UNOCAL CORP
Form 10-K
March 21, 2003

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

FORM 10-K

x	**Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
	For the fiscal year ended December 31, 2002
	or
o	**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	No
x	o

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. o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

Yes	No
x	o

The aggregate market value of the common stock held by non-affiliates of the registrant as of February 28, 2003 (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 $6.8 billion.

Shares of common stock outstanding as of February 28, 2003: 258,013,728

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive Proxy Statement for its 2003 Annual Meeting of Stockholders (to be filed with the Securities and Exchange Commission on or about April 7, 2003) 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
MM	Million
B	Billion
T	Trillion
CF	Cubic feet
BOE	Barrels of oil equivalent
Liquids	Crude oil, condensate and NGLs
Bbl/d	Barrels per day
Bbl	Barrels
Cf/d	Cubic feet per day
Cfe/d	Cubic feet of gas equivalent per day
Btu	British thermal units
DD&A	Depreciation, depletion and amortization
NGLs	Natural gas liquids

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 equivalent 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 equivalent).

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 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 market 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 when cooled or subjected to pressure it can be stored and transported as a liquid.

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 the proceeds from the sale 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, consortium, project or acreage.

PART I

ITEMS 1 AND 2 - BUSINESS AND PROPERTIES.

Unocal Corporation was incorporated in Delaware in 1983, to operate as the parent of Union Oil Company of California (Union Oil), which was incorporated in California in 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 and should be read in conjunction with Management s Discussion and Analysis of Financial Condition (MD&A) and Results of Operations in Item 7 of this report, including the discussion of risk factors and the Cautionary Statement.

The Company makes available free of charge, on or through its Internet website, its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. The Company s Internet address is http://www.unocal.com.

STRATEGIC FOCUS

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

Enhancing legacy asset production and profitability in:

North America
Gulf of Thailand
East Kalimantan Shelf Indonesia

Delivering major development and transportation projects on time and on budget for:

Azerbaijan International Operating Company (AIOC) Phase I
Baku-Tbilisi-Ceyhan (BTC) pipeline
West Seno Indonesia
Mad Dog U.S. Gulf of Mexico Deep Water
South Kenai Gas Alaska

Advancing next tier of development projects at:

Ranggas, Gendalo, Merah Besar, Sadewa Indonesia
Thailand Oil II and Arthit Thailand
AIOC Phase II Azerbaijan
K2, Mirage and Trident Gulf of Mexico Deep Water

Making new discoveries with high-impact exploration programs in:

Indonesia Deep Water
Gulf of Mexico Deep Shelf and Deep Water
U.S. Onshore Deep Gas

Continuing to progress long-term Asia gas position in:

Bangladesh
Thailand
Vietnam
China
Indonesia

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 business units in the U.S. Lower 48, Alaska and Canada and International operations in various countries around the world.

In 2002, the Company s worldwide average production was approximately 167 MBbl/d of liquids and 1,826 MMcf/d of natural gas, primarily from U.S. onshore and offshore in the U.S. Gulf of Mexico, in the Gulf of Thailand, and offshore East Kalimantan, Indonesia. Approximately 44 percent of the Company s worldwide production in 2002 and 33 percent of the Company s worldwide proved oil and gas reserves at year-end 2002 were in the U.S. Exploration and production net properties accounted for approximately 91 percent of Unocal s total net properties at December 31, 2002, of which approximately 52 percent was related to properties in the U.S.

The Company reports all reserve and production data pursuant to production sharing contracts utilizing the economic interest method, which excludes host country shares. The Company also reports natural gas reserves and production on a dry basis, with natural gas liquids included with crude oil and condensate volumes.

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 129 through 138 of this report. During 2002, certain estimates of the Company s U.S. underground oil and gas reserves as of December 31, 2001, 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, 2001, included in this report.

Net Proved Reserves

Estimated net quantities of the Company s proved liquids and natural gas reserves at December 31, 2002, 2001 and 2000, including its proportional shares of the reserves of equity investees, were as follows:

	2002	2001	2000
Liquids - million barrels			
North America			
U. S. Lower 48	161	156	145
Alaska	74	74	72
Canada	56	51	47
International			
Far East	200	208	186
Other	183	195	116
Equity investees	7	9	6
Worldwide	681	693	572
Natural gas - billion cubic feet			
North America			
U. S. Lower 48	1,713	1,797	1,542
Alaska	180	212	227
Canada	306	289	280
International			
Far East	3,787	3,873	3,543
Other	346	346	328
Equity investees	227	232	119
Worldwide	6,559	6,749	6,039
Worldwide - millions of barrels oil equivalent	1,774	1,818	1,579

The year-end 2002 proved reserves included reserves attributable to minority interests of approximately 2 million barrels of liquids and 29 billion cubic feet of natural gas in the U.S. Lower 48. The year-end 2001 proved reserves included reserves attributable to minority interests 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 reserves attributable to minority interests of approximately 27 million barrels of liquids and 253 billion cubic feet of natural gas in the U.S. Lower 48. The higher volumes attributable to minority interests in the U.S. Lower 48 for 2001 and 2000 primarily reflected the outside ownership in the Company s Pure Resources Inc. (Pure) subsidiary.

Declines in International liquids and natural gas reserves in 2002 reflect price-related reductions in PSC reserve volumes. Under PSC arrangements, net entitlement reserves to the Company decrease when oil and/or gas prices rise because fewer production units need to be sold to reimburse the Company for its costs.

For additional details, see the Oil and Gas Reserve Data in Item 8 of this report.

Net Daily Production

Net quantities of the Company s daily liquids and natural gas production for the years 2002, 2001 and 2000, including its proportional shares of production of equity investees, were as follows:

	2002	2001	2000
Liquids - thousand barrels per day			
North America			
U. S. Lower 48	52	59	52
Alaska	24	25	26
Canada	18	16	17
International			
Far East	53	51	47
Other	20	19	18
Worldwide	167	170	160
Natural gas dry basis - million cubic feet per day			
North America			
U. S. Lower 48	719	905	764
Alaska	76	103	125
Canada	91	101	98
International			
Far East	847	829	799
Other	93	65	57
Worldwide	1,826	2,003	1,843
Worldwide - thousands of barrels oil equivalent per day	471	504	468

Net daily production of liquids in the U.S. Lower 48 included volumes attributable to minority interests of approximately 7 MBbl/d, 9 MBbl/d and 7 MBbl/d for 2002, 2001 and 2000, respectively. Natural gas net daily production in the U.S. Lower 48 included volumes attributable to minority interests of approximately 82 MMcf/d, 102 MMcf/d and 69 MMcf/d for 2002, 2001 and 2000, respectively. The volumes attributable to minority interests in the U.S. Lower 48 primarily reflected the outside ownership in the Company s Pure subsidiary. Canada s net daily production of liquids included volumes attributable to minority interests of approximately 2 MBbl/d for 2000. Canada s net daily production of natural gas included volumes attributable to minority interests of approximately 15 MMcf/d for 2000. There were no volumes attributable to minority interests for Canada in 2002 or 2001.

Oil and Gas Acreage

As of December 31, 2002, 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				
U.S. Lower 48 (a)	2,177	1,031	9,749	5,692
Alaska	276	58	585	345
Canada	593	294	2,661	1,356
International				
Far East	886	504	24,749	12,013
Other	45	24	7,900	4,331
Worldwide	3,977	1,911	45,644	23,737
(a) Includes fee mineral lands of:	249	130	5,926	3,114

Producible Oil and Gas Wells

The numbers of oil and gas producible wells at December 31, 2002 were as follows:

	Oil		Gas	
	Gross	Net	Gross	Net
North America				
U.S. Lower 48	5,537	2,997	1,820	920
Alaska	722	148	33	24
Canada	1,556	787	616	287
International				
Far East	269	209	950	633
Other	105	41	11	7
Worldwide (a)	8,189	4,182	3,430	1,871

(a) The Company had 203 gross and 77 net producible wells with multiple completions.

Drilling in Progress

The numbers of oil and gas wells in progress at December 31, 2002 were as follows:

	Gross	Net
North America		
U.S. Lower 48	46	19
Alaska	1	0
Canada	31	13
International		
Far East	6	5
Other	3	0
Worldwide (a) (b)	87	37

(a) Excludes service wells in progress (4 gross, 2 net).
(b) The Company had no waterflood projects under development at December 31, 2002.

Net Oil and Gas Wells Completed and Dry Holes

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

	Productive			Dry		
	2002	2001	2000	2002	2001	2000
Exploratory						
North America						
U.S. Lower 48	23	66	26	17	18	11
Alaska	2	2		3		2
Canada	20	23	19	9	6	14
International						
Far East	19	23	23	6	9	19
Other					2	
Worldwide	64	114	68	35	35	46
Development						
North America						
U.S. Lower 48	54	96	67	1		
Alaska	2	8	3			
Canada	56	51	68	8	6	9
International						
Far East	174	67	104	1		
Other	3	3	2			
Worldwide	289	225	244	10	6	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, the shelf and deepwater areas of the Gulf of Mexico and operations in New Mexico. 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 30 percent equity interest in Matador Petroleum Corporation, which conducts its activities in southeastern New Mexico and East Texas.

The Company holds approximately 5.7 million net acres of prospective land in the onshore, the shelf and deepwater areas of the Gulf of Mexico region. Nearly 28 percent of the prospective acreage is located in federal leases offshore in the Gulf of Mexico. Prospective lands include over 3 million net acres of fee mineral lands, which are primarily located in Alabama, Arkansas, Mississippi, Louisiana, Texas and Florida. The Company holds approximately 1 million net acres of proved lands. Approximately 42 percent of these proved lands are located in federal leases offshore in the Gulf of Mexico. Onshore proved acreage is primarily located in Texas, New Mexico, Louisiana, Alabama and Colorado. The Company s reported U.S. Lower 48 acreage does not include acreage held by its equity interest investees.

In 2002, net liquids production averaged 52 MBbl/d, which was produced from fields onshore (60 percent) and offshore the Gulf of Mexico (36 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 719 MMcf/d, which was principally from fields in the offshore Gulf of Mexico (55 percent) and onshore (39 percent), primarily in Texas, Louisiana, New Mexico and Colorado. The remaining 6 percent was from the Company s equity interest holdings.

Most of the Company s U.S. Lower 48 production, except for the production of Pure, 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 production is sold mostly to third parties at spot market prices.

Gulf of Mexico Shelf and Onshore

The Gulf of Mexico shelf and onshore areas include assets that are primarily located offshore and in Louisiana, Texas, Mississippi, Alabama, New Mexico and Colorado. The Company has over 150 producing properties and about 350 exploration blocks in the Gulf of Mexico shelf and onshore. The Company produces from over 3,900 net wells in both the Gulf of Mexico shelf and onshore. The Company also owns approximately 6 million gross acres (3 million net) of prospective mineral fee lands in the Gulf Coast region where it is identifying a number of exploratory drilling opportunities.

During 2002, the Company, through its Gulf Region business unit and Pure subsidiary, drilled 37 exploratory discoveries (gross wells) that were primarily natural gas, which was a success rate of 58 percent in the Gulf of Mexico shelf and onshore. The 2002 exploration program of the Gulf Region business unit was limited with seven discoveries (gross), which was a success rate of 54 percent. Two of the more significant discoveries were made late in 2002. A well drilled on the Jalapeno prospect located on High Island Block 36 encountered 90 net feet of natural gas pay. It began producing in mid-December at a gross rate of 40 MMcf/d. The Company has a 100 percent working interest in the well. Another well was drilled on the Rio Grande prospect on Mustang Island Block 746 and encountered more than 250 net feet of pay. The well was drilled in mid-December and flowed at an initial gross rate of 15 MMcfe/d. The well began production in the first quarter of 2003. The Company has a 50 percent working interest in the well. Pure had a 56 percent success rate in its 2002 exploration program, with 30 discovery wells (gross), primarily in West Texas, South Texas and offshore the Gulf of Mexico.

Net production in 2002, which was heavily weighted toward natural gas, averaged 168 MBOE/d. Lower production in 2002 principally stemmed from the Ship Shoal Block 295 (Muni field) production decline. In 2002, production from the Muni field averaged 10 MMcf/d, net of royalty, versus 105 MMcf/d, net of royalty, in 2001. Hurricane Lili also affected operations in the Eastern Gulf of Mexico including production from the Ship Shoal, Eugene Island and South Marsh Island fields. Production shut-ins from the storm and the resulting damage to facilities had a significant effect on production in the fourth quarter of 2002. Production losses from shut-ins were as high as 66,000 BOE/d. The Company resumed most of this production by the end of 2002. The Company has insurance coverage for the damages incurred, subject to a $15 million deductible. The Eastern Gulf area is also where the Company was planning to focus the majority of its development and workover activities in the fourth quarter of 2002. A significant number of these projects were delayed.

The Company sold some of its lower margin properties in the Gulf of Mexico shelf and onshore in 2002 and expects to continue reviewing its portfolio for possible additional asset sales in 2003.

Deepwater Gulf of Mexico

Over the past four years, the Company has acquired acreage positions in the deepwater Gulf of Mexico, with interests in 237 exploration leases. The Company s acreage is primarily in the Subsalt/Foldbelt trend, which lies beyond the Primary Basin deepwater trend.

Further offshore in the Subsalt/Foldbelt trend, sometimes referred to as the ultra-deep , the Company has a number of 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 159 blocks.

The Company s current producing field in the Primary Basin is the Garden Banks Block 409 (Lady Bug field). Lady Bug production averaged 4 MBOE/d (net) for 2002. The Company has a 50 percent non-operating working interest in the field.

The Company also participated in the 1999 discovery of the Mirage prospect, located on Mississippi Canyon Block 941, where it has a 25 percent non-operating working interest. The prospect is currently under evaluation.

The Company participated in discoveries made on the Mad Dog and K2 prospects. The Company has a 15.6 percent working interest in Mad Dog on Green Canyon Block 826. In 2002, development of Mad Dog commenced and the Company anticipates first production in late 2004, with expected gross peak production of 75 MBbl/d of liquids and 30 MMcf/d of natural gas in 2007. The Company has committed approximately $200 million for its portion of the development costs for Mad Dog.

The K2 discovery is located on Green Canyon Block 562. In 2002, the Company participated in an appraisal well, which encountered more than 300 feet of net oil pay in three sands and confirmed the findings of the discovery well. The well also encountered pay in additional intervals where no pay was found in the discovery well. The Company and its co-venturers are evaluating the well data to determine the size of the reservoir. The Company is currently participating in an additional appraisal well. The Company holds a 12.5 percent working interest in the K2 discovery.

In late 2002, the Company drilled a second successful appraisal well on the Trident prospect utilizing the deepwater drillship *Discoverer Spirit*. In 2001, the Company made the initial discovery on the Trident prospect and drilled a subsequent successful appraisal well. The Trident prospect covers seven blocks in Alaminos Canyon in the ultra-deep water of the Gulf of Mexico. The Trident #3 well is located approximately 2 miles southwest of the original discovery in Alaminos Canyon Block 903 and was drilled to a total depth of 19,700 feet. The objectives of the second appraisal well were to test the horizontal direction of the structure. The Company now expects to move forward with studies on development options. The development will also depend on industry drilling results in the area. The Company is the operator and has a 59.5 percent working interest in the seven-block prospect.

ALASKA

The Company operates ten platforms in the Cook Inlet and five producing natural gas fields. In 2002, the Company s net natural gas production from the Cook Inlet averaged 76 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.

At the end of 2002, the Company shut down one of the ten platforms in the Cook Inlet. Another platform is expected to be shut down by the end of the second quarter of 2003. In addition, the Company restructured its operations to streamline costs and improve profitability.

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 2002, net liquids production averaged approximately 24 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.

The Company has 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.

In 2002, the Company announced the successful completion and testing of two additional exploration wells in the Ninilchik Exploration Unit on the Kenai Peninsula. The Grassim Oskolkoff #2 well tested at a combined flow rate of 12 MMcf/d from three zones. The Falls Creek #1RD was also tested from a single zone at a rate of 7 MMcf/d. In 2002, the Company participated in a discovery of a new natural gas reservoir in the Ninilchik Exploration Unit with the Grassim Oskolkoff #1 well, which tested at a flow rate of 11 MMcf/d from one zone. The Company holds a 40 percent working interest in the 25,000-acre Ninilchik Exploration Unit. Marathon Oil Company is operator and holds the remaining interest. The Ninilchik Exploration Unit is located about 35 miles south of Kenai. The two companies also formed Kenai Kachemak Pipeline LLC to develop a natural gas pipeline that would connect the producing area with the existing south central Alaska pipeline system. The Company s interest in the pipeline is reported in the Midstream segment.

The Company failed to find commercial quantities of natural gas in a three-well program on the southern Kenai Peninsula. Due to the lack of commercial success in South Kenai, the Kenai Kachemak Pipeline LLC pipeline project was revised and now is approximately 33 miles in length between Kenai and Ninilchik. As originally planned, the pipeline would have run 62 miles between Kenai and Anchor Point.

CANADA

The Company s operations in Canada are primarily carried out by its wholly owned subsidiary Northrock Resources Ltd. (Northrock), which focuses on three core areas: West Central Alberta (O Chiese, Garrington, Caroline and Pass Creek areas), Northwest Alberta (Red Rock and Knopcik areas), and the Williston Basin (Southeastern Saskatchewan).

In 2002, Northrock acquired all the outstanding shares of common stock of Corsair Exploration Inc. (Corsair). The acquisition was funded with cash on hand. Corsair is a Canadian exploration and production company primarily engaged in activity in West Central Alberta, Canada. The transaction was valued at approximately $36 million, which included $7 million in assumed debt and working capital deficiency.

The Company s Canadian production in 2002 averaged approximately 18 MBbl/d of liquids and 91 MMcf/d of natural gas.

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 2002, International operations accounted for 51 percent and 44 percent of the Company s natural gas and liquids production, respectively. International operations also include exploration activities and the development of energy projects primarily in Asia, Australia, Brazil and West Africa.

Certain Oil and Gas Concessions and Production Sharing Contracts

Country	Agreement Type	Area	W.I. Share % (a)	Expiration Date	Renewal Option (b)
Thailand	Concession	Blocks 10, 11, 12 & 13	70 - 80	2012	Y
	Concession	Block 12/27	35	2028	Y
	Concession	Blocks 14A, 15A & 16A	16	2036	Y
Myanmar	Production Sharing Contract	Blocks M5 & M6	28	2028	N (c)
Indonesia	Production Sharing Contract	East Kalimantan	95	2018	Y
	Production Sharing Contract	Makassar Strait	90	2020	Y
	Production Sharing Contract	Rapak	80	2027	Y
	Production Sharing Contract	Ganal	80	2028	Y
Azerbaijan	Production Sharing Contract	Azeri, Chirag & Deepwater Portion of Gunashli	10	2024	Y
Bangladesh	Production Sharing Contract	Blocks 13 & 14	100	2024	Y
	Production Sharing Contract	Block 12	100	(d)	Y
Vietnam	Production Sharing Contract	Blocks B & 48/95	42	2021	Y
	Production Sharing Contract	Block 52/97	43	2029	Y

(a) Share percentages rounded to the nearest whole number
(b) Terms of agreement renewal are subject to negotiation
(c) None specified in the PSC
(d) Production period is 25 years for gas fields from the date of approval of the development plan

Thailand

The Company, through its Unocal Thailand, Ltd. (Unocal Thailand) subsidiary, currently operates 15 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 1,100 employees in its Thailand operations at year-end 2002. Approximately 91 percent of these employees were Thai nationals.

Gross natural gas production from Unocal-operated fields in 2002 averaged 1,033 MMcf/d (585 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 2002 averaged 48 MBbl/d (27 MBbl/d net to the Company). The produced crude oil is sold to both domestic and export markets, and the condensate is sold primarily 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 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. In 2002, Unocal Thailand and its partners agreed to a price reduction for the natural gas it sells to PTT. The discount covers natural gas supplies produced in the Gulf of Thailand under three gas sales contracts (GSAs). The effective date of the discount for GSA 1 (Erawan field) was July 2002, with October 2002 being the start of the new pricing arrangement under GSAs 2 and 3.

As part of the agreement, PTT agreed to extend the GSA for the Erawan field by five-and-one-half years to 2012. The average realized price for all of Unocal s Thailand GSAs in 2002 was $2.55 per Mcf. For 2003 through 2012, the Company s sales price is expected to be discounted by an average of 2 percent. The Company s net working interest share of daily contract quantities of natural gas sold from the Gulf of Thailand, under existing contracts, during the period of 2003 through 2012 is anticipated to be approximately 575 MMcf/d.

In the middle of 2002, Unocal Thailand started natural gas production from the Phase II development in the northern part of Pailin field in the B12/27 concession area in the Gulf of Thailand. The minimum daily contract quantity of natural gas sales from Phase II (North Pailin) facilities is 165 gross MMcf/d, raising the gross contracted natural gas sales from the Pailin field to 330 MMcf/d under an agreement with PTT. Unocal Thailand has installed 12 wellhead platforms and two processing platforms to serve the entire field.

The Company has typically supplied more natural gas to PTT than the minimum daily contract quantity provision of its sales contracts. 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 is now 1,070 MMcf/d (gross) after North Pailin was added in 2002.

Gas supplies coming into Thailand from the Yadana project in neighboring Myanmar, in which the Company has a 28.26 percent non-operating working interest (see Myanmar discussion below), have displaced some of the gas volumes that PTT had purchased 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 discover additional oil and gas reserves during 2002 drilling 15 gross exploratory wells, of which 8 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 237 (gross) successful development wells in the Gulf of Thailand.

Myanmar

The Company, through subsidiaries, has a 28.26 percent non-operating working interest in a PSC that produces natural gas 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. Gross natural gas production averaged 612 MMcf/d (118 MMcf/d net to the Company) in 2002, which was more than the contract rate of 525 MMcf/d.

Indonesia

The Company, through Unocal Indonesia Company and other subsidiaries, held varying interests in 11 offshore PSC areas at December, 31, 2002. Eight PSC areas including East Kalimantan, Ganal, Sesulu, Rapak, Makassar Strait, Muara Bakau, Popodi and Papalang are located offshore the island of Borneo, on the western side of the Makassar Strait, East Kalimantan, and cover more than 6.4 million acres. Another PSC area, Sangkarang, is on the eastern side of the Makassar Strait, offshore the island of 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. The Company had about 1,640 employees in its Indonesian oil and gas operations at year-end 2002, of which approximately 91 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. The Company has a 95 percent working interest in 10 of the fields, and a 47.5 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.

Under the terms of the Indonesia PSCs, the Company is required to sell a portion of its net entitlement crude oil production to the Indonesia government at reduced prices. For 2002, approximately 15 percent of the Company s share of this production was sold to the government for an average price that was substantially lower than market.

Gross production from Company-operated fields averaged 63 MBbl/d of liquids and 269 MMcf/d of natural gas in 2002. The average economic interest production under the PSCs was 26 MBbl/d of liquids and 144 MMcf/d of natural gas in 2002.

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 95 percent in the East Kalimantan, 90 percent in the Makassar Strait and 80 percent in the Rapak, Ganal and Sesulu PSCs. The Company, through subsidiaries, also holds a 24 percent non-operating working interest in the Popodi and Papalang PSCs.

In December 2002, the Company s Muara Bakau Limited subsidiary acquired a 50 percent non-operating working interest in the Muara Bakau PSC area, located offshore East Kalimantan and adjacent to the Ganal PSC area. Water depth in the Muara Bakau PSC area ranges from 250 to 4,500 feet.

In January 2003, the Company s Unocal Donggala Limited (Unocal Donggala) subsidiary agreed to farm in to the deepwater Donggala PSC. The farm-in agreement was approved by the Indonesian government in February 2003. Unocal Donggala acquired a 19.55% non-operating working interest in the PSC, which lies adjacent to the Rapak PSC area. Water depth at Donggala ranges from 6,000 to 8,000 feet.

The Company has 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 area and the northern portion of the Makassar Strait PSC area. Development activity is planned in three phases, with phase one production from the West Seno field expected to begin by the end of the second quarter of 2003. The second phase of development will seek to expand the West Seno production plateau in mid-2005. Production from the West Seno field is anticipated to reach about 35 MBbl/d to 40 MBbl/d by the end of 2003 and 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 $500 million with an additional $240 million for the second phase. The Company s net share is expected to be approximately $450 million and $215 million for the first and second phases, 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 2003 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 2002, Unocal Rapak successfully tested an appraisal well in the deepwater Ranggas oil field offshore Indonesia. The Ranggas-4 appraisal well flowed at a daily rate of 8 MBbl/d of oil and 6 MMcf/d of gas. The Ranggas-4 well encountered 181 feet of net oil pay and 57 feet of net gas pay. The well was drilled in 5,208 feet of water to 11,252 feet true vertical depth subsea. The well is located 2.4 miles north of the Ranggas-1 discovery well and 1.2 miles south of the Ranggas-3 appraisal well. The test results are another step towards the future possible commercialization of the Company s third deepwater oil field in Indonesia. The Company also drilled the Ranggas-5 and Ranggas-6 appraisal wells, also on the main Ranggas structure. Both wells were successful in finding significant quantities of oil and gas. The Ranggas-5 well encountered 203 feet of net oil pay and 618 feet of net gas pay. The Ranggas-6 well encountered 68 feet of net oil pay and 465 feet of net gas pay.

Also in 2002, two wells were drilled to test structures on both the north and the west parts of the large central Ranggas prospect. The Ranggas Utara-1 well encountered 33 feet of net oil pay and 44 feet of net gas pay. The well was drilled in 5,258 feet of water to 12,650 feet TVD. The well is located 2.5 miles north of the Ranggas-3 well. This accumulation was deemed sub-commercial as an independent development at this time, but it demonstrates the potential for additional hydrocarbons to the north of the Ranggas field. The Ranggas West-1 well encountered 85 feet of net gas pay in two intervals. The well was drilled to 9,955 feet TVD in 4,483 feet of water. The well is located 2.9 miles west of Ranggas-3. This accumulation could be tied back to the future Ranggas development facilities via a single subsea well. Oil potential remains in the southern extension of this trend. Several additional prospects on trend or adjacent to the main Ranggas structure remain to be drilled.

The Company also drilled the Sadewa-1 discovery well in approximately 1,100 feet of water and reached a measured depth of 14,845 feet in 2002. The well penetrated 151 feet of net gas pay in the intermediate target section and 14 feet of net oil pay near total depth. The discovery is approximately 5 kilometers from shallower water depths of 250 feet and may be brought on-line as early as 2004 to supplement near-term gas deliverability for the existing East Kalimantan gas contracts. The oil pay found near the bottom of the well provides encouragement for deeper oil potential that was not reached. The Company has a 50 percent working interest in the well.

Azerbaijan

Unocal, through a subsidiary, has a 10.28 percent working interest in the Azerbaijan International Operating Company (AIOC) that is producing and developing offshore oil reserves in the Caspian Sea from the Azeri and Chirag fields. In 2002, AIOC s gross oil production averaged 130 MBbl/d (12 MBbl/d net to the Company). AIOC currently 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, Azerbaijan through Georgia. Both pipelines connect with ports on the Black Sea. In 2002, the production from the consortium was exported through the western pipeline.

AIOC is in the process of developing Phase I of the offshore Azeri field in the Azeri Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea. Phase I will develop an estimated 1.5 billion gross barrels of proved crude oil reserves. The Company has approved the expenditure of $310 million for its share of the costs for Phase I. The project is under construction and on schedule with first oil from Phase I expected early in 2005. Phase I gross production is expected to peak at approximately 350 MBbl/d. AIOC is also developing Phase II of the project, which is expected to be similar in size to Phase I. Phase II is expected to begin production from two additional platforms in 2006 and 2007. The Company has approved the expenditure of $400 million for its share of the costs for Phase II. The Company, through its AIOC participation, is participating in the development of a pipeline from Baku to Ceyhan, Turkey (see the discussion under the Midstream segment for further details).

Bangladesh

The Company, through subsidiaries, holds interests in three PSCs in Bangladesh. Two PSCs cover Blocks 12, 13 and 14, which encompass 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 88 MMcf/d (73 MMcf/d net to the Company) of natural gas and 1 MBbl/d (830 b/d net to the Company) of liquids in 2002. 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 included construction of a 30-inch diameter, 1,363-kilometer (847-mile) pipeline, with an initial capacity of 500 MMcf/d, from the Bibiyana field to targeted markets in India. The review by Petrobangla and the government of Bangladesh continues and has been a lengthy process since the export of any quantity of natural gas to India 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 2002 was approximately 5 MBbl/d of crude oil (4 MBbl/d net to the Company) and 15 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 16 MBbl/d of crude oil (2 MBbl/d net to the Company) from seven fields in 2002.

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 2002, gross production from the project averaged 3 MBbl/d of oil and 36 MMcf/d of natural gas. Net production from the project averaged 1 MBbl/d of oil and 13 MMcf/d of natural gas.

As part of a consortium, Unocal recently submitted a successful bid for BM-POT-13 in the June 2002 ANP Bid Round 4. The 523 square mile block is located offshore Natal in the Potiguar Basin. Block BM-POT-13 borders the six fields comprising the Pescada-Arabaiana project. The Company has a 30 percent non-operating working interest.

In 2002, the Company relinquished its 25 percent non-operating working interest in the exploration block BM-ES-1 in the Espirito Santo basin and its 40.5 percent working interest in the adjacent BM-ES-2 Block. The Company also relinquished its 30 percent working interest in Block BES-2.

Vietnam

The Company, through subsidiaries, holds interests in two PSCs offshore southwest Vietnam in the northern part of the Malay Basin. The Company is the operator and has a 42.38 percent working interest in one PSC, which includes Block B and Block 48/95. This PSC covers 2.2 million acres. The Company made the initial gas discovery on the Kim Long prospect on Block B in 1997. The Company also holds a 43.4 percent working interest in a PSC for exploration of Block 52/97, which covers 500,000 acres.

In 2002, the Company s Vietnam subsidiaries filed a declaration of commercial discovery with PetroVietnam, the national oil company, for three natural gas fields offshore southwest Vietnam. The declaration followed the drilling of 10 successful exploration wells on Blocks B and 52/97. The declaration was the first step toward signing a gas sales agreement, which is required before any field development can begin.

The Company continues to 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 two exploration blocks located in deep water offshore Gabon, West Africa. The Company holds a 25 percent working interest.

Australia

In 2002, the Company, through a subsidiary, acquired two exploration blocks offshore Australia. The Company holds a 50 percent non-operating working interest in block T/32P, which is located in the Sorell Basin, off the northwestern shore of Tasmania. This block covers approximately 1.3 million acres. Also, the Company holds a 33.33 percent non-operating working interest in block VIC/P52, which is located in the Otway Basin, offshore Victoria. Block VIC/P52 covers approximately 645,000 acres.

