30, 2002. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit. In addition, the Company has various other guarantees for approximately $410 million. Approximately $200 million of the $410 million in guarantees would require the Company to obtain a surety bond or a letter of credit, or establish a trust fund if its credit rating drops below investment grade, that is BBB- or Baa3 from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively. Approximately $180 million of the surety bonds, letters of credit and other guarantees that the Company is required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note.

As mentioned in the previous paragraph, the Company's Molycorp subsidiary has permits covering discharges from its Questa, New Mexico, molybdenum mine. Obtaining these permits involved the posting by Molycorp of two bonds totaling

$152 million that provide financial assurance of completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. These costs are based on estimations provided by agencies of the state of New Mexico. Unocal has indemnified the insurance company that issued the bonds with respect to all amounts that may be drawn against them.

The Company has certain investments in entities that it accounts for under the equity method, such as Colonial Pipeline Company. These entities have approximately $1.8 billion of their own debt obligations that are either fully non-recourse or of limited recourse to the Company. Of the total $1.8 billion in equity investee debt, $1.1 billion belongs to the Colonial Pipeline Company, in which the Company holds a 23.44 percent equity interest. The Company guarantees only $27 million of the total $1.8 billion debt obligations.

The Company also has other contingent liabilities with respect to litigation, claims and contractual agreements arising in the ordinary course of business. On the basis of management's assessment of the ultimate amount and timing of possible adverse outcomes and associated costs, none of such matters is presently expected to have a material adverse effect on the Company's consolidated financial condition, liquidity or results of operations.

13. Financial Instruments and Commodity Hedging

Fair values of debt and other long-term instruments - The estimated fair value of the Company's long-term debt at June 30, 2002, including the current portion, was approximately $3.31 billion. The fair value was based on the discounted amounts of future cash outflows using the rates offered to the Company for debt with similar remaining maturities.

The estimated fair value of the mandatorily redeemable convertible preferred securities of the Company's subsidiary trust was approximately $527 million at June 30, 2002. The fair value was based on the trading prices of the preferred securities on June 28, 2002, as reported to the Company.

Commodity hedging activities - During the second quarter of 2002, the Company recognized $1 million in after-tax losses for the ineffectiveness of both cash flow and fair value hedges. For the six months ended June 30, 2002, the earnings impact of ineffectiveness was immaterial. At June 30, 2002, the Company had approximately $9 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future commodity sales for the period beginning July 2002 through October 2004. Of this amount, approximately $3 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Foreign currency contracts - At June 30, 2002, the Company had approximately $1 million of after-tax deferred gains in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future foreign currency denominated payment obligations through December 2003. Of this amount, the losses expected to be reclassified to the consolidated earnings statement during the next twelve months are immaterial.

Interest rate contracts - At June 30, 2002, the Company had approximately $3 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges of interest rate exposure through September 2012. Of this amount, the losses expected to be reclassified to the consolidated earnings statement during the next twelve months are immaterial.

14. Supplemental Condensed Consolidating Financial Information

Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiaries Unocal Capital Trust and Union Oil. Such guarantees are full and unconditional and no subsidiaries of Unocal or Union Oil guarantee these securities.

The following tables present condensed consolidating financial information for (a) Unocal (Parent), (b) the Trust, (c) Union Oil (Parent) and (d) on a combined basis, the subsidiaries of Union Oil (non-guarantor subsidiaries). Virtually all of the Company's operations are conducted by Union Oil and its subsidiaries.

CONDENSED CONSOLIDATING EARNINGS STATEMENT
For the three months ended June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminatio
Revenues					
Sales and operating revenues	$ -	$ -	$ 286	$ 1,298	$ (2
Interest, dividends and miscellaneous income	-	9	-	10	(
Gain (loss) on sales of assets	-	-	1	(2)	
Total revenues	-	9	287	1,306	(2
Costs and other deductions					
Purchases, operating and other expenses	1	-	259	836	(2
Depreciation, depletion and amortization	-	-	93	162	
Impairments	-	-	21	-	
Dry hole costs	-	-	2	11	
Interest expense	9	1	35	9	(
Distributions on convertible preferred securities	-	8	-	-	
Total costs and other deductions	10	9	410	1,018	(2
Equity in earnings of subsidiaries	118	-	198	-	(3
Earnings from equity investments	-	-	2	49	
Earnings from continuing operations before income taxes and minority interests	108	-	77	337	(3
Income taxes	(3)	-	(41)	139	
Minority interests	-	-	-	1	
Earnings from continuing operations	111	-	118	197	(3
Earnings from discontinued operations	-	-	-	1	
Net earnings	$ 111	$ -	$ 118	$ 198	$ (3

CONDENSED CONSOLIDATING EARNINGS STATEMENT
For the three months ended June 30, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminatio
Revenues					
Sales and operating revenues	$ -	$ -	$ 487	$ 1,604	$ (4
Interest, dividends and miscellaneous income	-	9	4	8	(
Gain on sales of assets	-	-	1	-	
Total revenues	-	9	492	1,612	(4
Costs and other deductions					
Purchases, operating and other expenses	1	-	272	1,112	(4
Depreciation, depletion and amortization	-	-	91	154	
Dry hole costs	-	-	24	23	
Interest expense	9	1	40	8	(
Distributions on convertible preferred securities	-	8	-	-	
Total costs and other deductions	10	9	427	1,297	(4
Equity in earnings of subsidiaries	252	-	202	-	(4
Earnings from equity investments	-	-	10	39	
Earnings from continuing operations before income taxes and minority interests	242	-	277	354	(4
Income taxes	(4)	-	37	147	
Minority interests	-	-	-	5	
Earnings from continuing operations	246	-	240	202	(4
Earnings from discontinued operations	-	-	12	-	
Cumulative effect of accounting change	-	-	-	-	
Net earnings	$ 246	$ -	$ 252	$ 202	$ (4

CONDENSED CONSOLIDATING EARNINGS STATEMENT
For the six months ended June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eli
Revenues					
Sales and operating revenues	$ -	$ -	$ 495	$ 2,279	
Interest, dividends and miscellaneous income	-	17	7	15	
Gain (loss) on sales of assets	-	-	14	(13)	
Total revenues	-	17	516	2,281	
Costs and other deductions					
Purchases, operating and other expenses	3	-	486	1,470	
Depreciation, depletion and amortization	-	-	180	299	
Impairments	-	-	21	-	
Dry hole costs	-	-	17	24	
Interest expense	17	1	78	18	

Distributions on convertible preferred securities	-	16	-	-
Total costs and other deductions	20	17	782	1,811
Equity in earnings of subsidiaries	148	-	326	-
Earnings from equity investments	-	-	2	86
Earnings from continuing operations before income taxes and minority interests	128	-	62	556
Income taxes	(7)	-	(86)	228
Minority interests	-	-	-	3
Earnings from continuing operations	135	-	148	325
Earnings from discontinued operations	-	-	-	1
Cumulative effect of accounting change	-	-	-	-
Net earnings	$ 135	$ -	$ 148	$ 326

CONDENSED CONSOLIDATING EARNINGS STATEMENT
For the six months ended June 30, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eli
Revenues					
Sales and operating revenues	$ -	$ -	$ 1,180	$ 3,686	
Interest, dividends and miscellaneous income	5	17	3	13	
Gain on sales of assets	-	-	1	-	
Total revenues	5	17	1,184	3,699	
Costs and other deductions					
Purchases, operating and other expenses	2	-	667	2,734	
Depreciation, depletion and amortization	-	-	177	291	
Impairments	-	-	-	-	
Dry hole costs	-	-	34	53	
Interest expense	17	1	85	13	
Distributions on convertible preferred securities	-	16	-	-	
Total costs and other deductions	19	17	963	3,091	
Equity in earnings of subsidiaries	551	-	413	-	
Earnings from equity investments	-	-	8	83	
Earnings from continuing operations before income taxes and minority interests	537	-	642	691	
Income taxes	(5)	-	106	269	
Minority interests	-	-	-	9	
Earnings from continuing operations	542	-	536	413	
Earnings from discontinued operations	-	-	16	-	
Cumulative effect of accounting change	-	-	(1)	-	

Net earnings	$ 542	$ -	$ 551	$ 413

CONDENSED CONSOLIDATING BALANCE SHEET
At June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	El
Assets					
Current assets					
Cash and cash equivalents	$ 1	$ -	$ 61	$ 99	
Accounts and notes receivable - net	51	-	56	792	
Inventories	-	-	9	102	
Other current assets	-	-	130	31	
Total current assets	52	-	256	1,024	
Investments and long-term receivables - net	4,123	-	4,455	1,078	
Properties - net	-	-	2,141	5,600	
Other assets	3	541	456	2,130	
Total assets	$4,178	$ 541	$ 7,308	$ 9,832	
Liabilities and Stockholders' Equity					
Current liabilities					
Accounts payable	$ -	$ -	$ 242	$ 637	
Current portion of long-term debt and capital leases	-	-	-	8	
Other current liabilities	46	3	144	372	
Total current liabilities	46	3	386	1,017	
Long-term debt and capital leases	-	-	2,489	622	
Deferred income taxes	-	-	(20)	698	
Accrued abandonment, restoration and environmental liabilities	-	-	305	282	
Other deferred credits and liabilities	541	-	376	2,695	
Subsidiary stock subject to repurchase	-	-	-	92	
Minority interests	-	-	-	313	
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-	
Stockholders' equity	3,591	16	3,772	4,113	
Total liabilities and stockholders' equity	$4,178	$ 541	$ 7,308	$ 9,832	

CONDENSED CONSOLIDATING BALANCE SHEET
At December 31, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	El

