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FORM 10−K/A

UNOCAL CORP − ucl

Filed: September 23, 2002 (period: December 31, 2001)

Amendment to a previously filed 10−K

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

FORM 10-K/A
AMENDMENT NO. 2

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2001 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)

Registrant's telephone number, including area code (310) 726-7600

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00 per share	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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_____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

The aggregate market value of the common stock held by non-affiliates of the registrant as of February 28, 2002 (based upon the average of the high and low prices of these shares reported in the New York Stock Exchange Composite Transactions listing for that date) was approximately $8.8 billion.

Shares of common stock outstanding as of February 28, 2002: 244,119,771

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2002 Annual Meeting of Stockholders (to be filed with the Securities and Exchange Commission on or about April 8, 2002) are incorporated by reference into Part III.

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GLOSSARY

Below are certain definitions of key terms used in this Form 10-K.

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	DDA	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.

PART I

ITEMS 1 AND 2 - BUSINESS AND PROPERTIES.

Unocal Corporation was incorporated in Delaware on March 18, 1983, to operate as the parent of Union Oil Company of California ("Union Oil"), which was incorporated in California on October 17, 1890. Virtually all operations are conducted by Union Oil and its subsidiaries. The terms "Unocal" and "the Company" as used in this report mean Unocal Corporation and its subsidiaries, except where the text indicates otherwise.

Unocal is one of the world's leading independent oil and gas exploration and production companies, with principal operations in North America and Asia. Unocal is also a leading producer of geothermal energy and a provider of electrical power in Asia. Other activities include ownership in proprietary and common carrier pipelines, natural gas storage facilities and the marketing and trading of hydrocarbon commodities.

Information required under Items 1 and 2 are presented together in the following discussion of the Company's business and properties should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this report, including the Cautionary Statement.

STRATEGIC FOCUS

Unocal's strategy is focused on achieving profitable growth and creating value for its stockholders by:

Making multiple significant exploration discoveries in areas that offer long-term growth:
- U.S. Gulf of Mexico Deep Water
- East Kalimantan, Indonesia Deep Water
- U.S. Gulf of Mexico Deep Shelf
- Brazil Offshore

Delivering large development projects on time and on budget:
- West Seno - Offshore East Kalimantan, Indonesia
- Mad Dog - U.S. Gulf of Mexico Deep Water
- Azerbaijan International Operating Company ("AIOC") Phase I- Azerbaijan crude oil production
- South Kenai Gas - Alaska
- Plamuk, Yala, Surat - Gulf of Thailand crude oil production o Pailin II (North Pailin)- Gulf of Thailand natural gas production

Continuing to deliver expected performance from all existing sustaining businesses in North America and Asia utilizing our industry-leading drilling capabilities in:
- U.S. Gulf of Mexico Shelf and Onshore
- Gulf of Thailand
- East Kalimantan Shelf - Indonesia

Longer-term Asian natural gas projects:
- Bangladesh
- Thailand
- Vietnam
- China
- Indonesia

Continuing to pursue value-adding midstream opportunities, which include pipelines, terminals and natural gas storage facilities.

Pursuing and negotiating licensing agreements for reformulated gasoline patents with refiners, blenders and importers.

MERGERS AND ACQUISITIONS

In late 2001, the Company formed a 50-50 venture with Forest Oil Corporation ("Forest") related to certain oil and gas properties located in the central Gulf of Mexico. Under the terms of this transaction, the Company is the operator of the jointly owned properties and intends to exploit and explore these properties. This transaction is expected to provide the Company with potential production increases and further exploration opportunities. In addition, the transaction will allow the Company to leverage its operating and drilling expertise in the Gulf of Mexico and expand its presence and production on the shelf. The Company estimates that these properties contain net proved reserves of approximately 12 million BOE and additional net production of approximately 5 MBOE/d.

During the year, the Company's Northrock Resources Ltd. ("Northrock") Canadian subsidiary acquired all the outstanding common shares of Tethys Energy Inc. ("Tethys"). The asset base of Tethys is complementary to Northrock's operations in Western Canada, providing significant operational synergies with existing activity in Northrock's core areas. Based on an independent reserve report and successful exploration and development activity in 2001, Tethys has proved reserves of 12 million BOE, 60 percent of which were natural gas at the time of the acquisition. Tethys' production was approximately 5MBOE/d (net) at the time of the acquisition.

In early 2001, the Company's Pure Resources, Inc. ("Pure") subsidiary acquired oil and gas properties, certain general and limited oil and gas partnership interests and fee mineral and royalty interests from International Paper Company. This acquisition expanded Pure's business areas into the Gulf Coast region and offshore in the Gulf of Mexico. Included in the transaction were total proved reserves of approximately 25 million BOE, 69 percent of which were natural gas. In May 2001, Pure acquired all the outstanding equity shares of Hallwood Energy Corporation ("Hallwood"). This acquisition added to Pure's positions in its business areas of the San Juan and Permian Basins and the Gulf Coast region. Hallwood's emphasis on natural gas and its acreage position doubled Pure's production in the San Juan Basin to over 60 MMcf/d. Pure acquired total proved reserves of approximately 37 million BOE in the Hallwood purchase. The Company holds a 65 percent interest in Pure.

See note 3 to the consolidated financial statements for more detail on the principal terms of each of the acquisitions discussed in the above paragraphs.

SEGMENT AND GEOGRAPHIC INFORMATION

Financial information relating to the Company's business segments, geographic areas of operations, and sales revenues by classes of products is presented in note 29 to the consolidated financial statements and the selected financial data section in Item 8 of this report.

EXPLORATION AND PRODUCTION

Unocal's primary activities are oil and gas exploration, development and production. These activities are carried out by the Company's North America operations in the U.S. Lower 48, Alaska and Canada and by its International operations in approximately a dozen countries around the world.

In 2001, the Company's worldwide average production was approximately 170 MBbl/d of liquids and 2,003 MMcf/d of natural gas, primarily from onshore and offshore in the U.S. Gulf of Mexico, in the Gulf of Thailand, and offshore East Kalimantan, Indonesia. Approximately 50 percent of the Company's worldwide production and 30 percent of the Company's worldwide proved reserves were in the U.S. Exploration and production operations accounted for approximately 90 percent of Unocal's net properties at December 31, 2001, of which approximately 50 percent were in the U.S.

Beginning in 2001, the Company began reporting all reserve and production data pursuant to production sharing contracts utilizing the economic interest method, which excludes host country shares. In previous reporting, reserve and production data had included host country shares in Indonesia and the Democratic Republic of Congo. The Company also began reporting natural gas reserves and production on a dry basis, with natural gas liquids included with crude oil and condensate volumes. The reserve and production data included in the tables on the following pages reflect these changes.

Information regarding oil and gas financial data, oil and gas reserve data and the related present value of future net cash flows from oil and gas operations is presented on pages 124 through 133 of this report. During 2001, certain estimates of the Company's U.S. underground oil and gas reserves as of December 31, 2000, were filed with the U.S. Department of Energy and State agencies under the name of Union Oil. Such estimates were essentially identical to the corresponding estimates of such reserves at December 31, 2000, included in this report, before adjusting for the changes discussed above.

Net Proved Reserves

Estimated net quantities of the Company's proved liquids and natural gas reserves at December 31, 2001, 2000 and 1999, including its proportional shares of the reserves of equity investees, were as follows:

	2001	2000	1999
Liquids - million barrels			
North America			
Lower 48	156	145	127
Alaska	74	72	62
Canada	51	47	55
International			
Far East	208	186	155
Other	195	116	120
Equity investees	9	6	4
Worldwide	693	572	523
Natural gas - billion cubic feet			
North America			
Lower 48	1,797	1,542	1,336
Alaska	212	227	294
Canada	289	280	356
International			
Far East	3,873	3,543	3,705
Other	346	328	331
Equity investees	232	119	96
Worldwide	6,749	6,039	6,118
Worldwide - millions of barrels oil equivalent a)	1,818	1,579	1,543

<FN>
(a) Natural gas is converted into barrels of oil equivalent (BOE) based on 6 thousand cubic feet to one barrel of liquids.
</FN>

The year-end 2001 proved reserves included minority interest shares of approximately 32 million barrels of liquids and 397 billion cubic feet of natural gas in the U.S. Lower 48. The year-end 2000 proved reserves included minority interest shares of approximately 27 million barrels of liquids and 253 billion cubic feet of natural gas in the U.S. Lower 48. The year-end 1999 proved reserves included minority interest shares of approximately 7 million barrels of liquids and 100 billion cubic feet of natural gas in the U.S. Lower 48 and 18 million barrels of liquids and 176 billion cubic feet of natural gas in Canada. The minority interest shares in the U.S. Lower 48 primarily reflect the outside ownership of the Company's Pure subsidiary.

Net Daily Production

Net quantities of the Company's daily liquids and natural gas production for the years 2001, 2000 and 1999, including its proportional shares of production of equity investees, were as follows:

	2001	2000	1999
Liquids - thousand barrels per day			
North America			
Lower 48	59	52	50
Alaska	25	26	28
Canada	16	17	13
International			
Far East	51	47	54
Other	19	18	23
Worldwide	170	160	168
Natural gas dry basis - million cubic feet per day			
North America			
Lower 48	905	764	706
Alaska	103	125	130
Canada	101	98	70
International			
Far East	829	799	759
Other	65	57	39
Worldwide	2,003	1,843	1,704
Worldwide-thousands of barrels oil equivalent per day (a)	504	468	452

<FN>
(a) Natural gas is converted into barrels of oil equivalent (BOE) based on 6 thousand cubic feet to one barrel of liquids.
</FN>

Net daily production of liquids included minority interest shares of approximately 9 MBbl/d, 7 MBbl/d and 1 MBbl/d for 2001, 2000 and 1999, respectively, in the U.S. Lower 48. Natural gas net daily production included minority interest shares of approximately 102 MMcf/d, 69 MMcf/d and 21 MMcf/d for 2001, 2000 and 1999, respectively, in the U.S. Lower 48. The minority interest shares in the U.S. Lower 48 primarily reflect the outside ownership of the Company's Pure subsidiary. Canada's net daily production of liquids included minority interest shares of approximately 2 MBbl/d and 3 MBbl/d for 2000 and 1999, respectively. Canada's net daily production of natural gas included minority interest shares of approximately 15 MMcf/d and 35 MMcf/d for 2000 and 1999,respectively. There were no minority interest shares for Canada in 2001.

Oil and Gas Acreage

As of December 31, 2001, the Company's holdings of oil and gas rights acreage were as follows:

	(Thousands of acres)			
	Proved Acreage		Prospective Acreage	
	Gross	Net	Gross	Net
North America				
Lower 48	1,741	872	10,041	5,849
Alaska	88	59	346	232
Canada	545	264	2,671	1,399
International				
Far East	755	411	22,481	11,095
Other	45	24	10,563	5,119
Worldwide	3,174	1,630	46,102	23,694

Prospective acreage in the Lower 48 includes 6,090 thousand gross acres and 3,194 thousand net acres of fee mineral lands that the Company's Pure subsidiary acquired during 2001.

Producible Oil and Gas Wells

The number of producible wells at December 31, 2001 were as follows:

	Oil		Gas	
	Gross	Net	Gross	Net
North America				
Lower 48	5,279	3,071	2,020	991
Alaska	725	150	31	24
Canada	1,385	666	552	245
International				
Far East	242	188	674	458
Other	104	42	16	8
Worldwide (a)	7,735	4,117	3,293	1,726

<FN>
(a) The Company had 155 gross and 57 net producible wells with multiple completions.
</FN>

Drilling in Progress

The number of oil and gas wells in progress at December 31, 2001 were as follows:

	Gross	Net
North America		
Lower 48	29	17
Alaska	8	2
Canada	13	5
International		
Far East	5	3
Other	1	-
Worldwide (a)(b)	56	27

<FN>
(a) Excludes service wells in progress (3 gross, 1 net).
(b) The Company had no waterflood projects under development at December 31, 2001.
</FN>

Net Oil and Gas Wells Completed and Dry Holes

The following table shows the number of net wells drilled to completion:

	Productive			Dry		
	2001	2000	1999	2001	2000	1999
Exploratory						
North America						
Lower 48	66	26	15	18	11	8
Alaska	2	-	-	-	2	-
Canada	23	19	15	6	14	7
International						
Far East	23	23	32	9	19	10
Other	-	-	1	2	-	3
Worldwide	114	68	63	35	46	28
Development						
North America						
Lower 48	96	67	60	-	-	4
Alaska	8	3	3	-	-	-
Canada	51	68	39	6	9	5
International						
Far East	67	104	71	-	-	-
Other	3	2	1	-	-	-
Worldwide	225	244	174	6	9	9

NORTH AMERICA

U.S. LOWER 48

The U.S. Lower 48 business is primarily comprised of the Company's exploration and production operations in the onshore area of the Gulf of Mexico region located in Texas, Louisiana and Alabama, and the shelf and deepwater areas of the Gulf of Mexico. The U.S. Lower 48 also includes Pure, the Company's 65 percent owned consolidated subsidiary, which conducts its activities primarily in Texas, New Mexico and the Gulf Coast region. Further, the U.S. Lower 48 currently includes an approximate 15 percent equity interest in Tom Brown, Inc., which conducts its activities in North America, primarily in Colorado, Utah, Wyoming, New Mexico, Texas, and to a lesser extent, Canada. The Company also has an approximate 34 percent equity interest in Matador Petroleum Corporation, which conducts its activities in southeastern New Mexico and East Texas.

The Company holds approximately 5.8 million net acres of prospective land in the U.S. onshore, the shelf and deepwater areas of the Gulf of Mexico region. Nearly 28 percent of the prospective acreage is located offshore in the Gulf of Mexico. Onshore prospective lands include over 3 million net acres of fee mineral lands purchased by the Company's Pure subsidiary in 2001 which are primarily located in Alabama, Arkansas, Mississippi, Louisiana, Texas and Florida. The Company holds approximately 872,000 net acres of proved lands. Approximately 45 percent of these lands are located offshore in the Gulf of Mexico. Onshore proved acreage is primarily located in Texas, Louisiana, Alabama and New Mexico. The Company's reported U.S. Lower 48 acreage does not include acreage held by its equity interest holdings.

In 2001, net liquids production averaged 58 MBbl/d, which was produced from fields onshore (54 percent) and offshore the Gulf of Mexico (42 percent), primarily in Texas, Louisiana, Alabama and New Mexico. The remaining 4 percent was from the Company's equity interest holdings.

Net natural gas production averaged 904 MMcf/d, which was principally from fields in the offshore Gulf of Mexico (64 percent) and onshore (31 percent), primarily in Texas, Louisiana, New Mexico and Colorado. The remaining 5 percent was from the Company's equity interest holdings.

Most of the Company's U.S. Lower 48 production, except for Pure's production, is sold to the Company's Trade business segment. A small portion is sold to third parties at spot market prices or under long-term contracts. Pure's production is sold mostly to third parties at spot market prices.

Gulf of Mexico Shelf and U.S. Onshore (Excluding Pure Resources, Inc.)

The Gulf of Mexico shelf and U.S. onshore areas include assets that are primarily located in Louisiana, Texas, Mississippi and Alabama.

Net production in 2001 averaged 150 Mboe/d which included approximately 79 percent from the Gulf of Mexico shelf and 15 percent from U.S. onshore. The remaining 6 percent was from the Company's equity interest holdings. Production is heavily weighted toward natural gas, which makes up approximately 75 percent of the total.

The Company has 149 producing properties and 108 exploration blocks in the Gulf of Mexico shelf area. The Company operates or participates in over 2,500 gross wells in both the onshore and Gulf of Mexico shelf.

During 2001, the Company drilled 38 discoveries in this area, which was a success rate of 73 percent. The 2001 exploration program included the East Breaks area located in the Gulf of Mexico shelf, where the Company scored a 100 percent success rate in a three-well subsea exploration tieback program. Through this deep shelf pilot program, the Company employed subsea tiebacks to develop small-to-moderate discoveries in water deeper than the conventional shelf. This program allowed the Company to take advantage of existing infrastructure at two East Breaks blocks to achieve high profitability and quick turnaround. The exploration program also achieved success in the Mustang Island area of the Gulf of Mexico shelf, where the Company scored a 100 percent success rate on four wells. The Company plans to target more deep gas plays in the shelf in its 2002 exploration program based on the successful results it achieved in 2001.

These discoveries added to the Company's natural gas production base, along with the production from Ship Shoal Block 295 ("Muni field") offshore Louisiana. The Muni field is one of the largest natural gas discoveries made in the Gulf of Mexico shelf in recent years. The field reached a peak production rate of 235 million gross cubic feet of natural gas equivalent per day (MMcfe/d) in 2001 and produced at an average gross rate of 166 MMcfe/d during the year. The field is now experiencing a decline in production, which averaged 34 gross MMcfe/d in 2002 through February. The Company is evaluating several options, including additional drilling. The Company holds a 100 percent working interest in this field.

Deepwater Gulf of Mexico

Over the past four years, the Company has acquired acreage positions in the deepwater Gulf of Mexico, with interests in 235 exploration leases. The Company's acreage is primarily in the Subsalt/Foldbelt trend, which lies outboard of the Primary Basin deepwater trend.

The Company has drilled or participated in nine Primary Basin wells, with two discoveries. The Company participated in the discovery of the Lady Bug prospect, which began production in 2001. The Lady Bug discovery, which is located on Garden Banks Block 409, marked the Company's first development in the Gulf of Mexico Primary Basin. Lady Bug produced at an initial rate of 9 mboe/d (gross) in September 2001 and the field averaged 3 mboe/d (gross) for 2001. Lady Bug is currently producing approximately 9 mboe/d (gross). The Company has a 50 percent working interest. The Company also participated in the 1999 discovery of the Mirage prospect, located on Mississippi Canyon Block 941, where the Company has a 25 percent working interest.

Further offshore in the Subsalt/Foldbelt trend, sometimes referred to as the ultra-deep, the Company has a number of high-potential prospects in water depths of 5,000 feet and greater. The Company was an early entrant in the "ultra-deep" area and has interests in 176 blocks.

The Company participated in the discoveries made on the Mad Dog and K2 prospects. The Company has a 15.6 percent working interest in the Mad Dog discovery on Green Canyon Block 826. In 2001, the Company completed drilling of a delineation well in the field, which was successful in proving commerciality of the prospect. A development plan for Mad Dog has been approved. The Company anticipates first production in 2004, with gross production of 80 MBbl/d of liquids and 40 MMcf/d of natural gas. The K2 exploration well is located on Green Canyon Block 562, and the Company has a 12.5 percent working interest in the prospect. The Company plans to participate in an appraisal well in the second quarter of 2002.

The Company commenced its ultra-deep drilling program in late 2000, utilizing the state-of-the-art deepwater drillship Discoverer Spirit. After drilling three non-commercial wells, the Company made an oil discovery on the Trident prospect in July 2001. The discovery well is located on Alaminos Canyon Block 903 and was drilled in 9,687 feet of water to a total depth of 20,500 feet. The well encountered more than 300 feet of hydrocarbon bearing pay section and additional zones of interest. The Company also completed the first appraisal well on the prospect in late 2001. The Trident #2 well is located approximately one and a half miles northwest of the original discovery and was drilled to a total depth of 20,500 feet in 9,727 feet of water. The objectives of the appraisal well were to test the lower portion of the sands encountered in the Trident discovery well and to gather critical information about reservoir quality. The appraisal well encountered the same hydrocarbon-bearing intervals found in the discovery well, a favorable indication of lateral reservoir continuity. The well penetrated oil-water transition zones. In one of the key findings, preliminary analysis of the core data confirms the presence of good quality reservoir rock in the key uppermost pay zones in the structure. Tests conducted on oil samples taken from the appraisal well indicate the same fluid quality of 40(degree) API gravity found in the discovery well, which is an important factor in future development economics. The Company plans to drill a second appraisal well at Trident in late 2002 and plans to put significant effort into analyzing deepwater development options, including the likely use of FPSO technology. The Company is the operator and has a 59.5 percent working interest in the seven-block prospect.

Pure Resources, Inc.

Unocal holds a 65 percent interest in Pure. Pure is engaged in the exploration, development and production of oil and natural gas primarily in the Permian Basin of west Texas and southeastern New Mexico. Pure is also engaged in activities in the San Juan Basin area of New Mexico and Colorado, the Gulf Coast region covering Texas, Louisiana, Arkansas, Mississippi, Alabama and Florida and offshore the Gulf of Mexico. Pure's net production in 2001 averaged 60 mboe/d, which is reported in the Company's total U.S. Lower 48 production. Production is weighted toward natural gas, which made up 63 percent of the total production in 2001. Ninety-five percent of Pure's production is from U.S. onshore areas and five percent is from the Gulf of Mexico offshore. As of December 31, 2001, Pure operated over 4,500 gross productive wells (over 2,400 net productive wells). Pure's proved oil and gas properties are located in more than 400 fields, primarily in the Permian Basin.

Pure acquired approximately 6 million gross acres (3 million net) of prospective lands in the Gulf Coast region in 2001 and has identified a number of exploratory drilling opportunities.

ALASKA

The Company's Alaska oil and gas operations are located in the Cook Inlet. The Company operates 10 platforms in the Cook Inlet and five of twelve producing natural gas fields. In 2001, the Company's net natural gas production averaged 103 MMcf/d. Pursuant to agreements with the purchaser of the Company's former agricultural products business, most of the Company's natural gas production is sold, at an agreed price, for feedstock to a fertilizer manufacturing operation in Nikiski, Alaska.

The Company also holds working interests in two North Slope fields. The Company has a 10.52 percent working interest in the Endicott field and a 4.95 percent working interest in the Kuparuk and Kuparuk satellite fields.

In 2001, net liquids production averaged approximately 25 MBbl/d of which about 51 percent was from the Cook Inlet and 49 percent was from the North Slope. All of the Company's Alaska crude oil production is currently sold to Tesoro Petroleum Corporation at spot market prices.

In the Cook Inlet, the Company has refocused on its oil production assets. In 2001, the Company drilled four development oil wells from the King Salmon platform in the McArthur River Field. One of the wells, the K-13, came on production in July at about 8 MBbl/d. The Company holds a 53 percent working interest in the McArthur River Field. The Company is looking to increase production from its oil and gas fields in the Cook Inlet in 2002 by applying the advanced analytical and precision-drilling techniques that were used in 2001 to turn the King Salmon platform from a marginally economic operation into the highest-rate oil production facility in southern Alaska. The 2002 drilling program calls for additional wells from the Monopod and Grayling platforms. The King Salmon and Grayling platforms are located in the Trading Bay Unit and the Monopod platform is located in the Trading Bay Field, all of which are located in the Cook Inlet.

Early in 2002, the Company announced a discovery of a new natural gas reservoir on Alaska's Kenai Peninsula. The Grassim Oskolkoff #1 (GO#1) well, the first exploration well drilled under a joint operating agreement between the Company and Marathon Oil Company (Marathon) in the Ninilchik Exploration Unit, indicated significant natural gas accumulations. Operated by Marathon, the GO#1 well is located 35 miles south of Kenai, Alaska, on the Kenai Peninsula. The well was drilled to a total depth of 11,600 feet. Exploration efforts also continue at several other wells in the unit. The Company holds a 40 percent working interest in the 25,000-acre Ninilchik Exploration Unit. Marathon is operator and holds the remaining interest.

The Company has signed a contract to sell, at its option, up to 450 billion cubic feet of natural gas to an affiliate of ENSTAR Natural Gas Company beginning in January 2004. ENSTAR distributes natural gas to Anchorage, the Matanuska-Susitna Valley, and the Kenai Peninsula. The Regulatory Commission of Alaska approved the Unocal-ENSTAR gas contract in December 2001.

CANADA

Production in 2001 averaged approximately 16 MBbl/d of liquids and 101 MMcf/d of natural gas. The Company's operations in Canada are carried out by its wholly owned subsidiary Northrock, which focuses on three core areas in West Central Alberta (O'Chiese, Garrington, Caroline and Pass Creek areas), Northwest Alberta (Red Rock and Knopcik areas), and the Williston Basin (Southeastern Saskatchewan).

INTERNATIONAL

The Company's International operations encompass oil and gas exploration and production activities outside of North America. The Company, through its International subsidiaries, operates or participates in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. In 2001, Unocal's International operations accounted for 45 percent and 41 percent of the Company's natural gas and liquids production, respectively. International operations also include the Company's exploration activities outside of North America and the development of energy projects primarily in Asia, Latin America and West Africa.

Thailand

The Company, through its Unocal Thailand, Ltd. (Unocal Thailand), subsidiary, currently operates 14 fields producing natural gas, crude oil and condensate in four sales contract areas offshore in the Gulf of Thailand. Unocal's average working interest (net of royalty) for three of the contract areas is 64 percent, while for the fourth contract area, Pailin, it is 31 percent. The Thailand operation, producing since 1981, has installed over 100 platforms in the Gulf of Thailand. The Company had 1,080 employees in its Thailand operations at year-end 2001. Approximately 92 percent of these employees were Thai nationals.

Gross natural gas production from Unocal-operated fields in 2001 averaged 974 MMcf/d (576 MMcf/d net to the Company). The natural gas is used mainly in power generation, but also in the industrial and transportation sectors and in the petrochemical industry. Gross crude oil and condensate production in 2001 averaged 37 MBbl/d (21 MBbl/d net to the Company). The produced crude oil is sold to both domestic and export markets and the condensate is used primarily as a blending stock in oil refineries, as a chemical solvent and as a petrochemical feedstock. The Company's natural gas production fulfills approximately 30 percent of Thailand's total electricity demand.

The Company sells all of its natural gas production to PTT Public Co., Ltd. ("PTT"), under various long-term contracts with expiration dates ranging from 2006 to 2029. The contract prices are based on formulas that allow prices to fluctuate with market prices for crude oil and refined products and are indexed to the U.S. dollar. The Company has typically supplied substantially more natural gas to PTT than the minimum daily contract quantity provision of its sales contracts. In 2001, the Company and its partners reached an agreement with PTT, which provided PTT a cash incentive to take an incremental 18 billion cubic feet of natural gas above contract minimums from certain fields in the Gulf of Thailand over a 15-month period. If by the end of the incentive period PTT fails to take the full incremental volume, then PTT is obligated to refund to the Company and its partners a pro-rata share of the cash incentive. During the incentive period, the existing contract pricing mechanism continues for all quantities of gas taken under the contracts. The Company is holding discussions with the government of Thailand regarding the latter's request to lower the price of natural gas under most of the existing contracts.

Gas supplies coming into Thailand from the Yadana project, in which the Company has a 28.26 percent non-operating working interest (see discussion below) in neighboring Myanmar have displaced some of the gas volumes that PTT had taken from the Company's Thailand operations. See note 29 to the consolidated financial statements for the amount of combined sales to PTT from the Company's Thailand and Myanmar operations.

Unocal Thailand continued to strengthen its resource base during 2001 with a successful exploration program - drilling 24 gross exploratory wells, of which 21 were successful - supporting the Company's position as a long-term gas supplier in Thailand. In order to continue meeting its ongoing contractual gas delivery commitments, the Company drilled 79 (gross) successful development wells in the Gulf of Thailand and continued construction of facilities for its Pailin II (North Pailin) development project. Production is expected to commence from North Pailin in mid-year 2002, with gross production expected to reach approximately 165 MMcf/d of natural gas and 8 MBbl/d of condensate. Effective with the start of production from North Pailin, the minimum quantity of natural gas that PTT is contractually obligated to purchase from the Company and its partners under existing contracts in the Gulf of Thailand will increase by 165 MMcf/d (gross) to 1,070 MMcf/d (gross).

During 2001, Unocal Thailand participated in drilling 10 successful exploratory and delineation wells on the Arthit prospect in the Gulf of Thailand. The Company holds a 16 percent working interest in the Arthit prospect, which encompasses three blocks totaling 1.5 million acres.

The Company began oil operations in fields in the northwest part of its concession in the Gulf of Thailand. Crude oil production began in August 2001 from the Plamuk field, and the Company has completed the initial stage of oil development for its Yala field. The Plamuk, Yala and adjacent Surat fields contain both oil and natural gas reserves and are expected to increase oil production to about 15 MBbl/d in 2002. The gas associated with these fields will be sold under an existing contract to PTT. The Company has a 62.34 percent working interest (net of royalty) in these fields.

Myanmar

The Company, through subsidiaries, has a 28.26 percent non-operating working interest in natural gas production from the Yadana field, offshore Myanmar in the Andaman Sea. The offshore facilities consist of four platforms with 14 wells. Another subsidiary of the Company has a 28.26 percent equity ownership in a pipeline company that owns and operates a natural gas pipeline extending from the offshore facilities across Myanmar's remote southern panhandle to Ban-I-Tong at the Myanmar-Thailand border.

The gas is purchased by PTT to fuel a portion of the power plant which is operated by the Electric Generating Authority of Thailand (EGAT) at Ratchaburi, located southwest of Bangkok. Production from the Yadana field began in 1999. Gross natural gas production averaged 533 MMcf/d (98 MMcf/d net to the Company) in 2001, which was more than the contract rate of 525 MMcf/d.

The gas sales agreement with PTT includes a "take-or-pay" provision, which requires PTT to purchase and pay for the specified annual contract quantity of natural gas, whether or not it takes delivery of the full quantity. PTT did not incur a "take-or-pay" obligation in 2001, and the Company does not expect PTT to incur one in 2002.

The Company, through Unocal Indonesia Company and other subsidiaries, holds varying interests in 10 offshore PSC areas. Seven PSC areas including East Kalimantan, Ganal, Sesulu, Rapak, Makassar, Popodi and Papalang are located offshore Borneo, on the western side of the Makassar Strait, East Kalimantan, and cover more than 5.9 million acres. Another PSC area, Sangkarang, is on the eastern side of the Makassar Strait, offshore Sulawesi, and covers nearly 1.5 million acres. Two additional PSC areas, Bukat and Ambalat, are located in the Tarakan Basin offshore Northeast Kalimantan and cover nearly 1.7 million acres. Farm-in agreements to acquire interests in the Popodi and Papalang PSC areas were signed in December 2001 and are currently pending approval by the Indonesian Government. The Company has over 1,700 employees in its Indonesian oil and gas operations at year-end 2001, of which approximately 94 percent were Indonesian nationals.

Shelf - The Company currently operates 11 producing oil and gas fields offshore East Kalimantan, including Indonesia's largest offshore oil and gas field, Attaka, which the Company discovered in 1970. In early 2001, this oil field surpassed 600 million BOE of cumulative gross production. The Company has a 100 percent working interest in 10 of the fields, and a 50 percent working interest in the Attaka field.

Oil and associated gas production from its northern fields are processed at the Company-operated Santan terminal and liquids extraction plant, and the dry gas is transported by pipelines to an LNG plant, located nearby at Bontang, East Kalimantan. Dry gas is also transported by pipelines to a fertilizer, ammonia and methanol complex, located north of Bontang. LNG is currently sold to Japan, Korea and Taiwan and the extracted LPG is exported to Japan. Oil and gas from the Company's southern fields are sent to the Company-operated Lawe-Lawe terminal located onshore south of Balikpapan. The stored oil is either exported by tanker or transported by pipeline to a refinery in Balikpapan owned by Pertamina, the Indonesian national petroleum company. The gas is transported by pipeline and sold as fuel gas to the Pertamina refinery.

Gross production from Company-operated fields averaged 67 MBbl/d of liquids and 275 MMcf/d of natural gas in 2001. The average economic interest production under the PSCs was 30 MBbl/d of liquids and 155 MMcf/d of natural gas in 2001.

Deep Water - The Company, through subsidiaries, is the operator of the East Kalimantan, Ganal, Sesulu, Rapak and Makassar Strait PSCs. The Company holds working interests of 100 percent in the East Kalimantan, 90 percent in the Makassar Strait and 80 percent in the Rapak, Ganal and Sesulu PSCs.

The Company previously received approvals from Pertamina to develop the West Seno and Merah Besar oil and gas fields in the deepwater Kutei Basin, offshore East Kalimantan. The West Seno field is located in the Makassar Strait PSC area while the Merah Besar field straddles the East Kalimantan PSC and the northern portion of the Makassar Strait PSC areas. Development activity is planned in three phases, with phase one production from the West Seno field expected to begin in 2003. The second phase of development will seek to expand the West Seno production plateau in early 2005. Production from the West Seno field is anticipated to reach a peak production level of approximately 60 MBbl/d and 150 MMcf/d (gross) in 2005 with the second phase of development. Gross development costs for West Seno's 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. The Merah Besar field will be developed as a separate project and development plans are being finalized at the present time. The two fields qualify to supply gas for the latest package of LNG, LPG and domestic gas sales at the Bontang facilities.

In early 2001, the Company discovered natural gas and crude oil on the Ranggas prospect in the southern portion of the Rapak PSC area. The Ranggas-1 well encountered 250 feet of net gas pay and 40 feet of net oil pay. The discovery well is located on a separate geologic structure approximately 28 miles southeast of West Seno. The Company drilled two successful appraisal wells on the prospect in 2001. The Ranggas-2 well encountered 155 feet of net oil pay and 118 feet of net gas pay. The Ranggas-2 well is located in the southern portion of the Ranggas structure, nearly a mile southwest of the discovery well. The Ranggas-3 well encountered 306 feet of net oil pay and 123 feet of net gas pay. The well is located 3.4 miles north of the discovery well in the central portion of the structure. Additional appraisal work will be done during 2002 to determine the commerciality of the discovery.

In 2000, the Company discovered natural gas in the Gula, Gada, Gendalo and Gandang prospects in the Ganal PSC area. The Gula discovery well encountered 260 feet of net gas pay. The Gada discovery well encountered 70 feet of net gas pay. The Gendalo discovery well encountered 242 feet of net gas pay. The Gandang discovery well encountered 136 feet of net gas pay. In early 2002, the Company drilled two successful appraisal wells, the Gendalo-3 well and the Gandang-2 well, which encountered 102 feet and 185 feet of net pay respectively. Additional delineation work will be required before commercialization may be declared. This delineation work is planned for 2002.

Azerbaijan

Unocal has a 10.28 percent working interest in the Azerbaijan International Operating Company (AIOC) consortium that is producing and developing offshore oil reserves in the Caspian Sea from the Azeri and Chirag fields. In 2001, AIOC's gross oil production averaged 119 MBbl/d (11 MBbl/d net to the Company). AIOC has access to two pipelines to export its oil production: a northern pipeline route, which connects in Russia to an existing pipeline system and a western pipeline route from Baku in Azerbaijan through Georgia. In 2001, the production from the consortium was exported through the western pipeline. Both pipelines connect with ports on the Black Sea.

In 2001 the consortium approved development of the "Phase I" portion of the offshore oil reserves. This phase of the project will develop an estimated 1.5 billion barrels of proved crude oil reserves. Phase I gross production is scheduled to commence in late 2004 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 I.

Bangladesh

The Company, through subsidiaries, holds interests in three PSCs in Bangladesh. Two PSCs cover Blocks 12, 13 and 14, which total more than 3 million acres. The Company has a 98 percent working interest in these three blocks and is the operator. Gross production from the Jalalabad field on Block 13 averaged 83 MMcf/d (55 MMcf/d net to the Company) of natural gas and 1 MBbl/d (700 b/d net to the Company) of liquids in 2001. The natural gas production supplies approximately 12 percent of the country's gas demand. The Company also discovered the Moulavi Bazar gas field on Block 14. The discovery was Unocal's third major gas field discovered in Bangladesh. The Bibiyana field, a major gas field located on Block 12, was discovered in 1998. The third PSC covers Block 7 in the southwest of Bangladesh, which encompasses more than 2 million acres. The Company has a 90 percent working interest in Block 7.

In 2001, the Company submitted a detailed gas export pipeline development plan to Petrobangla, the state oil and gas company of Bangladesh. This proposal includes construction of a new 30-inch diameter, 1,363-kilometer (847-mile) pipeline, with an initial capacity of 500 MMcf/d, from the Bibiyana field in northeast Bangladesh to targeted markets in India. The review by Petrobangla and the government of Bangladesh is a lengthy process since the export of any quantity of natural gas to neighboring countries is a contentious national political issue in Bangladesh.

The Netherlands

The Company, through a subsidiary, has interests ranging from 34 percent to 80 percent in four blocks in the Netherlands sector of the North Sea. Average gross production in 2001 was approximately 6 MBbl/d of crude oil (5 MBbl/d net to the Company) and 16 MMcf/d (7 MMcf/d net to the Company) of natural gas. The Company is the operator and has an average 70 percent working interest.

Democratic Republic of Congo

The Company, through a subsidiary, has a 17.7 percent non-operating working interest in the rights to explore and produce hydrocarbons in the entire offshore area of the country. Gross production averaged about 18 MBbl/d of crude oil (3 MBbl/d net to the Company) from seven fields in 2001.

Brazil

The Company, through an affiliate, holds a 50 percent interest in a company that has a 35 percent participation agreement with Petrobras in the Pescada-Arabaiana oil and gas project in the Potiguar basin, offshore Brazil. The agreement covered the acquisition of an initial 79 percent participation interest from Petrobras in five concession areas containing six proven oil and gas reservoirs, plus a 35 percent interest in a 55,000-acre exploration block. The project currently consists of six production platforms and a 45-mile long, 26-inch diameter multi-phase pipeline already in operation. In 2001, gross production from the project averaged 700 b/d of oil and 7 MMcf/d of natural gas. Net production from the project averaged 300 b/d of oil and 3 MMcf/d of natural gas. Annual gross production is expected to reach 5 MBbl/d of oil and 55 MMcf/d by 2003. The annual net production is expected to reach approximately 1 MBbl/d of oil and 17 MMcf/d of natural gas.

The Company, through Brazilian subsidiaries, is active in other projects in the country. The Company holds a 40.5 percent working interest in Block BM-ES-2. The 593,000-acre offshore deepwater block is located in Brazil's Espirito Santo Basin in water depths of 5,000 to 8,000 feet. The Company is the operator. Seismic data for the block is being evaluated, and the consortium hopes to drill one well in late 2002 or early 2003, depending on the results of the seismic interpretation.

The Company also holds a 30 percent working interest in Block BES-2. This offshore block covers 642,000 acres and is located in water depths ranging from 1,200 to 4,500 feet. In 2001, the first exploration well drilled had hydrocarbon shows but was not commercial.

In February 2002, the Company signed an agreement to acquire a 25 percent non-operating working interest in the exploration block BM-ES-1 in the Espirito Santo basin. The block covers 670,000 acres and is approximately 93 miles offshore in water depths from 4,900 to 9,000 feet.

Vietnam

The Company, through subsidiaries, holds interests in two PSCs offshore southern Vietnam in the northern part of the Malay Basin. The Company is the operator and has an approximate 42 percent working interest in one PSC, which includes Block B and Block 48/95. This PSC covers more than 2.2 million acres. The Company made the initial gas discovery on the Kim Long prospect on Block B in late 1997. The Company also holds an approximate 43 percent working interest in a PSC for exploration of Block 52/97, which covers more than 500,000 acres.

