UNOCAL CORP
Form 10-K
March 11, 2004
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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, 2003

or

¨ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from ________ to ________

Commission file number 1-8483

UNOCAL CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE **(State or other jurisdiction of incorporation or organization)**	**95-3825062** **(I.R.S. Employer Identification No.)**
2141 Rosecrans Avenue, Suite 4000, El Segundo, California **(Address of principal executive offices)**	**90245** **(Zip Code)**

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

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

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

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes x No ¨

The aggregate market value of the common stock held by non-affiliates of the registrant as of June 30, 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 $7.4 billion.

Shares of common stock outstanding as of February 27, 2004: 261,970,895

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive Proxy Statement for its 2004 Annual Meeting of Stockholders (to be filed with the Securities and Exchange Commission on or about April 12, 2004) are incorporated by reference into Part III.

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GLOSSARY

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

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

API Gravity is a measurement of the gravity (density) of crude oil and other liquid hydrocarbons by a system recommended by the American Petroleum Institute (API). The measuring scale is calibrated in terms of API degrees. The higher the API gravity, the lighter the oil.

Bilateral institution refers to a country specific institution, which lends funds primarily to promote the export of goods from that country. Examples of bilateral institutions are Ex-Im (U.S.), Hermes (Germany), SACE (Italy), COFACE (France), and JBIC (Japan).

BOE is 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 standardized unit of measure for energy, equivalent to the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. Ten thousand MMBtu (million Btu) is the standard volume for exchange traded natural gas derivative contracts, the approximate heat content of ten thousand Mcf (thousand cubic feet) of natural gas.

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.

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Gross acres or gross wells are the total acres or wells in which the Company has a working interest.

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 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.

OPEC is the abbreviation for Organization of Petroleum Exporting Countries.

Production Sharing Contract (PSC) is a contractual agreement between the Company and a host government whereby the Company, acting as contractor, bears all exploration, 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 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 the Company has in a joint venture, partnership, consortium, project or acreage. Net working interest is working interest after deducting royalties.

West Texas Intermediate (WTI) crude oil is a light, sweet crude oil (high API gravity, low sulfur) used as the benchmark for U.S. crude oil refining and trading. WTI is deliverable at Cushing, Oklahoma to fill New York Mercantile Exchange (NYMEX) futures contracts for light, sweet crude oil.

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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. The Company will also make available to any stockholder, without charge, copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this, or any other filings, please contact: Unocal Stockholder Services, 2141 Rosecrans Avenue, Suite 4000, El Segundo, California 90245 or call (800) 252-2233.

STRATEGIC FOCUS

The Company s strategy is focused on creating value for its stockholders by continuing to advance oil and gas development projects and delivering successful exploration results through the drill bit. The Company is striving to create such value while maintaining a strong balance sheet, which was strengthened in 2003 with significant reductions in long-term debt and other financings.

The Company s advancement of development projects is focused in deepwater Indonesia, the Gulf of Mexico deepwater, the Gulf of Thailand, the Azerbaijan portion of the Caspian Sea and Alaska.

The Company is committed to streamlining and maintaining a profitable and sustainable North American business, with stable production and manageable capital requirements. In 2003, the Company moved aggressively to restructure its operations to fit this profile by selling assets, exchanging properties and selling its equity interests in Matador Petroleum Corporation (Matador) and Tom Brown, Inc. (Tom Brown).

The Company s global exploration effort picked up steam in 2003 and was focused in the Gulf of Mexico deepwater, Indonesia deepwater and the Gulf of Mexico deep shelf. The results in the deepwater of the Gulf of Mexico and Indonesia were very encouraging. However, the results in the Gulf of Mexico deep shelf were disappointing.

Construction of the Baku-Tbilsi-Ceyhan (BTC) pipeline, which will transport oil from the Azerbaijan International Operating Company (AIOC) development project in the Caspian Sea to the Mediterranean port of Ceyhan for export to world markets, has made significant progress.

The Company strengthened its Asia natural gas position by signing agreements to explore for and develop natural gas in the Xihu Trough area of the East China Sea, the execution of a new gas sales agreement in Bangladesh to develop the Moulavi Bazar natural gas field for the domestic Bangladesh market and reaching a heads of agreement with the Petroleum Authority of Thailand to extend the terms and increase the quantities of natural gas production in Thailand.

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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 31 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, and they are carried out by business units in North America and Internationally in Asia and other locations around the world. In 2003, the Company s worldwide average production was approximately 160 MBbl/d of liquids and 1,728 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 39 percent of the Company s worldwide production in 2003 and 27 percent of the Company s worldwide proved oil and gas reserves at year-end 2003 were in the U.S. Exploration and production net properties accounted for approximately 89 percent of Unocal s total net properties at December 31, 2003. Exploration and production properties in the U.S., as a percentage of total exploration and production properties were 39 percent in 2003.

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 133 through 142 of this report. During 2003, certain estimates of the Company s U.S. underground oil and gas reserves as of December 31, 2002, 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, 2002, included in this report.

Net Proved Reserves

Estimated net quantities of the Company s proved liquids and natural gas reserves at December 31, 2003, 2002 and 2001, including its proportional shares of the reserves of equity investees, were as follows:

	U.S. Lower 48	Alaska	Canada	Total N.A.	Far East	Other	Total Int l	Total
2003								
Liquids - million barrels	141	70	57	**268**	217	190	**407**	**675**
Natural gas - billion cubic feet	1,395	183	315	**1,893**	3,994	618	**4,612**	**6,505**
Millions of barrels oil equivalent	373	101	109	**583**	883	293	**1,176**	**1,759**
2002								
Liquids - million barrels	165	74	56	**295**	200	186	**386**	**681**
Natural gas - billion cubic feet	1,896	180	306	**2,382**	3,787	390	**4,177**	**6,559**

Millions of barrels oil equivalent	481	104	107	**692**	831	251	**1,082**	**1,774**
2001								
Liquids - million barrels	161	74	51	**286**	208	199	**407**	**693**
Natural gas - billion cubic feet	1,965	212	289	**2,466**	3,873	410	**4,283**	**6,749**
Millions of barrels oil equivalent	489	109	99	**697**	854	267	**1,121**	**1,818**

There were no amounts of proved reserves attributable to minority interests at December 31, 2003. 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, while 2001 proved reserves included 32 million barrels of liquids and 397 billion cubic feet of natural gas in the U.S. Lower 48. The volumes attributable to minority interests in the U.S. Lower 48 for 2001 primarily reflected the outside ownership in the Company s Pure Resources Inc. (Pure) subsidiary at that time. For additional details, see the Oil and Gas Reserve Data in Item 8 of this report.