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, marketing and trading companies. These transactions effectively transfer the 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 commodity-related risks 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 s 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 Exploration and Production segment. 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 exposures to commodity price changes for future sales transactions. These commodity-risk management activities are authorized by the Company s senior management and board of directors.

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

MIDSTREAM

The Midstream segment 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 certain 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.

In November 2002, the Company completed the sale of certain investment interests in three non-strategic refined product pipelines in the U.S. for a total cash consideration of $54 million.

The Company, through its participation in AIOC, is pursuing the development of a 42-inch pipeline from Baku, Azerbaijan to Ceyhan, Turkey. Construction of the Baku-Tbilisi-Ceyhan (BTC) pipeline started in mid-September 2002. The BTC pipeline will carry crude oil from Azerbaijan through Georgia and Turkey to the deep water port facilities on the Mediterranean Sea, bypassing the Bosporus Straits through Istanbul. The pipeline is planned to have a crude oil capacity of 1 million Bbl/d. Completion of the pipeline is expected in late 2004 at an overall estimated cost of approximately $3 billion, and the pipeline is expected to be in operation in early 2005. The Company has an 8.9 percent interest and is one of eleven shareholders in the BTC pipeline project. The pipeline company anticipates financing up to 70 percent of the pipeline s cost.

The Company and Marathon Oil formed the Kenai Kachemak Pipeline LLC to develop a natural gas pipeline between Kenai and Ninilchik in Alaska. The Kachemak pipeline, currently under construction, is approximately 33 miles in length.

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. 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 was completed in 2002. The project began storage operations with initial storage capacity of 3 billion cubic feet. The Company holds a 100 percent interest in the project.

GEOTHERMAL AND POWER OPERATIONS

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 1,120 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, to fuel three power generation plants at Gunung Salak, West Java, with a total installed capacity of 165 megawatts, 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 plants with a total installed capacity of 197 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. The Company also operates 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 rests with the Indonesian central government.

In July 2002, the Company s Unocal Geothermal of Indonesia, Ltd. (UGI), subsidiary and DSPL reached agreement over pricing and production issues at Gunung Salak with PLN and Pertamina. The new agreement extended the primary terms of the Joint Operation Contract and Energy Sales Contract (ESC) to 2040. The new agreement increased the Unit Rated Capacities for the generating plants operated by DSPL by 32 megawatts, thereby increasing minimum take-or-pay amounts payable under the ESC, and also included a commitment by PLN to accept as much steam and electricity as possible to meet increased demand. In addition, the agreement reaffirmed the Indonesian Government s guarantee of PLN s obligations to UGI, DSPL, Pertamina and the project s lenders. Under the new agreement, the selling price of electricity delivered by DSPL was lowered from 8.49 cents per kilowatt-hour (kWh) to 4.45 cents per kWh and steam supplied to PLN by UGI from 4.25 cents per kWh to 3.72 cents per kWh. Under the terms of the amended ESC, both the selling price for electricity and the selling price for geothermal steam are indexed for changes in foreign exchange rates and inflation. The new agreement also provided for payment by PLN of a portion of the past due receivable balances to the Company while the Company forewent a portion of the receivables.

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 power plants with a combined installed generating capacity of 649 megawatts 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. See page 54 under the Outlook Geothermal and Power Operations section in MD&A for a discussion of the settlement.

In 2002, PGI and the Power Section Assets and Liabilities Management Corporation (PSALM) signed a Term Sheet setting forth the key terms of a settlement of the long-standing dispute. PSALM was created by the Electric Power Industry Reform Act of 2001 and is responsible for restructuring the electric power industry, including the sale of NPC s generation assets. The Term Sheet was approved by the boards of directors of NPC and PSALM. Definitive documentation of the settlement is expected to provide that: the 1971 service contract will be terminated upon completion by NPC of the rehabilitation of the Tiwi and Mak-Ban power plants (expected completion by January 2005) so that such power plants will have an installed capacity of at least 634 megawatts; PGI will continue to operate the Tiwi and Mak-Ban geothermal fields until at least 2021; and PGI will sell geothermal resources to NPC/PSALM at a price calculated to ensure base-load operation of the Tiwi and Mak-Ban power plants. Once the definitive documentation is completed, NPC and PSALM plan to seek all necessary Philippine government and court approvals of the settlement.

Thailand - The Company, through subsidiaries, also has various equity interests in four gas-fired power plant projects in Thailand.

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

	2002	2001	2000
Net proved geothermal reserves at year end: (a)			
billion kilowatt-hours	155	108	114
million equivalent oil barrels	232	162	170
Net daily production			
million kilowatt-hours	13	14	16
thousand equivalent oil barrels	20	22	25
Net geothermal lands in thousand acres			
proved	9	9	9
prospective	314	314	314
Net producible geothermal wells	85	84	83

(a) Includes reserves underlying a service fee arrangement in the Philippines.

The 2002 increase in geothermal reserves reflects the aforementioned signing of amended Joint Operations and Energy Sales Contracts in July 2002 covering operations in Indonesia.

PATENTS

Between 1994 and 2000, the Company was awarded five U.S. patents resulting from its independent research on reformulated gasolines (RFG). The Company believes that its patented formulations provide refiners, blenders and importers with a cost-effective way of meeting California and federal standards for cleaner-burning gasolines. The Company has entered into eight licensing agreements that grant motor gasoline refiners, blenders and importers the right to make cleaner-burning gasolines using these formulations. 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.

Although the Company had indicated a willingness to enter into licensing negotiations, the first of these patents (the 393 patent) was the subject of litigation initiated in 1995 in the U. S. District Court for the Central District of California by the major California refiners. Following a jury verdict in a 1997 trial upholding the patent and the award of damages to the Company, the refiners appealed unsuccessfully to the U.S. Circuit Court of Appeals for the Federal Circuit and were denied a review by the U. S. Supreme Court. 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 at issue in the trial. In 2002, the Court determined that the 5.75 cent per gallon royalty rate determined by the jury in the trial would apply to the defendants infringing gasolines in California for the period subsequent to July 1996. No determination has been made by the Court as to the royalty rate for non-California gasolines in this action.

In 2002, the Company filed a lawsuit against Valero Energy Corporation in the same U.S. District Court for infringement of both the 393 patent and a subsequent 126 patent 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.

Proceedings in both of the Company s lawsuits have been temporarily suspended pending the outcomes of the administrative challenges to the patents discussed below.

In 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 reexaminations of the 393 and 126 patents based on the existence of alleged prior art . In 2002, the PTO initially rejected all of the claims of the two patents as part of the reexamination process. The PTO subsequently granted a second request for reexamination of the 393 patent based on additional alleged prior art and later rejected all of the claims of the 393 patent in a non-final Office Action . In March 2003, the Company filed a response to this rejection, including an appeal within the PTO. The Company is awaiting a response from the PTO to its submission arguing against the initial rejection of the 126 patent, but has been informed that a second petition for reexamination of this patent has been filed. The completion of the reexamination processes, including appeals within the PTO, is expected to take several months, but the Company believes the claims of both patents are novel and non-obvious and expects them ultimately to be sustained. Licensing fees and judgments collected during the pendency of the reexaminations are not refundable.

Also in 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 the regulatory processes that established California and federal standards for RFG, thereby allegedly gaining monopoly profits in the RFG market. ExxonMobil requested that the FTC use its authority to fashion an appropriate remedy. Subsequently, the FTC conducted a nonpublic investigation.

In March 2003, the FTC issued a complaint alleging that the Company had illegally monopolized, attempted to monopolize and otherwise engaged in unfair methods of competition with respect to California RFG. The complaint alleges that the Company made materially false and misleading statements to the California Air Resources Board (CARB) which resulted in regulations that benefited the Company and created anticompetitive effects. The complaint alleges that the Company s failure to disclose its 393 patent application to the CARB was misleading and resulted in the impression Unocal would not assert RFG patent rights. The FTC is requesting remedies that include orders that the Company cease and desist from any efforts to continue or commence any actions with respect to infringement of its RFG patents for gasolines sold in California. The Company will vigorously contest this action and believes that it did not engage in misleading or deceptive practices before the CARB.

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, 2002, Unocal and its subsidiaries had 6,615 employees compared to 6,980 and 6,800 in 2001 and 2000, respectively. Of the total Unocal employees at year-end 2002, 200 in the U.S. were represented by various labor unions and 420 in Thailand were represented by a trade union.

GOVERNMENT REGULATION

As a lessee from the U.S. government, Unocal is subject to Department of the Interior Minerals Management Service 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.

Certain interstate crude oil pipeline subsidiaries of Unocal are regulated (as common carriers) by the Federal Energy Regulatory Commission.

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 REGULATION

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 the laws and 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 storm water 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 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 nonhazardous 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. At year-end 2002, the Company had been identified as a Potentially Responsible Party (PRP) under CERCLA at approximately 26 sites by the EPA and various state agencies and private parties had identified the Company as a PRP at 23 other similar sites. A PRP has strict and joint and several liability for site remediation and agency oversight 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 material impacts on the Company include the following:

- 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 of 1986, 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 radioactive 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 Acts 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.

In 1997, the Third Conference of the Parties to the United Nations Framework Convention on Climate Change adopted the Kyoto Protocol, which sets legally binding commitments for developed nations to reduce their emissions of greenhouse gases by 2008-2012. The Kyoto Protocol will come into force upon ratification by 55 parties, including developed country parties representing 55 percent of developed country greenhouse gas emissions in 1990. At year-end 2002, the Kyoto Protocol had not achieved sufficient ratification to bring it into force. Among the developed countries covered by the Kyoto Protocol, Unocal currently conducts operations in the United States, Canada, and the Netherlands. These countries are in various stages of formulating regulations and programs to address global climate change. Canada and the Netherlands have ratified. The United States has indicated that does not intend to ratify the Kyoto Protocol, but it may take appropriate domestic action to reduce greenhouse gas emissions. Although it is not possible to estimate the cost of complying with the Kyoto Protocol and domestic climate change programs, such costs could be substantial. Unocal does not expect that it will be affected differently from other companies with similar assets and business interests.

For information regarding the Company s environment-related capital expenditures, charges to earnings, reserves for probable environmental remediation liabilities and possible future environmental cost exposures, 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 and possible additional remediation costs in notes 18 and 22 to the consolidated financial statements in Item 8 of this report; the discussion of such amounts in the Environmental Matters section of Management s Discussion and Analysis in Item 7 of this report; and the information regarding certain litigation and claims, tax matters 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 and administrative proceedings involving the Company s patents for cleaner-burning gasolines. Set forth below is information with respect to certain additional legal proceedings pending or threatened against the Company:

1. The Company has been named a defendant in two 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 in violation of the federal False Claims Act (FCA). 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 (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 intends to vigorously defend both cases and believes that their outcomes are not likely to have a material adverse effect on the Company s financial condition, liquidity or results of operations.

2. 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; and *John Roe III, et al. v. Unocal, Inc.* [sic]*, et al.,* Case No. CV 96-6112-RWSL). 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 its border with 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 was 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 District Court granted the Company s motions for summary judgment in both actions, ordered the federal law claims dismissed and, after declining to exercise jurisdiction over the pendant state law claims, ordered them dismissed without prejudice.

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). In 2002, a three-judge panel of the Circuit Court issued an opinion that reversed in part and affirmed in part the District Court s ruling and remanded the case for further proceedings in the District Court. The panel held that, if proved at trial, the alleged conduct of the Myanmar military, consisting of alleged forced labor and certain alleged related violence, would constitute violations of international law actionable under the Alien Tort Claims Act (28 U.S.C. §1350). The panel further held that international law concerning the standard for aiding and abetting liability applies to the plaintiffs claims against the Company and found sufficient disputed facts to warrant a trial. Subsequently, the Company requested a rehearing by an eleven-judge *en banc* panel of the Circuit Court. Such rehearing was ordered in February 2003 and is currently scheduled for June 2003.

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. The plaintiffs seek compensatory and punitive damages on behalf of the named plaintiffs, as well as injunctive relief, disgorgement of profits and other equitable relief.

In 2002, the state court dismissed all of the plaintiffs tort causes of action that were premised on alleged intentional or negligent actions of the Company. The remaining causes of action in both state cases are all premised on whether the Company should be held vicariously liable to the individual plaintiffs for the alleged wrongful acts of the Myanmar military. The court has indicated that the scheduling of a trial in second half of 2003 is likely.

The Company believes that the outcomes of the federal and state cases are not likely to have a material adverse effect on the Company s financial condition or liquidity or, based on management s current assessment of the cases, the Company s results of operations.

Certain Environmental Matters Involving Civil Penalties

3. In 2002, the EPA issued to the Company an administrative complaint alleging 16 violations of the Emergency Planning and Community Right-To-Know Act of 1986. The complaint, which sought civil penalties aggregating $365,000, alleged that the Company failed to make timely and/or complete and accurate chemical release reports to the EPA with regard to certain chemicals manufactured, processed, or otherwise used at its former Los Angeles refinery during 1996 and 1997. As a result of negotiations with the EPA, the number of violations was reduced to six and the complaint was settled in March 2003 for $105,600 in civil penalties.

4. The Company s Molycorp, Inc., subsidiary has concluded preliminary discussions 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. If the parties resolve this matter in accordance with the preliminary discussions, there could be a payment by Molycorp of civil penalties in an amount greater than $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	**Recent business experience**
CHARLES R. WILLIAMSON, 54 Chairman of the Board and Chief Executive Officer Chairman of Company Management Committee	Mr. Williamson has been Chairman of the Board since 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.
TIMOTHY H. LING, 45 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.
TERRY G. DALLAS, 52 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.
CHARLES O. STRATHMAN, 59 Vice President and Chief Legal Officer	Mr. Strathman was elected Vice President and Chief Legal Officer on December 3, 2002. Prior to that date, he served as Vice President, Law, since 2000 and as Senior Deputy General Counsel from 1995 to 2000.
JOE D. CECIL, 54 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, 43 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.

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 19, 2003, and until his successor shall be elected and qualified, unless he shall resign or shall be removed or otherwise disqualified to serve.

PART II

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

	2002 Quarters				2001 Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Market price per share of common stock								
- High	$ 39.24	$ 39.70	$ 36.92	$ 32.40	$ 39.94	$ 40.00	$ 37.36	$ 36.15
- Low	$ 33.09	$ 35.25	$ 29.14	$ 26.58	$ 32.31	$ 32.26	$ 29.72	$ 29.51
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, 2003, the high price per share was $26.79 and the low price per share was $26.25.

Unocal common stock is listed for trading on the New York Stock Exchange.

As of February 28, 2003, the number of holders of record of Unocal common stock was 21,677 and the number of shares outstanding was 258,013,728.

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 87 consecutive years.

See Item 12 in Part III of this report for information with respect to shares of Unocal common stock authorized for issuance under equity compensation plans.

On February 20, 2002, two shares of Unocal common stock, together with cash in lieu of a fractional share, were issued upon conversion of two of the 6-1/4% trust convertible preferred securities of Unocal Capital Trust. The common shares were not registered under the Securities Act of 1933, as amended (the 1933 Act), in reliance upon the exemption from registration afforded by Section 3(a)(9) of the 1933 Act, together with interpretations thereof by the staff of the Division of Corporation Finance of the Securities and Exchange Commission, for a security exchanged by the issuer with its existing security holders, or those of a subsidiary, exclusively where no commission or other remuneration is paid or given directly or indirectly for soliciting such exchange.

ITEM 6 - SELECTED FINANCIAL DATA: see pages 139 and 140.

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. 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

	Years ended December 31,					
Millions of dollars	**2002**		**2001**		**2000**	
Earnings from continuing operations (a)	$	330	$	599	$	723
Earnings from discontinued operations		1		17		37
Cum ulative effect of accounting change				(1)		
Net earnings	$	331	$	615	$	760
(a) Includes m inority interests of:	$	(6)	$	(41)	$	(16)

Earnings From Continuing operations

2002 vs. 2001 Earnings from continuing operations were $330 million in 2002, compared with $599 million a year ago. The decrease was primarily due to lower North America production and natural gas prices. Lower production in North America reduced net earnings by approximately $175 million from 2001. North America natural gas production averaged 886 MMcf/d in 2002, compared with 1,109 MMcf/d in 2001. The lower production was principally in the U.S. Lower 48 operations, which reflected lower Gulf of Mexico natural gas production stemming from the decline in Muni field production (10 MMcf/d, net of royalty, in 2002 versus 105 MMcf/d, net of royalty, in 2001), the natural declines in existing fields and hurricane-related production curtailments in the Gulf of Mexico. The lower production in North America was partially offset by higher production from International operations, which contributed approximately $25 million in higher 2002 after-tax earnings. Lower North America natural gas prices reduced net earnings by approximately $160 million in 2002. The Company s North America average natural gas price, including a benefit of 5 cents per Mcf from hedging activities, was $2.88 per Mcf for 2002, which was a decrease of 97 cents per Mcf, or 25 percent, from the $3.85 per Mcf, including a loss of 4 cents per Mcf from hedging activities, in 2001.

The full-year results in 2002 included $25 million after-tax in higher pension related costs, a $15 million after-tax charge for impairments in Alaska, a $12 million after-tax restructuring provision for the Gulf Region business unit, $9 million after-tax for uninsured losses due to hurricane damage in the Gulf of Mexico and $8 million after-tax in costs related to the acquisition of the outstanding minority interest in Pure Resources, Inc. (Pure), common stock. The full-year of 2002 included an after-tax loss of $6 million in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives by the Company s Northrock subsidiary, compared with an after-tax gain of $10 million in 2001. In 2002, net earnings benefited from $10 million after-tax related to participation agreements covering the Company s former agricultural products business and former oil and gas operations in California, while the earnings impact in 2001 was $18 million.

The aforementioned negative earnings variances in 2002 were partially offset by lower dry hole costs compared with the same period a year ago, which increased net earnings by approximately $40 million. The 2001 results also included an $86 million non-cash after-tax charge for impairments of certain Gulf of Mexico shelf and onshore properties, including those of an equity investee. In addition, after-tax environmental and litigation expenses were $92 million in 2002, compared with $108 million in 2001. The 2002 results also included a $2 million after-tax gain from an insurance settlement reached with insurers for the recovery of amounts previously paid out for environmental pollution claims. The 2002 results included $26 million in net after-tax gains from asset sales, while 2001 included $13 million in after-tax gains from asset sales.

Income taxes on earnings from continuing operations in 2002 were $280 million compared with $452 million for 2001. The effective income tax rate was approximately 45 percent for 2002 as compared to approximately 41 percent in 2001. The higher effective tax income tax rate in 2002, as compared to 2001, reflected the change in the mix of domestic losses and foreign earnings in 2002 compared to the mix of domestic and foreign earnings in 2001. Foreign earnings are generally taxed at higher rates.

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 the $86 million non-cash after-tax charge for impairment of certain Gulf of Mexico shelf and onshore properties, including those of an equity investee. 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 $22.95 per barrel in 2001, which was a decrease of $3.36 per barrel, or 13 percent, from 2000. In 2001, the Company s worldwide average natural gas price, including a 2 cents loss per Mcf from hedging activities, was $3.31 per Mcf, which was an increase of 32 cents per Mcf, or 11 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 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 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.

Earnings From Discontinued Operations

Earnings from discontinued operations were $1 million in 2002 compared to $17 million in 2001. The 2002 and 2001 amounts 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 $29 million (pre-tax) related to the agreement.

Earnings from discontinued operations in 2000 reflect the sale of the agricultural products business. The 2000 gain on disposal amount included $14 million from the sale of the agricultural business and $23 million from the operation of the business prior to the sale.

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 .

Operating Highlights	2002	2001	2000
North America Net Daily Production (a)			
Liquids (thousand barrels)			
U.S. Lower 48 (b)	52	59	52
Alaska	24	25	26
Canada	18	16	17
Total liquids	94	100	95
Natural gas - dry basis (million cubic feet)			
U.S. Lower 48 (b)	719	905	764
Alaska	76	103	125
Canada	91	101	98
Total natural gas	886	1,109	987
North America Average Prices (excluding hedging activities) (c) (d)			
Liquids (per barrel)			
U.S. Lower 48	$ 22.85	$ 23.35	$ 27.16
Alaska	$ 24.21	$ 24.69	$ 26.22
Canada	$ 20.70	$ 18.53	$ 24.31
Average	$ 22.79	$ 22.90	$ 26.40
Natural gas (per mcf)			
U.S. Lower 48	$ 3.01	$ 4.14	$ 3.91
Alaska	$ 1.42	$ 1.37	$ 1.20
Canada	$ 2.67	$ 4.34	$ 3.45
Average	$ 2.83	$ 3.89	$ 3.50
North America Average Prices (including hedging activities) (c) (d)			
Liquids (per barrel)			
U.S. Lower 48	$ 22.87	$ 23.41	$ 27.20
Alaska	$ 24.21	$ 24.69	$ 26.22
Canada	$ 20.70	$ 18.53	$ 22.46
Average	$ 22.81	$ 22.93	$ 26.10
Natural gas (per mcf)			
U.S. Lower 48	$ 3.07	$ 4.23	$ 3.93
Alaska	$ 1.42	$ 1.37	$ 1.20
Canada	$ 2.66	$ 3.17	$ 2.30
Average	$ 2.88	$ 3.85	$ 3.40

(a)	Includes minority interests of:			
	Liquids	7	9	9
	Natural gas	82	102	84
	Barrels oil equivalent	21	26	23

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

(c) Excludes Trade segment margins.

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

Operating Highlights (continued)	2002	2001	2000
International Net Daily Production (e)			
Liquids (thousand barrels)			
Far East	53	51	47
Other (b)	20	19	18
Total liquids	73	70	65
Natural gas - dry basis (million cubic feet)			
Far East	847	829	799
Other (b)	93	65	57
Total natural gas	940	894	856
International Average Prices (f)			
Liquids (per barrel)			
Far East	$ 22.88	$ 22.50	$ 26.17
Other	$ 25.47	$ 24.15	$ 27.84
Average	$ 23.57	$ 22.97	$ 26.61
Natural gas (per mcf)			
Far East	$ 2.75	$ 2.67	$ 2.51
Other	$ 2.72	$ 2.75	$ 2.81
Average	$ 2.75	$ 2.67	$ 2.53
Worldwide Net Daily Production (a) (b) (e)			
Liquids (thousand barrels)	167	170	160
Natural gas - dry basis (m illion cubic feet)	1,826	2,003	1,843
Barrels oil equivalent (thousands)	471	504	468
Worldwide Average Prices (excluding hedging activities) (c) (d)			
Liquids (per barrel)	$ 23.13	$ 22.93	$ 26.49
Natural gas (per mcf)	$ 2.79	$ 3.33	$ 3.05
Worldwide Average Prices (including hedging activities) (c) (d)			
Liquids (per barrel)	$ 23.14	$ 22.95	$ 26.31
Natural gas (per mcf)	$ 2.81	$ 3.31	$ 2.99

(a) Includes minority interests of :			
Liquids	7	9	9
Natural gas	82	102	84
Barrels oil equivalent	21	26	23

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

(c) Excludes Trade segment margins.

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

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

(f) International operations did not have any hedging activities.

Sales and Operating Revenues

2002 vs. 2001   Sales and operating revenues in 2002 were $5,224 million, which was a decrease of $1,484 million from 2001. The decrease was primarily due to lower average hydrocarbon commodity prices, lower domestic natural gas production and reduced marketing activity related to the Company s domestic equity crude production. Sales and operating revenues from the Trade business segment were $2,524 million in 2002, which was a decrease of $1,332 million from 2001. During 2002 and 2001, approximately 25 percent and 31 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 commodity-related risk and seek higher profit margins by effectively 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 natural gas price, including a benefit of 2 cents per Mcf from hedging activities, was $2.81 per Mcf, which was a decrease of 50 cents per Mcf, or 15 percent, from the $3.31 per Mcf, including a loss of 2 cents per Mcf from hedging activities, in 2001. In 2002, the Company s worldwide average liquids price was $23.14 per barrel, which was an increase of 19 cents per barrel from the $22.95 per barrel price, including a gain of 2 cents per barrel from hedging activities, in 2001.

2001 vs. 2000   Sales and operating revenues in 2001 were $6,708 million, which was a decrease of $2,248 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 segment s marketing activities.

Interest, Dividends and Miscellaneous Income

2002 vs. 2001   Interest, dividends and miscellaneous income in 2002 was $31 million, which was a decrease of $33 million from 2001. This decrease was primarily due to lower participation payments from the Company s former agricultural products business. In addition, the Company s interest income from marketable securities was lower in 2002 mainly due to lower investment balances.

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. 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.

Selected Costs and Other Deductions

	Years ended December 31,		
Millions of dollars	2002	2001	2000
Pre-tax costs and other deductions:			
Crude oil, natural gas and product purchases	$ 1,701	$ 2,492	$ 5,158
Operating expense	1,338	1,420	1,214
Depreciation, depletion and amortization	973	967	821
Impairments	47	118	66
Dry hole costs	107	175	156
Exploration expense (see table below)	246	252	260
Interest expense	179	192	210

	Years ended December 31,		
Millions of dollars	2002	2001	2000
Exploration operations	$ 80	$ 85	$ 91
Geological and geophysical	53	56	71
Amortization of exploratory leases	98	95	85
Leasehold rentals	15	16	13
Exploration expense	$ 246	$ 252	$ 260

2002 vs. 2001 - Crude oil, natural gas and product purchases decreased by $791 million in 2002. This decrease was principally due to lower purchases of domestic crude oil by the Trade segment in its marketing activities. In 2002, operating expense decreased by $82 million due to lower receivable provisions related to geothermal operations in Indonesia and lower environmental and litigation provisions. These two factors were partially offset by higher International operating expense primarily from added production operations in Thailand. Depreciation, depletion and amortization expense increased slightly in 2002, primarily due to higher production from the added operations in Thailand, which was offset by lower production from the Company s Gulf of Mexico operations. Impairments in 2002 were $47 million, which primarily reflected asset write-downs of certain oil and gas fields in Alaska and the Gulf of Mexico region, in addition to an impairment related to the Company s investment in a U.S. pipeline company.

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 Trade 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 $206 million due to higher receivable provisions related to geothermal operations in Indonesia and higher expenses related to the full year activities of Pure, 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 Pure and a full year of Pure s activities compared to only seven months in the prior year. Impairments in 2001 reflected $118 million for asset write-downs of certain Gulf of Mexico shelf and onshore properties, due principally to lower commodity prices. Impairments in 2000 included a write-down of a mining operation at Questa, New Mexico.

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 US Lower 48 operations is on the onshore, the shelf and deepwater areas of the Gulf of Mexico region and the Permian and San Juan Basins in west Texas and New Mexico. A substantial portion of the crude oil and natural gas produced in the US Lower 48 operations, excluding Pure s production, is sold to the Company s Trade business segment. The remainder of North America production, including that of Pure and of Northrock in Canada, is sold to third parties. In Alaska, natural gas production, pursuant to agreements with the purchaser of the Company s former agricultural products business, is sold to a fertilizer plant in Nikiski, Alaska. In addition, the Company uses hydrocarbon derivative financial instruments such as futures, swaps and options to hedge portions of the Company s exposure to commodity price fluctuations.

2002 vs. 2001 After-tax earnings were $33 million in 2002 compared to $440 million in 2001, which was a decrease of $407 million. The decrease was primarily due to lower production and natural gas prices. Lower production in North America reduced net earnings by approximately $175 million from 2001. Natural gas production averaged 886 MMcf/d in 2002, compared with 1,109 MMcf/d in 2001. The lower production was principally in the US Lower 48 operations, which reflected lower Gulf of Mexico natural gas production stemming from the decline in Muni field production (10 MMcf/d, net of royalty, in 2002 versus 105 MMcf/d, net of royalty, in 2001), the natural declines in existing fields and hurricane-related production curtailments in the Gulf of Mexico. Lower natural gas prices reduced after-tax earnings by approximately $160 million in 2002. North America s average natural gas price, including a benefit of 5 cents per Mcf from hedging activities, was $2.88 per Mcf for 2002, which was a decrease of 97 cents per Mcf, or 25 percent, from the $3.85 per Mcf, including a loss of 4 cents per Mcf from hedging activities, in 2001. The 2002 results included approximately $17 million in after-tax losses from asset sales, a $15 million after-tax charge for impairments in Alaska, a $12 million after-tax restructuring provision for the Gulf Region business unit, $9 million for uninsured losses due to hurricane damage in the Gulf of Mexico, $8 million in costs related to the acquisition of the outstanding minority interest in Pure common stock and an $10 million after-tax charge for impairments in the Gulf Region business unit. The 2002 results also included an after-tax loss of $6 million in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives by Northrock, compared with an after-tax gain of $10 million in 2001.

These negative factors in 2002 were partially offset by lower dry hole costs compared with 2001 of approximately $20 million. Lower drilling activity in the Gulf of Mexico was partially offset by higher dry hole costs in Alaska. The 2001 results also included $86 million non-cash after-tax charge for impairments of certain Gulf of Mexico shelf and onshore properties, including those of an equity investee.

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 averaged, including a 3 cents gain per barrel from hedging activities, $22.93 per barrel, which was a decrease of $3.17 per barrel, or 12 percent, lower than 2000. Lower liquids prices and the $86 million non-cash after-tax charge were partially offset by the Company s higher average North America natural gas price 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 $3.85 per Mcf in 2001, which was an increase of 45 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 US Lower 48 production. After-tax earnings in 2001 also benefited from the $10 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives 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 Pure.

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, Australia, Latin America and West Africa.

2002 vs. 2001 After-tax earnings totaled $503 million in 2002 compared to $443 million in 2001. The increase was primarily due to $34 million in lower dry holes and exploratory costs, $30 million in higher natural gas and liquids prices, and $23 million in higher liquids and natural gas production. Dry hole costs for 2002 were lower, primarily due to exploratory dry holes in Brazil and Gabon in 2001 and lower Indonesia dry holes in the current year. Liquids production increased by approximately 4 percent, primarily from higher oil production in Thailand. Natural gas production increased 5 percent, primarily from Bangladesh, Myanmar and Brazil. The average natural gas price for International operations was $2.75 per Mcf in 2002 compared with $2.67 per Mcf in 2001. The average liquids price for International operations was $23.57 per Bbl in 2002, which was an increase of 60 cents per Bbl, or 3 percent, from 2001. These positive factors were partially offset by $15 million in higher operating expense.

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 to 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 $2.67 per Mcf in 2001, which was an increase of 14 cents per Mcf, or 6 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.