In 2001, the Company added to its natural gas resources in Vietnam with four more successful wells. In 2000, the Company drilled five successful wells that confirmed natural gas resources in the Kim Long, Ac Qui and Ca Voi trends.

The Company has begun work towards commercializing its offshore natural gas resources. The Company is in discussions with PetroVietnam, the state oil and gas company, concerning a natural gas pipeline to serve power plants proposed for construction in southern Vietnam.

Gabon

Unocal is a member of the Vanco Gabon Group, a consortium of French and U.S. oil and gas exploration companies that has PSCs for three exploration blocks located in deep water offshore Gabon, West Africa. The Company drilled four exploration wells in 2001. All four wells were dry. The Company and the other consortium members are evaluating the remaining features on the blocks. The Company holds a 25 percent working interest.

TRADE

The primary function of the Trade segment is to externally market the Company's hydrocarbon production. Marketing activities include transporting and selling the Company's production. To that end, the Trade segment conducts the majority of the Company's: (a) worldwide crude oil and condensate marketing activities, excluding those of Pure and (b) North American natural gas marketing activities, excluding those of Pure and the Alaska business unit. Commodities are sold to third parties at market prices, terms and conditions. Most of the Company's U.S. production is sold on an intracompany basis from the Exploration and Production segment to the Trade segment at market prices and then resold by the Trade segment to third-party customers. These intracompany sales and purchase transactions, including any intracompany profits and losses, are eliminated upon consolidation. To market the Company's crude oil production, the segment enters into various sale and purchase transactions with unaffiliated oil and gas producing, refining, and trading companies. These transactions transfer commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity. These transactions allow the Company to better manage its risk and seek higher profit margins than if the Exploration and Production segment were to sell the Company's production directly to third parties at production locations. Currently, these sale and purchase transactions represent a significant portion of the segment's U.S. crude oil sales and purchases. The Company's non-U.S. crude and condensate production and Northrock natural gas production is marketed by the Trade segment on a commission or fee basis on behalf of the Exploration and Production segment. Intracompany profits and losses related to the commissions or fee arrangements are eliminated upon consolidation.

The Trade segment is also responsible for implementing commodity-specific risk management activities on behalf of the Company's Exploration and Production segment, excluding Pure. The objectives of these risk management activities include reducing the overall volatility of the Company's cash flows and preserving revenues. The segment enters into various hydrocarbon derivative financial instrument contracts, such as futures, swaps and options (derivative contracts) to hedge or offset portions of the Company's exposure to commodity price changes for future sales transactions. These commodity-risk management activities are authorized by the Company's senior management.

The segment also purchases crude oil, condensate and natural gas for resale from certain of the Company's royalty owners, joint venture partners and unaffiliated oil and gas producing, refining, and trading companies.

The segment also trades hydrocarbon derivative instruments, for which hedge accounting is not used, to exploit anticipated opportunities arising from commodity price fluctuations. These instruments primarily consist of exchange-traded futures and options contracts. The segment also purchases limited amounts of physical inventories for energy trading purposes when arbitrage opportunities arise. These 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.

As mentioned above, a large portion of the Exploration and Production segment's production is sold to the Trade segment. However, since this production is sold to the Trade segment at market prices or marketed on a commission or fee basis, the Trade segment's business is, as a consequence, a low-margin business. Intracompany profits and losses related to the Trade segment's intracompany purchases, commissions, or fee arrangements are eliminated upon consolidation.

For additional details on the on the Trade segment activities, see note 29 to the consolidated financial statements in Item 8 of this report.

MIDSTREAM

In 2001, the Midstream segment was formed and is comprised of the Company's pipelines business and North America gas storage businesses.

The pipelines business principally includes the Company's equity interests in affiliated petroleum pipeline companies and wholly-owned pipeline systems throughout the U.S. Included in Unocal's pipeline investments is the Colonial Pipeline Company, in which the Company holds a 23.44 percent equity interest. The Colonial Pipeline system runs from Texas to New Jersey and transports a significant portion of all petroleum products consumed in its 13-state market area. Also included is the Unocal Pipeline Company, a wholly-owned subsidiary, which holds a 1.36 percent participation interest in the TransAlaska Pipeline System (TAPS). TAPS transports crude oil from the North Slope of Alaska to the port of Valdez. In addition, the Company holds a 27.75 percent interest in the Trans-Andean oil pipeline, which transports crude oil from Argentina to Chile.

The Company, through its participation in the AIOC consortium, is pursuing the development of a 42-inch pipeline from Baku in Azerbaijan to Ceyhan in Turkey. The pipeline project is planned to have a crude oil capacity of 1 million b/d. The pipeline will enable crude oil production from AIOC's future development, as well as other possible sources, to reach market. Individual company ownership percentages in the pipeline are currently being determined.

The Company owns varying interests in natural gas storage facilities in west-central Canada and Texas. The Company, through Canadian subsidiaries, holds a 94 percent interest in the Aitken Creek Gas Storage Project in British Columbia, which was expanded to 48 billion cubic feet of capacity and 500 MMcf/d of deliverability in 2001. The Company also holds an interest in the Cal Ven Pipeline and the Alberta Hub natural gas storage facility in Alberta. Construction of the Keystone Gas Storage Project in West Texas is proceeding on schedule. The project is slated to begin storage operations in 2002 with initial storage capacity of 3 billion cubic feet. The Company holds a 100 percent interest in the project.

The Company is a producer of geothermal energy, with more than 35 years experience in geothermal resource exploration, reservoir delineation, and management. The Company also has proven experience in planning, designing, building and operating private power projects and related project finance and economics.

The Company, through subsidiaries, operates major geothermal fields producing steam for power generation projects at Gunung Salak and Wayang Windu in Indonesia and at Tiwi and Mak-Ban in the Philippines. Together, these projects have a combined installed electrical generating capacity of 1,200 megawatts.

Indonesia - The Company explores for, develops and produces geothermal steam pursuant to the terms of exclusive joint operation contracts with Pertamina and sells geothermal steam to PT PLN (Persero) ("PLN"), the state electricity company, pursuant to the terms of energy sales contracts. The Company also has a 50 percent non-controlling interest in, Dayabumi Salak Pratama, Ltd. ("DSPL"), which operates three power generation facilities with a total installed capacity of 165 megawatts associated with the Gunung Salak steam field. DSPL operates these power plants and sells electrical energy to PLN pursuant to the build-operate-transfer provisions of current contracts. In 2001, the Company began operating the Wayang Windu geothermal power project near Bandung, West Java on behalf of an equity investee, which owns a 50 percent non-controlling interest in the project. The project, which includes a 110 megawatt power plant and geothermal steam field, is currently operating at full capacity. Title to geothermal resources in Indonesia rests with the central government.

Efforts to renegotiate the geothermal steam sales and electrical energy sales contracts at Gunung Salak in Indonesia are continuing. The Company believes that significant progress has been made towards an agreement that is acceptable to all parties to resolve outstanding issues (see the discussion under Geothermal and Power Operations in the "Outlook" section of Management's Discussion and Analysis in Item 7 of this report).

Philippines - The Republic of the Philippines retains title to geothermal resources in the ground and the National Power Corporation ("NPC"), a Philippine government-owned corporation, acts as the steward to develop steam resources. Philippine Geothermal, Inc. ("PGI"), a wholly-owned subsidiary, has developed and produced steam resources for NPC pursuant to a 1971 service contract. NPC is the owner of all of the equipment and surface lands used in steam field operations and owns and operates the power plants at Tiwi and Mak-Ban on the island of Luzon. PGI continues to operate the steam fields under an Interim Agreement with NPC while PGI and NPC continue negotiations to settle their long-standing contract dispute. The dispute involves the renewability of the service contract between NPC and PGI. PGI claims that the contract is renewable on the same terms as the initial 25-year term of the contract while NPC claims otherwise. As a result, the renewal has been the subject of arbitration at the International Chamber of Commerce and litigation in the Philippine courts. Arbitration and litigation actions have been suspended while NPC and PGI attempt to negotiate a settlement. These negotiations center on a revised contract, which would address the length (term), the cost of geothermal steam and the requirement for Filipino ownership. Provisions of the 1987 Philippine Constitution prohibit foreign-owned companies from exploring, developing and utilizing geothermal resources. The original service contract was structured such that PGI was designated as the exclusive provider of technical and financial services to NPC, which had sole responsibility for exploiting the geothermal resources. As noted in the "Outlook" section of Item 7 ("Management's Discussion & Analysis"), recent Philippine legislation mandating the eventual privatization of NPC's assets will ultimately result in transferring the responsibility for exploiting the geothermal resources. The current discussions center on PGI directly developing the geothermal resources through a 60 percent Filipino-owned company in order to meet the requirements of the Philippine Constitution.

Thailand - The Company, through subsidiaries, also has various equity interests in four gas-fired power plant projects in Thailand. One of the projects has been in operation since 1998 while two of the power projects began commercial operations in 2000, and the fourth began commercial operations in 2001.

The Company's geothermal reserves and operating data are summarized in the following table:

	2001	2000	1999
Net proved geothermal reserves at year end: (a)			
billion kilowatt-hours	108	114	120
million equivalent oil barrels	162	170	179
Net daily production			
million kilowatt-hours	14	16	17
thousand equivalent oil barrels	22	25	25
Net geothermal lands in thousand acres			
proved	9	9	9
prospective	314	314	314
Net producible geothermal wells	84	83	79

<FN>
(a) Includes reserves underlying a service fee arrangement in the Philippines.
</FN>

PATENTS

Between 1994 and 2000 the Company was awarded five patents resulting from its independent research on reformulated gasolines ("RFG"). Although the Company indicated a willingness to enter into licensing negotiations, the first of these patents (the `393 patent) was the subject of litigation initiated in 1995 by the major refiners in California. Following a jury verdict upholding the patent and the award of damages to the Company, the refiners appealed unsuccessfully to the U.S. Circuit Court of Appeals. In 2000, the Company received payment on a judgment, including interest and attorneys fees, of approximately $91 million for infringement by the refiners for the period of March through July of 1996.

The Company has entered into eight licensing agreements that grant motor gasoline refiners, blenders and importers (including CITGO Petroleum Corporation, Tesoro Petroleum Corporation and units of The Williams Companies, Inc.) the right to make cleaner-burning gasolines using formulations patented by the Company. The Company continues to negotiate with other refiners, blenders and importers on licensing agreements. The Company has a uniform licensing schedule that specifies a range from 1.2 to 3.4 cents per gallon for volumes that fall under the patents. As a licensee uses the license more frequently, the rate per gallon is reduced. The Company believes that its patented formulations provide refiners and blenders with a cost-effective way of meeting California and federal standards for cleaner-burning gasolines.

In February and March 2001, petitions were filed with the U.S. Patent and Trademark Office ("PTO") by Washington, D.C., law firms, acting on behalf of unnamed parties, requesting reexamination of two of the Company's patents (the `126 and `393 patents, respectively). In 2001 the PTO granted reexamination as to the `393 patent and in January 2002 initially rejected all of the claims of that patent. The Company is responding to this initial rejection of claims. In January 2002, the PTO also granted the reexamination request for the `126 patent. The reexamination process is expected to take several months, but the Company believes the `126 and `393 patent claims are novel and non-obvious and expects the patents to be sustained. Licensing fees and judgments collected during the pendency of the reexaminations are not refundable.

In March 2001, ExxonMobil Corporation requested the U.S. Federal Trade Commission ("FTC") to conduct an investigation into certain alleged unfair competition practices allegedly engaged in by the Company in connection with its patents. ExxonMobil alleges that the Company engaged in anti-competitive conduct in the regulatory processes that established California and federal standards for RFG and thus gained "monopoly profits" in the RFG market. ExxonMobil requests that the FTC use its authority to fashion an appropriate remedy. In August 2001, the Company received notice that the FTC was conducting a non-public investigation of this matter. The Company has been cooperating with the FTC in its inquiry.

In October 2001, the Company was informed that the U.S. District Court in Los Angeles had granted the Company's motion for summary judgment requesting an accounting of infringement of the `393 patent from August 1996 through December 2000 by the five defendants. The Company had requested that the court apply the 5.75 cents per gallon awarded in the original 1997 trial to the defendants' infringing volumes produced during this period. The court also denied the defendants' motions that these damage proceedings be stayed pending the outcome of the patent reexaminations or, alternatively, that the defendants be granted a new trial as to damages. In December 2001, the judge recused himself from the case without signing Unocal's proposed judgment implementing the decision. The case was subsequently transferred to another Judge. In February 2002, the defendants requested that the new judge reconsider the status of the case and vacate the earlier rulings. A ruling on these matters is tentatively scheduled for May 2002.

In January 2002, the Company filed suit against Valero Energy Corporation in the U.S. District Court in Los Angeles for infringement of both the `393 and `126 patents by Valero and Ultramar Diamond Shamrock (acquired by Valero in 2001). The Company is seeking 5.75 cents per gallon for motor gasolines infringing one or more claims under the patents and a trebling of the amount for willful infringement. The Company is also seeking a mandatory licensing of its patents by Valero with respect to future activities.

COMPETITION

The energy resource industry is highly competitive around the world. As an independent oil and gas exploration and production company, Unocal competes against integrated oil and gas companies, independent oil and gas companies, government-owned oil and gas companies, individual producers, marketing companies and operators for finding, developing, producing, transporting and marketing oil and gas resources. The Company believes that it is in a position to compete effectively. Competition occurs in bidding for U.S. prospective leases or international exploration rights, acquisition of geological, geophysical and engineering knowledge, and the cost-efficient exploration, development, production, transportation, and marketing of oil and gas. The future availability of prospective leases/concessions is subject to competing land uses and federal, state, foreign and local statutes and policies. The principal factors affecting competition for the energy resource industry are oil and gas sales prices, demand, worldwide production levels, alternative fuels and government and environmental regulations. The Company's geothermal and power operations are in competition with producers of other energy resources.

EMPLOYEES

As of December 31, 2001, Unocal and its subsidiaries had approximately 6,980 employees, compared to 6,800 and 7,550 in 2000 and 1999, respectively. The totals included approximately 320 and 230 employees of the Company's Pure subsidiary in 2001 and 2000, respectively. Of the total Unocal employees at year-end 2001, 215 in the U.S. were represented by various labor unions and 355 in Thailand were represented by a trade union.

GOVERNMENT REGULATIONS

Certain interstate crude oil pipeline subsidiaries of Unocal are regulated (as common carriers) by the Federal Energy Regulatory Commission. As a lessee from the U.S. government, Unocal is subject to Department of the Interior regulations covering activities onshore and on the Outer Continental Shelf ("OCS"). In addition, state regulations impose strict controls on both state-owned and privately-owned lands.

Some federal and state bills would, if enacted, significantly and adversely affect Unocal and the petroleum industry. These include the imposition of additional taxes, land use controls, prohibitions against operating in certain foreign countries and restrictions on exploration and development.

Regulations promulgated by the Environmental Protection Agency ("EPA"), the Department of the Interior, the Department of Energy, the State Department, the Department of Commerce and other government agencies are complex and subject to change. New regulations may be adopted. The Company cannot predict how existing regulations may be interpreted by enforcement agencies or court rulings, whether amendments or additional regulations will be adopted, or what effect such changes may have on its current or future business or financial condition.

ENVIRONMENTAL REGULATIONS

Federal, state and local laws and provisions regulating the discharge of materials into the environment or otherwise relating to environmental protection have continued to impact the Company's operations. Significant federal legislation applicable to the Company's operations includes the following: the Clean Water Act, as amended in 1977; the Clean Air Act, as amended in 1977 and 1990; the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"); the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended in 1986; the Oil Pollution Act of 1990 and laws governing low level radioactive materials. Various foreign, state and local governments have adopted or are considering the adoption of similar laws and regulations. The Company believes that it can continue to meet the requirements of existing environmental laws and regulations. The following discussion describes the nature and impact of regulations that may have a material affect on the Company.

The Clean Water Act, as amended in 1977, requires all oil and gas exploration and production facilities, as well as mining and other operations, of the Company and its subsidiaries to eliminate or meet stringent permit standards for the discharge of pollutants into the waters of the United States from both point sources and from stormwater runoff. The act requires the Company to construct and operate waste water treatment systems and injection wells, to transport and dispose of onshore spent drilling muds and other associated wastes, to monitor compliance with permit requirements and to implement other control and preventive measures. Requirements under the act have become more stringent in recent years and now include increased control of toxic discharges.

The Clean Air Act, as amended in 1977 and 1990, and its regulations require, among other things, enhanced monitoring of major sources of specified pollutants; stringent air emission limits on the Company's marine terminals, mining operations and other facilities; and risk management plans for storage of hazardous substances. Title V of the act requires major emission sources to obtain new permits. Title V also requires more comprehensive measurement of specified air pollutants from major emission sources. Title V has a significant impact on Company monitoring, recording and reporting requirements ("MR&R"). MR&R involves periodic reporting such as semi-annual monitoring reports, permit deviation reports and annual compliance certifications. Failure to properly file these reports may result in a Notice of Violation and possible fine. The Risk Management Plan regulations under the Clean Air Act require that any non-exempted facility that processes or stores a threshold amount of a regulated substance prepare and implement a risk management plan to detect, prevent and minimize accidental releases. The regulations require undertaking an offsite hazard assessment, preparing a response plan and communication with the local community. The Company has risk management plans in place for these potential hazards.

Under the Clean Air Act, the U.S. Environmental Protection Agency ("EPA") is required to adopt a number of national air toxic reduction programs that address hazardous air pollutants, also known as HAPs. One of these programs is the adoption of Maximum Achievable Control Technology ("MACT") for large HAP sources. Once the EPA has issued all of the MACT standards, it is required to conduct a health risk assessment and revise the standards if it is shown to be necessary to protect public health. The EPA must promulgate regulations establishing emission standards for about 175 categories of HAP sources. The standards require the maximum degree of emission reduction that the EPA determines to be achievable for each particular source category. Different MACT criteria are applicable for new and for existing sources. Under the act, the EPA is required to develop and implement a program for assessing the risk remaining ("residual risk") after facilities have implemented MACT standards. The EPA has finalized MACT control requirements for certain categories of oil and gas production and gas transmission and storage facilities. There are pending MACT regulations under the categories of Organic Liquids Distribution, Combustions, Turbines, Industrial Boilers and Heaters and Reciprocating Internal Combustion Engines. In order to comply with National Ambient Air Quality Standards, which were promulgated to protect public health, some states and the proposed MACT rules will require large reductions in the emission of nitrogen oxides and carbon monoxide. This will require the addition of significant new controls and associated MR&R.

The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"), regulates the storage, handling, treatment, transportation and disposal of hazardous and non-hazardous wastes. It also requires the investigation and remediation of certain locations at several former Company facilities, where such wastes have been handled, released or disposed. RCRA requirements have become increasingly stringent in recent years and the EPA has expanded the definition of hazardous wastes. Company facilities generate and handle a number of wastes regulated by RCRA and have facilities that have been used for the storage, handling or disposal of RCRA wastes that are subject to investigation and corrective action. The Company must provide financial assurance for future closure and post-closure costs of its RCRA-permitted facilities and for potential third party liability. Management of wastes from the exploration and production of oil and gas are typically classified as non-hazardous oil field wastes regulated by the states rather than the EPA. Subchapter IX regulates underground storage tanks, including corrective action for releases and financial assurance for corrective action and third party liability. This subchapter and similar state laws, such as the California Health and Safety Code, the Texas Administrative Code, Title 30 (Environmental Quality), and the Alaska Administrative Code, Title 18 (Environmental Conservation), impact the cleanup of the Company's former service stations and other facilities.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended in 1986, provides that waste generators, site owners, facility operators and certain other parties may be strictly and jointly and severally liable for the costs of addressing sites contaminated by spills or waste disposal regardless of fault or the amount of waste sent to a site. Additionally, each state has laws similar to CERCLA. A federal tax on oil and certain chemical products was enacted to fund a part of the CERCLA program, but this tax has been suspended for several years while CERCLA reform legislation is debated in the U.S. Congress. The Company has been identified as a Potentially Responsible Party ("PRP") under CERCLA at approximately 26 sites by the EPA and various state agencies and private parties have identified the Company as a PRP at 28 other similar sites. A PRP has strict joint and several liability for site remediation costs and so the Company may be required to assume, among other costs, all or portions of the shares attributed to insolvent, unidentified or other parties. The Company does not anticipate that its ultimate exposure at these sites individually, or in the aggregate, will have a material adverse impact on the Company's financial condition or liquidity, but could have a material adverse impact on results of operations.

The Oil Pollution Act of 1990 significantly increased spill response planning obligations, oil spill prevention requirements and spill liability for tank vessels transporting oil, for offshore facilities such as platforms, and for onshore terminals. The act created a tax on imported and domestic oil to provide funding for response to and compensation for oil spills when the responsible party cannot do so.

Other regulations and requirements that may have a material impact on the Company: The Toxic Substances Control Act of 1976, as amended in 1986, regulates the development, testing, import, export and introduction of new chemical products into commerce. SARA Title III, the Emergency Planning and Community Right to Know Act requires the Company to prepare emergency planning and spill notification plans, as well as public disclosure of chemical usage and emissions. The Safe Drinking Water Act and related state programs regulate underground injection control wells, including those used for the injection of fluids brought to the surface in connection with oil and gas production or for secondary or tertiary recovery of oil and gas. The Atomic Energy Act and related federal and state laws have a significant impact on the mining operations and former processing plants of the Company's Molycorp subsidiary. These laws govern management of low level waste materials associated with mineral production and licensing and decommissioning of facilities, as well as naturally occurring radioactive materials from oil and gas operations. These laws also require the Company to provide financial assurances related the decommissioning of facilities and waste disposal.

Environmental regulatory requirements impacting the cleanup of petroleum release sites may also include state and local laws, including the California Safe Drinking Water and Toxic Enforcement Act ("Proposition 65"), the federal and state Endangered Species Act and the Archaeological and Historic Preservation Act of 1974, which protects certain archaeological and historical areas from destruction.

The Company has been a party to a number of administrative and judicial proceedings under federal, state and local provisions relating to environmental protection. These proceedings include actions for civil penalties or fines for alleged environmental violations, orders to investigate and/or cleanup past environmental contamination under CERCLA or other laws, closure of waste management facilities under RCRA or decommissioning of facilities under radioactive materials licenses, permit proceedings and variance requests under air, water or waste management laws and similar matters.

For information regarding the Company's environment-related capital expenditures, charges to earnings and possible future environmental exposure, see Item 3 - Legal Proceedings, the Environmental Matters section of Management's Discussion and Analysis in Item 7 of this report and notes 18 and 22 to the consolidated financial statements in Item 8 of this report.

ITEM 3 - LEGAL PROCEEDINGS.

There is incorporated by reference the information regarding environmental remediation reserves in note 18 to the consolidated financial statements in Item 8 of this report, the discussion of such reserves in the Environmental Matters section of Management's Discussion and Analysis in Item 7 of this report, and the information regarding certain legal proceedings and other contingent liabilities in note 22 to the consolidated financial statements in Item 8 of this report. See also the information under "Patents " in Items 1 and 2 - "Business and Properties" of this report regarding certain lawsuits in which the Company is seeking to enforce its patents for cleaner-burning gasolines.

Set forth below is information with respect to certain specific legal proceedings pending or threatened against the Company or settled and/or disposed of subsequent to September 30, 2001:

1. The U.S. Department of Interior Minerals Management Service (the "MMS") announced in 1996 that it would pursue claims against several oil companies for their alleged underpayment of royalties on crude oil produced from federal leases in California covering the period from 1980 forward. Following that announcement, the Company received from the MMS three orders to pay additional royalties, penalties and interest, covering periods from January 1980 through April 1996, and totaling in excess of $75 million. The Company initiated appropriate administrative appeals. In 1999, the Company also filed an action in the U.S. District Court for the Northern District of Oklahoma (Union Oil Company of California v. Bruce Babbitt, et al.) seeking a declaratory judgment that the applicable statute of limitations barred amounts claimed by the MMS for periods prior to July 1991.

   In 1998, the Company was served with a lawsuit brought by private plaintiffs on behalf of the U.S. government against the Company and numerous other oil companies (United States, ex rel. Johnson v. Shell Oil Company et al., in the U.S. District Court for the Eastern District of Texas, Lufkin Division). The lawsuit alleged intentional underpayment of royalties from 1986 forward on oil produced from federal and Indian land leases in violation of the federal False Claims Act (the "FCA"). In 1999, the U.S. Department of Justice intervened in the lawsuit against the Company. The plaintiffs sought recovery of $52 million in damages and prejudgment interest, to be trebled as provided by the FCA, plus attorneys' fees and civil penalties authorized by the act.

   In 2000, the Company reached an agreement in principle to settle the lawsuits and administrative claims described above. Following the consent of appropriate state governments and certain Native American Indian tribes, the settlement became final in December 2001 and the court dismissed all claims against the Company with prejudice. Under the terms of the settlement, the Company paid an aggregate of $25.5 million, including certain attorneys fees, from reserves which had been previously provided.

2. The Company has been named a defendant in two additional FCA proceedings brought by private plaintiffs on behalf of the United States alleging underpayment of royalties since the mid-1980s on natural gas production from federal and Indian land leases. The first action (United States, ex rel. Harrold E. (Gene) Wright v. Amerada Hess Corporation, et al., in the U.S. District Court for the Eastern District of Texas, Lufkin Division) was filed in 1996 against the Company and 130 other energy industry companies and seeks damages collectively from all defendants of $3 billion, which, to the extent awarded, would be trebled pursuant to the FCA. In 2000, the U.S. Department of Justice (the "DOJ") intervened in the lawsuit against four of the defendants, but has not intervened against the remaining defendants, including the Company.

   The second action (United States, ex rel. Jack Grynberg v. Unocal, in the U.S. District Court for the District of Wyoming) was filed in 1997, as one of 77 separate cases filed by the plaintiff, and seeks damages of approximately $200 million from the Company, which, to the extent awarded, would be trebled pursuant to the FCA. In 1999, the DOJ notified the courts in the Grynberg litigation of its election not to intervene in these actions.

A decision by the DOJ to intervene against a defendant sued under the FCA normally is an indication that the DOJ has investigated and concluded that there is some basis in fact to support the private plaintiff's claim against that particular defendant. Conversely, a decision not to intervene is normally an indication that the DOJ has found no basis in fact to support the private plaintiff's assertions. The Company has cooperated fully with the DOJ in connection with its investigations in both the Wright and Grynberg cases. To date, the Company has received no indication from the DOJ that it contemplates intervening against the Company in either lawsuit.

The Wright and Grynberg cases have been consolidated by the Judicial Panel on Multi-District Litigation as MDL Docket No. 1293 and subsequently transferred for pre-trial proceedings to the U.S. District Court for the District of Wyoming. In 2000, the court entered an order staying the Wright case. The court has yet to lift the stay or to enter an order controlling the progress of these cases. The Company believes the allegations in the Wright and Grynberg cases are without merit and intends to vigorously defend both cases.

3. The Company is a defendant in lawsuits by anonymous representatives purportedly on behalf of a class of plaintiffs consisting of residents and former residents of the Tenasserim region of Myanmar. The lawsuits were initially filed in 1996 in the U.S. District Court for the Central District of California (John Doe I, et al. v. Unocal Corporation, et al., Case No. CV 96-6959-RWSL, referred to as the "Doe" action; and John Roe III, et al. v. Unocal, Inc. [sic], et al., Case No. CV 96-6112-RWSL, referred to as the "Roe" action). The plaintiffs alleged that the company was liable for alleged acts of mistreatment and forced labor by the government of Myanmar allegedly in connection with the construction of the Yadana natural gas pipeline, which transports natural gas from fields in the Andaman Sea across Myanmar to Thailand.

The complaints contained numerous counts and alleged violations of several U.S. and California laws and U.S. treaties. The plaintiffs sought compensatory and punitive damages on behalf of the named plaintiffs, as well as disgorgement of profits. Injunctive and declaratory relief were also requested on behalf of the named plaintiffs and the purported class to direct the defendants to cease payments to the Myanmar government and to cease participation in the Yadana project.

In its answers to amended complaints in both actions, the Company denied that it was either properly named as a party or subject to joint venture, partnership or other liability with respect to the Yadana pipeline. In 2000, the court granted the Company's motions for summary judgment in the two proceedings, ordered the federal law claims dismissed with prejudice and, after declining to exercise jurisdiction over the pendant state law claims, ordered them dismissed without prejudice.

Subsequently, the plaintiffs in both actions appealed the final judgments to the U.S. Court of Appeals for the Ninth Circuit (Case Nos. 00-56603 and 00-56628, respectively), where oral argument was conducted in December 2001. The court's ruling on the appeals remains pending.

In 2000, following the dismissal of their claims by the federal court, the plaintiffs filed actions against the Company in the Superior Court of the State of California for the County of Los Angeles, Central District (John Doe I, et al. v. Unocal Corp., et al., No. BC237980; and John Roe III, et al. v. Unocal Corporation, et al., No. BC237679). The complaints allege that, by virtue of the Company's participation in the Yadana project, it is liable under California law for alleged acts of mistreatment and forced labor by the government of Myanmar.

The complaints contain numerous counts alleging various violations by the defendants of the constitution, statutes and common law of California. With respect to liability for alleged unfair business practices, the Doe action is also styled as a purported class action on behalf of two classes of plaintiffs: all affected residents and former residents of the Tenasserim region of Myanmar and all California residents and the general public within the State of California. The plaintiffs seek compensatory and punitive damages on behalf of the named plaintiffs and the purported classes, as well as injunctive relief, disgorgement of profits and other equitable relief.

The Company's demurrers, which sought to have the actions dismissed from the state court, were denied in September 2001. Subsequently, the Company moved for summary judgment in both actions on all claims, which motions remain pending.

4. In 1998, the Attorney General of Hawaii filed an action (Anzai [formerly Bronster] (State of Hawaii) v. Unocal Corporation, et al., in the U.S. District Court for the District of Hawaii) on behalf of both the people of Hawaii and the state itself against the Company and six other major Hawaii oil refiners, two of which subsequently settled. The amended complaint alleged that the defendants conspired to restrict the production and fix the price of gasoline and diesel fuel in Hawaii in violation of the federal Sherman Act and various state laws. The state sought damages from all defendants in an amount exceeding $450 million covering a period starting in 1990, together with civil penalties in excess of $200 million. If liability were to have been established, the Company would have been jointly and severally liable for any damages awarded.

   The Company and its co-defendants believed that there was no merit to the Attorney General's claim that there was a conspiracy to fix prices or restrict the supply of gasoline or diesel fuel. Moreover, even if such an agreement did exist among some of the defendants, the Company believed that there was no evidence linking it to such an agreement. Further, the Company believed that the sale of its marketing and refining assets to Tosco Corporation ("Tosco") in 1997 would be deemed to constitute an effective withdrawal from any alleged conspiracy. In March 2002, the Company and its co-defendants entered into an agreement with the state to settle this action, subject to court approval, on terms which would include the Company's payment of $3.3 million, for which a reserve has been previously provided.

5. In 1998, a purported class action was filed (Cal-Tex Citrus Juice, Inc., et al. v. Unocal Corporation, et al., in the California Superior Court for Sacramento County) against the Company and eight major California oil refiners by direct and indirect purchasers of diesel fuel in the state of California from March 1996, through 1997. The complaint alleges that the defendants conspired to restrict the production and fix the price of "CARB" diesel fuel in violation of the California Cartwright and Unfair Competition Acts. The total amount of damages sought by the plaintiffs is unknown. If liability were established, the Company would be jointly and severally liable for any damages awarded. Any such damages would be trebled if a Cartwright Act violation were found and attorneys' fees and costs would also be recoverable. "Fluid recovery" and cy pres restitution would be available under the Unfair Competition Act if a violation of that act were found. Any damages awarded would be allocated among the defendants according to their market shares.

   The Company and its co-defendants believe that there is no merit to the plaintiffs' claim that there was a conspiracy to fix prices or restrict the supply of CARB diesel fuel. Moreover, even if such an agreement did exist among some of the defendants, the Company believes that there is no evidence linking it to such an agreement. Further, the Company believes that the sale of its marketing and refining assets to Tosco in 1997 would be deemed to constitute an effective withdrawal from any alleged conspiracy. In 2000, the court entered a stay in this case pending the decision of the California Supreme Court in the case of Aguilar v. Atlantic Richfield Company. In light of the decision favorable to the defendants in the Aguilar case by the California Supreme Court in June 2001, the Company no longer considers this case to be material.

6. In 1999, the lawsuit captioned The Sweet Lake Land & Oil Company, Inc., et al. v. Union Oil Company of California (No. CV 99-1226 in the U.S. District Court for the Western District of Louisiana) was filed against the Company. The plaintiffs sought damages for land loss and erosion allegedly resulting from oil and gas operations in the Sweet Lake Field by the Company and its predecessor in interest, The Pure Oil Company. The plaintiffs' estimated cost of restoring the damaged property was between approximately $86 million and $142 million. The plaintiffs also asserted a claim for loss of agricultural revenues, which they estimated at approximately $8 million. The plaintiffs additionally sought unspecified damages for the plugging and abandonment of wells alleged to have no future utility and the removal of associated flowlines and facilities. This lawsuit was settled in November 2001 on terms pursuant to which the Company paid $2 million in December 2001 and is to pay an aggregate of $13 million over a 12-year period, all from reserves previously provided.

Certain Environmental Matters Involving Civil Penalties

7. The Company's Molycorp, Inc., subsidiary is continuing to negotiate with the Office of the California Attorney General and the Lahontan Regional Water Quality Control Board with respect to the settlement of alleged violations of water quality discharge permits issued under the California Water Code for its Mountain Pass, California, lanthanide facility. The settlement of these matters could result in the payment of civil penalties exceeding $100,000.

ITEM 4 - SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS: None.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name, age and present positions with Unocal	Business experience
CHARLES R. WILLIAMSON, 53 Chairman of the Board and Chief Executive Officer Chairman of Company Management Committee	Mr. Williamson became Chairman of the Board in October 2001 and has been Chief Executive Officer since January 2001. He has served as a Director since January 2000. He was Executive Vice President, International Energy Operations, during 1999 and 2000. He served as Group Vice President, Asia Operations, in 1998 and 1999, having previously served as Group Vice President, International Operations, since 1996.
TIMOTHY H. LING, 44 President and Chief Operating Officer Director Member of Company Management Committee	Mr. Ling has been President and Chief Operating Officer since January 2001. He was Executive Vice President, North American Energy Operations, in 1999 and 2000, and Chief Financial Officer from 1997 to 2000. He was a partner of McKinsey & Company, Inc. from 1994 through 1997. He is also a director of Pure Resources, Inc.
TERRY G. DALLAS, 51 Executive Vice President and Chief Financial Officer Member of Company Management Committee	Mr. Dallas has been Executive Vice President since February 2001. He joined Unocal in 2000 as Chief Financial Officer. Previously, he was Senior Vice President and Treasurer of Atlantic Richfield Company ("Arco"), where he worked for 21 years.
DENNIS P.R. CODON, 53 Senior Vice President, Chief Legal Officer and General Counsel	Mr. Codon has been Senior Vice President since 2000 and Chief Legal Officer and General Counsel since 1992. He was a Vice President from 1992 to 2000.
JOE D. CECIL, 53 Vice President and Comptroller	Mr. Cecil has been Vice President and Comptroller since December 1997. During 1997, he was Comptroller of International Operations. He was Comptroller of the 76 Products Company from 1995 until the sale of the West Coast refining, marketing and transportation assets in March 1997.
DOUGLAS M. MILLER, 42 Vice President, Corporate Development	Mr. Miller has been Vice President, Corporate Development, since January 2000. From 1998 until 2000 he was General Manager, Planning and Development, International Energy Operations. From 1996 to 1998, he was Resident Manager of Philippine Geothermal, Inc.

The bylaws of the Company provide that each executive officer shall hold office until the annual organizational meeting of the Board of Directors, to be held May 20, 2002, and until his successor shall be elected and qualified, unless he shall resign or shall be removed or otherwise disqualified to serve.

ITEM 5 - MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

	2001 Quarters				2000 Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Market price per share of common stock								
- High	$39.9375	$ 40	$37.36	$36.15	$35 5/16	$ 39	$38 3/16	$40 1/8
- Low	$32.3125	$32.26	$29.72	$29.51	$ 25	$28 1/16	$28 1/4	$32 1/2
Cash dividends paid per share of common stock	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20

Prices in the foregoing table are from the New York Stock Exchange Composite Transactions listing. On February 28, 2002, the high price per share was $36.28 and the low price per share was $35.79.

Unocal common stock is listed for trading on the New York Stock Exchange in the United States, and on the Stock Exchange of Switzerland.

As of February 28, 2002, the approximate number of holders of record of Unocal common stock was 22,959 and the number of shares outstanding was 244,119,771. Unocal's quarterly dividend declared has been $0.20 per common share since the third quarter of 1993. The Company has paid a quarterly dividend for 86 consecutive years.

ITEM 6 - SELECTED FINANCIAL DATA: see pages 134 and 135.

ITEM 7 - 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 Unocal should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes, as well as the business and properties descriptions in Items 1 and 2 of this report.

Effective in 2001, the Pipelines business segment was combined with certain activities of the Company's gas storage businesses in Canada, which were previously reported in the Exploration and Production segment, into a new segment called Midstream. The Carbon and Minerals businesses are no longer disclosed as a separate segment and are now reported under the Corporate and Other heading. The prior year results have been reclassified to conform to the 2001 presentation. See note 29 to the consolidated financial statements in Item 8 of this report for a description of the Company's reportable segments.