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Net Daily Production

Net quantities of the Company s daily liquids and natural gas production for the years 2003, 2002 and 2001, including its proportional shares of production of equity investees, were as follows:

	U.S. Lower 48	Alaska	Canada	Total N.A.	Far East	Other	Total Int'l	Worldwide
2003								
Liquids - million barrels	43	21	17	**81**	59	20	**79**	**160**
Natural gas - billion cubic feet	616	57	90	**763**	877	88	**965**	**1,728**
Millions of barrels oil equivalent	145	31	32	**208**	205	35	**240**	**448**
2002								
Liquids - million barrels	52	24	18	**94**	53	20	**73**	**167**
Natural gas - billion cubic feet	719	76	91	**886**	847	93	**940**	**1,826**
Millions of barrels oil equivalent	172	37	32	**241**	194	36	**230**	**471**
2001								
Liquids - million barrels	59	25	16	**100**	51	19	**70**	**170**
Natural gas - billion cubic feet	905	103	101	**1,109**	829	65	**894**	**2,003**
Millions of barrels oil equivalent	210	42	33	**285**	189	30	**219**	**504**

Net daily production of liquids in the U.S. Lower 48 included volumes attributable to minority interests of approximately 7 MBbl/d and 9 MBbl/d for 2002 and 2001, respectively. There were no liquids volumes attributable to minority interests in 2003. Natural gas net daily production in the U.S. Lower 48 included volumes attributable to minority interests of approximately 5 MMcf/d, 82 MMcf/d and 102 MMcf/d for 2003, 2002 and 2001, respectively. In 2002 and 2001, the volumes attributable to minority interests in the U.S. Lower 48 primarily reflected the outside ownership in the Company s Pure subsidiary.

Oil and Gas Acreage

As of December 31, 2003, the Company s holdings of oil and gas rights acreage were as follows:

	(Thousands of acres)			
	Proved Acreage		Prospective Acreage	
	Gross	Net	Gross	Net
U.S. Lower 48	1,672	728	8,597	5,329
Alaska	271	57	604	349
Canada	577	286	2,274	1,139

North America Total	**2,520**	**1,071**	**11,475**	**6,817**
Far East	983	571	29,247	10,515
Other	45	24	6,410	3,960
International Total	**1,028**	**595**	**35,657**	**14,475**
Worldwide	**3,548**	**1,666**	**47,132**	**21,292**

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Producible Oil and Gas Wells

The numbers of oil and gas producible wells at December 31, 2003 were as follows:

	Oil		Gas	
	Gross	Net	Gross	Net
U.S. Lower 48	5,033	2,800	1,952	1,025
Alaska	698	127	29	18
Canada	1,491	784	626	343
North America Total	**7,222**	**3,711**	**2,607**	**1,386**
Far East	302	233	891	582
Other	110	41	11	7
International Total	**412**	**274**	**902**	**589**
Worldwide [a]	**7,634**	**3,985**	**3,509**	**1,975**

[a] The Company had 179 gross and 66 net producible wells with multiple completions.

Drilling in Progress

The numbers of oil and gas wells in progress at December 31, 2003 were as follows:

	Gross	Net
U.S. Lower 48	41	23
Alaska	1	0
Canada	16	10
North America Total	**58**	**33**
Far East	17	13
Other	14	2
International Total	**31**	**15**
Worldwide [a] [b]	**89**	**48**

(a) Excludes service wells in progress (3 gross and 3 net).

(b) The Company had one waterflood project under development at December 31, 2003.

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Net Oil and Gas Wells Completed and Dry Holes

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

	Productive			Dry		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
Exploratory						
U.S. Lower 48	8	23	66	8	17	18
Alaska	1	2	2		3	
Canada	14	20	23	4	9	6
North America Total	**23**	**45**	**91**	**12**	**29**	**24**
Far East	7	19	23	10	6	9
Other						2
International Total	**7**	**19**	**23**	**10**	**6**	**11**
Worldwide	**30**	**64**	**114**	**22**	**35**	**35**
Development						
U.S. Lower 48	75	54	96		1	
Alaska	3	2	8			
Canada	51	56	51	3	8	6
North America Total	**129**	**112**	**155**	**3**	**9**	**6**
Far East	118	174	67	1	1	
Other	4	3	3			
International Total	**122**	**177**	**70**	**1**	**1**	
Worldwide	**251**	**289**	**225**	**4**	**10**	**6**

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; operations in New Mexico and Colorado; and the shelf and deepwater areas of the Gulf of Mexico.

The Company holds approximately 5.3 million net acres of prospective land in the U.S. Lower 48. Nearly 21 percent of the prospective acreage is located in federal leases, offshore in the Gulf of Mexico. Prospective lands include over 3.7 million net acres of fee mineral lands, which are primarily located in Alabama, Arkansas, Texas, Mississippi, Florida and Louisiana. The majority of the fee mineral lands were held for sale at the end of 2003. The Company also holds approximately 728 thousand net acres of proved lands. Approximately 20 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.

In 2003, net liquids production averaged 43 MBbl/d, which was produced from fields onshore and offshore the Gulf of Mexico, primarily in Texas, Louisiana, Alabama and New Mexico. Net natural gas production averaged 616 MMcf/d, which was principally from fields in the offshore Gulf of Mexico and onshore, primarily in Texas, Louisiana, New Mexico and Colorado. In 2003, the Company s production base in the region was impacted by the sale of assets, including the sale of equity interests in Tom Brown and Matador and continued field declines.

A substantial portion of the crude oil and natural gas produced in the U.S. Lower 48 operations is sold to the Company s Trade business segment. The remaining production is sold to third-parties at spot market prices or under long-term contracts.

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Gulf of Mexico Shelf and Onshore

During 2003, the Company refocused its efforts in the Gulf of Mexico shelf and onshore areas to improve its cost structure by selling non-core properties with low margins. However, the Company retained its deep mineral rights from a substantial number of the properties sold.

The Company s exploration program in the Gulf of Mexico shelf was focused on the deep shelf. While the Company achieved some measure of success in early 2003, overall performance was disappointing. During an 18-month drilling program that began in 2002, the Company drilled 15 wells, of which 10 were dry holes. In 2003, the Company had two noteworthy discoveries in the deep shelf Harvest and Red Pepper. The Harvest discovery located on West Cameron Block 44 commenced production in late June 2003. In late October, the Company also drilled a successful appraisal well on the Harvest deep shelf prospect. The Company placed the Harvest-2 well on production in late 2003. Production at the Red Pepper discovery, located on High Island Block 37, commenced in October 2003. While the results of the deep shelf program have been disappointing, the Company believes that even modest deep shelf discoveries are advantaged due to the potential speed and low cost in bringing them to production.

Net production in 2003, which was 70 percent weighted toward natural gas, averaged 145 MBOE/d. The average production in 2003 was approximately 15 percent lower than the previous year, principally from the sale of non-core properties and natural field declines.

Deepwater Gulf of Mexico

Over the past five years, the Company has acquired acreage positions in the deepwater Gulf of Mexico, with interests in 224 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 128 blocks. In 2003, the Company relinquished 44 deepwater Gulf of Mexico blocks before their expiration dates to focus its deepwater Gulf of Mexico acreage positions on blocks that have more potential.

In October, the Company completed a discovery well on the Saint Malo prospect located on Walker Ridge Block 678. The discovery well encountered more than 450 feet of net oil pay. Based on the evaluation of this well, the Company expects to begin an appraisal program in 2004. The Company holds a 28.75 percent working interest in the prospect. In addition, the Company farmed-in to an exploratory well on the Puma prospect, located on Green Canyon Block 823, to earn a 15 percent working interest. The prospect is an exploration play offsetting the Mad Dog discovery. The well was a discovery and encountered approximately 500 feet of net oil pay. The Puma discovery s proximity to the Mad Dog field allows for the option of either a stand-alone development or a tie-back, depending on future appraisal results. The Puma discovery is structurally complex and will require additional seismic data and appraisal drilling to determine its size.