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 Exploration and Production segment in order to manage the Company s exposures to commodity price changes. The Trade segment also purchases liquids and natural gas from certain of the Company s royalty owners, joint venture partners and unaffiliated oil and gas producing and trading companies for resale. In addition, the segment trades hydrocarbon derivative instruments, for which hedge accounting is not used, to exploit anticipated opportunities arising from commodity price fluctuations. The segment also purchases limited amounts of physical inventories for energy trading purposes when arbitrage opportunities arise. These commodity risk-management and trading activities are subject to internal restrictions, including value at risk limits, which measure the Company s potential loss from likely changes in market prices.

2002 vs. 2001 After-tax earnings totaled $4 million in 2002 compared to $6 million in 2001. The lower results primarily reflected decreased domestic natural gas earnings from marketing activities due to lower production from the U.S. Lower 48 operations of the Exploration and Production segment and lower natural gas prices.

Sales and operating revenues were $2,524 million in 2002 compared to $3,856 million in 2001, which was a decrease of $1,332 million. These revenues represented approximately 48 percent and 58 percent of the Company s sales and operating revenues for 2002 and 2001, respectively. In 2002, crude oil revenues declined by approximately $650 million, primarily due to reduced activity in the purchase and resale of third-party barrels intended to take advantage of marketing opportunities, reflecting management s continued efforts to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets. Natural gas revenues declined by approximately $645 million, primarily due to lower U.S. domestic production volumes and commodity prices.

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

Sales and operating revenues 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.

Midstream

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

2002 vs. 2001 After-tax earnings totaled $104 million in 2002 compared to $54 million in the same period a year ago. The increase was due primarily to $30 million in after-tax gains from the sales of certain investment interests in nonstrategic pipelines in the U.S. In addition, after-tax earnings in the gas storage business in 2002 improved by $14 million compared with 2001, and the pipeline business had an $8 million improvement in throughput volumes. The earnings from equity investees in 2002 also included $6 million in after-tax charges for a litigation provision and a project impairment related to the Colonial Pipeline Company and a $2 million after-tax asset impairment related to another U.S. pipeline company in which the Company owns an equity interest. The 2001 results included a $6 million after-tax asset write-down related to an investment by Colonial Pipeline Company.

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.

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.

2002 vs. 2001 After-tax earnings totaled $30 million in 2002 compared to $11 million in 2001. The improved results were due to approximately $33 million after-tax in lower receivable provisions related to geothermal operations in Indonesia as a consequence of the agreements reached on the Indonesia geothermal contracts discussed below. This was partially offset by a decrease of $14 million from lower operational results in Indonesia and lower results from the equity interests in the gas-fired power plants in Thailand.

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. 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.

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

The new agreement extends the terms of the Joint Operation Contract and Energy Sales Contract (ESC) to 2040. The new agreement increases the Unit Rated Capacities for the generating plants operated by DSPL by 32 megawatts thereby increasing minimum take-or-pay amounts payable under the ESC and also includes a commitment by PLN to accept as much steam and electricity as possible to meet increased demand. In addition, the agreement reaffirms the Indonesian Government s guarantee of PLN s obligations to UGI, DSPL, Pertamina and the project s lenders. The new agreement lowers the selling price of electricity delivered by DSPL from 8.49 cents per kilowatt-hour (kWh) to 4.45 cents per kWh and steam supplied to PLN by UGI from 4.25 cents per kWh to 3.72 cents per kWh. Under the terms of the amended ESC both the selling price for electricity and the selling price for geothermal steam are indexed for changes in foreign exchange rates and inflation.

The new agreement also provides for payment by PLN of a portion of the past due receivable balances to the Company while the Company forewent a portion of the receivables. In 2002, the Company received $51 million from PLN in payment of a portion of the past due receivable balances. The Company retained a receivable balance of $93 million plus interest that it expects to collect in full. The remaining part of the outstanding receivables was written-off against a previously established allowance for doubtful receivables.

Corporate and Other

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

2002 vs. 2001 The after-tax earnings effect for 2002 was a loss of $344 million compared to a loss of $355 million in the same period a year ago. Environmental and litigation expenses were $93 million after-tax in 2002 compared to $108 million after-tax in 2001. In 2002, the results reflected approximately $15 million after-tax in higher minerals earnings compared to 2001. Net interest expense was $3 million lower in 2002, as higher interest expense from a premium on an early repayment of long-term debt was more than offset by higher capitalized interest on development projects. In 2002, earnings from real estate activities increased by $10 million after-tax and a $2 million after-tax gain from an insurance settlement was reached with insurers for the recovery of amounts previously paid out for environmental pollution claims and related costs. These positive factors in 2002 were partially offset by $25 million after-tax in higher pension related expenses.

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 decreased due to lower executive compensation expense. Net interest expense was lower by $14 million primarily due to higher capitalized interest on development projects. The 2001 results 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 2001 results 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 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. Environmental and litigation expenses were $108 million after-tax in 2001 compared to $112 million after-tax in 2000.

FINANCIAL CONDITION

	At December 31,		
Millions of dollars except as indicated	2002	2001	2000
Current ratio (a)	0.8:1	0.9:1	1.0:1
Total debt and capital leases	$ 3,008	$ 2,906	$ 2,506
Trust convertible preferred securities	522	522	522
Stockholders equity (b)	3,298	3,124	2,719
Total capitalization	6,828	6,552	5,747
Floating-rate debt/total debt (c)	6%	8%	3%

(a) 2002 reflects higher accounts payable balances due to increased development activities in International Exploration and Production. 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.
(b) 2002 includes $391 million reflecting the value of common stock issued to acquire Pure s outstanding common stock, which was offset by $334 million after-tax charge to other comprehensive income to recognize the minimum pension liability for the Company s Qualified Retirement Plan.
(c) Excludes interest rate swap derivatives. With the swaps included the ratios would be 5%, 7% and 3% for 2002, 2001 and 2000, respectively.

Cash Flows from Operating Activities

Cash flows from operating activities, including discontinued operations and working capital and other changes, were $1,571 million in 2002, $2,125 million in 2001 and $1,668 million in 2000.

2002 vs. 2001 Cash flows from operating activities decreased by $554 million in 2002 versus 2001. This decrease principally reflected the effects of lower North America natural gas production volumes and lower worldwide commodity prices. The decrease was partially offset by $120 million in lower income tax payments, net of refunds, compared to 2001, an increase of $38 million from the sale of certain domestic trade receivables during 2002 (see note 12 to the consolidated financial statements in Item 8 of this report), and the receipt of $51 million from PLN in July 2002 for payment of past due receivables as a result of the agreement reached on the Indonesia geothermal contracts at Gunung Salak.

2001 vs. 2000 Cash flows from operating activities increased by $457 million in 2001 versus 2000. This increase primarily 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. The 2000 results 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. due under the sales agreements for natural gas produced in Myanmar.

Capital Expenditures

Millions of dollars	Estimated 2003	Years ended December 31, 2002	2001	2000
Continuing operations				
Exploration and production				
North America				
U.S. Lower 48 (a)	$ 500	$ 544	$ 861	$ 628
Alaska	35	72	81	34
Canada (b)	105	147	113	164
International				
Far East (c)	550	626	425	325
Other	290	157	148	62
Total exploration and production	1,480	1,546	1,628	1,213
Trade				1
Midstream	155	71	41	16
Geothermal and power operations	30	14	7	18
Corporate and other	35	39	51	40
Total from continuing operations	$ 1,700	$ 1,670	$ 1,727	$ 1,288
Discontinued operations				
Agricultural products				14
Total capital expenditures (d)	$ 1,700	$ 1,670	$ 1,727	$ 1,302

(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 2003 exclude any possible major acquisitions.

The Company expects to keep its overall capital expenditures in 2003 about even with the 2002 level. In 2003, capital expenditures are expected to increase on large development projects and to decrease on the smaller scale development and exploitation projects. Capital spending for large development projects, including the West Seno field in deepwater Indonesia and Mad Dog in the Gulf of Mexico, and the Caspian crude oil development and the Baku-Tbilisi-Ceyhan (BTC) pipeline project (Midstream) are expected to total $700 million in 2003, up from $430 million in 2002. Other development capital in the Exploration and Production segment for 2003 is expected to be about $600 million, compared with $825 million in 2002. The Company is forecasting exploration capital spending in 2003 to be about $300 million, down from $330 million in 2002.

2002 vs. 2001 - Capital expenditures for 2002 decreased slightly from 2001, but there was a significant shift in spending between exploration and development. Development capital increased 30 percent over 2001. Capital spending included approximately $500 million for the Mad Dog development project in the Gulf of Mexico (U.S. Lower 48), Phase I development in the Caspian (International Other), the West Seno project in Indonesia and crude oil production development in Thailand (International Far East), and the Caspian crude oil pipeline (Midstream). These expenditures were primarily offset by lower Gulf of Mexico exploration activity in 2002 and the 2001 exploration activity in Brazil (International Other).

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, higher development expenditures in Indonesia and

Thailand and higher expenditures by Pure (U.S. Lower 48).

Major Acquisitions

In 2002, the Company acquired the shares of Pure that it did not already own. This transaction, which was accomplished through an exchange of Unocal common stock, was valued at approximately $410 million and was accounted for as a purchase.

In 2001, the Company formed a 50-50 joint venture with Forest Oil Corporation related to certain oil and gas properties located in the central Gulf of Mexico. The Company acquired a portion of proved reserves and 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.

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. These acquisitions were accounted for as purchases.

Asset Sale Proceeds

In 2002, pre-tax cash proceeds received from asset sales and discontinued operations totaled $166 million. The proceeds included $65 million from the sale of certain investment interests in non-strategic pipelines in the U.S., approximately $44 million from the sale of real estate and other miscellaneous properties, and approximately $32 million from the sale, by the Company s Pure subsidiary, of oil and gas producing properties in the U.S. Sale proceeds also included $22 million from various other oil and gas asset sales and cash proceeds of $3 million related to a participation payment received from the purchaser of the Company s former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline.

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 aforementioned participation payment relating to the Company s former West Coast refining, marketing and transportation assets, $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 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.

Long-term Debt and Other Financial Commitments

The Company s long-term debt at year-end 2002, including the current portion, increased by $90 million to $3.0 billion from $2.91 billion at year-end 2001. In 2002, the Company issued $400 million principal amount of 5.05 % notes with a maturity date of October 1, 2012. The net proceeds from the sale of the notes were primarily used to repay outstanding commercial paper that had been issued during the year. At December 31, 2002, the Company had no outstanding commercial paper. During 2002, the Company also retired $172 million of maturing medium-term notes. Northrock redeemed its $35 million Series A and $40 million Series B senior U.S. dollar-denominated notes. The Company also obtained a 3-year $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest. At December 31, 2002, the borrowings under the credit facility translated to $186 million using the applicable foreign exchange rate. At the end of 2002, Pure had no borrowings outstanding under its 3-year $275 million revolving credit facility or its $125 million (reduced from $235 million in December 2002) 5-year revolving credit facility.

Outstanding borrowings under both facilities were repaid in the fourth quarter of 2002 subsequent to the Company s acquisition of the outstanding Pure common shares. The Company cancelled both credit facilities in January 2003.

The Company s long-term debt at year-end 2001, including the current portion, increased by $400 million from $2.51 billion at year-end 2000. This increase primarily reflected 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 % notes.

The Company has two credit facilities in place: a $400 million 364-day credit agreement and a $600 million 5-year credit agreement. On October 7, 2002, the Company extended the 364-day credit agreement to October 6, 2003. The agreements provide for the termination of the loan commitments and require the prepayment of all outstanding borrowings in the event that (1) any person or group becomes the beneficial owner of more than 30 percent of the then outstanding voting stock of UNOCAL other than in a transaction having the approval of UNOCAL s board of directors, at least a majority of which are continuing directors, or (2) if continuing directors shall cease to constitute at least a majority of the board. The agreements do not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade. Both agreements limit the Company s debt to equity ratio to 70 percent, with the Company s convertible preferred securities included as equity in the ratio calculation.

Based on current commodity prices and current development projects, the Company expects cash generated from operating activities, asset sales and cash on hand in 2003 to be sufficient to cover its operating and capital spending requirements and to meet dividend payments and to pay down debt. Further, the Company has substantial borrowing capacity to enable it to meet unanticipated cash requirements. The Company relies on the commercial paper market, its accounts receivable securitization program and its revolving credit facilities to cover near-term borrowing requirements. The Company decreased the funding availability of its accounts receivable securitization program to $125 million from $204 million in 2002. At December 31, 2002, the Company had sold $108 million of its domestic trade receivables under this program.

The Company also had in place a universal shelf registration statement as of December 31, 2002, with an unutilized balance of approximately $339 million. In February 2003, a new $1.2 billion universal shelf registration statement was filed with and declared effective by the Securities and Exchange Commission. The $339 million balance of securities available under the prior registration statement was combined with the amount of securities under the new registration statement. The total of $1.539 billion will be available for the future issuance of other 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+ / Baa2 credit rating by Standard & Poor s and Moody s, respectively. In September 2002, Moody s downgraded the Company s credit rating to Baa2 from Baa1 and maintained a stable rating outlook on the Company. In September 2002, Standard & Poor s affirmed its rating for the Company s long-term debt with a stable rating outlook. Moody s and Standard & Poor s outlooks remained stable for the Company s Prime-2 and A-2 commercial paper ratings, respectively. The Company does not believe it has a significant exposure to liquidity risk in the event of a credit rating downgrade.

The following tables outline arious financial contractual obligations and commitments of the Company, including the potential effects in the event of a credit rating downgrade.

Contractual Obligations (millions of dollars)	Total	Less than 1 Year	1-5 Years	After 5 Years	Credit Rating Triggers
	Payments Due by Period				
Unocal bonds, notes and other debt (a)	$ 2,471	$ 105	$ 967	$ 1,399	None
UNOCAL Canada Ltd. Canadian dollar-denominated (C$295MM) bank credit agreement - guaranteed by UNOCAL - $186 million outstanding	186		186		Interest rate varies marginally based on rating. Ratings downgrade does not prevent drawdown or require pre-payment .
Pure s notes - not guaranteed by UNOCAL (b)	350			350	None
Pure s various lines of credit - not guaranteed by UNOCAL (b)	1	1			None for working capital line of credit. Other two credit facilities cancelled in January 2003.
Trust convertible preferred securities (c)	522			522	None
Non - cancelable operating leases (d)	473	169	279	25	None
Minority interest transaction (e)	252		252		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)	108	108			Sales of receivables prohibited if rating below Baa3 or BBB-
Derivative liabilities - (g) (h) (Including interest rate, foreign exchange rate and hydrocarbon derivatives)	151	113	38		Approximately $3 million would require collateral if rating drops below Baa3 or BBB-
Forward gas sale (i)	73	12	61		None

(a) The Company has the ability to refinance the portion of debt due within one-year. See note 17 for further details.
(b) See note 17 for further detail on Pure s debt.
(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. In 2003, a new accounting rule will result in the balance sheet reclassification of $242 million of this amount from minority interest to long-term debt.
(f) As more fully described in note 12, a non-consolidated UNOCAL subsidiary had sold $108 million in accounts receivable to an outside entity for cash. UNOCAL s accounts receivable have been reduced by this amount.
(g) Derivative assets of $162 million result in a net derivative receivable of $11 million.
(h) See discussion in Item 7A and note 27 for further detail on derivatives.
(i) 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.

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 - no balance outstanding	275		275		Cancelled in January 2003.
Pure s 5-year line of credit - not guaranteed by UNOCAL - no balance outstanding	125		125		Cancelled in January 2003.
Standby letters of credit (a)	39	39			None - one year term
Other financial assurances (a)	545	545			Approx. $332 million would require bonds, letter of credit or trust funds if rating below Baa3 or BBB-
Performance bonds (with indemnity (a) (b)	215	92	123		Approx. $79MM in bonds would require additional collateral if rating below Baa3 or BBB-
Guaranteed debt of equity investees (c)	25	25			UNOCAL guarantees are limited
Non-guaranteed debt of equity investees (d)					None
Environmental indemnification related to sold or formerly-operated properties (c)					None

(a) Majority of letters of credit, guarantees and performance bonds are renewed yearly. These are financial assurances related to UNOCAL obligations and are not guarantees of third party obligations, assets or performance.
(b) Includes $73 million of a performance bond for which a liability is included on the balance sheet in other current liabilities and other deferred credits.
(c) See note 22 for further details.
(d) See note 14 for further details.

In the normal course of business, the Company has performance obligations which are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions but are funded by the Company if exercised. At December 31, 2002, the Company had obtained various surety bonds for $215 million. These surety bonds included a bond for $93 million securing the Company s performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten-year period that began in January of 1999 and will end in December of 2008 and approximately $122 million in various other routine performance bonds held by local, city, state and federal agencies. The Company also had obtained approximately $39 million in standby letters of credit at December 31, 2002. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit. In addition, the Company has various other outstanding guarantees for approximately $545 million. Guarantees for approximately $332 million of this amount would require the Company to obtain a surety bond or a letter of credit or establish a trust fund if its credit rating were to drop below investment grade--that is BBB- or Baa3 from Standard & Poor s and Moody s, respectively. Approximately $160 million of the surety bonds, letters of credit and other guarantees that the Company is required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed in the Environmental Matters discussion starting on page 49.

Approximately $134 million of the $545 million in guarantees mentioned in the previous paragraph represents financial assurance given by the Company on behalf of its Molycorp subsidiary relating to permits covering operations and discharges from its Questa, New Mexico, molybdenum mine. The Company s financial assurance is for the completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. The costs associated with the financial assurance are based on estimates provided by agencies of the state of New Mexico.

The Company has certain investments in entities that it accounts for under the equity method, such as Colonial Pipeline Company. These entities have approximately $1.5 billion of their own debt obligations that are either fully non-recourse or of limited recourse to the Company. Of the total $1.5 billion in equity investee debt, $1.2 billion belongs to the Colonial Pipeline Company, in which the Company holds a 23.44 percent equity interest. The Company guarantees only $25 million of the total $1.5 billion debt obligations.

The Company has a 50 percent interest in an equity investee, Dayabumi Salak Pratama, Ltd. (DSPL), a company which sells electricity generated from geothermal steam in Indonesia, that it accounts for under the equity method. At December 31, 2002, DSPL had outstanding third-party debt of approximately $88 million. This debt is non-recourse to the Company. Due to a future accounting rule change (see FASB Interpretation No. 46 under Future Accounting Pronouncements) related to variable interest entities, the Company will be required to consolidate $78 million of this long-term debt amount effective with the third quarter of 2003.

The Company has a 55 percent interest in Spirit Energy 76 Development, L.P. (Spirit LP), a limited partnership. An unaffiliated investor contributed $250 million in cash to the partnership in exchange for an initial limited partnership interest of approximately 45 percent. The Company consolidates this partnership. 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. The minority interest on the Company s consolidated balance sheet related to this transaction was approximately $252 million at December 31, 2002. Due to a future accounting rule change (see FASB Interpretation No. 46 under Future Accounting Pronouncements) related to variable interest entities, the Company will be required to consolidate the unaffiliated investor. This is expected to result in a reclassification of $242 million from minority interests to long-term debt on the Company s consolidated balance sheet.

The Company has 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 of the Azerbaijan International Operating Company (AIOC) s Phase I development of offshore oil reserves in the Caspian Sea and $400 million for Phase II. The Company, through its participation in AIOC, is also pursuing the development of a 42-inch pipeline from Baku, Azerbaijan to Ceyhan, Turkey. The Company has committed up to $270 million for its share of the construction costs of the BTC pipeline. The pipeline company anticipates financing up to 70 percent of the pipeline s cost. The Company has also committed approximately $665 million to develop phases 1 and 2 of the West Seno field, offshore East Kalimantan in Indonesia. The Company and its co-venturer anticipate securing $350 million in financing from two loans through the Overseas Private Investment Corporation to develop the West Seno field (see page 12 of this report for further detail on the West Seno development project). Expenditures for the Mad Dog, AIOC Phase I, BTC pipeline and West Seno projects are on-going, and the aforementioned commitments reflect the Company s share of the total project costs and are not intended to communicate the remaining future commitments.

Critical Accounting and Other Policies

A critical accounting policy is one that is important to the portrayal of the Company s financial condition, results of operations or liquidity, and requires management to make difficult and/or complex judgments. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. 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 judgment, 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. Different views of future commodity prices could have a significant impact on whether the Company records asset impairments. 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.

Post-employment Benefits The Company utilizes US generally accepted accounting principles, as promulgated by the Financial Accounting Standards Board, to recognize the projected benefit obligations associated with pension and health care plans and for recording the costs of such plans in its income statement. The actuarial determination of projected benefit obligations (PBO) and related costs involves considerable judgment concerning events that are expected to occur over varying lengths of time in the future. Some of the key variables that impact measurement include future salary growth, estimated employee turnover rates and retirement dates, mortality, lump-sum election rates, long-term rates of return on plan assets, interest (discount) rates, initial and long-term cost trend rates and retiree utilization rates for health care services. Due to the complex and specialized nature of these calculations, the Company engages the services of outside actuarial firms to assist in the determination of these obligations and their related costs.

The recent decline in interest rates, to near 40-year lows, and lower market returns on plan assets have negatively impacted the company s benefit plans. While no cash contributions have been required in recent years the low interest rates and market returns have increased pension and other related retirement benefit expenses. The Company and its actuaries utilize both forecasted and historical data to adjust assumptions. Assumed interest (discount) rates reflect the rates at which pension benefits can be effectively settled. The Company has little leeway in selecting a discount rate as such rates are required to reflect rates implicit in current annuity contracts and/or current market rates for high-quality fixed income investments. A lower discount rate increases both the present value of benefit obligations and pension expense. For the Company s principal plans, a 50 basis point (1/2 %) decrease in the discount rate, with all other assumptions held constant, would have increased the PBO by approximately $70 million at December 31, 2002 and would increase pre-tax pension expense for 2003 by approximately $9 million. The expected rate of return on plan assets (ROA) reflects the average rate of returns expected on funds invested to provide the projected benefits. By definition the ROA is an estimate of long-term returns. The Company considers both current and expected asset allocations as well as historical and forecasted returns on all categories of plan assets when selecting an ROA. A 50 basis point decrease in the expected return on the assets of the Company s principal pension plans, with all other assumptions held constant, would increase pretax pension expense $5 million in 2003.

Interest rates, asset returns and inflation have varied significantly over time and are likely to continue to do so in the future. Likewise, actual results in any given year will often differ from actuarial assumptions because of changes in plan benefits and terms plus legal, economic and other factors. In 2002 the Company recognized a minimum pension liability of $103 million reflecting the excess of the accumulated benefit obligation (ABO) over the fair value of plan assets at December 31, 2002, for its Qualified Retirement Plan covering current and former U.S. payroll employees. The recognition of this liability resulted in an after-tax charge of $334 million to the other comprehensive income (OCI) component of stockholders equity. If in subsequent years returns on plan assets improve and/or interest rates rise the fair value of plan assets may again exceed the ABO. If and when this occurs, the liability will be reversed and a pre-paid pension cost asset will be re-established on the balance sheet with the offsetting credit booked to OCI. The Company was not required to make any contributions to the plan in 2002 nor will it be required to make any contributions in 2003 or 2004. However, continued poor returns on plan assets could accelerate the requirement to make cash contributions to the plan after 2004. The Company may elect, however, to make voluntary cash contributions to the plan at any time.

See note 16 to the consolidated financial statements in Item 8 of this report for additional disclosures on the Company s various post-employment benefit plans.

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

Unocal is committed to operating its business in a manner that is environmentally responsible. This commitment is fundamental to the Company s core values. As a part of this commitment, the Company has procedures in place to audit and monitor its environmental performance. In addition, Unocal has implemented programs to identify and address environmental risks throughout the Company. Consequently, 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	**2003**	**2002**	**2001**	**2000**
Environmental related capital expenditures				
Continuing operations	$ 35	$ 22	$ 19	$ 15
Discontinued operations				$ 2

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. Higher 2003 estimated expenditures versus 2002 are partially due to environmental expenditures that will be incurred in 2003 to prepare properties owned by the Company for sale. Higher 2003 capital expenditures are also attributed to various planned environmental projects in the Company s International subsidiaries related to process improvements and regulatory compliance.

Amounts recorded for environmental related expenses were approximately $170 million in 2002, $175 million in 2001 and $160 million in 2000. Environmental expenses include provisions for remediation that were identified during the Company s ongoing review of its environmental obligations and operating, maintenance and administrative expenses. Lower expenses in 2002 versus 2001 were primarily due to lower remediation provisions in 2002. Higher expenses in 2001 versus 2000 were due partially to additional remediation provisions recorded in 2001 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.

At December 31, 2002, the Company s reserves for environmental remediation obligations totaled $245 million, of which $113 million was included in current liabilities. During 2002, cash payments of $114 million were applied against the reserves and $122 million in provisions were added to the reserves. 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 stages 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 $245 million. The reserve amounts and possible additional costs are grouped into the following four categories:

	At December 31, 2002	
Millions of Dollars	Reserve	Possible Additional Costs
Superfund and similar sites	$ 17	$ 10
Active Company facilities	37	55
Company facilities sold with retained liabilities and former Company-operated sites	104	75
Inactive or closed Company facilities	87	105
Total Reserve	$ 245	$ 245

Also see notes 18 and 22 to the consolidated financial statements in Item 8 of this report for additional information on environmental related matters.

In 2002, provisions of $8 million were recorded for the Superfund and similar sites category. The provisions were primarily for the Company s estimated remaining share of oversight and monitoring costs related to the McColl Superfund site in Fullerton, California as the result of a federal appeals court overturning a 1998 lower court decision that held the federal government responsible for cleanup of the site because of its role in encouraging oil companies to produce gasoline during World War II. Payments for this category of sites were $3 million in 2002.

Provisions of $12 million were recorded for sites included in the Company s Active Company facilities category. These provisions were primarily for the estimated cost of studies, investigations and remediation activities at Molycorp s molybdenum mine located in Questa, New Mexico. Molycorp has been working cooperatively with the State of New Mexico and the U.S. Environmental Protection Agency to determine if past mining operations have had an adverse ecological impact on surface water and groundwater, and to identify remedial alternatives to mitigate any impact identified. Through this collaborative effort, it was determined that the scope of the environmental studies and investigations for the site needed to be expanded. The Company made payments of $15 million for this category of sites in 2002.

During 2002, provisions of $75 million were recorded for the Company facilities sold with retained liabilities and former Company-operated sites category. The provisions included revised remediation cost estimates that the Company received from the purchaser of service stations, bulk plants, terminals, refineries and pipelines that were part of the Company s former West Coast refining, marketing and transportation assets sold in 1997. Provisions for this category were also recorded as a result of revised cost estimates related to the cleanup of the Company s former service stations and distribution facilities throughout the U.S. and the estimated additional cost to clean up contaminated areas that had been identified at a former oil field in Michigan that was previously operated by the Company. Cash payments of $69 million were made in 2002 for sites in this category.

Provisions of $27 million were recorded in 2002 for sites included in the Inactive or closed Company facilities category. These provisions were principally for the cost of remediation work related to the decommissioning and decontamination of Molycorp s closed molybdenum and rare earth processing facilities in Washington and York, Pennsylvania. As a result of ongoing cooperative efforts between the Company and the Nuclear Regulatory Commission, it was determined that additional volumes of low-level radioactive contaminated material, in excess of amounts previously estimated, needed to be removed at the York and Washington sites. Provisions were also recorded for revised cost estimates related to various remediation projects at the Company s former Guadalupe oil field on the central California coast. During 2002, $27 million in payments were made for this category.

The possible additional remediation costs of $245 million estimated at December 31, 2002, were $15 million lower than at year-end 2001.

The net decrease for the year included lower estimated possible additional costs of $10 million for Superfund and similar sites. Estimated oversight and monitoring costs for the McColl site previously included in the possible costs for this category were added to the reserve in 2002 as discussed above.

Estimated possible additional costs for the Active Company facilities category of sites decreased by $35 million in 2002. The decrease was the result of adding estimated costs to the reserve and revising cost estimates in this category for various sites, including the Company s oil and gas sites in Alaska and Molycorp s Questa, New Mexico, molybdenum mine.

Partially offsetting the foregoing decreases in 2002 was a $5 million increase in estimated possible costs for the Company facilities sold with retained liabilities and former Company-operated sites category. The Company increased its estimate for possible additional costs for areas within the former Company-operated Michigan oilfield that have not yet been investigated. Higher possible costs were also estimated for Company s former West Coast refining, marketing and transportation assets sold in 1997; a portion of these estimated costs were subsequently added to the reserve for these sites as discussed above. The higher costs were based on estimates provided by the purchaser of these sites. Partially offsetting the above increases for this category of sites were lower cost estimates for service stations and distribution facilities located throughout the U.S. that were formerly operated by the Company.

Possible additional costs for the Inactive or closed Company facilities category of sites increased by $25 million. The increase included the higher estimated possible decommissioning and decontamination costs related to the additional volumes of radioactive contaminated material, in excess of amounts previously estimated that may be present at the Washington, Pennsylvania site. A portion of these estimated possible additional costs for this site were subsequently added to the reserve during 2002 as discussed above. The Company also estimated possible additional costs for a closed tank farm in San Luis Obispo, California. The estimate is based on the upper end of the range of costs for possible cleanup and restoration scenarios evaluated by the Company during the year for the final disposition of the site that could occur but are not yet required.

OUTLOOK

Volatile energy prices are expected to continue to impact financial results. 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, especially events concerning Iraq and Venezuela, and security and other factors.

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

The Company currently estimates its full-year 2003 production to be at the lower end of the 480,000 to 495,000 BOE/d range. The Company s total actual production for the year could be impacted by cost recovery volume reductions under the Company s various foreign PSCs due to higher oil prices, demand for gas in Thailand, production and exploration performance in the Gulf of Mexico, and possible asset sales of marginal producing properties from North America operations. For 2003, the Company has hedged 72.8 billion Btus of U.S. Lower 48 natural gas production with collars of $3.97 to $4.87 per MMBtu as of March 14, 2003. This volume represents approximately 30 percent of expected U.S. Lower 48 natural gas production. The Company has also hedged 4.4 million barrels of 2003 U.S. Lower 48 crude oil production with collars between $28.50 and $32.34 per barrel. Hedged crude oil production volumes represent 26 percent of expected U.S. Lower 48 crude oil production in 2003. The Company s net earnings for the full-year are expected to change 14 cents per share for each $1 change in the Company s average worldwide realized price for crude oil and 7 cents per share for every 10-cent change in its average realized North America natural gas price, excluding the effect of hedging activities. The Company forecasts pre-tax dry hole costs of $115 to $145 million and forecasts pre-tax pension-related expenses will increase over 2002 by approximately $55 million to $60 million. The Company currently forecasts that after-tax net interest expense for the full-year 2003 to be between $140 and $150 million.