Assets				
Current assets				
Cash and cash equivalents	$ -	$ -	$ 62	$ 128
Accounts and notes receivable - net	51	-	154	693
Inventories	-	-	3	99
Other current assets	-	-	122	34
Total current assets	51	-	341	954
Investments and long-term receivables - net	4,032	-	4,143	968
Properties - net	-	-	2,149	5,365
Other assets	3	541	214	2,403
Total assets	$4,086	$ 541	$ 6,847	$ 9,690
Liabilities and Stockholders' Equity				
Current liabilities				
Accounts payable	$ -	$ -	$ 278	$ 596
Current portion of long-term debt and capital leases	-	-	-	9
Other current liabilities	42	3	145	400
Total current liabilities	42	3	423	1,005
Long-term debt and capital leases	-	-	2,181	716
Deferred income taxes	-	-	(71)	698
Accrued abandonment, restoration and environmental liabilities	-	-	293	297
Other deferred credits and liabilities	541	-	312	2,821
Subsidiary stock subject to repurchase	-	-	-	70
Minority interests	-	-	-	309
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-
Stockholders' equity	3,503	16	3,709	3,774
Total liabilities and stockholders' equity	$4,086	$ 541	$ 6,847	$ 9,690

CONDENSED CONSOLIDATING CASH FLOWS
For the six months ended June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elim
Cash Flows from Operating Activities	$ 80	$ -	$ (110)	$ 656	
Cash Flows from Investing Activities					
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(213)	(617)	
Proceeds from sales of assets and discontinued operations	-	-	15	32	
Net cash used in investing activities	-	-	(198)	(585)	

Cash Flows from Financing Activities				
Change in long-term debt and capital leases	-	-	307	(96)
Dividends paid on common stock	(98)	-	-	-
Other	19	-	-	(4)
Net cash provided by (used in) financing activities	(79)	-	307	(100)
Net increase in cash and cash equivalents	1	-	(1)	(29)
Cash and cash equivalents at beginning of period	-	-	62	128
Cash and cash equivalents at end of period	$ 1	$ -	$ 61	$ 99

CONDENSED CONSOLIDATING CASH FLOWS
For the six months ended June 30, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elim
Cash Flows from Operating Activities	$ 83	$ -	$ 572	$ 589	
Cash Flows from Investing Activities					
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(373)	(868)	
Proceeds from sales of assets and discontinued operations	-	-	28	2	
Net cash used in investing activities	-	-	(345)	(866)	
Cash Flows from Financing Activities					
Change in long-term debt and capital leases	-	-	(5)	371	
Dividends paid on common stock	(97)	-	-	-	
Other	13	-	-	(10)	
Net cash provided by (used in) financing activities	(84)	-	(5)	361	
Net increase (decrease) in cash and cash equivalents	(1)	-	222	84	
Cash and cash equivalents at beginning of period	1	-	84	150	
Cash and cash equivalents at end of period	$ -	$ -	$ 306	$ 234	

15. Segment Data

The Company's reportable segments are: Exploration and Production, Trade, Midstream, and Geothermal and Power Operations. General corporate overhead, unallocated costs and other miscellaneous operations, including real estate, carbon and minerals and those businesses that were sold, are included under the

Corporate and Other heading.

Segment Information For the Three Months ended June 30, 2002 Millions of dollars	Exploration & Produc North America Lower 48	 Alaska	 Canada	 F
Sales & operating revenues	$ 124	$ 73	$ 61	
Other income (loss) (a)	1	-	-	
Inter-segment revenues	234	-	-	
Total	359	73	61	
Earnings (loss) from equity investments	1	-	-	
Earnings (loss) from continuing operations	20	(5)	6	
Earnings from discontinued operations	-	-	-	
Net earnings (loss)	20	(5)	6	
Assets (at June 30, 2002)	3,255	352	1,125	

	Midstream	Geothermal & Power Operations	Corporate & Other Administrative & General	 Net Interest Expense	 Envi & Li
Sales & operating revenues	$ 76	$ 33	$ -	$ -	
Other income (loss) (a)	1	2	-	5	
Inter-segment revenues	4	-	-	-	
Total	81	35	-	5	
Earnings (loss) from equity investments	18	5	-	-	
	-				
Earnings (loss) from continuing operations	23	14	(19)	(28)	
Earnings from discontinued operations	-	-	-	-	
Net earnings (loss)	23	14	(19)	(28)	
Assets (at June 30, 2002)	506	595	-	-	

Segment Information For the Three Months ended June 30, 2001 Millions of dollars	Exploration & Production North America Lower 48	 Alaska	 Canada	 Inter Far Ea

Sales & operating revenues	$ 167	$ 63	$ 97	$ 26
Other income (loss) (a)	-	-	2	(
Inter-segment revenues	406	-	-	5
Total	573	63	99	32
Earnings from equity investments	8	-	-	
Earnings (loss) from continuing operations	142	13	14	11
Earnings from discontinued operations	-	-	-	
Cumulative effect of accounting change	-	-	-	
Net earnings (loss)	142	13	14	11
Assets (at December 31, 2001)	3,345	344	1,015	2,46

	Midstream	Geothermal & Power Operations	Corporate & Other		
			Administrative & General	Net Interest Expense	Environ & Litig
Sales & operating revenues	$ 39	$ 45	$ -	$ -	$
Other income (loss) (a)	1	4	-	7	
Inter-segment revenues	2	-	-	-	
Total	42	49	-	7	
Earnings from equity investments	19	-	-	-	
Earnings (loss) from continuing operations	18	2	(21)	(32)	(1
Earnings from discontinued operations	-	-	-	-	
Cumulative effect of accounting change	-	-	-	-	
Net earnings (loss)	18	2	(21)	(32)	(1
Assets (at December 31, 2001)	479	594	-	-	

Segment Information For the Six Months ended June 30 2002 Millions of dollars	Exploration & Producti			
	North America			In
	Lower 48	Alaska	Canada	Far
Sales & operating revenues	$ 237	$ 124	$ 100	$
Other income (loss) (a)	4	-	-	
Inter-segment revenues	400	-	-	
Total	641	124	100	

Earnings (loss) from equity investments	-	-	-	
Earnings (loss) from continuing operations	24	(11)	(3)	
Earnings from discontinued operations	-	-	-	
Net earnings (loss)	24	(11)	(3)	
Assets (at June 30, 2002)	3,255	352	1,125	2

	Midstream	Geothermal & Power Operations	Corporate & Other Administrative & General	Net Interest Expense	Envi & Li
Sales & operating revenues	$ 139	$ 61	$ -	$ -	
Other income (loss) (a)	2	4	-	8	
Inter-segment revenues	6	-	-	-	
Total	147	65	-	8	
Earnings (loss) from equity investments	37	2	-	-	
Earnings (loss) from continuing operations	42	20	(43)	(65)	
Earnings from discontinued operations	-	-	-	-	
Net earnings (loss)	42	20	(43)	(65)	
Assets (at June 30, 2002)	506	595	-	-	

Segment Information For the Six Months ended June 30, 2001 Millions of dollars	Exploration & Production North America Lower 48	Alaska	Canada	Intern Far Eas
Sales & operating revenues	$ 328	$ 135	$ 129	$ 501
Other income (loss) (a)	1	-	1	(6
Inter-segment revenues	972	-	-	110
Total	1,301	135	130	605
Earnings from equity investments	14	-	-	19
Earnings (loss) from continuing operations	383	32	11	219
Earnings from discontinued operations	-	-	-	-
Cumulative effect of accounting change	-	-	-	-
Net earnings (loss)	383	32	11	219

Assets (at December 31, 2001)	3,345	344	1,015	2,463

	Midstream	Geothermal & Power Operations	Administrative & General	Net Interest Expens	Corporate & Other Environm & Litiga
Sales & operating revenues	$ 139	$ 89	$ -	$ -	$ -
Other income (loss) (a)	2	7	-	13	-
Inter-segment revenues	4	-	-	-	-
Total	145	96	-	13	-
Earnings from equity investments	28	-	-	-	-
Earnings (loss) from continuing operations	27	3	(44)	(65)	(50
Earnings from discontinued operations	-	-	-	-	-
Cumulative effect of accounting change	-	-	-	-	-
Net earnings (loss)	27	3	(44)	(65)	(50
Assets (at December 31, 2001)	479	594	-	-	-

16. Subsequent Event

In July 2002, the Company's Unocal Geothermal of Indonesia, Ltd. ("UGI") subsidiary and Dayabumi Salak Pratama, Ltd. ("DSPL"), a 50-percent equity investee of UGI, reached agreement over pricing and production issues at its Gunung Salak geothermal project in Indonesia with PT. PLN (Persero) ("PLN"), the Indonesian state-owned electricity company, and Pertamina, the Indonesian state-owned oil and natural gas company. The new agreement extends the primary terms of the Joint Operation Contract and Energy Sales Contract ("ESC") to 2040 and also contains provisions to extend the deadline for transferring to PLN generating plants currently operated by DSPL plus any additional plants subsequently developed and operated by DSPL or the Company to the expiration date of the ESC. The new agreement lowers the selling price of electricity delivered by DSPL from 8.49 cents per kilowatt-hour (kWh) to 4.45 cents per kWh and steam supplied to PLN by UGI from 4.25 cents per kWh to 3.75 cents per kWh. Under the terms of the amended ESC both the selling price for electricity and the selling price for geothermal steam are indexed for changes in foreign exchange rates and inflation. The new agreement also provides for payment by PLN of a portion of the past due receivable balances to the Company while the Company foregoes a portion of the receivables.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion and analysis of the consolidated financial condition and results of operations of the Company should be read in conjunction with Management's Discussion and Analysis in Item 7 of the Unocal's 2001 Annual

Report on Form 10-K.