The Company continues to move forward with studies on development options for its Trident discovery. The Trident prospect covers seven blocks in Alaminos Canyon in the ultra-deep water of the Gulf of Mexico. The Company is in discussions with other operators in the area about development scenarios and joint development planning. The Company is the operator of the discovery and has a 59.5 percent working interest in a seven-block area.

The Company participated in discoveries made on the Mad Dog and K-2 fields in prior years. The Company has a 15.6 percent working interest in Mad Dog on Green Canyon Block 826. In 2003, development of Mad Dog continued on track and the Company anticipates first production in the first half of 2005, 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 $225 million for its portion of the development costs for Mad Dog. The K-2 discovery is located on Green Canyon Block 562. At the end of 2003, the co-venture integrated project team of the K-2 discovery completed a development plan, and the working interest owners sanctioned the project in early 2004. The Company has committed approximately $50 million for its portion of the development costs. The Company holds a 12.5 percent working interest in the K-2 discovery.

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The Company completed a successful appraisal well on the Champlain discovery in July 2003 and has a 30-percent working interest in the prospect. The Company and its co-venturers are working on development options with the aim of sanctioning development of the Champlain discovery in 2004. While the Champlain field is small for a stand-alone development, it is located near large discoveries that could enable early production through subsea tiebacks or other joint development options.

The Company participated in the prior discovery of the Mirage prospect, located on Mississippi Canyon Block 941, where it has a 25 percent non-operating working interest. In 2003, the Company signed a participation agreement with another company that would allow them to earn an interest in the prospect by drilling a well in 2004. Upon completion of the farm-in requirements, the Company s interest will drop to 8.57 percent.

ALASKA

The Company operates ten platforms in the Cook Inlet and five producing natural gas fields. 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 2003, the Company s net natural gas production from the Cook Inlet averaged 57 MMcf/d. Pursuant to agreements with the purchaser of the Company s former agricultural products business, most of the Company s natural gas production was sold, at an agreed price, for feedstock to a fertilizer manufacturing operation in Nikiski, Alaska.

In 2003, net liquids production averaged approximately 21 MBbl/d of which about 55 percent was from the North Slope. All of the Company s Alaska crude oil production is sold to third parties at spot market prices.

The Company also has an interest in the Ninilchik Unit, on the South Kenai Peninsula, which began first production from five wells in 2003. The production from these wells was put into the Company s gas storage facility in 2003. The Ninilchik wells are currently producing 14 MMcf/d net to the Company. The Company has a 40 percent non-operating interest in the unit. The Company has a contract to sell up to 450 billion cubic feet of natural gas to an affiliate of ENSTAR Natural Gas Company and began deliveries on the contract in January 2004. ENSTAR distributes natural gas to Anchorage, the Matanuska-Susitna Valley, and the Kenai Peninsula. The natural gas sold to ENSTAR is priced based on a 36-month trailing average of Henry Hub natural gas prices.

The Company discovered a new natural gas field at the Happy Valley prospect located approximately seven miles southeast of Ninilchik on Alaska s Kenai Peninsula. The discovery well found 110 feet of natural gas pay. The Company sanctioned development of the discovery in November 2003. First production is planned for late 2004. The field is expected to produce about 25 MMcf/d during 2005, to supply the ENSTAR market. The total capital investment to develop the field is estimated to be $50 million. The Company holds a 100 percent working interest in the field.

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).

The Company s Canadian production in 2003 averaged approximately 17 MBbl/d of liquids and 90 MMcf/d of natural gas.

The Company participated in drilling 127 wells in 2003 resulting in 48 natural gas wells, 65 crude oil wells and four service wells, for an overall success rate of 92 percent.

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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 2003, International operations accounted for 56 percent and 49 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. Listed below are certain of the more material oil and gas concessions and PSCs within the International operations:

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[c]
	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[d]
Indonesia	Production Sharing Contract	East Kalimantan	93	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	98	2024	Y
	Production Sharing Contract	Block 12	98	[e]	Y
Vietnam	Production Sharing Contract	Blocks B & 48/95	42	2021	Y
	Production Sharing Contract	Block 52/97	43	2029	Y
China	Production Sharing Contracts	Xihu Trough	20	2033	N

(a) Share percentages rounded to the nearest whole number

(b) Terms of agreement renewal are subject to negotiation

(c) Ten-year extension option is available to the Company

(d) No renewal option specified in the PSC

(e) 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 conducts oil and gas operations in five contract areas in the Pattani field located in the Gulf of Thailand. This field is subdivided into 15 operating areas. Unocal s average net working interest in contract areas 1, 2, 3 and 5 is 62 percent and 31 percent in contract area 4, the Pailin operational area. The Company had 1,100 employees in its Thailand operations at year-end 2003. Approximately 92 percent of these employees were Thai nationals.

Very strong sales resulting from continued strengthening in the Thai economy and the related increase in power and gas demand capped off a record year for Unocal Thailand. New daily, monthly, and annual records were set for natural gas and liquids production. Gross natural gas production from Unocal s Gulf of Thailand operations in 2003 averaged 1,151 MMcf/d (627 MMcf/d net to the Company). The natural gas produced is used mainly in power generation, but it is also consumed by the industrial and transportation sectors and in the petrochemical industry. Gross crude oil and condensate production in 2003 averaged 58 MBbl/d, or 33 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.

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The Company sells all of its natural gas production to PTT Public Co., Ltd. (PTT), under long-term natural gas sales agreements (GSA) with expiration dates ranging from 2010 to 2029. The GSA 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 2003, the Company signed a heads of agreement with PTT with a goal towards amending and extending two of the Company s GSAs, while increasing gross contracted sales volumes from 740 MMcf/d to 850 MMcf/d in 2006, with additional increases up to 1,240 MMcf/d in subsequent years. The Company and its co-venturers also signed an agreement in 2003 with PTT to increase gross contracted gas sales volumes from the Pailin production area from 330 MMcf/d to 353 MMcf/d, and ultimately up to 368 MMcf/d around 2006. The Company has typically supplied more natural gas to PTT than the minimum daily contract quantity provision of its GSAs. The minimum gross quantity of natural gas that PTT is contractually obligated to purchase from the Company and its co-venturers under the existing GSAs in the Gulf of Thailand is now 1,093 MMcf/d for 2004.

In September 2003, the Company filed a notice with the government of Thailand seeking approval for the second phase of the Company s offshore oil development. The second phase is designed to double gross oil production from the Yala and Plamuk areas to 40 MBbl/d. Current plans call for the required new facilities to be installed by mid-2005 with start-up of new production commencing shortly thereafter. The Company has a 71.25 percent working interest in the Yala and Plamuk areas (62 percent net of royalty).

Unocal Thailand continued to meet its ongoing contractual gas delivery commitments in 2003 by drilling 138 gross successful development wells.

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 and 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.

Natural gas from the Yadana field is purchased by PTT and contributes to the fuel requirements of three major power plants in Thailand. Gross natural gas production averaged 614 MMcf/d (99 MMcf/d net to the Company) in 2003, which was more than the contract rate of 525 MMcf/d. See note 31 to the consolidated financial statements for sales to PTT from the Company s Thailand and Myanmar operations.