Exploration and Production   North America

U.S. Lower 48

The Company expects to drill 12 to 18 deep shelf wells in the Gulf of Mexico in 2003.

The Company is currently logging and evaluating a well utilizing the *Discoverer Spirit* drillship, on the Bohr prospect located on Mississippi Canyon Block 637 in the deepwater Gulf of Mexico, a farm-in for the Company in 2002. The Company has a 27.5 percent working interest. Results are expected in March 2003.

In the Gulf of Mexico deep water, the Company plans to continue funding the development of the Mad Dog discovery. The Company anticipates first production in 2004, with gross expected production of 75 MBbl/d of liquids and 35 MMcf/d of natural gas in 2007. The Company expects the co-venture integrated project team of the K-2 discovery to have a development plan in 2003. The Company also expects to drill 4 to 5 wells in the Gulf of Mexico deep water in 2003.

The Company now expects to move forward with studies on development options for its Trident discovery in the deepwater Gulf of Mexico. The development will depend on industry drilling results in the area. The Company is the operator and has a 59.5 percent working interest in a seven-block prospect.

The acquisition of the Pure minority interest shares in 2002 is expected to offer the Company a number of operational efficiency opportunities, of which the Company expects to take full advantage in 2003.

The Company has sold and anticipates selling more of its lower margin properties in the U.S. in 2003.

Alaska

The Ninilchik Unit development in the South Kenai Peninsula is progressing. Four exploration and development wells have tested successfully, and the plans call for two additional wells in 2003. The Company has a 40 percent non-operating interest in the unit. First production from the Ninilchik Unit is also expected in the fourth quarter of 2003. Plans call for drilling at least one new exploration well on the Kenai Peninsula in 2003.

Exploration and Production   International

Far East

Thailand: The Company s Unocal Thailand, Ltd. (Unocal Thailand), subsidiary expects modest production growth in 2003, with the full-year effect of the Phase II development in the northern part of the Pailin field in the B12/27 concession area in the Gulf of Thailand. Unocal Thailand is operator of the field and holds a 35 percent working interest (31 percent net of royalty). The Company also expects higher average liquids production, with the full-year effect of crude oil production from its Yala field. The Company has a 71 percent working interest in the Yala field (62 percent net of royalty). In 2003, the Company s plans are geared towards exploring for additional oil and gas resources in the Gulf of Thailand and supporting the efforts of PTT Exploration and Production PLC (PTTEP) in the development of the Arthit gas field in the gulf. The Company has a 16 percent working interest in the Arthit gas field.

Indonesia: The Company s Unocal Rapak, Ltd. (Unocal Rapak), subsidiary is continuing its evaluation of engineering and development studies for the deepwater Ranggas oil prospect offshore East Kalimantan, Indonesia. The Company expects to complete the pre-development engineering to determine if Ranggas is a commercial development later in 2003. Unocal Rapak is operator of the Rapak PSC area and holds an 80 percent working interest. Two wells, the Ranggas Selatan-1 and Gehem-1, are planned to be drilled in the second quarter of 2003 to test the oil potential of structures south of the main Ranggas discovery area. The Company is also evaluating early development options for the condensate discovered at its deepwater Gendalo-Gandang discovery in the Ganal PSC, offshore Indonesia. The Company s Unocal Ganal, Ltd., subsidiary is the operator of the Ganal PSC and holds an 80 percent working interest.

In 2003, the Company expects new production from the deepwater West Seno oil and gas field to come on line in the second quarter. Gross daily production from the first phase of development is expected to reach about 35 MBOE to 40 MBOE by the end of 2003, increasing to a peak production level of approximately 60 MBbl/d of oil and 150 MMcf/d of natural gas (gross) in late 2005 with the second phase of development. Gross development costs for the first phase are expected to be approximately $500 million, with an additional $240 million for the second phase (Unocal s net share is expected to be approximately $450 million and $215 million for the first and second phases, 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 2003 for two loans. One loan is $300 million for the first phase, and the other loan is $50 million for the second phase.

In January 2003, the Company s UNOCAL Donggala Limited (UNOCAL Donggala) subsidiary agreed to farm in to the deepwater Donggala PSC. The farm-in agreement was approved by the Indonesian government in February 2003. UNOCAL Donggala acquired a 19.55% non-operating working interest in the PSC, which lies adjacent to and east of the Rapak PSC area. Water depth at Donggala ranges from 6,000 to 8,000 feet. The Company is currently drilling the Oti-1 exploratory well on the Donggala PSC.

In 2003, the Company will also drill a deep well in the Sadewa field in the East Kalimantan PSC area to test for oil. The Sadewa discovery well was drilled in 2002 and found both natural gas and oil. The oil play found near the bottom of the well provided encouragement for deeper oil potential that could not be fully evaluated at the time. The Company holds a 50 percent working interest in the well.

China: 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 sign PSCs in 2003 to explore and develop natural gas resources. The Company s working interest is expected to be 20 percent.

Other International

Azerbaijan: The Azerbaijan International Operating Company (AIOC) consortium, in which the Company has a 10.28% working interest, is developing Phases I and II of the offshore Azeri field in the Azeri Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea. Phase I is to develop an estimated 1.5 billion barrels of proved crude oil reserves and Phase II is to add approximately the same amount of reserves. The Company has approved the expenditure of $310 million and $400 million for its share of the costs for Phases I and II, respectively. The project is under construction and on schedule with first oil from the Phase 1 Central Azeri platform expected early in 2005. The Company expects production from Phase I to add 350 MBbl/d (gross). Phase II production is expected from two additional platforms in 2006 and 2007 and is expected to add another 350 MBbl/d (gross). A third phase is in early engineering and is expected to be approved in 2004. Gross production from the combined phases, plus the currently producing Early Oil Project in the Chirag Field, is forecasted to be over 1 MMBbl/d (gross) by 2009. This forecast is contingent upon the completion of the BTC pipeline project and the general political risks inherent to the region. The multi-country nature of this pipeline along with multinational participation in the consortium, in addition to expected project financing from international lending institutions like the IFC and EBRD and from several export credit agencies, should help to mitigate the political risk.

Bangladesh: The Company continues to work with the government of Bangladesh and Petrobangla, the state oil and gas company, to develop additional reserves and export natural gas to markets in neighboring India. At February 28, 2003, the Company s business unit in Bangladesh had a gross receivable balance of approximately $27 million relating to invoices billed for natural gas and condensate sales to Petrobangla. Approximately $16 million of the outstanding balance represented past due amounts and accrued interest for invoices covering October 2002 through December 2002. Generally, invoices, when paid, have been paid in full. The Company is working with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables.

The Company is proposing to develop the Moulavi Bazar natural gas field in Bangladesh that could provide up to 100 MMcf/d to meet the needs of the domestic Bangladesh market. The Company estimates that commercial production of natural gas from the field could begin within a year after a gas purchase and sales agreement is signed with Petrobangla.

Midstream

Construction of the Baku-Tbilisi-Ceyhan (BTC) pipeline will continue in 2003. The pipeline project is planned to have a crude oil capacity of 1 million Bbl/d. Completion of the pipeline is expected in late 2004 at an overall estimated cost of approximately $3 billion, and the pipeline is expected to be in operation in early 2005. The Company has an 8.9 percent interest and is one of eleven shareholders in the BTC pipeline project. The pipeline company anticipates financing up to 70 percent of the pipeline s cost.

The Kenai Kachemak Pipeline, currently under construction, will transport natural gas from Ninilchik to Kenai, where it will tie into the existing gas grid serving south central Alaska. The Company expects the 32-mile pipeline to be in operation in the fourth quarter of 2003.

Geothermal and Power Operations

The Company expects net earnings from Geothermal and Power operations for 2003 to be between $55 million and $65 million. This forecast includes the impact of the first full year of operations pursuant to the amended agreements covering operations at Gunung Salak in Indonesia. In the Philippines, negotiations between the Company s wholly-owned subsidiary Philippines Geothermal, Inc. (PGI) and two government-owned entities, the National Power Corporation (NPC) and the Power Sector Assets and Liabilities Corporation (PSALM), resulted in the signing of a Term Sheet in October 2002. The boards of directors of NPC and PSALM approved the Term Sheet. In March 2003, PGI, NPC, PSALM and the Philippine Department of Energy signed a compromise settlement agreement covering the definitive terms of settlement. The parties are now in the process of securing all necessary Philippine government and court approvals of the settlement.

FUTURE ACCOUNTING CHANGES

SFAS No. 143: In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires that the Company recognize liabilities related to the legal obligations associated with the retirement of its tangible long-lived assets at fair values in the periods in which the obligations are incurred (typically when the assets are installed). These obligations include the required decommissioning and removal of certain oil and gas platforms, plugging and abandonment of oil and gas wells and facilities and the closure and site restoration of certain mining facilities.

Prior to January 1, 2003, the Company was required under SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies to accrue its abandonment and restoration costs ratably over the productive lives of its assets. The Company previously used the units-of-production method to accrue these costs. SFAS No. 19 resulted in higher costs being accrued early in the fields lives when production was at its highest levels and abandonment and restoration costs accruals were matched with the revenues as oil and gas were produced.

Under SFAS No. 143, when the liabilities for asset retirement obligations are initially recorded at fair values, capital costs of the related assets will be increased by equal corresponding amounts. Over time, changes in the present value of the liabilities will be accreted and expensed and the capitalized asset costs will be depreciated over the useful lives of the corresponding assets. Because SFAS No. 143 requires the use of interest accretion for revaluing asset retirement obligation liabilities as a result of the passage of time, associated accretion costs will be higher near the end of the fields lives when oil and gas production and related revenues are at their lowest levels.

Accounting Principles Board Opinion (APB) No. 20, Accounting Changes requires that the Company calculate the retroactive impact of adopting SFAS No. 143 from the inception of its asset retirement obligations to its January 1, 2003 adoption date. APB No. 20 requires that this impact be quantified and reported as a cumulative effect of an accounting change on the earnings statement. This cumulative effect will include the catch up of SFAS No. 143 accretion expense related to the fair value of the liabilities as well as the catch up of associated depreciation expense related to the increased capital costs of the corresponding assets. The cumulative effect will also include the reversal of abandonment and restoration costs previously charged to earnings under SFAS No. 19. In addition to the impact on earnings due to the differences in applying SFAS No. 19 and SFAS No. 143 to the Company s oil and gas operations, the cumulative effect will also include the impact related to the Company s mining operations under SFAS No. 143. The Company expects to finalize its abandonment plans by late March 2003 and will record the effects of adopting SFAS No. 143 as of January 1, 2003 in the first quarter of 2003. The Company expects to recognize a one time after-tax charge in the range of $70 million to $85 million as the cumulative effect of an accounting change related to the adoption of SFAS No. 143.

SFAS No. 146: In June 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities . This statement provides guidance on the recognition and measurement of liabilities associated with disposal activities and is effective for the Company on January 1, 2003. The Company does not expect the adoption of SFAS No. 146 to have a significant impact on its financial position or results of operations.

SFAS No. 148: In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation--Transition and Disclosure--an amendment of SFAS No. 123. The statement provides for three methods of transitioning from the intrinsic value to the fair value method of accounting for stock-based compensation. This statement also amends the disclosure requirements of SFAS No. 123 and APB Opinion No. 28, Interim Financial Reporting, to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The disclosure requirements of the statement are effective for the Company immediately and are reflected in this report (see note 1 to the consolidated financial statements in Item 8). The Company expects to adopt the fair value recognition provisions of SFAS No. 148, on a prospective basis, effective January 1, 2003. This change is estimated to decrease 2003 after-tax net income by approximately $5 million. When fully phased in for future grants over the next three years, the annual expense is estimated to be approximately $10 million after-tax.

FASB Interpretation No. 45: In November 2002, the FASB issued Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. This Interpretation requires the recognition of certain guarantees as liabilities at fair market value and is effective for guarantees issued or modified after December 31, 2002. The Company has included the disclosure requirements of the Interpretation in this report (see note 22 to the consolidated financial statements in Item 8) and does not expect that the adoption will have a significant impact on its financial position or results of operations.

FASB Interpretation No. 46: In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities. This Interpretation requires the consolidation of certain companies that are defined as variable interest entities. This Interpretation is effective for new variable interest entities as of February 1, 2003. The effective date for entities existing prior to February 1, 2003 is July 1, 2003. The Company has included the disclosure requirements of the Interpretation in this report and expects the adoption of the recognition (i.e., consolidation) requirements of the Interpretation to increase its consolidated long-term debt by approximately $320 million. This amount that the Company anticipates to consolidate when it adopts the Interpretation includes $242 million related to a partnership interest in which it has a minority interest liability (see note 21 to the consolidated financial statements in Item 8 of this report) and $78 million of third-party debt of DSPL (see note 14 to the consolidated financial statements in Item 8 of this report).

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

RISK FACTORS

Our business activities and our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments. Additional risks relating to our securities may be included in the prospectuses for securities we issue in the future.

Our profitability is highly dependent on the prices of crude oil, natural gas and natural gas liquids, which have historically been very volatile.

Our revenues, profitability, operating cash flows and future rate of growth are highly dependent on the prices of crude oil, natural gas and natural gas liquids, which are affected by numerous factors beyond our control. Historically these prices have been very volatile. For example, our U.S. Lower 48 gas prices declined significantly in 2001 and 2002 from the very high levels reached in the second half of 2000 and early 2001. Recently, these prices have increased again substantially. A significant downward trend in commodity prices would have a material adverse effect on our revenues, profitability and cash flow and could result in a reduction in the carrying value of our oil and gas properties and the amounts of our proved oil and gas reserves.

Our commodity hedging and speculating activities may prevent us from benefiting fully from price increases and may expose us to other risks.

To the extent that we engage in hedging activities to endeavor to protect ourselves from commodity price volatility, we may be prevented from realizing the benefits of price increases above the levels of the hedges. In addition, we engage in limited speculative trading in hydrocarbon commodities and derivative instruments in connection with our risk management activities, which subjects us to additional risk.

Our drilling activities may not be productive.

Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blow-outs and surface cratering;
- marine risks such as capsizing, collisions and hurricanes;
- other adverse weather conditions; and
- shortages or delays in the delivery of equipment.

Certain of our future drilling activities may not be successful and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of our capital budget devoted to higher risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

As part of our strategy, we explore for oil and gas offshore, often in deep water or at deep drilling depths, where operations are more difficult and costly than on land or than at shallower depths and in shallower waters. Deepwater operations generally require a significant amount of time between a discovery and the time that we can produce and market the oil or gas, increasing both the operational and financial risks associated with these activities.

We may not be insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the operating risks normally associated with the exploration for and production of oil and gas, including blowouts, leaks, spills, cratering and fire, as well as weather-related risks, such as severe storms and hurricanes, any of which could result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property, some of which may be difficult and expensive to control and/or remediate, as well as injuries and/or deaths. In addition, our pipeline, midstream and mining activities are subject to similar risks. As protection against financial loss resulting from these operating hazards, we maintain insurance coverages, including certain physical damage, comprehensive general liability and worker s compensation insurance. However, because of deductibles and other limitations, we are not fully insured against all risks in our business. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our results of operations and possibly on our financial position.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from development projects.

We are involved in several large development projects, principally offshore. Key factors that may affect the timing and outcome of those projects include: project approvals by joint venture partners; timely issuance of permits and licenses by governmental agencies; manufacturing and delivery schedules of critical equipment, such as offshore platforms, and commercial arrangements for pipelines and related equipment to transport and market hydrocarbons. Delays and differences between estimated and actual timing of critical events may adversely affect the completion of and commencement of production from such projects and, consequently, the economic value of and returns on such projects.

Our oil and gas reserve data and future net revenue estimates are uncertain.

Estimates of reserves by necessity are projections based on engineering data, future rates of production and the amounts and timing of future expenditures. We base the estimates of our proved oil and gas reserves and projected future net revenues on reserve reports we prepare. The process of estimating oil and gas reserves requires substantial judgment on the part of the petroleum engineers, resulting in imprecise determinations, particularly with respect to new discoveries. Different reserve engineers may make different estimates of reserve quantities and revenues attributable to those reserves based on the same data. Future performance that deviates significantly from reserve reports could have a material adverse effect on our business and prospects, as well as on the amounts and carrying values of such reserves.

Fluctuations in the prices of oil and natural gas can have the effect of significantly altering reserve estimates, because the economic projections inherent in the estimates and the terms of production sharing contracts for our foreign operations may reduce or increase the quantities of recoverable reserves. Under our production sharing contracts, under which we receive shares of production to recover our costs, our entitlement share of reserves and production generally decrease as sales prices increase, and vice versa. We may not realize the prices our reserve estimates reflect or produce the estimated volumes during the periods those estimates reflect. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates.

Any downward revision in our estimated quantities of reserves or of the carrying values of our reserves could have adverse consequences on our financial results, such as increased depreciation, depletion and amortization charges and/or impairment charges, which would reduce earnings and stockholders equity.

If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.

The rate of production from oil and gas properties generally declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or, through engineering studies, identify additional productive zones or secondary recovery reserves, or acquire additional properties containing proved reserves, our proved reserves will decline materially as oil and gas are produced. Future oil and gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves.

Our growth may depend on our ability to acquire oil and gas properties on a profitable basis.

Acquisitions of producing oil and gas properties have been a key element of maintaining and growing our reserves and production in recent years, particularly in North America. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves and to assess future abandonment and possible future environmental liabilities.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates.

We are subject to domestic governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and by federal, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price controls and environmental protection laws and regulations.

Global political and economic developments may impact our operations.

Political and economic factors in international markets may have a material adverse effect on our operations. On an equivalent-barrel basis, over one-half of our oil and gas production in 2002 was outside the United States, and approximately two-thirds of our proved oil and gas reserves at December 31, 2002 were located outside of the United States. All of our geothermal operations and reserves are located outside the United States.

There are many risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas liquids, natural gas and geothermal steam pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. These risks include:

- political and economic instability or war;
- the possibility that a foreign government may seize our property with or without compensation;
- confiscatory taxation;
- legal proceedings and claims arising from our foreign investments or operations;
- a foreign government attempting to renegotiate or revoke existing contractual arrangements;
- fluctuating currency values and currency controls; and
- constrained natural gas markets dependent on demand in a single or limited geographical area.

Actions of the United States government through tax and other legislation, executive order and commercial restrictions can adversely affect our operating profitability overseas, as well as in the U.S. Various agencies of the United States and other governments have from time to time imposed restrictions which have limited our ability to gain attractive opportunities or even operate in various countries. These restrictions have in the past limited our foreign opportunities and may continue to do so in the future.

The oil and gas exploration and production industry is very competitive, and many of our exploration and production competitors have greater financial and other resources than we do.

Strong competition exists in all sectors of the oil and gas exploration and production industry and, in particular, in the exploration and development of new reserves. We compete with major integrated and other independent oil and gas companies for the acquisition of oil and gas leases and other properties, for the equipment and labor required to explore, develop and operate those properties and in the marketing of oil and natural gas production. Many of our competitors have financial and other resources substantially greater than those available to us. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect the demand for oil and natural gas production, such as changes in worldwide prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers and other specialists.

Environmental compliance and remediation have resulted in and could continue to result in increased operating costs and capital requirements.

Our operations are subject to numerous laws and regulations relating to the protection of the environment. We have incurred, and will continue to incur, substantial operating, maintenance, remediation and capital expenditures as a result of these laws and regulations. Our compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination may require us to make material expenditures or subject us to liabilities beyond what we currently anticipate. In addition, any failure by us to comply with existing or future laws could result in civil or criminal fines and other enforcement action against us.

Our past and present operations and those of companies we have acquired expose us to civil claims by third parties for alleged liability resulting from contamination of the environment or personal injuries caused by releases of hazardous substances.

For example:

- we are investigating or remediating contamination at a large number of formerly and currently owned or operated sites and have recently recorded additional liabilities relating to some of these sites; and
- we have been identified as a potentially responsible party at several Superfund and other multi-party sites where we or our predecessors are alleged to have disposed of wastes in the past.

Environmental laws are subject to frequent change and many of those laws have become more stringent. In some cases, they can impose liability for the entire cost of cleanup on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them.

It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental and legal matters and other contingencies because:

- some potentially contaminated sites are in the early stages of investigation, and other sites may be identified in the future;

- cleanup requirements are difficult to predict at sites where remedial investigations have not been completed or final decisions have not been made regarding cleanup requirements, technologies or other factors that bear on cleanup costs;

- environmental laws frequently impose joint and several liability on all potentially responsible parties, and it can be difficult to determine the number and financial condition of other potentially responsible parties and their shares of responsibility for cleanup costs;

- environmental laws and regulations are continually changing, and court proceedings are inherently uncertain; and

- some legal matters are in the early stages of investigation or proceeding or their outcomes otherwise may be difficult to predict, and other legal matters may be identified in the future.

Although our management believes that it has established appropriate reserves for cleanup costs, due to these uncertainties, we could be required to provide significant additional reserves in the future, which could adversely affect our results of operations and possibly our financial position.

More detailed information with respect to the matters discussed above is set forth under the caption Environmental Regulation , under the Environmental Matters section of the Management s Discussion and Analysis, and in note 22 to the Consolidated Financial Statements in Item 8.

We are subject to lawsuits and claims involving substantial amounts and sometimes asserting novel theories of recovery.

We have a number of lawsuits and claims pending against us as a consequence of the past conduct of our business, some of which seek large amounts of damages. While we currently believe that none of them will have a material adverse effect on our financial condition or liquidity, certain of them could have a material adverse effect on our results of operations for the accounting period or periods in which one or more of them might be resolved adversely.

In addition, certain of the pending matters are seeking to take advantage of expansive judicial interpretations of laws and precedents to impose liability for acts that we believed to be in compliance with applicable laws and regulations at the time, and we could be the subject of similar such lawsuits and/or claims in the future.

We depend upon payments from our subsidiaries.

We conduct substantially all of our operations through Union Oil and other domestic and international subsidiaries. Our principal sources of cash are dividends and advances from our subsidiaries, investments, including certain equity investments in other operating companies, payments by subsidiaries for services rendered and interest payments from subsidiaries on cash advances. The amount of cash and income available to us from our subsidiaries largely depends upon each subsidiary s earnings and operating and capital requirements. In addition, the ability of our subsidiaries to make any payments or transfer funds will depend on the subsidiaries earnings, business and tax considerations and legal restrictions. Failure to receive adequate cash and income from our subsidiaries could jeopardize our ability to make payments on debt securities we issue, including those held by Unocal Capital Trust or that we may issue in the future to UNOCAL Capital Trust II, to satisfy our guarantees of debt securities of Union Oil and the trust preferred securities of UNOCAL Capital Trust or that UNOCAL Capital Trust II may issue, and to pay dividends on our common stock and any preferred stock we may issue.

Our debt level may limit our financial flexibility.

As of December 31, 2002, our consolidated balance sheet showed $3.0 billion of total debt outstanding. In addition, UNOCAL Capital Trust, a consolidated finance subsidiary, has $522 million of convertible trust preferred securities outstanding, which represent beneficial interests in a like amount of subordinated debt we issued to it. Effective in the third quarter of 2003, pursuant to a recently issued accounting requirement, we will be recording as an additional $320 million of debt amounts that, at December 31, 2002, had either been classified as a minority interest on the balance sheet or omitted from the balance sheet as the debt of an unconsolidated equity investee. We may incur additional debt in the future, including in connection with acquisitions, recapitalizations and refinancings.

The level of our debt could have several important effects on our future operations, including, among others:

- a significant portion of our cash flow from operations will be applied to the payment of principal and interest on the debt and will not be available for other purposes;
- credit rating agencies have changed, and may continue to change, their ratings of our debt and other obligations as a result of changes in our debt level, financial condition, earnings and cash flow, which in turn impacts the costs, terms and conditions and availability of financing;
- covenants contained in our existing and future debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate and other purposes may be limited or burdened by increased costs or more restrictive covenants;
- we may be at a competitive disadvantage to similar companies that have less debt; and
- our vulnerability to adverse economic and industry conditions may increase.

We have substantial financial obligations and commitments, which are not reflected on our consolidated balance sheet.

In the normal course of business we and our subsidiaries had incurred, at December 31, 2002, substantial contractual obligations for, non-cancelable operating leases ($473 million), including drill ship leases, reimbursement obligations under standby letters of credit ($39 million) and performance bonds ($215 million) posted by third-party financial institutions on our behalf, and other financial assurances that we and/or our subsidiaries have given to satisfy the requirements of federal, state, local and foreign governmental entities and other parties ($545 million).

Furthermore, at year-end 2002, we had firmly commited to approximately $700 million in capital expenditures in 2003 for the development of offshore oil and gas fields, including related platforms, pipelines and other infrastructures, in the Gulf of Mexico, Indonesia and Azerbaijan. We hope to finance a portion of these projects through governmental and multilateral agencies.

While we expect, based on current commodity prices, to be able to satisfy these obligations, to the extent they become due in 2003, with cash on hand and expected to be generated from operating activities and asset sales, declines in commodity prices from current levels could require us to sell additional assets, incur significant additional debt or issue other securities to obtain the necessary funds.

A change of control of us could result in the acceleration of our outstanding bank borrowings and trigger various change-of-control provisions included in employee and director plans and agreements.

Two bank credit facilities guaranteed by us, under which Union Oil can borrow an aggregate of up to $1.0 billion, provide for the termination of their loan commitments and require the prepayment of all outstanding borrowings under the facilities in the event that (1) any person or group becomes the beneficial owner of more than 30 percent of our then-outstanding voting stock other than in a transaction having the approval of our board of directors, at least a majority of which are continuing directors, or (2) our continuing directors cease to constitute at least a majority of the board. If this situation were to occur, we and Union Oil would likely be required to refinance the outstanding indebtedness under these credit facilities. There can be no assurance that we would be able to refinance this indebtedness or, if a refinancing were to occur, that the refinancing would be on terms favorable to us.

Under various employee and director plans and agreements, in the event of a change in control, restricted stock would become unrestricted, unvested options and phantom units would vest, performance shares, performance bonus awards and incentive compensation would be paid out, and directors units would be paid out if the director has so elected. We are also party to employment agreements and other agreements with certain of our employees containing change-of-control provisions.

We have adopted an enhanced severance program for approximately 2,800 U.S.-payroll employees not represented by collective bargaining agreements and a limited number of international employees in the event they lose their jobs through a change of control.

We may issue preferred stock, the terms of which could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes our board of directors to issue, without the approval of our stockholders, one or more series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over our common stock respecting dividends and distributions, as the board of directors generally may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power and/or value of our common stock. For example, we could grant holders of preferred stock the right to elect some number of directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of us, even if that change would be beneficial to our stockholders.

Our certificate of incorporation and bylaws contain provisions that may make a change of control of us difficult, even if it would be beneficial to our stockholders, including:

- provisions governing the classification, nomination and removal of directors;
- a provision prohibiting stockholder action by written consent;
- a provision that allows only our board of directors to call a special meeting of stockholders;
- provisions regulating the ability of our stockholders to bring matters for action before annual stockholder meetings; and
- the authorization given to our board of directors to issue and set the terms of preferred stock.

In addition, we have adopted a stockholder rights plan, which would cause extreme dilution to any person or group that attempts to acquire a significant interest in Unocal without advance approval of our board of directors, while Section 203 of the Delaware General Corporation Law would impose restrictions on mergers and other business combinations between UNOCAL and any holder of 15 percent or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. The amount of cash dividends, if any, to be paid in the future will depend upon their declaration by our board of directors and upon our financial condition, results of operations, cash flow, the levels of our capital and exploration expenditures, our future business prospects and other related matters that our board of directors deems relevant.

In addition, under the terms of the outstanding trust preferred securities of Unocal Capital Trust and the Unocal subordinated debt securities held by that trust, we have the right, under certain circumstances to suspend the payment to that trust of interest on the subordinated debt securities, in which event the trust has the right to suspend the payment of distributions on its trust preferred securities. In this situation, we would be prohibited from paying dividends on our common stock.

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

This report discusses our plans, strategies and expectations for our business and contains other forward-looking statements, as this term is defined in the Private Securities Litigation Reform Act of 1995, as embodied in Section 27A of the Securities Act 1933, as amended, and Section 21E of the Securities Exchange Act 1934, as amended. In addition, from time to time in the future our management or other persons acting on our behalf may make, in both written publications and oral presentations, additional forward-looking statements to inform investors and other interested persons about our estimates and projections of, or increases or decreases in, amounts of our 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, our 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 our 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, although these are not the exclusive means of identifying those statements. We desire to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 with respect to such forward-looking statements, and are including this statement in this report in order to do so.

While such forward-looking statements are made in good faith, forward-looking statements and their underlying assumptions are by their nature subject to risks and uncertainties and their outcomes will be influenced by various operating, market, economic, competitive, credit, environmental, legal and political factors. These factors could cause actual results to differ, even materially, from those expressed in the forward-looking statements. Some of these factors are described in the preceding Risk Factors section of this report, as well as in the specific parts of this report referenced below, but are not necessarily all of the important factors that could cause actual results, performance or achievements to differ from those expressed in, or implied by, our forward-looking statements. Other unknown or unpredictable factors also could have material adverse effects on our future results, performance or achievements. Accordingly, our actual results may differ from those expressed in, or implied by, our forward-looking statements. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or circumstances or otherwise, except to the extent we may be legally required to do so.