CONSOLIDATED RESULTS

Millions of dollars	For the Three Months Ended June 30, 2002	2001
Earnings from continuing operations	$ 113	$ 235
Earnings from discontinued operations	1	12
Cumulative effect of accounting change	-	-
Net earnings	$ 114	$ 247

Continuing Operations

Second Quarter Results: Earnings from continuing operations were $113 million in the second quarter of 2002 compared to $235 million for the same period a year ago. The decrease was primarily due to lower natural gas production and lower prices for natural gas and liquids. The second quarter of 2002 was impacted by lower production compared with the same period a year ago, principally in the Lower 48 operations, which reflected lower Gulf of Mexico natural gas production stemming from a decline in Ship Shoal Block 295 ("Muni field") production(10 MMcf/d, net of royalty, in the second quarter of 2002 versus 126 MMcf/d, net of royalty, in the second quarter of 2001) and reduced second-half 2001 drilling activity, compared to the first half of 2001, in response to lower commodity prices. Worldwide net daily production in the second quarter of 2002 averaged 486,000 BOE per day compared with 516,000 BOE per day a year ago. The lower worldwide production reduced net earnings by approximately $70 million.

Lower natural gas prices reduced net earnings by approximately $25 million, while lower liquids prices reduced net earnings by approximately $15 million. The Company's worldwide average natural gas price, which was not impacted by hedging activities, was $2.80 per Mcf in the second quarter of 2002, which was a decrease of 61 cents per Mcf, or 18 percent, from the same period a year ago. The Company's second quarter of 2001 included a loss of one cent per Mcf from hedging activities. In the second quarter of 2002, the Company's worldwide average liquids price was $22.63 per Bbl, which was a decrease of $1.70 per Bbl, or 7 percent, from the same period a year ago. The Company's hedging program had no impact on the average liquids price in the second quarter of 2002 while the second quarter of 2001 included a loss of 5 cents per Bbl from hedging activities.

The second quarter of 2002 was also negatively impacted by a $12 million after-tax impairment in Alaska and a $12 million after-tax restructuring provision for the Gulf Region business unit, which is part of the U.S. Lower 48 operations of the Exploration and Production segment. After-tax provisions for environmental and litigation matters were $13 million in the second quarter of 2002, compared with $14 million in the same period a year ago. The second quarter of 2002 also included an after-tax gain of $4 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives recorded by the Company's Northrock Resources Ltd. ("Northrock") subsidiary, compared to an after-tax gain of $21 million in the same period a year ago.

Six Months Results: Earnings from continuing operations were $135 million in the first six months of 2002 compared to $527 million for the same period a year ago. The decrease was primarily due to lower commodity prices and lower worldwide production. Lower natural gas prices reduced net earnings by approximately $155 million, while lower liquids prices reduced net earnings by approximately $50 million. The Company's worldwide average natural gas price, including a benefit of 6 cents per Mcf from hedging activities, was $2.61 per Mcf for the first six months of 2002, which was a decrease of $1.28 per Mcf or 33 percent from the $3.89 per Mcf, including a loss of 3 cents per Mcf from hedging activities, from the same period a year ago. In the first six months of 2002, the Company's worldwide average liquids price was $20.53 per Bbl, including a benefit of 2 cents per Bbl from hedging activities, which was a decrease of $3.92 per Bbl or 16 percent from the $24.45 per Bbl, including a loss of 5 cents per Bbl from hedging activities, from the same period a year ago.

The results in the first six months of 2002 were also impacted by lower production compared with the same period a year ago, which reduced net earnings by approximately $190 million. The impact was principally in the Lower 48 operations, which reflected lower Gulf of Mexico natural gas production stemming from the decline in Muni field production(13 MMcf/d net of royalty in the first six months of 2002 versus 91 MMcf/d net of royalty for the first six months of 2001) and the reduction in the second-half 2001 drilling activity. The first six months of 2002 included $6 million after-tax in pension related expenses, compared to a benefit of $5 million after-tax in the first six months of 2001.

The results in the first six months of 2002 included the $12 million after-tax impairment in Alaska and the $12 million after-tax restructuring provision for the Gulf Region business unit. After-tax provisions for environmental and litigation matters were $34 million in the first six months of 2002, compared with $45 million in the same period a year ago. The first six months of 2002 also included a $2 million after-tax gain from an insurance settlement reached with insurers for the recovery of amounts previously paid out for environmental pollution claims and related costs and a $2 million after-tax gain adjustment related to a Lower 48 prior year asset sale. The first six months of 2001 included an after-tax gain of $4 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives by the Company's Northrock subsidiary, while the first six months of 2002 did not have any gains or losses.

Revenues: Total revenues from continuing operations in the second quarter of 2002 were $1.36 billion compared with $1.70 billion for the same period a year ago. In the first six months of 2002, total revenues from continuing operations were $2.39 billion compared with $3.91 billion for the same period a year ago. The decreases, in both the quarter and six months amounts, primarily reflected lower hydrocarbon commodity prices, lower domestic natural gas production and reduced activity in the purchase and resale of third party crude oil barrels intended to take advantage of market price differentials. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets.

Discontinued Operations

The second quarter of 2002 included a $1 million after-tax gain from discontinued operations, related to a participation payment received from the purchaser of the Company's former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. The second quarter of 2001 included a similar after-tax gain for $12 million. The total after-tax gain in the first six months of 2001 from discontinued operations was $16 million.

Cumulative Effect of Accounting Change

In the first quarter of 2001, the Company recorded a one-time non-cash $1 million after-tax charge consisting of the cumulative effect of a change in accounting principle related to the initial adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities".

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Exploration and Production

The Company engages in oil and gas exploration, development and production worldwide. The results of this segment are discussed under two geographical breakdowns of North America and International:

North America - Included in this category are the U.S. Lower 48, Alaska and Canada oil and gas operations. The emphasis of the U.S. Lower 48 operations is on the onshore, the shelf and deepwater areas of the Gulf of Mexico region. The U.S. Lower 48 also includes the consolidated results of Pure Resources, Inc. ("Pure"), which operates primarily in the Permian and San Juan Basins in west Texas and New Mexico, the Gulf of Mexico region and offshore in the Gulf of Mexico. A substantial portion of the crude oil and natural gas produced in the U.S. Lower 48 operations, excluding that of Pure, is sold to the Company's Trade business segment. The remainder of North America production, including the production of Pure and Northrock in Canada, is sold to third parties. In Alaska, natural gas production, pursuant to agreements with the purchaser of the Company's former agricultural products business, is sold to a fertilizer plant in Nikiski, Alaska. In addition, the Company, including Pure, uses hydrocarbon derivative financial instruments such as futures, swaps and options to hedge portions of the Company's exposure to commodity price fluctuations.

Second Quarter Results: After-tax earnings were $21 million in the second quarter of 2002 compared to $169 million for the same period a year ago, which was a decrease of $148 million. The decrease was primarily due to lower natural gas production and lower natural gas and liquids prices. Lower natural gas production during the second quarter of 2002 compared to the same period a year ago reduced after-tax earnings by approximately $55 million. North America average net daily natural gas production was 935 MMcf/d in the second quarter of 2002 compared to 1,132 MMcf/d in the same period a year ago, which was a decrease of 17 percent. Natural gas production in the Lower 48 was 766 MMcf/d in the second quarter of 2002 compared to 954 MMcf/d in the same period a year ago. This decline reflected lower natural gas production from the Gulf of Mexico shelf area including production from the Muni field, which averaged 10 MMcf/d, net of royalty, in the second quarter of 2002 compared to 126 MMcf/d, net of royalty, during the second quarter of 2001. Lower natural gas prices reduced after-tax earnings by approximately $45 million, while lower liquids prices reduced after-tax earnings by approximately $5 million. The average natural gas price for North America, including a gain of one cent per Mcf from hedging activities, was $2.97 per Mcf in the second quarter of 2002 compared to $4.16 per Mcf in the same period a year ago, which included a loss of 3 cents per Mcf from hedging activities. In the second quarter of 2002, the Company's North America average liquids price, with no impact from hedging activities, was $22.47 per Bbl compared to $23.45 per Bbl in the same period a year ago, which included a loss of 9 cents per Bbl from hedging activities. The results in the second quarter of 2002 were also negatively impacted by a $12 million after-tax impairment in Alaska and a $12 million after-tax restructuring provision for the Gulf Region business unit. In addition, the Company's Northrock subsidiary recorded $4 million in after-tax gains related to accruals and realized gains and losses for non-hedging commodity derivative positions during the second quarter of 2002 compared to an after-tax gain of $21 million in the same period a year ago.

Restructuring: In June 2002, the Company adopted a restructuring plan that resulted in a $12 million after-tax restructuring charge. The restructuring charge covers the costs of terminating approximately 200 employees in the Company's Sugar Land, Texas office and field locations. All of the affected employees have been terminated or had received termination notices as of June 30, 2002. The restructuring plan involves organizational changes to eliminate unnecessary work processes in the Company's Gulf Region business unit, which is part of the U.S. Lower 48 operations.

The restructuring charge was included in the results of the U.S. Lower 48 section of the Exploration & Production segment. Cash expenditures related to the restructuring plan are expected to be approximately $9 million in the second half of 2002 and $7 million in 2003. The Company expects the plan to reduce future salaries and benefits by an estimated $20 million pre-tax annually.

Six Months Results: After-tax earnings were $10 million in the first six months of 2002 compared to $426 million for the same period a year ago, which was a decrease of $416 million. The decrease was primarily due to lower natural gas and liquids prices and lower natural gas production. The average natural gas price for North America, including a gain of 11 cents per Mcf from hedging activities, was $2.66 per Mcf in the first six months of 2002 compared to $5.01 per Mcf in the same period a year ago, which included a loss of 6 cents per Mcf from hedging activities. In the first six months of 2002, the Company's North America average liquids price, including a benefit of 3 cents per Bbl from hedging activities, was $19.88 per Bbl compared to $23.96 per Bbl in the same period a year ago, which included a loss of 9 cents per Bbl from hedging activities. The lower natural gas prices reduced after-tax earnings by approximately $200 million, while the lower liquids prices reduced after-tax earnings by approximately $40 million. Natural gas production in North America was 934 MMcf/d in the first six months of 2002 compared to 1,138 MMcf/d in the same period a year ago. This decline reflected primarily lower natural gas production from the Gulf of Mexico shelf area including production from the Muni field, which averaged 13 MMcf/d net of royalty in the first six months of 2002 compared to 91 MMcf/d net of royalty during the first six months of 2001. Lower natural gas production during the first six months of 2002 compared to the same period a year ago reduced after-tax earnings by approximately $130 million. The results in the first six months of 2002 also included the $12 million after-tax impairment in Alaska and the $12 million after-tax restructuring provision for the Gulf Region business unit. The first six months of 2001 included an after-tax gain of $4 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives by the Company's Northrock subsidiary, while the first six months of 2002 did not have any gains or losses. Dry hole costs in the first six months of 2002 were lower by $18 million after-tax than the same period a year ago, primarily due to lower drilling activity in the Gulf of Mexico.