In July 2003, the President of the United States signed the Burmese Freedom and Democracy Act of 2003 and issued Executive Order 13310 expanding existing U.S. sanctions against Myanmar. The Company believes that this action will not have a material adverse effect on revenues it receives from its interests in Myanmar.

Indonesia

The Company, through its subsidiaries, held varying interests in 10 offshore PSC areas, covering approximately 8 million acres, at December 31, 2003. Eight PSC areas including East Kalimantan, Ganal, Rapak, Makassar Strait, Muara Bakau, Popodi, Papalang and Donggala are located offshore the island of Borneo, on the western side of the Makassar Strait, East Kalimantan. Two additional PSC areas, Bukat and Ambalat, are located in the Tarakan Basin offshore Northeast Kalimantan. The Company had about 1,700 employees in its Indonesian oil and gas operations at year-end 2003, of which approximately 92 percent were Indonesian nationals.

Gross production from Company-operated fields averaged 60 MBbl/d of liquids and 266 MMcf/d of natural gas in 2003. The average economic interest production under the PSCs was 26 MBbl/d of liquids and 151 MMcf/d of natural gas in 2003.

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Shelf - The Company currently operates 11 producing oil and gas fields offshore East Kalimantan. The Company has a 92.5 percent working interest in 10 of the fields, and a 46.25 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 2003, approximately 13 percent of the Company s share of this production was sold to the government for an average price that was substantially lower than market.

Deep Water The Company, through its subsidiaries, is the operator of the East Kalimantan, Ganal, Rapak and Makassar Strait PSCs. The Company holds working interests of 92.5 percent in the East Kalimantan, 90 percent in the Makassar Strait and 80 percent in the Rapak and Ganal PSCs.

The Company, through its subsidiaries, also holds a 24 percent non-operating working interest in the Popodi and Papalang PSCs and holds a 50 percent non-operating working interest in the Muara Bakau PSC area. The Company also holds a 19.55% non-operating working interest in the Donggala PSC and 33.75 percent non-operating working interests in the Bukat and Ambalat PSCs.

The Company s new production from the deepwater West Seno oil and gas field came on line in early August 2003. The Company experienced facility related start-up and processing issues, which have been largely corrected. The Company continued to drill additional development wells, which ramped up gross production from the field to an average 15 MBOE/d in December 2003. The Company expects to achieve peak gross production rates of 35 to 45 MBOE/d from Phase 1 in 2004, rising to 55 to 65 MBOE/d when Phase 2 is completed. The field is supplying natural gas to the Bontang facility. Gross development costs for the first phase are expected to be approximately $525 million with an additional $260 million for the second phase (Unocal s net share is expected to be approximately $475 million and $235 million for the first and second phases, respectively). The Company and its co-venturer completed financing arrangements for a portion of the total costs through the Overseas Private Investment Corporation in late March 2003 through two loans. One loan is for $300 million and covers the first phase, and the other loan is for $50 million and is for the second phase. The loan associated with the second phase is still subject to a final construction contract being obtained.

In 2003, the Company made a gas-condensate and oil discovery on the deepwater Gehem prospect in the Ganal PSC. Gehem-1 is the first of a series of exploration wells that are designed to test the prospectivity of deeper, previously untested intervals underlying previous deepwater discoveries offshore East Kalimantan. The Gehem-1 well encountered 617 feet of net gas and gas-condensate pay and 18 feet of net oil pay. More than 400 feet of the net pay was in a stratigraphic interval that had not been penetrated during drilling in the nearby Ranggas field. The Company believes that the Gehem structure, which covers nearly 8,000 acres, has the potential for oil pay in several zones downdip of the Gehem-1 well and in deeper intervals, which will be tested in subsequent appraisal wells in 2004. Gehem by itself has a number of characteristics that favor early development. The size of the potential Gehem resource, reservoir quality, potential high condensate yields and location relative to the Bontang liquefied natural gas plant, position Gehem to be a low-cost gas supplier to the plant.

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The Company also successfully completed drilling the Ranggas Selatan-1 appraisal well, extending the Ranggas field to the south on the Rapak production-sharing contract area. The Selatan-1 well penetrated 187 feet of net oil pay and 258 feet of net gas pay in several zones of high quality reservoir rock. The Company is conducting engineering studies for the development of the Ranggas field. Extending the Ranggas oil and gas accumulations was an important and positive appraisal step for the field and the results at Gehem have implications for appraising the deeper oil potential at Ranggas and optimizing the development. The Company plans to test the deeper potential at Ranggas in the equivalent zone as the primary Gehem reservoir. The Company plans to move the Ranggas development along while assessing the deep potential and options for co-development with Gehem.

Azerbaijan

The Company, through a subsidiary, has a 10.28 percent working interest in the AIOC project that is producing and developing offshore oil reserves in the Caspian Sea from the Azeri and Chirag fields. In 2003, AIOC s gross oil production averaged 131 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 2003, approximately 90 percent of production from the consortium was exported through the western pipeline and the remaining 10 percent through the northern pipeline.

AIOC is in the process of constructing 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, which will develop an estimated 1.5 billion gross barrels of proved crude oil reserves, is under construction and on schedule with first oil expected in early 2005. Phase II of the project is expected to be similar in size to Phase I and is expected to begin production from two additional platforms in 2006 and 2007. The Company has approved $710 million in expenditures for its share of the costs for Phases I and II. The Company anticipates financing portions of these costs. The Company closed its financing of Phase 1 development in February of 2004 and anticipates funding early in 2004. The Company, through its AIOC participation, has an equity interest 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 its subsidiaries, holds interests in three PSCs in Bangladesh, encompassing over 3.5 million acres. Two PSCs cover Blocks 12, 13 and 14 and the third PSC covers Block 7. The Company has a 98 percent working interest in Blocks 12, 13 and 14 and is the operator. The Company s working interest in Block 7 is 90 percent. Gross production from the Jalalabad field on Block 13 averaged 120 MMcf/d (64 MMcf/d net to the Company) of natural gas and 1,300 Bbl/d (506 b/d net to the Company) of liquids in 2003. The natural gas production supplies approximately 10 percent of the country s gas demand. The Company also discovered the Moulavi Bazar gas field on Block 14 in 1999 and the Bibiyana field, a major gas field located on Block 12, in 1998.

Natural gas sales in the country have increased and the Company and Petrobangla, the state oil and gas company of Bangladesh, have amended agreements to increase the take-or-pay volume for natural gas sold to Petrobangla. The new agreement increased the take-or-pay volume of natural gas from the Jalalabad field from 80 MMcf/d to 100 MMcf/d gross. In addition, the Company signed agreements with Petrobangla to develop and produce natural gas from the Moulavi Bazar field. Under the agreement, the Company expects to produce 70 to 100 MMcf/d of natural gas beginning in the first quarter of 2005 subject to timely government approvals. Total development cost of the project is estimated at approximately $45 million.

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 2003 was approximately 5 MBbl/d of crude oil (4 MBbl/d net to the Company) and 13 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.

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Democratic Republic of Congo

The Company, through a subsidiary, has a 17.7 percent non-operating working interest in the rights to explore and produce hydrocarbons in the entire offshore area of the country. Gross production averaged about 18 MBbl/d of crude oil (2 MBbl/d net to the Company) from seven fields in 2003.