See the discussions of: the uncertainties surrounding the commerciality of the K2 and Trident deepwater discoveries under Exploration and Production North America U.S. Lower 48 Deepwater Gulf of Mexico in combined Items 1 and 2 Business and Properties of this report and under Outlook Exploration and Production North America US Lower 48 above in this Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A); the uncertainty surrounding the Company s proposal to export natural gas form the Bibiyana field in Bangladesh to India under Exploration and Production International Bangladesh in Items 1 and 2; the commodity-specific risks that the Company s Trade segment endeavors to manage under Trade in Items 1 and 2 and in note 29 to the consolidated financial statements in Item 8 of this report; 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 and under Outlook Geothermal and Power Operations above in MD&A; the lawsuits and administrative proceedings involving the Company s patents for formulations of cleaner-burning gasolines under Patents in Items 1 and 2; the uncertainties surrounding the competition the Company faces under Competition in Items 1 and 2; the uncertainties surrounding the laws and regulations that affect the Company s business under Government

Regulation and Environmental Regulation in Items 1 and 2; the uncertainties surrounding certain legal proceedings involving the Company under Item 3 Legal Proceedings, as well as in note 22 to the consolidated financial statements in Item 8, which note also contains a discussion of certain other contingent liabilities and commitments; the Company s estimated 2003 capital expenditures under Financial Condition Capital Expenditures above in MD&A; the circumstances under which the loan commitments of banks party to the Company s two principal credit facilities could be terminated and outstanding borrowings could become prepayable by the Company under Financial Condition Long-term Debt and Other Financial Commitments above in MD&A; the Company s 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 MD&A; certain of the Company s financial contractual obligations and commitments under Long-term Debt and Other Financial Commitments above in MD&A and in the various notes to the consolidated financial statements referenced therein; the Company s critical accounting policies and practices under Critical Accounting and Other Policies above in MD&A; 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 anticipated continued volatility of energy commodity prices in 2003 under Outlook above in MD&A; the uncertainties related to the Company s forecasts of its 2003 aggregate oil and gas production levels and certain costs under Outlook above in MD&A; the uncertainties surrounding the commercial development of deepwater oil and natural gas/condensate discoveries offshore East Kalimantan, Indonesia under Outlook Exploration and Production International Far East Indonesia above in MD&A; the uncertainties surrounding Phases I and II of the development of the Azeri-Chirag-Gunashli structure in the Caspian Sea offshore Azerbaijan and the related Baku-Tbilisi-Ceyhan pipeline under Azerbaijan and Midstream above in the Outlook section of MD&A; the uncertainties surrounding the outstanding receivables balance due for sales of natural gas and condensate to Petrobangla under Bangladesh above in the Outlook section of MD&A; the impact of future accounting changes upon the Company s consolidated financial statements under Future Accounting Changes above in MD&A; and 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.

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 changes 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 trades hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations.

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

Interest Rate Risk - From time to time the Company temporarily invests its excess cash in short-term interest-bearing securities issued by high-quality issuers. Company policies limit the amount of investment in securities of any one financial institution. Due to the short time the investments are outstanding and their general liquidity, these instruments are classified as cash equivalents in the consolidated balance sheet and do not represent a material interest rate risk to the Company. The Company s primary market risk exposure to 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, 2002. Assuming a ten percent decrease in the Company s weighted average borrowing costs at December 31, 2002 and 2001, respectively, the potential increase in the fair value of the Company s debt obligations and associated interest rate derivative instruments, including the debt obligations and associated interest rate derivative instruments of its subsidiaries, would have been approximately $105 million and $109 million at December 31, 2002 and 2001, respectively.

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, 2002, the Company had various foreign currency swaps and foreign currency forward contracts outstanding related to operations in Canada, Thailand and The Netherlands. The Company evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of the Company s combined foreign currency position related to its outstanding foreign currency swaps and forward contracts. Assuming an adverse change of ten percent in foreign exchange rates at December 31, 2002, the potential decrease in fair value of the Company s foreign currency forward contracts, foreign-currency denominated debt, foreign currency swaps and foreign currency forward contracts of its subsidiaries, would have been approximately $35 million at December 31, 2002.

At year-end 2001, 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 2001, 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 $12 million at December 31, 2001.

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 current market data and uses a three-day time interval with a 97.5 percent confidence level. The model includes offsetting physical positions for any existing 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 hedging purposes was approximately $20 million and $11 million at December 31, 2002 and 2001, respectively. The value at risk related to hydrocarbon derivatives held for non-hedging purposes was approximately $4 million and $5 million at December 31, 2002 and 2001, respectively.

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, 2002, along with the fair values of those instruments.

Open Hydrocarbon Hedging Derivative Instruments (a)

	2003	2004	2005	2006	2007-2008	(Thousands of dollars) Fair Value Asset (Liability) (b) (c)
Natural Gas Futures Positions						
Volume (MMBtu)	1,470,000					$ 93
Average price, per MMBtu	$ 3.96					
Natural Gas Swap Positions						
Pay fixed price						
Volume (MMBtu)	8,268,000	7,241,000	7,218,000	7,218,000	14,459,000	$ 54,706
Average swap price, per MMBtu	$ 2.50	$ 2.33	$ 2.37	$ 2.42	$ 2.50	
Natural Gas Basis Swap Positions						
Volume (MMBtu)	36,500,000					$ 3,783
Average price received, per MMBtu	$ 4.28					
Average price paid, per MMBtu	$ 3.62					
Natural Gas Collar Positions						
Volume (MMBtu)	68,791,000	268,500				$ (16,577)
Average ceiling price, per MMBtu	$ 4.79	$ 5.45				
Average floor price, per MMBtu	$ 3.86	$ 2.82				
Natural Gas Option (Listed)						
Call Volume (MMBtu)	180,000					$ 178
Average Call price	$ 6.35					
Put Volume (MMBtu)	(10,280,000)					$ 908
Average Put Price	$ 3.19					
Natural Gas Option (OTC)						
Put Volume (MMBtu)	(21,400,000)					$ 865
Average Put Price	$ 3.25					

Crude Oil Future position							
Volume (Bbls)		(692,000)				$	(1,697)
Average price, per Bbl	$	29.92					
Crude Oil Option							
Put Volume (Bbls)						$	(97)
Average price, per Bbl							
Crude Oil Collar Positions							
Volume (Bbls)		1,902,000		90,000		$	(1,578)
Average ceiling price, per Bbl	$	31.19	$	26.21			
Average floor price, per Bbl	$	27.47	$	18.67			

(a) Positions reflect long (short) volumes.
(b) Net claims against counterparties with non-investment grade credit ratings are immaterial.
(c) Includes $7,430 thousand in assumed liabilities which were capitalized as acquisition costs.

Open Hydrocarbon Non-Hedging Derivative Instruments (a)

		2003	2004	(Thousands of dollars) Fair Value Asset (Liability) (b)
Natural Gas Futures Positions				
	Volume (MMBtu)	2,400,000		$ (383)
	Average price, per MMBtu	$ 3.24		
Natural Gas Swap Positions				
Pay fixed price				
	Volume (MMBtu)	6,877,571		$ 2,280
	Average swap price, per MMBtu	$ 4.63		
Receive fixed price				
	Volume (MMBtu)	5,667,479	95,438	$ (14,139)
	Average swap price, per MMBtu	$ 4.46	$ 1.99	
Natural Gas Basis Swap Positions				
	Volume (MMBtu)	5,650,000	3,640,000	$ 631
	Average price received, per MMBtu	$ 5.00	$ 5.70	
	Average price paid, per MMBtu	$ 4.85	$ 6.11	
Natural Gas Option (Listed)				
	Call Volume (MMBtu)	(12,950,000)		$ 1,540
	Average Call price	$ 4.77	$	
	Put Volume (MMBtu)	(1,000,000)		$ (192)
	Average Put Price	$ 3.43	$	
Natural Gas Option (Over the Counter)				
	Call Volume (MMBtu)	(7,305,200)		$ (6,463)
	Average Call price	$ 3.93	$	
	Put Volume (MMBtu)	(950,000)		$ 43
	Average Put price	$ 3.00		
Natural Gas Spread Option (Over the Counter)				
NYMEX / IFERC (c)				
	Put Volume (MMBtu)	(8,800,000)		$ 393
	Average Strike price	$ 0.32	$	
Crude Oil Future position				
	Volume (Bbls)	1,088,000		$ 3,014
	Average price, per Bbl	$ 27.76		
Crude Oil Option				
	Put Volume (Bbls)	200,000		$ (367)
	Average price, per Bbl	$ 28.25		
	Call Volumes (Bbls)	(400,000)		$ 21
	Average price, per Bbl	$ 34.25		
Crude Oil Option (Calender Spread)				
	Put Volume (Bbls)	500,000		$ (93)
	Average price, per Bbl	$ 0.50	$	
	Call Volumes (Bbls)	(400,000)		$ (60)
	Average price, per Bbl	$ 0.90	$	
Crude Oil Swap Positions				
Pay fixed price				
	Volume (Bbls)	(2,282,144)		$ 10,081

Average swap price, per Bbl	$ 26.87		
Receive fixed price			
Volume (Bbls)	1,925,000	$	(12,291)
Average swap price, per Bbl	$ 26.62		

(a) Positions reflect long (short) volumes.
(b) Includes $1,541 thousand net claims against counterparties with non-investment grade credit ratings.
(c) Prices quoted from the New York Mercantile Exchange (NYMEX) and Inside FERC Gas Report (IFERC).

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 Audit Committee of the Board of Directors, consisting solely of independent directors, each of whom meets the independence standard of the New York Stock Exchange, is responsible for: assisting the Board in monitoring: 1) the integrity and reliability of the Company s financial reporting; 2) the Company s compliance with legal and regulatory requirements; 3) the adequacy of the Company s internal operating policies and controls; and 4) the quality and performance of combined management, independent accountant, and the internal audit function. The Audit Committee is also responsible for the appointment of the independent accountants (which in turn is submitted to the stockholders for ratification) and reviewing their independence from the Company; and initiating special investigations as deemed necessary. The independent accountants and the internal auditors have full and free access to the Audit Committee and meet with it, with and without the presence of management, to discuss all appropriate matters.

CHARLES R. WILLIAMSON	TIMOTHY H. LING	TERRY G. DALLAS	JOE D. CECIL
Chairman of the Board and	President and	Executive Vice President	Vice President and
Chief Executive Officer	Chief Operating Officer	and Chief Financial Officer	Comptroller
March 20, 2003			

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of Unocal Corporation:

We have audited the accompanying consolidated balance sheets of Unocal Corporation and its subsidiaries as of December 31, 2002 and 2001, 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, 2002 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 73 through 131 of this Annual Report on Form 10-K, present fairly, in all material respects, the consolidated financial position of Unocal Corporation and its subsidiaries as of December 31, 2002 and 2001 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, 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 therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
February 14, 2003
Los Angeles, California

CONSOLIDATED EARNINGS **UNOCAL CORPORATION**

Millions of dollars except per share amounts	Years ended December 31, 2002	2001	2000
Revenues			
Sales and operating revenues	$ 5,224	$ 6,708	$ 8,956
Interest, dividends and miscellaneous income	31	64	176
Gain on sales of assets	42	24	85
Total revenues	5,297	6,796	9,217
Costs and other deductions			
Crude oil, natural gas and product purchases	1,701	2,492	5,158
Operating expense	1,338	1,420	1,214
Administrative and general expense	151	122	129
Depreciation, depletion and amortization	973	967	821
Impairments	47	118	66
Dry hole costs	107	175	156
Exploration expense	246	252	260
Interest expense (a)	179	192	210
Property and other operating taxes	60	77	68
Distributions on convertible preferred securities of subsidiary trust	33	33	33
Total costs and other deductions	4,835	5,848	8,115
Earnings from equity investments	154	144	134
Earnings from continuing operations before income taxes and minority interests	616	1,092	1,236
Income taxes	280	452	497
Minority interests	6	41	16
Earnings from continuing operations	330	599	723
Discontinued operations			
Refining, marketing and transportation			
Gain on disposal (b)	1	17	
Agricultural products			
Gain on disposal (c)			37
Earnings from discontinued operations	1	17	37
Cumulative effect of accounting change		(1)	
Net earnings	$ 331	$ 615	$ 760
Basic earnings per share of common stock:			
Continuing operations	$ 1.34	$ 2.45	$ 2.98
Net earnings	$ 1.34	$ 2.52	$ 3.13
Diluted earnings per share of common stock:			

Continuing operations	$	1.34	$	2.43	$	2.93
Net earnings	$	1.34	$	2.50	$	3.08

(a)	Net of capitalized interest of :	$	46	$	27	$	13
(b)	Net of tax expense of :	$	1	$	10	$	
(c)	Net of tax expense of :	$		$		$	18

See Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET **UNOCAL CORPORATION**

Millions of dollars	At December 31, 2002		2001	
Assets				
Current assets				
Cash and cash equivalents	$	168	$	190
Accounts and notes receivable - net		994		847
Inventories		97		102
Deferred income taxes		90		123
Other current assets		26		33
Total current assets		1,375		1,295
Investments and long-term receivables - net		1,044		1,405
Properties - net		7,879		7,484
Goodwill		122		30
Deferred income taxes		210		128
Other assets		130		83
Total assets	$	10,760	$	10,425
Liabilities and Stockholders Equity				
Current liabilities				
Accounts payable	$	1,024	$	823
Taxes payable		223		249
Dividends payable		51		49
Interest payable		50		49
Current portion of environmental liabilities		113		124
Current portion of long-term debt and capital leases		6		9
Other current liabilities		165		119
Total current liabilities		1,632		1,422
Long-term debt and capital leases		3,002		2,897
Deferred income taxes		593		627
Accrued abandonment, restoration and environmental liabilities		622		590
Other deferred credits and liabilities		816		724
Subsidiary stock subject to repurchase				70
Minority interests		275		449
Commitments and contingencies - Note 22				
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent subordinated debentures		522		522
Common stock ($1 par value, shares authorized: 750,000,000 (a))		269		255
Capital in excess of par value		962		551
Unearned portion of restricted stock issued		(20)		(29
Retained earnings		3,021		2,888
Accumulated other comprehensive income (loss)		(486)		(88
Notes receivable - key employees		(37)		(42
Treasury stock - at cost (b)		(411)		(411

Total stockholders equity	3,298	3,124
Total liabilities and stockholders equity	$ 10,760	$ 10,425
(a) Number of shares outstanding	257,980,454	243,998,088
(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.

See Notes to the Consolidated Financial Statements.

CONSOLIDATED CASH FLOWS **UNOCAL CORPORATION**

	Year ended December 31,		
Millions of dollars	2002	2001	2000
Cash Flows from Operating Activities			
Net earnings	$ 331	$ 615	$ 760
Adjustments to reconcile net earnings to net cash provided by operating activities			
Depreciation, depletion and amortization	973	967	821
Impairments	47	118	66
Dry hole costs	107	175	156
Amortization of exploratory leasehold costs	98	95	85
Deferred income taxes	22	81	17
Gain on sales of assets (pre-tax)	(42)	(24)	(85)
Gain on disposal of discontinued operations (pre-tax)	(2)	(27)	(23)
Earnings applicable to minority interests	6	41	16
Other	(55)	31	172
Working capital and other changes related to operations			
Accounts and notes receivable	(160)	462	(389)
Inventories	5	(14)	24
Accounts payable	196	(273)	91
Taxes payable	52	(33)	92
Other	(7)	(89)	(135)
Net cash provided by operating activities	1,571	2,125	1,668
Cash Flows from Investing Activities			
Capital expenditures (includes dry hole costs)	(1,670)	(1,727)	(1,302)
Major acquisitions		(646)	(318)
Proceeds from sales of assets	163	81	284
Proceeds from sales of discontinued operations	3	25	267
Net cash used in investing activities	(1,504)	(2,267)	(1,069)
Cash Flows from Financing Activities			
Proceeds from issuance of common stock	21	15	7
Long-term borrowings	585	519	
Reduction of long-term debt and capital lease obligations	(495)	(225)	(453)
Dividends paid on common stock	(196)	(195)	(194)
Loans to key employees	6		(32)
Minority interests	(8)	(17)	(25)
Other	(2)		1
Net cash provided by (used in) financing activities	(89)	97	(696)
Decrease in cash and cash equivalents	(22)	(45)	(97)

Cash and cash equivalents at beginning of year	190	235	332
Cash and cash equivalents at end of year	$ 168	$ 190	$ 235
Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 180	$ 195	$ 221
Income taxes (net of refunds)	$ 249	$ 368	$ 374

See Notes to the Consolidated Financial Statements.

CONSOLIDATED STOCKHOLDERS EQUITY **UNOCAL CORPORATION**

	At December 31,		
Millions of dollars except per share amounts	**2002**	**2001**	**2000**
Common stock			
Balance at beginning of year	$ 255	$ 254	$ 253
Issuance of common stock for acquisition of Pure Resources minority interest	13		
Other issuance of common stock	1	1	1
Balance at end of year	269	255	254
Capital in excess of par value			
Balance at beginning of year	551	522	493
Issuance of common stock for acquisition of Pure Resources minority interest	378		
Other issuance of common stock	33	29	29
Balance at end of year	962	551	522
Unearned portion of restricted stock and options issued			
Balance at beginning of year	(29)	(21)	(20)
Issuance of restricted stock and options	(3)	(18)	(12)
Amortization of restricted stock and options	12	10	11
Balance at end of year	(20)	(29)	(21)
Retained earnings			
Balance at beginning of year	2,888	2,468	1,902
Net earnings for year	331	615	760
Cash dividends declared on common stock ($0.80 per share)	(198)	(195)	(194)
Balance at end of year	3,021	2,888	2,468
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	(42)	(40)	
Accrued interest on loans to key employees	(2)	(2)	
Principal and interest payments received from key employees	7		
Issuance of loans to key employees			(40)
Balance at end of year	(37)	(42)	(40)
Accumulated other comprehensive income (loss)			
Balance at beginning of year	(88)	(53)	(33)
Foreign currency translation adjustments	(15)	(40)	(20)
Deferred net gains (losses) on hedging instruments	(49)	60	
Cumulative effect of accounting change		(59)	

Minimum pension liability adjustment	(334)	4	
Balance at end of year (a)	(486)	(88)	(53)
Total stockholders equity	$ 3,298	$ 3,124	$ 2,719

(a) At year-end 2002, other comprehensive income was comprised of unrealized currency translation losses of $100 million, deferred net losses on hedging instruments of $48 million and minimum pension liability adjustment of $338 million. Year-end 2001 other comprehensive income consisted 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 of $59 million. Year-end 2000 comprehensive income consisted of unrealized currency translation losses of $45 million and minimum pension liability adjustment of $8 million.

See Notes to the Consolidated Financial Statements.

COMPREHENSIVE INCOME **UNOCAL CORPORATION**

Millions of dollars	Years ended December 31, 2002	2001	2000
Net earnings	$ 331	$ 615	$ 760
Cumulative effect of change in accounting principle SFAS No. 133 adoption (a)		(59)	
Change in unrealized gains (losses) on hedging instruments (b)	(57)	32	
Reclassification adjustment for settled hedging contracts (c)	8	28	
Unrealized foreign currency translation adjustments	(15)	(40)	(20)
Minimum pension liability adjustment (d)	(334)	4	
Total comprehensive income	$ (67)	$ 580	$ 740

(a) Net of tax effect of:		36
(b) Net of tax effect of:	33	(19)
(c) Net of tax effect of:	(4)	(16)
(d) Net of tax effect of:	196	(2)

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, 2002 and 2001, 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 $29 million and $42 million, for the two years respectively.

Inventories - Inventories are generally valued at the lower of cost or market. The costs of inventories are primarily determined using the last-in, first-out (LIFO) method or average costs method. 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, including goodwill, 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, notwithstanding a required annual review of goodwill.

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 s (FASB) 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 applies Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees , and related interpretations in accounting for stock-based compensation. Stock-based compensation expense recognized in the Company s consolidated earnings 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 and total shareholder return. In addition, the amounts also include expenses related to the Company s Pure subsidiary, which had its own stock-based compensation plans. Had the Company recorded compensation expense using the fair value accounting method recommended by SFAS No. 123, net earnings and earnings per share would have been reduced to the pro-forma amounts indicated on the table on page 81:

Millions of dollars except per share amounts	Years Ended December 31, 2002	2001	2000
Net earnings			
As reported	$ 331	$ 615	$ 760
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects and minority interests	26	9	21
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects and m inority interests	(56)	(21)	(27)
Pro forma net earnings	$ 301	$ 603	$ 754
Net earnings per share:			
Basic - as reported	$ 1.34	$ 2.52	$ 3.13
Basic - pro forma	$ 1.22	$ 2.48	$ 3.10
Diluted - as reported	$ 1.34	$ 2.50	$ 3.08
Diluted - pro forma	$ 1.21	$ 2.45	$ 3.05

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 2002 presentation.

NOTE 2 ACCOUNTING CHANGES

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

SFAS No. 143: In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires that the Company recognize liabilities related to the legal obligations associated with the retirement of its tangible long-lived assets at fair values in the periods in which the obligations are incurred (typically when the assets are installed). These obligations include the required decommissioning and removal of certain oil and gas platforms, plugging and abandonment of oil and gas wells and facilities and the closure and site restoration of certain mining facilities.

Prior to January 1, 2003, the Company was required under SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies to accrue its abandonment and restoration costs ratably over the productive lives of its assets. The Company previously used the units-of-production method to accrue these costs. SFAS No. 19 resulted in higher costs being accrued early in the fields lives when production was at its highest levels and abandonment and restoration costs accruals were matched with the revenues as oil and gas were produced.

Under SFAS No. 143, when the liabilities for asset retirement obligations are initially recorded at fair values, capital costs of the related assets will be increased by equal corresponding amounts. Over time, changes in the present value of the liabilities will be accreted and expensed and the capitalized asset costs will be depreciated over the useful lives of the corresponding assets. Because SFAS No. 143 requires the use of interest accretion for revaluing asset retirement obligation liabilities as a result of the passage of time, associated accretion costs will be higher near the end of the fields lives when oil and gas production and related revenues are at their lowest levels.

Accounting Principles Board Opinion (APB) No. 20, Accounting Changes requires that the Company calculate the retroactive impact of adopting SFAS No. 143 from the inception of its asset retirement obligations to its January 1, 2003 adoption date. APB No. 20 requires that this impact be quantified and reported as a cumulative effect of an accounting change on the earnings statement. This cumulative effect will include the catch up of SFAS No. 143 accretion expense related to the fair value of the liabilities as well as the catch up of associated depreciation expense related to the increased capital costs of the corresponding assets. The cumulative effect will also include the reversal of abandonment and restoration costs previously charged to earnings under SFAS No. 19. In addition to the impact on earnings due to the differences in applying SFAS No. 19 and SFAS No. 143 to the Company s oil and gas operations, the cumulative effect will also include the impact related to the Company s mining operations under SFAS No. 143. The Company expects to finalize its abandonment plans by late March 2003 and will record the effects of adopting SFAS No. 143 as of January 1, 2003 in the first quarter of 2003.

The Company expects to recognize a one time after-tax charge in the range of $70 million to $85 million as the cumulative effect of an accounting change related to the adoption of SFAS No. 143.

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

SFAS No. 145: The Company adopted SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections , effective January 1, 2002. This statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishment of Debt , and an amendment of that statement, SFAS No. 64, Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements . This statement also rescinds or amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The adoption of SFAS No. 145 did not have a material effect on the Company s financial position or results of operations.

SFAS No. 146: In June 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities . This statement provides guidance on the recognition and measurement of liabilities associated with disposal activities and is effective for the Company on January 1, 2003. The Company does not expect the adoption of SFAS No. 146 to have a significant impact on its financial position or results of operations.

SFAS No. 148: In December 2002, the FASB issued SFAS No. 148. The statement provides for three methods of transitioning from the intrinsic value to the fair value method of accounting for stock-based compensation. This statement also amends the disclosure requirements of SFAS No. 123 and APB Opinion No. 28, Interim Financial Reporting, to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The disclosure requirements of the statement are effective for the Company immediately and are reflected in note 1. The Company expects to adopt the fair value recognition provisions of SFAS No. 148, on a prospective basis, effective January 1, 2003.

FASB Interpretation No. 45: In November 2002, the FASB issued Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. This Interpretation requires the recognition of certain guarantees as liabilities at fair market value and is effective for guarantees issued or modified after December 31, 2002. The Company has included the disclosure requirements of the Interpretation in note 22 and does not expect the adoption of this Interpretation to have a significant impact on its financial position or results of operations.

FASB Interpretation No. 46: In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities. This Interpretation requires the consolidation of certain companies that are defined as variable interest entities. This Interpretation is effective for new variable interest entities as of February 1, 2003. The effective date for entities existing prior to February 1, 2003 is July 1, 2003. The Company has included the disclosure requirements of the Interpretation in this report and expects the adoption of the recognition (i.e., consolidation) requirements of the Interpretation to increase its consolidated long-term debt by approximately $320 million. This amount that the Company anticipates to consolidate when it adopts the Interpretation includes $242 million related to a partnership interest in which it has a minority interest liability (see note 21 for further details) and $78 million of third-party debt related to Dayabumi Salak Pratma, Ltd. (DSPL), an equity investee that sells electricity generated from geothermal steam in Indonesia (see note 14 for further details).

NOTE 3 ACQUISITION*S*

On October 29, 2002, the Company completed its exchange offer for the remaining shares of Pure Resources, Inc. (Pure) that it did not already own. Pursuant to the offer, the Company exchanged 0.74 shares of Unocal common stock for each share of Pure common stock tendered. The Company accepted tenders of 16,634,625 Pure shares in the exchange offer which, when combined with the 65 percent of the shares it already owned, represented approximately 97.5 percent of Pure s outstanding common shares. On October 30, 2002, the Company completed a short-form merger to acquire the remaining 2.5 percent of Pure s outstanding shares at the same 0.74 exchange ratio used in the exchange offer. Consequently, Pure became a wholly owned subsidiary of the Company. This transaction was valued at approximately $410 million and was accounted for as a purchase. As a result of the transaction, properties have increased by $121 million, goodwill of $80 million was recorded representing the excess of cost over fair value of the asset and liabilities acquired, deferred tax liabilities increased by $53 million, long-term debt increased by $10 million, reflecting the fair value of Pure s debt, and stockholders equity increased by $391 million for the value of the common stock. This acquisition provides the Company with a number of operational efficiency opportunities including: combining certain Pure operations with similar Unocal operations to reduce costs; technology efficiencies; the elimination of redundant overhead and administrative costs including public company costs. Recognition of the value of these opportunities contributed to a purchase price that exceeded the fair value assigned to the assets and liabilities acquired and resulted in an allocation of cost to goodwill. A minority interest liability of $151 million relating to the Pure shares and a $112 million obligation for Subsidiary stock subject to repurchase were eliminated from the Company s consolidated balance sheet. See notes 21, 22 and 25 for further details.

NOTE 4 - DISPOSITIONS OF ASSETS

In 2002, cash proceeds received from asset sales and discontinued operations totaled $166 million, with pre-tax gains of $44 million. The proceeds included $65 million from the sale of certain investment interests in nonstrategic pipelines in the U.S, with a pretax gain of $49 million. Cash proceeds of approximately $44 million were from the sale of real estate and other miscellaneous properties, with a pretax gain of $20 million, and $32 million were from the sale, by the Company s Pure subsidiary, of oil and gas producing properties in the US, with a pretax gain of $4 million. Sale proceeds also included $22 million from various other oil and gas asset sales, with a pretax loss of $31 million, and cash proceeds of $3 million related to a participation payment received from the purchaser of the Company s former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline, which included $2 million pretax that was earned in 2001.

In 2001, cash proceeds received from asset sales and discontinued operations totaled $106 million, with pretax gains of $51 million. The proceeds included $25 million of payments received from the purchaser 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 pretax gain of $27 million. The Company also received $63 million from the sale of certain oil and gas properties, primarily located in the US Gulf of Mexico, with a pretax gain of $21 million. In addition, the Company received $18 million from the sale of real estate and other assets, with a pretax gain of $3 million.

In 2000, cash proceeds received from asset sales and discontinued operations totaled $551 million, with pretax gains of $108 million. The proceeds included $242 million received from the sale of the agricultural products business, with a pretax gain of $23 million. The proceeds also included $80 million from the sale of the Company s graphite business, with a pretax 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 pretax loss of $6 million. The Company also received cash proceeds of $98 million from the sale of certain oil and gas properties, with a pretax gain of $3 million and $35 million in real estate and other assets, with a pretax gain of $10 million. Cash proceeds also included $25 million received from the purchaser of the Company's former West Coast refining, marketing and transportation assets.

NOTE 5 - LEASE RENTAL OBLIGATIONS

The Company has operating leases for drilling rigs, 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, 2002 were as follows:

Millions of dollars		
2003		169
2004		140
2005		96
2006		25
2007		18
Thereafter		25
Total minimum lease rental payments	$	473

The Company has a five-year lease agreement relating to its *Discoverer Spirit* deepwater drillship, with a remaining term of approximately two years and nine months at December 31, 2002. In 2001, the Company signed a sublease agreement with a third party for a period that began in December 2001 and ended in mid-September 2002. Under the provisions of that agreement, the third party assumed all of the lease payments to the lessor during the sublease period. The drillship has a current minimum daily rate of approximately $224,000. At December 31, 2002, the future remaining minimum lease-rental payment obligation was $222 million as included in the table above.

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

	Years ended December 31,		
Millions of dollars	**2002**	**2001**	**2000**
Fixed rentals	$ 72	$ 58	$ 58
Contingent rentals (based primarily on sales and usage)			1
Sublease rental income	(4)	(3)	(4)
Net rental expense	$ 68	$ 55	$ 55

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 for possible impairment. In 2002, the Company recorded pre-tax charges of $41 million ($26 million after-tax) for the impairment of oil and gas fields in Alaska and the Gulf of Mexico region primarily due to lower reserve estimates, production forecasts and future expenses. The impairment in Alaska was $24 million pre-tax while the impairment for the Gulf of Mexico region was $17 million. The Company also recorded a pre-tax charge of $4 million ($2 million after-tax), for the impairment of its investment in a U.S. pipeline company, carried in its Midstream segment, in which the Company owns an equity interest and that was being held for sale. Lastly, the Company recorded a pre-tax charge of $2 million to impair its investment in an electronic commerce provider.

In 2001, the Company recorded pre-tax charges 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 pre-tax charges 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 a pre-tax charge of $53 million for the impairment of the Questa, New Mexico, molybdenum mining operation.

NOTE 7 - RESTRUCTURING COSTS

In June 2002, the Company adopted a restructuring plan that resulted in the accrual of a $19 million pre-tax restructuring charge. The charge included the estimated costs of terminating 202 employees in the Company s Sugar Land, Texas, office and field locations. The restructuring plan involved organizational changes to eliminate unnecessary work processes in the Company s Gulf Region business unit, which is part of the U.S. Lower 48 operations in the Exploration and Production segment.

The restructuring charge was reflected in the operating expense line on the consolidated earnings statement and included approximately $14 million for termination costs to be paid to the employees over time, about $3 million for outplacement and other costs and about $2 million for benefit plan curtailment costs. All of the affected employees had been terminated as of December 31, 2002. Approximately $12 million of the restructuring costs had been paid and charged against the liability in 2002, leaving accrued costs of $7 million on the consolidated balance sheet at December 31, 2002. The remaining costs are expected to be paid in 2003.