International - Unocal's International operations include oil and gas exploration and production activities outside of North America. The Company operates or participates in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. International operations also include the Company's exploration and development activities primarily in Asia, Latin America and West Africa.

Second Quarter Results: After-tax earnings totaled $125 million in the second quarter of 2002 compared to $118 million in the same period a year ago, which was an increase of $7 million. The increase was primarily due to $8 million in higher liquids sales volumes, $7 million in higher natural gas prices and $8 million in lower dry hole costs. These positive factors were partially offset by $9 million in lower liquids prices and $8 million in higher tax expense due to higher effective tax rates, primarily due to changes in the Thai baht/U.S. dollar exchange rate. Liquids sales volumes increased primarily due to the startup of oil production in Thailand. The average natural gas price for International operations was $2.64 per Mcf in the second quarter of 2002, which was an increase of 3 percent from the same period a year ago. Dry hole costs in the second quarter of 2002 were lower primarily due to exploratory dry holes recorded during the second quarter of 2001 in Brazil and Gabon. The average liquids price for International operations was $22.84 per Bbl in the second quarter of 2002, which was a decrease of $2.77 per Bbl, or 11 percent, from the same period a year ago.

Six Months Results: After-tax earnings totaled $227 million in the first six months of 2002 compared to $246 million in the same period a year ago, which was a decrease of $19 million. The decrease was primarily due to $20 million in lower liquids prices and $15 million in higher tax expense due to higher effective tax rates, primarily due to changes in the Thai baht/U.S. dollar exchange rate. The average liquids price for International operations was $21.43 per Bbl in the first six months of 2002, which was a decrease of $3.67 per Bbl, or 15 percent, from the same period a year ago. These negative factors were partially offset by $7 million in higher natural gas prices and $11 million in lower dry hole costs. The average natural gas price for International operations was $2.56 per Mcf in the first six months of 2002 compared with $2.54 per Mcf in the same period a year ago. Dry hole costs for the six months of 2002 were lower primarily due to the 2001 exploratory dry holes in Brazil and Gabon.

OPERATING HIGHLIGHTS

	For the Three Months Ended June 30,		Fo E
	2002	2001	
North America Net Daily Production			
Liquids (thousand barrels)			
Lower 48 (a) (b)	54	59	
Alaska	25	24	
Canada	17	15	
Total liquids	96	98	
Natural gas - dry basis (million cubic feet)			
Lower 48 (a) (b)	766	954	
Alaska	77	93	
Canada	92	85	
Total natural gas	935	1,132	
North America Average Prices (excluding hedging activities) (c) (d)			
Liquids (per barrel)			
Lower 48	$ 23.48	$ 24.72	$
Alaska	$ 20.86	$ 22.27	$
Canada	$ 21.92	$ 20.84	$
Average	$ 22.47	$ 23.54	$
Natural gas (per mcf)			
Lower 48	$ 3.12	$ 4.62	
Alaska	$ 1.57	$ 1.20	
Canada	$ 2.90	$ 2.85	

Average	$ 2.96	$ 4.19	
North America Average Prices (including hedging activities) (c) (d)			
Liquids (per barrel)			
Lower 48	$ 23.47	$ 24.57	$
Alaska	$ 20.86	$ 22.27	$
Canada	$ 21.92	$ 20.84	$
Average	$ 22.47	$ 23.45	$
Natural gas (per mcf)			
Lower 48	$ 3.12	$ 4.62	
Alaska	$ 1.57	$ 1.20	
Canada	$ 2.97	$ 2.48	
Average	$ 2.97	$ 4.16	

OPERATING HIGHLIGHTS (CONTINUED)

	For the Three Months Ended June 30,		Fo E
	2002	2001	
International Net Daily Production (e)			
Liquids (thousand barrels)			
Far East	54	48	
Other (a)	20	19	
Total liquids	74	67	
Natural gas - dry basis (million cubic feet)			
Far East	883	908	
Other (a)	79	69	
Total natural gas	962	977	
International Average Prices (f)			
Liquids (per barrel)			
Far East	$ 22.50	$ 24.91	$
Other	$ 23.91	$ 27.51	$
Average	$ 22.84	$ 25.61	$
Natural gas (per mcf)			
Far East	$ 2.63	$ 2.54	$
Other	$ 2.79	$ 2.92	$
Average	$ 2.64	$ 2.56	$
Worldwide Net Daily Production (a) (b) (e)			
Liquids (thousand barrels)	170	165	
Natural gas - dry basis (million cubic feet)	1,897	2,109	
Barrels oil equivalent (thousands)	486	516	
Worldwide Average Prices (excluding hedging activities) (c) (d)			
Liquids (per barrel)	$ 22.63	$24.38	$
Natural gas (per mcf)	$ 2.80	$ 3.42	$
Worldwide Average Prices (including hedging activities) (c) (d)			
Liquids (per barrel)	$ 22.63	$24.33	$
Natural gas (per mcf)	$ 2.80	$ 3.41	$

TRADE

The Trade segment externally markets the majority of the Company's worldwide liquids production, excluding that of Pure, and North American natural gas production, excluding that of Pure and the Alaska business unit. It is also responsible for executing various derivative contracts on behalf of the Company's Exploration and Production segment, excluding Pure, in order to manage the Company's exposure to commodity price changes. The Trade segment also purchases liquids and natural gas from certain of the Company's royalty owners, joint venture partners and other unaffiliated oil and gas producing and trading companies for resale. In addition, the segment trades hydrocarbon derivative instruments to manage exposures to commodity price fluctuations for which hedge accounting is not used and to exploit anticipated opportunities arising from commodity price fluctuations. These general risk-management and trading activities are subject to internal restrictions, including value at risk limits, which measure the Company's potential loss from likely changes in market prices. The segment also purchases limited amounts of physical commodity inventories for energy trading purposes when arbitrage opportunities arise.

Second Quarter Results: After-tax earnings totaled $1 million in the second quarter of 2002 compared to $4 million in the same period a year ago. The decrease was primarily due to lower results related to domestic natural gas and crude oil marketing activities.

Sales and operating revenues from the Trade business segment were $645 million in the second quarter of 2002 compared to $925 million in the same period a year ago, which was a decrease of $280 million. These revenues represented approximately 48 percent and 55 percent of the Company's total sales and operating revenues for the second quarters of 2002 and 2001, respectively. In the second quarter of 2002, natural gas revenues declined by $160 million primarily due to lower commodity prices and lower domestic production volumes. Crude oil revenues declined by $115 million, primarily due to reduced activity in the purchase and resale of third party barrels intended to take advantage of marketing opportunities. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets.

Six Months Results: After-tax earnings totaled $2 million in the first six months of 2002 compared to $7 million in the same period a year ago. The decrease was primarily due to lower results related to domestic natural gas marketing activities.

Sales and operating revenues were $1,100 million in the first six months of 2002 compared to $2,428 million in the same period a year ago, which was a decrease of $1,328 million. These revenues represented approximately 46 percent and 62 percent of the Company's total sales and operating revenues for the first six months of 2002 and 2001, respectively. In the first six months of 2002, natural gas revenues declined by $625 million primarily due to lower commodity prices and lower domestic production volumes. Crude oil revenues declined by $640 million, primarily due to reduced activity in the purchase and resale of third party barrels intended to take advantage of market price differentials. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets.

MIDSTREAM

The Midstream segment is comprised of the Company's equity interests in petroleum pipeline companies, wholly-owned pipeline systems throughout the U.S., and the Company's North America gas storage business.

Second Quarter Results: After-tax earnings totaled $23 million in the second quarter of 2002 compared to $18 million in the same period a year ago. The increase was due primarily to improved results in the gas storage business.

Six Months Results: After-tax earnings totaled $42 million in the first six months of 2002 compared to $27 million in the same period a year ago. The increase was due primarily to $4 million in improved throughput volumes from the pipeline business and a $6 million asset write-down related to a Colonial Pipeline Company investment that was recorded in the first six months of 2001. In addition, after-tax earnings in the gas storage business in the first six months of 2002 have improved by $5 million compared with the same period a year ago.

GEOTHERMAL AND POWER OPERATIONS

The Geothermal and Power Operations business segment produces geothermal steam for power generation, with operations in the Philippines and Indonesia. The segment's activities also include the operation of power plants in Indonesia and equity interests in gas-fired power plants in Thailand. The Company's non-exploration and production business development activities, primarily power-related, are also included in this segment.

Second Quarter Results: After-tax earnings totaled $14 million in the second quarter of 2002 compared to $2 million in the same period a year ago. The improved results were primarily due to approximately $7 million after-tax in lower receivable provisions related to geothermal operations in Indonesia and $4 million after-tax in improved equity earnings from the Company's investments in non-geothermal power plants in Thailand.

Six Months Results: After-tax earnings totaled $20 million in the first six months of 2002 compared to $3 million in the same period a year ago. The improved results were primarily due to approximately $15 million after-tax in lower receivable provisions related to geothermal operations in Indonesia.

Agreements Reached on Indonesia Geothermal Contracts: In July 2002, the Company's Unocal Geothermal of Indonesia, Ltd. ("UGI"), subsidiary and Dayabumi Salak Pratama, Ltd. ("DSPL"), a 50-percent equity investee of UGI, reached agreement over pricing and production issues at its Gunung Salak geothermal project in Indonesia with PT. PLN (Persero) ("PLN"), the Indonesian state-owned electricity company, and Pertamina, the Indonesian state-owned oil and natural gas company.