Brazil

The Company, through an affiliate, holds a 50 percent interest in a company that has a 35 percent participation agreement with Petroleo Brasileiro SA (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. The project currently consists of six production platforms and a 45-mile long, 26-inch diameter multi-phase pipeline. In 2003, gross production from the project averaged 3 MBbl/d of oil and 47 MMcf/d of natural gas. Net production from the project averaged 1 MBbl/d of oil and 17 MMcf/d of natural gas.

After six years of active exploration in Brazil, the Company in 2003 suspended exploration activities in the country and phased out its administrative and support operations.

Vietnam

The Company, through its subsidiaries, is the operator of two PSCs offshore southwest Vietnam in the northern part of the Malay Basin, which encompass approximately 1.1 million acres. The Company has a 42.38 percent working interest in one PSC, which includes Block B and Block 48/95. 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 Block 52/97, which covers 500,000 acres.

In total the Company has drilled 13 successful wells offshore Vietnam, three of which were drilled in 2003. Also in 2003, the Company received approval for a development area and submitted an outline development plan to PetroVietnam, the national oil and gas company, for several natural gas trends offshore southwest Vietnam.

The Company continues to work towards commercializing its offshore natural gas resources. The Company is in discussions with PetroVietnam concerning a natural gas pipeline to serve power plants proposed for construction in southern Vietnam.

China

The Company, through its subsidiaries, signed five PSCs in 2003 to explore and develop natural gas resources in the Xihu Trough, off the coast of Shanghai, in the East China Sea. The project area covers nearly 5.5 million acres in approximately 300 feet of water. The project scope includes appraisal and development of discovered fields, as well as further exploration potential. The Company is working with China National Offshore Oil Corporation (CNOOC), China New Star Petroleum Corporation, the Shanghai Municipality and the State Planning Commission on these projects. CNOOC is the operator of all five contract areas. The appraisal and exploration work for Phase 1 of the project will focus on development of the resources in and around the 173,000-acre Chunxiao Block. The near-term work program involves evaluation of technical information on wells drilled in the past, to process recently acquired seismic data, and to finalize the appraisal and development program for 2004. The Company has the option to withdraw from the project in October 2004 if sufficient commercial reserves are not proven. If the exploration and appraisal programs prove sufficient reserves, commercial gas production could begin in late 2005. Natural gas from the project would be delivered by pipeline 220 miles to the Zhejiang province and Shanghai area markets. Liquids would be transported by pipeline to the Pinghu offshore development that is 37 miles from the proposed Xihu central processing platform. The Chinese government has encouraged the project participants to bring production on stream as soon as possible, targeting the middle of 2005. Production from the first phase of development could be 250 MMcf/d within two years of first production. The Company holds a 20-percent working interest in the five PSCs.

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Australia

In 2003, the Company, through a subsidiary, acquired additional exploration areas off the coast of southeastern Australia. The Company acquired a 50 percent non-operating working interest in Block T/35P and T/36P in the Otway and Sorrel Basins between Victoria and Tasmania.

The Company, through the same subsidiary, also holds two other exploration blocks offshore southeast 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. In addition, the Company holds a 33.33 percent non-operating working interest in Block VIC/P52, which is located in the Otway Basin, offshore Victoria.

In 2003, the Company, through another subsidiary, also acquired a 50 percent non-operating working interest in Block WA-274-P off the coast of Western Australia in the Browse Basin. In total, the Company holds interests in over 5 million acres in the five blocks held offshore Australia.

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, and (b) North American natural gas marketing activities, excluding those of 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 additional revenues beyond the market values available 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 oil and condensate production is generally 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 these marketing 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.

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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, 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 31 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.

The Company also holds a 27.75 percent interest in the Trans-Andean oil pipeline, which transports crude oil from Argentina to Chile. This pipeline was held for sale at December 31, 2003.

The Company, through an equity investee and its working interest in AIOC, is participating in the construction of a 42-inch pipeline from Baku, Azerbaijan to Ceyhan, Turkey. The BTC pipeline will carry crude oil from Azerbaijan through Georgia and Turkey to the deep water port facilities on the Mediterranean Sea. The pipeline is planned to have a crude oil capacity of 1 million Bbl/d. The pipeline is estimated to cost approximately $3 billion and is expected to be in operation in the middle of 2005. Construction on the pipeline has progressed with the overall project now more than 50 percent complete. The Company has an 8.9 percent equity interest in the pipeline company and is one of eleven shareholders. A financing agreement of up to 70 percent of the pipeline s cost closed in February 2004.

The Company and Marathon Oil formed the Kenai Kachemak Pipeline LLC, which operates a natural gas pipeline between Kenai and Ninilchik in Alaska, which began operations in 2003. The Kachemak pipeline 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. The Company also operates the Keystone Gas Storage Project in West Texas with a storage capacity of 3 BCF and holds a 100 percent interest in the project.

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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 its 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 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 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 Energy Sales 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. The Company s Unocal North Sumatra Geothermal, Ltd. subsidiary sold its rights and interest in the Sarulla geothermal project on the island of Sumatra, Indonesia to PLN. The sales price was $60 million, and the transaction closed in February 2004.

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 had been operating the steam fields under an Interim Agreement with NPC while the parties were negotiating a settlement. PGI, NPC and the Power Sector Assets and Liabilities Management Corporation (PSALM) signed a compromise settlement agreement covering the definitive terms of settlement in March 2003. The settlement is expected to provide that: the 1971 service contract (and Interim Agreement), will be terminated upon completion by NPC of the rehabilitation of the Tiwi and Mak-Ban power plants, expected in early 2005; PGI will be granted the right to operate the steam fields until at least 2021; and PGI will sell geothermal resources to NPC/PSALM at a renegotiated price to ensure base-load operation of the Tiwi and Mak-Ban power plants. The parties are continuing the process of securing all necessary Philippine government and court approvals of the settlement.

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

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

	2003	2002	2001
Net proved geothermal reserves at year end: [a]			
billion kilowatt-hours	150	155	108
million equivalent oil barrels	225	232	162
Net daily production			
million kilowatt-hours	12	13	14
thousand equivalent oil barrels	19	20	22
Net geothermal lands in thousand acres			
proved	6	9	9
prospective	314	314	314
Net producible geothermal wells	87	85	84

(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.

Geothermal energy reserves and production data are expressed as a capacity to generate electrical power in kilowatt-hours. To facilitate comparison with the Company s oil and gas operations the Company also reports geothermal reserves and production data in terms of equivalent barrels of oil. This calculation, which incorporates the average heat content of low sulfur residual fuel and average heat rate factor for fossil fuel power plants, yields a generation rate of 1 kilowatt-hour of electricity for each 0.0015 barrels of oil consumed. Hence, 1 million kilowatt-hours equals 1,500 equivalent oil barrels.

PATENTS

The Company holds five U.S. patents resulting from its independent research on cleaner-burning reformulated gasolines (RFG). 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.

The first of these patents (the 393 patent) was the subject of litigation initiated 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. In 2000, the Company received approximately $91 million, including interest and attorneys fees, for infringement by the refiners for the period of March through July of 1996. 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 outcome of the reexamination of the patents discussed below.