CONSOLIDATED RESULTS

Millions of dollars	Years ended December 31, 2001	2000	1999
Earnings from continuing operations (a)	$ 599	$ 723	$ 113
Earnings from discontinued operations	17	37	24
Cumulative effect of accounting change	(1)	-	-
Net earnings	$ 615	$ 760	$ 137

<FN>
(a) Includes minority interests of: $ (41) $ (16) $ (16)
</FN>

Continuing operations

2001 vs. 2000 - Earnings from continuing operations totaled $599 million in 2001, which was a decrease of $124 million from 2000. The decrease was primarily due to lower worldwide average prices for liquids and an $86 million non-cash after-tax charge for impairment of certain Gulf of Mexico shelf properties, due principally to lower commodity prices. Higher worldwide average natural gas prices and higher natural gas production partially offset these two negative factors. The Company's worldwide average liquids price, including a 2 cents gain per barrel from hedging activities, was $22.31 per barrel in 2001, which was a decrease of $3.79 per barrel, or 15 percent, from 2000. In 2001, the Company's worldwide average natural gas price, including a 2 cents loss per Mcf from hedging activities, was $3.25 per Mcf, which was an increase of 29 cents per Mcf, or 10 percent, from 2000. The Company's worldwide natural gas production increased by 9 percent in 2001, primarily due to higher natural gas production from the U.S. Lower 48 and Far East operations. The 2001 results also benefited from $18 million in after-tax earnings related to participation payments, to be collected in 2002, from the Company's former agricultural products business and the Company's former oil and gas operations in California; $17 million after-tax gains from the sale of Gulf of Mexico producing properties and a $10 million after-tax gain from mark-to-market accruals for non-hedge commodity derivatives. The results in 2000 included a $55 million after-tax benefit from payments received for infringement of one of the Company's five reformulated gasoline patents during a five-month period in 1996, a $42 million after-tax gain from the Pure Resources, Inc. ("Pure") transaction and a $21 million after-tax gain related to a settlement agreement reached with an insurer for the recovery of amounts previously paid out for environmental pollution claims and related costs. These gains in 2000 were offset by $48 million in after-tax losses related to the mark-to-market accruals for non-hedge commodity derivatives, a $33 million after-tax charge to write-down the Company's investment in the Questa, New Mexico, molybdenum mining operation and $11 million in after-tax restructuring costs. In addition, earnings from continuing operations in 2001 and 2000 included $95 million and $99 million, respectively, in after-tax provisions for litigation and environmental matters. In 2000, earnings from continuing operations included $28 million in net positive deferred tax adjustments. The amount included a $46 million deferred tax benefit related to a prior period sale of certain Canadian oil and gas properties. The 2000 results also included a $28 million provision for prior years income tax issues.

2000 vs. 1999 - Earnings from continuing operations totaled $723 million in 2000, which was an increase of $610 million from 1999. Higher worldwide average crude oil and natural gas prices were the primary factors for the increase. The Company's worldwide average crude oil price, including an 18 cents loss per barrel from hedging activities, was $26.10 per barrel in 2000, which was an increase of $11.08 per barrel, or 74 percent, from the 1999 prices. The Company's worldwide average natural gas price, including a 6 cents loss per Mcf from hedging activities, was $2.96 per Mcf in 2000, which was an increase of 92 cents per Mcf, or 45 percent, from the 1999 prices. In addition to the positive impact of prices, earnings in 2000 included the $55 million after-tax benefit from payments received for infringement of one of the Company's patents and the $42 million after-tax gain from the Pure transaction. The impact of prices and the other two factors was partially offset by higher depreciation, depletion and amortization expense and higher losses related to non-hedging commodity derivative positions. In addition, earnings from continuing operations in 2000 included $112 million after-tax in environmental and litigation expenses, which was higher than the 1999 amount of $29 million, and the $33 million after-tax charge to write-down the Company's investment in the mining operation. In 1999, earnings from continuing operations included a loss of $10 million from the sale of the Company's interest in a geothermal steam production operation at The Geysers in Northern California.

Discontinued Operations

Millions of dollars	Years ended December 31, 2001	2000	1999
Refining, marketing and transportation			
Gain on disposal (net of tax)	$ 17	$ -	$ 25
Agricultural products			
Loss from operations (net of tax)	-	-	(1)
Gain on disposal (net of tax)	-	37	-
Earnings from discontinued operations	$ 17	$ 37	$ 24

Earnings from discontinued operations were $17 million in 2001 compared to $37 million in 2000. The 2001 amount related to the Company's 1997 sale of its former West Coast refining, marketing and transportation assets. The sales agreement contains provisions calling for payments to the Company for price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. The maximum potential payments under the sales agreement are capped at $100 million, and the period covered extends through 2003. To date, the Company has earned approximately $27 million (pre-tax) related to the agreement, all of which was recorded in 2001.

Earnings from discontinued operations in 2000 included the sale of the agricultural products business, and increased $13 million from 1999. The 2000 gain on disposal amount included $14 million from the sale of the agricultural business and $23 million from the operation of the agricultural products business prior to the sale. Higher agricultural products commodity prices in 2000, compared to 1999, were the major factor for the improved results over 1999.

In 1999, the Company recorded a $25 million net gain on the disposal of the refining, marketing and transportation business, which included a $32 million after-tax gain from a settlement with the purchaser to resolve certain contingent payment issues related to gasoline margins, partially offset by an additional $11 million after-tax charge on the disposal of assets. The 1997 sale agreement included a provision for up to $250 million in participation payments to the Company, contingent upon increased refining premiums and retail gasoline margins subsequent to the sale. The 1999 settlement agreement was for the resolution of discrepancies in the calculation of retail margins for conventional motor gasoline. The settlement did not cover potential future participation payments with respect to price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline.

For more information on Discontinued Operations, see note 9 to the consolidated financial statements in Item 8 of this report.

Cumulative Effect of Accounting Change

In 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".

Net Earnings Reconciliation to Adjusted Earnings

The purpose of the table below is to provide the investment community supplemental financial data in addition to the data prepared in accordance with generally accepted accounting principles.

The table includes a reconciliation of consolidated net earnings to adjusted after-tax earnings. Special items represent certain significant transactions, the results of which are included in net earnings, that management determines to be unrelated to or not representative of the Company's ongoing operations.

	Years ended December 31,		
Millions of dollars	2001	2000	1999
Net earnings (a)	$ 615	$ 760	$ 137
Less: Earnings from discontinued operations	17	37	24
Less: Cumulative effect of accounting change	(1)	-	-
Earnings from continuing operations	599	723	113
Special items:			
Continuing operations			
Asset sales	17	49	(10)
Asset write-downs	(86)	(33)	(12)
Deferred tax adjustments	-	28	-
Environmental, litigation and other provisions	(95)	(99)	(19)
Executive stock purchase program	-	(9)	-
Insurance benefits related to environmental issues	-	21	16
Trading derivatives -- non-hedging	10	(48)	-
Provision for prior years income tax issues	-	(28)	-
Reformulated gasoline patent case	-	55	-
Restructuring costs	-	(11)	(11)
Total special items from continuing operations	(154)	(75)	(36)
Adjusted after-tax earnings(before special items)(a)	$ 753	$ 798	$ 149

<FN>
(a) Includes minority interests of: $ (41) $ (16) $ (16)
</FN>

Operating Highlights	2001	2000	1999
North America Net Daily Production			
Liquids (thousand barrels)			
Lower 48 (a) (b)	59	52	50
Alaska	25	26	28
Canada (c)	16	17	13
Total liquids	100	95	91
Natural gas - dry basis (million cubic feet)			
Lower 48 (a) (b)	905	764	706
Alaska	103	125	130
Canada (c)	101	98	70
Total natural gas	1,109	987	906
North America Average Prices (excluding hedging activities)(d)(e)			
Liquids (per barrel)			
Lower 48	$ 23.22	$ 27.16	$ 15.73
Alaska	$ 20.74	$ 24.93	$ 13.07
Canada	$ 18.53	$ 24.31	$ 15.90
Average	$ 21.80	$ 26.05	$ 14.94
Natural gas (per mcf)			
Lower 48	$ 4.13	$ 3.91	$ 2.22
Alaska	$ 1.37	$ 1.20	$ 1.20
Canada	$ 4.34	$ 3.45	$ 2.54
Average	$ 3.88	$ 3.50	$ 2.10
North America Average Prices (including hedging activities)(d)(e)			
Liquids (per barrel)			
Lower 48	$ 23.28	$ 27.20	$ 15.22
Alaska	$ 20.74	$ 24.93	$ 13.07
Canada	$ 18.53	$ 22.46	$ 13.88
Average	$ 21.83	$ 25.75	$ 14.37
Natural gas (per mcf)			
Lower 48	$ 4.22	$ 3.93	$ 2.17
Alaska	$ 1.37	$ 1.20	$ 1.20
Canada	$ 3.17	$ 2.30	$ 2.31
Average	$ 3.84	$ 3.40	$ 2.03

<FN>

(a) Includes proportional shares of production of equity investees.

(b) Includes minority interest shares of :

Liquids	9	7	1
Natural gas	102	69	21
Barrels oil equivalent	26	19	5

(c) Includes minority interest shares of :

Liquids	0	2	3
Natural gas	0	15	35
Barrels oil equivalent	0	4	9

(d) Excludes Trade segment margins.

(e) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portion of hedges.

</FN>

Operating Highlights (continued)	2001	2000	1999
International Net Daily Production (f)			
Liquids (thousand barrels)			
Far East	51	47	54
Other (a)	19	18	23
Total liquids	70	65	77
Natural gas - dry basis (million cubic feet)			
Far East	829	799	759
Other (a)	65	57	39
Total natural gas	894	856	798
International Average Prices (g)			
Liquids (per barrel)			
Far East	$ 22.50	$ 26.17	$ 15.42
Other	$ 24.15	$ 27.84	$ 16.80
Average	$ 22.97	$ 26.61	$ 15.82
Natural gas (per mcf)			
Far East	$ 2.52	$ 2.46	$ 2.03
Other	$ 2.75	$ 2.81	$ 2.19
Average	$ 2.54	$ 2.48	$ 2.04
Worldwide Net Daily Production (a) (b) (c) (f)			
Liquids (thousand barrels)	170	160	168
Natural gas - dry basis (million cubic feet)	2,003	1,843	1,704
Barrels oil equivalent (thousands)	504	468	452
Worldwide Average Prices (excluding hedging activities)(d)(e)			
Liquids (per barrel)	$ 22.29	$ 26.28	$ 15.33
Natural gas (per mcf)	$ 3.27	$ 3.02	$ 2.07
Worldwide Average Prices (including hedging activities)(d)(e)			
Liquids (per barrel)	$ 22.31	$ 26.10	$ 15.02
Natural gas (per mcf)	$ 3.25	$ 2.96	$ 2.04

<FN>

(a) Includes proportional shares of production of equity investees.

(b) Includes minority interest shares of :

Liquids	9	7	1
Natural gas	102	69	21
Barrels oil equivalent	26	19	5

(c) Includes minority interest shares of :

Liquids	0	2	3
Natural gas	0	15	35
Barrels oil equivalent	0	4	9

(d) Excludes Trade segment margins.

(e) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portion of hedges.

(f) International production is presented utilizing the economic interest method.

(g) International did not have any hedging activities.

</FN>

Sales and Operating Revenues

2001 vs. 2000 - Sales and operating revenues in 2001 were $6,664 million, which was a decrease of $2,277 million from 2000. The decrease was primarily due to lower sales of domestic crude oil purchased from third parties for resale by the Company's Trade business segment and lower worldwide average liquids prices. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets. Sales and operating revenues from the Trade business segment were $3,856 million in 2001, which was a decrease of $2,837 million from 2000. During 2001 and 2000, approximately 31 percent and 54 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from others in connection with the Trade's segment's marketing activities. These activities allow the Company to better manage its risk and seek higher profit margins by transferring its production and commodity purchases to industry marketing centers with higher volumes of commercial activity and greater market liquidity.

The Company's worldwide average liquids price, including a 2 cents gain per barrel from hedging activities, was $22.31 per barrel in 2001, which was a decrease of $3.79 per barrel, or 15 percent, from 2000. These decreases were partially offset by higher natural gas prices and higher natural gas and liquids sales volumes. In 2001, the Company's worldwide average natural gas price, including hedging activities, was $3.25 per Mcf, which was an increase of 29 cents per Mcf, or 10 percent, from 2000. The Company's worldwide natural gas production increased by 9 percent in 2001, primarily due to higher natural gas production from the U.S. Lower 48 and Far East operations.

2000 vs. 1999 - Sales and operating revenues in 2000 were $8,941 million, which was an increase of $3,099 million from 1999. The increase was primarily due to higher worldwide average crude oil and natural gas prices. During 2000 and 1999, approximately 54 percent and 52 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from others in connection with the Trade segment's marketing activities. These activities allow the Company to better manage its risk and seek higher profit margins by transferring its production and commodity purchases to industry marketing centers with higher volumes of commercial activity and greater market liquidity. An increase in natural gas sales volumes also contributed to the higher level of sales revenues compared to 1999.

Interest, Dividends and Miscellaneous Income

2001 vs. 2000 - Interest, dividends and miscellaneous income in 2001 was $64 million, which was a decrease of $112 million from 2000. This decrease was primarily due to $87 million (net of related costs) recognized in miscellaneous income in 2000 related to the payments received for infringement of one of the Company's five reformulated gasoline patents during a five-month period in 1996 that were recorded in 2000. The year 2000 amount also included $33 million pre-tax ($21 million after-tax) related to a settlement agreement with an insurer for the recovery of amounts previously paid out for environmental pollution claims and related costs.

2000 vs. 1999 - Interest, dividends and miscellaneous income in 2000 was $176 million, which was an increase of $71 million from 2000. This increase was primarily due to the $87 million related to the gasoline patents in 2000. The year 1999 amount included $25 million pre-tax ($16 million after-tax) related to a settlement agreement reached with an insurer for the recovery of environmental contamination and environmental hazards claims and related costs.

Selected Costs and Other Deductions

Millions of dollars	2001	2000	1999
	Years ended December 31,		
Pre-tax costs and other deductions:			
Crude oil, natural gas and product purchases	$ 2,492	$ 5,158	$ 3,296
Operating expense	1,376	1,199	952
Depreciation, depletion and amortization	967	821	718
Impairments	118	66	23
Dry hole costs	175	156	148
Exploration expense (see table below)	252	260	253
Interest expense	192	210	199

Millions of dollars	2001	2000	1999
	Years ended December 31,		
Exploration operations	$ 85	$ 91	$ 100
Geological and geophysical	56	71	65
Amortization of exploratory leases	95	85	77
Leasehold rentals	16	13	11
Exploration expense	$ 252	$ 260	$ 253

2001 vs. 2000 - Crude oil, natural gas and product purchases decreased by $2,666 million in 2001. This decrease was principally due to lower purchases of domestic crude oil from third parties for resale by the Company's Trade business segment and lower commodity prices. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets. In 2001, operating expense increased by $177 million due to higher receivable provisions related to geothermal operations in Indonesia and higher expenses related to the full year activities of the Company's Pure subsidiary, including its 2001 acquisitions, compared to only seven months in 2000. Depreciation, depletion and amortization expense increased by $146 million in 2001, primarily due to additional properties acquired by the Company's Pure subsidiary and a full year related to Pure's activities compared to only seven months in the prior year. Impairments in 2001 reflect $118 million for asset write-downs of certain Gulf of Mexico shelf and onshore properties, due principally to lower commodity prices.

2000 vs. 1999 - Crude oil, natural gas and product purchases increased by $1,862 million in 2000. This increase was principally due to higher worldwide crude oil and natural gas prices. Operating expense increased by $247 million, principally due to higher environmental and litigation provisions and the inclusion of the results of the Company's Pure subsidiary since May 2000, and Northrock Resources Ltd. ("Northrock"), for the full year of 2000, compared with only seven months following the initial acquisition of Northrock common shares in May 1999. Depreciation, depletion and amortization expense increased by $103 million in 2000, primarily due to higher charges in the U.S. due to increases in natural gas production volumes combined with higher investment costs associated with offshore production. In addition, depreciation, depletion and amortization expense increased due to the inclusion of Pure for a partial year and Northrock for a full year in 2000. For more information on major acquisitions, see note 3 to the consolidated financial statements in Item 8 of this report. Impairments in 2000 included a write-down of a mining operation at Questa, New Mexico, while 1999 included asset write-downs for U.S. oil and gas properties.

BUSINESS SEGMENT RESULTS

Exploration and Production

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

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, 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 those of Pure, is sold to the Company's Trade business segment. The remainder of North America production, including the production of Pure and Northrock, 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, Pure and Northrock take pricing positions in hydrocarbon derivative instruments in support of their oil and gas operations.

2001 vs. 2000 − After−tax earnings were $440 million in 2001, which was a decrease of $108 million from 2000. In 2001, the Company's average liquids prices for North America declined throughout the year and averaged, including a 3 cents gain per barrel from hedging activities, $21.83 per barrel, which was a decrease of $3.92 per barrel, or 15 percent lower than 2000. Lower liquids prices and the $86 million non−cash after−tax charge for impairment of certain Gulf of Mexico shelf and onshore properties were partially offset by the Company's higher average North America natural gas prices and higher natural gas production. The Company's average North America natural gas price, including a 4 cents loss per Mcf from hedging activities, was $3.84 per Mcf in 2001, which was an increase of 44 cents per Mcf, or 13 percent higher than 2000. North America average net daily natural gas production was 1,109 MMcf/d in 2001 compared to 987 MMcf/d in 2000, which was an increase of 12 percent, primarily from higher Lower 48 production. After−tax earnings in 2001 also benefited from $10 million of after−tax gains related to non−hedging commodity derivative positions taken by Northrock versus $48 million of after−tax losses in 2000. After−tax earnings in 2001 also included $17 million in after−tax gains on the sale of certain Gulf of Mexico production properties. The 2000 results included a $46 million deferred tax benefit adjustment in Canada related to a prior period sale of certain Canadian oil and gas properties and a $42 million after−tax gain related to the formation of the Company's Pure subsidiary.

2000 vs. 1999 − After−tax earnings in 2000 were $548 million, which was an increase of $462 million from 1999. This increase was primarily due to higher North America average crude oil prices, higher U.S. Lower 48 average natural gas prices, higher U.S. Lower 48 natural gas sales volumes, the $46 million deferred tax benefit adjustment in Canada and the $42 million after−tax gain related to the formation of Pure. The average liquids price for North America, including a 30 cents loss per barrel from hedging activities, was $25.75 per barrel for 2000, which was an increase of $11.38 per barrel, or 79 percent, from 1999. The average natural gas price in the U.S. Lower 48, including a 2 cents gain per Mcf from hedging activities, was $3.93 per Mcf for 2000, which was an increase of $1.76 per Mcf, or 81 percent, from 1999. The U.S. Lower 48 operations benefited from higher natural gas production in 2000 compared to 1999. This increase in production came primarily from the Company's Pure subsidiary, the Gulf of Mexico shelf production and the Company's proportional share of production of equity investees. These positive items were partially offset by after−tax losses related to non−hedging commodity derivative positions taken by the Company's Northrock subsidiary in Canada and higher depreciation, depletion and amortization expense for the Lower 48 and Canada. The 1999 results included a $12 million after−tax non−cash charge for impairment of certain Gulf of Mexico properties and a $7 million after−tax gain for a litigation settlement, partially offset by $5 million in litigation provisions.

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 activities and the development of energy projects primarily in Asia, Latin America and West Africa.

2001 vs. 2000 - After-tax earnings totaled $443 million in 2001, which was a decrease of $20 million from 2000. The decrease was primarily due lower liquids prices and 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 $22.97 per barrel in 2001, which was a decrease of $3.64 per barrel, or 14 percent, from 2000. These two negative factors were partially offset by higher natural gas prices and natural gas production in the Far East. The average natural gas price for International operations was $2.54 per mcf in 2001, which was an increase of 6 cents per mcf, or 2 percent, from the same period a year ago. Natural gas production increased 4 percent in 2001, primarily in the Far East, as the result of the first full year of natural gas deliveries at annual contract quantities from the Yadana field in Myanmar. The average net daily natural gas production was 894 MMcf/d in 2001 compared to 856 MMcf/d in 2000.

2000 vs. 1999 - After-tax earnings totaled $463 million in 2000, which was an increase of $265 million from 1999. The increase was primarily due to higher average International liquids and natural gas prices. International's average liquids price was $26.61 per barrel in 2000, which was an increase of $10.79 per barrel, or 68 percent, from 1999. International's average natural gas price was $2.48 per mcf in 2000, which was an increase of 44 cents per mcf, or 22 percent, from 1999. The 2000 results also benefited from higher Far East natural gas production, primarily from the Yadana field in Myanmar due to the ramp up of operations at the Ratchaburi power plant in Thailand. These positive results were partially offset by higher depreciation, depletion and amortization expense, primarily in Thailand and Indonesia. In 1999, after-tax earnings included a $2 million payment related to a litigation matter.

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 crude oil, condensate 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 for non-hedge purposes for its own account subject to internal restrictions, including value at risk limits. The segment also trades limited amounts of physical inventories for energy trading purposes.

2001 vs. 2000 - After-tax results totaled $6 million in 2001, which was a decrease of $1 million from 2000. The decrease included a non-cash $4 million after-tax provision for receivables related to the bankruptcy of Enron Corporation. This negative factor was mostly offset by higher results from non-hedging commodity derivative positions related to crude oil.

Sales and operating revenues from the Trade business segment were $3,856 million in 2001, which was a decrease of $2,837 million from 2000. These revenues represented approximately 58 percent and 75 percent of the Company's total sales and operating revenues for 2001 and 2000, respectively. The decrease in 2001 was primarily due to lower sales of domestic crude oil purchased from third parties for resale and lower worldwide average liquids prices. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets.

2000 vs. 1999 - After-tax results totaled $5 million in 2000, which was an increase of $7 million from 1999 The increase was primarily due to improved results from non-hedging natural gas derivative positions, which were partially offset by lower results for non-hedging crude oil derivative positions.

Sales and operating revenues from the Trade business segment were $6,693 million in 2000, which was an increase of $2,392 million from 1999. These revenues represented approximately 75 percent of the Company's total sales and operating revenues in both 2000 and 1999. The increase in 2000 was primarily due to higher domestic crude oil and natural gas prices.

Midstream

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

2001 vs. 2000 − After−tax earnings in 2001 totaled $54 million, which was a decrease of $8 million from 2000. The decrease was due primarily to lower results from the Company's North America gas storage operations.

2000 vs. 1999 − After−tax earnings in 2000 totaled $62 million, which was a decrease of $4 million from 1999. The results included an asset write−down related to a Colonial Pipeline Company investment, which was partially offset by higher results from the Company's North America gas storage business.

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.

2001 vs. 2000 − After−tax earnings totaled $11 million for 2001, which was a decrease of $13 million from 2000. This decrease was primarily due to higher receivable provisions related to geothermal operations in Indonesia (see the Geothermal and Power Operations discussion in the Outlook section of Management's Discussion and Analysis). The receivable provisions were partially offset by higher electricity generation and steam sales and the service fees earned by the Company for operating the Wayang Windu project in Indonesia.

2000 vs. 1999 − After−tax earnings totaled $24 million for 2000, which was an increase of $10 million from the same period a year ago. During 2000, higher electricity generation and steam sales in Indonesia were offset by higher foreign exchange losses in Indonesia and the Philippines and higher provisions on accounts receivable in Indonesia. In 1999, after−tax earnings included a loss of $10 million from the sale of the Company's interest in a geothermal steam production operation at The Geysers in Northern California. This loss was partially offset by the recognition of a fee earned related to the construction of the Salak power plant units 4 through 6 in Indonesia.

Corporate and Other

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

2001 vs. 2000 - The after-tax earnings effect for 2001 was a loss of $355 million compared to a loss of $379 million for 2000. Administrative and general expense in 2001 benefited from lower executive compensation expense. Net interest expense was lower by $14 million primarily due to higher capitalized interest on development projects. The 2001 results for the Other category included foreign exchange losses related to financing activities, a $10 million pre-tax contribution to a charitable foundation, higher employee benefit costs and lower earnings from the minerals businesses. The Other category also included lower income tax expense adjustments compared to 2000 and after-tax earnings related to participation payments from the Company's former agricultural products business. The 2000 results for the Other category included a $33 million after-tax charge related to an asset write-down of the Company's Molycorp, Inc. property investment in its Questa, New Mexico, molybdenum mining operation, a $55 million after-tax gain related to payments received in the Company's first reformulated gasoline patent infringement case, a $21 million after-tax insurance recovery, a $7 million after-tax gain from the sale of the Company's graphite business and a $9 million after-tax charge related to the Company's executive stock purchase program. In addition, the 2001 and 2000 results included $95 million and $99 million, respectively, in after-tax provisions for litigation and environmental matters. Activities related to the restructuring plans adopted in 2000, 1999 and 1998 are now complete and no material changes to the costs accrued for the plans were made (see note 7 to the consolidated financial statements in Item 8 of this report for additional information on the restructuring programs).

2000 vs. 1999 - The after-tax earnings effect for 2000 was a loss of $379 million compared to a loss of $249 million for 1999. Administrative and general expense was higher by $7 million, primarily due to higher provisions for employee related bonus and incentive plans. Net interest expense was higher by $7 million primarily due to the consolidation of Northrock debt for the full year 2000, compared with seven months following the initial acquisition of Northrock common shares in May 1999, and the consolidation of Pure debt, since May 2000, and lower capitalized interest, which were partially offset by higher interest income. In 2000, the Other category included lower gains from the sale of real estate properties and lower results from the minerals operations. Further, the 2000 after-tax earnings included $79 million from higher environmental and litigation provisions, $46 million in income tax expense adjustments, the $33 million asset write-down of the Questa mining operation and the $21 million insurance recovery, which was $5 million more than a similar recovery received in 1999. These negative factors in the Other category were partially offset by the $55 million gain related to the Company's RFG patent infringement case.

FINANCIAL CONDITION

Millions of dollars except as indicated	At December 31, 2001	2000	1999
Current ratio (a)	0.9:1	1.0:1	1.0:1
Total debt and capital leases	$ 2,906	$ 2,506	$ 2,854
Trust convertible preferred securities	522	522	522
Stockholders' equity	3,124	2,719	2,184
Total capitalization	6,552	5,747	5,560
Total debt/total capitalization	44%	44%	51%
Floating-rate debt/total debt	8%	3%	10%

<FN>
(a) 2001 reflects the acquisition of properties from Forest Oil Corporation and the acquisition of Tethys Energy Inc., both of which were funded with cash on hand.
</FN>

Cash Flows from Operating Activities

Cash flows from operating activities, including discontinued operations and working capital and other changes, were $2,125 million in 2001, $1,668 million in 2000 and $1,026 million in 1999.

2001 vs. 2000 - Cash flows from operating activities increased by $457 million in 2001 versus 2000. This increase included positive cash flows from reduced working capital and reflected the positive effects of higher worldwide average natural gas prices and higher worldwide natural gas production. Cash flows from operating activities in 2001 also included $70 million for the advance sale of certain domestic trade receivables (see note 12 to the consolidated financial statements in Item 8 of this report for additional information on the sale of trade receivables).

2000 vs. 1999 - Cash flows from operating activities increased by $642 million in 2000 versus 1999. This increase primarily reflected the effects of higher worldwide crude oil and natural gas prices. The 2000 results also included $87 million in payments (net of related costs) received in the Company's reformulated gasoline patent case, a $33 million cash insurance recovery related to prior years environmental issues and the collection of $65 million for the 1999 "take-or-pay" obligation of PTT Public Co., Ltd.("PTT") due under the sales agreements for gas produced in Myanmar. These positive factors were partially offset by higher estimated income tax payments made during 2000, while 1999 included an income tax refund in Canada. In addition, cash flows from operating activities were negatively impacted by the deliveries made in 2000 under a 1999 advance crude oil forward sale and the cessation, at December 31, 2000, of the sale of certain domestic trade receivables.

Capital Expenditures

Millions of dollars	Estimated 2002	Years ended December 31, 2001	2000	1999
Continuing operations				
Exploration and production				
North America				
Lower 48 (a)	$ 500	$ 861	$ 628	$ 530
Alaska	70	81	34	28
Canada (b)	130	113	164	112
International				
Far East (c)	590	425	325	321
Other	180	148	62	117
Total exploration and production	1,470	1,628	1,213	1,108
Trade	2	-	1	3
Midstream	70	41	16	7
Geothermal and power operations	18	7	18	21
Corporate and other	55	51	40	22
Total from continuing operations	$1,615	$ 1,727	$ 1,288	$ 1,161
Discontinued operations				
Agricultural products	-	-	14	10
Total capital expenditures (d)	$1,615	$ 1,727	$ 1,302	$ 1,171

<FN>
(a) Excludes in 2001 - $267 million for asset acquisitions from International Paper Company, $173 million for the acquisition of Hallwood Energy Corporation and $113 million for the joint venture properties acquired from Forest Oil Corporation.
(b) Excludes $93 million for the acquisition of Tethys Energy Inc. in 2001 and $161 million in 2000 and $205 million in 1999 for the acquisition of Northrock Resources Ltd.
(c) Excludes $157 million in 2000 for the acquisition of additional interests in Indonesia production sharing contracts.
(d) Estimated capital expenditures for 2002 exclude major acquisitions.
</FN>

Forecasted 2002 capital expenditures for the Company are currently expected to decrease by approximately $115 million from the 2001 levels, due to generally lower commodity prices, especially for North American natural gas, and the Company's desire to maintain a strong balance sheet. In 2002, capital expenditures are expected to shift more towards development programs, such as the West Seno project in Indonesia (International - Far East), the Phase I crude oil development project in Azerbaijan (International - Other) and the Mad Dog project in the Gulf of Mexico deep water (North America - Lower 48). Development expenditures are expected to total about $1.15 billion, up from $1.0 billion in 2001. Exploration capital is expected to total about $325 million, down from about $600 million in 2001. The 2002 exploration capital estimate includes spending for delineation drilling at the Trident discovery in the Gulf of Mexico deep water and the Ranggas discovery in deepwater Indonesia. The Company's capital spending plans are reviewed and adjusted periodically depending on current economic conditions, and the Company is prepared to make additional cuts if the commodity price environment weakens.

2001 vs. 2000 - Capital expenditures increased by 33 percent in 2001 from 2000. The higher capital expenditures in 2001 were primarily due to higher exploratory expenditures and property acquisitions in the Gulf of Mexico and Brazil (International - Other), higher development expenditures in Indonesia and Thailand (International - Far East) and higher expenditures by the Company's Pure subsidiary (Lower 48).

2000 vs. 1999 - Capital expenditures increased by 11 percent in 2000 from 1999. The increase was primarily due to higher capital expenditures by Pure, higher development expenditures in Thailand and higher producing property acquisitions in Canada and the Gulf of Mexico. These increases were partially offset by lower deepwater exploration in the Gulf of Mexico, lower deepwater exploration in Indonesia and lower exploration capital in Bangladesh (International - Other).

Major Acquisitions

In 2001, the Company formed a 50-50 venture with Forest Oil Corporation related to certain oil and gas properties located in the central Gulf of Mexico. Under the terms of this transaction, the Company acquired a portion of proved reserves and current production for approximately $113 million. Other major acquisitions included Pure's acquisition of properties from International Paper Company for $267 million, Pure's cash outlay of $173 million for the acquisition of all the shares of Hallwood Energy Corporation and Northrock's cash outlay of $93 million for the acquisition of all the shares of Tethys Energy Inc. (see note 3 to the consolidated financial statements in Item 8 of this report).

In 2000, the Company acquired additional interests in the Makassar Strait and Rapak production-sharing contracts in Indonesia for $157 million. The Company also acquired the remaining common shares of Northrock, which it did not already own, for a cash cost of approximately $161 million. This acquisition was accounted for as a purchase.

In 1999, the Company acquired an approximate 48 percent controlling interest in Northrock for approximately $205 million.

Asset Sale Proceeds

In 2001, pre-tax proceeds from asset sales, including those classified as discontinued operations, were $106 million. The proceeds included a $25 million payment related to the Company's sale of its former West Coast refining, marketing and transportation assets, which were sold to Tosco Corporation ("Tosco") in 1997 (see note 4 to the consolidated financial statements in Item 8 of this report), $63 million from the sale of certain oil and gas properties, primarily in the U.S. Gulf of Mexico, and $18 million from the sale of real estate and other assets.

In 2000, pre-tax proceeds from asset sales, including discontinued operations, were $551 million. The proceeds included $242 million (net of closing costs) received from the sale of the agricultural products business, $80 million from the sale of the Company's graphite business, $71 million from the sale of securities (received as part of the consideration for the agricultural products sale) and $25 million received from Tosco related to the sale of the Company's former West Coast refining, marketing and transportation assets. The proceeds also included $74 million from the sale of U.S. oil and gas properties and $59 million from the sale of real estate and other assets.

In 1999, pre-tax proceeds from asset sales, including discontinued operations, were $238 million. The proceeds consisted of $101 million from the sale of the Company's interest in a geothermal production operation at The Geysers in Northern California, $77 million from the sale of surplus real estate properties and $29 million from the sale of certain oil and gas properties. Pre-tax proceeds also included $31 million received from Tosco associated with the aforementioned sale of the Company's West Coast refining, marketing and transportation assets.

Long-term Debt and Other Financial Commitments

The Company's long-term debt at year-end 2001, including the current portion, increased by $400 million from $2.51 to $2.91 billion. This increase primarily reflects the borrowings made by Pure to fund its acquisition of properties from International Paper Company and its purchase of Hallwood Energy Corporation. The increase in Pure's debt, none of which is guaranteed by Unocal or Union Oil, was partially offset by the Company's retirement of $67 million of maturing medium-term notes and $39 million of maturing 8.75 percent notes.

The Company's long-term debt at year-end 2000, including the current portion, decreased by $348 million from $2.85 billion in 1999 to $2.51 billion. This decrease primarily reflected the retirement of $125 million of commercial paper borrowings, the repayment of $65 million of maturing 9.75 percent notes, the repayment of all $60 million of the outstanding borrowing under the Company's previous $1 billion bank credit agreement, the retirement of $55 million in maturing medium-term notes and the repayment of about $100 million of Northrock's consolidated debt. These decreases were partially offset by the consolidation of $68 million of Pure debt.

In February 2002, the Company redeemed $35 million and $40 million in senior U.S. dollar-denominated notes, which bore interest of 6.54 and 6.74 percent, respectively. The two notes had been issued by the Company's Northrock subsidiary.

In 2001, the Company replaced its $1 billion bank credit agreement with two new revolving credit facilities totaling $1 billion. One of these credit facilities is a $400 million 364-day credit agreement and the other credit facility is a $600 million 5-year credit agreement. The credit facilities 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 the Company'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 bank credit agreements do not have a drawdown restriction or a prepayment obligation 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 facility to cover short-term borrowing requirements. 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. As outlined in the tables below, the Company does not believe it has a significant liquidity exposure in the event of a credit rating downgrade.

The following tables outline the Company's various financial contractual obligations and commitments:

Contractual Obligations (millions of dollars)	Total	Less than 1 Year	1-5 Years	After 5 Year	Credit Rating Triggers
	Payments Due by Period				
Unocal bonds, notes and other debt (a)	$ 2,319	$ 191	$ 927	$ 1,201	None
Pure's notes - not guaranteed by Unocal (b)	350	-		350	None
Pure's various lines of credit - not guaranteed by Unocal (b)	239	6	233	-	Interest rate varies marginally for $275 million line of credit based on Pure's rating
Trust convertible preferred securities (c)	522	-	-	522	None
Non - cancelable operating leases (d)	540	148	356	36	None
Minority interest transaction (e)	253	3	-	250	If rating less than Ba1 or BB+; priority return paid to investor increases approx. 2 percent and Unocal must provide $250 million in cash collateral or letter of credit
Receivable securitization program (f)	70	70	-	-	Sales of receivables prohibited if rating below Baa3 or BBB-
Derivatives - net (g) (Inc1uding interest rate, foreign exchange rate and hydrocarbon derivatives)	14	7	7	-	Approximately $7 million would require collateral if rating drops below Baa3 or BBB-
Forward gas sale (h)	85	12	60	13	None
Subsidiary stock subject to repurchase (i)	70	-	-	70	None

<FN>

(a) The Company has the intent and ability to refinance the portion of debt due within one-year. See note 17 for further detail on the Company's long-term debt.

(b) See note 17 for further detail on the debt of the Company's Pure subsidiary.

(c) See note 23 for further detail on the trust convertible securities.

(d) See note 5 for further detail on non-cancelable operating leases.

(e) Refers to capital raised through a transaction where Unocal contributed certain assets to a limited partnership. A third party investor contributed $250 million in cash to the partnership for a limited partnership interest. The partnership is included in Unocal's consolidated financial statements as Unocal is the general partner and controls the entity. The limited partner's interest is reflected as a minority interest liability in Unocal's consolidated financial statements. See note 21 for a further discussion of this arrangement.

(f) As more fully described in note 12, a non-consolidated Unocal subsidiary had sold $70 million in accounts receivable to an outside entity for cash. Unocal's accounts receivable have been reduced by this amount.

(g) See discussion in Item 7A and note 27 for further detail on derivatives.

(h) Represents future sales of natural gas for which Unocal received an advance payment. The balance is reduced as deliveries are made over the term of the agreement that extends through 2008. See note 20 for a further discussion of this transaction. Obligation is fully hedged, eliminating fixed price risk exposure.

(i) See discussion in note 22 regarding Pure's employment and severance agreements.

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Other Financial Commitments (millions of dollars)	Amount of Commitment Expiration Total	Less than 1 Year	1-5 Years	After 5 Years	Recourse & Credit Rating Triggers
Unocal 5-year credit agreement - no balance outstanding	$ 600	$ -	$ 600	$ -	Interest rate varies marginally based on rating. Ratings downgrade does not prevent drawdown or require pre payment and the 364-day credit agreement allows Company to extend term yearly for an additional 364-day period.
Unocal 364-day credit agreement - no balance outstanding	400	400	-	-	
Pure's 3-year line of credit - not guaranteed by Unocal - $175 million outstanding	275	-	275	-	Interest rate varies marginally on rating
Pure's 5-year line of credit - not guaranteed by Unocal - $58 million outstanding	235	-	235	-	None
Pure's working capital line of credit - not guaranteed by Unocal - $6 million outstanding	10	10	-	-	None
Standby letters of credit (a)(b)	41	41	-	-	None - one year term
Unocal other guarantees(a)	370	370	-	-	Approx. $150 million would require bonds, letter of credit or trust funds if below Baa3 or BBB-
Performance bonds including Pure's (Unocal bonds with indemnity) (a)(c)	280	259	-	21	None - during one year term
Guaranteed debt of equity investees	72	46	-	26	Unocal guarantees are limited; $46 million expiring June 2002
Non-guaranteed debt of equity investees	-	-	-	-	None

<FN>
(a) Majority of letters of credit, guarantees and performance bonds are renewed yearly.
(b) Excludes a letter of credit of $15 million for which a liability has been recognized on the balance sheet in other current liabilities.
(c) Excludes $85 million of a performance bond for which a liability is included on the balance sheet in other current liabilities and other deferred credits.
</FN>

In the normal course of business, the Company has performance obligations that are supported by surety bonds or letters of credit. These obligations primarily cover self insurance, site restoration and dismantlement, or other programs where governmental organizations require such support. At December 31, 2001, the Company had in place various surety performance bonds aggregating $280 million, including $11 million related to Pure (see table above). The surety bonds included $152 million related to two bonds acquired by the Company's Molycorp subsidiary for its Questa, New Mexico, molybdenum mine (see note 22 of the consolidated financial statements in Item 8 of this report). The Company also had approximately $41 million in standby letters of credit (see table above).