Gunung Salak is a 330-megawatt (nominal installed nameplate rating) geothermal production and electricity generation project on the western side of the island of Java. UGI operates the steam fields as a contractor to Pertamina and delivers geothermal steam to PLN, which operates three electricity-generating plants at Salak. UGI also delivers steam to DSPL for three generating plants that supply electricity to PLN on behalf of Pertamina.

The new agreement extends the primary terms of the Joint Operation Contract and Energy Sales Contract ("ESC") to 2040. The new agreement increases the Unit Rated Capacities for the generating plants operated by DSPL by 32 megawatts thereby increasing minimum take-or-pay amounts payable under the ESC and also includes a commitment by PLN to accept as much steam and electricity as possible over the take-or-pay quantities in order to meet increased demand. In addition, the agreement reaffirms the Government of Indonesia guarantee of PLN's obligations to UGI, DSPL, Pertamina and the project's lenders.

The new agreement lowers the selling price of electricity delivered by DSPL from 8.49 cents per kilowatt-hour (kWh) to 4.45 cents per kWh and steam supplied to PLN by UGI from 4.25 cents per kWh to 3.75 cents per kWh. Under the terms of the amended ESC both the selling price for electricity and the selling price for geothermal steam are indexed for changes in foreign exchange rates and inflation.

The new agreement also provides for payment by PLN of a portion of the past due receivable balances to the Company while the Company foregoes a portion of the receivables. As of June 30, 2002, the Company's Indonesian Geothermal business unit had a gross receivable balance of approximately $455 million. In July 2002, the Company received $51 million from PLN in payment of a portion of the past due receivable balances. The Company will retain a receivable balance of $93 million plus interest and expects to collect in full this amount over a period of approximately four years. The remaining part of the outstanding receivables will be written-off against a previously established allowance for bad debts.

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CORPORATE AND OTHER

Corporate and Other includes general corporate overhead, miscellaneous operations (e.g., real estate activities, carbon and minerals) and other corporate unallocated costs. Net interest expense represents interest expense, net of interest income and capitalized interest.

Second Quarter Results: The after-tax earnings effect for the second quarter of 2002 was a loss of $71 million compared to a loss of $76 million in the same period a year ago. Lower after-tax expenses for environmental and litigation matters benefited the second quarter of 2002, with expenses of $13 million after-tax compared to $16 million after-tax for the same period a year ago. The second quarter of 2002 results included tax related benefit adjustments and lower employee related compensation, which was offset by higher pension related expenses.

Six Months Results: The after-tax earnings effect for the first six months of 2002 was a loss of $166 million compared to a loss of $182 million in the same period a year ago. Lower after-tax provisions for environmental and litigation matters benefited the first six months of 2002, with expenses of $36 million after-tax compared to $50 million after-tax for the same period a year ago. The first six months of 2002 also benefited from a $2 million after-tax gain from an insurance settlement related reached with insurers for the recovery of amounts previously paid out for environmental pollution claims and related costs. The first six months results of 2001 included a $10 million pre-tax, or $7 million after-tax, contribution to a charitable foundation, while the first six months of 2002 included a similar contribution of $3 million pre-tax, or $2 million after-tax. The 2002 earnings benefit from the lower contribution and the tax related benefit adjustments were partially offset by higher pension related expenses. The first six months of 2002 included $6 million after-tax in pension related expenses, compared to a benefit of $5 million after-tax in the first six months of 2001. Net interest expense remained unchanged in the first six months of 2002, as higher interest expense from a premium on an early repayment of long-term debt was offset by higher capitalized interest on development projects.

FINANCIAL CONDITION

	At June 30,	At December 31,
Millions of dollars	2002	2001

Current ratio	0.9:1	0.9:1
Total debt and capital leases	$ 3,119	$ 2,906
Trust convertible preferred securities	522	522
Stockholders' equity	3,210	3,124
Total capitalization	$ 6,851	$ 6,552
Total debt/total capitalization	46%	44%
Floating-rate debt/total debt	21%	8%

Cash flows from operating activities, including discontinued operations and working capital and other changes, were $626 million in the first six months of 2002 compared to $1,244 million in the same period a year ago. This decrease principally reflected the effects of lower worldwide average natural gas and liquids prices. The decrease was partially offset by $155 million in lower income tax payments, net of refunds, compared to the first six months of 2001 and $30 million from the sale of certain domestic trade receivables during the first six months of 2002.

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Pre-tax proceeds from asset sales, including those classified as discontinued operations, were $47 million for the first six months of 2002. Proceeds of approximately $27 million were from an asset sale by the Company's Pure subsidiary of oil and gas producing properties in the U.S. The remaining $20 million of proceeds were from various other oil and gas asset sales and other miscellaneous properties. Pre-tax proceeds from asset sales, including those classified as discontinued operations, were $30 million for the first six months of 2001. The proceeds included $12 million from the sale of certain oil and gas properties, $11 million from the sale of miscellaneous assets and $7 million related to a participation payment received from the purchaser of the Company's former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline.

Capital expenditures in the first six months of 2002 were $830 million, compared with $824 million in the same period a year ago. The higher capital expenditures in 2002 were primarily due to higher development expenditures in Indonesia and an acquisition in Canada, the aggregate of which was substantially offset by lower Gulf of Mexico exploratory expenditures. The Canadian acquisition involved the Company's Northrock subsidiary, which completed, in June 2002, a cash acquisition of all the outstanding shares of common stock of Corsair Exploration Inc. ("Corsair") for $1.98 per share, or approximately $29 million. This acquisition was funded with cash on hand. Corsair is a Canadian exploration and production company primarily engaged in activity in West Central Alberta, Canada. The transaction was valued at approximately $36 million, which included $7 million in assumed debt and working capital deficiency. The capital expenditures amount for the first six months of 2001 excludes Pure's acquisition of properties from International Paper Company for $267 million and Pure's cash outlay of $150 million, as of June 30, 2001, for the acquisition Hallwood Energy Corporation, which are included as part of the major acquisitions line on the consolidated cash flows statement.

The Company has taken appropriate action to mitigate credit exposure to counterparties whose creditworthiness has deteriorated since the beginning of the year. Counterparty credit lines have been reduced substantially or rescinded entirely where it has been determined that there is unwarranted credit exposure. In other instances, credit assurances in the form of prepayments, letters of credit or guarantees have been obtained to support the credit extension.

The Company's long-term debt, including the current portion, was $3.12 billion at June 30, 2002, compared with $2.91 billion at year-end 2001. This increase primarily reflected the commercial paper borrowings made by the Company to fund scheduled maturing fixed-rate debt and for other general corporate purposes (see note 10 for further detail on the Company's long-term debt).

The Company has two credit facilities in place: a $400 million 364-day credit agreement and a $600 million 5-year credit agreement. The agreements provide for the termination of their loan commitments and require the prepayment of all outstanding borrowings in the event that (1) any person or group becomes the beneficial owner of more than 30 percent of the then outstanding voting stock of Unocal other than in a transaction having the approval of Unocal's board of directors, at least a majority of which are continuing directors, or (2) if continuing directors shall cease to constitute at least a majority of the board. The agreements do not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade.

Based on current commodity prices and current development projects, the Company does not expect cash generated from operating activities, asset sales and cash on hand in 2002 to be sufficient to cover its operating and capital spending requirements and to meet dividend payments. The Company has substantial borrowing capacity to enable it to meet anticipated and unanticipated cash requirements. The Company relies on the commercial paper market on an interim basis, its accounts receivable securitization program and its revolving credit facilities to cover short-term borrowing requirements. The Company decreased the fund availability of its accounts receivable securitization program availability to $125 million from $204 million in the second quarter of 2002. At June 30, 2002, the Company had sold $100 million of its domestic trade receivables under this program. The Company also has in place a universal shelf registration statement with an unutilized balance of approximately $739 million, which can be issued as debt and/or equity securities, depending on the Company's needs and market conditions. From time to time, the Company may also look to fund some of its long-term projects using other financing sources, including multilateral and bilateral agencies.

Maintaining investment-grade credit ratings, that is "BBB- / Baa3" and above from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively, is a significant factor in the Company's ability to raise short-term and long-term financing. As a result of the Company's current investment grade ratings, the Company has access to both the commercial paper and bank loan markets. The Company currently has a BBB+ / Baa1 credit rating by Standard & Poor's and Moody's, respectively. In May 2002, Moody's changed its rating outlook for the Company's long-term debt to negative from stable and retained an outlook of stable for the Company's Prime-2 commercial paper rating. As outlined in the tables on pages 40 and 41 of Management's Discussion and Analysis in Item 7 of the Company's 2001 Annual Report on Form 10-K, the Company continues to believe that it does not have a liquidity exposure in the event of a credit rating downgrade. In the event that the Company's credit ratings fall to a level that prohibits it from accessing the commercial paper markets, the Company would still be able to access funds under its revolving credit facilities.

ENVIRONMENTAL MATTERS

At June 30, 2002, the Company's reserves for environmental remediation obligations totaled $231 million, of which $116 million was included in current liabilities. During the six months ended June 30, 2002, cash payments of $55 million were applied against the reserve and $49 million in provisions were added to the reserve balance. In the first quarter of 2002, provisions of $31 million were recorded primarily for service stations and distribution facilities; the former Guadalupe oil field; and the McColl Superfund site. A provision was recorded for revised cost estimates related to the anticipated cleanup of the Company's former service stations and distribution facilities throughout the United States. The reserves for these sites are included in the "Former Company-operated Sites" environmental reserve category shown in the table below. The first quarter provisions also included an additional accrual for revised cost estimates for various remediation projects at the Company's former Guadalupe oil field on the central California coast. The reserve for the Guadalupe oil field is included in the "Inactive or Closed Company Facilities" category. The Company also recorded a provision for its estimated remaining share of oversight and monitoring costs related to the McColl Superfund site in Fullerton, California. The provision was recorded as the result of a federal appeals court overturning a 1998 court decision that held the federal government responsible for cleanup of the site because of its role in encouraging oil companies to produce gasoline during World War II.