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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, which was followed by yet a third reexamination request. The Company is now awaiting an action from the USPTO in this reexamination. Likewise the Company is awaiting a response from the PTO to its submission arguing against the initial rejection of the 126 patent.

A second reexamination request of the 126 patent has been made, and it was merged with the first. 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.

In November 2003, an Administrative Law Judge issued an initial decision granting the Company s motion to dismiss the compliant on the basis of Noerr-Pennington immunity and the absence of jurisdiction by the FTC to resolve substantive patent issues. The complaint counsel appealed that decision to the FTC in December 2003. Oral argument will be heard in March 2004.

The Company will continue to 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.

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EMPLOYEES

As of December 31, 2003, Unocal and its subsidiaries had about 6,700 employees compared to 6,615 and 6,980 in 2002 and 2001, respectively. Of the total Unocal employees at year-end 2003, approximately 220 in the U.S. were represented by various labor unions, 420 in Thailand were represented by a trade union and 180 in Philippines 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

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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 2003, 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 20 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.

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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, but not developing, nations to reduce their emissions of greenhouse gases (GHG) 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 emissions of GHG in 1990. At year-end 2003, the Kyoto Protocol had not achieved sufficient ratification to bring it into force. Currently, 120 developed and developing countries have ratified the Kyoto Protocol and its entry into force is now pending Russia s ratification. Among the developed countries that have ratified the Kyoto Protocol, Unocal currently conducts operations in Canada and the Netherlands. The United States has indicated that it does not intend to ratify the Kyoto Protocol, but it may take appropriate domestic action to reduce GHG emissions. Some states have either passed or proposed GHG-related legislation, including limited, but mandatory, emission reduction requirements. In addition, GHG-related legislation is being considered in Congress. Although the Kyoto Protocol s fate is uncertain, the European Union has indicated that its GHG cap-and-trade Emissions Trading System (ETS), which is set to start in 2005, will proceed. Other developed countries that have ratified have made similar commitments. Unocal also operates in many developing countries, primarily Thailand, Indonesia, Philippines, Bangladesh, China and Vietnam, where the Kyoto Protocol GHG reduction commitments or similar regulations are not expected to be adopted for some time. Although it is not possible to estimate the cost of complying with the emerging foreign and U.S. climate change programs, such costs could be substantial.

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The Company should, however, benefit from a general shift away from GHG emission-intensive fuels, such as coal, and toward relatively cleaner natural gas and geothermal power. Natural gas and geothermal energy resources comprise a significant portion of Unocal s current global production. Also, the Kyoto Protocol and similar policy frameworks allow credits from qualifying GHG emission-reduction projects to be sold to entities seeking compliance with anticipated GHG regulations. GHG emission-reduction projects include flaring and venting reduction and switching from coal-fired power systems to natural gas or geothermal power. Such credits can provide an incentive for end-users to switch to the Company s less emissions-intensive fuels as well as encourage efficiency within Unocal s operations. The Company is continuing to analyze these developments.

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 20 and 24 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 20 and 24 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 24 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. Since 1993, the Company, along with other shippers of Alaska North Slope (ANS) crude oil through the Trans-Alaska Pipeline System (TAPS), has been a party to proceedings pending jointly before the Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA) relating to the TAPS Quality Bank. ANS crude oil comes from various fields, and has varying constituents and qualities. All crude oil is blended in the TAPS for transmission from the North Slope to the tanker port at Valdez, where shippers then take their respective volumes of the blended stream. The TAPS Quality Bank is a mechanism that provides for adjustments among the shippers based on their entitlements to the co-mingled stream due to the effect of the varying constituents and qualities on the relative values of the crude oils they each put through the pipeline. As a shipper of lower-quality crude oil, compared to that of the blended stream, the Company is generally required to pay an assessed sum into the Quality Bank for distribution to those shippers who placed higher-quality crude oil into TAPS.

In December 2000, the U.S. Court of Appeals for the District of Columbia Circuit reversed a decision by FERC relating to the methodology to be applied in calculating the valuation of the distillation components of the various crude oils shipped through TAPS. The court remanded the matter to FERC for further proceedings, including arguments by ExxonMobil Corporation and Tesoro Petroleum Corporation that the distillation methodology for valuing the crude oils is not just and reasonable and that a new, revised methodology, if and when adopted by FERC, should be made retroactive to 1993. A hearing before a FERC administrative law judge was concluded in June 2003. Post-hearing briefing was completed in November of 2003. The initial decision by the administrative law judge, anticipated in late April 2004, is subject to the FERC s authority to change it. This will determine the value of certain cuts of the crude oil stream and will assess retroactive amounts as well as set the value of the cuts going forward. It is anticipated that the RCA will then adopt the FERC decision for intrastate transportation of ANS crude oil.

2. 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 Corp., 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 were 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 December 2003, the *Wright* case was remanded to the Eastern District of Texas, Texarkana Division. The *Grynberg v. Unocal* lawsuit remains consolidated in MDL-1293 with the 76 other *Grynberg* cases. Limited discovery has been allowed in both proceedings to address threshold jurisdictional issues concerning whether Messrs. Grynberg and Wright have standing as proper qui tam relators. Motions to dismiss for lack of subject matter jurisdiction will be presented in the coming months to the U.S. District Courts in Wyoming and Texarkana. All other aspects of these cases have been stayed pending resolution of the jurisdictional issues. The parties in the *Wright* case have recently been directed by the Court to formulate a scheduling order to govern further case proceedings. The Company is vigorously defending 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.

3. The Company is a defendant in lawsuits by anonymous 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 Corp., 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.

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.

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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 was granted a rehearing by an 11-judge *en banc* panel of the Circuit Court in June 2003. Because of a pending U.S. Supreme Court case raising similar issues (*Sosa v. Alvarez-Machian*), the Circuit Court will not issue a decision until that case is decided.

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. In December 2003 a bifurcated trial commenced on whether the plaintiffs could proceed against the Company and/or Union Oil Company of California as the alter-egos of the subsidiaries that actually hold the interest in the Yadana pipeline. Following trial, the court held that Unocal and Union Oil were not the alter-egos of the subsidiaries. The Company anticipates further proceedings over the next several months as to whether this decision effectively ends the state court proceedings.

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.

4. 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 natural 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.

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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 in the Purchase and Sale Agreement for the plant (the PSA) 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 addition, Agrium seeks a declaration by the arbitral panel that has been convened (see below) that natural gas from Unocal s Ninilchik, Happy Valley fields or elsewhere should be delivered to the plant to meet Unocal s alleged obligations under the GPSA.

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 $17 million plus interest accrued subsequent to May 2002. Unocal is also seeking over $900,000 in reliability bonuses due under the GPSA and reimbursement of over $5 million in royalties paid to the State of Alaska.

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

On July 16, 2003, the court approved an agreed stipulation between the parties to submit all issues under the GPSA to arbitration. The arbitration proceedings are scheduled to commence May 24, 2004. Discovery is now proceeding.

5. In June, 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). The City alleged that releases from sites owned by Shell, ChevronTexaco Corporation and ExxonMobil Corporation caused the wellfield to be shut down, and that releases from sites owned by Unocal subsequently impacted the wellfield. The City also alleged Unocal was liable under a products liability theory for gasoline it manufactured or sold that was ultimately distributed to area facilities operated by others. The Company was also subject to potential contractual liability for contamination from former facilities related to our gasoline marketing business sold in 1997. 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.