In November 2002, the Company adopted a restructuring plan that resulted in the accrual of a $4 million pre-tax restructuring charge related to Exploration and Production operations in Alaska. The restructuring charge was included in the operating expense line on the consolidated earnings statement and reflected the costs of terminating 46 employees in order to streamline operations, technical and support functions. Fourteen of the affected employees had been terminated as of December 31, 2002, while the other affected employees have been given notice of termination dates in the first quarter of 2003. Approximately $1 million of the restructuring costs had been paid and charged against the liability in 2002, leaving accrued costs of $3 million on the consolidated balance sheet at December 31, 2002. The remaining costs are expected to be paid during 2003 and the first half of 2004.

NOTE 8 - INCOME TAXES

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

	Years ended December 31,		
Millions of dollars	**2002**	**2001**	**2000**
Earnings (loss) from continuing operations before income taxes and minority interests (a)			
United States	$ (181)	$ 409	$ 618
Foreign	797	683	618
Earnings from continuing operations before income taxes and minority interests	$ 616	$ 1,092	$ 1,236
Income taxes			
Current			
Federal	$ (47)	$ 8	$ 43
State	7	12	20
Foreign	221	351	374
Total current taxes	181	371	437
Deferred			
Federal	(60)	68	155
State		(1)	(2)
Foreign	159	14	(93)
Total deferred taxes	99	81	60
Total income taxes	$ 280	$ 452	$ 497

(a) Amounts attributable to the Corporate and Other segment are allocated.

For 2002 the Company will elect to carryback its current year domestic source net operating loss, which will result in a refund of prior year federal income tax paid. In addition, 2002 reflects a decrease in current foreign tax provision of $78 million and an increase in deferred foreign tax provision of $89 million due to the settlement of past issues as a result of renegotiating the geothermal sales contract in Indonesia. The Indonesia geothermal adjustments relate to prior year tax provisions and have no cash flow impact.

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	**2002**	**2001**	**2000**
Federal statutory rate	35%	35%	35%
Taxes on earnings from continuing operations before minority interests at statutory rate	$ 216	$ 382	$ 433
Taxes on foreign earnings in excess of statutory rate	73	73	23

Provision for prior year income tax issues			28
Dividend exclusion	(15)	(17)	(16)
Other	6	14	29
Total	$ 280	$ 452	$ 497

The significant components of deferred income tax assets and liabilities included in the consolidated balance sheet at December 31, 2002 and 2001 were as follows:

	At December 31,	
Millions of dollars	**2002**	**2001**
Deferred tax assets:		
Exploratory costs	$ 285	$ 321
Federal AMT and other tax credits	209	136
Future abandonment costs	139	142
Litigation and environmental costs	107	106
Doubtful receivables	14	96
Postretirement benefit costs	82	87
Pension plans	28	
Forward sales of natural gas	27	31
Price risk and interest rate management activities	41	18
Other deferred tax assets	176	139
Total deferred tax assets	1,108	1,076
Deferred tax liabilities:		
Depreciation, depletion and intangible drilling costs	(1,153)	(1,018)
Pension plans		(181)
Investment in subsidiaries and affiliates	(79)	(125)
Other deferred tax liabilities	(169)	(128)
Total deferred tax liabilities	(1,401)	(1,452)
Total net deferred tax liabilities	$ (293)	$ (376)

The net deferred tax liabilities at December 31, 2002 reflect the recognition of a minimum pension liability for the Company s Qualified Retirement Plan in 2002 and the resulting charge to the other comprehensive income component of stockholders equity which was recorded net of $196 million in deferred income taxes. See note 16 for additional information. 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 $1.9 billion as of December 31, 2002.

The Company estimates that approximately $154 million of unused foreign tax credits will be available after the filing of the 2002 consolidated tax return, with various expiration dates through the year 2007. No deferred tax asset for these foreign tax 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, 2002, the Company s Pure subsidiary had net operating loss carryforwards of approximately $21 million, which are available to offset future taxable income subject to annual limitations. 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

	Years ended December 31,		
Millions of dollars	**2002**	**2001**	**2000**
Gain on disposal before income taxes (a)	2	27	55

Income taxes	1	10	18
Total earnings from discontinued operations	1	17	37

(a) Gain on disposal in 2002 and 2001 is related to the refining, marketing and transportation business. Gain on disposal in 2000 is exclusively related to the agricultural products business.

In 2002, discontinued operations included a $2 million pre-tax gain ($1 million after-tax) related to a participation payment received from the purchaser of the Company s former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. In 2001, the Company recorded pre-tax gains of $27 million ($17 million after-tax) related to this sales agreement. The maximum potential payments under this agreement are capped at $100 million and will expire at the end of 2003. To date, the Company has recorded $29 million pre-tax.

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. 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.

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 2002, 2001 and 2000.

Millions except per share amounts		**Earnings (Numerator)**	**Shares (Denominator)**		**Per Share Amount**
Year ended December 31, 2002					
Earnings from continuing operations	$	330	247		
Basic EPS				$	1.34
Effect of dilutive securities					
Options and common stock equivalents			1		
Diluted EPS		330	248	$	1.34
Distributions on subsidiary trust preferred securities (after-tax)		28	12		
Antidilutive	$	358	260	$	1.37(a)
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

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

Not included in the computation of diluted EPS at December 31, 2002 were options outstanding to purchase approximately 7.6 million shares of common stock. 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. 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:

Millions except per share am ounts	Years ended December 31, 2002	2001	2000
Basic earnings per share of com m on stock:			
Discontinued operations:			
Earnings from discontinued operations	$ 1	$ 17	$ 37
Weighted average common shares outstanding	247	244	243
Earnings from discontinued operations	$	$ 0.07	$ 0.15
Dilutive earnings per share of common stock:			
Discontinued operations:			
Earnings from discontinued operations	$ 1	$ 17	$ 37
Weighted average common shares outstanding	248	257	256
Earnings from discontinued operations	$	$ 0.07	$ 0.15

NOTE 11 CASH AND CASH EQUIVALENTS

Millions of dollars	At December 31, 2002	2001
Cash	$ 58	$ 12
Time deposits	110	123
Restricted cash		5
Marketable securities		50
Cash and cash equivalents	$ 168	$ 190

At December 31, 2002, no cash was restricted as to usage or withdrawal, while $5 million was restricted at December 31, 2001. Under the terms of the Company s limited recourse project financing for its share of the Azerbaijan International Operating Company Early Oil Project, the principal and interest payments are payable only out of the proceeds from the Company s sale of crude oil from the project. The next semi-annual debt payment of approximately $3 million will be replenished in the restricted cash account upon the receipt of the next crude oil proceeds.

NOTE 12 SALES 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 unrelated party that provided 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, 2002 and 2001, were $2 million and $1 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. During 2002, the sale agreement was modified to reduce the maximum sales of receivables from $204 million to $125 million. At December 31, 2002, the Company had sold $108 million of its domestic trade receivables under this agreement. At December 31, 2001, the Company had sold $70 million of such receivables under this agreement.

The Company s consolidated balance sheet included a note receivable from URC of approximately $66 million and $54 million at December 31, 2002 and 2001, respectively, representing the unsold balance of trade receivables transferred to URC.

NOTE 13 - INVENTORIES

Millions of dollars	At December 31, 2002	2001
Crude oil and other petroleum products	$ 43	$ 46
Carbon and mineral products	34	37
Materials , supplies and other	20	19
Total inventories	$ 97	$ 102

Inventories are generally valued at the lower of cost or market. Inventories using the LIFO cost method amounted to $16 million and $20 million as of December 31, 2002 and 2001, respectively. The remaining inventory balances primarily use average cost. The current replacement cost of inventories exceeding the LIFO inventory values was not material at December 31, 2002 and 2001.

NOTE 14 - EQUITY INVESTMENTS

Investments in companies accounted for by the equity method were $686 million, $625 million and $618 million at December 31, 2002, 2001 and 2000, respectively. These investments are reported in investments and long-term receivables on the consolidated balance sheet.

Dividends or cash distributions received from the Company s equity investees were $160 million, $213 million and $77 million for the years 2002, 2001 and 2000, respectively. At December 31, 2002, 2001 and 2000, the excess of the Company s investments in Colonial Pipeline Company and various other pipeline companies was approximately $143 million, $153 million and $159 million, respectively. These equity investees have approximately $1.5 billion of their own debt obligations that are either fully non-recourse or of limited recourse to the Company. Of the total $1.5 billion in equity investee debt, $1.2 billion is that of Colonial Pipeline Company, in which the Company holds a 23.44 percent equity interest. The Company guarantees only $25 million of the $1.5 billion total. At December 31, 2002, 2001 and 2000, the Company s shares of the net capitalized costs of other companies engaged in oil and gas exploration and production activities were $347 million, $309 million and $300 million, respectively.

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

	Years ended December 31,					
	2002		2001		2000	
Millions of dollars	Total	Unocal s Share	Total	Unocal s Share	Total	Unocal s Share
Revenues	$ 1,965	$ 548	$ 2,429	$ 515	$ 2,067	$ 705
Costs and other deductions	1,419	394	1,684	371	1,609	571
Net earnings	$ 546	$ 154	$ 745	$ 144	$ 458	$ 134

	At December 31,					
	2002		2001		2000	
Millions of dollars	Total	Unocal s Share	Total	Unocal s Share	Total	Unocal s Share
Current assets	$ 756	$ 248	$ 873	$ 324	$ 706	$ 239

Noncurrent assets	4,653	1,088	4,069	1,084	3,383	916
Current liabilities	787	257	1,429	453	898	304
Noncurrent liabilities	1,975	521	1,753	475	1,718	484
Net equity	2,647	558	1,760	480	1,473	367

DSPL is a special purpose company formed for the purpose of building and operating a geothermal energy fueled power generating facility in Indonesia. Under a long-term electricity sales contract, this entity provides power to the Indonesian state-owned electricity company, PT. PLN (Persero) (PLN). Unocal Geothermal of Indonesia, Ltd. (UGI) owns a 50 percent interest in DSPL and is under contract to administer DSPL operations. DSPL has no employees of its own. DSPL had loans and notes payable totaling $88 million at December 31, 2002. DSPL s debt obligations are non-recourse to UGI and to the Company, as neither entity has guaranteed these obligations. Effective in the third quarter of 2003, a new accounting rule, FASB Interpretation No. 46 (see note 2 for further details), will require the Company to consolidate DSPL resulting in the reporting of the $78 million as long-term debt on the consolidated balance sheet at that time. At December 31, 2002, the Company s maximum exposure to loss as a result of its involvement with DSPL was approximately $100 million.

NOTE 15 PROPERTIES AND CAPITAL LEASES

Investments in owned and capitalized-leased properties are shown below. Accumulated depreciation, depletion, and amortization for continuing operations were $12,277 million and $11,648 million at December 31, 2002 and 2001, respectively.

	At December 31,			
	2002		2001	
Millions of dollars	Gross	Net	Gross	Net
Owned Properties (at cost)				
Exploration and Production				
Exploration				
North America				
Lower 48	$ 527	$ 381	$ 543	$ 420
Alaska	5	5	8	7
Canada	206	137	168	118
International				
Far East	275	250	234	205
Other	147	82	144	99
Production				
North America				
Lower 48	7,548	2,656	7,317	2,638
Alaska	1,410	254	1,356	275
Canada	1,183	837	1,066	811
International				
Far East	5,811	2,002	5,302	1,724
Other	1,185	521	1,045	419
Total exploration and production	18,297	7,125	17,183	6,716
Trade	7	2	8	3
Midstream	496	221	480	216
Geothermal & Power Operations	658	279	644	284
Corporate & Other	693	247	811	259
Total owned properties	20,151	7,874	19,126	7,478
Capitalized-leased properties	5	5	6	6
Total properties and capital leases	$ 20,156	$ 7,879	$ 19,132	$ 7,484

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, 2002 and 2001. Prepaid 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	**2002**	**2001**	**2002**	**2001**
Change in benefit obligation:				
Projected benefit obligation at January 1,	$ 1,065	$ 925	$ 306	$ 252
Service cost	24	20	3	2
Interest cost	77	75	22	19
Employee contributions			5	5
Disbursements	(115)	(114)	(29)	(24)
Actuarial losses	143	124	69	52
Plan amendments	13	36		
Curtailments and settlements	(11)		(4)	
Divestitures	1			
Effect of foreign exchange rates		(1)		
Projected benefit obligation at December 31,	$ 1,197	$ 1,065	$ 372	$ 306
Change in plan assets:				
Fair value of plan assets at January 1,	$ 1,026	$ 1,201	$	$
Actual return on plan assets	(40)	(64)		
Employer contributions	1	(17)		
Employee contributions				
Disbursements	(100)	(86)		
Administrative expenses	(5)	(6)		
Settlements				
Divestitures				
Effect of foreign exchange rates		(2)		
Fair value of plan assets at December 31,	$ 882	$ 1,026	$	$
Net amount recognized:				
Funded status	$ (315)	$ (39)	$ (372)	$ (306)
Unrecognized net obligation at transition	1	2		
Unrecognized prior service cost	48	44	4	5
Unrecognized net actuarial losses (gains)	676	423	145	85
Net amount recognized	$ 410	$ 430	$ (223)	$ (216)
Components of the above amounts consist of:				
Prepaid pension cost	$ 9	$ 491	$	$

Accrued benefit liability	(193)	(82)	(223)	(216)
Intangible asset	45	10		
Accumulated other comprehensive loss	549	11		
Net amount recognized	$ 410	$ 430	$ (223)	$ (216)

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. In 2002 the Company recognized a minimum pension liability of $103 million reflecting the excess of the accumulated benefit obligation over the fair value of plan assets at December 31, 2002 for its Qualified Retirement Plan covering current and former U.S. payroll employees. The recognition of this liability resulted in an after-tax charge of $334 million to the other comprehensive income component of stockholders equity. The Company was not required to make any cash contributions to the Qualified Retirement Plan during 2002. Pension plan funds are invested in a variety of assets including U.S. and foreign equity securities, debt and fixed income securities, cash and cash equivalents. None of the plans hold Company stock.

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,	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Discount rates	6.74%	7.24%	7.73%	6.75%	7.25%	7.74%
Rates of salary increases	4.93%	4.50%	4.45%	4.99%	4.50%	4.50%
Expected returns on plan assets	8.40%	9.33%	9.28%	N/A	N/A	N/A

The health care cost trend rate used in measuring the 2002 benefit obligation for the U.S. plan was 9 percent, decreasing ratably to 5 percent in 2006. A one percentage-point change in the assumed health care cost trend rate would have had the following effects on 2002 service and interest cost and the accumulated postretirement benefit obligation at December 31, 2002:

Millions of dollars	One percent Increase	One percent Decrease
Effect on total of service and interest cost components of net periodic expense	$ 3	$ (2)
Effect on postretirement benefit obligation	$ 40	$ (34)

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

	Pension Benefits			Other Benefits		
Millions of dollars	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Service cost (net of employee contributions)	$ 24	$ 20	$ 24	$ 3	$ 2	$ 3
Interest cost	77	75	73	21	19	17
Expected return on plan assets	(105)	(111)	(110)			
Amortization of:						
Transition obligation						
Prior service cost	6	6	4	1	1	1
Net actuarial (gains) losses	33	2	3	5	1	
Curtailment and settlement (gains) losses	5	7	(13)			(6)
Cost of special separation benefits						
Net periodic pension and other benefit cost (credit)	$ 40	$ (1)	$ (19)	$ 30	$ 23	$ 15

The Company amortizes the cost of plan amendments and unrecognized actuarial gains and losses on a straight-line basis over the average remaining service period of active plan participants expected to receive benefits.

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 at December 31, 2002 were approximately $1,152 million, $1,019 million and $833 million, respectively. At December 31, 2001 pension plans with accumulated benefit obligations in excess of plan assets consisted solely of unfunded plans with projected benefit obligations of $104 million and accumulated benefit obligations of $74 million.

In 2002 and 2000, 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 $12 million, $11 million and $13 million in 2002, 2001, and 2000 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 $15 million and $13 million at December 31, 2002 and 2001, 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	**2002**	**2001**
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	20	21
7% Debentures due 2028	200	200
7-1/2% Debentures due 2029	350	350
Notes		
Medium-term notes due 2003 to 2015 (7.84%) (a)	330	502
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
5.05% Notes due 2012	400	
Other		
Canadian Bank Credit Agreement	186	
Northrock consolidated debt and capital leases	6	81
Pure consolidated debt	359	587
Azerbaijan Limited Recourse Loan	28	36
Other miscellaneous debt	1	1
Bond (discount) premium	(11)	(11)
Total debt and capital leases	3,008	2,906
Less current portion of long-term debt and capital leases	6	9
Total long-term debt and capital leases	$ 3,002	$ 2,897

(a) Weighted average interest rate at December 31, 2002.

At December 31, 2002, the amounts of debt and capital leases maturing in 2003, 2004, 2005, 2006, and 2007 were $106 million, $237 million, $476 million, $236 million and $76 million, respectively. Based on commodity prices at December 31, 2002, the Company had the intent and the ability to refinance most of the current maturities, and consequently it did not record $101 million of debt maturing in 2003 as part of the current portion of long-term debt.

On October 3, 2002, the Company issued $400 million principal amount of 5.05 percent notes with a maturity date of October 1, 2012. The net proceeds from the sale of the notes were primarily used to repay outstanding commercial paper borrowings that had been made during the year. At December 31, 2002, the Company had no outstanding commercial paper borrowings. During 2002, the Company also retired $172 million of maturing medium-term notes.

At December 31, 2002, the Company had $28 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 London Interbank Offered Rates (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, 2002, included $359 million of debt of the Company s Pure subsidiary. This debt primarily included $350 million in unsecured senior notes, which bear interest at 7.125 percent and mature in 2011. The notes were issued at a discount to their face value. As a result of the Company s acquisition of the Pure minority interests shares, long-term debt increased by $10 million reflecting the fair value of Pure s debt at the time of the purchase. Other Pure debt included $1 million outstanding under a $10 million working capital revolving credit facility. At the end of 2002, Pure had no borrowings outstanding under its 3-year $275 million revolving credit facility or its $125 million (reduced from $235 million in December 2002) 5-year revolving credit facility. Outstanding borrowings under both facilities were repaid in the fourth quarter of 2002 subsequent to the Company s acquisition of the remaining Pure minority interests shares. The Company cancelled both credit facilities in January 2003. Neither Unocal nor Union Oil guarantees any of Pure s debt.

In February 2002, the Company s Northrock Resources Ltd. subsidiary redeemed its $35 million Series A and $40 million Series B senior U.S. dollar-denominated notes, which bore interest of 6.54 percent and 6.74 percent, respectively. The remaining $6 million of debt primarily consisted of capital leases.

The Company has two credit facilities in place: a $400 million 364-day credit agreement and a 5-year $600 million credit agreement. Borrowings under the bank credit agreements bear interest at a margin above 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 agreements do not have drawdown restrictions or prepayment obligations 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. Both agreements limit the Company s debt to equity ratio to 70 percent, with the Company s convertible preferred securities included as equity in the ratio calculation. The Company had not drawn any funds under either credit facility at year-end 2002.

In December 2002, the Company also obtained a 3-year $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest. At December 31, 2002, the borrowings under the credit facility translated to $186 million, using applicable foreign exchange rates.

The Company had undrawn letters of credit at year-end 2002 that approximated $39 million. The majority of these letters of credit are maintained for operational needs and are renewed yearly.

NOTE 18 - ACCRUED ABANDONMENT, RESTORATION AND ENVIRONMENTAL LIABILITIES

At December 31, 2002 and 2001, the Company had accrued $490 million and $477 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. Under current accounting rules, these abandonment figures were estimated to be approximately $755 million at December 31, 2002 and $670 million at December 31, 2001. 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. See note 2 for additional discussion regarding the adoption of SFAS No. 143, new accounting pronouncement, effective January 1, 2003.

At December 31, 2002 and 2001, the Company s reserve for environmental remediation obligations totaled $245 million and $237 million, respectively, of which $113 million at year-end 2002 and $124 million at year-end 2001 were included in current liabilities. The reserve, at December 31, 2002 and 2001, included estimated probable future costs of $17 million and $12 million, respectively, for federal Superfund and comparable state-managed multi-party disposal sites; $37 million and $40 million, respectively, for active sites owned and/or controlled by the Company and utilized in its present operations; $104 million and $98 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 in each year, 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:

	At December 31,	
Millions of dollars	**2002**	**2001**
Other deferred credits and liabilities:		
Postretirement medical benefits	$ 223	$ 216
Pension and other employee benefits	195	92
Advances related to future production	110	105
Derivative liabilities	83	64
Prepaid forward sales	61	73
Reserves for litigation and other claims	45	72
Northrock (a)	6	32
Other	93	70
Total other deferred credits and liabilities	$ 816	$ 724
Allowances for doubtful accounts and notes receivables	$ 26	$ 146
Allowances for investments and long-term receivables	$ 3	$ 171

(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.

In 2002, pension and other employee benefits included $103 million to recognize the minimum pension liability for the Company s Qualified Retirement Plan. This reflected the excess of the accumulated benefit obligation for vested current and former employees over the fair value of plan assets at December 31, 2002. See note 16 for a full discussion of the minimum pension liability for the Company s Qualified Retirement Plan.

In 2001, the allowances for doubtful accounts and notes receivables and the allowances for investments and long-term receivables primarily related to the Company s geothermal operations in Indonesia. In July 2002, the Company s UGI subsidiary and DSPL, a 50-percent equity investee of UGI, reached agreement over pricing and production issues at the Gunung Salak geothermal project in Indonesia with PLN and Pertamina, the Indonesian state-owned oil and natural gas company. Part of the new agreement provided for payment by PLN of a portion of the past due receivable balances to the Company while the Company forewent a portion of the receivables. The Company retained a receivable balance of $93 million plus interest that it expects to collect in full. The remaining outstanding receivables were written-off against the aforementioned allowances.

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 refloated 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 2002, approximately $61 million related to deliveries scheduled to be made in the years 2004 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 2003. At December 31, 2002, the Company had in place an irrevocable surety bond in the amount of $93 million securing its performance under the sales contract.

NOTE 21 MINORITY INTERESTS

At December 31, 2002, The Company s minority interests on the consolidated balance sheet were $275 million, a decrease of $174 million from 2001. This decrease was primarily due to the acquisition of the outstanding minority interest shares of the Company s Pure subsidiary. See note 3 for details on the acquisition.

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 Company consolidates this partnership. 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 $7 million and $16 million, for 2002 and 2001, respectively. The minority interest on the Company s consolidated balance sheet related to this transaction was approximately $252 million at December 31, 2002. The primary purpose of this transaction was to raise capital. In 2003, a new accounting rule, FASB Interpretation No. 46, related to variable interest entities will require that the Company consolidate the unaffiliated investor (see note 2). This is expected to result in a reclassification of $242 million from minority interests to long-term debt on the Company s consolidated balance sheet.

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 matters, taxes, guarantees 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 the 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 continues to move forward to address environmental issues for which it is responsible. The Company, in cooperation with regulatory agencies and others, follows procedures that it has established to identify and cleanup contamination associated with its past operations. 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 compensatory and 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, 2002, the Company had accrued $245 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 $245 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.

During 2002, cash payments of $114 million were applied against the reserves and $122 million in provisions were added to the reserves. Possible additional remediation costs decreased by approximately $15 million in 2002. The accrued costs and the possible additional costs are shown below in four categories of sites.

	At December 31, 2002	
Millions of Dollars	**Reserve**	**Possible Additional Costs**
Superfund and similar sites	$ 17	$ 10
Active Company facilities	37	55
Company facilities sold with retained liabilities and former Company-operated sites	104	75
Inactive or closed Company facilities	87	105
Total Reserve	$ 245	$ 245

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, pipelines or other equipment 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, rare earth production 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 of the sites in 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 s contribution to the contamination at these sites was primarily from waste from the current and former operations identified above.

Superfund and similar sites 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

At year-end 2002, Unocal had received notification from the U.S. Environmental Protection Agency (EPA) that the Company may be a PRP at 26 sites and may share certain liabilities at these sites. Of the total, two 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. At one site, the Company has made a final settlement payment and is in the process of completing its involvement in the site. Of the remaining 22 sites, for those where probable costs can be reasonably estimated, reserves of $13 million have been established for future remediation and settlement costs.

Various state agencies and private parties had identified 23 other similar PRP sites. Four sites are under investigation and/or litigation and the Company s potential liability is not presently determinable. At three sites the Company s potential liability appears to be *de minimis*. At another site, the Company has made a final settlement payment and is in the process of completing its involvement in the sites. The Company has denied responsibility for two sites. Where probable costs can be reasonably estimated with respect to the remaining 13 sites, reserves of $4 million have been established for future remediation and settlement costs.

In 2002, provisions of $8 million were recorded for the Superfund and Similar Sites category. The provisions were primarily for the Company s estimated remaining share of oversight and monitoring costs related to the McColl Superfund site in Fullerton, California as the result of a federal appeals court overturning a 1998 court decision that held the federal government responsible for cleanup of the site because of its role in encouraging oil companies to produce gasoline during World War II. Payments for this category of sites were $3 million in 2002.

The sites discussed above exclude 112 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 - 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 has a reserve of $37 million for estimated future costs of remedial orders, corrective actions and other investigation, remediation and monitoring obligations at certain operating facilities and producing oil and gas fields. Provisions of $12 million were recorded in 2002 for sites included in this category. These provisions were primarily for the estimated cost of studies, investigations and remediation activities at a molybdenum mine located in Questa, New Mexico, that is owned by the Company s Molycorp, Inc. (Molycorp) subsidiary. Molycorp has been working cooperatively with the State of New Mexico and the U.S. Environmental Protection Agency to determine if past mining operations have had an adverse ecological impact on surface water and groundwater, and to identify remedial alternatives to mitigate any impact identified. Through the collaborative effort described above, it was determined that the scope of the environmental studies and investigations for the site needs to be expanded. The Company made payments of $15 million for this category of sites in 2002.

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 in various locations in 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 that resulted from operations prior to the sale. 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 $104 million for this group of sites. During 2002, provisions of $75 million were recorded for these sites. The provisions included revised remediation cost estimates that the Company received from the purchaser of service stations, bulk plants, terminals, refineries and pipelines that were part of the Company s former West Coast refining, marketing and transportation assets sold in 1997. Provisions for this category were also recorded as a result of revised cost estimates related to the cleanup of the Company s former service stations and distribution facilities throughout the U.S. and the estimated additional cost to cleanup contaminated areas that have been identified at a former oil field in Michigan that were previously operated by the Company. Cash payments of $69 million were made in 2002 for sites in this category.

Inactive or closed Company facilities - The major sites in this category are:

- The Guadalupe oil field on the central California coast
- The Molycorp Washington and York facilities in Pennsylvania
- The Beaumont Refinery in Texas

Reserves of $87 million have been established for these types of facilities. Provisions of $27 million were recorded in 2002 for this category of sites. These provisions were principally for the cost of remediation work related to the decommissioning and decontamination of Molycorp s closed molybdenum and rare earth processing facilities in Washington and York, Pennsylvania. As a result of ongoing cooperative efforts between the Company and the Nuclear Regulatory Commission, a determination that probable additional volumes of low-level radioactive contaminated material, in excess of amounts previously estimated, needed to be removed at the York and Washington sites. Provisions were also recorded for revised cost estimates related to various remediation projects at the Company s former Guadalupe oil field on the central California coast which is also included in this category of sites. During 2002, $27 million in payments were made for sites in this category.

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 existing and/or possible obligations to remove or mitigate the environmental effects of the disposal or release of certain chemical, petroleum and radioactive substances at various sites. Corrective investigations and actions pursuant to RCRA and other federal, state and local environmental laws are being performed at the Company s Beaumont, Texas, facility, a former agricultural chemical facility in Corcoran, California, and Molycorp s Washington, Pennsylvania, facility. In addition, Molycorp is required to decommission its Washington and York facilities in Pennsylvania pursuant to the terms of their respective radioactive source materials licenses and decommissioning plans.

The Company also must provide financial assurance for future closure and post-closure costs of its RCRA-permitted facilities and for decommissioning costs at facilities that are under radioactive source materials licenses. Pursuant to a 1998 settlement agreement between the Company and the State of California (and the subsequent stipulated judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of remediation activities at its inactive Guadalupe oil field. Also, pursuant to a 1995 settlement agreement between Molycorp and the California Department of Toxic Substances Control (and subsequent final judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of disposing of certain wastes, as well as closing facilities associated with the handling of those wastes, at Molycorp s Mountain Pass, California, facility. At December 31, 2002, 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 $74 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 reserve 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.

Certain Litigation and Claims

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

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

In November 2002, the City, ChevronTexaco and ExxonMobil entered into a settlement (the Chevron-Exxon Settlement), subject to court approval, under which the two companies would pay the City $30 million and construct and operate a water treatment plant. The City s expert has estimated that the cost of treatment plant construction and operation could exceed $500 million, but other experts estimate the cost of aquifer restoration at $33 million. The City alleges $15 million in non-treatment facility damages. Future settlement and/or judgment amounts paid to the City from other defendants would go in part into an operating account, from which the two companies could be reimbursed for part or all of their treatment plant costs, as well as certain other costs. The court has scheduled a hearing for March 28, 2003 to consider approval of the settlement and its value as a credit against future recoveries from non-settling parties, which the settling parties have proposed at $40 million. The Company, Tosco Corporation (now part of Conoco Phillips) and other defendants, but not the Shell defendants, had been invited to participate in this settlement on terms which would have involved the Company paying the City $7.5 million and contributing to the costs of the treatment plant. Neither the Company nor the other invited defendants elected to participate on these terms.

In March 2003, the Company and two other defendants filed a joint opposition to the Chevron-Exxon Settlement. Based on a rigorous technical analysis of the data, the Company believes it has strong defenses to the allegations in the complaint, including the lack of evidence that its former service stations or activities are responsible for any contamination that has reached or threatens the wellfield. The Company also believes it has certain available defenses that the settling defendants and others may not have due to tolling agreements they entered into with the City; and, unlike the Shell defendants and the settling defendants, the Company is neither the object of punitive damages claims nor a cause of the wellfield s being originally shut down. The Company is also subject to potential partial responsibility for MTBE or TBA contamination in the wellfield arising from certain operations in the area of the Company s former gasoline marketing business that was sold in 1997, and is subject to potential liability, under a products liability theory, for gasoline it manufactured or sold that was ultimately distributed to area facilities operated by others. The Company s current analysis does not indicate any such liabilities are likely to be significant.