In the second quarter of 2002, provisions of $18 million were recorded primarily for a former oil field in Michigan and for a site in York, Pennsylvania. A provision for the estimated cost to cleanup contaminated areas that have been identified at a former oil field in Michigan was added to the reserve in the second quarter. This reserve is included in the "Former Company-operated Sites" category. In the second quarter, a provision was also recorded for revised remediation cost estimates related to a shutdown facility in York, Pennsylvania. The facility had been operated by the Company's Molycorp subsidiary. The reserve for this site is included in the "Inactive or Closed Company Facilities" category.

The Company also estimated as of June 30, 2002, that it possibly could incur additional remediation costs aggregating approximately $245 million. The Company's total environmental reserve and possible additional liability amounts are grouped into the following four categories.

	At June 30, 2002	
Millions of dollars	Reserves	Possible Additional
Superfund and similar sites	$ 18	$ 11
Active company facilities	37	66
Company facilities sold with retained liabilities and former company-operated sites	97	71
Inactive or closed company facilities	79	107
Total reserves	$ 231	$ 255

Also see notes 11 and 12 to the consolidated financial statement in Item 1 of this report for additional information on environmental related matters.

OUTLOOK

Certain of the statements in this discussion, as well as other forward-looking statements within this document, contain estimates and projections of amounts of or increases / decreases in future revenues, earnings, cash flows, capital expenditures, assets, liabilities and other financial items and of future levels of or increases / decreases in reserves, production, sales including related costs and prices, drilling activities and other statistical items; plans and objectives of management regarding the Company's future operations, products and services; and certain assumptions underlying such estimates, projection plans and objectives. While these forward-looking statements are made in good faith, future operating, market, competitive, legal, economic, political, environmental, and other conditions and events could cause actual results to differ materially from those in the foward-looking statements. See pages 51 through 53 of Management's Discussion and Analysis in Item 7 of the Company's 2001 Annual Report on Form 10-K for a discussion of certain of such conditions and events.

Volatile energy prices are expected to continue to impact financial results in the year 2002. The Company expects energy prices to remain volatile due to changes in climate conditions, worldwide demand, crude oil and natural gas inventory levels, production quotas set by OPEC, current and future worldwide political instability and security and other factors.

The economic situation in Asia, where most of the Company's international activity is centered, is still recovering with positive signs showing in the region. The Company looks at the natural gas market in Asia as one of its major strategic investments and believes that the governments in the region are committed to undertaking the reforms and restructuring necessary to enable their nations to continue their recoveries from the downturn.

The Company estimates that its net worldwide daily production for 2002 will average in the lower end of the range between 490,000 and 500,000 BOE. The anticipated production increase through the remainder of 2002 reflects new projects in the Far East and Gulf of Mexico. The Company forecasts its net earnings per share to be between $1.60 and $1.80 in 2002. This forecast assumes average NYMEX benchmark prices of $25.10 per Bbl of crude oil and $3.05 per MMBtus for North America natural gas. These price assumptions are based on year-to-date actual prices and the NYMEX strip for the remainder of the year. Earnings are expected to change 16 cents per share for every $1 change in the Company's average worldwide realized price for crude oil and 8 cents per share for every 10-cent change in the Company's average realized North America natural gas price. The full-year forecast also includes pre-tax dry hole costs of $110 to $125 million.

Exploration and Production - North America

U.S. Lower 48: In the Gulf of Mexico deep water, the Company is continuing its appraisal of the Trident discovery and is planning to drill a second appraisal well in late 2002. After completing the Trident second appraisal well, the Company plans to commence drilling another deepwater prospect by the end of 2002 or early 2003. In addition, the Company is continuing its participation in the development of the Mad Dog discovery.

The Company is continuing to focus its exploration effort on deeper prospects with higher resource potential in the Gulf of Mexico shelf.

The Company anticipates selling some of its low margin properties in the Gulf Region towards the end of 2002 or in early 2003.

Alaska: The Company continues its participation in the Ninilchik Exploration Unit on Alaska's Kenai Peninsula, where it holds a 40 percent working interest in the 25,000-acre Ninilchik Exploration Unit. Marathon Oil Corporation ("Marathon") is operator and holds the remaining interest. The Ninilchik

Exploration Unit is located about 35 miles south of Kenai, Alaska.

Canada: The Company's Northrock subsidiary will work on integrating the recently acquired operations of Corsair, a Canadian exploration and production company primarily engaged in activity in West Central Alberta, Canada.

Exploration and Production - International

Far East

Thailand: The Company's Unocal Thailand, Ltd. ("Unocal Thailand"), subsidiary started natural gas production from the Phase II development in the northern part of Pailin field in the B12/27 concession area in the Gulf of Thailand. The minimum daily contract quantity of natural gas sales from the Phase II ("North Pailin") facilities is 165 gross MMcf/d, raising the gross contracted natural gas sales from the Pailin field to 330 MMcf/d under an agreement with PTT Public Co., Ltd. ("PTT"), the partially privatized state petroleum company. The North Pailin facilities have produced an average of 180 gross MMcf/d throughout the month of July. In addition, the North Pailin facilities have produced an average of 5,300 gross b/d of condensate throughout the month of July, raising total condensate production from Pailin to more than 14,600 gross b/d. Unocal Thailand is operator of the field and holds a 35 percent working interest (31 percent net of royalty).

The Company began crude oil production in May 2002 from its Yala field in the Gulf of Thailand. The Company began initial production of crude oil from the neighboring Plamuk field in 2001. The Company expects production from the Plamuk, Yala and Surat fields to reach 15 MBbl/d gross in 2002. The Company has a 71 percent working interest in these fields (62 percent net of royalty).

Vietnam: In May 2002, the Company's Vietnam subsidiaries filed a declaration of commercial discovery with PetroVietnam, the national oil company, for three natural gas fields offshore southwest Vietnam. The declaration followed the drilling of 10 successful exploration wells on Blocks B and 52/97, including four wells that were drilled in 2001. The declaration is the first step toward signing a gas sales agreement, which is required before any field development can begin. As a result of the declaration, PetroVietnam may exercise its option to convert its carried participating interests into paying working interests. Should PetroVietnam opt to convert to normal working interests, the Company would hold a 42 percent working interest in Block B and Block 48/95 and a 43 percent working interest in Block 52/97.

Indonesia: The Company's Unocal Rapak, Ltd. ("Unocal Rapak"), subsidiary is continuing its evaluation of engineering and development studies for the deepwater Ranggas oil prospect offshore East Kalimantan, Indonesia. The Company plans to drill the Ranggas #6 delineation well in the third quarter of 2002. Unocal Rapak is operator of the Rapak PSC area and holds an 80 percent working interest. The Company is also evaluating early development options for the condensate discovered at its deepwater Gendalo-Gandang discovery in the Ganal PSC, offshore Indonesia. The Company is the operator of the Ganal PSC and holds an 80 percent working interest.

The Company is continuing its development of the West Seno project. Gross development costs for the first phase are expected to be approximately $460 million, with an additional $225 million for the second phase (Unocal's net share is expected to be approximately $415 million and $200 million for phase 1 and 2, respectively). The Company and its co-venturer are currently working to secure financing for a portion of the total costs through the Overseas Private Investment Corporation ("OPIC"). The Company and its co-venturer expect to complete financing arrangements with OPIC in 2002 for two loans. One loan is $300 million for the first phase, and the other loan is $50 million for the second phase.

Other International

Azerbaijan: The Azerbaijan International Operating Company ("AIOC") consortium is working on the development of the "Phase 1" portion of the offshore oil reserves in the Caspian Sea from the Azeri and Chirag fields. This phase of the project will develop an estimated 1.5 billion barrels of proved crude oil reserves. Phase 1 gross production is scheduled to commence in early 2005 and is expected to peak at approximately 360 MBbl/d. The Company has committed up to $310 million for its share of the costs to develop Phase 1.

The Company has approved the expenditure of $400 million representing its share of the estimated Azeri-Chirag-Gunashli Production Sharing Agreement Phase 2 project expenditures over a five to six year period. Such expenditure is subject to partner and government approval of the project which the Company anticipates occurring in the third quarter of 2002.

Bangladesh: The Company continues to work with the government of Bangladesh and Petrobangla, the state oil and gas company, to develop additional reserves and export natural gas to markets in neighboring India. At June 30, 2002, the Company's business unit in Bangladesh had a gross receivable balance of approximately $31 million relating to invoices billed for natural gas and condensate sales to Petrobangla. Approximately $27 million of the outstanding balance represented past due amounts and accrued interest for invoices covering December 2001 through May 2002. In July 2002, payments were received for natural gas sales and condensate covering billings for December 2001 and January 2002. Generally, invoices, when paid, have been paid in full. The Company is working with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables. See also Note 12 to the consolidated financial statement in Item 1 of this report for information regarding a claim made by Petrobangla in July 2002 against one of the Company's subsidiaries for compensation with respect to a 1997 well blowout.

Brazil: The drilling of an exploratory well on the BM-ES-1 Block in the Espirito Santo Basin began in July of 2002. The Company acquired a 25 percent non-operating working interest in the Block earlier in 2002. Drilling in the adjacent BM-ES-2 Block will wait on results from the BM-ES-1 Block and is projected to commence in the first quarter of 2003 at the earliest. The Company, as operator, holds a 40.5 percent working interest in the BM-ES-2 Block.

Midstream

Construction of the Keystone Gas Storage Project in West Texas continues and is expected to be on-line by the end of third quarter of 2002. The project will initially have storage capacity of 3 billion cubic feet. The Company holds a 100 percent interest in the project.