The parties reached a settlement on all matters relating to the lawsuit, which was approved by the court as a good faith settlement without objection on December 19, 2003. Unocal s portion of the settlement required payment to the plaintiff of $5 million, which was paid in February 2004.

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The Company has recently been named as a defendant in numerous other MTBE lawsuits brought by water companies throughout the country. These cases typically involve numerous other defendants, and do not allege specific facts which would make Unocal responsible for the claims asserted. Many of these cases appear to have no basis for the imposition of liability against the Company because the Company did not operate service stations or market gasoline in the geographic areas involved in the lawsuits. Many also appear to involve uncertain threats to water supplies rather than actual injury. Some of these cases may be subject to contractual indemnification by third parties once the allegations are clarified. Most have been removed to federal court, and may or may not be remanded to state court for discovery and trial. It is too early to determine what, if any, liability Unocal may have in these cases.

6. 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.

On June 30, 2003, Nuevo filed suit against Unocal in the U.S. District Court for the Central District of California, Case No. 03-4664 (RCx). Nuevo seeks $10.8 million, the amount Nuevo alleges it paid Unocal in error. Nuevo also seeks a declaratory judgment regarding its right to take deductions in calculating the contingent payment in the future. Unocal has counterclaimed, seeking in excess of $16 million for amounts owed from 2002 under the contingent payment agreement and for a declaratory judgment regarding the rights and relations of Unocal and Nuevo under that agreement. The case is scheduled to go to trial on May 11, 2004.

7. In July 2002, the Company s subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. (Unocal Blocks 13 and 14 Ltd.) received a letter from the Bangladesh Oil, Gas & Mineral Corporation (Petrobangla) 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 Occidental Petroleum Corporation (known at that time in Bangladesh as Occidental of Bangladesh Ltd.) (OBL), as operator, of the Moulavi Bazar #1 (MB #1) exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout.

Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractor s 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 (the Supplemental Agreement), 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 (Unocal Bangladesh)) of entitlement to the recovery of costs incurred in the drilling of the MB #1 and 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 present or development is not feasible, from other commercial fields in the Moulavi Bazar ring-fenced area of Block 14. Consequently, the Company and OBL consider the matter closed and Unocal Blocks 13 and 14 Ltd. has advised Petrobangla that no additional compensation is warranted. By Writ Petition Affidavit dated March 24, 2003, a concerned citizen filed suit in the Bangladesh lower court (*Alam v. Bangladesh, Petrobangla, Department of Environment, and Unocal Bangladesh, Ltd.*, Supreme Court of Bangladesh, High Court Division, Writ Petition No. 2461 of 2003) on the basis of the MB #1 blowout. The Company was notified of the suit on May 26, 2003 when it received the court s order to show cause why the Supplemental Agreement should not be declared illegal and cancelled on account of its having been executed without lawful authority, and why Unocal Bangladesh should not be directed to stop exploration until it compensates for the MB#1 blowout. No

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hearing is currently scheduled on the matter, and the Company believes the action is not well founded.

Certain Environmental Matters Involving Civil Penalties

On February 13, 2004, the U.S. Coast Guard provided the Company, as operator, with a draft complaint regarding a discharge of oil-based drilling mud from an injection of drilling mud and cuttings into the annulus of a well on the King Salmon Platform. The Coast Guard has agreed in principle to settle the matter. The Company anticipates that the Alaska Department of Environmental Conservation (DEC) will also seek civil penalties for the discharge, but no complaint has been filed or provided to the Company. The Company estimates that its share of the aggregate fine for the discharge from both the Coast Guard and the Alaska DEC may be over $100,000.

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

EXECUTIVE OFFICERS OF THE REGISTRANT

The following is a list of the executive officers as of February 27, 2004, showing their ages, present positions and their business experience during the past five or more years. 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 24, 2004, and until his successor shall be elected and qualified, unless he shall resign or shall be removed or otherwise disqualified to serve.

Name, age and present positions with Unocal	Recent business experience
CHARLES R. WILLIAMSON, 55 Chairman of the Board, Chief Executive Officer and President Chairman of Company Management Committee	Mr. Williamson has been Chairman of the Board since October 2001, Chief Executive Officer since January 2001 and President since February 2004. 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.
TERRY G. DALLAS, 53 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.

SAMUEL H. GILLESPIE, III, 61 Senior Vice President, Chief Legal Officer, General Counsel and Corporate Secretary Member of Company Management Committee	Mr. Gillespie joined Unocal on October 1, 2003. Mr. Gillespie joined Unocal from the Washington, D.C., office of the law firm of Skadden, Arps, Slate, Meagher and Flom, where he advised energy clients and worked on a variety of international projects. Previously, he was senior vice president and general counsel with Mobil Corporation, where he worked for 20 years.
THOMAS E. FISHER, 59 Senior Vice President, Commercial Affairs.	Mr. Fisher has been Senior Vice President, Commercial affairs, since June 1998.
JOE D. CECIL, 55 Vice President and Comptroller	Mr. Cecil has been Vice President and Comptroller since December 1997.
DOUGLAS M. MILLER, 44 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.

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PART II

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

	2003 Quarters				2002 Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Market price per share of common stock								
- High	$ 31.76	$ 31.38	$ 32.45	$ 37.08	$ 39.24	$ 39.70	$ 36.92	$ 32.40
- Low	$ 24.97	$ 26.14	$ 27.79	$ 30.72	$ 33.09	$ 35.25	$ 29.14	$ 26.58
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 27, 2004, the high price per share was $38.22 and the low price per share was $37.72.

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

As of February 27, 2004, the number of holders of record of Unocal common stock was 20,485 and the number of shares outstanding was 261,970,895.

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 88 consecutive years.

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ITEM 6 - SELECTED FINANCIAL DATA:

Millions of dollars except as indicated	2003	2002	2001	2000	1999
Revenue Data					
Sales					
Crude oil, condensate and natural gas liquids	$ 2,761	$ 2,477	$ 3,053	$ 5,872	$ 3,584
Natural gas	3,153	2,367	3,068	2,526	1,646
Geothermal steam	133	100	160	161	153
Petroleum products	52	50	203	286	209
Minerals	25	31	28	29	35
Other	95	55	68	137	124
Total sales revenues	6,219	5,080	6,580	9,011	5,751
Operating revenues	176	144	128	(55)	91
Other revenues [a]	144	73	88	261	119
Total revenues from continuing operations	$ 6,539	$ 5,297	$ 6,796	$ 9,217	$ 5,961
Earnings Data					
Earnings from continuing operations	$ 710	$ 330	$ 599	$ 723	$ 113
Earnings from discontinued operations (net of tax)	16	1	17	37	24
Cumulative effect of accounting change (net of tax)	(83)		(1)		
Net earnings	$ 643	$ 331	$ 615	$ 760	$ 137
Basic earnings (loss) per share:					
Continuing operations	$ 2.75	$ 1.34	$ 2.45	$ 2.98	$ 0.47
Discontinued operations	0.06		0.07	0.15	0.10
Cumulative effect of accounting change (net of tax)	(0.32)				
Net earnings per share	$ 2.49	$ 1.34	$ 2.52	$ 3.13	$ 0.57
Share Data					
Cash dividends declared on common stock	$ 208	$ 198	$ 195	$ 194	$ 194
Per share	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80
Number of common stockholders of record at year end	20,735	21,870	23,213	24,910	27,026
Weighted average common shares - thousands	258,563	246,759	243,568	242,863	242,167
Balance Sheet Data					
Current assets	$ 1,991	$ 1,375	$ 1,295	$ 1,802	$ 1,631
Current liabilities [b]	2,085	1,632	1,422	1,845	1,559
Working capital	(94)	(257)	(127)	(43)	72
Ratio of current assets to current liabilities	1.0:1	0.8:1	0.9:1	1.0:1	1.0:1
Total assets	11,798	10,846	10,491	10,066	8,967
Total debt and capital leases	2,883	3,008	2,906	2,506	2,854
Trust convertible preferred securities	522	522	522	522	522
Total stockholders equity	4,009	3,298	3,124	2,719	2,184
Stockholders equity - per common share	15.39	12.78	12.80	11.19	9.01
Return on average stockholders equity:					
Continuing operations	19.4%	10.3%	20.5%	29.5%	5.2%
Net Earnings	17.6%	10.3%	21.1%	31.0%	6.2%