For several years prior to the City s suit, the EPA and the California Regional Water Quality Control Board have asserted jurisdiction over contamination of groundwater potentially affecting the wellfield, and these agencies have issued a number of orders under RCRA and state law to the Shell defendants and the other defendant oil companies, including the Company, with respect to both investigation of individual facilities and regional contamination, and requiring replacement of water lost to the City, which Shell is currently providing. In January 2003, the EPA Regional Administrator for Region IX wrote to the settling parties advising that it intended to issue a unilateral order to all parties whose releases have been demonstrated to contribute to contamination in the Charnock Sub-Basin ordering cleanup of MTBE and TBA hot spots , unless a settlement in principle among all concerned parties is reached by March 31, 2003. The EPA also intends to defer to the City of Santa Monica s request to select and implement a wellhead treatment system. The Company received a copy of this letter. The Company has submitted to these agencies several technical analyses, which it believes demonstrate that its sites are not a part of any regional contamination problem, but, rather, present, at the most, localized issues which the Company, under agency oversight, has been successfully resolving.

Agrium Litigation: In June 2002, a lawsuit was filed against the Company by Agrium Inc., a Canadian corporation, and Agrium U.S. Inc., its U. S. subsidiary, in the Superior Court of the State of California for the County of Los Angeles (*Agrium U.S. Inc. and Agrium Inc. v. Union Oil Company of California*, Case No. BC275407) (the Agrium Claim). Simultaneously, the Company filed suit against the Agrium entities (Agrium) in the U.S. District Court for the Central District of California (*Union Oil Company of California v. Agrium, Inc.*, Case No. 02-04518 NM) (the Company Claim). The Company subsequently removed the Agrium Claim to the U.S. District Court for the Central District of California (Case No. 02-04769 NM). The federal court has since remanded the Agrium Claim to the California Superior Court. In addition, the Company has initiated arbitration concerning the Gas Purchase and Sale Agreement (GPSA) between the Company and Agrium U.S. Inc. (AAA Case No. 70 198 00539 02) (the Arbitration).

The Agrium Claim alleges numerous causes of action relating to Agrium s purchase from the Company of a nitrogen-based fertilizer plant on the Kenai Peninsula, Alaska, in September 2000. The primary allegations involve the Company s obligation to supply natural gas to the plant pursuant to the GPSA. Agrium alleges that the Company misrepresented the amount of gas reserves available for sale to the plant as of the closing of the transaction and that the Company has failed to develop additional natural gas reserves for sale to the plant. Agrium also alleges that the Company misrepresented the condition of the general effluent sewer at the plant and made misrepresentations regarding other environmental matters.

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

In September 2002, Agrium amended its complaint to add allegations that the Company breached certain conditions of the September 2000 closing, breached certain indemnification obligations, and violated the pertinent health and safety code. Agrium also asked for recission of the sale of the fertilizer plant, in addition, or as an alternative, to money damages.

In the Company Claim, the Company seeks declaratory relief in its favor against the allegations of Agrium set forth above and for judgment on the Retained Earnout in the amount of $16.6 million, together with interest accrued subsequent to May 2002.

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

The Company believes that certain portions of its disputes with Agrium are subject to binding arbitration under the terms of the GPSA. The Company initiated the Arbitration to determine the amount and delivery rate of the remaining gas supply available under that agreement. Agrium claims the dispute resolution provisions of the PSA supersede the arbitration provisions of the GPSA.

In January 2003, the state court ordered that the arbitration issues should be combined in the litigation but the scope of the court s order is unclear. Agrium has filed a motion to clarify the order with respect to the Arbitration. The Company is appealing the order and has filed a motion to stay discovery pending resolution of that appeal. The parties have agreed in principle to postpone the Arbitration, pending resolution of the appeal, and to stay discovery until May 1, 2003 (except with respect to the environmental issues) in order to allow settlement discussions to proceed.

Petrobangla Claim: In July 2002, the Company s subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. (Unocal Blocks 13 and 14 Ltd.) (which was acquired in 1999 from Occidental Petroleum Corporation and, prior to the recent completion of Bangladesh name-change formalities, was still known in Bangladesh as Occidental of Bangladesh Ltd.) (OBL), received from the Bangladesh Oil, Gas & Mineral Corporation (Petrobangla) a letter claiming, on behalf of the Bangladesh government and Petrobangla, compensation allegedly due in the amount of $685 million for 246 BCF of recoverable natural gas allegedly lost and damaged in a 1997 blowout and ensuing fire during the drilling by OBL, as operator, of the Moulavi Bazar #1 (MB #1) exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout.

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Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractors operations. Even if some form of compensation were due, the Company and OBL believe that settlement compensation for the blowout was fully addressed in a 1998 Supplemental Agreement to the PSC, which, among other matters, waived OBL s then 50-percent contractor s share (as well as the then 50-percent contractor s share held by the Company s Unocal Bangladesh, Ltd., subsidiary) of entitlement to the recovery of costs incurred in the blowout, waived their right to invoke *force majeure* in connection with the blowout, and reduced by five percentage points their contractors profit share (with a concomitant increase in Petrobangla s profit share) of future production from the sands encountered by the MB #1 well to a drill depth of 840 meters or, if the blowout sand reservoir were not deemed commercial, from other commercial fields in the Moulavi Bazar ring-fenced area of Block 14. Consequently, the Company and Occidental Petroleum Corporation consider the matter closed and Unocal Blocks 13 and 14 Ltd. has advised Petrobangla that no additional compensation is warranted.

Nuevo Energy Claim: In March 2003, the Company received a letter from Nuevo Energy Company regarding a contingent payment for the year 2002 owed by Nuevo to the Company under the terms of the 1996 Asset Purchase Agreement pursuant to which Nuevo purchased substantially all of the Company s operating California oil and gas properties. Notwithstanding that Nuevo had notified the Company in January 2003 of its estimate of the payment for 2002, Nuevo now claims that the long-standing calculation methodology for this payment was incorrect, that no payment should be due for 2002, and that the payment made for 2001 should be refunded. The Company disputes Nuevo s new position and expects to commence litigation in the event that the 2002 payment is not received. The potential cash exposure to the Company is $27 million.

In view of the inherent difficulty of predicting the outcome of legal matters, the Company cannot state with confidence what the eventual outcome of the four preceding matters will be. However, based on current knowledge, none of the preceding matters is presently expected to have a material adverse effect on the Company s consolidated financial condition or liquidity, but each of them could have a material adverse effect on the Company s results of operations for the accounting period or periods in which one or more of them might be resolved adversely.

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

As part of the acquisition of the Pure minority interests shares by Unocal at the end of October 2002 (see note 21), the Pure stock subject to repurchase by Pure, which was owed to Pure officers, was replaced by Unocal stock and the repurchase requirement was cancelled. At December 31, 2001, the repurchase amount under these agreements was approximately $70 million.

Guarantees Related to Assets or Obligations of Third Parties

The Company indemnified certain third parties for particular future remediation costs that may be incurred for properties held by these parties. The guarantees were established when the Company either leased property from or sold property to these third parties. The properties may or may not have been contaminated by various Company operations. Where it has been or will be determined that the Company is responsible for contamination, the guarantees require the Company to pay the costs to remediate the sites to specified cleanup levels or to levels that will be determined in the future.

The maximum potential amount of future payments that the Company could be required to make under these guarantees is indeterminate primarily due to the following: the indefinite term of the majority of these guarantees; the unknown extent of possible contamination; uncertainties related to the timing of the remediation work; possible changes in laws governing the remediation process; the unknown number of claims that may be made; changes in remediation technology, and because most of these guarantees lack limitations on the maximum potential amount of future payments.

The Company has accrued probable and reasonably estimable assessment and remediation costs for the locations covered under these guarantees. These amounts are included in the Company facilities sold with retained liabilities and former Company-operated sites category of the Company s reserve for environmental remediation obligations. At December 31, 2002, the reserve for this category totaled $104 million. For 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 $75 million. See the discussion elsewhere in this footnote for additional information regarding this category.

The Company has guaranteed the debt of certain joint ventures accounted for by the equity method. The majority of this debt matures evenly through the year 2014. The maximum potential amount of future payments the Company could be required to make is approximately $25 million.

In the ordinary course of business, the Company has made indemnifications for cash deficiencies for certain domestic pipeline joint ventures, which the Company accounts for on the equity method. These guarantees are considered in the Company s analysis of overall risk. Since most of these agreements do not contain spending caps, it is not possible to quantify the amount of maximum payments that may be required. Nevertheless, the Company believes the payments would not have a material adverse impact on its financial condition or liquidity.

Financial Assurance for Unocal Obligations

In the normal course of business, the Company has performance obligations which are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions but are funded by the Company if exercised. At December 31, 2002, the Company had obtained various surety bonds for approximately $215 million. These surety bonds included a bond for $93 million securing the Company s performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten-year period that began in January of 1999 and will end in December of 2008 and approximately $122 million in various other routine performance bonds held by local, city, state and federal agencies. The Company also had obtained approximately $39 million in standby letters of credit at December 31, 2002. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit. In addition, the Company has various other guarantees for approximately $545 million. Guarantees for approximately $332 million of this amount would require the Company to obtain a surety bond or a letter of credit or establish a trust fund if its credit rating were to drop below investment grade--that is BBB- or Baa3 from Standard & Poor s Ratings Services and Moody s Investors Service, Inc., respectively. Approximately $160 million of the surety bonds, letters of credit and other guarantees that the Company is required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note.

Approximately $134 million of the $545 million in guarantees mentioned in the previous paragraph represents financial assurance given by the Company on behalf of its Molycorp subsidiary relating to permits covering operations and discharges from its Questa, New Mexico, molybdenum mine. The Company s financial assurance is for the completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. The costs associated with the financial assurance are based on estimations provided by agencies of the state of New Mexico.

Other matters

The Company has a lease agreement relating to its *Discoverer Spirit* deepwater drillship, with a remaining term of approximately two years and nine months at December 31, 2002. In 2001, the Company signed a sublease agreement with a third party for a period that began in December 2001 and ended in mid-September 2002. Under the provisions of that agreement, the third party assumed all of the lease payments to the lessor during the sublease period. The drillship has a current minimum daily rate of approximately $224,000. The future remaining minimum lease payment obligation was approximately $222 million at December 31, 2002.

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

NOTE 23 - TRUST CONVERTIBLE PREFERRED SECURITIES

In 1996, Unocal exchanged 10,437,873 newly issued 6 ¼% trust convertible preferred securities of Unocal Capital Trust, a Delaware statutory trust (the Trust), for shares of a then-outstanding issue of convertible preferred stock. Unocal acquired the convertible preferred securities, which had an aggregate liquidation value of $522 million, from the Trust, together with 322,821 common securities of the Trust, which had an aggregate liquidation value of $16 million, in exchange for $538 million principal amount of 6 ¼% convertible junior subordinated debentures of Unocal. The convertible preferred securities and the common securities of the Trust, which have been retained by Unocal, represent undivided beneficial interests in the debentures, which constitute substantially all of the assets of the Trust. The numbers of convertible preferred securities outstanding on December 31, 2002 and December 31, 2001 were 10,437,105 and 10,437,107, respectively.

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.

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 102.5 percent (since September 1, 2002), 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.

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 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. 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

	At December 31,		
Thousands of shares	**2002**	**2001**	**2000**
Outstanding at beginning of year	243,998	243,044	242,441
Issuance of common stock in exchange for Pure Resources, Inc. common stock	13,247		
Other issuances of common stock (a)	735	954	603
Outstanding at end of year	257,980	243,998	243,044

At December 31, 2002, there were approximately 12.3 million shares reserved for the conversion of Unocal Capital Trust convertible preferred securities, 27.0 million shares for the Company s employee benefit plans and Directors plans and 2.7 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 had authorized the repurchase of $400 million of common stock in 1996, and authorized management to repurchase up to an additional $200 million of common stock. At December 31, 2002, 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, 2002, 2001 or 2000. 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 (the 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 and reserved 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 and reserved under the 1990 Rights Plan.

The 2000 Rights Plan, as amended in 2002, 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, an acquiring person by virtue of obtaining the beneficial ownership of 15 percent or more (25 percent or more in the case of qualified institutional investors) of the outstanding common shares, each Right (other than Rights held by the acquiring person) 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 an acquiring person, each Right (other than Rights held by the acquiring person) 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 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 acquiring person) 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, which the Board may do, at a price of $.001 per Right, at any time before any person or group becomes an acquiring person. 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. The balance of the loans under this Program, including accrued interest, totaled $35 million, both at December 31, 2002 and December 31, 2001, and was reflected as a reduction to stockholders equity on the consolidated balance sheet. During 2002, accrued interest of $2 million was offset by payments from the officers of $1 million in principal and $ 1 million in interest.

The Company s Pure subsidiary also had a loan program for certain of its officers and key employees. At December 31, 2002, loans under this program totaled $2 million and were also reflected as a reduction to stockholders equity on the consolidated balance sheet. At December 31, 2001, loans under this program totaled $7 million. This decrease of $5 million primarily reflects loan repayments by certain former officers and key employees of Pure that departed after Unocal purchased the minority interests share remaining in Pure (see note 3). Most of the remaining $2 million balance will be repaid in early 2003.

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 1998 Management Incentive Program and the Management Incentive Program of 1991 authorized up to 8.75 million and 11 million shares of common stock, respectively, for stock options, performance stock options, restricted stock and performance share awards. The Union Oil Restricted Stock Plan authorized 0.4 million shares of common stock for restricted stock awards. The UNOCAL Stock Option Plan and the Special Stock Option Plan of 1996 authorized up to 8 million and 1.1 million shares of common stock, respectively, for stock option awards. The Directors Restricted Stock Units Plan authorized the issuance of up to 300,000 shares of common stock and the 2001 Director s Deferred Compensation and Stock Award Plan authorized the issuance of up to 500,000 shares of common stock.

In connection with the Pure acquisition, on October 30, 2002, employee nonqualified stock options to acquire Pure stock (that were issued by Pure and its predecessors) became fully vested stock options to acquire UNOCAL common stock; options to acquire a total of 4,252,253 shares with a weighted average exercise price of $18.86 were outstanding at December 31, 2002, and all of these options became fully vested at the time of the acquisition. Most of the Pure employee stock options were issued under Pure s 1999 incentive Plan. No further awards will be made under the Pure plans.

All employee and director stock options are nonqualified with a maximum term of ten years. Except for certain stock options granted under Pure s 1999 Incentive Plan that were granted at prices below fair market value on the grant date, the exercise price for options may not be less than the fair market value of the common stock on the grant date. Director options vest ratably over three years for initial grants and over two years for annual grants. Employee options 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.

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 Management Incentive Program of 1998.

The Compensation Committee of Pure Resources, Inc. may approve the extension of a loan by the Company to assist in paying the exercise price of an option and/or any tax required by law to be withheld upon exercise of an option assumed by Unocal Corporation in connection with the acquisition.

Stock options generally cease to vest upon termination of employment. Vested options generally may be exercised for up to three years (depending upon the terms of the individual award agreements), or the original expiration date, whichever is earlier, from the date of death, disability, or termination of employment other than for cause or resignation. A majority of the options assumed by Unocal in connection with the Pure acquisition are exercisable until the end of their full ten-year terms. Options are generally nontransferable except in the event of an employee s death or pursuant to a court order.

Outstanding performance share awards have four-year terms and can be paid out in common stock and/or cash. 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 at the discretion of 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.

Holders of restricted stock are entitled to vote the shares, and receive dividends, except that dividends for restricted stock granted under the Union Oil Restricted Stock Plan 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. 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.

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.

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 Market Price Per Share
Options outstanding at January 1, 2000	9,987,837	$ 39.79	$
Options granted during year	2,705,057	29.02	29.02
Options exercised during year	(312,773)	26.75	
Options canceled/forfeited during year	(1,044,526)	39.47	
Options outstanding at December 31, 2000	11,335,595	37.60	
Options exercisable at December 31, 2000	5,999,097	33.12	
Restricted stock awarded during year	382,434		30.16
Performance shares awarded during year	256,041		34.91
Options outstanding at January 1, 2001	11,335,595	$ 37.60	$
Options granted during year	3,440,919	34.99	34.99
Options exercised during year	(551,788)	27.39	
Options canceled/forfeited during year	(3,226,949)	49.35	
Options outstanding at December 31, 2001	10,997,777	33.85	
Options exercisable at December 31, 2001	6,571,071	34.08	
Restricted stock awarded during year	558,836		33.10
Performance shares awarded during year	204,142		36.39
Options outstanding at January 1, 2002	10,997,777	$ 33.85	$
Options granted during year	1,710,027	34.68	34.68
Options assumed from Pure Resources	4,325,436	18.94	
Options exercised during year	(791,428)	27.98	
Options canceled/forfeited during year	(462,766)	35.10	
Options outstanding at December 31, 2002	15,779,046	30.11	
Options exercisable at December 31, 2002	12,437,204	29.07	
Restricted stock awarded during year	60,957		33.06
Performance shares awarded during year	224,672		33.88

Significant option groups outstanding at December 31, 2002 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
$11.58 - $15.31	2,027,046	6.7	$ 12.96	2,027,046	$ 12.96
$19.64 - $24.99	1,836,599	6.8	$ 23.33	1,836,599	$ 23.33
$25.18 - $30.94	2,698,797	5.2	$ 28.05	2,230,001	$ 27.99
$31.03 - $36.88	5,995,586	7.6	$ 34.55	3,189,720	$ 34.33
$37.03 - $45.25	3,221,018	4.5	$ 38.22	3,153,838	$ 38.22

The estimated fair value at date of grant of options for common stock granted in 2002, 2001 and 2000, using the Black-Scholes option pricing model is as follows:

	2002	2001	2000
Weighted-average fair value of common stock options granted during the year	**$ 9.35**	**$ 9.22**	**$ 9.64**
Assumptions:			
Expected life (years)	4.5	4.5	4.2
Expected volatility	32.7%	30.5%	40.7%
Expected dividend yield	2.2%	2.2%	2.5%
Risk-free interest rate	4.3%	4.6%	6.3%

See Note 1 for pro-forma stock-based compensation expense if the Company had used the fair value accounting method recommended by SFAS No. 123.

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. The Company may also enter into interest rate option contracts to protect its interest rate positions, depending on market conditions. At December 31, 2002, the Company had approximately $26 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges of interest rate exposures through September 2012. Of this amount, $4 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

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

Commodity hedging activities The Company uses hydrocarbon derivatives to mitigate the Company s overall exposure to fluctuations in hydrocarbon commodity prices. During 2002, the Company recognized about $1 million in after-tax losses for the ineffectiveness of both cash flow and fair value hedges. At December 31, 2002, the Company had approximately $21 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future commodity sales for the period beginning January 2003 through October 2004. Of this amount, approximately $14 million in after-tax losses are 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 $3,352 million and $2,809 million at year-end 2002 and 2001, 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 ¼ % convertible preferred securities were $535 million and $523 million at year-end 2002 and 2001, respectively. Fair values were based on the trading prices of the preferred securities on December 31, 2002 and 2001.

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.

During 2002, the Company took appropriate actions to help mitigate credit exposure to counterparties whose creditworthiness had deteriorated. In some cases, counterparty credit lines were reduced or rescinded. In other instances, the Company obtained credit assurances in the form of prepayments, letters of credit or guarantees to support the credit decision.

The majority of the Company s trade receivables balance at December 31, 2002, 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, 2002, approximately $95 million, or 10 percent, of the Company s net accounts receivable balance was due from PTT Public Co., Ltd. This amount primarily represented payments due for sales of natural gas from the Company s fields in the Gulf of Thailand and offshore Myanmar. No other individual crude oil or natural gas customer accounted for 10 percent or more of the Company s consolidated net trade receivable balance at December 31, 2002.

The Company continues to work with the government of Bangladesh and Petrobangla, the state oil and gas company, to develop additional reserves and export natural gas to markets in neighboring India. At December 31, 2002, the Company s business unit in Bangladesh had a gross receivable balance of approximately $27 million relating to invoices billed for natural gas and condensate sales to Petrobangla. Approximately $22 million of the outstanding balance represented past due amounts and accrued interest for invoices covering August 2002 through November 2002. Generally, invoices, when paid, have been paid in full. The Company continues to work 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 2002, 2001 and 2000 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, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues						
Sales and operating revenues	$	$	$ 1,098	$ 4,952	$ (826)	$ 5,224
Interest, dividends and miscellaneous income	1	34	(61)	94	(37)	31
Gain (loss) on sales of assets			4	38		42
Total revenues	1	34	1,041	5,084	(863)	5,297
Costs and other deductions						
Purchases, operating and other expenses	5		699	3,618	(826)	3,496
Depreciation, depletion and amortization			342	631		973
Impairments			41	6		47
Dry hole costs			33	74		107
Interest expense	34	1	144	37	(37)	179
Distributions on convertible preferred securities		33				33
Total costs and other deductions	39	34	1,259	4,366	(863)	4,835
Equity in earnings of subsidiaries	355		519		(874)	
Earnings from equity investments			4	150		154
Earnings from continuing operations before income taxes and minority interests	317		305	868	(874)	616
Income taxes	(14)		(50)	344		280
Minority interests				6		6
Earnings from continuing operations	331		355	518	(874)	330
Earnings from discontinued operations				1		1
Cumulative effect of accounting change						
Net earnings	$ 331	$	$ 355	$ 519	$ (874)	$ 331

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	$ 6,320	$ (1,447)	$ 6,708
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	6,341	(1,484)	6,796
Costs and other deductions						
Purchases, operating and other expenses	4		1,240	4,594	(1,475)	4,363
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 securities		33				33
Total costs and other deductions	38	34	1,930	5,358	(1,512)	5,848
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	$ 8,380	$ (1,541)	$ 8,956
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	8,416	(1,578)	9,217
Costs and other deductions						
Purchases, operating and other expenses	3		1,461	6,959	(1,594)	6,829
Depreciation, depletion, amortization and impairments			339	548		887
Dry hole costs			56	100		156
Interest expense	34	1	204	8	(37)	210
Distributions on convertible preferred securities		33				33
Total costs and other deductions	37	34	2,060	7,615	(1,631)	8,115
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 BALANCE SHEET
At December 31, 2002

Millions of dollars	Unocal (Parent)	UNOCAL Capital Trust	UNOCAL Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash and cash equivalents	$	$	$ (18)	$ 186	$	$ 168
Accounts and notes receivable - net	54		276	738	(74)	994
Inventories			10	87		97
Other current assets	1		85	30		116
Total current assets	55		353	1,041	(74)	1,375
Investments and long-term receivables - net	4,562		4,513	960	(8,991)	1,044
Properties - net			2,255	5,624		7,879
Other assets including goodwill	3	541	272	(12)	(342)	462
Total assets	$ 4,620	$ 541	$ 7,393	$ 7,613	$ (9,407)	$ 10,760
Liabilities and Stockholders Equity						
Current liabilities						
Accounts payable	$	$	$ 290	$ 788	$ (54)	$ 1,024
Current portion of long-term debt and capital leases				6		6
Other current liabilities	44	3	120	455	(20)	602
Total current liabilities	44	3	410	1,249	(74)	1,632
Long-term debt and capital leases			2,418	584		3,002
Deferred income taxes			(116)	709		593
Accrued abandonment, restoration and environmental liabilities			320	302		622
Other deferred credits and liabilities	541		424	184	(333)	816
Subsidiary stock subject to repurchase						
Minority interests				313	(38)	275
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures		522				522
Stockholders equity	4,035	16	3,937	4,272	(8,962)	3,298
	$ 4,620	$ 541	$ 7,393	$ 7,613	$ (9,407)	$ 10,760

Total liabilities and stockholders equity						

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	5,335		7,484
Other assets including goodwill	3	541	214	2,433	(2,950)	241
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
	$ 4,086	$ 541	$ 6,847	$ 9,690	$ (10,739)	$ 10,425

Total liabilities and stockholders equity						

CONDENSED CONSOLIDATED CASH FLOWS
Year ended December 31, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flows from Operating Activities	$ 175	$	$ 92	$ 1,304	$	$ 1,571
Cash Flows from Investing Activities						
Capital expenditures and acquisitions (includes dry hole costs)			(446)	(1,224)		(1,670)
Proceeds from sales of assets and discontinued operations			50	116		166
Net cash used in investing activities			(396)	(1,108)		(1,504)
Cash Flows from Financing Activities						
Change in long-term debt and capital leases			225	(135)		90
Dividends paid on common stock	(196)					(196)
Minority interests				(8)		(8)
Other	21		(1)	5		25
Net cash provided by (used in) financing activities	(175)		224	(138)		(89)
Increase (decrease) in cash and cash equivalents			(80)	58		(22)
Cash and cash equivalents at beginning of year			62	128		190
Cash and cash equivalents at end of year	$	$	$ (18)	$ 186	$	$ 168

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						
			(105)	399		294

Change in long-term debt and capital leases						
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 Subsidiaries	Eliminations	Consolidated
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

NOTE 29 SEGMENT AND GEOGRAPHIC DATA

The Company s reportable segments are as follows:

Exploration and Production Segment - This segment 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 production in Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. The Company is also involved in exploration and development activities in Asia, Australia, Brazil and West Africa. In 2002, $790 million, or approximately 15 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 PTT. In 2002, the Company booked $92 million in goodwill related to two acquisitions in North America, including $80 million in conjunction with the acquisition of the minority interests of Pure. The Company recognized $30 million in goodwill related to one acquisition in North America in 2001. The Company periodically, and at a minimum annually, tests for impairment of goodwill. As of December 31, 2002, no such impairments had been recorded.

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 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 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 purchases limited amounts of physical inventories held for energy trading purposes.

Midstream Segment - The Midstream 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 US, and the Company s North America gas storage business.

Geothermal and Power Operations Segment - This 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 (including environmental and litigation expenses). 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, which are eliminated upon consolidation, in business segment data are primarily sales from the Exploration and Production segment to the Trade segment. Intersegment sales prices approximate market prices. The revenues presented in the geographic area disclosure table primarily represent sales of crude oil and natural gas produced within the countries or regions shown.

SEGMENT DATA

2002 Segment Information Millions of dollars	Exploration & Production					
	North America			International		
	U.S. Lower 48	Alaska	Canada	Far East	Other	Trade
Sales & operating revenues	$ 509	$ 251	$ 207	$ 1,062	$ 151	$ 2,524
Other income (loss) (a)	(27)		(1)	1	1	(1)
Inter-segment revenues	825			238	116	1
Total	1,307	251	206	1,301	268	2,524
Depreciation, depletion & amortization	479	63	97	239	48	1
Impairments	17	24				
Dry hole costs	53	17	9	23	5	
Exploration expense						
Amortization of exploratory leases	55	1	18	1	23	
Earnings (loss) from equity investments	2			33	7	2
Earnings (loss) from continuing operations before income taxes and minority interests	58		3	731	103	6
Income taxes (benefit)	10		3	300	31	2
Minority interests	15					
Earnings (loss) from continuing operations	33			431	72	4
Net earnings (loss)	33			431	72	4
Capital expenditures and acquisitions	544	72	147	626	157	
Assets	3,358	326	1,113	2,861	821	304
Equity investments	146			23	174	14

			Corporate & Other				
	Midstream	Geothermal & Power Operations	Administrative & General	Net Interest Expense	Environmental & Litigation	Other (b)	Total
Sales & operating revenues	$ 276	$ 120	$	$	$	$ 124	$ 5,224
Other income (loss) (a)	52	(3)		17		34	73
Inter-segment revenues	12					(1,192)	
Total	340	117		17		(1,034)	5,297
Depreciation, depletion & amortization	11	18				17	973
Impairments	4					2	47

Dry hole costs							107
Exploration expense							
Amortization of exploratory leases							98
Earnings (loss) from equity investments	63	(1)				48	154
Earnings (loss) from continuing operations before income taxes and minority interests	143	51	(120)	(163)	(119)	(77)	616
Income taxes (benefit)	39	21	(38)	(29)	(43)	(16)	280
Minority interests				(6)		(3)	6
Earnings (loss) from continuing operations	104	30	(82)	(128)	(76)	(58)	330
Discontinued operations (net)						1	1
Cumulative effect of accounting changes							
Net earnings (loss)	104	30	(82)	(128)	(76)	(57)	331
Capital expenditures and acquisitions	71	14				39	1,670
Assets	511	526				940	10,760
Equity investments	215	36				78	686

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

SEGMENT DATA (Continued)

2001 Segment Information	**Exploration & Production**					
	North America			**International**		
Millions of dollars	**U.S. Lower 48**	**Alaska**	**Canada**	**Far East**	**Other**	**Trade**
Sales & operating revenues	$ 626	$ 282	$ 239	$ 1,013	$ 138	$ 3,856
Other income (loss) (a)	28		(1)	27	(35)	(1)
Inter-segment revenues	1,438			199	112	1
Total	2,092	282	238	1,239	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)			39	(2)	
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

			Corporate & Other				
	Midstream	**Geothermal & Power Operations**	**Administrative & General**	**Net Interest Expense**	**Environmental & Litigation**	**Other (b)**	**Total**
Sales & operating revenues	$ 242	$ 181	$	$	$	$ 131	$ 6,708
Other income (loss) (a)	2	16		24		28	88
Inter-segment revenues	8					(1,758)	
Total	252	197		24		(1,599)	6,796
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

(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets.

(b) Includes eliminations and consolidation adjustments.

SEGMENT DATA (Continued)

2000 Segment Information
Millions of dollars

	Exploration & Production					
	North America			**International**		
	U.S. Lower 48	**Alaska**	**Canada**	**Far East**	**Other**	**Trade**
Sales & operating revenues	$ 298	$ 254	$ 168	$ 1,018	$ 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	1,241	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			19	(1)	
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

			Corporate & Other				
	Midstream	**Geothermal & Power Operations**	**Administrative & General**	**Net Interest Expense**	**Environmental & Litigation**	**Other (b)**	**Total**
Sales & operating revenues	$ 51	$ 161	$	$	$	$ 168	$ 8,956
Other income (loss) (a)	12	17		31		142	261
Inter-segment revenues	11					(1,900)	
Total	74	178		31		(1,590)	9,217
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

(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.