In addition, the Company had various other guarantees for approximately $370 million. Approximately $150 million of the $370 million amount in guarantees would require the Company to obtain a bond or letter of credit, or set up a trust fund, if its credit rating drops below Baa3 or BBB-.

The Company has certain investments in entities that it accounts for under the equity method, such as Colonial Pipeline Company (see note 14 to the consolidated financial statements in Item 8 of this report). These entities have approximately $1.8 billion of their own debt obligations that are either fully non-recourse to the Company or the recourse is limited. Of the total $1.8 billion in equity investee debt, $1.1 billion belongs to the Colonial Pipeline Company, in which Unocal holds a 23.44 percent equity interest. The Company guarantees only $72 million of the total $1.8 billion debt obligation (see table above). Approximately $46 million of the $72 million in debt guarantees will be expiring in June 2002. The Company also has other contingent liabilities with respect to certain of these entities which on the basis of management's best assessment, are not expected to have a material adverse impact on the Company's consolidated financial condition or liquidity.

The Company has a 50 percent interest in an affiliate, Dayabumi Salak Pratama, Ltd. (DSPL), a company which sells electricity generated from geothermal steam in Indonesia, that it accounts for under the equity method. Unocal made an initial $8 million equity investment in this entity and has outstanding advances of $219 million covering steam sales. At December 31, 2001, DSPL had outstanding third party debt of approximately $200 million. This debt is non-recourse to the Company. The Company's Indonesian geothermal business has certain outstanding receivables from DSPL (see the discussion under Geothermal and Power Operations in the Outlook section of Management's Discussion and Analysis).
Management believes that even if the debt obligations of DSPL were required to be recorded on the balance sheet of the Company, due to any future changes in accounting rules, the amounts would not have a material impact on the Company's liquidity.

The Company has also committed approximately $200 million for its portion of the development costs for the Mad Dog discovery in the deepwater Gulf of Mexico. In addition, the Company has committed up to $310 million for its share of the costs to develop the Azerbaijan International Operating Company ("AIOC")'s Phase I of offshore oil reserves in the Caspian Sea as well as approximately $615 million to develop phase 1 and phase 2 of the West Seno field, offshore East Kalimantan in Indonesia. In 2002, the Company and its co-venturer anticipate securing $350 million in financing through two loans through the Overseas Private Investment Corporation to develop the West Seno field (see page 14 of this report for further detail on the West Seno development project).

Critical Accounting and Other Policies

In December 2001, the Securities and Exchange Commission ("SEC") issued a release regarding the selection and disclosure of "critical accounting policies and practices" by public companies. The SEC encouraged companies to include in the Management's Discussion and Analysis ("MD&A") section a discussion of the effects of critical accounting policies applied, the judgments made in their application, and the likelihood of materially different reported results if different assumptions were to prevail. The following discussion represents management's view of accounting policies and practices that are critical for the Company.

Oil and Gas Accounting - The Company follows the successful efforts method of accounting for its oil and gas activities. Acquisition and development costs of proved properties are capitalized and each is amortized on a units-of-production basis over the remaining life of proved and proved developed reserves, respectively. If reserve estimates are revised downward, earnings could be affected by higher depreciation and depletion expense or an immediate write-down of the property's book value (see impairments discussion below). Another element that is critical and could cause material fluctuations in earnings relates to the disposition of exploratory oil and gas well expenditures under successful efforts accounting. If an exploratory well results in the discovery of commercial reserves, the well investment is transferred to proved properties at the time the reserves are booked. Exploratory wells that are non-commercial are expensed as dry hole costs. Acquisition costs of exploratory acreage are capitalized when incurred. Such costs related to the portion of properties expected to be noncommercial, based on exploratory experience and judgement, are amortized for impairment over the shorter of the exploratory period or the lease/concession holding period.

Oil and Gas Reserves - Estimates of physical quantities of oil and gas reserves are determined by Company engineers and in some cases by third-party experts. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Accordingly, these estimates do not include probable or possible reserves. Estimated oil and gas reserves are based on available reservoir data and are subject to future revision. Significant portions of the Company's undeveloped reserves, principally in offshore areas, require the installation or completion of related infrastructure facilities such as platforms, pipelines, and the drilling of development wells. Proved reserve quantities exclude royalty and other interests owned by others. The Company reports all reserves held under PSCs utilizing the "economic interest" method, which excludes host country shares.
Estimated quantities for PSCs reported under the "economic interest" method are subject to fluctuations in the price of oil and gas and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. This change would be partially offset by a change in the Company's net equity share.

Impairment of Assets -- Oil and gas developed and undeveloped properties are regularly assessed for possible impairment, generally on a field-by-field basis where applicable, using the estimated undiscounted future cash flows of each field. Impairment losses are recognized when the estimated undiscounted future cash flows are less than the current net book values of the properties in a field. The measurement amount to be recorded is based on expected discounted future cash flows. The expected future cash flows are estimated based on management's plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on management's best estimate of future oil and gas prices using market-based information. The estimated future level of production is based on assumptions surrounding future commodity prices, lifting and development costs, field decline rates, market demand and supply, the economic regulatory climates and other factors. See note 6 to the consolidated financial statements in Item 8 of this report for details on impairments.

Environmental and Litigation - Company management also makes judgments and estimates pursuant to applicable accounting rules in recording costs and establishing reserves for environmental clean-up and remediation and potential costs of litigation matters. For environmental reserves, actual costs can differ from estimates because of changes in laws and regulations, discovery and analysis of site conditions and changes in clean-up technology. For additional details, refer to the ensuing "Environmental Matters" discussion and notes 18 and 22 to the consolidated financial statements in Item 8 of this report. Actual litigation costs can vary from estimates based on the facts and circumstances in the application of laws in the individual cases.

ENVIRONMENTAL MATTERS

The Company continues to incur substantial capital and operating expenditures for environmental protection and to comply with federal, state and local laws, as well as foreign laws, regulating the discharge of materials into the environment and management of hazardous and other waste materials. In many cases, investigatory or remedial work is now required at various sites even though past operations followed practices and procedures that were considered acceptable under environmental laws and regulations, if any, existing at the time.

	Estimated	Years Ended December 31,		
Millions of dollars	2002	2001	2000	1999
Environmental related capital expenditures				
Continuing operations	$25	$19	$ 15	$ 11
Discontinued operations	-	-	2	1

Environmental related capital expenditures include additions and modifications to Company facilities to mitigate and/or eliminate emissions and waste generation. Most of these capital expenditures are required to comply with federal, state, local and foreign laws and regulations.

Amounts recorded for environmental related expenses were approximately $175 million in 2001, $160 million in 2000 and $70 million in 1999. Environmental expenses include provisions for remediation and operating, maintenance and administrative expenses that were identified during the Company's ongoing review of its environmental obligations. The higher 2001 expenses were due partially to additional remediation provisions recorded for the cleanup of service station sites, distribution facilities and Central California oil and gas fields formerly operated by the Company. Higher 2001 expenses were also due to additional provisions that were recorded for remediation liabilities related to agricultural chemical sites sold by the Company in 1993. The higher 2000 expenses were due primarily to additional remediation provisions recorded for sites of the Company's Molycorp subsidiary, closed sites in Central California and refining, marketing and distribution sites that were sold in 1997.

At December 31, 2001, the Company's reserve for environmental remediation obligations totaled $237 million, of which $124 million was included in current liabilities. The total amount is grouped into the following four categories:

Reserve Summary

	At December 31,
Millions of dollars	2001
Superfund and similar sites	$ 12
Active company facilities	40
Company facilities sold with retained liabilities and former company-operated sites	98
Inactive or closed company facilities	87
Total reserves	$ 237

Superfund and similar sites - At year-end 2001, Unocal had received notification from the U.S. Environmental Protection Agency that the Company may be a potentially responsible party ("PRP") at 26 sites and may share certain liabilities at these sites. Of the total, eight sites are under investigation and/or litigation and the Company's potential liability is not presently determinable and for one site the Company has denied responsibility. Of the remaining 17 sites, where probable costs can be reasonably estimated, reserves of $4 million have been established for future remediation and settlement costs.

Various state agencies and private parties had identified 28 other similar PRP sites. Nine sites are under investigation and/or litigation and the Company's potential liability is not presently determinable. At five sites the Company's potential liability appears to be de minimis. At another two sites, 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 one site. Where probable costs can be reasonably estimated at the remaining eleven sites, reserves of $8 million have been established for future remediation and settlement costs.

These 54 sites exclude 105 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 several 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 as discussed in note 22 to the consolidated financial statements in Item 8 of this report. 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 $40 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. Also included in this category are the Questa molybdenum mine in New Mexico and the Mountain Pass, California, lanthanide facility, both operated by the Company's Molycorp subsidiary.

Company facilities sold with retained liabilites and former Company-operated sites - Company facilities sold with retained liabilities include certain sites of the Company's former West Coast refining, marketing and transportation business sold in March 1997, auto/truckstop facilities, industrial chemical and polymer sites and agricultural chemical sites. 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 presently estimated future costs for investigation/feasibility studies and 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 $98 million for this category.

Inactive or closed Company facilities - Reserves of $87 million have been established for these types of facilities. The major sites in this category are the former Guadalupe field site, Molycorp's Washington and York facilities in Pennsylvania and a former refinery in Beaumont, Texas.

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 are being performed at the Company's Beaumont, Texas facility, the Company's closed shale oil project, 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 and its Louviers, Colorado facility 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 a Superior Court, the Company must provide financial assurance for anticipated costs of remediation activities at its inactive Guadalupe oil field in California. Also, pursuant to a 1995 settlement agreement between Molycorp and the California Department of Toxic Substances Control (and subsequent Final Judgment entered by a 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 has estimated, to the extent that it was able to do so, that it could incur approximately $260 million of additional costs in excess of the $237 million accrued at December 31, 2001. The amount of such possible additional costs reflects the aggregate of the high end of the range 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 Company has posted various bonds and letters of credit for environmental obligations. A complete discussion on these types of financial commitments can be found under "Long-term Debt and Other Financial Commitments" in MD&A. Also see notes 18 and 22 to the consolidated financial statements in

Item 8 of this report for additional information on environmental related matters.

OUTLOOK

The Company is focused on striking the right balance between near-term returns and long-term value added growth from its exploration portfolio. The Company intends to accomplish this by maintaining strict discipline in its capital spending. In total, more than 90 percent of the capital spending plan targets oil and gas exploration and production projects. The Company will also closely manage its operating and administrative costs. This is expected to help the Company keep its balance sheet strong for maximum financial flexibility.

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. In Thailand and Indonesia, demand for electricity continues to increase. In Indonesia, the economic situation is slowly recovering. The Company 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 net worldwide daily production for 2002 will be essentially the same as the 504,000 BOE per day level achieved in 2001. The Company expects its net earnings per share to be between $1.40 to $1.50 in 2002. The forecast for full-year 2002 earnings assumes average NYMEX benchmark prices of $23.25 per barrel of crude oil and $2.80 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 forecast also includes pre-tax dry hole costs of $110 to $120 million (64% to 61% success rate). Net earnings are expected to change 8 cents per share for each 10 percent change in the overall success rate of the Company's exploration drilling program.

U.S. Lower 48: The Company plans to continue to optimize its production portfolio on the Gulf of Mexico shelf by shifting its exploration focus to deeper, more subtle plays, with significantly higher resource potential and where the Company has significant competitive advantages over some of its competitiors. The Company also plans to pursue selective acquisitions, farm-in and farm-out opportunities in 2002. In the Gulf of Mexico deep water, the Company plans to continue its appraisal of the Trident discovery and prepare to drill another appraisal well later in 2002. The Company plans to put significant effort into analyzing deepwater development options, including the likely use of FPSO technology. In 2002, the Company anticipates reviewing additional opportunities to drill in new ultra-deep prospects. Development of the Mad Dog discovery is scheduled to continue throughout 2002.

In 2001, the Company signed a sublease agreement with a third party for the Discoverer Spirit drillship for a minimum period of 200 days. The third party is responsible for making the lease payments directly to the lessor during the sublease period. The subleasing is expected to give the Company increased flexibility and the opportunity to optimize the use of the ship.

Alaska: The Company's discovery of significant gas resources on Alaska's Kenai Peninsula is expected to support the establishment of a new gas business to serve commercial and utility customers in south central Alaska. The Company has established a large acreage position in the South Kenai gas trend and plans to participate in the drilling and testing of eight wells, including five wells in the Ninilchik Unit and three wells on the other Unocal prospects by the end of 2002. Based on program results, the Company and its partner expect to have sufficient gas resources to support construction of the proposed Kenai-Kachemak pipeline. The two companies formed Kenai Kachemak Pipeline LLC to develop a natural gas pipeline that would connect the new producing area with the existing south central Alaska pipeline system. First production is anticipated to occur in late 2003. The Company has signed a contract to sell, at its option, up to 450 billion cubic feet of natural gas to an affiliate of ENSTAR Natural Gas Company beginning in January 2004. ENSTAR distributes natural gas to Anchorage, the Matanuska-Susitna Valley, and the Kenai Peninsula. The Regulatory Commission of Alaska approved the Unocal-ENSTAR gas contract in December 2001.

Thailand: The Company expects its Thailand operations to continue to perform strongly. Gas demand in Thailand continues to be strong. The Company anticipates domestic natural gas consumption to increase in 2002 about 5 percent over 2001. The Company expects net production levels in its Thailand operation to average about 580 MMcf/d in 2002. In 2002, the average natural gas sales price from the Company's Gulf of Thailand production is expected to be about $2.43 per mcf, or 3 percent higher than in 2001. At the present time, the Company is in discussions with the government of Thailand regarding its request to lower the price of natural gas from most of the current contracts.

The Company plans to drill about 13 exploration wells and over 200 development wells in the Gulf of Thailand in 2002. The Company intends to continue the development of its new crude oil fields in the Gulf of Thailand. Initial production from the Plamuk field began in 2001. The Company expects production from the Plamuk, Yala and Surat fields to reach 15 MBbl/d (gross) in 2002.

Myanmar: The Yadana gas project is now producing near its contract level of 525 MMcf/d. This production displaced some of the volumes of gas that PTT is taking from the Company's Gulf of Thailand operations. The Company expects that gas sales from its Myanmar operations will remain essentially unchanged in 2002 from the 2001 levels.

Indonesia: The Company will continue its development of the deepwater West Seno field in 2002. The Company expects first production from West Seno in 2003. Gross production is expected to reach 60 MBbl/d of crude oil and 150 MMcf/d of natural gas in 2005 with the second phase of development. The Company holds a 90 percent working interest in the Makassar Strait PSC area where the West Seno field is located. The Company will also continue to appraise the Ranggas discovery in the Rapak PSC area and the Gendalo, Gandang and Gula discoveries in the Ganal PSC area offshore East Kalimantan. The Company plans to drill four to eight wells to further delineate the Ranggas discovery in its next phase of drilling and plans to test at least two adjacent prospects. The company expects to determine commerciality and the size of the production facilities in this second drilling phase. The Company also had a successful appraisal well on the Gendalo-Gandang discovery in the Ganal PSC. The well was successfully tested, and the Company is encouraged by the significant natural gas and condensate rates tested from the well and the field's potential. The Gendalo #3 well flowed at a daily rate of 30 MMcf/d of natural gas and 2 MBbl/d of condensate, and the well encountered 102 feet of net pay. The well is located 2.8 miles east of the Gendalo #2 discovery well in the central portion of the Gendalo-Gandang gas field. Another appraisal well, Gandang #2, was drilled in the northern portion of the Gendalo-Gandang gas field. The Gandang #2 well encountered 185 feet of net gas pay. The Gandang #2 well is located 2.2 miles south of the Gandang #1 well discovery well. The Company is the operator of the Ganal PSC and holds an 80 percent working interest.

AIOC: The AIOC consortium, in which the Company has a 10.28 percent working interest, will be engaged in the "Phase I" portion of the development of oil reserves in the Caspian Sea offshore Azerbaijan. This phase of the project will develop 1.5 billion barrels of proved crude oil reserves. Phase I production is expected to commence in late 2004 and is expected to peak at approximately 360 MBbl/d.

Bangladesh: The Company continues to work with the government of Bangladesh and Petrobangla to develop additional reserves and open up the export of natural gas to energy-hungry markets in neighboring India. At December 31, 2001, 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 June 2001 through December 2001. In 2002, payments have been received for natural gas and condensate sales covering billings for June and July 2001 and a portion of August 2001. 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.

China: During the past five years, Unocal has worked with China National Offshore Oil Corporation, China New Star Petroleum Corporation, the Shanghai Municipality and the State Planning Commission to promote appraisal and development of natural gas resources in the Xihu Trough, off the coast of Shanghai, in the East China Sea. Unocal believes the area could contain significant amounts of recoverable natural gas. The Company expects to be part of the group that enters an agreement to proceed with this development project in 2002.

Brazil: The Company expects to participate in the drilling of one wildcat exploration well in 2002 on the BES-2 Block in which it holds a 30 percent working interest. The Company also is expecting to drill a well in late 2002 or early 2003 in the BM-ES-2 Block, where it holds a 40.5 percent working interest. In February 2002, the Company signed an agreement to acquire a 25 percent non-operating working interest in the exploration block BM-ES-1 in the Espirito Santo basin. The block covers 670,000 acres and is approximately 93 miles offshore in water depth from 4,900 to 9,000 feet. The first well on this block is scheduled to be drilled in the second half of 2002.

Midstream: The Company owns varying interests in natural gas storage facilities in Texas and west-central Canada. Construction of the Keystone Gas Storage Project in West Texas is proceeding on schedule. The project is slated to begin storage operations in 2002 with initial storage capacity of 3 billion cubic feet. The Company holds a 100 percent interest in the project. The Company will also be involved in the construction of the main export pipeline between the cities of Baku in Azerbaijan and Ceyhan in Turkey, which will transport future AIOC crude oil production to market.

Geothermal and Power Operations: As of December 31, 2001, the Company's Indonesian Geothermal business unit had a gross receivable balance of approximately $406 million. Approximately $170 million was related to Gunung Salak electric generating Units 1, 2, and 3, of which $167 million represented past due amounts and accrued interest resulting from partial payments for March 1998 through December 2001. Although invoices generally have not been paid in full, amounts that have been paid have been received in a timely manner in accordance with the steam sales contract. The remaining $236 million was primarily related to Salak electric generating Units 4, 5 and 6. Provisions covering portions of these receivables have been recorded from 1998 through 2001. The Company believes that it will be able to collect the net outstanding receivables. Efforts to renegotiate geothermal steam sales and electrical energy sales contracts at Gunung Salak in Indonesia are continuing. The Company believes that significant progress has been made towards an agreement that is acceptable to all parties to resolve the issues.

In 2001, the Philippine government passed a new power law. This new law, which requires the eventual privatization of the National Power Corporation ("NPC")'s assets, may impact the Company's ongoing negotiations with NPC.

Other Matters:

The Company has entered into eight licensing agreements that grant motor gasoline refiners, blenders and importers (including CITGO Petroleum Corporation, Tesoro Petroleum Corporation and units of The Williams Companies, Inc.) the right to make reformulated gasolines using formulations patented by the Company. The terms of the licensing agreements are confidential. The Company continues to negotiate with other refiners, blenders and importers on licensing agreements for the Company's gasoline patents (see also the discussion under "Patents " under Items 1 and 2 - "Business and Properties" of this report).

In 2002, the Company will continue its remediation efforts at various sites. The amount of cash expenditures for remediation work expected to be performed in 2002 is expected to be approximately $124 million. Provisions for these expenditures are included in the Company's environmental reserve (see also the discussion under "Environmental Matters" in MD&A).

Over the past few months, the Company and the purchaser of the Company's agricultural business, sold in 2000, have been engaged in discussions involving various aspects of the transaction and the obligations of the parties under the purchase and sale agreement. During February and March 2002, the Company and purchaser have engaged in discussions and negotiations in an attempt to resolve all outstanding differences between the two companies.

FUTURE ACCOUNTING CHANGES

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets", which is effective for fiscal years beginning after December 15, 2001. 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. In the first quarter of 2002, the Company will adopt SFAS No. 142 and does not expect the adoption of the statement to have a material effect on its financial position or results of operations.

In August 2001, SFAS No. 143, "Accounting for Asset Retirement Obligations", was also issued by the FASB. 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 or results of operations.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of", 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". SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The Company does not expect the adoption of SFAS. No. 144 to have a material effect on its financial position or 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.

CAUTIONARY STATEMENT FOR PURPOSES OF
THE "SAFE HARBOR" PROVISIONS OF
THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Unocal desires to take advantage of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, as embodied in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, and is including this statement in this report in order to do so.

This report contains forward-looking statements and from time to time in the future the Company's management or other persons acting on the Company's behalf may make, in both written publications and oral presentations, additional forward-looking statements to inform investors and other interested persons of the Company's estimates and projections of, or increases or decreases in, amounts of future revenues, prices, costs, earnings, cash flows, capital expenditures, assets, liabilities and other financial items. Certain statements may also contain estimates and projections of future levels of, or increases or decreases in, crude oil and natural gas reserves and related finding and development costs, potential resources, production and related lifting costs, sales volumes and related prices, and other statistical items; plans and objectives of management regarding the Company's future operations, projects, products and services; and certain assumptions underlying such estimates, projections, plans and objectives. Such forward-looking statements are generally accompanied by words such as "estimate", "projection", "plan", "target", "goal", "forecast", "believes", "expects", "anticipates" or other words that convey the uncertainty of future events or outcomes.

While such forward-looking statements are made in good faith, forward-looking statements and their underlying assumptions are by their nature subject to certain risks and uncertainties and their outcomes will be influenced by various operating, market, economic, competitive, credit, environmental, legal and political factors. Certain of such factors, set forth elsewhere in this report, are important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. See the discussions of the decline in production from the Company's Muni field in the Gulf of Mexico under "Exploration and Production--North America--U.S. Lower 48--Gulf of Mexico Shelf and Onshore (Excluding Pure Resources, Inc.)" in combined Item 1 and 2 - "Business and Properties" of this report; the discussions of the negotiations with respect to the levels of natural gas and crude oil production from the Gulf of Thailand and natural gas contract prices under "Exploration and Production--International--Thailand" in Items 1 and 2 and under Outlook--Thailand" above in Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD the discussion of the effort by the Company's Philippine Geothermal, Inc., subsidiary to settle a contract dispute under "Geothermal and Power Operations" in Items 1 and 2; the discussion of negotiations, legal issues and related uncertainties involving the Company's patents for formulations of cleaner-burning gasolines under "Patents" in Items 1 and 2 and under "Outlook--Other Matters" above in MDA the discussions under "Government Regulations" and "Environmental Regulations" in Items 1 and 2; the discussions of certain lawsuits and claims, including tax matters, in "Item 3--Legal Proceedings" and in note 22 to the consolidated financial statements in Item 8 of this report, which note also contains a discussion of certain other contingent liabilities and commitments; the presentation and discussion of the Company's estimated 2002 capital expenditures under "Financial Condition--Capital Expenditures" above in MDA the discussion of the Company's need to borrow to meet a portion of its projected 2002 cash requirements, together with the available sources of borrowings and the related importance of maintaining the Company's investment-grade credit ratings, under "Long-term Debt and Other Financial Commitments" above in MDA the discussion of various of the Company's financial and other obligations and commitments under "Long-term Debt and Other Financial Commitments" above in MDA the discussion of the Company's critical accounting policies [and practices] under "Critical Accounting and Other Policies" above in MDA the discussions of the Company's reserves for and possible additional costs of remediation and other environment-related expenditures and expenses under "Environmental Matters" above in MD&A and in notes 18 and 22 to the consolidated financial statements; the discussion of the anticipated continued volatility of energy prices in 2002 under "Outlook" above in MDA the assumptions underlying the Company's forecasts of its 2002 aggregate oil and gas production levels and after-tax earnings per share under "Outlook" above in MDA the Company's sublease of its Discoverer Spirit drillship to a third party and the party's responsibility for the lease payments during the sublease period under "Outlook--U.S. Lower 48" above in MD&A, in note 5 to the consolidated financial statements and under "Other Matters" in note 22 to the consolidated financial statements; the discussion of the outstanding receivables balance due for sales of natural gas and condensate to Petrobangla under "Outlook--Bangladesh" above in MDA the discussions of the outstanding receivables balance due related to the Company's Indonesian geothermal and power operations under "Outlook--Geothermal and Power Operations" above in MD&A and under "Concentrations of Credit Risk" in note 27 to the consolidated financial statements; the discussion of the negotiations with the purchaser of the Company's agricultural products business involving various aspects of the transaction and the obligations of the parties under the purchase and sale agreement for the business under "Outlook--Other Matters" above in MDA the discussion under "Future Accounting Changes" above in MDA and the discussions of the risks associated with the Company's use of derivative financial instruments in its hedging and trading activities under Item 7A "Quantitative and Qualitative Disclosures about Market Risk" of this report and in note 27 to the consolidated financial statements.

Set forth below are additional important factors (but not necessarily all of such factors) that could cause actual results to differ materially from those expressed in the forward-looking statements.

Commodity Prices

A decline in the prices for crude oil, natural gas or other hydrocarbon commodities sold by the Company could have a material adverse effect on the Company's results of operations, on the quantities of crude oil and natural gas that could be economically produced from its fields, and on the quantities and economic values of its proved reserves and potential resources. Such adverse pricing scenarios could result in write-downs of the carrying values of the Company's properties, which could materially adversely affect the Company's financial condition, as well as its results of operations.

Exploration and Production Risks

The amounts of the Company's future crude oil and natural gas reserves and production will also be affected by its ability to replace declining reservoirs in existing fields with new reserves through its exploration and development programs and through acquisitions. The ability of the Company to replace reserves will depend not only on its ability to obtain acreage and contracts in the countries in which it currently operates, as well as in new countries, and to delineate prospects which prove to be successful geologically, but also to drill, find, develop and produce recoverable quantities of oil and gas economically in the price environment prevailing at the time.

The exploration for oil and gas is a high-risk business in which significant numbers of dry holes and high associated costs can be incurred in the processes of seeking commercial discoveries. The Company's exploration and production activities also are subject to all of the physical risks and uncertainties normally associated with such activities, including, but not limited to, such hazards as explosions, fires, blowouts, leaks and spills, some of which may be very difficult and expensive to control and/or remediate, and damages from hurricanes, typhoons, monsoons and other severe weather conditions.

The process of estimating quantities of oil and natural gas reserves and potential resources is inherently uncertain and involves subjective geological, engineering and economic judgments. Changes in operating conditions, such as unforeseen geological complexities and drilling and production difficulties, and changes in economic conditions, such as finding and development and production costs and sales prices, could cause material downward revisions in the Company's estimated proved reserves and potential resources.

Projections of future amounts of crude oil and natural gas production are also imprecise because they rely on assumptions about the future levels of prices and costs, field decline rates, market demand and supply, the political, economic and regulatory climates and, in the case of the Company's foreign production, the terms of the contracts under which the Company operates, which could result in mandated production cutbacks from existing or projected levels.

A significant portion of the Company's expectation for future oil and gas development involves large projects, primarily offshore in increasingly deeper waters. The timing and amounts of production from such projects will be dependent upon, among other things, the formulation of development plans and their approval by foreign governmental authorities and other working interest partners, the receipt of necessary permits and other approvals from governmental agencies, the obtaining of adequate financing, either internally or externally, the availability, costs and performance of drilling rigs and other equipment, and the timely construction of platforms, pipelines and other necessary infrastructure by specialized contractors.

Certain Political and Economic Risks

The Company's operations outside of the U.S. are subject to risks inherent in foreign operations, including, without limitation, the loss of revenues, property and equipment from hazards such as expropriation, nationalization, war, insurrection and other political risks, increases in taxes and governmental royalties or other takes, abrogation or renegotiation of contracts by governmental entities, changes in laws and policies governing operations of foreign-based companies, currency conversion and repatriation restrictions and exchange rate fluctuations, and other uncertainties arising out of foreign government sovereignty over the Company's international operations. Laws and policies of the U.S. government affecting foreign trade and taxation may also adversely affect the Company's international operations.

The Company's ability to market crude oil, natural gas and other commodities produced in foreign countries, and the prices the Company will be able to obtain for such production, will depend on many factors which are often beyond the Company's control, such as the existence or development of markets for its discoveries, the proximity and capacity of pipelines and other transportation facilities or the timely construction thereof, fluctuating demand for oil and natural gas, the availability and costs of competing fuels, and the effects of foreign governmental regulation of production and sales.

The Company's operations in the U.S. are also subject to political, regulatory and economic conditions.

In light of the foregoing, investors should not place undue reliance on forward-looking statements, which reflect management's views only as of the date they are published or presented. Although the Company from time to time may voluntarily revise its forward-looking statements to reflect subsequent events or circumstances, it undertakes no obligation to do so.

ITEM 7A − 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 movements in interest rates, foreign currency exchange rates 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 pursues outright pricing positions in certain hydrocarbon derivative instruments, such as futures contracts, swaps and options.

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 indicies. Some instruments with longer maturity periods require financial modeling to accommodate calculations beyond the horizon of available exchange quotes. These models calculate values for outer periods using current exchange quotes (forward curve) and assumptions regarding interest rates, commodity and interest rate volatility and, in some cases, foreign currency exchange rates in the outer periods. While the Company feels that its use of current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors used 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 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 December 31, 2001. Assuming a ten percent decrease in the Company's weighted average borrowing costs at December 31, 2001 and December 31, 2000, respectively, 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 $109 million at December 31, 2001 and $103 million at December 31, 2000.

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 December 31, 2001, the Company had various foreign currency swaps and foreign currency forward contracts outstanding to hedge its debt and other local currency obligations 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 December 31, 2001, 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 $12 million at December 31, 2001. At year-end 2000, the Company had various foreign currency swaps and foreign currency forward contracts outstanding to hedge some of its debt and other local currency obligations in Canada, Thailand and The Netherlands. Assuming an adverse change of ten percent in foreign exchange rates at year-end 2000, the potential decrease in fair value of the Company's foreign currency forward contracts, including the Company's net interests in the foreign currency denominated debt, foreign currency swaps and foreign currency forward contracts of its subsidiaries, would have been approximately $11 million at December 31, 2000.

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 $11 million at December 31, 2001 and approximately $12 million at December 31, 2000. The value at risk related to hydrocarbon derivatives held for hedging purposes was approximately $5 million at December 31, 2001 and approximately $13 million at December 31, 2000.

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 December 31, 2001, along with the fair values of those instruments.

Hydrocarbon Hedging Derivative Instruments (a)

	2002	2003	2004	2005	2006-2009	(Thousands of dollars) Fair Value Asset (Liability)(b)
Natural Gas Futures Positions						
Volume (MMBtu)	300,000	-	-	-	-	$ (1,868)
Average price, per MMBtu	$ 4.19					
Natural Gas Swap Positions						
Pay fixed price (c)						
Volume (MMBtu)	10,090,500	7,218,000	7,241,000	7,218,000	21,677,000	$ 19,485
Average swap price, per MMBtu	$ 2.74	$ 2.30	$ 2.33	$ 2.37	$ 2.47	
Receive fixed price (d)						
Volume (MMBtu)	12,393,899	166,999	95,438	-	-	$ 28
Average swap price, per MMBtu	$ 2.66	$ 1.98	$ 1.98			
Natural Gas Basis Swap Positions						
Volume (MMBtu)	7,117,500	-	-	-	-	$ (22)
Average price received, per MMBtu	$ 2.44					
Average price paid, per MMBtu	$ 2.45					
Natural Gas Collar Positions						
Volume (MMBtu)	36,167,000	866,000	-	-	-	$ 5,430
Average ceiling price, per MMBtu	$ 3.44	$ 5.28				
Average floor price, per MMBtu	$ 2.53	$ 3.05				
Natural Gas Option (Listed)						
Call Volume (MMBtu)	4,000,000	-	-	-	-	$ (109)
Average Call price, per MMBtu	$ 3.30					
Crude Oil Future position						
Volume (Bbls)	678,000	-	-	-	-	$ (1,556)
Average price, per Bbl	$19.15					
Crude Oil Option						
Put Volume (Bbls)	257,243	-	-	-	-	$ 897
Average price, per Bbl	$ 24.34					
Call Volume (Bbls)	(270,917)	-	-	-	-	$ (20)
Average price, per Bbl	$ 28.05					
Crude Oil Swap Positions						
Pay fixed price						
Volume (Bbls)	89,000	-	-	-	-	$ (548)
Average swap price, per Bbl	$ 26.48					
Receive fixed price (e)						
Volume (Bbls)	187,500	-	-	-	-	$ (297)
Average swap price, per Bbl	$ 18.71					
Crude Oil Collars						
Volume (Bbls)	88,421	132,913	1,667	-	-	$ 298
Average ceiling price, per Bbl	$ 27.15	$ 25.60	$ 23.50			
Average floor price, per Bbl	$ 20.61	$ 20.09	$ 18.00			

<FN>
(a) Positions reflect long (short) volumes.
(b) Includes $ 2,000 thousand net claims against counterparties with non-investment grade credit ratings.
(c) Includes $245 thousand in assumed liabilities which were capitalized as acquisition costs.
(d) Includes $11,815 thousand in assumed liabilities which were capitalized as acquisition costs.
(e) Includes $1,300 thousand in assumed liablities which were capitalized as acquisitions costs.
</FN>

Hydrocarbon Non-Hedging Derivative Instruments (a)

	2002	2003	(Thousands of dollars) Fair Value Asset (Liability)(b)(c)
Natural Gas Futures Positions			
Volume (MMBtu)	920,000	-	$ (653)
Average price, per MMBtu	$ 3.97		
Natural Gas Swap Positions			
Pay fixed price			
Volume (MMBtu)	166,225	828,400	$ 496
Average swap price, per MMBtu	$ 3.27	$ 3.27	
Receive fixed price			
Volume (MMBtu)	3,780,000	-	$(16,202)
Average swap price, per MMBtu	$ 2.46		
Natural Gas Basis Swap Positions			
Volume (MMBtu)	9,812,500	-	$ (3,515)
Average price received, per MMBtu	$ 3.15		
Average price paid, per MMBtu	$ 3.38		
Natural Gas Option (Listed)			
Call Volume (MMBtu)	(1,950,000)		$ 937
Average Call price, per MMBtu	$ 3.05		
Put Volume (MMBtu)	-	-	$ 519
Average Put Price, per MMBtu			
Natural Gas Option (Over the Counter)			
Call Volume (MMBtu)	(8,314,600)	(2,743,650)	$ (2,835)
Average Call price,per MMBtu	$ 3.14	$ 2.57	
Put Volume (MMBtu)	2,000,000	-	$ 17
Average Put price, per MMBtu	$ 2.58		
Natural Gas Spread Option (Over the Counter)			
NYMEX / IFERC (d)			
Put Volume (MMBtu)	(18,570,000)	-	$ 329
Average Strike price, per MMbtu	$ 0.39		
Crude Oil Future position			
Volume (Bbls)	37,000	-	$ (636)
Average price, per Bbl	$ 22.48		
Crude Oil Option			
Put Volume (Bbls)	-	-	$ (1,542)
Average price, per Bbl			
Call Volumes (Bbls)	-	-	$ -
Average price, per Bbl			
Crude Oil Swap Positions			
Pay Fixed price			
Volume (Bbls)	100,000		$ 449
Average price, per Bbl	21.69		
Receive fixed price			
Volume (Bbls)	1,327,500	-	$ (2,376)
Average swap price, per Bbl	$ 18.86		

<FN>
(a) Positions reflect long (short) volumes.
(b) Includes $1,000 thousand net claims against counterparties with non-investment grade credit ratings.
(c) Includes $39 thousand fair value derived from models using price quotes from non-exchange sources and other valuation methods.
(d) Prices quoted from the New York Mercantile Exchange (NYMEX) and Inside FERC Gas Report (IFERC).
</FN>

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ITEM 8 - FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Index to the Consolidated Financial Statements and Financial Statement Schedule

All other financial statement schedules have been omitted as they are not applicable, not material or the required information is included in the financial statements or notes thereto.

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REPORT ON MANAGEMENT'S RESPONSIBILITIES

To the Stockholders of Unocal Corporation:

Unocal's management is responsible for the integrity and objectivity of the financial information contained in this Annual Report. The financial statements included in this report have been prepared in accordance with generally accepted accounting principles and, where necessary, reflect the informed judgments and estimates of management.

The financial statements have been audited by the independent accounting firm of PricewaterhouseCoopers LLP. Management has made available to PricewaterhouseCoopers LLP all of the Company's financial records and related data, minutes of the meetings of the Board of Directors and its executive committee and of the management committee and all internal audit reports. The independent accountants conduct a review of internal accounting controls to the extent required by generally accepted auditing standards and perform such tests and procedures, as they deem necessary to arrive at an opinion on the fairness of the financial statements presented herein.

Management maintains and is responsible for systems of internal accounting controls designed to provide reasonable assurance that the Company's assets are properly safeguarded, transactions are executed in accordance with management's authorization and the books and records of the Company accurately reflect all transactions. The systems of internal accounting controls are supported by written policies and procedures and by an appropriate segregation of responsibilities and duties. The Company maintains an extensive internal auditing program that independently assesses the effectiveness of these internal controls with written reports and recommendations issued to the appropriate levels of management. Management believes that the existing systems of internal controls are achieving the objectives discussed herein.

Unocal's Accounting and Auditing Committee, consisting solely of directors who are not employees of Unocal and have no material existing or prior relationships with Unocal, is responsible for: reviewing the Company's financial reporting, accounting and internal control practices; recommending the selection of the independent accountants (which in turn are approved by the Board of Directors and ratified annually by the stockholders); monitoring compliance with applicable laws and Company policies; and initiating special investigations as deemed necessary. The independent accountants and the internal auditors have full and free access to the Accounting and Auditing Committee and meet with it, with and without the presence of management, to discuss all appropriate matters.

/s/Charles R. Williamson
Charles R. Williamson
Chairman of the Board
and Chief Executive Officer

/s/Timothy H. Ling
Timothy H. Ling
President and
Chief Operating Officer

/s/Terry G. Dallas
Terry G. Dallas
Executive Vice President and
Chief Financial Officer

/s/Joe D. Cecil
Joe D. Cecil
Vice President and
Comptroller

March 15, 2002

REPORT OF INDEPENDENT ACCOUNTANTS

To the Stockholders of Unocal Corporation:

We have audited the accompanying consolidated balance sheets of Unocal Corporation and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of earnings, cash flows and stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2001 and the related financial statement schedule. These financial statements and financial statement schedule are the responsibility of Unocal Corporation's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above, which appear on pages 71 through 126 of this Annual Report on Form 10-K/A, present fairly, in all material respects, the consolidated financial position of Unocal Corporation and its subsidiaries as of December 31, 2001 and 2000 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth, when read in conjunction with the related consolidated financial statements.