In early August, the Company, through its participation in the AIOC consortium, signed the agreement approving engineering plans for the Baku-Tblisi-Ceyhan ("BTC") pipeline in Turkey. The pipeline project is planned to have a crude oil capacity of 1 million b/d. Completion of the pipeline is excepted in late 2004 at an overall estimated cost of approximately $3 billion, and the pipeline is expected to be in operation in early 2005. The Company has an 8.9 percent interest and is one of eight shareholders in the BTC pipeline project. The pipeline company anticipates financing up to 70 percent of the pipeline's cost.

In Alaska, the Company along with Marathon, through their interests in the Kenai Kachemak Pipeline LLC, are developing a 33-mile natural gas pipeline that would connect a future producing area in Ninilchik with the existing south central Alaska pipeline system in Kenai. The cost of the pipeline is currently estimated to be $25 million. The Company holds a 40 percent interest in the pipeline company.

The Company anticipates the sale of certain interests in nonstrategic pipelines in the U.S. by the end of 2002.

Corporate and Other

For the full-year 2002, pension costs related to the Company's U.S. based employees are expected to increase by approximately $25 million after-tax compared to the full-year 2001. Lower returns on plan assets and the use of a lower discount rate to measure benefit-related liabilities are the principal factors behind the increase in current year expense.

The Company's consulting actuaries have completed the January 1, 2002 actuarial valuation calculations for the Unocal Qualified Retirement Plan ("Plan") covering eligible employees on the U.S. payroll and have reviewed pension trust investment results for the first six months of 2002. The fair value of the pension trust investments at June 30, 2002 is still in excess of the Plan's accumulated benefit obligation ("ABO"). The Company is closely monitoring the performance of the Plan's investment advisors and the returns on plan assets. If actual returns on plan assets were to continue to be negative for the balance of the current year resulting in the fair value of the Plan's assets falling below the ABO, the resulting shortfall would require a charge to accumulated other comprehensive income on the Company's consolidated balance sheet with no impact on earnings for 2002. Furthermore, continued negative returns on Plan assets would result in increased pension expense in future years and could result in the termination of the "contribution holiday" currently in effect for the Plan.

Reformulated Gasoline Patents

The Company's efforts to enforce its patents for reformulated gasolines continue. In its lawsuit to collect additional infringement damages from five California refiners, the court has requested additional information and arguments with respect to the royalty rate to be applied for infringing volumes produced subsequent to July 1996. In June 2002, the U.S. Patent and Trademark Office ("PTO") initially rejected all of the claims of the Company's '126 patent, as it had done earlier with respect to the '393 patent, as part of the reexamination process. In July, the PTO granted a second request for reexamination of the '393 patent based on additional alleged "prior art". The Company continues to expect the claims of these patents to be sustained following the conclusion of their reexamination.

FUTURE ACCOUNTING CHANGES

In August 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No 143, "Accounting for Asset Retirement Obligations". It is effective for fiscal years beginning after June 15, 2002, and it requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, as a capitalized cost of the long-lived asset and to depreciate it over the useful life of the asset. The Company is currently in the process of evaluating the impact that SFAS No. 143 will have on its financial position and results of operations.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". This statement provides guidance on the recognition and measurement of liabilities associated with disposal activities and is effective for the Company on January 1, 2003. The Company is currently reviewing the provisions of SFAS No. 146 to determine the impact that the statement will have on its financial position and results of operations.

Other proposed accounting changes considered from time to time by the FASB, the U.S. SEC, the American Institute of Certified Public Accountants and the United States Congress could materially impact the Company's reported financial position and results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk generally represents the risk that losses may occur in the values of financial instruments as a result of changes in interest rates, foreign currency exchange rates, counterparty liquidity and commodity prices. As part of its overall risk management strategies, the Company uses derivative financial instruments to manage and reduce risks associated with these factors. The Company also trades hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations.

The Company determines the fair values of its derivative financial instruments primarily based upon market quotes of exchange traded instruments. Most futures and options contracts are valued based upon direct exchange quotes or industry published price indices. Some instruments with longer maturity periods require financial modeling to accommodate calculations beyond the horizons of available exchange quotes. These models calculate values for outer periods using current exchange quotes (i.e., forward curve) and assumptions regarding interest rates, commodity and interest rate volatility and, in some cases, foreign currency exchange rates. While the Company feels that current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors to measure the fair value of its longer termed hydrocarbon derivative instruments, other pricing assumptions or methodologies may lead to materially different results in some instances.

Interest Rate Risk - From time to time the Company temporarily invests its excess cash in short-term interest-bearing securities issued by high-quality issuers. Company policies limit the amount of investment in securities of any one financial institution. Due to the short time the investments are outstanding and their general liquidity, these instruments are classified as cash equivalents in the consolidated balance sheet and do not represent a material interest rate risk to the Company. The Company's primary market risk exposure for changes in interest rates relates to the Company's long-term debt obligations. The Company manages its exposure to changing interest rates principally through the use of a combination of fixed and floating rate debt. Interest rate risk sensitive derivative financial instruments, such as swaps or options may also be used depending upon market conditions.

The Company evaluated the potential effect that near term changes in interest rates would have had on the fair value of its interest rate risk sensitive financial instruments at June 30, 2002. Assuming a ten percent decrease in the Company's weighted average borrowing costs at June 30, 2002, the potential increase in the fair value of the Company's debt obligations and associated interest rate derivative instruments, including the Company's net interests in the debt obligations and associated interest rate derivative instruments of its subsidiaries, would have been approximately $111 million at June 30, 2002.

Foreign Exchange Rate Risk - The Company conducts business in various parts of the world and in various foreign currencies. To limit the Company's foreign currency exchange rate risk related to operating income, foreign sales agreements generally contain price provisions designed to insulate the Company's sales revenues against adverse foreign currency exchange rates. In most countries, energy products are valued and sold in U.S. dollars and foreign currency operating cost exposures have not been significant. In other countries, the Company is paid for product deliveries in local currencies but at prices indexed to the U.S. dollar. These funds, less amounts retained for operating costs, are converted to U.S. dollars as soon as practicable. The Company's Canadian subsidiaries are paid in Canadian dollars for their crude oil and natural gas sales.

From time to time the Company may purchase foreign currency options or enter into foreign currency swap or foreign currency forward contracts to limit the exposure related to its foreign currency debt or other obligations. At June 30, 2002, the Company had various foreign currency swaps and foreign currency forward contracts outstanding related to operations in Canada, Thailand and The Netherlands. The Company evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of the Company's combined foreign currency position related to its outstanding foreign currency swaps and forward contracts.

Assuming an adverse change of ten percent in foreign exchange rates at June 30, 2002, the potential decrease in fair value of the Company's foreign currency forward contracts, foreign-currency denominated debt, foreign currency swaps and foreign currency forward contracts of its subsidiaries, would have been approximately $10 million at June 30, 2002.

Credit Risk - The Company has taken appropriate action to mitigate credit exposure to counterparties whose creditworthiness has deteriorated since the beginning of the year. Counterparty credit lines have been reduced substantially or rescinded entirely where it has been determined that there is unwarranted credit exposure. In other instances, credit assurances in the form of prepayments, letters of credit or guarantees have been obtained to support the credit extension.

Commodity Price Risk - The Company is a producer, purchaser, marketer and trader of certain hydrocarbon commodities such as crude oil and condensate, natural gas and refined products and is subject to the associated price risks. The Company uses hydrocarbon price-sensitive derivative instruments ("hydrocarbon derivatives"), such as futures contracts, swaps, collars and options to mitigate its overall exposure to fluctuations in hydrocarbon commodity prices. The Company may also enter into hydrocarbon derivatives to hedge contractual delivery commitments and future crude oil and natural gas production against price exposure. The Company also actively trades hydrocarbon derivatives, primarily exchange regulated futures and options contracts, subject to internal policy limitations.

The Company uses a variance-covariance value at risk model to assess the market risk of its hydrocarbon derivatives. Value at risk represents the potential loss in fair value the Company would experience on its hydrocarbon derivatives, using calculated volatilities and correlations over a specified time period with a given confidence level. The Company's risk model is based upon historical data and uses a three-day time interval with a 97.5 percent confidence level. The model includes offsetting physical positions for hydrocarbon derivatives related to the Company's fixed price pre-paid crude oil and pre-paid natural gas sales. The model also includes the Company's net interests in its subsidiaries' crude oil and natural gas hydrocarbon derivatives and forward sales contracts. Based upon the Company's risk model, the value at risk related to hydrocarbon derivatives held for purposes other than hedging was approximately $2 million at June 30, 2002. The value at risk related to hydrocarbon derivatives held for hedging purposes was approximately $5 million at June 30, 2002.

In order to provide a more comprehensive view of the Company's commodity price risk, a tabular presentation of open hydrocarbon derivatives is also provided. The following table sets forth the future volumes and price ranges of hydrocarbon derivatives held by the Company at June 30, 2002, along with the fair values of those instruments.