GEOGRAPHIC INFORMATION

2002 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations	$ 2,785	$ 442	$ 789	$ 644	$ 535	$ 29	$ 5,224
Long lived assets:							
Gross	10,389	1,511	3,316	2,887	1,876	177	20,156
Net	3,595	1,064	1,123	1,278	736	83	7,879

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	$ 529	$ 23	$ 6,708
Long lived assets:							
Gross	10,161	1,387	2,982	2,541	1,857	234	19,162
Net	3,637	1,024	1,016	1,002	723	82	7,484

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	$ 380	$ 1	$ 8,956
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

QUARTERLY FINANCIAL DATA (Unaudited)

	2002 Quarters			
Millions of dollars except per share amounts	**1st**	**2nd**	**3rd**	**4th**
Total revenues	$ 1,049	$ 1,368	$ 1,297	$ 1,583
Earnings from equity investments	37	51	35	31
Total costs, including minority interests and income taxes	1,064	1,306	1,233	1,518
After-tax earnings from continuing operations	22	113	99	96
Discontinued operations				
Gain on disposal (net of tax)		1		
Cumulative effect of accounting change (net of tax)				
Net earnings	$ 22	$ 114	$ 99	$ 96
Basic earnings per share of common stock (a)				
Continuing operations	$ 0.09	$ 0.46	$ 0.41	$ 0.38
Discontinued operations				
Basic earnings per share of common stock	$ 0.09	$ 0.46	$ 0.41	$ 0.38
Diluted earnings per share of common stock (a)				
Continuing operations	$ 0.09	$ 0.46	$ 0.41	$ 0.38
Discontinued operations				
Diluted earnings per share of common stock	$ 0.09	$ 0.46	$ 0.41	$ 0.38
Net sales and operating revenues	$ 1,024	$ 1,349	$ 1,287	$ 1,519
Gross margin (b)	$ 71	$ 204	$ 180	$ 147

(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.

QUARTERLY FINANCIAL DATA (continued)

	2001 Quarters			
Millions of dollars except per share amounts	**1st**	**2nd**	**3rd**	**4th**
Total revenues	$ 2,225	$ 1,707	$ 1,591	$ 1,273
Earnings from equity investments	42	49	37	16
Total costs, including minority interests and income taxes	1,975	1,521	1,526	1,319
After-tax earnings (loss) 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 (loss)	$ 295	$ 247	$ 102	$ (29)
Basic earnings (loss) 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 (loss) per share of common stock	$ 1.21	$ 1.02	$ 0.42	$ (0.12)
Diluted earnings (loss) 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 (loss) 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)

(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.

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	**U.S. Lower 48**	**Alaska**	**Canada**	**Far East**	**Other**	**Total**
2002						
Sales						
To public	$ 338	$ 249	$ 217	$ 1,060	$ 137	$ 2,001
Intercompany	825			238	116	1,179
Other revenues	5	2		2	3	12
Total	1,168	251	217	1,300	256	3,192
Production costs	265	81	52	176	46	620
Exploration expenses	190	23	34	58	47	352
Depreciation, depletion and amortization	496	87	97	239	48	967
Other operating expenses	161	60	17	131	19	388
Pre-tax results of operations	56		17	696	96	865
Income taxes	9		7	287	29	332
Results of operations	$ 47	$	$ 10	$ 409	$ 67	$ 533
Results of equity investees (a)	2			33	7	42
Total	$ 49	$	$ 10	$ 442	$ 74	$ 575

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

2001						
Sales						
To public	$ 374	$ 278	$ 223	$ 1,029	$ 129	$ 2,033
Intercompany	1,439			199	111	1,749
Other revenues	51	4		(1)	(2)	52
Total	1,864	282	223	1,227	238	3,834
Production costs	278	86	54	156	45	619
Exploration expenses	223	2	40	84	78	427
	623	53	104	212	40	1,032

Depreciation, depletion and amortization						
Other operating expenses	86	54	20	114	34	308
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

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

Results of Operations (Continued)

	North America			International		
Millions of dollars	U.S. Lower 48	Alaska	Canada	Far East	Other	Total
2000						
Sales						
To public	$ 109	$ 260	$ 198	$ 1,009	$ 126	$ 1,702
Intercompany	1,442	47		207	98	1,794
Other revenues	75	3	31	9	1	119
Total	1,626	310	229	1,225	225	3,615
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	21	15	80	32	226
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

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

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	**U.S. Lower 48**	**Alaska**	**Canada**	**Far East**	**Other**	**Total (a)**
2002						
Property acquisition						
Proved (b)	$ 110	$	$ 45	$	$	$ 155
Unproved (c)	55		5	22	3	85
Exploration	246	20	31	110	22	429
Development	292	57	79	564	147	1,139
Costs incurred by equity investees (d)	48				3	51
2001						
Property acquisition						
Proved (e) (f) (g)	$ 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 (d)	86				78	164
2000						
Property acquisition						
Proved (h) (i)	$ 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 (d)	103					103

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

2002	$	63
2001	$	305
2000	$	154

(b) U.S. Lower 48 includes $73 million for the increased proved property basis resulting from the acquisition of the Pure minority interest shares.

(c) U.S. Lower 48 includes $48 million for the increased unproved property basis resulting from the acquisition of the Pure minority interest shares.

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

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

(f) U.S. 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.

(g) 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.

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

(i) 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.

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, which represents the approximate energy content of the gas.

	North America			International		
	U.S. Lower 48	**Alaska**	**Canada**	**Far East**	**Other**	**Total**
2002 Average prices: (a) (b)						
Liquids - per barrel	$ 22.87	$ 24.21	$ 20.70	$ 22.88	$ 25.47	$ 23.14
Natural gas - per mcf	3.07	1.42	2.66	2.75	2.72	2.81
Average production costs per BOE	4.47	6.00	4.37	2.49	3.87	3.70
2001 Average prices: (a) (b)						
Liquids - per barrel	$ 23.41	$ 24.69	$ 18.53	$ 22.50	$ 24.15	$ 22.95
Natural gas - per mcf	4.23	1.37	3.17	2.67	2.75	3.31
Average production costs per BOE	3.83	5.55	4.46	2.26	4.21	3.44
2000 Average prices: (a) (b)						
Liquids - per barrel	$ 27.20	$ 26.22	$ 22.46	$ 26.17	$ 27.84	$ 26.31
Natural gas - per mcf	3.93	1.20	2.30	2.51	2.81	2.99
Average production costs per BOE	3.31	4.48	4.21	2.30	4.50	3.17

(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

2002						
Liquids - per barrel	$ 0.02	$	$	$	$	$
Natural gas - per mcf	0.06		(0.01)			0.02
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)

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 2002, 2001 and 2000 are presented on pages 134 and 135. 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. The Company reports all reserves held under PSCs in Indonesia, Myanmar, Bangladesh, Azerbaijan and a concession in the Democratic Republic of Congo 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 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.

The Company also reports natural gas reserves on a dry basis, with natural gas liquids included with crude oil and condensate reserves. For informational purposes, natural gas liquids reserves are estimated to be 30 million, 32 million and 31 million barrels at December 31, 2002, 2001, and 2000, respectively. Of the aforementioned totals, 12 million, 10 million and 12 million barrels, for the respective periods, are located in the United States.

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

	Consolidated Subsidiaries							
	North America			International			Equity	
Millions of barrels	U.S. Lower 48 (a)	Alaska	Canada (a)	Far East (b)	Other (b)	Total (a) (b)	Investees (c)	Worldwide (a) (b)
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 (d)	37		1	26	2	66	2	68
Sales (d)	(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 (d)	21		6			27	4	31
Sales (d)								
Production	(20)	(9)	(6)	(18)	(7)	(60)	(1)	(61)
As of December 31, 2001	156	74	51	208	195	684	9	693
Revisions of estimates	15	7		(7)	(6)	9	(1)	8
Improved recovery	6			1		7		7
Discoveries and extensions	6	2	9	24	1	42		42
Purchases (d)	1		3			4		4
Sales (d)	(5)			(7)		(12)		(12)
Production	(18)	(9)	(7)	(19)	(7)	(60)	(1)	(61)
As of December 31, 2002	161	74	56	200	183	674	7	681
Proved Developed Reserves at:								
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

December 31, 2002	111	62	52	53	29	307	6	313

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

December 31, 1999:	7	18	25	25
December 31, 2000:	27		27	27
December 31, 2001:	32		32	32
December 31, 2002:	2		2	2

(b) Quantities under production sharing contracts are calculated utilizing the economic interest method, which excludes host countries shares. Quantities under production sharing contracts comprised 42% of the worldwide liquid reserves at December 31, 2002.

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

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

Estimated Proved Reserves of Natural Gas (a)

	Consolidated Subsidiaries							
	North America			International				
Billions of cubic feet	U.S. Lower 48 (b)	Alaska	Canada (b)	Far East (c)	Other (c)	Total (b) (c)	Equity Investees (d)	Worldwide (b) (c)
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
Revisions of estimates	(20)	(21)	1	(61)	17	(84)	(10)	(94)
Improved recovery	2			31		33		33
Discoveries and extensions	206	26	43	296	8	579	9	588
Purchases (e)	12	1	10			23	16	39
	(30)			(34)		(64)		(64)

Sales (e)								
Production	(254)	(38)	(37)	(318)	(25)	(672)	(20)	(692)
As of December 31, 2002	1,713	180	306	3,787	346	6,332	227	6,559
Proved Developed Reserves at:								
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
December 31, 2002	1,349	119	273	1,486	201	3,428	177	3,605

(a) Estimates are on a Dry Gas basis, as sold or consumed in the course of operations.

(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
December 31, 2002:	29		29	29

(c) Quantities under production sharing contracts are calculated utilizing the economic interest method, which excludes host countries shares. Quantities under production sharing contracts comprised 27% of the worldwide gas reserves at December 31, 2002.

(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.

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 2002, 2001 and 2000 are presented on page 137. Revenues are based on estimated production of proved reserves from existing and planned facilities and on prices of oil and gas at year-end 2002. 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 137, the year-end prices required to be used in the calculations are highly volatile and were either at or near, in the case of U.S. Lower 48 and Canada natural gas prices, historically high levels at the end of 2000. Subsequent price changes in 2001 and 2002 have had a significant impact on the calculated present values of proved oil and gas reserves. See *Changes in Standardized Measure of Discounted Future Net Cash Flows* table on page 138 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 134 and 135. 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	U.S. Lower 48	Alaska	Canada	Far East	Other	Total
2002						
Revenues (a)	$ 12,211	$ 2,060	$ 2,651	$ 15,423	$ 5,756	$ 38,101
Production costs	3,115	992	541	3,205	824	8,677
Development costs (b)	961	214	62	2,654	1,146	5,037
Income tax expense	2,404	288	654	3,763	1,061	8,170
Future net cash flows	5,731	566	1,394	5,801	2,725	16,217
10% annual discount	2,219	223	577	2,566	1,391	6,976
Present values of future net cash flows	3,512	343	817	3,235	1,334	9,241
Company s share of present values of future net cash flows of equity investees (c)	238	4		355		597
Total (d)	$ 3,750	$ 347	$ 817	$ 3,590	$ 1,334	$ 9,838
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 (e)	$ 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 (f)	$ 7,137	$ 207	$ 1,059	$ 2,985	$ 728	$ 12,116

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

Crude oil, condensate and NGLs, per barrel	2002	$ 28.89	$ 24.66	$ 25.85	$ 27.89	$ 27.29
	2001	$ 17.58	$ 13.06	$ 18.02	$ 17.12	$ 17.76
	2000	$ 25.28	$ 17.45	$ 20.09	$ 22.66	$ 23.27
Natural gas, per mcf	2002	$ 4.56	$ 2.43	$ 3.97	$ 3.08	$ 1.98
	2001	$ 2.46	$ 1.61	$ 2.99	$ 2.33	$ 1.93
	2000	$ 10.02	$ 1.20	$ 10.50	$ 2.75	$ 2.49

(b) Includes dismantlement and abandonment costs. Future development costs include $3,388 million, $3,278 million and $2,578 million at December 31, 2002, 2001 and 2000, respectively required to promote proved undeveloped reserves.

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

(d) Included in U.S. 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 $69 million.

(e) Included in U.S. 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.

(f) Included in U.S. 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.

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

Millions of dollars	2002	2001	2000
Present value at beginning of year	$ 5,664	$ 12,116	$ 5,975
Discoveries and extensions, net of estimated future costs	1,119	1,260	2,333
Net purchases and sales of proved reserves (a)	37	1,198	1,354
Revisions to prior estimates:			
Prices net of estimated changes in production costs	6,780	(10,693)	9,196
Future development costs	(1,204)	(879)	(820)
Quantity estimates	27	392	(232)
Production schedules and other	115	(309)	(584)
Accretion of discount	757	1,433	724
Development costs related to beginning of year reserves	1,134	911	696
Sales of oil and gas net of production costs of: ($620 million in 2002, $619 million in 2001 and $536 million in 2000)	(2,560)	(3,163)	(2,960)
Net change in income taxes	(2,031)	3,398	(3,566)
Present value at end of year	$ 9,838	$ 5,664	$ 12,116

(a) Reserves purchased were valued at $106 million, $1,361 million and $1,512 million in 2002, 2001 and 2000, respectively. Reserves sold were valued at $69 million, $163 million and $158 million for the same years, respectively.

SELECTED FINANCIAL DATA (Unaudited)

Millions of dollars except as indicated	2002	2001	2000	1999	1998
Revenue Data					
Sales					
Crude oil, condensate and natural gas liquids	$ 2,477	$ 3,053	$ 5,872	$ 3,584	$ 2,274
Natural gas	2,367	3,068	2,526	1,646	1,823
Geothermal steam	100	160	161	153	166
Petroleum products	50	203	286	209	32
Minerals	31	28	29	35	67
Other	55	68	137	124	142
Total sales revenues	5,080	6,580	9,011	5,751	4,504
Operating revenues	144	128	(55)	91	123
Other revenues (a)	73	88	261	119	380
Total revenues from continuing operations	$ 5,297	$ 6,796	$ 9,217	$ 5,961	$ 5,007
Earnings Data					
Earnings from continuing operations	$ 330	$ 599	$ 723	$ 113	$ 93
Earnings from discontinued operations (net of tax)	1	17	37	24	37
Cumulative effect of accounting change (net of tax)		(1)			
Net earnings	$ 331	$ 615	$ 760	$ 137	$ 130
Basic earnings (loss) per share:					
Continuing operations	$ 1.34	$ 2.45	$ 2.98	$ 0.47	$ 0.39
Discontinued operations		0.07	0.15	0.10	0.15
Net earnings per share	$ 1.34	$ 2.52	$ 3.13	$ 0.57	$ 0.54
Share Data					
Cash dividends declared on common stock	$ 196	$ 195	$ 194	$ 194	$ 192
Per share	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80
Number of common stockholders of record at year end	21,870	23,213	24,910	27,026	29,567
Weighted average common shares - thousands	246,759	243,568	242,863	242,167	241,332

(a) Excludes earnings from equity investments.

SELECTED FINANCIAL DATA (Continued)

Millions of dollars except as indicated	2002	2001	2000	1999	1998
Balance Sheet Data					
Current assets (c)	$ 1,375	$ 1,295	$ 1,802	$ 1,631	$ 1,388
Current liabilities (c) (d)	1,632	1,422	1,845	1,559	1,376
Working capital (c)	(257)	(127)	(43)	72	12
Ratio of current assets to current liabilities (c)	0.8:1	0.9:1	1.0:1	1.0:1	1.0:1
Total assets	10,760	10,425	10,010	8,967	7,952
Total debt and capital leases	3,008	2,906	2,506	2,854	2,558
Trust convertible preferred securities	522	522	522	522	522
Total stockholders equity	3,298	3,124	2,719	2,184	2,202
Stockholders equity - per common share	12.78	12.80	11.19	9.01	9.13
Return on average stockholders equity:					
Continuing operations	10.3%	20.5%	29.5%	5.2%	4.1%
Net Earnings	10.3%	21.1%	31.0%	6.2%	5.8%
General Data					
Salaries, wages and employee benefits (e)	$ 622	$ 548	$ 546	$ 578	$ 596
Number of regular employees at year-end	6,615	6,980	6,800	7,550	7,880

(c) In 2001 lower current assets and negative working capital reflect major acquisitions funded from cash on hand.
In 2002 higher current liabilities and negative working capital reflect increased development activities in International E&P.

(d) 2002 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

OPERATING SUMMARY (Unaudited)

	2002	2001 (a)	2000 (a)	1999	1998
Exploration & Production					
Net exploratory wells completed:					
Oil	8	56	15	31	19
Gas	56	58	53	32	24
Net development wells completed:					
Oil	80	152	102	81	113
Gas	209	73	142	93	105
Net dry holes:					
Exploratory	35	35	46	28	34
Development	10	6	9	9	10
Total net wells	398	380	367	274	305
Net producible wells at year end (b)	6,053	5,843	4,638	3,511	3,193
Net undeveloped acreage at year end - thousands of acres:					
North America					
U.S. Lower 48	5,692	5,849	2,199	1,743	1,664
Alaska	345	232	221	186	215
Canada	1,356	1,399	1,285	1,440	39
International					
Far East	12,013	11,095	14,505	20,677	20,167
Other	4,331	5,119	6,172	5,043	4,975
Total	23,737	23,694	24,382	29,089	27,060
Net proved reserves at year end (c)(d):					
Crude oil, condensate and natural gas liquids - million barrels (e)					
North America					
U.S. Lower 48	161	156	145	127	134
Alaska	74	74	72	62	60
Canada	56	51	47	55	19
International					
Far East	200	208	186	155	149
Other	183	195	116	120	135
Equity investees	7	9	6	4	2
Total	681	693	572	523	499
Natural gas - billion cubic feet (f)					
North America					
U.S. Lower 48	1,713	1,797	1,542	1,336	1,511
Alaska	180	212	227	294	372
Canada	306	289	280	356	11
International					
Far East	3,787	3,873	3,543	3,705	3,544
Other	346	346	328	331	216
Equity investees	227	232	119	96	21

Total	6,559	6,749	6,039	6,118	5,675

(a) Reflects the acquisition of Titan Exploration, Inc. by Pure Resources, Inc. in U.S. 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) Excludes 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.
(f) Excludes natural gas liquids previously included in natural gas quantities.

OPERATING SUMMARY (continued)

	2002	2001	2000	1999	1998
Exploration & Production (continued)					
Net daily production (a) (b):					
Crude oil, condensate and natural gas liquids - thousand barrels					
North America					
U.S. Lower 48	52	59	52	50	54
Alaska	24	25	26	28	30
Canada	18	16	17	13	11
International					
Far East	53	51	47	54	75
Other	20	19	18	23	19
Total	167	170	160	168	189
Natural gas - million cubic feet					
North America					
U.S. Lower 48	719	905	764	706	762
Alaska	76	103	125	130	129
Canada	91	101	98	70	24
International					
Far East	847	829	799	759	798
Other	93	65	57	39	21
Total	1,826	2,003	1,843	1,704	1,734
Geothermal Operations					
Net wells completed:					
Exploratory					3
Development	1				8
Total	1				11
Net producible wells at year end	85	84	83	79	287
Net undeveloped acreage at year end - thousands of acres	314	314	314	314	338
Net proved reserves at year end: (c) (d)					
Billion kilowatt-hours	155	108	114	120	157
Million equivalent oil barrels	232	162	170	179	235
Net daily production:					
Million kilowatt-hours	13	14	16	17	21
Thousand equivalent oil barrels	20	22	25	25	32

(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.
(d) The 2002 increase reflects the signing of amended Joint Operations and Energy Sales Contracts covering operations in Indonesia, where the primary term of the contracts was extended to 2040 and the minimum annual take-or-pay was increased.

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 as otherwise indicated) is incorporated by reference to Unocal s Proxy Statement for its 2003 Annual Meeting of Stockholders (the 2003 Proxy Statement) (File No. 1-8483), as indicated below. The 2003 Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about April 7, 2003.

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 2003 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 2003 Proxy Statement under the captions Section 16(a) Beneficial Ownership Reporting Compliance and Other Information .

ITEM 11 - EXECUTIVE COMPENSATION.

See the information regarding executive compensation to appear in the 2003 Proxy Statement under the captions Summary Compensation Table, Option/SAR Grants in 2002, Aggregated Option/SAR Exercises in 2002 and December 31, 2002 Option/SAR Values, Long-Term Incentive Plans - Awards in 2002, Pension Plan Table, Employment Contracts and Termination of Employment and Change-in-Control Arrangements, and the information regarding directors compensation to appear in the 2003 Proxy Statement under the caption Directors Compensation.

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

See the information regarding security ownership to appear in the 2003 Proxy Statement under the captions Security Ownership of Certain Beneficial Owners and Security Ownership of Management.

The following table shows the number of Unocal common shares authorized for grants of options and other stock-based awards at December 31, 2002:

Equity Compensation Plan Information (a)

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	5,567,462 (b)	$35.06	6,053,687 (c)
Equity compensation plans not approved by security holders	5,959,331 (d)	$33.51	1,979,591 (e)
Total	11,526,793	$34.26	8,033,278

(a) Excludes certain other stock-based compensation plans which do not involve the issuance of common shares.

(b) There remained options outstanding for 2,590,986 shares under the Long-Term Incentive Plan of 1991; 2,915,581 under the Long-Term Incentive Plan of 1998; and 60,895 under the Directors Deferred Compensation and Stock Award Plan.

(c) Includes 806,208 shares reserved for outstanding performance shares awarded under the Long-Term Incentive Plan of 1998, 93,025 shares reserved for outstanding directors units awarded under the 2001 Directors Deferred Compensation and Stock Award Plan and 9,570 shares reserved for outstanding directors units awarded under the Directors Restricted Stock Units Plan. A total of 335,848 shares were available for future grants of director stock options or director units under the 2001 Directors Deferred Compensation and Stock Award Plan, and 112,517 shares were available for future grants of dividend equivalents under the Directors Restricted Stock Units Plan. A total of 4,696,519 shares were available for future grants of stock options, restricted stock, and performance shares under the 1998 Management Incentive Program. Of the 4,696,519 shares, a total of 1,699,836 shares were available for future grants of restricted stock and performance shares.

(d) There remained options outstanding for 334,620 shares under the Special Stock Option Plan of 1996; and 5,624,711 shares under the Unocal Stock Option Plan. Additionally, in connection with the merger of a wholly-owned subsidiary of Unocal into Pure Resources, Inc. (Pure), on October 30, 2002, that resulted in Pure becoming a wholly-owned subsidiary of Unocal, employee nonqualified stock options to acquire Pure stock (that were issued by Pure and its predecessors) became fully vested stock options to acquire Unocal common stock; options to acquire a total of 4,252,253 shares with a weighted average exercise price of $18.86 were outstanding at December 31, 2002 and all of these options became fully vested at the time of the acquisition. Most of the Pure employee stock options were issued under Pure s 1999 Incentive Plan, as approved by Pure stockholders in May of 1999.

(e) A total of 1,925,199 shares were reserved for future grants of stock options under the Unocal Stock Option Plan and 54,392 shares were reserved for future grants of restricted stock under the Union Oil Restricted Stock Plan.

See note 26 Stock-Based Compensation Plans to the consolidated financial statements in Item 8 for information with respect to the material features of the Company s equity compensation plans, which information is incorporated by reference in this Item 12.

ITEM 13 - CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

See the information regarding certain loans to executive officers to appear in the 2003 Proxy Statement under the caption Indebtedness of Management.

ITEM 14 CONTROLS AND PROCEDURES.

Within the 90 days prior to the date of this report, the Company carried out an evaluation of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to Rule 13a-14 of the Securities Exchange Act of 1934. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective in timely identifying material information potentially required to be included in the Company s SEC filings.

There were no significant changes in the Company s internal controls or other factors that could significantly affect these controls subsequent to the date of their evaluation and there were no corrective actions required with regard to significant deficiencies and material weaknesses.

PART IV

ITEM 15 - 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 151 through 153 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:

During the fourth quarter of 2002:

(1) Current Report on Form 8-K, dated October 1, 2002, and filed October 2, 2002, for the purpose of reporting, under Item 5, a revised exchange offer relating to Pure Resources Inc.

(2) Current Report on Form 8-K, dated October 8, 2002, and filed October 9, 2002, for the purpose of reporting, under Item 5, an update on hurricane Lili and a revised exchange offer relating to Pure Resources.

(3) Amended Current Report on Form 8-K/A, dated September 27, 2002, and filed October 11, 2002, for the purpose of reporting, under Item 5, a third quarter 2002 environmental provision.

(4) Current Report on Form 8-K, dated October 23, 2002, and filed October 24, 2002, for the purpose of reporting, under Item 5, the Company s third quarter 2002 earnings, the Company s 2002 earnings forecast, the Company s 2003 and beyond production outlook and the extension of the revised exchange offer relating to Pure Resources Inc.

(5) Current Report on Form 8-K, dated October 30, 2002, and filed October 31, 2002, for the purpose of reporting, under Item 5, the Company s acquisition of the remaining shares of Pure Resources Inc., which it did not already own.

(6) Current Report on Form 8-K, dated November 12, 2002, and filed November 21, 2002, for the purpose of reporting, under Item 5, various of the Company s operational activities and a five-year earnings growth projection.

(7) Current Report on Form 8-K, dated December 3, 2002, and filed December 8, 2002, for the purpose of reporting, under Item 5, the appointment of a new director to the Company s Board, the resignation of the Company s Senior Vice President and Chief Legal Officer and Unocal Corporation s bylaw amendments, filed as an exhibit under Item 7, and effective December 3, 2002.

(8) Current Report on Form 8-K, dated and filed December 26, 2002, for the purpose of reporting, under Item 5, a revision in the Company s outlook for the fourth quarter and full-year 2002.

During the first quarter of 2003 to the date hereof:

(1) Current Report on Form 8-K, dated January 28, 2003 and filed February 5, 2003, for the purpose of reporting, under Item 5, the Company s fourth quarter 2002 earnings and related information, the Company s 2002 reserve replacement and finding development and acquisitions costs, the Company s 2003 outlook and other operational activity updates.

(2) Current Report on Form 8-K, date February 4, 2003 and filed February 10, 2003, for the purpose of reporting, under Item 5, the Company s designation of its Vice President and Chief Legal Officer as an executive officer .

SIGNATURES

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: March 20, 2003

By: /s/ TERRY G. DALLAS

Terry G. Dallas
Executive Vice President
and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 20, 2003.

Signature	Title
/s/ CHARLES R. WILLIAMSON **Charles R. Williamson**	Chief Executive Officer and Chairman of the Board of Directors
/s/ JOHN W. CREIGHTON, JR. **John W. Creighton, Jr.**	Vice Chairman of the Board of Directors
/s/ TIMOTHY H. LING **Timothy H. Ling**	Director
/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 (Principal Accounting Officer)
/s/ JOHN W. AMERMAN **John W. Amerman**	Director
/s/ JAMES W. CROWNOVER **James W. Crownover**	Director
/s/ FRANK C. HERRINGER **Frank C. Herringer**	Director
/s/ FERRELL P. MCLEAN	Director

Ferrell P. McClean	
/s/ DONALD B. RICE	Director
Donald B. Rice	
/s/ KEVIN W. SHARER	Director
Kevin W. Sharer	
/s/ MARINA v.N. WHITMAN	Director
Marina v.N. Whitman	

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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;

4. The registrant s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant s other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant s auditors and the audit committee of registrant s board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant s ability to record, process, summarize and report financial data and have identified for the registrant s auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant s internal controls; and

6. The registrant s other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

/s/ Charles R. Williamson

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

CERTIFICATIONS

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;

4. The registrant s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant s other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant s auditors and the audit committee of registrant s board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant s ability to record, process, summarize and report financial data and have identified for the registrant s auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant s internal controls; and

6. The registrant s other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

/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 2002					
Amounts deducted from applicable assets:					
Accounts and notes receivable	$ 146	$ 6	$	$ (126)	$ 26
Investments and long-term receivables	$ 171	$ 2	$	$ (170)	$ 3
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

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

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 December 3, 2002, and currently in effect (incorporated by reference to Exhibit 3 to Unocal s Current Report on Form 8-K dated December 3, 2002, 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), as amended by (1) Amendment to Rights Agreement, dated as of March 27, 2002 (incorporated by reference to Exhibit 10 to Unocal s Current Report on Form 8-K dated March 27, 2002, File No. 1-8483) and (2) Amendment No. 2 to Rights Agreement, dated as of August 2, 2002 (incorporated by reference to Exhibit 10 to Unocal s Current Report on Form 8-K dated August 2, 2002, File No. 1-8483).

The following Exhibits 10.2 through 10.34 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 and the Long-Term Incentive Plan of 1998 (incorporated by reference to Exhibit A to Unocal s Proxy Statement dated April 8, 2002, for its 2002 Annual Meeting of Stockholders, File No. 1-8483).

Exhibit 10.6* 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).

* Previously filed.

Exhibit 10.7*	Form of Nonqualified Stock Option Grant under the Long-Term Incentive Plan of 1998, effective July 27, 2001, 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 10.8*	Form of Nonqualified Stock Option Grant under the Long-term Incentive Plan of 1998, effective August 20, 2001, 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 10.9**	Unocal Stock Option Plan, as amended through December 4, 2001.
Exhibit 10.10*	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 10.11*	Amendment to the 2000 Executive Stock Purchase Program, effective February 12, 2002 (incorporated by reference to Exhibit 10.13 to Unocal s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 1-8483.)
Exhibit 10.12*	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 10.13*	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 10.14*	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 10.15**	Unocal Nonqualified Retirement Plan A , as amended through January 1, 2002.
Exhibit 10.16**	Unocal Nonqualified Retirement Plan B , as amended through January 1, 2002.
Exhibit 10.17**	Unocal Nonqualified Retirement Plan C , as amended through January 1, 2002.
Exhibit 10.18*	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 10.19*	Amendments to the Supplemental Savings Plan, effective January 1, 2001 (incorporated by reference to Exhibit 10.21 to Unocal s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 1-8483).
Exhibit 10.20**	Summary of Enhanced Severance Program, adopted December 5, 2000.
Exhibit 10.21**	Summary of Other Compensatory Arrangements.
Exhibit 10.22*	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 10.23*	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 10.24*	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 10.25*	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 10.26**	Amendment No. 1 to 2001 Directors Deferred Compensation and Stock Award Plan, effective February 7, 2003.

* Previously filed.
** Filed herewith.

Exhibit 10.27*	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 10.28*	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 10.29*	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 10.30**	Employment Agreement, effective as of March 12, 2003, by and between Unocal and Charles R. Williamson.
Exhibit 10.31**	Change in Control Agreement, effective as of March 12, 2003, by and between Unocal and Timothy H. Ling.
Exhibit 10.32**	Employment Agreement, effective as of March 12, 2003, by and between Unocal and Terry G. Dallas.
Exhibit 10.33*	Agreement and General Release, dated November 6, 2002, between Unocal and Dennis P. R. Codon (incorporated by reference to Exhibit 10 to Unocal s Current Report on Form 8-K dated December 3, 2002, File No. 1-8483).
Exhibit 10.34*	Agreement, dated February 4, 2003, between Charles O. Strathman, Union Oil Company of California and Unocal (incorporated by reference to Exhibit 10 to Unocal s Current Report on Form 8-K dated February 4, 2003, 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, 2002.
Exhibit 12.2**	Statement regarding computation of ratio of earnings to fixed charges of Union Oil Company of California for the five years ended December 31, 2002.
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.