/s/PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
February 14, 2002
Los Angeles, California

Millions of dollars except per share amounts	Years ended December 31, 2001	2000	1999
Revenues			
Sales and operating revenues	$ 6,664	$ 8,941	$ 5,842
Interest, dividends and miscellaneous income	64	176	105
Gain on sales of assets	24	85	14
Total revenues	6,752	9,202	5,961
Costs and other deductions			
Crude oil, natural gas and product purchases	2,492	5,158	3,296
Operating expense	1,376	1,199	952
Administrative and general expense	122	129	135
Depreciation, depletion and amortization	967	821	718
Impairments	118	66	23
Dry hole costs	175	156	148
Exploration expense	252	260	253
Interest expense (a)	192	210	199
Property and other operating taxes	77	68	50
Distributions on convertible preferred securities of subsidiary trust	33	33	33
Total costs and other deductions	5,804	8,100	5,807
Earnings from equity investments	144	134	96
Earnings from continuing operations before income taxes and minority interests	1,092	1,236	250
Income taxes	452	497	121
Minority interests	41	16	16
Earnings from continuing operations	599	723	113
Discontinued operations			
Refining, marketing and transportation			
Gain on disposal (b)	17	-	25
Agricultural products			
Earnings (loss) from operations (c)	-	-	(1)
Gain on disposal (d)	-	37	-
Earnings from discontinued operations	17	37	24
Cumulative effect of accounting change	(1)	-	-
Net earnings	$ 615	$ 760	$ 137
Basic earnings per share of common stock:			
Continuing operations	$ 2.45	$ 2.98	$ 0.47
Net earnings	$ 2.52	$ 3.13	$ 0.57
Diluted earnings per share of common stock:			
Continuing operations	$ 2.43	$ 2.93	$ 0.46
Net earnings	$ 2.50	$ 3.08	$ 0.56

<FN>

(a) Net of capitalized interest of :	$ (27)	$ (13)	$ (16)
(b) Net of tax expense of :	$ 10	$ -	$ 14
(c) Net of tax expense (benefit) of :	$ -	$ -	$ (5)
(d) Net of tax expense of :	$ -	$ 18	$ -

</FN>

See Notes to Consolidated Financial Statements.

Millions of dollars	At December 31, 2001	2000
Assets		
Current assets		
Cash and cash equivalents	$ 190	$ 235
Accounts and notes receivable - net	847	1,299
Inventories	102	88
Deferred income taxes	123	155
Other current assets	33	25
Total current assets	1,295	1,802
Investments and long-term receivables - net	1,405	1,379
Properties - net	7,514	6,433
Deferred income taxes	128	231
Other assets	83	165
Total assets	$ 10,425	$ 10,010
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 823	$ 1,022
Taxes payable	249	282
Dividends payable	49	49
Interest payable	49	55
Current portion of environmental liabilities	124	124
Current portion of long-term debt and capital leases	9	114
Other current liabilities	119	199
Total current liabilities	1,422	1,845
Long-term debt and capital leases	2,897	2,392
Deferred income taxes	627	618
Accrued abandonment, restoration and environmental liabilities	590	554
Other deferred credits and liabilities	724	832
Subsidiary stock subject to repurchase	70	136
Minority interests	449	392
Commitments and contingencies - Note 22		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent subordinated debuntures	522	522
Common stock ($1 par value, shares authorized:750,000,000(a))	255	254
Capital in excess of par value	551	522
Unearned portion of restricted stock issued	(29)	(21)
Retained earnings	2,888	2,468
Accumulated other comprehensive income (loss)	(88)	(53)
Notes receivable - key employees	(42)	(40)
Treasury stock - at cost (b)	(411)	(411)
Total stokholders' equity	3,124	2,719
Total liabilities and stockholders' equity	$ 10,425	$ 10,010

<FN>

(a) Number of shares outstanding	243,998,088	243,044,589
(b) Number of shares held	10,622,784	10,622,784

The company follows the successful efforts method of accounting for its oil and gas activities.
</FN>

See Notes to the Consolidated Financial Statements.

Millions of dollars	2001	2000	1999
	Years ended December 31,		
Cash Flows from Operating Activities			
Net earnings	$ 615	$ 760	$ 137
Adjustments to reconcile net earnings to net cash provided by operating activities			
Depreciation, depletion and amortization	967	821	733
Impairments	118	66	23
Dry hole costs	175	156	148
Amortization of exploratory leasehold costs	95	85	77
Deferred income taxes	81	17	(58)
Gain on sales of assets (pre-tax)	(24)	(85)	(14)
Gain on disposal of discontinued operations(pre-tax)	(27)	(23)	(39)
Earnings applicable to minority interests	41	16	16
Other	31	172	(133)
Working capital and other changes related to operations			
Accounts and notes receivable	462	(389)	(173)
Inventories	(14)	24	-
Accounts payable	(273)	91	234
Taxes payable	(33)	92	(68)
Other	(89)	(135)	143
Net cash provided by operating activities	2,125	1,668	1,026
Cash Flows from Investing Activities			
Capital expenditures (includes dry hole costs)	(1,727)	(1,302)	(1,171)
Major acquisitions	(646)	(318)	(205)
Proceeds from sales of assets	81	284	207
Proceeds from sales of discontinued operations	25	267	31
Net cash used in investing activities	(2,267)	(1,069)	(1,138)
Cash Flows from Financing Activities			
Proceeds from issuance of common stock	15	7	24
Long-term borrowings	519	-	862
Reduction of long-term debt and capital lease obligations	(225)	(453)	(718)
Dividends paid on common stock	(195)	(194)	(194)
Loans to key employees	-	(32)	-
Minority interests	(17)	(25)	233
Other	-	1	(1)
Net cash provided by (used in) financing activities	97	(696)	206
Increase (decrease) in cash and cash equivalents	(45)	(97)	94
Cash and cash equivalents at beginning of year	235	332	238
Cash and cash equivalents at end of year	$ 190	$ 235	$ 332

<FN>

Supplemental disclosure of cash flow information:
Cash paid during the period for:

	2001	2000	1999
Interest (net of amount capitalized)	$ 195	$ 221	$ 196
Income taxes (net of refunds)	$ 368	$ 374	$ 197

</FN>

See Notes to the Consolidated Financial Statements.

Millions of dollars except per share amounts	At December 31, 2001	2000	1999
Common stock			
Balance at beginning of year	$ 254	$ 253	$ 252
Issuance of common stock	1	1	1
Balance at end of year	255	254	253
Capital in excess of par value			
Balance at beginning of year	522	493	460
Issuance of common stock	29	29	33
Balance at end of year	551	522	493
Unearned portion of restricted stock and options issued			
Balance at beginning of year	(21)	(20)	(24)
Issuance of restricted stock and options	(18)	(12)	(5)
Amortization of stock and options	10	11	9
Balance at end of year	(29)	(21)	(20)
Retained earnings			
Balance at beginning of year	2,468	1,902	1,959
Net earnings for year	615	760	137
Cash dividends declared on common stock ($0.80 per share)	(195)	(194)	(194)
Balance at end of year	2,888	2,468	1,902
Treasury stock			
Balance at beginning of year	(411)	(411)	(411)
Purchased at cost	-	-	-
Balance at end of year	(411)	(411)	(411)
Notes receivable - key employees			
Balance at beginning of year	(40)	-	-
Accrued interest on loans to key employees	(2)	-	-
Issuance of loans to key employees	-	(40)	-
Balance at end of year	(42)	(40)	-
Accumulated other comprehensive income (loss)			
Balance at beginning of year	(53)	(33)	(34)
Foreign currency translation adjustments	(40)	(20)	-
Deferred net gains on hedging instruments	60	-	-
Cumulative effect of accounting change	(59)	-	-
Minimum pension liability adjustment	4	-	1
Balance at end of year (a)	(88)	(53)	(33)
Total stockholders' equity	$ 3,124	$ 2,719	$ 2,184

<FN>

(a) At year-end 2001, other comprehensive income was comprised of unrealized currency translation losses of $85 million, deferred net gains on hedging instruments of $60 million, minimum pension liability adjustment of $4 million and cumulative effect of accounting change $59 million. Year-end 2000 other comprehensive income consisted of unrealized currency translation losses of $45 million and minimum pension liability adjustment of $8 million. Year-end 1999 comprehensive income consisted of unrealized currency translation losses of $25 million and minimum pension liability adjustment of $8 million.

</FN>

See Notes to the Consolidated Financial Statements.

Millions of dollars	2001	2000	1999
	Years ended December 31,		
Net earnings	$ 615	$ 760	$ 137
Cumulative effect of change in accounting principle SFAS No. 133 adoption (a)	(59)	-	-
Change in unrealized loss on hedging instruments (b)	32	-	-
Reclassification adjustment for settled hedging contracts (c)	28	-	-
Unrealized foreign currency translation adjustments	(40)	(20)	-
Minimum pension liability adjustment (d)	4	-	1
Total comprehensive income	$ 580	$ 740	$ 138

<FN>

(a) Net of tax effect of:	36	-	-
(b) Net of tax effect of:	(19)	-	-
(c) Net of tax effect of:	(16)	-	-
(d) Net of tax effect of:	(2)	-	-

</FN>

See Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - For the purpose of this report, Unocal Corporation ("Unocal") and its consolidated subsidiaries, including Union Oil Company of California ("Union Oil"), will be 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. 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.

Use of Estimates - The consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America, which require management to make estimates and assumptions that affect the amounts of assets and liabilities and the disclosures of contingent liabilities as of the financial statement date and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition - Revenues associated with sales of crude oil, condensate, natural gas, natural gas liquids and other products are recorded when title passes to the customer. Natural gas sales revenues from properties in which the Company has an interest with other producers are recognized on the basis of Unocal's working interest ("entitlement" method of accounting). Natural gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company takes less than it is entitled, the under-delivery is recorded as a receivable. At December 31, 2001 and 2000, the Company had both receivables and payables related to under and over liftings of natural gas. The Company's worldwide net gas imbalance was a receivable of $42 million and $37 million, for the two years respectively.

Inventories - Inventories are generally valued at lower of cost or market. The costs of crude oil and other petroleum products are determined using the last-in, first-out ("LIFO") method except for inventories held as energy trading assets, which are determined by market prices. The costs of other inventories are determined by using various methods. Cost elements primarily consist of raw materials and production expenses.

Impairment of Assets - Oil and gas developed and undeveloped properties are regularly assessed for possible impairment, generally on a field-by-field basis where applicable, using the estimated undiscounted future cash flows of each field. Impairment losses are recognized when the estimated undiscounted future cash flows are less than the current net book values of the properties in a field. The measurement of the impairment amount to be recorded is based on expected discounted future cash flows. These expected future cash flows are estimated based on management's plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on management's best estimate of future oil and gas prices using market-based information. The estimated future level of production is based on assumptions surrounding future commodity prices, lifting and development costs, field decline rates, market demand and supply, the economic regulatory climates and other factors.

Impairment charges are also made for other long-lived assets when it is determined that the carrying values of the assets may not be recoverable. A long-lived asset is reviewed for impairment whenever events or changes in circumstances indicate that the carrying value of the asset may not be recoverable.

Oil and Gas Exploration and Development Costs - The Company follows the successful efforts method of accounting for its oil and gas activities. Acquisition costs of exploratory acreage are capitalized when incurred. Such costs related to the portion of properties expected to be non-commercial, based on exploratory experience and judgment, are amortized for impairment over the shorter of the exploratory period or the lease/concession holding period. This impairment amortization is reflected as a component of exploration expense on the consolidated earnings statement. Costs of successful leases are transferred to proved properties. Exploratory drilling costs are initially capitalized. If an exploratory well results in discovery of commercial reserves, the well investment is transferred to proved properties at the time reserves are booked. Exploratory wells that are non-commercial are expensed as dry holes. Geological and geophysical costs for exploration and leasehold rentals for unproved properties are expensed. Development costs of proved properties, including unsuccessful development wells, are capitalized.

Depreciation, Depletion and Amortization - Depreciation, depletion and amortization related to acquisition costs and development costs of proved properties are calculated at unit-of-production rates based upon total proved and proved developed reserves, respectively. Estimated future abandonment and removal costs for onshore and offshore producing facilities are calculated at unit-of-production rates based upon estimated proved reserves. Depreciation of other properties is generally on a straight-line method using various rates based on estimated useful lives.

Maintenance and Repairs - Expenditures for maintenance and repairs are expensed. In general, improvements are charged to the respective property accounts.

Retirement and Disposal of Properties - Upon retirement of facilities depreciated on an individual basis, remaining book values are charged to depreciation expense. For facilities depreciated on a group basis, remaining book values are charged to accumulated allowances. Gains or losses on sales of properties are included in current earnings.

Income Taxes - The Company uses the liability method for reporting income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Under this method, the amounts of deferred tax liabilities and assets at the end of each period are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. Future tax benefits are recognized to the extent that realization of such benefits is more likely than not.

Deferred income taxes are provided for the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities. Deferred tax assets are also provided for certain tax credit carryforwards. A valuation allowance to reduce deferred tax assets is established when deemed appropriate.

Foreign Currency Translation − Foreign exchange translation adjustments as a result of translating a foreign entity's financial statements from its functional currency into U.S. dollars are included as a separate component of other comprehensive income in stockholders' equity. The functional currency for all operations, except Canada and equity investments in Thailand and Brazil, is the U.S. dollar. Gains or losses incurred on currency transactions in other than a country's functional currency are included in net earnings.

Environmental Expenditures − Expenditures that relate to existing conditions caused by past operations are expensed. Environmental expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to environmental assessments and future remediation costs are recorded when such liabilities are probable and the amounts can be reasonably estimated. The Company considers a site to present a probable liability when an investigation has identified environmental remediation requirements for which the Company is responsible. The timing of accruing for remediation costs generally coincides with the Company's completion of investigation or feasibility work and its recommendation of a remedy or commitment to an appropriate plan of action. Environmental liabilities are not discounted or reduced by possible recoveries from third parties. However, accrued liabilities for Superfund and similar sites reflect anticipated allocations of liabilities among settling participants. Environmental remediation expenditures required for properties held for sale are capitalized up to the realizable market value.

Risk Management − The objectives of the Company's risk management strategies include reducing the overall volatility of the Company's cash flows, preserving revenues and pursuing outright pricing positions in hydrocarbon derivative financial instruments (hydrocarbon derivatives). As part of its overall risk management strategy, the Company enters into various derivative instrument contracts to offset portions of its exposures to changes in interest rates, changes in foreign currency exchange rates, and fluctuations in crude oil and natural gas prices. In general, the Company enters into derivative instruments to hedge two types of exposures: cash flow exposures and fair value exposures. Hedges of cash flow exposures are generally undertaken to reduce cash flow volatility associated with forecasted transactions. They may also be used to reduce volatility associated with cash flows to be paid related to recognized liabilities. Hedges of fair value exposures are undertaken to hedge recognized assets or liabilities or unrecognized firm commitments against changes in value.

Interest Rates − From time to time, the Company enters into interest rate swap contracts to manage the interest cost of its debt with the objective of minimizing the volatility and magnitude of the Company's borrowing costs.

Foreign Currency − Various foreign currency forward, option and swap contracts are entered into by the Company to manage its exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions.

Commodities − The Company uses hydrocarbon derivatives such as futures, swaps, collars and options to mitigate the Company's overall exposure to fluctuations in hydrocarbon commodity prices. The Company also pursues outright pricing positions using derivatives.

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities", all derivative instruments are recorded as assets or liabilities on the balance sheet at their fair values. The Company routinely enters into various purchase and sale contracts that will ultimately result in the physical delivery of hydrocarbon commodities. The Company has determined that the normal purchase and normal sale exception included in paragraph 10(b) of SFAS No. 133 applies to such contracts. Accordingly, such contracts are not accounted for as derivatives pursuant to SFAS No.133.

At the inception of a derivative contract, the Company may choose to designate and document a derivative as a cash flow hedge or a fair value hedge. Changes in the values of derivatives not designated and documented as hedges are recorded in current−period earnings. Changes in the values of derivatives that qualify for, and are designated and effective as, cash flow hedges are deferred and recorded as components of accumulated other comprehensive income until the hedged transactions occur and are then recognized in earnings. Any ineffectiveness that is related to changes in the values of cash flow hedge derivatives is recognized immediately in earnings as a component of sales revenues. During 2001, the Company changed its methodology for calculating the effectiveness of options used in cash flow hedges to conform with the April 2001 interpretation of SFAS No. 133 by the Financial Accounting Standards Board ("FASB")'s "Derivatives Implementation Group". Unrealized gains and losses associated with the time value of cash flow hedging options that are expected to be held to maturity are included in the effectiveness calculations and, generally, deferred as components of other comprehensive income until the hedged transactions are recognized in earnings. Previously, these unrealized gains and losses had been excluded from the measurement of hedge effectiveness and recognized in sales revenues as they occurred. Changes in the values of derivatives that qualify for, and are designated and effective as, fair value hedges are recognized in current-period earnings as components of the line items reflecting the underlying hedged transactions. Changes in the fair values of the underlying hedged items (e.g., recognized assets, liabilities or unrecognized firm commitments) are also recognized in current-period earnings and offset the changes in the values of the corresponding hedging derivatives. Any resulting fair value hedge ineffectiveness is recognized in current-period earnings as the difference between the offsetting changes in values of the derivative and the underlying hedged items.

The Company documents its risk management objectives, its strategies for undertaking various hedge transactions and the relationships between hedging instruments and hedged items. Derivatives designated as cash flow hedges are linked to forecasted transactions. Derivatives identified as fair value hedges are linked to specific assets, liabilities or firm commitments. At hedge inceptions and on an on-going basis, the Company assesses whether changes in the values of derivatives used in hedging activities are highly effective in offsetting changes in the values of the hedged items. The Company discontinues hedge accounting prospectively when either (1) it determines that a derivative is not highly effective as a hedge, (2) the derivative is sold, exercised or otherwise terminated, (3) management elects to remove the derivative's hedge designation, (4) the hedged transaction is no longer expected to occur, or (5) a hedged item no longer meets the definition of a firm commitment. When a hedged forecasted transaction is no longer expected to occur, the derivative continues to be carried on the balance sheet at its fair value and all unrealized gains and losses that were previously deferred in accumulated other comprehensive income are recognized immediately in earnings. When a hedged item no longer meets the definition of a firm commitment, the derivative continues to be carried on the balance sheet at its fair value and any asset or liability that was recorded on the balance sheet for the change in value of the hedged firm commitment is removed from the balance sheet and recognized immediately in current-period earnings. In all other situations where hedge accounting is discontinued, the derivatives continue to be carried on the balance sheet at their fair values and any prospective changes in their fair values are recognized in current-period earnings. Deferred gains and losses already recorded in accumulated other comprehensive income remain until the forecasted transactions occur, at which time those gains and losses are recognized in earnings.

Stock-Based Compensation - The Company accounts for its stock-based compensation plans using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees". SFAS No. 123, "Accounting for Stock-Based Compensation", allows companies to record stock-based employee compensation plans at fair value. The Company has elected to continue accounting for stock-based compensation in accordance with APB Opinion No. 25, but complies with the required disclosures under SFAS No. 123 (see note 26).

Earnings Per Share - Basic earnings per share ("EPS") is computed by dividing earnings available to common stockholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is similar to basic EPS except that the denominator is increased to include the number of common shares that would have been outstanding if potential dilutive common shares had been issued. The numerator is also adjusted for convertible securities by adding back any convertible preferred distributions. Each group of potential dilutive common shares must be ranked and included in the diluted EPS calculation by first including the most dilutive, then the next dilutive, and so on, to the least dilutive shares. The process stops when the resulting diluted EPS is the lowest figure obtainable.

Capitalized Interest - Interest is capitalized on certain construction and development projects as part of the costs of the assets.

Other - The Company considers cash equivalents to be all highly liquid investments purchased with a maturity of three months or less.

Expenses incurred for transporting crude oil and natural gas are included as a component of operating expense.

Certain items in prior year financial statements have been reclassified to conform to the 2001 presentation.

NOTE 2 - ACCOUNTING CHANGES

Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". These standards require that all derivative instruments be recorded on the balance sheet at their fair values. Changes in the fair values of derivative instruments are reported in current-period earnings unless they are designated and qualify as effective hedges.

In accordance with the transition provisions of SFAS No. 133, the Company recorded a one-time after-tax charge of approximately $1 million during the first quarter of 2001 in its consolidated earnings statement, representing the cumulative effect of the accounting change, and an after-tax unrealized loss of approximately $59 million to accumulated other comprehensive income in its consolidated balance sheet, of which $28 million was reclassified to the consolidated earnings statement during 2001. The transition amounts represented accumulated changes in the fair values of derivative instruments that were previously off-balance sheet and used to hedge certain future commodity sales (e.g., commodity swaps, options). Accumulated losses in fair value of these derivative instruments will be substantially offset by corresponding gains on the hedged commodity sales when those sales occur. Amounts pertaining to the derivative contracts of acquired companies that were previously capitalized under purchase accounting rules were not impacted.

Effective July 1, 2001, the Company adopted SFAS No. 141, "Business Combinations," which eliminated the pooling method of accounting for a business combination, except for qualifying business combinations that were initiated prior to July 1, 2001, and requires that all combinations be accounted for using the purchase method. Any goodwill acquired in a business combination under the provisions of SFAS No. 141 is to be accounted for in accordance with the provisions of 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. In the first quarter of 2002, the Company will adopt SFAS No. 142 and does not expect the adoption of the statement to have a material effect on its financial position or results of operations.

In August 2001, SFAS No. 143, "Accounting for Asset Retirement Obligations", was also issued by the FASB. 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 or results of operations.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of", 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 Occuring Events and Transactions". SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The Company does not expect the adoption of SFAS. No. 144 to have a material effect on its financial position or results of operations.

NOTE 3 − MAJOR ACQUISITIONS

In December 2001, the Company completed a joint venture agreement with Forest Oil Corporation ("Forest") to jointly explore and develop certain properties in the central Gulf of Mexico Shelf. The Company acquired a portion of Forest's proved reserves and current production for $113 million in cash. The Company is the operator of the jointly owned properties. The transaction was funded from cash on hand.

In July 2001, the Company's Northrock Resources Ltd. ("Northrock") Canadian subsidiary completed its cash acquisition of all the outstanding shares of common stock of Tethys Energy Inc. ("Tethys") for $2.76 per share. The asset base of Tethys is complementary to Northrock's operations in Western Canada, providing significant operational synergies with existing activity in Northrock's West−Central Alberta and Southeast Saskatchewan core areas. The results of Tethys' operations have been included in the consolidated financial statements since the acquisition date of July 16, 2001. The transaction was valued at approximately $117 million. The value of the transaction included $20 million in assumed debt and working capital and other obligations of $4 million. The assumed debt was repaid at the end of July subsequent to the acquisition. Goodwill of $30 million was recorded as part of the transaction and is related to the required deferred tax liability. The acquisition was accounted for as a purchase and was funded using cash on hand. None of the goodwill amount recorded is expected to be deductible for income tax purposes.

In May 2001, the Company's Pure Resources, Inc. ("Pure"), subsidiary completed its cash acquisition of all the outstanding shares of common stock of Hallwood Energy Corporation ("Hallwood") for $12.50 per share and all the outstanding shares of Series A Cumulative Preferred Stock of Hallwood at a price of $10.84 per share. The total transaction was valued at approximately $276 million, including assumed debt of $87 million, which was subsequently refinanced in May 2001 (see note 17), and other obligations. The acquisition was accounted for as a purchase and was funded by Pure through the combination of a new line of credit and borrowings made under existing revolving credit facilities, none of this debt is guaranteed by Unocal or Union Oil. This acquisition added to Pure's positions in its business areas of the San Juan and Permian Basins and the Gulf Coast region.

In January 2001, Pure acquired oil and gas properties, certain general and limited oil and gas partnership interests and fee mineral and royalty interests from International Paper Company. The total cost of the acquisition was approximately $267 million, which was paid in cash. Included in the transaction were total proved reserves of approximately 25 million barrels of oil equivalent and ownership in 6 million gross fee mineral acres (3.2 million net) along with participation in several offshore exploration programs. The transaction was funded from Pure's credit facilities (see note 17). This acquisition expanded Pure's business areas into the Gulf Coast region and offshore in the Gulf of Mexico, subject to limitations in an agreement between Pure and the Company.

NOTE 4 - DISPOSITIONS OF ASSETS

In 2001, cash proceeds received from asset sales and discontinued operations totaled $106 million, with pre-tax gains of $51 million. The proceeds included $25 million of payments received from Tosco Corporation ("Tosco") associated with the sale to Tosco in 1997 of the Company's former West Coast refining, marketing and transportation assets. The 2001 payment of $25 million, along with another $2 million earned in 2001 but yet to be collected, was recorded as a pre-tax gain of $27 million. The Company also received $63 million from the sale of certain oil and gas properties, primarily located in the U.S. Gulf of Mexico, with a pre-tax gain of $21 million. In addition, the Company received $18 million from the sale of real estate and other assets, with a pre-tax gain of $3 million.

In 2000, cash proceeds received from asset sales and discontinued operations totaled $551 million, with pre-tax gains of $108 million. The proceeds included $242 million received from the sale of the agricultural products business, with a pre-tax gain of $23 million. The proceeds also included $80 million from the sale of the Company's graphite business, with a pre-tax gain of $12 million and $71 million from the sale of securities received as part of the consideration in the sale of the agricultural business, with a pre-tax loss of $6 million. The Company also received cash proceeds of $98 million from the sale of certain oil and gas properties, with a pre-tax gain of $3 million and $35 million in real estate and other assets, with a pre-tax gain of $10 million. Cash proceeds also included $25 million received from Tosco associated with the refining, marketing and transportation sales agreement. The gain related to the Tosco amount was recorded in 1999 at the time the agreement was reached.

Proceeds received from asset sales and discontinued operations during 1999 totaled $238 million, with pre-tax gains of $53 million. Proceeds from the sale of the Company's interest in a geothermal production operation in Northern California were $101 million, with a pre-tax loss of $16 million. The sale of certain oil and gas assets generated proceeds of $29 million and a pre-tax gain of $3 million. The sale of certain real estate assets generated proceeds of $77 million and a pre-tax gain of $27 million. The Company recorded a pre-tax gain of $56 million in 1999 related to certain gasoline margins pursuant to the terms of the sales agreement with Tosco. Of the total $56 million, $31 million of proceeds were received in 1999 with the balance of $25 million received in 2000. The $56 million gain was partially offset by a $17 million pre-tax loss adjustment related to the sale of the refining, marketing and transportation business.

NOTE 5 - LEASE RENTAL OBLIGATIONS

The Company has operating leases for drilling rig contracts, office space and other property and equipment having initial or remaining noncancelable lease terms in excess of one year.

Future minimum rental payments for operating leases at December 31, 2001 were as follows:

Millions of dollars	
2002	148
2003	134
2004	113
2005	88
2006	21
Thereafter	36
Total minimum lease rental payments	$ 540

The Company has a five-year lease agreement relating to its Discoverer Spirit deepwater drillship, with a remaining term of approximately three years and nine months at December 31, 2001. In 2001, the Company signed a sublease agreement with a third party for a minimum period of 200 days. Under the provisions of the agreement, the third party will assume all of the lease payments to the lessor during the sublease period. The sublease period began in December 2001. The drillship had a minimum daily rate of approximately $219,000 as of December 31, 2001.

At December 31, 2001, the future remaining minimum lease-rental payment obligation was $255 million as included in the table above. This amount excluded the 200-day sublease period. If the sublease period runs longer than the minimum period of 200 days, the amount of the future remaining lease rental payment obligation in the above table would decrease by the minimum daily rate amount times the number of days over the minimum sublease period.

Net operating lease rental expense for continuing operations was as follows:

	Years ended December 31,		
Millions of dollars	2001	2000	1999
Fixed rentals	$ 58	$ 58	$ 60
Contingent rentals (based primarily on sales and usage)	-	1	7
Sublease rental income	(3)	(4)	(4)
Net rental expense	$ 55	$ 55	$ 63

NOTE 6 - IMPAIRMENT OF ASSETS

The Company, as part of its regular assessment, reviewed its developed and undeveloped oil and gas properties and other long-lived assets in 2001 for possible impairment. The Company recorded a pre-tax charge of $118 million ($74 million after-tax) for the impairment of certain oil and gas properties, primarily located in the Gulf of Mexico shelf, due principally to lower commodity prices. Earnings from equity investments included a pre-tax charge of $19 million ($12 million after-tax), reflecting the Company's portion of the impairment of certain oil and gas Gulf of Mexico shelf properties held by one of its equity investees.

In 2000, the Company recorded pre-tax charges of $13 million for the impairment of certain U.S. Lower 48 oil and gas properties. The Company's Molycorp, Inc. ("Molycorp"), subsidiary recorded pre-tax charges of $53 million for the impairment of the Questa, New Mexico, molybdenum mining operation.

In 1999, the Company recorded pre-tax charges of $23 million for the impairment of certain U.S. Lower 48 oil and gas properties.

NOTE 7 - RESTRUCTURING COSTS

Activities related to the restructuring plan adopted in the first quarter of 2000 were completed in 2001. The Company had accrued $17 million pre-tax ($11 million after-tax) for the restructuring charge. Of the 195 targeted employees, 171 were terminated or received termination notices as a result of the plan. The restructuring charge included approximately $17 million for termination costs to be paid to the employees over time, approximately $2 million for outplacement and other costs and a net reduction in pension and post retirement expenses of $2 million. The charge was included in administrative and general expense on the consolidated earnings statement. No material changes to the cost accrued for the plan was made.

Restructuring plans adopted in the fourth quarter of 1998 and the second quarter of 1999 were completed in 2000. The Company had accrued $45 million pre-tax ($28 million after-tax) for the restructuring charges. The restructuring charges included the estimated costs of terminating approximately 725 employees. Of the targeted employees, 695 (96 percent) were terminated or received termination notices as a result of the plans. The restructuring charges included approximately $39 million for termination costs to be paid to the employees over time, about $2 million in benefit plan curtailment costs and about $4 million related to outplacement and other costs. The charge was included in administrative and general expense on the consolidated earnings statement. No material changes to the costs accrued for these plans were made.

NOTE 8 - INCOME TAXES

The components of the income tax provision for continuing operations were as follows:

	Years ended December 31,		
Millions of dollars	2001	2000	1999
Earnings (loss) from continuing operations before income taxes and minority interests (a)			
United States	$ 409	$ 618	$ (107)
Foreign	683	618	357
Earnings from continuing operations before income taxes and minority interests	$1,092	$ 1,236	$ 250
Income taxes			
Current			
Federal	$ 8	$ 43	$ 15
State	12	20	7
Foreign	351	374	163
Total current taxes	371	437	185
Deferred			
Federal	68	155	(118)
State	(1)	(2)	(5)
Foreign	14	(93)	59
Total deferred taxes	81	60	(64)
Total income taxes	$ 452	$ 497	$ 121

<FN>
(a) Amounts attributable to the Corporate and Other segment are allocated.
</FN>

The following table is a reconciliation of income taxes at the federal statutory income tax rates to income taxes as reported in the consolidated earnings statement.

	Years ended December 31,		
Millions of dollars	2001	2000	1999
Federal statutory rate	35%	35%	35%
Taxes on earnings from continuing operations before minority interests at statutory rate	$ 382	$ 433	$ 88
Taxes on foreign earnings in excess of statutory rate	73	23	50
Provision for prior year income tax issues	-	28	-
Dividend exclusion	(17)	(16)	(15)
Other	14	29	(2)
Total	$ 452	$ 497	$ 121

The significant components of deferred income tax assets and liabilities included in the consolidated balance sheet at December 31, 2001 and 2000 were as follows:

	At December 31,	
Millions of dollars	2001	2000
Deferred tax assets:		
Exploratory costs	$ 321	$ 315
Federal AMT and other tax credits	136	99
Future abandonment costs	142	131
Litigation and environmental costs	106	109
Doubtful receivables	96	52
Postretirement benefit costs	87	88
Forward sales of natural gas	31	36
Price risk management activities	25	66
Other deferred tax assets	139	150
Total deferred tax assets	1,083	1,046
Deferred tax liabilities:		
Depreciation, depletion and intangible drilling costs	(1,018)	(790)
Pension assets	(181)	(173)
Investment in subsidiaries and affiliates	(125)	(174)
Other deferred tax liabilities	(135)	(141)
Total deferred tax liabilities	(1,459)	(1,278)
Total net deferred tax liabilities	$ (376)	$ (232)

No deferred U.S. income tax liability has been recognized on the undistributed earnings of foreign subsidiaries that have been retained for reinvestment. If distributed, no additional U.S. tax is expected due to the availability of foreign tax credits. The undistributed earnings for tax purposes, excluding previously taxed earnings, were estimated at $1.2 billion as of December 31, 2001.

The Company estimates that approximately $101 million of unused foreign tax credits will be available after the filing of the 2001 consolidated tax return, with various expiration dates through the year 2006. No deferred tax asset for these foreign credits has been recognized for financial statement purposes. The federal alternative minimum tax credits are available to reduce future U.S. federal income taxes on an indefinite basis. At December 31, 2001, the Company's Pure subsidiary had net operating loss carryforwards of approximately $52 million, which are available to offset future taxable income of Pure. The loss carryforwards begin to expire in 2010, and the tax effect of those carryforwards are included in other deferred tax assets.

NOTE 9 - DISCONTINUED OPERATIONS

The results of discontinued operations and related effect per common share are summarized below:

	Years ended December 31,		
Millions of dollars	2001	2000	1999
Revenues	$ -	$ -	$ 313
Total costs and other deductions	-	-	319
Earnings (loss) from discontinued operations before income taxes	-	-	(6)
Income taxes (benefits)	-	-	(5)
Earnings (loss) from discontinued operations (a)	-	-	(1)
Gain on disposal before income taxes	27	55	39
Income taxes	10	18	14
Gain on disposal (b)	17	37	25
Total earnings from discontinued operations	$ 17	$ 37	$ 24

<FN>
(a) Earnings (loss) attributable to the agricultural products business.
(b) Gain on disposal in 2001 and 1999 is related to the refining, marketing and transportation business. Gain on disposal in 2000 is exclusively related to the agricultural products business.
</FN>

In 2001, the Company recorded pre-tax gains of $27 million ($17 million after-tax) related to the Company's sale of its former West Coast refining, marketing and transportation assets. The sales agreement covers price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. The maximum potential payments under this sales agreement are capped at $100 million and extend to 2003. To date, the Company has earned $27 million (pre-tax), with $2 million to be collected in 2002.

In 2000, the Company completed the sale of its agricultural products business for approximately $323 million. The Company reclassified the business unit as a discontinued operation at the end of 1999. Net proceeds received from the sale totaled approximately $242 million in cash. The Company also received $50 million principal amount of the purchaser's junior convertible subordinated debentures and approximately 2.6 million shares of the purchaser's common stock, which were valued at approximately $27 million at the close of the sale. The Company recorded a pre-tax gain of $55 million ($37 million after-tax) on the disposal of the business. The gain included $32 million pre-tax ($23 million after-tax) from the results of operations up to the sale date, which was an increase from 1999 primarily due to higher agricultural products commodity prices.

In 1999, the Company recorded a pre-tax gain of $39 million ($25 million after-tax) related to its West Coast refining, marketing and transportation assets. The pre-tax gain included a partial settlement with Tosco on the $250 million participation agreement regarding increased refining premiums and gasoline marketing margins. The Company recorded a pre-tax gain of $56 million ($36 million after-tax) with respect to contingency payments involving retail gasoline margins. In 1999, the Company also adjusted its loss provisions by $17 million pre-tax ($11 million after-tax). The additional provision was primarily due to higher than anticipated charges for various outstanding issues related to the sold properties.

NOTE 10 - EARNINGS PER SHARE

The following table includes a reconciliation of the numerators and denominators of the basic and diluted EPS computations for earnings from continuing operations for the years 2001, 2000 and 1999.

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Year ended December 31, 2001			
Earnings from continuing operations	$ 599	244	
Basic EPS			$2.45
Effect of Dilutive Securities			
Options and common stock equivalents		1	
	599	245	$2.44
Distributions on subsidiary trust preferred securities (after-tax)	27	12	
Diluted EPS	$ 626	257	$2.43
Year ended December 31, 2000			
Earnings from continuing operations	$ 723	243	
Basic EPS			$2.98
Effect of Dilutive Securities			
Options and common stock equivalents		1	
	723	244	$2.96
Distributions on subsidiary trust preferred securities (after-tax)	27	12	
Diluted EPS	$ 750	256	$2.93
Year ended December 31, 1999			
Earnings from continuing operations	$ 113	242	
Basic EPS			$0.47
Effect of Dilutive Securities			
Options and common stock equivalents		1	
Diluted EPS	113	243	$0.46
Distributions on subsidiary trust preferred securities (after-tax)	26	12	
Antidilutive	$ 139	255	$0.55 (a)

<FN>
(a) The effect of assumed conversion of preferred securities on earnings per share is antidilutive.
</FN>

Not included in the computation of diluted EPS at December 31, 2001 were options outstanding to purchase approximately 6.2 million shares of common stock. Options to purchase approximately 6.7 million shares of common stock were not included in the computation of diluted EPS at December 31, 2000, and options to purchase approximately 7 million shares of common stock were not included at December 31, 1999. These options were not included in the computation as the exercise prices were greater than the average market price of the common shares during the respective years.

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

	Years ended December 31,		
Millions except per share amounts	2001	2000	1999
Basic earnings per share of common stock:			
Discontinued operations:			
Earnings from discontinued operations	$ 17	$ 37	$ 24
Weighted average common shares outstanding	244	243	242
Earnings from discontinued operations	$ 0.07	$ 0.15	$ 0.10
Dilutive earnings per share of common stock:			
Discontinued operations:			
Earnings from discontinued operations	$ 17	$ 37	$ 24
Weighted average common shares outstanding	257	256	243
Earnings from discontinued operations	$ 0.07	$ 0.15	$ 0.10

NOTE 11 - CASH AND CASH EQUIVALENTS

	At December 31,	
Millions of dollars	2001	2000
Cash	$ 12	$ (10)
Time deposits	123	171
Restricted cash	5	33
Marketable securities	50	41
Cash and cash equivalents	$ 190	$ 235

At December 31, 2001 and 2000, cash in the amounts of $5 million and $33 million, respectively, was restricted as to usage or withdrawal. Under the terms of the Company's limited recourse project financing for its share of the Azerbaijan International Operating Company Early Oil Project, the lenders' principal and interest payments are payable only out of the proceeds from the Company's sale of crude oil from the project. In keeping with the terms of the financing agreements, $5 million at December 31, 2001, and $9 million at December 31, 2000, of the Company's oil sales proceeds (cash) were reserved for debt principal and interest obligations falling due within the next 180 days. At December 31, 2000 the Company had placed with a trustee $24 million in cash, which was used in December of 2001 to settle claims arising out of the valuation of the royalty owners' portions of crude oil produced from certain federal and Indian leases.