Open Hydrocarbon Hedging Derivative Instruments (a)

	2002	2003	2004	2005	2006-2009
Natural Gas Futures Positions					
Volume (MMBtu)	2,450,000	-	-	-	
Average price, per MMBtu	$ 3.43				
Natural Gas Swap Positions					
Pay fixed price					
Volume (MMBtu)	4,915,500	7,498,000	7,241,000	7,218,000	21,677,00
Average swap price, per MMBtu	$ 2.46	$ 2.33	$ 2.33	$ 2.37	$ 2.4
Receive fixed price (c)					
Volume (MMBtu)	13,190,875	131,508	95,438	-	
Average swap price, per MMBtu	$ 2.77	$ 1.97	$ 1.97		
Natural Gas Basis Swap Positions					
Volume (MMBtu)	-	-	-	-	
Average price received, per MMBtu					
Average price paid, per MMBtu					
Natural Gas Collar Positions					
Volume (MMBtu)	34,255,000	5,636,010	202,500	-	
Average ceiling price, per MMBtu	$ 4.08	$ 4.67	$ 4.94		
Average floor price, per MMBtu	$ 2.92	$ 3.64	$ 2.92		
Natural Gas Option (Listed)					
Call Volume (MMBtu)	180,000	180,000	-	-	
Average Call price	$ 5.95	$ 6.35			
Put Volume (MMBtu)	(1,180,000)	(180,000)			
Average Put Price	$ 3.04	$ 3.25			
Natural Gas Option (OTC)					
Put Volume (MMBtu)	94,944	-	-	-	
Average Put Price	$ 3.96				
Crude Oil Future position					

Volume (Bbls)	427,000	-	-	-
Average price, per Bbl	$ 22.72			
Crude Oil Option				
Put Volume (Bbls)	500,000	-	-	-
Average price, per Bbl	$ 22.90			
Call Volume (Bbls)	350,000	-	-	-
Average price, per Bbl	$ 32.14			
Crude Oil Option (Calender Spread)				
Put Volume (Bbls)	300,000	-	-	-
Average price, per Bbl	$ 0.22			
Call Volume (Bbls)	(400,000)	-	-	-
Average price, per Bbl	$ 0.14			
Crude Oil Option (Calender Spread) OTC				
Put Volume (Bbls)	600,000	-	-	-
Average price, per Bbl	$ 0.10			
Call Volume (Bbls)	(200,000)	-	-	-
Average price, per Bbl	$ 0.50			
Crude Oil Swap Positions				
Pay fixed price				
Volume (Bbls)	19,500	-	-	-
Average swap price, per Bbl	$ 25.88			
Receive fixed price				
Volume (Bbls)	27,500	-	-	-
Average swap price, per Bbl	$ 18.71			
Crude Oil Collars				
Volume (Bbls)	88,421	156,802	77,778	-
Average ceiling price, per Bbl	$ 27.15	$ 25.33	$ 24.87	
Average floor price, per Bbl	$ 20.61	$ 19.77	$ 18.77	

Open Hydrocarbon Non-Hedging Derivative Instruments (a)

	2002
Natural Gas Futures Positions	
Volume (MMBtu)	(370,000)
Average price, per MMBtu	$ 3.73
Natural Gas Swap Positions	
Pay fixed price	
Volume (MMBtu)	8,823,725
Average swap price, per MMBtu	$ 3.35
Receive fixed price	
Volume (MMBtu)	8,967,500
Average swap price, per MMBtu	$ 3.36
Natural Gas Basis Swap Positions	

Volume (MMBtu)	2,725,000
Average price received, per MMBtu	$ 2.92
Average price paid, per MMBtu	$ 2.77
Natural Gas Option (Listed)	
Call Volume (MMBtu)	(2,250,000)
Average Call price	$ 3.53
Put Volume (MMBtu)	(250,000)
Average Put Price	$ 3.00
Natural Gas Option (Over the Counter)	
Call Volume (MMBtu)	(4,833,050)
Average Call price	$ 4.40
Put Volume (MMBtu)	(5,500,000)
Average Put price	$ 2.14
Natural Gas Spread Option (Over the Counter)	
NYMEX / IFERC (c)	
Put Volume (MMBtu)	(12,310,000)
Average Strike price	$ 0.24
Crude Oil Future position	
Volume (Bbls)	(441,000)
Average price, per Bbl	$ 27.11
Crude Oil Option	
Put Volume (Bbls)	-
Average price, per Bbl	
Call Volumes (Bbls)	300,000
Average price, per Bbl	$ 26.92
Crude Oil Option (Calender Spread)	
Put Volume (Bbls)	200,000
Average price, per Bbl	$ 0.15
Crude Oil Swap Positions	
Pay fixed price	
Volume (Bbls)	7,738,006
Average swap price, per Bbl	$ 27.00
Receive fixed price	
Volume (Bbls)	2,925,024
Average swap price, per Bbl	$ 23.36

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PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

See the information with respect to certain legal proceedings pending or threatened against the Company previously reported in Item 3 of Unocal's Annual Report on Form 10-K for the year ended December 31, 2001 ("2001 Form 10-K"), and in Item 1 of Part II of Unocal's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002. There is incorporated by reference: the information regarding environmental remediation reserves and possible additional remediation costs in notes 11 and 12 to the consolidated financial statements in Item 1 of

Part I of this report; the discussion of such amounts in the Environmental Matters section of Management's Discussion and Analysis in Item 2 of Part I; and the information regarding certain litigation and claims, tax matters and other contingent liabilities in note 12 to the consolidated financial statements. See also the discussion under "Reformulated Gasoline Patents" in the Outlook section of Management's Discussion and Analysis of recent developments in certain proceedings in which the Company is seeking to enforce its patents for cleaner-burning gasolines.

Information with respect to recent developments in certain previously reported proceedings and with respect to certain additional proceedings is set forth below:

1. In the California Superior Court cases (the Doe and Roe cases) alleging the Company's liability in connection with the construction of the natural gas pipeline from the Yadana field across Myanmar to the Thailand border, described in Paragraph 3 of Item 3 of the 2001 Form 10-K, in June 2002, the court, ruling on various pending motions, dismissed all of the plaintiffs' tort causes of action that were premised on alleged intentional or negligent actions of the Company. In August 2002, the court orally denied the Doe plantiffs' motion for class certification and set a February 2003 trial date. The remaining causes of action in both cases are all premised on whether the Company should be held vicariously liable for the alleged wrongful acts of the Myanmar military. Therefore, the Company views the award of any punitive or exemplary damages against the Company to be remote, as it is not claimed that the Company was a direct perpetrator of any wrongful acts. With possible damages at trial limited to lost wages and property appropriation claims of the individual plaintiffs, the Company believes that the outcomes of these cases are not likely to have a material adverse effect on the Company's financial condition or liquidity or, based on management's current assessment of the cases, the Company's results of operations.

Certain Environmental Matters Involving Civil Penalties

2. In June 2002, the U.S. Environmental Protection Agency ("EPA") issued to the Company an administrative complaint alleging 16 violations of the Emergency Planning and Community Right-To-Know Act of 1986. The complaint, which seeks civil penalties aggregating $385,000, alleges that the Company failed to make timely and/or complete and accurate chemical release reports to the EPA with regard to certain chemicals manufactured, processed or otherwise used at its former Los Angeles refinery during 1996 and 1997.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

The 2002 Annual Meeting of Stockholders of Unocal was held on May 20, 2002. The following actions were taken by the stockholders at the Annual Meeting, for which proxies were solicited pursuant to Regulation 14 under the Securities Exchange Act of 1934, as amended:

1. The three nominees proposed by the board of directors were elected as directors by the following votes for three-year terms expiring at the 2005 Annual Meeting of Stockholders, or until their successors are duly elected and qualified:

Name	Votes For	Votes Withheld
James W. Crownover	213,235,772	6,327,893

Timoth H. Ling	214,066,046	5,497,619
Donald B. Rice	214,593,616	4,970,049

2. A proposal to ratify the appointment of PricewaterhouseCoopers LLP as Unocal's independent accountants for 2002 was passed by a vote of 213,626,825 for versus 4,941,605 against and 995,235 abstentions. There were no broker non-votes.

3. A proposal to approve the amendments to the 1998 Management Incentive Program was passed by a vote of 200,022,248 for versus 17,507,867 against and 2,033,549 abstentions. There were no broker non-votes.

4. A stockholder proposal to urge the Board of Directors to adopt, implement and enforce a code of conduct based on the International Labor Organization's Conventions on Workplace Human Rights failed to pass, with a vote of 61,266,708 for versus 125,497,527 against and 8,731,434 abstentions. There were 24,067,996 broker non-votes.

5. A stockholder proposal to link compensation and bonus packages of Unocal's executives to the Company's ethical and social performance failed to pass, with a vote of 16,276,788 for versus 173,508,678 against and 5,710,203 abstentions. There were 24,067,996 broker non-votes.

ITEM 5. OTHER INFORMATION.

Effective June 27, 2002, Charles R. Larson resigned from the Unocal Board of Directors to pursue his candidacy for Lieutenant Governor in the State of Maryland. His position is currently vacant.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K.

(a) Exhibits: The Exhibit Index on page 46 of this report lists the exhibits that are filed as part of this report.

(b) Reports on Form 8-K:

Filed during the second quarter of 2002:

(1) Current Report on Form 8-K, dated and filed April 8, 2002, for the purpose of reporting, under Item 5, the Company's drilling results in Indonesia and a first quarter 2002 provision for environmental remediation.

(2) Current Report on Form 8-K, dated and filed April 25, 2002, for the purpose of reporting, under Item 5, the Company's first quarter 2002 earnings and related information and the Company's 2002 earnings forecast.

(3) Current Report on Form 8-K, dated June 20, 2002, and filed June 25, 2002, for the purpose of reporting, under Item 5, the Company's restructuring of its Gulf business unit.

Filed during the third quarter of 2002 to the date hereof:

(1) Current Report on Form 8-K, dated June 10, 2002, and filed July 29, 2002, for the purpose of reporting, under Item 5, the Company's second quarter 2002

earnings, the commencement of production from Phase II of the Pailin field in Thailand, Agreements reached on Indonesia Geothermal Contracts, Agrium Inc. Litigation, a Bangladesh-related claim and the Company's 2002 earnings forecast.

(2) Current Report on Form 8-K, dated and filed August 2, 2002, for the purpose of reporting, under Item 5, Amendment No. 2 to the Rights Agreement, dated as of August 2, 2002, between Unocal Corporation and Mellon Investor Services LLC.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNOCAL CORPORATION
(Registrant)

Dated: August 12, 2002

By: /s/JOE D. CECIL

Joe D. Cecil
Vice President and Comptroller
(Duly Authorized Officer
Principal Accounting Officer)

EXHIBIT INDEX

12.1 Statement regarding computation of ratio of earnings to fixed charges of Unocal Corporation for the six months ended June 30, 2002 and 2001.

12.2 Statement regarding computation of ratio of earnings to fixed charges of Union Oil Company of California for the six months ended June 30, 2002 and 2001.

Copies of exhibits will be furnished upon request. Requests should be addressed to the Corporate Secretary.