NOTE 12 - SALE OF ACCOUNTS RECEIVABLE

During 1999, the Company, through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation ("URC"), entered into a sales agreement with an outside party which provides for the sale of up to $204 million of an undivided interest in domestic crude oil and natural gas trade receivables. Under the terms of the agreement, the receivables are sold at a discount on a revolving basis and without recourse. The costs incurred under the agreement for the years ended December 31, 2001 and 2000 were $1 million and $10 million, respectively, which was charged to operating expense in the consolidated earnings statement. Amounts sold were reflected as a reduction of accounts and notes receivable in the consolidated balance sheet and in net cash provided by operating activities in the consolidated cash flows statement. At December 31, 2001, the Company had sold $70 million of its domestic trade receivables under this agreement. Sales under the program in 2001 occurred only in December. At December 31, 2000, the Company had a zero balance outstanding under this agreement.

The Company's consolidated balance sheet included a note receivable of approximately $54 million and $562 million at December 31, 2001 and 2000, respectively, due from URC representing the unsold balance of trade receivables transferred to URC.

NOTE 13 - INVENTORIES

Millions of dollars	At December 31, 2001	2000
Crude oil and other petroleum products	$ 46	$ 46
Carbon and mineral products	37	27
Materials, supplies and other	19	15
Total inventories	$ 102	$ 88

NOTE 14 - EQUITY INVESTMENTS

Investments in companies accounted for by the equity method were $625 million, $618 million and $556 million at December 31, 2001, 2000 and 1999, respectively. These investments are reported as a component of investments and long-term receivables on the consolidated balance sheet.

Dividends or cash distributions received from the Company's equity investees were $213 million, $77 million and $91 million for the years 2001, 2000 and 1999, respectively. Unamortized excesses of the Company's investments in these companies have been excluded from the table below. At December 31, 2001, 2000 and 1999, the unamortized excess of the Company's investments in Colonial Pipeline Company, West Texas Gulf Pipeline Company and various other pipeline companies was approximately $153 million, $159 million and $104 million, respectively. At December 31, 2001, the Company had guarantees outstanding for approximately $72 million of the total outstanding debt of the various pipeline and power companies in which the Company has an equity investment. A guarantee of $46 million for the debt of Colonial Pipeline Company made up the majority of the $72 million in total guarantees, and it will expire in June 2002.

At December 31, 2001, 2000 and 1999, the Company's shares of the net capitalized costs of other companies engaged in oil and gas exploration and production activities were $309 million, $300 million and $278 million, respectively.

Summarized financial information for these investments and the Company's equity shares are shown below.

	Years ended December 31,					
	2001		2000		1999	
Millions of dollars	Total	Unocal's Share	Total	Unocal's Share	Total	Unocal's Share
Revenues	$ 2,429	$ 515	$ 2,067	$ 705	$ 1,541	$ 591
Costs and other deductions	1,684	371	1,609	571	1,242	495
Net earnings	$ 745	$ 144	$ 458	$ 134	$ 299	$ 96

	At December 31,					
	2001		2000		1999	
Millions of dollars	Total	Unocal's Share	Total	Unocal's Share	Total	Unocal's Share
Current assets	$ 873	$ 324	$ 706	$ 239	$ 626	$ 208
Noncurrent assets	4,069	1,084	3,383	916	3,122	816
Current liabilities	1,429	453	898	304	724	245
Noncurrent liabilities	1,753	475	1,718	484	1,479	402
Net equity	1,760	480	1,473	367	1,545	377

NOTE 15 - PROPERTIES AND CAPITAL LEASES

Investments in owned and capitalized-leased properties are shown below. Accumulated depreciation, depletion, and amortization for continuing operations was $11,648 million and $10,745 million at December 31, 2001 and 2000, respectively.

	At December 31,			
	2001		2000	
Millions of dollars	Gross	Net	Gross	Net
Owned Properties (at cost)				
Exploration and Production				
Exploration				
North America				
Lower 48	$ 543	$ 420	$ 526	$ 437
Alaska	8	7	4	4
Canada	198	148	195	162
International				
Far East	234	205	210	179
Other	144	99	156	118
Production				
North America				
Lower 48	7,317	2,638	6,163	1,832
Alaska	1,356	275	1,287	249
Canada	1,066	811	896	727
International				
Far East	5,302	1,724	4,974	1,600
Other	1,045	419	1,001	412
Total exploration and production	17,213	6,746	15,412	5,720
Trade	8	3	7	4
Midstream	480	216	443	185
Geothermal &Power Operations	644	284	642	296
Corporate &Other	811	259	666	220
Total owned properties	19,156	7,508	17,170	6,425
Capitalized-leased properties	6	6	8	8
Total properties and capital leases	$ 19,162	$ 7,514	$ 17,178	$ 6,433

NOTE 16 - POSTEMPLOYMENT BENEFIT PLANS

The Company has numerous plans worldwide that provide eligible employees with retirement benefits. The Company also has medical plans that provide health care benefits for eligible employees and many of its retired employees. The following table sets forth the postretirement benefit obligations recognized in the consolidated balance sheet at December 31, 2001 and 2000. Pre paid pension costs are reported as a component of investments and long-term receivables on the consolidated balance sheet. Postemployment benefit liabilities, including pensions, postretirement medical benefits and other postemployment benefits, are reported as a component of other deferred credits and liabilities on the consolidated balance sheet.

	Pension Benefits		Other Benefits	
Millions of dollars	2001	2000	2001	2000
Change in benefit obligation:				
Projected benefit obligation at January 1,	$ 925	$ 939	$ 252	$ 223
Service cost	20	24	2	3
Interest cost	75	73	19	17
Employee contributions	-	-	5	4
Disbursements	(114)	(98)	(24)	(23)
Actuarial (gain) losses	124	12	52	36
Plan amendments	36	2	-	-
Curtailments and settlements	-	(26)	-	(8)
Divestitures	-	-	-	-
Effect of foreign exchange rates	(1)	(1)	-	-
Projected benefit obligation at December 31,	$ 1,065	$ 925	$ 306	$ 252
Change in plan assets:				
Fair value of plan assets at January 1,	$ 1,201	$ 1,317	$ -	$ -
Actual return on plan assets	(64)	7	-	-
Employer contributions	(17)	(15)	-	-
Employee contributions	-	-	-	-
Disbursements	(86)	(89)	-	-
Administrative expenses	(6)	(7)	-	-
Settlements	-	(11)	-	-
Divestitures	-	-	-	-
Effect of foreign exchange rates	(2)	(1)	-	-
Fair value of plan assets at December 31,	$ 1,026	$ 1,201	$ -	$ -
Net amount recognized:				
Funded status	$ (39)	$ 277	$ (306)	$ (252)
Unrecognized net obligation at transition	2	2	-	-
Unrecognized prior service cost	44	17	5	6
Unrecognized net actuarial losses (gains)	423	123	85	33
Net amount recognized	$ 430	$ 419	$ (216)	$ (213)
Amounts recognized in the balance sheet consist of:				
Prepaid pension cost	$ 491	$ 478	$ -	$ -
Accrued benefit liability	(82)	(77)	(216)	(213)
Intangible asset	10	6	-	-
Accumulated other comprehensive income (loss)	11	8	-	-
Deferred taxes	-	4	-	-
Net amount recognized	$ 430	$ 419	$ (216)	$ (213)

Most of the Company's plans covering employees outside of North America are unfunded and resulting liabilities are extinguished on a "pay as you go" basis. The Unocal Qualified Retirement Plan, covering eligible employees on the U.S. payroll, had funding surpluses of $55 million and $346 million as of December 31, 2001 and December 31, 2000, respectively.

The assumed rates to measure the benefit obligation and the expected earnings on plan assets were:

	Pension Benefits			Other Benefits		
Weighted-average assumptions as of December 31,	2001	2000	1999	2001	2000	1999
Discount rates	7.24%	7.73%	7.90%	7.25%	7.74%	7.75%
Rates of salary increases	4.50%	4.45%	4.74%	4.50%	4.50%	4.50%
Expected returns on plan assets	9.33%	9.28%	9.33%	N/A	N/A	N/A

The health care cost trend rate used in measuring the 2001 benefit obligation for the U.S. plan was 8 percent, decreasing ratably to 5 percent in 2004. A one percentage-point change in the assumed health care cost trend rate would have had the following effects on 2001 service and interest cost and the accumulated postretirement benefit obligation at December 31, 2001.

Thousands of dollars	One percent Increase	One percent Decrease
Effect on total of service and interest cost components of net periodic expense	$ 2,443	$ (2,041)
Effect on postretirement benefit obligation	$ 30,027	$ (25,446)

Net periodic pension and postretirement benefits cost are comprised of the following components:

	Pension Benefits			Other Benefits		
Millions of dollars	2001	2000	1999	2001	2000	1999
Service cost (net of employee contributions)	$ 20	$ 24	$ 26	$ 2	$ 3	$ 3
Interest cost	75	73	75	19	17	13
Expected return on plan assets	(111)	(110)	(104)	-	-	-
Amortization of:						
Transition obligation	-	-	-	-	-	-
Prior service cost	6	4	4	1	1	1
Net actuarial (gains) losses	2	3	1	1	-	-
Curtailment and settlement (gains) losses	7	(13)	1	-	(6)	2
Cost of special separation benefits	-	-	-	-	-	-
Net periodic pension and other benefits cost (credit)	$ (1)	$ (19)	$ 3	$ 23	$15	$ 19

The projected benefit obligations, accumulated benefit obligations and fair values of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were approximately $104 million, $74 million and nil, respectively as of December 31, 2001 and approximately $98 million, $66 million and nil, respectively as of December 31, 2000.

In 2000 and 1999, the Company recorded costs for employees displaced as a result of asset sales and the Company's restructuring programs. In 2000, the Company completed the transfer of pension assets and liabilities from a retirement plan of a subsidiary to the Unocal Retirement Plan.

The Company has a 401(k) defined contribution savings plan designed to supplement retirement income for U.S. employees. The Company's contributions to the plan were $11 million, $13 million, and $14 million in 2001, 2000, and 1999 respectively, which were used by the plan trustee to purchase shares of Unocal common stock in the open market. The Company has the option to direct the trustee to purchase Unocal common stock either in the open market or from Unocal. Once the Company's contributions have been used to purchase Unocal common stock, employees have the ability to convert the shares to other investment options, including a variety of mutual funds or a money market fund.

The Company also provides benefits such as workers' compensation and disabled employees' medical care to former or inactive employees after employment but before retirement. The accumulated postemployment benefit obligation was $13 million and $11 million at December 31, 2001 and 2000, respectively.

NOTE 17 - LONG-TERM DEBT AND CREDIT AGREEMENTS

The following table summarizes the Company's long-term debt:

	At December 31,	
Millions of dollars	2001	2000
Bonds and debentures		
9-1/4% Debentures due 2003	$ 89	$ 89
9-1/8% Debentures due 2006	200	200
6-1/5% Industrial Development Revenue Bonds due 2008	21	21
7% Debentures due 2028	200	200
7-1/2% Debentures due 2029	350	350
Notes		
Medium-term notes due 2002 to 2015 (7.95%) (a)	502	569
8-3/4% Notes due 2001	-	39
6-3/8% Notes due 2004	200	200
7-1/5% Notes due 2005	200	200
6-1/2% Notes due 2008	100	100
7.35% Notes due 2009	350	350
Azerbaijan Limited Recourse Loan	36	47
Other		
Northrock consolidated debt and capital leases	81	82
Pure consolidated debt	587	68
Other miscellaneous debt	1	2
Bond (discount) premium	(11)	(11)
Total debt and capital leases	2,906	2,506
Less current portion of long-term debt and capital leases	9	114
Total long-term debt and capital leases	$ 2,897	$ 2,392

<FN>
(a) Weighted average interest rate at December 31, 2001.
</FN>

At December 31, 2001, the amounts of long-term debt maturing in 2002, 2003, 2004, 2005, and 2006 were $191 million, $93 million, $447 million, $347 million and $249 million, respectively. The Company has the intent and the ability to refinance most of the current maturities, and thus it did not record $182 million of debt maturing in 2002 as part of the current portion of long-term debt.

During 2001, the Company retired $67 million of maturing medium-term notes and $39 million in 8 3/4 percent notes, which matured in 2001.

At the end of October 2001, the Company replaced its $1 billion bank credit agreement with two new revolving credit facilities totaling $1 billion. One of these credit facilities is a $400 million 364-day credit agreement and the other credit facility is a $600 million 5-year credit agreement. The Company had not drawn any funds under either credit facility at year-end 2001. Borrowings under the bank credit agreements bear interest at a margin above London Interbank Offered Rates ("LIBOR") and the agreements call for a facility fee on the total commitment. The credit facilities 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 the Company'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 bank credit agreements do not have a drawdown restriction or a prepayment obligation in the event of a credit rating downgrade. The interest rates charged on these credit facilities would vary marginally if a change occurred in the Company's credit rating.

The Company had other undrawn letters of credit at year-end 2001 that approximated $41 million. The majority of these letters of credit are maintained for operational needs and are renewed yearly.

At December 31, 2001, the Company had $36 million outstanding on its Azerbaijan limited recourse loan. The Company completed the limited recourse project financing for its separate share of the Azerbaijan International Operating Company Early Oil Project under an International Finance Corporation and European Bank for Reconstruction and Development loan structure in 1998 for up to $77 million. The borrowing bears interest at a margin above LIBOR. The lenders' principal and interest payments are payable only out of the cash flow from the Company's sales of crude oil from the project.

Consolidated debt, at December 31, 2001, included $587 million of debt of the Company's Pure subsidiary. This was an increase of $519 million from year-end 2000, which was substantially all incurred to fund two of its acquisitions (see note 3). Pure issued, in a private placement, $350 million in unsecured senior notes, which bear interest at 7.125 percent and mature in 10 years. The notes were issued at a discount to their face value. Pursuant to a registration rights agreement, Pure registered the notes in the fourth quarter of 2001. Pure used the proceeds to repay a portion of its senior credit facilities and to repay interim financing associated with the Hallwood acquisition (see note 3). At December 31, 2001, Pure had $175 million outstanding under a 3-year $275 million revolving credit facility due November 2004, $58 million outstanding under its $235 million 5-year revolving credit facility due September 2005, and $6 million outstanding under its $10 million working capital revolver. Neither Unocal or Union Oil guarantee any of the Pure debt. The interest rates charged on these revolving credit facilities would vary marginally if a change occurred in Pure's credit rating.

The Company's consolidated debt at December 31, 2001, also included $81 million of debt of its Northrock subsidiary. The debt was primarily composed of $35 million and $40 million for two senior U.S. dollar-denominated notes, which bore interest of 6.54 percent and 6.74 percent, respectively. Principal payments are not due on the $35 million note until it matures in 2004. Principal payments of approximately $13 million are due on the $40 million note in each of 2006, 2007 and 2008. Northrock entered into Canadian dollar currency swap agreements for the senior U.S. dollar-denominated notes, which convert the interest and principal payments to Canadian dollars and effectively reduce the interest rates on the notes to 6.325 percent and 6.04 percent, respectively. The remaining $6 million of Northrock's debt primarily consisted of long-term capital leases.

NOTE 18 - ACCRUED ABANDONMENT, RESTORATION AND ENVIRONMENTAL LIABILITIES

At December 31, 2001 and 2000, the Company had accrued $477 million and $465 million, respectively, for the estimated future costs to abandon and remove wells and production facilities. The total costs for abandonments are predominantly accrued for on a unit-of-production basis and are estimated to be approximately $670 million at December 31, 2001 and $640 million at December 31, 2000. These estimates were derived in large part from abandonment cost studies performed by independent third party firms and are used to calculate the amount to be amortized.

At December 31, 2001 and 2000, the Company's reserve for environmental remediation obligations totaled $237 million and $213 million, respectively, of which $124 million, in each year, was included in current liabilities. The reserve, at December 31, 2001 and 2000, included estimated probable future costs of $12 million and $14 million, respectively, for federal Superfund and comparable state-managed multi-party disposal sites; $40 million and $46 million, respectively, for active sites owned and/or controlled by the Company and utilized in its present operations; $98 million and $51 million, respectively, for formerly-operated sites for which the Company has remediation obligations and sites related to businesses or operations that have been sold with contractual remediation or indemnification obligations; and $87 million and $102 million, respectively, for Company-owned or controlled sites where facilities have been closed or operations shut down.

NOTE 19 - OTHER FINANCIAL INFORMATION

The consolidated balance sheet included the following:

Millions of dollars	At December 31, 2001	2000
Other deferred credits and liabilities:		
Postretirement medical benefits obligation	$ 216	$ 213
Advances related to future production	105	123
Other employee benefits	92	110
Prepaid forward sales	73	86
Reserves for litigation and other claims	72	119
Derivative liabilities	64	-
Northrock (a)	32	71
Other	70	110
Total other deferred credits and liabilities	$ 724	$ 832
Allowances for doubtful accounts and notes receivables	$ 146	$ 97
Allowances for investments and long-term receivables	$ 171	$ 80

<FN>
(a) Includes liability amounts associated with U.S. dollar forward contracts and commodity derivative contracts used by Northrock for general risk management purposes. Also includes liability amounts related to commodity sales contracts with below market prices and derivative contracts used for hedging purposes that were capitalized when Northrock was acquired.
</FN>

The allowances for doubtful accounts and notes receivables and the allowances for investments and long-term receivables primarily relate to the Geothermal operations in Indonesia. See note 27 under "Concentrations of Credit Risk" for a discussion relating to these receivables.

NOTE 20 − ADVANCE SALES OF NATURAL GAS

The Company entered into a long−term fixed price natural gas sales contract for the delivery of approximately 72 billion cubic feet of gas over a ten−year period beginning in January 1999 and ending in December 2008. In January 1999, the Company received a non−refundable payment of approximately $120 million pursuant to the contract. The Company will also receive a fixed monthly reservation fee over the life of the contract. The Company entered into a ten−year natural gas price swap agreement, which effectively refloats the fixed price that the Company received under the long−term natural gas sales contract. The Company did not dedicate a portion of its natural gas reserves to the contract and it has the option to satisfy contract delivery requirements with natural gas purchased from third parties. Accordingly, the obligation associated with the future delivery of the natural gas has been recorded as deferred revenue and will be amortized into revenue as scheduled deliveries of natural gas are made throughout the contract period. Of the remaining unamortized balance at year−end 2001, approximately $73 million related to deliveries scheduled to be made in the years 2003 through 2008 and was recorded in other deferred credits and liabilities on the consolidated balance sheet. Approximately $12 million was included in other current liabilities on the consolidated balance sheet, representing deliveries to be made in 2002. At December 31, 2001, the Company had in place an irrevocable surety bond in the amount of $106 million securing its performance under the sales contract.

NOTE 21 − MINORITY INTERESTS

The Company's minority interests on the consolidated balance sheet includes the minority shares related to its Pure subsidiary. At December 31, 2001, the minority interest amount related to Pure was $180 million, which was an increase of $56 million from year−end 2000. This was primarily due to the 2001 undistributed earnings and the reduction of Pure's outstanding liability related to the amount of its common stock that it may have to repurchase (see note 22 under "Pure Resources, Inc. Employment and Severance Agreements").

In 1999, the Company contributed fixed−price overriding royalty interests from its working interest shares in certain oil and gas producing properties in the Gulf of Mexico to Spirit Energy 76 Development, L.P. ("Spirit LP"), a limited partnership. In exchange for its overriding royalty contributions, valued at $304 million, the Company received an initial general partnership interest in Spirit LP of approximately 55 percent. An unaffiliated investor contributed $250 million in cash to the partnership in exchange for an initial limited partnership interest of approximately 45 percent. The fixed−price overrides are subject to economic limitations of production from the affected fields. The limited partner is entitled to receive a priority allocation of profits and cash distributions. The limited partner's share has a maximum term of 20 years, but may terminate after six years, subject to certain conditions. If the Company's credit rating falls below Ba1 or BB+, then the priority return to the limited partner increases by two percent and the Company would have to provide cash collateral or a letter of credit for the $250 million. Almost all the minority interests in earnings were paid out to the limited partner as cash distributions and amounted to approximately $16 million and $18 million, for 2001 and 2000, respectively. The minority interest on the Company's consolidated balance sheet related to this transaction was approximately $253 million at December 31, 2001.

NOTE 22 - COMMITMENTS AND CONTINGENCIES

The Company has certain 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 18, at December 31, 2001, the Company had accrued $237 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 $260 million. The amount of such possible additional costs reflects the aggregate of the high end of the range 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.

Millions of dollars	At December 31, 2001 Reserve	Additional
Superfund and similar sites	$ 12	$ 20
Active company facilities	40	90
Company facilities sold with retained liabilities and former company-operated sites	98	70
Inactive or closed company facilities	87	80
Totals	$ 237	$ 260

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.

The contamination of the sites included in the above categories was primarily caused by the former operations 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.

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

Contamination in the sites of the "Superfund and Similar Sites" category is the result of the disposal of substances at these sites by one or more potentially responsible parties ("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 contribution to the contamination at these sites was primarily from waste from the current and former operations identified above.

Superfund and similar sites - At year-end 2001, Unocal had received notification from the U.S. Environmental Protection Agency that the Company may be a PRP at 26 sites and may share certain liabilities at these sites. Of the total, eight sites are under investigation and/or litigation and the Company's potential liability is not presently determinable and for one site the Company has denied responsibility. Of the remaining 17 sites, where probable costs can be reasonably estimated, reserves of $4 million have been established for future remediation and settlement costs.

Various state agencies and private parties had identified twenty-eight other similar PRP sites. Nine sites are under investigation and/or litigation and the Company's potential liability is not presently determinable. At five sites the Company's potential liability appears to be de minimis. At another two sites, 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 one site. Where probable costs can be reasonably estimated at the remaining eleven sites, reserves of $8 million have been established for future remediation and settlement costs.

In addition to the total of $12 million in reserves mentioned above, the Company has also estimated that additional costs of $20 million are possible for the "Superfund and Similar Sites" category.

Included in this category of sites are:

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

These 54 sites exclude 105 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 $40 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:

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

The company estimates that it may incur possible additional costs of $90 million for this group of sites.

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

- West Coast refining, marketing and transportation sites
- Auto/truckstop facilities throughout the U.S.
- Industrial chemical and polymer sites in the South, Midwest and California
- 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 $98 million and additional costs of $70 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 $87 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 $80 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 a 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 a 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. At December 31, 2001, amounts included in the remediation reserve for these facilities totaled $93 million. At those sites where investigations or feasibility studies have advanced to the stage of analyzing alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $67 million. Although any possible additional costs for these sites 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 either due 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.

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 December 31, 2001, Pure estimated that the amount it may have to repurchase under these agreements was approximately $70 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, 2000, the repurchase amount under these agreements was approximately $136 million.

Other matters

The Company has a five-year lease agreement relating to its Discoverer Spirit deepwater drillship, with a remaining term of approximately three years and nine months at December 31, 2001. In 2001, the Company signed a sublease agreement with a third party for a minimum period of 200 days. Under the provisions of the agreement, the third party will assume all of the lease payments to the lessor during the sublease period. The sublease period began in December 2001. The drillship has a minimum daily rate of approximately $219,000. The future remaining minimum lease payment obligation excluding the 200-day sublease period was approximately $255 million at December 31, 2001. If the sublease period runs longer than the minimum period of 200 days, the amount of the future remaining lease rental payment obligation would decrease by the minimum daily rate amount times the number of days over the minimum sublease period.

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 and dismantlement, or 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 December 31, 2001, the Company, including its Pure subsidiary, had obtained various surety performance bonds for approximately $280 million. These bonds primarily included the bonds for the Company's mining operation discussed in the following paragraph and $11 million related to its Pure subsidiary. The $280 million amount for performance bonds excluded an $85 million portion of a bond for which a liability is included on the consolidated balance sheet in other current liabilities and other deferred credits. The Company also had approximately $41 million in standby letters of credit at December 31, 2001. The $41 million amount for letters of credit excluded a $15 million letter of credit for which a liability is included on the consolidated balance sheet in other current liabilities. The Company also has various other guarantees for approximately $370 million. Approximately $150 million of the $370 million in guarantees would require the Company to obtain a bond or a letter of credit, or set-up a trust fund if its credit rating drops below Baa3 or BBB-.

The Company's Molycorp subsidiary, working cooperatively and collaboratively with the New Mexico Environmental Department and other state agencies, has secured new and revised permits covering discharges from its Questa, New Mexico, molybdenum mine. This process involved the posting by Molycorp of two performance bonds totaling $152 million that are intended to provide financial assurance of completion of temporary closure plans (only required upon cessation of operations) and other obligations required under the terms of the permits. These costs are based on estimations provided by the state of New Mexico agencies. 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 to the Company or the recourse is limited. Of the total $1.8 billion in equity investee debt, $1.1 billion belongs to the Colonial Pipeline Company, in which Unocal holds a 23.44 percent equity interest. The Company guarantees only $72 million of the total $1.8 billion debt obligations. Approximately $46 million of the $72 million in debt guarantees is expiring June 2002.

The Company also has certain 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.

NOTE 23 - TRUST CONVERTIBLE PREFERRED SECURITIES

In 1996, Unocal exchanged 10,437,873 newly issued 6.25 percent trust convertible preferred securities of Unocal Capital Trust, a Delaware business trust (the "Trust"), for shares of a then-outstanding issue of convertible preferred stock. Unocal acquired the convertible preferred securities, which have an aggregate liquidation value of $522 million, from the Trust, together with 322,821 common securities of the Trust, which have an aggregate liquidation value of $16 million, in exchange for $538 million principal amount of 6.25 percent convertible junior subordinated debentures of Unocal. The convertible preferred securities and common securities of the Trust, which have been retained by Unocal, represent undivided beneficial interests in the debentures, which are the sole assets of the Trust.

The convertible preferred securities have a liquidation value of $50 per security and are convertible into shares of Unocal common stock at a conversion price of $42.56 per share, subject to adjustment upon the occurrence of certain events. Distributions on the convertible preferred securities are cumulative at an annual rate of 6.25 percent of their liquidation amount and are payable quarterly in arrears on March 1, June 1, September 1 and December 1 of each year to the extent that the Trust receives interest payments on the debentures, which payments are subject to deferral by Unocal under certain circumstances.

Upon repayment of the debentures by Unocal, whether at maturity, upon redemption or otherwise, the proceeds thereof must immediately be applied to redeem a corresponding amount of the convertible preferred securities and the common securities of the Trust.

The debentures mature on September 1, 2026, and may be redeemed, in whole or in part, at the option of Unocal at a redemption price equal to 103.125 percent (since September 1, 2001), of the principal amount redeemed, declining annually, to 100 percent of the principal amount redeemed on or after September 1, 2006, plus accrued and unpaid interest thereon to the redemption date. The debentures, and hence the convertible preferred securities, may become redeemable at the option of Unocal upon the occurrence of certain special events or restructuring transactions.

The Trust is accounted for as a 100 percent-owned consolidated finance subsidiary of Unocal, with the debentures and payments thereon by Unocal to the Trust eliminated in the consolidated financial statements. The payment obligations of the Trust under the convertible preferred securities are unconditionally guaranteed on a subordinated basis by Unocal. Such guarantee, when taken together with Unocal's obligations under the debentures and the indenture pursuant to which the debentures were issued and its obligations under the amended and restated declaration of trust governing the Trust, provides a full and unconditional guarantee by Unocal of the Trust's obligations under the convertible preferred securities. The numbers of convertible preferred securities outstanding on December 31, 2001 and December 31, 2000 were 10,437,107 and 10,437,137, respectively. See note 28 for certain financial statement information regarding the Trust.

NOTE 24 - CAPITAL STOCK

Common Stock

Authorized - 750,000,000
$1.00 Par value per share

Thousands of shares	At December 31, 2001	2000	1999
Outstanding at beginning of year	243,044	242,441	241,378
Issuances of common stock (a)	954	603	1,063
Outstanding at end of year	243,998	243,044	242,441

<FN>
(a) net of cancellations
</FN>

At December 31, 2001, there were approximately 12.3 million shares reserved for the conversion of Unocal Capital Trust convertible preferred securities, 19 million shares for the Company's employee benefit plans and Directors' plans and 2.8 million shares for the Company's Dividend Reinvestment and Common Stock Purchase Plan.

Treasury Stock - In January 1998, the Board of Directors extended the repurchase program which authorized the repurchase of $400 million of common stock in 1996 and authorized management to repurchase up to an additional $200 million. At December 31, 2001, the Company held 10,622,784 common shares as treasury stock at a cost of $411 million.

Preferred Stock - The Company has authorized 100,000,000 shares of preferred stock with a par value of $0.10 per share. No shares of preferred stock were issued at December 31, 2001, 2000 or 1999. See "Stockholder Rights Plan" below with respect to shares of preferred stock reserved for issuance.

Stockholder Rights Plan - In 2000, the Board of Directors adopted a new stockholder rights plan ("2000 Rights Plan") to replace the 1990 Rights Plan. The Board declared a dividend of one preferred share purchase right ("Right") for each share of common stock outstanding, which was paid to stockholders of record on January 29, 2000, when the rights outstanding under the 1990 Rights Plan expired. The Board also authorized the issuance of one Right for each common share issued after January 29, 2000, and prior to the earlier of the date on which the Rights become exercisable, the redemption date or the expiration date. Until the Rights become exercisable, as described below, the outstanding Rights trade with, and will be inseparable from, the common stock and will be evidenced only by certificates or book-entry credits that represent shares of common stock. The Board of Directors has designated 5,000,000 shares of preferred stock as Series B Junior Participating Preferred Stock ("Series B preferred stock") in connection with the 2000 Rights Plan. The Series B preferred stock replaces the Series A preferred stock that was designated under the 1990 Rights Plan.

The 2000 Rights Plan provides that in the event any person or group of affiliated persons (a) becomes, or (b) commences a tender offer or exchange offer pursuant to which such person or group would become, the beneficial owner of 15 percent or more of the outstanding common shares, each Right (other than Rights held by the 15 percent stockholder) will be exercisable on and after the close of business on the tenth day or the tenth business day following the public announcement of such events, respectively, unless the Rights are redeemed by the Board of Directors, to purchase one one-hundredth of a share of Series B preferred stock for $180. If such a person or group becomes such a 15 percent beneficial owner of common stock, each Right (other than Rights held by the 15 percent stockholder) will be exercisable to purchase, for $180, shares of common stock with a market value of $360, based on the market price of the common stock prior to such 15 percent acquisition. If the Company is acquired in a merger or similar transaction following the date the Rights become exercisable, each Right (other than Rights held by the 15 percent stockholder) will become exercisable to purchase, for $180, shares of the acquiring corporation with a market value of $360, based on the market price of the acquiring corporation's stock prior to such merger. The Board of Directors may reduce the 15 percent beneficial ownership threshold to not less than 10 percent.

The Rights will expire on January 29, 2010, unless previously redeemed by the Board of Directors. The Rights do not have voting or dividend rights and, until they become exercisable, have no diluting effect on the earnings per share of the Company.

NOTE 25 - LOANS TO CERTAIN OFFICERS AND KEY EMPLOYEES

In March 2000, the Company entered into loan agreements with ten of its officers pursuant to the Company's 2000 Executive Stock Purchase Program (the "Program"). The Program was approved by the Board of Directors of the Company and by the Company's stockholders at the Annual Stockholders meeting in May 2000. The loans were granted to the officers to enable them to purchase shares of Company stock in the open market. The loans, which except under certain limited circumstances are full recourse to the officers, mature on March 16, 2008, and bear interest at the rate of 6.8 percent per annum. At December 31, 2001 and 2000, the balance of the loans under the Program, including accrued interest, totaled $35 million and $33 million, respectively, and was reflected as a reduction to stockholders' equity on the consolidated balance sheet. During 2001, the amount of accrued interest on the 2000 year-end balance was approximately $2 million.

The Company's Pure subsidiary also had a loan program for certain of its officers and key employees. At December 31, 2001, loans under this program totaled $7 million and were also reflected as a reduction to stockholders' equity on the consolidated balance sheet.

NOTE 26 - STOCK-BASED COMPENSATION PLANS

The Company has adopted incentive programs for executives, directors and certain employees to provide incentives and rewards to strengthen their commitment to maximizing the profitability of the Company and increasing stockholder value. The following table shows the number of Unocal common shares authorized, issued and remaining available, and the outstanding grants for which Unocal common shares may be issued, for all stock-based compensation plans for which Unocal common shares have been authorized for future issuance at December 31, 2001:

Stock-Based Compensation Plans (a)	Shares Authorized	Shares Issued (b)	Shares Reserved For Outstanding Grants			Shares Reserved for future grants	Shares unused and not available for future grants
			Performance Shares	Stock Options (c)	Stock Units		
Management Incentive Program of 1991	11,000,000	3,619,880	None	3,490,165	N/A	None	3,889,955
1998 Management Incentive Program	8,250,000	625,680	613,754	2,373,506	N/A	1,725,073	2,911,987
Special Stock Option Plan of 1996 (d)	1,100,000	298,251	N/A	402,019	N/A	None	399,730
Unocal Stock Option Plan (d)	8,000,000	203,641	N/A	4,689,151	N/A	3,107,208	None
Union Oil Co. Restricted Stock Plan (d)	400,000	360,790	N/A	N/A	N/A	39,210	None
Executive Stock Purchase Program	1,750,000	None	N/A	N/A	N/A	599,690	1,150,310
Directors' Restricted Stock Units Plan	300,000	104,587	N/A	N/A	12,431	112,759	70,223
2001 Directors' Deferred Compensation and Stock Award Plan	500,000	None	N/A	42,936	81,310	375,754	None

<FN>
(a) Excludes certain other stock-based compensation plans which do not involve the issuance of common shares.
(b) Amounts shown include shares of outstanding restricted stock and exclude restricted stock forfeited prior to vesting or cancelled for payment of withholding tax upon vesting.
(c) Included in the 2,373,506 shares reserved for stock options awarded under the 1998 Management Incentive Program are 1,080,000 shares underlying stock option grants made to four executive officers subject to stockholder approval at the Company's 2002 annual stockholders meeting. These grants are 3-year grants, therefore the recipients are not eligible for additional grants in the calendar years 2002, 2003, and 2004, absent unanticipated developments.
(d) Plan not approved by stockholders nor is such approval required.
</FN>

Stock options generally have a maximum term of ten years and generally vest over a three-year period at a rate of 50 percent the first year and 25 percent per year in each of the two succeeding years. Stock options granted under the 2001 Directors' Deferred Compensation and Stock Award Plan vest ratably over a three-year period. During 2001, all outstanding stock options granted under the Performance Stock Option Plan included in the 1998 Management Incentive Program were cancelled due to certain additional vesting requirements related to the common stock price not being realized.

The option price for grants under all plans may not be less than the fair market value of the common stock on the date the option is granted. Restrictions may be imposed for a period of five years on certain shares acquired through the exercise of options granted after 1990 under the Management Incentive Program of 1991 and the 1998 Management Incentive Program. Generally, restricted stock awards are based on the average closing price of the common stock for the last 30 trading days of the year prior to the grant date or on the average price of the common stock on the trading day that the stock is awarded. Holders of outstanding restricted stock are entitled to receive dividends and vote the shares, except for dividends on restricted stock granted under the Union Oil Restricted Stock Plan, which are accumulated and paid out when the shares vest. Restricted shares are not delivered until the end of the restricted period, which does not exceed ten years. Outstanding performance share awards have four-year terms and can be paid out in common stock and/or cash, with the common stock portion not exceeding 50 percent of the total award. The amount of the payout is based on a percentile ranking of the Company's common stock total return relative to the total returns on the common stocks of a peer group of companies, subject to further downward adjustments by the Management Development and Compensation Committee. The directors' units represent unfunded bookkeeping entries that are paid out in an equal number of shares of common stock at the end of the applicable deferral period. The unit holders do not have any voting rights until the common shares are issued. Dividend equivalents are credited to the unit holders as additional units. Additional grants of units under the Directors' Restricted Stock Units Plan will be solely for the purpose of meeting future requirements for dividend equivalents.

In the event of a "change in control", restricted stock will become vested, unvested options will become vested, performance shares will be paid out and directors' units will be paid out if the director has elected accelerated payout upon a change in control.

Restricted stock is subject to forfeiture if the holder terminates employment during the restriction period for reasons other than for the convenience of the Company or normal retirement at age 65.

A summary of the Company's stock plans for the last three years is presented below:

	Number of Options/Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share
Options outstanding at 01/01/1999	9,274,922	$ 39	$ -
Options granted during year	2,138,280	40	40
Options exercised during year	(993,412)	29	-
Options canceled/forfeited during year	(431,953)	43	-
Options outstanding at 12/31/1999	9,987,837	40	-
Options exercisable at 12/31/1999	4,595,864	33	-
Restricted stock awarded during year	173,089	-	34
Performance shares awarded during year	287,742	-	37
Options outstanding at 01/01/2000	9,987,837	$ 40	$ -
Options granted during year	2,705,057	29	29
Options exercised during year	(312,773)	27	-
Options canceled/forfeited during year	(1,044,526)	39	-
Options outstanding at 12/31/2000	11,335,595	38	-
Options exercisable at 12/31/2000	5,999,097	33	-
Restricted stock awarded during year	382,434	-	30
Performance shares awarded during year	256,041	-	34
Options outstanding at 01/01/2001	11,335,595	$ 38	$ -
Options granted during year	3,440,919	35	35
Options exercised during year	(551,788)	27	-
Options canceled/forfeited during year	(3,226,949)	49	-
Options outstanding at 12/31/2001	10,997,777	34	-
Options exercisable at 12/31/2001	6,571,071	34	-
Restricted stock awarded during year	558,836	-	33
Performance shares awarded during year	204,142	-	36

Significant option groups outstanding at December 31, 2001 and related weighted average price and life information follows:

	Options Outstanding			Options Exercisable	
Range of Exercise prices	Number Outstanding	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$21	116,145	0.2	$21	116,145	$21
$26 - $29	2,606,499	6.4	$28	1,617,329	$28
$30 - $35	3,122,909	6.8	$33	1,426,355	$33
$36 - $40	5,038,994	6.7	$37	3,309,579	$38
$42 - $45	113,230	6.4	$44	101,663	$44

The fair value of options at date of grant was estimated using the Black-Scholes model with the following weighted average assumptions:

	2001	2000	1999
Expected life (years)	4.5	4.2	4.3
Interest rate	4.6%	6.3%	5.6%
Volatility	30.5%	40.7%	36.6%
Dividend yield	2.2%	2.5%	2.1%

The Company applies APB Opinion No. 25 and related interpretations in accounting for stock-based compensation. Stock-based compensation expense recognized in the Company's consolidated earnings statement was $48 million in 2001, $49 million in 2000 and $31 million in 1999. These amounts include expenses related to the Company's various cash incentive plans that are paid to certain employees based upon defined measures of the Company's common stock price performance, total shareholder return and certain other Company performance metrics. In addition, the amounts for 2001 and 2000 also included expenses related to the Company's Pure subsidiary, which had its own stock-based compensation plan. Had the Company recorded compensation expense using the accounting method recommended by SFAS No. 123, net earnings and earnings per share would have been reduced to the pro-forma amounts indicated below:

	Years Ended December 31,		
Millions of dollars except per share amounts	2001	2000	1999
Net earnings			
As reported	$ 615	$ 760	$ 137
Pro forma	603	754	125
Net basic earnings per share			
As reported	$ 2.52	$ 3.13	$ 0.57
Pro forma	2.48	3.10	0.52

NOTE 27 − FINANCIAL INSTRUMENTS AND COMMODITY HEDGING

The Company does not generally hold or issue financial instruments for trading purposes other than those that are hydrocarbon based. The counterparties to the Company's financial instruments include regulated exchanges, international and domestic financial institutions and other industrial companies. All of the counterparties to the Company's financial instruments must pass certain credit requirements deemed sufficient by management before trading physical commodities or financial instruments with the Company.

Interest rate contracts − The Company enters into interest rate swap contracts to manage its debt with the objective of minimizing the volatility and magnitude of the Company's borrowing costs. During 2001, the Company's Pure subsidiary acquired fixed for floating interest rate swaps with a notional principal amount of $37.5 million as part of its Hallwood acquisition (see note 3). These derivatives have different maturity dates than Pure's debt instruments and, therefore, do not qualify as hedges. Accordingly, these instruments are marked−to−market each reporting period, with changes in value recorded in interest expense. The related liability is included in other deferred credits and liabilities on the consolidated balance sheet. The Company had no interest rate swap contracts outstanding at December 31, 2000.

The Company may also enter into interest rate option contracts to protect its interest rate positions, depending on market conditions. The Company had no interest rate option contracts outstanding at December 31, 2001 and 2000.

Foreign currency contracts − Various foreign exchange currency forward, option and swap contracts are entered into by the Company from time to time to manage its exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions. At December 31, 2001, the Company had approximately $1 million of after−tax deferred gains in accumulated other comprehensive income ("OCI") on the consolidated balance sheet related to cash flow hedges for future foreign currency denominated payment obligations through August 2008. Of this amount, the losses expected to be reclassified to the consolidated earnings statement during the next twelve months are immaterial.

Commodity hedging activities − The Company used hydrocarbon derivatives to mitigate the Company's overall exposure to fluctuations in hydrocarbon commodity prices. During 2001, the Company recognized $2 million in after−tax gains for the ineffectiveness of cash flow hedges. Ineffectiveness related to fair value hedges was immaterial. At December 31, 2001, 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 commodity sales for the period beginning January 2002 through December 2008. Of this amount, approximately $8 million in after−tax gains were expected to be reclassified to the consolidated earnings statement during the next twelve months.

Fair values for debt and other long−term instruments − The estimated fair values of the Company's long−term debt were $2,809 and $2,610 million at year−end 2001 and 2000, respectively. Fair values were 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 values of Unocal Capital Trust's 6.25 percent convertible preferred securities were $523 and $536 million at year−end 2001 and 2000, respectively. Fair values were based on the trading prices of the preferred securities on December 31, 2001 and 2000.

Concentrations of credit risks − Financial instruments that potentially subject the Company to concentrations of credit risks primarily consist of temporary cash investments and trade receivables. The Company places its temporary cash investments with high credit quality financial institutions and, by policy, limits the amount of credit exposure to any one financial institution. The concentration of trade receivable credit risk is generally limited due to the Company's customers being spread across industries in several countries. The Company's management has established certain credit requirements that its customers must meet before sales credit is extended. The Company monitors the financial condition of its customers to help ensure collections and to minimize losses.

The majority of the Company's trade receivables balance at December 31, 2001, was attributable to the sale of crude oil and natural gas produced by the Company or purchased by the Company for resale. The Company has receivable concentrations for its crude oil and natural gas sales and geothermal steam and related electricity sales in certain Asian countries that are subject to currency fluctuations and other factors affecting the region.

At December 31, 2001, approximately $95 million or 11 percent of the Company's net accounts receivable balance was due from the Petroleum Authority of Thailand. This amount primarily represented payments due for sales of natural gas production from the Company's fields in the Gulf of Thailand and offshore Myanmar. No other individual crude oil and natural gas customer accounted for ten percent or more of the Company's consolidated net trade receivable balance at December 31, 2001.

As of December 31, 2001, the Company's Indonesian Geothermal business unit had a gross receivable balance of approximately $406 million. Approximately $170 million was related to Gunung Salak electric generating Units 1, 2 and 3, of which $167 million represented past due amounts and accrued interest resulting from partial payments for March 1998 through December 2001. Although invoices generally have not been paid in full, amounts that have been paid have been received in a timely manner in accordance with the steam sales contract. The remaining $236 million primarily related to Salak electric generating Units 4, 5 and 6. Provisions covering a portion of these receivables were recorded in each year from 1998 through 2001. Approximately 50 percent of the gross outstanding receivable balance was included in accounts and notes receivables and the remainder was included in investments and long-term receivables on the consolidated balance sheet, net of provisions. The Company believes that significant progress has been made towards an agreement that is acceptable to all parties to resolve the issues.

The Company continues to work with the government of Bangladesh and Petrobangla, the state oil and gas company of Bangladesh, to open up the export of natural gas to neighboring India. At December 31, 2001, 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 June 2001 through December 2001. The invoices have been generally paid in full and were paid through May 2001. The Company is working with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables.

NOTE 28 - SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiaries Unocal Capital Trust (see note 23) 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 2001, 2000 and 1999 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 CONSOLIDATED EARNINGS STATEMENT
Year ended December 31, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues						
Sales and operating revenues	$ -	$ -	$ 1,835	$ 6,276	$ (1,447)	$ 6,664
Interest, dividends and miscellaneous income	6	34	35	26	(37)	64
Gain (loss) on sales of assets	-	-	29	(5)	-	24
Total revenues	6	34	1,899	6,297	(1,484)	6,752
Costs and other deductions						
Purchases, operating and other expenses	4	-	1,240	4,550	(1,475)	4,319
Depreciation, depletion, amortization and impairments	-	-	491	594	-	1,085
Dry hole costs	-	-	37	138	-	175
Interest expense	34	1	162	32	(37)	192
Distributions on convertible preferred securties	-	33	-	-	-	33
Total costs and other deductions	38	34	1,930	5,314	(1,512)	5,804
Equity in earnings of subsidiaries	635	-	673	-	(1,308)	-
Earnings from equity investments	-	-	10	134	-	144
Earnings from continuing operations before income taxes and minority interests	603	-	652	1,117	(1,280)	1,092
Income taxes	(12)	-	33	431	-	452
Minority interests	-	-	-	13	28	41
Earnings from continuing operations	615	-	619	673	(1,308)	599
Earnings from discontinued operations	-	-	17	-	-	17
Cumulative effect of accounting change	-	-	(1)	-	-	(1)
Net earnings	$ 615	$ -	$ 635	$ 673	$ (1,308)	$ 615

CONDENSED CONSOLIDATED EARNINGS STATEMENT
Year ended December 31, 2000

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues						
Sales and operating revenues	$ –	$ –	$ 2,117	$ 8,365	$ (1,541)	$ 8,941
Interest, dividends and miscellaneous income	11	34	142	26	(37)	176
Gain on sales of assets	–	–	75	10	–	85
Total revenues	11	34	2,334	8,401	(1,578)	9,202
Costs and other deductions						
Purchases, operating and other expenses	3	–	1,461	6,945	(1,594)	6,815
Depreciation, depletion, amortization and impairments	–	–	339	547	–	886
Dry hole costs	–	–	56	100	–	156
Interest expense	34	1	204	8	(37)	210
Distributions on convertible preferred securties	–	33	–	–	–	33
Total costs and other deductions	37	34	2,060	7,600	(1,631)	8,100
Equity in earnings of subsidiaries	776	–	645	–	(1,421)	–
Earnings from equity investments	–	–	36	98	–	134
Earnings from continuing operations before income taxes and minority interests	750	–	955	899	(1,368)	1,236
Income taxes	(10)	–	222	285	–	497
Minority interests	–	–	(2)	(1)	19	16
Earnings from continuing operations	760	–	735	615	(1,387)	723
Earnings from discontinued operations	–	–	41	30	(34)	37
Net earnings	$ 760	$ –	$ 776	$ 645	$ (1,421)	$ 760

CONDENSED CONSOLIDATED EARNINGS STATEMENT
Year ended December 31, 1999

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsi-diaries	Elim-nations	Conso-lidated
Revenues						
Sales and operating revenues	$ -	$ -	$ 1,212	$ 5,629	$ (999)	$ 5,842
Interest, dividends and miscellaneous income	1	34	57	54	(41)	105
Gain (loss) on sales of assets	-	-	34	(7)	(13)	14
Total revenues	1	34	1,303	5,676	(1,053)	5,961
Costs and other deductions						
Purchases, operating and other expenses	3	-	1,010	4,689	(1,016)	4,686
Depreciation, depletion, amortization and impairments	-	-	353	388	-	741
Dry hole costs	-	-	41	107	-	148
Interest expense	34	1	202	3	(41)	199
Distributions on convertible preferred securties	-	33	-	-	-	33
Total costs and other deductions	37	34	1,606	5,187	(1,057)	5,807
Equity in earnings of subsidiaries	160	-	323	-	(483)	-
Earnings from equity investments	-	-	44	56	(4)	96
Earnings from continuing operations before income taxes and minority interests	124	-	64	545	(483)	250
Income taxes	(13)	-	(70)	204	-	121
Minority interests	-	-	(2)	18	-	16
Earnings from continuing operations	137	-	136	323	(483)	113
Earnings from discontinued operations	-	-	24	-	-	24
Net earnings	$ 137	$ -	$ 160	$ 323	$ (483)	$ 137

CONDENSED CONSOLIDATED BALANCE SHEET
At December 31, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash and cash equivalents	$ –	$ –	$ 62	$ 128	$ –	$ 190
Accounts and notes receivable – net	51	–	154	693	(51)	847
Inventories	–	–	3	99	–	102
Other current assets	–	–	122	34	–	156
Total current assets	51	–	341	954	(51)	1,295
Investments and long-term receivables – net	4,032	–	4,143	968	(7,738)	1,405
Properties – net	–	–	2,149	5,365	–	7,514
Other assets	3	541	214	2,403	(2,950)	211
Total assets	$4,086	$ 541	$ 6,847	$ 9,690	$(10,739)	$10,425
Liabilities and Stockholders' Equity						
Current liabilities						
Accounts payable	$ –	$ –	$ 278	$ 596	$ (51)	$ 823
Current portion of long-term debt and capital leases	–	–	–	9	–	9
Other current liabilities	42	3	145	400	–	590
Total current liabilities	42	3	423	1,005	(51)	1,422
Long-term debt and capital leases	–	–	2,181	716	–	2,897
Deferred income taxes	–	–	(71)	698	–	627
Accrued abandonment, restoration and environmental liabilities	–	–	293	297	–	590
Other deferred credits and liabilities	541	–	312	2,821	(2,950)	724
Subsidiary stock subject to repurchase	–	–	–	70	–	70
Minority interests	–	–	–	309	140	449
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	–	522	–	–	–	522
Stockholders' equity	3,503	16	3,709	3,774	(7,878)	3,124
Total liabilities and stockholders' equity	$4,086	$541	$6,847	$ 9,690	$(10,739)	$10,425

CONDENSED CONSOLIDATED BALANCE SHEET
At December 31, 2000

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash and cash equivalents	$ 1	$ -	$ 84	$ 150	$ -	$ 235
Accounts and notes receivable - net	51	-	165	1,134	(51)	1,299
Inventories	-	-	13	75	-	88
Other current assets	-	-	127	53	-	180
Total current assets	52	-	389	1,412	(51)	1,802
Investments and long-term receivables - net	3,620	-	3,765	781	(6,787)	1,379
Properties - net	-	-	1,988	4,445	-	6,433
Other assets	5	541	646	1,153	(1,949)	396
Total assets	$3,677	$ 541	$ 6,788	$ 7,791	$(8,787)	$10,010
Liabilities and Stockholders' Equity						
Current liabilities						
Accounts payable	$ -	$ -	$ 334	$ 739	$ (51)	$ 1,022
Current portion of long-term debt and capital leases	-	-	105	9	-	114
Other current liabilities	42	3	233	431	-	709
Total current liabilities	42	3	672	1,179	(51)	1,845
Long-term debt and capital leases	-	-	2,181	211	-	2,392
Deferred income taxes	-	-	(10)	628	-	618
Accrued abandonment, restoration and environmental liabilities	-	-	-	554	-	554
Other deferred credits and liabilities	541	-	670	1,562	(1,941)	832
Subsidiary stock subject to repurchase	-	-	-	136	-	136
Minority interests	-	-	-	287	105	392
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-	-	522
Stockholders' equity	3,094	16	3,275	3,234	(6,900)	2,719
Total liabilities and stockholders' equity	$3,677	$541	$6,788	$ 7,791	$(8,787)	$10,010

CONDENSED CONSOLIDATED BALANCE SHEET
At December 31, 1999

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsi-diaries	Elim-nations	Conso-lidated
Assets						
Current assets						
Cash and cash equivalents	$ 1	$ -	$162	$ 169	$ -	$ 332
Accounts and notes receivable - net	50	-	193	801	(50)	994
Inventories	-	-	15	164	-	179
Other current assets	-	-	112	14	-	126
Total current assets	51	-	482	1,148	(50)	1,631
Investments and long-term receivables - net	3,074	-	3,475	639	(5,924)	1,264
Properties - net	-	-	2,097	3,883	-	5,980
Other assets	4	541	432	94	(979)	92
Total assets	$3,129	$ 541	$ 6,486	$ 5,764	$(6,953)	$ 8,967
Liabilities and Stockholders' Equity						
Current liabilities						
Accounts payable	$ -	$ -	$ 298	$ 731	$ (50)	$ 979
Current portion of long-term debt and capital leases	-	-	-	1	-	1
Other current liabilities	74	3	273	229	-	579
Total current liabilities	74	3	571	961	(50)	1,559
Long-term debt and capital leases	-	-	2,531	322	-	2,853
Deferred income taxes	-	-	(109)	339	-	230
Accrued abandonment, restoration and environmental liabilities	-	-	-	567	-	567
Other deferred credits and liabilities	541	-	709	325	(955)	620
Minority interests	-	-	-	426	6	432
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-	-	522
Stockholders' equity	2,514	16	2,784	2,824	(5,954)	2,184
Total liabilities and stockholders' equity	$3,129	$541	$6,486	$ 5,764	$(6,953)	$ 8,967

CONDENSED CONSOLIDATED CASH FLOWS
Year ended December 31, 2001

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flows from Operating Activities	$ 179	$ -	$ 889	$ 1,057	$ -	$ 2,125
Cash Flows from Investing Activities						
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(890)	(1,483)	-	(2,373)
Proceeds from sales of assets and discontinued operations	-	-	84	22	-	106
Net cash used in investing activities	-	-	(806)	(1,461)	-	(2,267)
Cash Flows from Financing Activities						
Change in long-term debt and capital leases	-	-	(105)	399	-	294
Dividends paid on common stock	(195)	-	-	-	-	(195)
Minority interests	-	-	-	(17)	-	(17)
Other	15	-	-	-	-	15
Net cash provided by (used in) financing activities	(180)	-	(105)	382	-	97
Increase (decrease) in cash and cash equivalents	(1)	-	(22)	(22)	-	(45)
Cash and cash equivalents at beginning of year	1	-	84	150	-	235
Cash and cash equivalents at end of year	$ -	$ -	$ 62	$ 128	$ -	$ 190

CONDENSED CONSOLIDATED CASH FLOWS
Year ended December 31, 2000

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsi-diaries	Elim-nations	Conso-lidated
Cash Flows from						
Operating Activities	$ 218	$ -	$ 180	$ 1,270	$ -	$ 1,668
Cash Flows from Investing Activities						
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(546)	(1,074)	-	(1,620)
Proceeds from sales of assets and discontinued operations	-	-	535	16	-	551
Net cash used in investing activities	-	-	(11)	(1,058)	-	(1,069)
Cash Flows from Financing Activities						
Change in long-term debt and capital leases	-	-	(247)	(206)	-	(453)
Dividends paid on common stock	(194)	-	-	-	-	(194)
Minority interests	-	-	-	(25)	-	(25)
Other	(24)	-	-	-	-	(24)
Net cash provided by (used in) financing activities	(218)	-	(247)	(231)	-	(696)
Increase (decrease) in cash and cash equivalents	-	-	(78)	(19)	-	(97)
Cash and cash equivalents at beginning of year	1	-	162	169	-	332
Cash and cash equivalents at end of year	$ 1	$ -	$ 84	$ 150	$ -	$ 235

CONDENSED CONSOLIDATED CASH FLOWS
Year ended December 31, 1999

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flows from						
Operating Activities	$ 170	$ -	$ 324	$ 532	$ -	$ 1,026
Cash Flows from Investing Activities						
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(504)	(872)	-	(1,376)
Proceeds from sales of assets and discontinued operations	-	-	234	4	-	238
Net cash used in investing activities	-	-	(270)	(868)	-	(1,138)
Cash Flows from Financing Activities						
Change in long-term debt and capital leases	-	-	41	103	-	144
Dividends paid on common stock	(194)	-	-	-	-	(194)
Minority interests	-	-	-	233	-	233
Other	24	-	(1)	-	-	23
Net cash provided by (used in) financing activities	(170)	-	40	336	-	206
Increase (decrease) in cash and cash equivalents	-	-	94	-	-	94
Cash and cash equivalents at beginning of year	1	-	68	169	-	238
Cash and cash equivalents at end of year	$ 1	$ -	$162	$ 169	$ -	$ 332

NOTE 29 - SEGMENT AND GEOGRAPHIC DATA

The Company's reportable segments are as follows:

Exploration and Production Segment - This category includes the Company's North American and International oil and gas operations. North America includes the U.S. Lower 48, Alaska and Canada oil and gas operations. The Company's International operations include activities outside of North America and are categorized under Far East and Other International. The Company's International Far East operations include production activities in Thailand, Indonesia and Myanmar. The Company's Other International operations include Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. The Company is also involved in exploration and development activities in Asia, Latin America and West Africa. In 2001, $663 million, or approximately 10 percent, of the Company's total external sales and operating revenues were attributable to the sale of natural gas and condensate, produced offshore Thailand and Myanmar, to the Petroleum Authority of Thailand. The Company's International crude oil is primarily sold to third parties at spot market prices.

Trade Segment - The Trade segment externally markets most 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 crude oil, condensate and natural gas from certain 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 for non-hedge purposes for its own account subject to internal restrictions, including value at risk limits. The segment also trades limited amounts of physical inventories held for energy trading purposes.

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

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

Corporate and Other - The Corporate and Other grouping includes general corporate overhead, miscellaneous operations (including real estate, carbon and minerals businesses) and other unallocated costs. Net interest expense represents interest expense, net of interest income and capitalized interest.

The following tables present the Company's financial data by business segment and geographic area of operations. Intersegment revenues in business segment data are primarily sales from the Exploration and Production segment to the Trade segment. Intersegment sales prices approximate market prices. Geographic revenues primarily represent sales of crude oil and natural gas produced within the countries or regions shown.

SEGMENT DATA

2001 Segment Information Millions of dollars	Exploration & Production					Trade
	North America			International		
	Lower 48	Alaska	Canada	Far East	Other	
Sales & operating revenues	$ 616	$ 282	$ 239	$ 969	$ 138	$ 3,856
Other income (loss) (a)	28	–	(1)	27	(35)	(1)
Inter-segment revenues	1,438	–	–	199	112	1
Total	2,082	282	238	1,195	215	3,856
Depreciation, depletion & amortization	505	53	104	212	40	1
Impairments	118	–	–	–	–	–
Dry hole costs	99	–	11	25	40	–
Exploration expense						
Amortization of exploratory leases	51	–	21	9	14	–
Earnings (loss) from equity investments	(11)	–	–	(2)	39	–
Earnings (loss) from continuing operations before income taxes and minority interests	643	87	20	700	40	8
Income taxes (benefit)	221	32	10	284	13	2
Minority interests	47	–	–	–	–	–
Earnings (loss) from continuing operations	375	55	10	416	27	6
Net earnings (loss)	375	55	10	416	27	6
Capital expenditures and acquisitions	1,414	81	206	425	148	–
Assets	3,345	344	1,015	2,463	741	156
Equity investments	117	–	–	24	172	11

	Midstream	Geothermal &Power Operations	Corporate &Other Admin & General	Net Interest Expense	Environmental & Litigation	Other (b)	Total
Sales &operating revenues	$ 242	$ 181	$ −	$ −	$ −	$ 141	$ 6,664
Other income (loss) (a)	2	16	−	24	−	28	88
Inter−segment revenues	8	−	−	−	−	(1,758)	−
Total	252	197	−	24	−	(1,589)	6,752
Depreciation, depletion &amortization	14	14	−	−	−	24	967
Impairments	−	−	−	−	−	−	118
Dry hole costs	−	−	−	−	−	−	175
Exploration expense							
Amortization of exploratory leases	−	−	−	−	−	−	95
Earnings (loss) from equity investments	62	1	−	−	−	55	144
Earnings (loss) from continuing operations before income taxes and minority interests	69	17	(119)	(168)	(166)	(39)	1,092
Income taxes (benefit)	15	6	(39)	(31)	(62)	1	452
Minority interests	−	−	−	(6)	−	−	41
Earnings (loss) from continuing operations	54	11	(80)	(131)	(104)	(40)	599
Discontinued operations (net)	−	−	−	−	−	17	17
Cumulative effect of accounting changes	−	−	−	−	−	(1)	(1)
Net earnings (loss)	54	11	(80)	(131)	(104)	(24)	615
Capital expenditures and acquisitions	41	7	−	−	−	51	2,373
Assets	479	594	−	−	−	1,288	10,425
Equity investments	187	54	−	−	−	60	625

<FN>
(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets.
(b) Includes eliminations and consolidation adjustments.
</FN>

SEGMENT DATA (Continued)

2000 Segment Information Millions of dollars	Exploration &Production					Trade
	North America			International		
	Lower 48	Alaska	Canada	Far East	Other	
Sales &operating revenues	$ 298	$ 254	$ 168	$ 1,003	$ 145	$ 6,693
Other income (loss) (a)	63	−	2	16	(22)	−
Inter−segment revenues	1,528	48	−	207	98	8
Total	1,889	302	170	1,226	221	6,701
Depreciation, depletion &amortization	370	57	90	212	39	1
Impairments	13	−	−	−	−	−
Dry hole costs	85	3	7	58	3	−
Exploration expense						
Amortization of exploratory leases	44	−	19	9	11	−
Earnings (loss) from equity investments	18	−	−	(1)	19	−
Earnings (loss) from continuing operations before income taxes and minority interests	756	146	(94)	691	62	6
Income taxes (benefit)	267	54	(80)	274	16	1
Minority interests	39	−	(20)	−	−	−
Earnings (loss) from continuing operations	450	92	6	417	46	5
Net earnings (loss)	450	92	6	417	46	5
Capital expenditures and acquisitions	628	34	325	482	62	1
Assets	2,701	315	1,119	2,251	603	655
Equity investments	128	−	3	143	27	10

	Midstream	Geothermal &Power Operations	Corporate &Other				Total
			Admin & General	Net Interest Expense	Environmental & Litigation	Other (b)	
Sales &operating revenues	$ 51	$ 161	$ –	$ –	$ –	$ 168	$ 8,941
Other income (loss) (a)	12	17	–	31	–	142	261
Inter–segment revenues	11	–	–	–	–	(1,900)	–
Total	74	178	–	31	–	(1,590)	9,202
Depreciation, depletion &amortization	14	15	–	–	–	23	821
Impairments	–	–	–	–	–	53	66
Dry hole costs	–	–	–	–	–	–	156
Exploration expense							
Amortization of exploratory leases	–	2	–	–	–	–	85
Earnings (loss) from equity investments	57	(2)	–	–	–	43	134
Earnings (loss) from continuing operations before income taxes and minority interests	83	45	(124)	(178)	(134)	(23)	1,236
Income taxes (benefit)	21	21	(36)	(30)	(50)	39	497
Minority interests	–	–	–	(3)	–	–	16
Earnings (loss) from continuing operations	62	24	(88)	(145)	(84)	(62)	723
Discontinued operations (net)	–	–	–	–	–	37	37
Net earnings (loss)	62	24	(88)	(145)	(84)	(25)	760
Capital expenditures and acquisitions (c)	16	18	–	–	–	54	1,620
Assets	316	574	–	–	–	1,476	10,010
Equity investments	189	50	–	–	–	68	618

<FN>
(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets.
(b) Includes eliminations and consolidation adjustments.
(c) Includes capital expenditures for discontinued operations (agricultural products) of $14 million.
</FN>

SEGMENT DATA (Continued)

1999 Segment Information Millions of dollars	Exploration &Production North America Lower 48	 Alaska	 Canada	 International Far East	 Other	 Trade
Sales &operating revenues	$ 72	$ 129	$ 160	$ 723	$ 103	$ 4,301
Other income (loss) (a)	4	–	1	3	4	1
Inter–segment revenues	974	63	–	177	65	8
Total	1,050	192	161	903	172	4,310
Depreciation, depletion &amortization	318	53	39	201	49	1
Impairments	23	–	–	–	–	–
Dry hole costs	82	–	4	41	21	–
Exploration expense						
Amortization of exploratory leases	44	–	13	6	14	–
Earnings (loss) from equity investments	3	–	–	(3)	(1)	3
Earnings (loss) from continuing operations before income taxes and minority interests	78	50	20	390	(52)	(7)
Income taxes (benefit)	22	19	5	166	(26)	(5)
Minority interests	11	–	5	–	–	–
Earnings (loss) from continuing operations	45	31	10	224	(26)	(2)
Net earnings (loss)	45	31	10	224	(26)	(2)
Capital expenditures and acquisitions	530	28	317	321	117	3
Assets	2,178	326	946	1,856	586	439
Equity investments	87	–	2	192	19	2

	Midstream	Geothermal &Power Operations	Corporate &Other Admin & General	Net Interest Expense	Environmental & Litigation	Other (b)	Total
Sales &operating revenues	$ 38	$ 153	$ −	$ −	$ −	$ 163	$ 5,842
Other income (loss) (a)	8	12	−	21	−	65	119
Inter−segment revenues	10	−	−	−	−	(1,297)	−
Total	56	165	−	21	−	(1,069)	5,961
Depreciation, depletion &amortization	14	22	−	−	−	21	718
Impairments	−	−	−	−	−	−	23
Dry hole costs	−	−	−	−	−	−	148
Exploration expense							
Amortization of exploratory leases	−	−	−	−	−	−	77
Earnings (loss) from equity investments	64	−	−	−	−	30	96
Earnings (loss) from continuing operations before income taxes and minority interests	79	27	(117)	(176)	(49)	7	250
Income taxes (benefit)	13	13	(36)	(36)	(18)	4	121
Minority interests	−	−	−	(2)	−	2	16
Earnings (loss) from continuing operations	66	14	(81)	(138)	(31)	1	113
Discontinued operations (net)	−	−	−	−	−	24	24
Net earnings (loss)	66	14	(81)	(138)	(31)	25	137
Capital expenditures and acquisitions (c)	7	21	−	−	−	32	1,376
Assets (d)	299	532	−	−	−	1,805	8,967
Equity investments	185	24	−	−	−	45	556

<FN>
(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets.
(b) Includes eliminations and consolidation adjustments.
(c) Includes capital expenditures for discontinued operations (agricultural products) of $10 million.
(d) Includes assets for discontinued operations (agricultural products) of $289 million.
</FN>

GEOGRAPHIC INFORMATION

2001 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total
Sales and operating revenues							
from continuing operations	$ 4,418	$ 442	$ 683	$ 613	$ 485	$ 23	$ 6,664
Long lived assets:							
Gross	10,161	1,387	2,982	2,541	1,857	234	19,162
Net	3,637	1,054	1,016	1,002	723	82	7,514

2000 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total
Sales and operating revenues							
from continuing operations	$ 6,956	$ 184	$ 735	$ 700	$ 365	$ 1	$ 8,941
Long lived assets:							
Gross	8,620	1,200	2,803	2,390	1,793	372	17,178
Net	2,699	975	967	921	720	151	6,433

1999 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total (a)
Sales and operating revenues							
from continuing operations	$ 4,333	$ 160	$ 618	$ 483	$ 252	$ (4)	$ 5,842
Long lived assets: (a)							
Gross	8,698	998	2,641	2,063	1,734	381	16,515
Net	2,626	868	952	657	713	164	5,980

<FN>
(a) Includes long lived assets for discontinued business (agricultural products) of $621 million (gross) and $197 million (net).
</FN>

QUARTERLY FINANCIAL DATA (Unaudited)

Millions of dollars except per share amounts	2001 Quarters 1st	2nd	3rd	4th
Total revenues	$ 2,214	$ 1,696	$ 1,579	$ 1,263
Earnings from equity investments	42	49	37	16
Total costs, including minority interests and income taxes	1,964	1,510	1,514	1,309
After-tax earnings from continuing operations	292	235	102	(30)
Discontinued operations				
Gain on disposal (net of tax)	4	12	-	1
Cumulative effect of accounting change (net of tax)	(1)	-	-	-
Net earnings	$ 295	$ 247	$ 102	$ (29)
Basic earnings per share of common stock (a)				
Continuing operations	$ 1.19	$ 0.98	$ 0.42	$ (0.13)
Discontinued operations	0.02	0.04	-	0.01
Basic earnings per share of common stock	$ 1.21	$ 1.02	$ 0.42	$ (0.12)
Diluted earnings per share of common stock (a)				
Continuing operations	$ 1.16	$ 0.95	$ 0.42	$ (0.13)
Discontinued operations	0.02	0.04	-	0.01
Diluted earnings per share of common stock	$ 1.18	$ 0.99	$ 0.42	$ (0.12)
Net sales and operating revenues	$ 2,206	$ 1,684	$ 1,573	$ 1,201
Gross margin (b)	$ 505	$ 424	$ 200	$ (44)

<FN>

(a) Due to changes in the number of weighted average common shares outstanding each quarter, the earnings per share amounts by quarter may not be additive.

(b) Gross margin equals sales and operating revenues less crude oil, natural gas and product purchases, operating and selling expenses, depreciation, depletion and amortization, impairments, dry hole costs, exploration expenses, and other operating taxes.

</FN>

QUARTERLY FINANCIAL DATA (continued)

Millions of dollars except per share amounts	2000 Quarters 1st	2nd	3rd	4th
Total revenues	$ 1,856	$ 2,216	$ 2,347	$ 2,783
Earnings from equity investments	25	32	44	33
Total costs, including minority interests and income taxes	1,757	1,998	2,215	2,643
After-tax earnings from continuing operations	124	250	176	173
Discontinued operations				
Gain on disposal (net of tax)	9	14	14	-
Net earnings	$ 133	$ 264	$ 190	$ 173
Basic earnings per share of common stock (a)				
Continuing operations	$ 0.51	$ 1.03	$ 0.72	$ 0.71
Discontinued operations	0.04	0.05	0.06	-
Basic earnings per share of common stock	$ 0.55	$ 1.08	$ 0.78	$ 0.71
Diluted earnings per share of common stock (a)				
Continuing operations	$ 0.51	$ 1.00	$ 0.71	$ 0.70
Discontinued operations	0.04	0.05	0.06	-
Diluted earnings per share of common stock	$ 0.55	$ 1.05	$ 0.77	$ 0.70
Net sales and operating revenues	$ 1,841	$ 2,025	$ 2,333	$ 2,742
Gross margin (b)	$ 224	$ 241	$ 259	$ 360

<FN>

(a) Due to changes in the number of weighted average common shares outstanding each quarter, the earnings per share amounts by quarter may not be additive.

(b) Gross margin equals sales and operating revenues less crude oil, natural gas and product purchases, operating and selling expenses, depreciation, depletion and amortization, impairments, dry hole costs, exploration expenses, and other operating taxes.

</FN>

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

Results of Operations

Results of operations of oil and gas exploration and production activities are shown below. Sales revenues are shown net of purchases. Other revenues primarily include gains or losses on sales of oil and gas properties and miscellaneous rental income. Production costs include costs incurred to operate and maintain wells and related facilities, operating overhead and taxes other than income. Exploration expenses consist of geological and geophysical costs, leasehold rentals, amortization of exploratory leases and dry hole costs. Depreciation, depletion and amortization expense includes impairments and provisions of estimated future abandonment liabilities. Other operating expenses primarily include administrative and general expense. Income tax expense is based on the tax effects arising from the operations. Results of operations do not include general corporate overhead, interest costs, minority interests expense or the activities of the Trade business segment.

	North America			International		
Millions of dollars	Lower 48	Alaska	Canada	Far East	Other	Total
2001						
Sales						
To public	$ 374	$ 278	$ 223	$ 985	$ 129	$1,989
Intercompany	1,439	-	-	199	111	1,749
Other revenues	51	4	-	(1)	(2)	52
Total	1,864	282	223	1,183	238	3,790
Production costs	278	123	54	156	45	656
Exploration expenses	223	2	40	84	78	427
Depreciation, depletion and amortization	623	53	104	212	40	1,032
Other operating expenses	86	17	20	70	34	227
Pre-tax results of operations	654	87	5	661	41	1,448
Income taxes	221	32	4	284	13	554
Results of operations	$ 433	$ 55	$ 1	$ 377	$ 28	$ 894
Results of equity investees (a)	(11)	-	-	39	(1)	27
Total	$ 422	$ 55	$ 1	$ 416	$ 27	$ 921
2000						
Sales						
To public	$ 109	$ 248	$ 198	$ 994	$ 126	$1,675
Intercompany	1,442	47	-	207	98	1,794
Other revenues	75	3	31	9	1	119
Total	1,626	298	229	1,210	225	3,588
Production costs	208	80	51	152	45	536
Exploration expenses	219	6	33	108	47	413
Depreciation, depletion and amortization	383	57	90	212	39	781
Other operating expenses	78	9	15	65	32	199
Pre-tax results of operations	738	146	40	673	62	1,659
Income taxes	267	54	(20)	274	16	591
Results of operations	$ 471	$ 92	$ 60	$ 399	$ 46	$1,068
Results of equity investees (a)	18	-	-	18	-	36
Total	$ 489	$ 92	$ 60	$ 417	$ 46	$1,104

<FN>
(a) Unocal's proportional shares of investees accounted for by the equity method.
</FN>

Results of Operations (continued)

Millions of dollars	North America			International		
	Lower 48	Alaska	Canada	Far East	Other	Total
1999						
Sales						
To public	$ 39	$ 121	$ 113	$ 684	$ 94	$1,051
Intercompany	781	61	-	177	65	1,084
Other revenues	28	3	13	9	2	55
Total	848	185	126	870	161	2,190
Production costs	167	70	35	134	44	450
Exploration expenses	200	2	24	83	87	396
Depreciation, depletion and amortization	341	53	39	201	49	683
Other operating expenses	65	10	8	59	32	174
Pre-tax results of operations	75	50	20	393	(51)	487
Income taxes	22	19	7	166	(26)	188
Results of operations	$ 53	$ 31	$ 13	$ 227	$ (25)	$ 299
Results of equity investees (a)	3	-	-	(3)	(1)	(1)
Total	$ 56	$ 31	$ 13	$ 224	$ (26)	$ 298

<FN>
(a) Unocal's proportional shares of investees accounted for by the equity method.
</FN>

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities, both capitalized and charged to expense, are shown below. Data for the Company's capitalized costs related to oil and gas exploration and production activities are presented in note 15.

	North America			International		
Millions of dollars	Lower 48	Alaska	Canada	Far East	Other	Total(a)
2001						
Property acquisition						
Proved (b) (c) (d)	$ 725	$ -	$121	$ -	$ -	$ 846
Unproved	103	4	16	2	1	126
Exploration	412	13	34	115	59	633
Development	361	67	66	374	37	905
Costs incurred by equity investees (e)	86	-	-	-	78	164
2000						
Property acquisition						
Proved (f) (g)	$ 312	$ -	$346	$ 157	$ 18	$ 833
Unproved	57	-	6	6	1	70
Exploration	294	6	34	134	46	514
Development	279	30	70	237	33	649
Costs incurred by equity investees (e)	103	-	-	-	-	103
1999						
Property acquisition						
Proved (h)	$ 18	$ -	$283	$ -	$ 22	$ 323
Unproved	29	1	5	6	15	56
Exploration	320	4	26	155	95	600
Development	240	25	76	204	44	589
Costs incurred by equity investees (e)	11	-	-	4	-	15

<FN>

(a) Includes costs attributable to outstanding minority interests in consolidated subsidiaries of:

2001	$305
2000	$154
1999	$ 53

(b) Lower 48 includes $267 million cash for the acquisition by Pure of certain assets from International Paper Company.

(c) Lower 48 includes $173 million of cash, $87 million of net debt, $31 million of hedge liabilities and $11 million of other net liabilities assumed for the acquisition by Pure of the common stock of Hallwood Energy Corporation.

(d) Canada includes $93 million cash, $20 million of net debt and $4 million of other net liabilities for the acquisition of the common stock of Tethys Energy Inc.

(e) Represents Unocal's proportional shares of costs incurred by investees accounted for by the equity method.

(f) Lower 48 includes $244 million for the acquisition by Pure of the common stock of Titan Exploration, Inc.

(g) Canada includes $161 million of cash, $82 million of net debt and $65 million of hedge liabilities for the remaining interest in Northrock Resources Ltd.

(h) Canada includes $205 million of common stock and $69 million of net debt for the acquisition of a 48 percent interest in Northrock Resources Ltd.

</FN>

Average Prices and Production Costs per Unit (Unaudited)

The average sales price is based on sales revenues and volumes attributable to net working interest production. Where intersegment sales occur, intersegment sales prices approximate market prices. The average production costs are stated on a BOE basis, which includes natural gas that is converted at a ratio of 6.0 Mcf to one barrel of oil equivalent (this ratio represents the approximate energy content of the gas).

	North America			International		
	Lower 48	Alaska	Canada	Far East	Other	Total
2001 Average prices: (a)(b)						
Liquids - per barrel	$23.28	$20.74	$18.53	$22.50	$24.15	$22.31
Natural gas - per mcf	4.22	1.37	3.17	2.52	2.75	3.25
Average production costs per BOE	3.83	5.55	4.46	2.26	4.09	3.44
2000 Average prices: (a)(b)						
Liquids - per barrel	$27.20	$24.93	$22.46	$26.17	$27.84	$26.10
Natural gas - per mcf	3.93	1.20	2.30	2.46	2.81	2.96
Average production costs per BOE	3.31	4.65	4.21	2.30	4.50	3.19
1999 Average prices: (a)(b)						
Liquids - per barrel	$ 15.22	$13.07	$13.88	$15.42	$16.80	$15.02
Natural gas - per mcf	2.17	1.20	2.31	2.03	2.19	2.04
Average production costs per BOE	2.73	3.87	3.88	2.03	4.00	2.72

<FN>

(a) Average prices include hedging gains and losses but exclude gains or losses on derivative positions not accounted for as hedges, the ineffective portion of hedges and other Trade margins.

(b) Hedging gains (losses) included in average prices:

	Lower 48	Alaska	Canada	Far East	Other	Total
2001						
Liquids - per barrel	$ 0.06	$ -	$ -	$ -	$ -	$ 0.02
Natural gas - per mcf	0.09	-	(1.17)	-	-	(0.02)
2000						
Liquids - per barrel	$ 0.04	$ -	$(1.85)	$ -	$ -	$(0.18)
Natural gas - per mcf	0.02	-	(1.15)	-	-	(0.06)
1999						
Liquids - per barrel	$(0.51)	$ -	$(2.02)	$ -	$ -	$(0.31)
Natural gas - per mcf	(0.05)	-	(0.23)	-	-	(0.03)

</FN>

Oil and Gas Reserve Data (Unaudited)

Proved oil and gas reserves are estimated by the Company in accordance with the Securities and Exchange Commission's definitions in Rule 4-10 of Regulation S-X. These definitions can be found on the SEC website at http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Estimates of physical quantities of proved oil and gas reserves, determined by Company engineers, for the years 2001, 2000, and 1999 are presented on pages 129 through 130. These estimates do not include probable or possible reserves. Estimated oil and gas reserves are based on available reservoir data and are subject to future revision. Significant portions of the Company's proved undeveloped reserves, principally in offshore areas, require the installation or completion of related infrastructure facilities such as platforms, pipelines, and the drilling of development wells. Proved reserve quantities exclude royalty and other interests owned by others, as well as volumes received by Company owned gas plants in lieu of processing fees. Effective in 2001, the Company began reporting all reserves held under PSCs in Indonesia and a concession in the Democratic Republic of Congo utilizing the "economic interest" method, which excludes host country shares. The Company was already reporting its shares of reserves in Bangladesh, Myanmar and Azerbaijan utilizing the "economic interest" method. Estimated quantities for PSCs reported under the "economic interest" method are subject to fluctuations in the prices of oil and gas and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. This change would be partially offset by a change in the Company's net equity share. The reserve quantities also include barrels of oil that the Company is contractually obligated to sell in Indonesia at prices substantially below market.

Beginning in 2001, the Company also began reporting natural gas reserves on a dry basis, with natural gas liquids included with crude oil and condensate reserves. The reserve data in the tables on the following pages reflect these adjustments. For informational purposes, natural gas liquids reserves are estimated to be 32 million, 31 million, and 32 million barrels at December 31, 2001, 2000, and 1999, respectively. Of the aforementioned totals, 10 million, 12 million, and 14 million barrels, for the respective periods, are located in the United States.

Estimated Proved Reserves of Crude Oil, Condensate and Natural Gas Liquids (a)

Millions of barrels	Consolidated Subsidiaries						Equity	
	North America			International				
	Lower 48 (b)	Alaska	Canada (b)	Far East (c)	Other (c)	Total (b) (c)	Investees (d)	Worldwide (b) (c)
As of December 31, 1998	134	60	19	149	135	497	2	499
Revisions of estimates	7	9	3	9	-	28	-	28
Improved recovery	-	-	-	2	-	2	-	2
Discoveries and extensions	7	3	4	16	-	30	-	30
Purchases (e)	1	-	34	-	1	36	2	38
Sales (e)	(6)	-	-	-	(8)	(14)	-	(14)
Production	(16)	(10)	(5)	(21)	(8)	(60)	-	(60)
As of December 31, 1999	127	62	55	155	120	519	4	523
Revisions of estimates	(4)	16	(5)	(2)	(18)	(13)	1	(12)
Improved recovery	-	1	-	1	-	2	-	2
Discoveries and extensions	7	3	4	25	18	57	-	57
Purchases (e)	37	-	1	26	2	66	2	68
Sales (e)	(5)	-	(2)	-	-	(7)	-	(7)
Production	(17)	(10)	(6)	(19)	(6)	(58)	(1)	(59)
As of December 31, 2000	145	72	47	186	116	566	6	572
Revisions of estimates	(18)	(3)	(3)	24	14	14	-	14
Improved recovery	-	3	-	-	-	3	-	3
Discoveries and extensions	28	11	7	16	72	134	-	134
Purchases (e)	21	-	6	-	-	27	4	31
Sales (e)	-	-	-	-	-	-	-	-
Production	(20)	(9)	(6)	(18)	(7)	(60)	(1)	(61)
As of December 31, 2001	156	74	51	208	195	684	9	693
Proved Developed Reserves at:								
December 31, 1998	102	46	17	62	35	262	2	264
December 31, 1999	105	50	51	59	37	302	3	305
December 31, 2000	113	55	43	54	40	305	5	310
December 31, 2001	109	57	46	54	41	307	8	315

<FN>

(a) Includes natural gas liquids previously included in natural gas quantities. Previous years' quantities have been restated to conform to the 2001 presentation.

(b) Includes reserves attributable to minority interests in consolidated subsidiaries:

	Lower 48	Alaska	Canada	Far East	Other	Total	Investees	Worldwide
December 31, 1999:	7	-	18	-	-	25	-	25
December 31, 2000:	27	-	-	-	-	27	-	27
December 31, 2001:	32	-	-	-	-	32	-	32

(c) Quantities are calculated utilizing the economic interest method on all production sharing contracts, which excludes host countries' shares. Previous years' quantities have been adjusted to conform to the 2001 presentation.

(d) Represents proportional shares of reserves of investees accounted for by the equity method.

(e) Purchases and sales include reserves acquired and relinquished through property exchanges.

</FN>

Estimated Proved Reserves of Natural Gas (a)

	Consolidated Subsidiaries						Equity	
	North America			International				
Billions of cubic feet	Lower 48 (b)	Alaska	Canada (b)	Far East (c)	Other (c)	Total (b) (c)	Investees (d)	Worldwide (b) (c)
As of December 31, 1998	1,511	372	11	3,544	216	5,654	21	5,675
Revisions of estimates	4	(21)	–	(5)	(24)	(46)	3	(43)
Improved recovery	21	–	1	26	2	50	–	50
Discoveries and extensions	160	1	36	440	4	641	1	642
Purchases (e)	17	–	333	–	150	500	80	580
Sales (e)	(113)	–	–	–	–	(113)	–	(113)
Production	(264)	(58)	(25)	(300)	(17)	(664)	(9)	(673)
As of December 31, 1999	1,336	294	356	3,705	331	6,022	96	6,118
Revisions of estimates	37	(11)	(55)	(263)	18	(274)	23	(251)
Improved recovery	10	1	–	25	1	37	–	37
Discoveries and extensions	173	1	31	360	–	565	4	569
Purchases (e)	298	–	13	24	–	335	14	349
Sales (e)	(44)	–	(26)	–	–	(70)	(4)	(74)
Production	(268)	(58)	(39)	(308)	(22)	(695)	(14)	(709)
As of December 31, 2000	1,542	227	280	3,543	328	5,920	119	6,039
Revisions of estimates	(101)	(12)	(16)	373	44	288	36	324
Improved recovery	–	1	–	31	–	32	–	32
Discoveries and extensions	322	43	33	257	–	655	18	673
Purchases (e)	383	–	32	–	–	415	77	492
Sales (e)	(25)	–	–	–	–	(25)	–	(25)
Production	(324)	(47)	(40)	(331)	(26)	(768)	(18)	(786)
As of December 31, 2001	1,797	212	289	3,873	346	6,517	232	6,749
Proved Developed Reserves at:								
December 31, 1998	1,172	210	11	2,092	141	3,626	16	3,642
December 31, 1999	1,130	184	298	1,819	222	3,653	91	3,744
December 31, 2000	1,280	154	223	1,509	202	3,368	110	3,478
December 31, 2001	1,440	149	218	1,547	208	3,562	181	3,743

<FN>

(a) Excludes natural gas liquids previously included in natural gas quantities. Previous years' quantities have been restated to conform to the 2001 presentation.

(b) Includes reserves attributable to minority interests in consolidated subsidiaries:

December 31, 1999:	100	–	176	–	–	276	–	276
December 31, 2000:	253	–	–	–	–	253	–	253
December 31, 2001:	397	–	–	–	–	397	–	397

(c) Quantities are calculated utilizing the economic interest method on all production sharing contracts, which excludes host countries' shares. Previous years' quantities have been adjusted to conform to the 2001 presentation.

(d) Represents proportional shares of reserves of investees accounted for by the equity method.

(e) Purchases and sales include reserves acquired and relinquished through property exchanges.

</FN>

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The standardized measure of discounted future net cash flows from proved oil and gas reserves for the years 2001, 2000, and 1999 are presented on page 132. Revenues are based on estimated production of proved reserves from existing and planned facilities and on prices of oil and gas at year-end 2001. Development and production costs related to future production are based on year-end cost levels and assume continuation of existing economic conditions. Income tax expense is computed by applying the appropriate year-end statutory tax rates to pre-tax future cash flows less recovery of the tax basis of proved properties and reduced by applicable tax credits.

The following data on the standardized measure of discounted future net cash flows from existing proved oil and gas reserves are calculated in the manner mandated by the FASB and SEC and are based on many subjective judgments and assumptions. Estimates of physical quantities of oil and gas reserves, future rates of production and the timing of such production, future production and development costs and the timing of said expenditures are subject to extensive revisions and a high degree of variability as a result of operating, political and general business risks. Different, but equally valid, assumptions and judgments could lead to significantly different results.

As set forth in note (a) to the table on page 132, the year-end prices required to be used in the calculations are highly volatile and were either at or near, in the case of Lower 48 and Canada natural gas prices, historically high levels at the end of 2000. Subsequent price decreases in 2001 had a significant adverse impact on the calculated present value of proved oil and gas reserves as of December 31, 2001. See "Summary of Changes in the Standardized Measure of Discounted Net Cash Flows" table on page 133 for the aggregate changes and significant components of such changes for the last three calendar years.

Probable and possible reserves and the value of exploratory acreage that may be developed in the future have not been included in the calculation of the data presented on pages 132 and 133. Likewise, future realized prices are expected to vary significantly from the mandated year-end prices utilized in the determination of the revenues included in the calculations. While the Company has exercised due care in the preparation of the data, it does not warrant that this data represent the fair market value of the Company's oil and gas properties or an estimate of the discounted present value of cash flows to be obtained from their development and production.

Standardized Measure of Discounted Future Net Cash Flows

	North America			International		
Millions of dollars	Lower 48	Alaska	Canada	Far East	Other	Total
2001						
Revenues (a)	$ 7,089	$ 1,152	$ 1,779	$ 11,507	$ 4,277	$ 25,804
Production costs	2,421	856	455	3,078	844	7,654
Development costs (b)	979	217	64	2,674	1,108	5,042
Income tax expense	780	20	363	2,084	559	3,806
Future net cash flows	2,909	59	897	3,671	1,766	9,302
10% annual discount	1,025	(8)	381	1,577	1,051	4,026
Present values of future net cash flows	1,884	67	516	2,094	715	5,276
Company's share of present values of future net cash flows of equity investees (c)	110	1	-	277	-	388
Total (d)	$ 1,994	$ 68	$ 516	$ 2,371	$ 715	$ 5,664
2000						
Revenues (a)	$ 18,926	$ 1,425	$ 3,838	$ 12,965	$ 3,467	$ 40,621
Production costs	2,795	826	512	2,454	624	7,211
Development costs (b)	750	221	79	2,607	624	4,281
Income tax expense	5,210	116	1,275	3,225	652	10,478
Future net cash flows	10,171	262	1,972	4,679	1,567	18,651
10% annual discount	3,416	55	913	1,994	839	7,217
Present values of future net cash flows	6,755	207	1,059	2,685	728	11,434
Company's share of present values of future net cash flows of equity investees (c)	382	-	-	300	-	682
Total (e)	$ 7,137	$ 207	$ 1,059	$ 2,985	$ 728	$ 12,116
1999						
Revenues (a)	$ 5,755	$ 1,496	$ 1,969	$ 12,172	$ 3,210	$ 24,602
Production costs	1,706	639	559	2,937	766	6,607
Development costs (b)	724	202	64	2,159	560	3,709
Income tax expense	1,044	211	469	2,754	430	4,908
Future net cash flows	2,281	444	877	4,322	1,454	9,378
10% annual discount	677	102	378	1,819	786	3,762
Present values of future net cash flows	1,604	342	499	2,503	668	5,616
Company's share of present values of future net cash flows of equity investees (c)	72	-	-	287	-	359
Total (f)	$ 1,676	$ 342	$ 499	$ 2,790	$ 668	$ 5,975

<FN>

(a) Weighted-average prices, based on year-end prices, were as follows:

		Lower 48	Alaska	Canada	Far East	Other
Crude oil, condensate and NGLs, per barrel						
	2001	$ 17.58	$ 13.06	$ 18.02	$ 17.12	$ 17.76
	2000	$ 25.28	$ 17.45	$ 20.09	$ 22.66	$ 23.27
	1999	$ 23.72	$ 19.85	$ 20.30	$ 22.83	$ 21.22
Natural gas, per mcf						
	2001	$ 2.46	$ 1.61	$ 2.99	$ 2.33	$ 1.93
	2000	$ 10.02	$ 1.20	$ 10.50	$ 2.75	$ 2.49
	1999	$ 2.23	$ 1.20	$ 1.85	$ 2.71	$ 2.48

(b) Includes dismantlement and abandonment costs.

(c) Represents proportional shares of investees accounted for under the equity method.

(d) Included in Lower 48 is the present value of Spirit Energy 76 Development, L. P., a consolidated subsidiary, in which there is a minority interest share representing approximately $95 million and the present value of Pure Resources, Inc., in which there is a minority interest share representing approximately $306 million.

(e) Included in Lower 48 is the present value of Spirit Energy 76 Development, L. P., a consolidated subsidiary, in which there is a minority interest share representing approximately $98 million and the present value of Pure Resources, Inc., in which there is a minority interest share representing approximately $656 million.

(f) Included in Lower 48 is the present value of Spirit Energy 76 Development, L. P., a consolidated subsidiary, in which there is a minority interest share representing approximately $112 million. Included in Canada is the present value of Northrock Resources, Ltd., a consolidated subsidiary, in which there is a minority interest share representing approximately $211 million.

</FN>

Changes in Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

Millions of dollars	2001	2000	1999
Present value at beginning of year	$ 12,116	$ 5,975	$ 2,576
Discoveries and extensions, net of estimated future costs	1,260	2,333	1,011
Net purchases and sales of proved reserves (a)	1,198	1,354	546
Revisions to prior estimates:			
Prices net of estimated changes in production costs	(10,693)	9,196	5,130
Future development costs	(879)	(820)	(555)
Quantity estimates	392	(232)	145
Production schedules and other	(399)	(595)	(1)
Accretion of discount	1,433	724	294
Development costs related to beginning of year reserves	911	696	584
Sales of oil and gas net of production costs of: ($656 million in 2001, $536 million in 2000 and $450 million in 1999)	(3,073)	(2,949)	(1,689)
Net change in income taxes	3,398	(3,566)	(2,066)
Present value at end of year	$ 5,664	$ 12,116	$ 5,975

<FN>

(a) Reserves purchased were valued at $1,361 million, $1,512 million, and $644 million in 2001, 2000, and 1999, respectively. Reserves sold were valued at $163 million, $158 million, and $98 million for the same years, respectively.

</FN>

SELECTED FINANCIAL DATA (Unaudited)

Millions of dollars except as indicated	2001	2000	1999	1998	1997
Revenue Data					
Sales					
Crude oil, condensate and natural gas liquids	$ 3,053	$ 5,872	$ 3,584	$ 2,274	$ 2,812
Natural gas	3,024	2,511	1,646	1,823	1,857
Geothermal steam	160	161	153	166	119
Petroleum products	203	286	209	32	13
Minerals	28	29	35	67	106
Other	68	137	124	142	319
Total sales revenues	6,536	8,996	5,751	4,504	5,226
Operating revenues	128	(55)	91	123	116
Other revenues (a)	88	261	119	380	129
Total revenues from continuing operations	$ 6,752	$ 9,202	$ 5,961	$ 5,007	$ 5,471
Earnings Data					
Earnings from continuing operations	$ 599	$ 723	$ 113	$ 93	$ 615
Earnings from discontinued operations (net of tax)	17	37	24	37	4
Extraordinary item - early extinguishment of debt (net of tax)	-	-	-	-	(38)
Cumulative effect of accounting change (net of tax)	(1)	-	-	-	-
Net earnings	$ 615	$ 760	$ 137	$ 130	$ 581
Basic earnings (loss) per share of common stock:					
Continuing operations	$ 2.45	$ 2.98	$ 0.47	$ 0.39	$ 2.47
Discontinued operations	0.07	0.15	0.10	0.15	0.02
Extraordinary item	-	-	-	-	(0.15)
Net earnings per share of common stock	$ 2.52	$ 3.13	$ 0.57	$ 0.54	$ 2.34
Share Data					
Cash dividends declared on common stock	$ 195	$ 194	$ 194	$ 192	$ 199
Per share	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80
Number of common stockholders of record at year end	23,213	24,910	27,026	29,567	31,919
Weighted average common shares - thousands	243,568	242,863	242,167	241,332	248,190

<FN>
(a) All years have been reclassified to exclude earnings from equity investments from revenues.
</FN>

SELECTED FINANCIAL DATA (Continued)

Millions of dollars except as indicated	2001	2000	1999	1998	1997
Balance Sheet Data					
Current assets (c)	$ 1,295	$ 1,802	$ 1,631	$ 1,388	$ 1,501
Current liabilities (d)	1,422	1,845	1,559	1,376	1,160
Working capital (c)	(127)	(43)	72	12	341
Ratio of current assets to current liabilities (c)	0.9:1	1.0:1	1.0:1	1.0:1	1.3:1
Total assets	10,425	10,010	8,967	7,952	7,530
Total debt and capital leases	2,906	2,506	2,854	2,558	2,170
Trust convertible preferred securities	522	522	522	522	522
Total stockholders' equity	3,124	2,719	2,184	2,202	2,314
Stockholders' equity - per common share	12.80	11.19	9.01	9.13	9.32
Return on average stockholders' equity:					
Continuing operations	20.5%	29.5%	5.2%	4.1%	26.8%
Net Earnings	21.1%	31.0%	6.2%	5.8%	25.3%
General Data					
Salaries, wages and employee benefits (e)	$ 548	$ 546	$ 578	$ 596	$ 640
Number of regular employees at year-end	6,980	6,800	7,550	7,880	8,394

<FN>

(c) In 2001 lower current assets and negative working capital amounts reflect major acquisitions funded from cash on hand.

(d) 2001 through 1998 includes liabilities associated with pre-paid commodity sales.

(e) Employee benefits are net of pension income recognized in accordance with current accounting standards for pension costs.

</FN>

OPERATING SUMMARY (Unaudited)

	2001(a)	2000(a)	1999	1998	1997
Exploration &Production					
Net exploratory wells completed:					
Oil	56	15	31	19	10
Gas	58	53	32	24	15
Net development wells completed:					
Oil	152	102	81	113	118
Gas	73	142	93	105	118
Net dry holes:					
Exploratory	35	46	28	34	29
Development	6	9	9	10	7
Total net wells	380	367	274	305	297
Net producible wells at year end (b)	5,843	4,638	3,511	3,193	3,884
Net undeveloped acreage at year end - thousands of acres:					
North America					
Lower 48	5,849	2,199	1,743	1,664	1,257
Alaska	232	221	186	215	174
Canada	1,399	1,285	1,440	39	747
International					
Far East	11,095	14,505	20,677	20,167	14,688
Other	5,119	6,172	5,043	4,975	3,573
Total	23,694	24,382	29,089	27,060	20,439
Net proved reserves at year end (c)(d):					
Crude oil, condensate and natural gas liquids - million barrels (e)					
North America					
Lower 48	156	145	127	134	142
Alaska	74	72	62	60	81
Canada	51	47	55	19	35
International					
Far East	208	186	155	149	111
Other	195	116	120	135	125
Equity investees	9	6	4	2	-
Total	693	572	523	499	494
Natural gas - billion cubic feet (f)					
North America					
Lower 48	1,797	1,542	1,336	1,511	1,641
Alaska	212	227	294	372	442
Canada	289	280	356	11	104
International					
Far East	3,873	3,543	3,705	3,544	3,722
Other	346	328	331	216	137
Equity investees	232	119	96	21	-
Total	6,749	6,039	6,118	5,675	6,046

<FN>

(a) Reflects the acquisition of Titan Exploration, Inc. by Pure Resources, Inc. in Lower 48 in 2000 and the acquisitions by Pure of International Paper Company assets and the Hallwood Energy Corporation acquisition in 2001.

(b) Producible wells exclude suspended wells not expected to be producing within a year and wells awaiting abandonment.

(c) All years have been reclassified to exclude host countries' shares under certain production sharing contracts.

(d) Includes 100% of consolidated subsidiaries.

(e) Includes natural gas liquids previously included in natural gas quantities. Prior years have been conformed to 2001 basis.

(f) Excludes natural gas liquids previously included in natural gas quantities. Prior years have been conformed to 2001 basis.

</FN>

	2001	2000	1999	1998	1997
Exploration &Production (continued)					
Net daily production (a) (b):					
Crude oil, condensate and natural gas liquids - thousand barrels					
North America					
Lower 48	59	52	50	54	53
Alaska	25	26	28	30	32
Canada	16	17	13	11	14
International					
Far East	51	47	54	75	72
Other	19	18	23	19	12
Total	170	160	168	189	183
Natural gas - million cubic feet					
North America					
Lower 48	905	764	706	762	813
Alaska	103	125	130	129	128
Canada	101	98	70	24	36
International					
Far East	829	799	759	798	760
Other	65	57	39	21	25
Total	2,003	1,843	1,704	1,734	1,762
Geothermal Operations					
Net wells completed:					
Exploratory	-	-	-	3	3
Development	-	-	-	8	7
Total	-	-	-	11	10
Net producible wells at year end	84	83	79	287	241
Net undeveloped acreage at year end - thousands of acres	314	314	314	338	384
Net proved reserves at year end: (c)					
Billion kilowatt-hours	108	114	120	157	149
Million equivalent oil barrels	162	170	179	235	223
Net daily production:					
Million kilowatt-hours	14	16	17	21	18
Thousand equivalent oil barrels	22	25	25	32	27

<FN>
(a) Includes the company's proportional shares of equity investees, 100% of consolidated subsidiaries.
(b) Natural gas is reported on a dry basis; production excludes gas consumed on lease.
(c) Includes reserves underlying a service fee arrangement in the Philippines.
</FN>

ITEM 9 - CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE: None

PART III

The information required by Items 10 through 13 (except for information regarding the Company's executive officers) is incorporated by reference to Unocal's Proxy Statement for its 2002 Annual Meeting of Stockholders (the "2002 Proxy Statement") (File No. 1-8483), as indicated below. The 2002 Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about April 8, 2002.

ITEM 10 - DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

See the information regarding Unocal's directors and nominees for election as directors to appear in the 2002 Proxy Statement under the captions "Election of Directors" and "Board Committee Meetings and Functions". Also, see the list of Unocal's executive officers and related information under the caption "Executive Officers of the Registrant" in Part I of this report.

See the information to appear in the 2002 Proxy Statement under the caption "Section 16(a) Beneficial Ownership Reporting Compliance".

ITEM 11 - EXECUTIVE COMPENSATION.

See the information regarding executive compensation to appear in the 2002 Proxy Statement under the captions "Summary Compensation Table," "Option/SAR Grants in 2001," "Aggregated Option/SAR Exercises in 2001 and December 31, 2001 Option/SAR Values," "Long-Term Incentive Plans - Awards in 2001," "Pension Plan Table," "Employment Contracts, Termination of Employment and Change of Control Arrangements" and the information regarding directors' compensation to appear in the 2002 Proxy Statement under the caption "Directors' Compensation."

ITEM 12 - SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

See the information regarding security ownership to appear in the 2002 Proxy Statement under the captions "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Management."

ITEM 13 - CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

See the information regarding certain loans to executive officers to appear in the 2002 Proxy Statement under the caption "Indebtedness of Management."

PART IV

ITEM 14 - EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) Financial statements, financial statement schedules and exhibits filed as part of this annual report:

(1) Financial Statements: See the "Index to Consolidated Financial Statements and Financial Statement Schedule" under Item 8 of this report.

(2) Financial Statement Schedule: See the "Index to Consolidated Financial Statements and Financial Statement Schedule" under Item 8 of this report.

(3) Exhibits: The Exhibit Index on pages 142 through 144 of this report lists the exhibits that are filed as part of this report and identifies each management contract and compensatory plan or arrangement required to be filed.

(b) Reports filed on Form 8-K:

(1) Current Report on Form 8-K, dated October 24, 2001 and filed October 30, 2001, for the purpose of reporting, under Item 5, the Company's third quarter 2001 earnings and related information and the Company's 2001 full year earnings and production forecast.

During the first quarter of 2002 to the date hereof:

(1) Current Report on Form 8-K, dated and filed January 24, 2002, for the purpose of reporting, under Item 5, the Company's fourth quarter 2001 impairment charge and other special items.

(2) Current Report on Form 8-K, dated January 22, 2002 and filed January 31, 2002, for the purpose of reporting, under Item 5, the Company's fourth quarter 2001 earnings and related information, the Company's 2001 reserve replacement and finding development and acquisitions results, the Company's 2002 earnings forecast and other operational activity updates.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this amendment to the report to be signed on its behalf by the undersigned, thereunto duly authorized.

UNOCAL CORPORATION
(Registrant)

Dated: September 23, 2002

By: /s/ TERRY G. DALLAS

Terry G. Dallas
Executive Vice President
and Chief Financial Officer

CERTIFICATIONS

I, Charles R. Williamson, certify that:

1. I have reviewed this annual report on Form 10-K of Unocal Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report.

Dated: September 23, 2002

/s/CHARLES R. WILLIAMSON

Charles R. Williamson
Chairman of the Board
and Chief Executive Officer

I, Terry G. Dallas, certify that:

1. I have reviewed this annual report on Form 10-K of Unocal Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report.

Dated: September 23, 2002

/s/TERRY G. DALLAS

Terry G. Dallas
Executive Vice President
and Chief Financial Officer

UNOCAL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
(Millions of dollars)

		Additions			
Description	Balance at beginning of period	Charged or (credited) to costs & expenses	Charged or (credited) to other accounts	Deductions from reserves (a)	Balance at end of period
YEAR 2001					
Amounts deducted from applicable assets:					
Accounts and notes receivable	$ 97	$ 47	$ 3	$ (1)	$ 146
Investments and long-term receivables	$ 80	$ 90	$ 5	$ (4)	$ 171
YEAR 2000					
Amounts deducted from applicable assets:					
Accounts and notes receivable	$ 71	$ 30	$ -	$ (4)	$ 97
Investments and long-term receivables	$ 81	$ 31	$ (32)	$ -	$ 80
YEAR 1999					
Amounts deducted from applicable assets:					
Accounts and notes receivable	$ 78	$ 29	$ (32)	$ (4)	$ 71
Investments and long-term receivables	$ 34	$ 15	$ 32	$ -	$ 81

<FN>
(a) Represents receivables written off, net of recoveries, reinstatement and losses sustained.
</FN>

UNOCAL CORPORATION

EXHIBIT INDEX

Exhibit 3.1*	Restated Certificate of Incorporation of Unocal, dated as of January 31, 2000, and currently in effect (incorporated by reference to Exhibit 3.1 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-8483).
Exhibit 3.2*	Bylaws of Unocal, as amended through October 31, 2001, and currently in effect (incorporated by reference to Exhibit 3 to Unocal's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 1-8483).
Exhibit 4.1*	Standard Multiple-Series Indenture Provisions, January 1991, dated as of January 2, 1991 (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3 of Union Oil Company of California and Unocal (File Nos. 33-38505 and 33-38505-01)).
Exhibit 4.2*	Form of Indenture, dated as of January 30, 1991, among Union Oil Company of California, Unocal and The Bank of New York (incorporated by reference to Exhibit 4.2 to the Registration Statement on Form S-3 of Union Oil Company of California and Unocal (File Nos. 33-38505 and 33-38505-01)).
Exhibit 4.3*	Form of Indenture, dated as of February 3, 1995, among Union Oil Company of California, Unocal and Chase Manhattan Bank and Trust Company, National Association, as successor Trustee (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-3 of Union Oil Company of California and Unocal (File Nos. 33-54861 and 33-54861-01).
	Other instruments defining the rights of holders of long term debt of Unocal and its subsidiaries are not being filed since the total amount of securities authorized under each of such instruments does not exceed 10 percent of the total assets of Unocal and its subsidiaries on a consolidated basis. Unocal agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon request.
Exhibit 10.1*	Rights Agreement, dated as of January 5, 2000, between Unocal and Mellon Investor Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4 to Unocal's Current Report on Form 8-K dated January 5, 2000, File No. 1-8483).

The following Exhibits 10.2 through 10.36 are management contracts or compensatory plans, contracts or arrangements as required by Item 14 (c) of Form 10-K and Item 601 (b) (10) (iii) (A) of Regulation S-K.

Exhibit 10.2*	1991 Management Incentive Program (incorporated by reference to Exhibit A to Unocal's Proxy Statement dated March 18, 1991, for its 1991 Annual Meeting of Stockholders, File No. 1-8483).
Exhibit 10.3*	Unocal Revised Incentive Compensation Plan Cash Deferral Program (incorporated by reference to Exhibit 10.3 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1996, File No. 1-8483).
Exhibit 10.4*	Amendments to 1991 Incentive Plan Awards (incorporated by reference to Exhibit 10 to Unocal's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 1-8483).
Exhibit 10.5*	1998 Management Incentive Program, as amended, consisting of the Revised Incentive Compensation Plan, the Long-Term Incentive Plan of 1998 and the 1998 Performance Stock Option Plan, (incorporated by reference to Exhibit B to Unocal's Proxy Statement dated April 12, 2000, for its 2000 Annual Meeting of Stockholders, File No. 1-8483).
Exhibit 10.6*	Amendment to the Revised Incentive Compensation Plan, effective December 5, 2000 (incorporated by reference to Exhibit 10.1 to Unocal's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 1-8483).
Exhibit 10.7*	Amendment to the Long-Term Incentive Plan of 1998, as amended, adopted July 27, 2001, subject to stockholder approval at Unocal's May 20, 2002, Annual Meeting of Stockholders (incorporated by reference to Exhibit 10.2 to

	Unocal's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001, File No. 1-8483).
Exhibit 10.8*	Amendments to the 1998 Management Incentive Program, as amended, adopted February 12, 2002, partially subject to stockholder approval at Unocal's May 20, 2002, Annual Meeting of Stockholders.

Exhibit 10.9*	Unocal Deferred Compensation Plan, effective September 24, 2001 (incorporated by reference to Exhibit 4 to Unocal's Registration Statement on Form S-8, File No. 333-73540).
Exhibit 10.10*	Form of Nonqualified Stock Option Grant under the Long-Term Incentive Plan of 1998, effective July 27, 2001, subject to stockholder approval, between Unocal and each of Charles R. Williamson (as to 450,000 shares Unocal Common Stock), Timothy H. Ling (as to 240,000 shares of Unocal Common Stock) and Dennis P.R. Codon (as to 150,000 shares of Unocal Common Stock), each with an exercise price of $35.355 per share (incorporated by reference to Exhibit 10.3 to Unocal's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001, File No. 1-8483).
Exhibit 10.11*	Form of Nonqualified Stock Option Grant under the Long-Term Incentive Plan of 1998, effective August 20, 2001, subject to stockholder approval, between Unocal and Terry G. Dallas as to 240,000 shares of Unocal Common Stock with an exercise price of $36.22 (incorporated by reference to Exhibit 10.2 to Unocal's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 1-8483).
Exhibit 10.12*	2000 Executive Stock Purchase Program (incorporated by reference to Exhibit 10.1 to Unocal's Current Report on Form 8-K dated March 16, 2000, File No. 1-8483).
Exhibit 10.13*	Amendment to the 2000 Executive Stock Purchase Program, effective February 12, 2002.
Exhibit 10.14*	Award Agreement (Loan Agreement), together with related promissory note, both dated March 16, 2000, between Unocal and Charles R. Williamson (incorporated by reference to Exhibit 10.4 to Unocal's Current Report on Form 8-K dated March 16, 2000, File No. 1-8483).
Exhibit 10.15*	Award Agreement (Loan Agreement), together with related promissory note, both dated March 16, 2000, between Unocal and Timothy H. Ling (incorporated by reference to Exhibit 10.3 to Unocal's Current Report on Form 8-K dated March 16, 2000, File No. 1-8483).
Exhibit 10.16*	Award Agreement (Loan Agreement), together with related promissory note, both dated March 16, 2000, between Unocal and Dennis P. R. Codon (incorporated by reference to Exhibit 10.5 to Unocal's Current Report on Form 8-K dated March 16, 2000, File No. 1-8483).
Exhibit 10.17*	Unocal Nonqualified Retirement Plan "A", as amended December 5, 2000 (incorporated by reference to Exhibit 10.12 to Unocal's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-8483).
Exhibit 10.18*	Unocal Nonqualified Retirement Plan "B", as amended December 5, 2000 (incorporated by reference to Exhibit 10.13 to Unocal's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-8483).
Exhibit 10.19*	Unocal Nonqualified Retirement Plan "C", adopted December 5, 2000 (incorporated by reference to Exhibit 10.14 to Unocal's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-8483).
Exhibit 10.20*	Unocal Supplemental Savings Plan, as amended December 5, 2000 (incorporated by reference to Exhibit 10.15 to Unocal's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-8483).
Exhibit 10.21*	Amendments to the plans filed as the preceeding four exhibits, effective January 1 and September 1, 2001.
Exhibit 10.22*	Summary of Enhanced Severance Program, adopted December 5, 2000 (incorporated by reference to Item 5--Other Events of Unocal's Current Report on Form 8-K dated December 5, 2000, File No. 1-8483).
Exhibit 10.23*	Other Compensatory Arrangements (incorporated by reference to Exhibit 10.4 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 1-8483).
Exhibit 10.24*	Directors' Restricted Stock Plan of 1991 (incorporated by reference to Exhibit B to Unocal's Proxy Statement dated March 18, 1991, for its 1991 Annual Meeting of Stockholders, File No. 1-8483).
Exhibit 10.25*	Amendments to the Directors Restricted Stock Plan, effective February 8, 1996 (incorporated by reference to Exhibit 10.7 to Unocal's Annual Report on Form 10-K for the

	year ended December 31, 1995, File No. 1-8483).
Exhibit 10.26*	Amendments to the Director's Restricted Stock Plan, effective June 1, 1998 (incorporated by reference to Exhibit 10.4 to Unocal's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, File No. 1-8483).

Exhibit 10.27*	2001 Directors' Deferred Compensation and Stock Award Plan (incorporated by reference to Exhibit B to Unocal's Proxy Statement dated April 9, 2001, for its 2001 Annual Meeting of Stockholders, File No. 1-8483).
Exhibit 10.28*	Form of Director Indemnity Agreement between Unocal and each of its directors (incorporated by reference to Exhibit 10.14 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1998, File No. 1-8483).
Exhibit 10.29*	Form of Director Insurance Agreement between Unocal and each of its directors (incorporated by reference to Exhibit 10.15 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1998, File No. 1-8483).
Exhibit 10.30*	Form of Officer Indemnity Agreement between Unocal and each of its officers (incorporated by reference to Exhibit 10.16 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1998, File No. 1-8483).
Exhibit 10.31*	Employment Agreement, effective as of March 27, 2000, by and between Unocal and Charles R. Williamson (incorporated by reference to Exhibit 10.6 to Unocal's Current Report on Form 8-K dated March 16, 2000, File No. 1-8483).
Exhibit 10.32*	Change in Control Agreement, effective as of July 28, 1998, by and between Unocal and Timothy H. Ling (incorporated by reference to Exhibit 10.21 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-8483).
Exhibit 10.33*	Amendment, dated February 28, 2000, to the agreement filed as the preceeding exhibit (incorporated by reference to Exhibit 10.22 to Unocal's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-8483).
Exhibit 10.34*	Employment Agreement, effective as of May 30, 2000, by and between Unocal and Terry G. Dallas (incorporated by reference to Exhibit 10.2 to Unocal's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 1-8483).
Exhibit 10.35*	Employment Agreement, effective as of July 28, 1998, by and between Unocal and Dennis P.R. Codon, (incorporated by reference to Exhibit 10.12 to Unocal's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, File No. 1-8483).
Exhibit 10.36*	Amendment, dated February 28, 2000, to the agreement filed as the preceeding exhibit (incorporated by reference to Exhibit 10.30 to Unocal's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-8483).
Exhibit 12.1*	Statement regarding computation of ratio of earnings to fixed charges of Unocal for the five years ended December 31, 2001.
Exhibit 12.2*	Statement regarding computation of ratio of earnings to combined fixed charges and preferred stock dividends of Unocal for the five years ended December 31, 2001.
Exhibit 12.3*	Statement regarding computation of ratio of earnings to fixed charges of Union Oil Company of California for the five years ended December 31, 2001.
Exhibit 21*	Subsidiaries of Unocal Corporation.
Exhibit 23**	Consent of PricewaterhouseCoopers LLP.
Exhibit 99.1*	Restated and Amended Articles of Incorporation of Union Oil Company of California, as amended through April 1, 1999, and currently in effect (incorporated by reference to Exhibit 99.1 to Unocal's Quarterly Report on Form 10-Q for the quarter ended March 31, 1999, File No. 1-8483).
Exhibit 99.2*	Bylaws of Union Oil Company of California, as amended through January 1, 2001, and currently in effect (incorporated by reference to Exhibit 99 to Unocal's Current Report on Form 8-K, dated December 8, 2000, File No. 1-8483).
Exhibit 99.3*	Summary of change-of-control provisions in certain compensation plans (incorporated by reference to Exhibit 99 to Unocal's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 1-8483).

* Previously filed.
** Filed herewith.

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

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EXHIBIT 23

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 33-63719 and 333-58415-01) of Unocal Corporation of our report dated February 14, 2002, relating to the consolidated financial statements and financial statement schedule, which appears in this Annual Report on Form 10-K/A (Amendment No. 2) for the year ended December 31, 2001.

/s/PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Los Angeles, California
September 23, 2002

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