(a) Excludes earnings from equity investments.

(b) Includes liabilities associated with pre-paid commodity sales.

See Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and the notes to the consolidated financial statements in Item 8 of this report for discussions on acquisitions, asset dispositions, impairments, discontinued operations, restructuring costs and other factors that will enhance the understanding of this data.

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ITEM 7 - MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Overview

The Company s strategy is focused on creating value for its stockholders by continuing to advance oil and gas development projects and delivering successful exploration results through the drill bit. To this end, the Company achieved the following in 2003:

- Began production from West Seno field in Indonesia.
- Made significant deepwater discoveries: Saint Malo and Puma in the Gulf of Mexico and Gehem in Indonesia.
- Improved Finding and Development costs.
- Signed preliminary agreements in Thailand to extend gas sales contracts and increase contract volumes.
- Set plans to double oil production in Thailand by 2005.
- Restructured North American business to focus on core assets and increase profitability.
- Signed East China Sea exploration & production PSCs.
- Signed gas sales agreement for new field in Bangladesh.
- Made major progress on Phases I and II of the Azerbaijan International Operating Company (AIOC) development project and the Baku-Tbilisi-Ceyhan (BTC) pipeline from Baku, Azerbaijan to Ceyhan, Turkey.

Along with these accomplishments, the Company also had to work through a few setbacks:

- West Seno production experienced start-up delay and facility problems in Indonesia.
- Gulf of Mexico deep shelf exploration program results were disappointing.

The Company, along with the oil and gas industry, benefited from higher commodity prices, which continued an upward trend in 2003 and were near historical highs. Crude oil and natural gas prices are key variables that drive industry performance, and they can vary significantly. For example, the 2003 WTI average crude oil price was $31.06 per barrel and the average Henry Hub natural gas price was $5.49 per Mcf. This compared with $26.17 per barrel and $3.37 per Mcf in 2002. The Company s worldwide production declined 5 percent in 2003 primarily due to asset sales in North America and the natural declines in existing fields in the Gulf of Mexico. During 2003, the Company generated $1.95 billion of net cash from operating activities, which it used in part to strengthen its balance sheet by paying down approximately $500 million of its debt and other financings.

The Company s year-end 2003 proved oil and gas reserves were 1.759 billion BOE, compared with 1.774 billion BOE at the end of 2002. In 2003, the Company replaced production and nearly offset the sale of 98 million BOE. Including the net effect of sales, reserve replacement was 91 percent of 2003 production; reserve replacement was 149 percent excluding the net effect of sales. The Company s finding, development and acquisition (FD&A) costs were approximately $7.05 per BOE, which was a major improvement from the $11.97 FD&A costs in 2002. Rising production costs remain a challenge and in 2004, the Company will be focused on improving its per unit production costs and finding and development costs, especially in its North American operations.

The Company s pension related expenses were significantly higher in 2003 as compared to 2002. The low interest rate environment and lower market returns on plan assets during the 2000-2002 time period have negatively impacted the Company s U.S. Qualified Retirement Plan. A detailed discussion regarding post-employment benefits may be found under the critical accounting policies section in this section and note 17 to the consolidated financial statements in Item 8 of this report.

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The Company s consolidated results are predominantly driven by the oil and gas exploration and production business; however, the Company does have other segments. 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.

CONSOLIDATED RESULTS

	Years ended December 31,		
Millions of dollars	**2003**	**2002**	**2001**
Earnings from continuing operations [(a)]	$ 710	$ 330	$ 599
Earnings from discontinued operations	16	1	17
Cumulative effect of accounting change	(83)		(1)
Net earnings	$ 643	$ 331	$ 615
[(a)] Includes minority interests of:	$ (9)	$ (6)	$ (41)

Earnings From Continuing Operations

2003 vs. 2002 Earnings from continuing operations were $710 million in 2003 compared to $330 million for 2002. Higher worldwide commodity prices increased net earnings by approximately $480 million. The Company s worldwide average realized natural gas price, including a loss of 7 cents per Mcf from hedging activities, was $3.66 per Mcf in 2003. This was an increase of 85 cents per Mcf, or 30 percent, from the $2.81 per Mcf, including a benefit of 2 cents per Mcf from hedging activities, realized in 2002. In 2003, the Company s worldwide average realized liquids price was $27.60 per Bbl, which was an increase of $4.46 per Bbl, or 19 percent, from a year ago. The Company s hedging program lowered the average realized liquids price by 10 cents per Bbl in 2003 while 2002 included a gain of one cent per Bbl from hedging activities. International production increases also contributed approximately $35 million in higher earnings, primarily from higher Indonesia and Thailand liquids and natural gas production. In 2003, asset sales added after-tax gains of approximately $65 million, which included the sale of the Company s equity interests in Matador Petroleum Corporation (Matador) and Tom Brown, Inc. (Tom Brown), and other asset divestitures in North America, compared to gains of approximately $26 million in 2002. The geothermal and power operations segment added $20 million in earnings improvement in 2003 as compared to 2002, primarily as a result of the amended Geothermal Salak energy sales agreements in Indonesia and improved results from the Company s equity interests in gas-fired power plants in Thailand. The 2003 results included a $4 million after-tax gain on mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives recorded by the Company s Northrock subsidiary in Canada, compared with a $6 million after-tax loss in 2002. The 2003 results also benefited from the Canadian statutory tax rate changes, which added $29 million to net earnings. In addition, the Company recorded $17 million after-tax related to insurance settlements compared to $2 million after-tax for 2002. The 2002 results included $9 million after-tax for uninsured losses due to hurricane damage in the Gulf of Mexico and $8 million after-tax of costs related to the acquisition of the outstanding minority interest in Pure Resources, Inc. (Pure) common stock.

The positive variance factors discussed in the previous paragraph were partially offset by lower North America production, higher pension related expenses (see note 17 to the consolidated financial statements in Item 8 of this report), higher asset impairments primarily related to the Gulf region non-core property divestitures, the premiums paid for the early redemption of long-term debt and higher exploration expenses including dry hole costs, which reduced net earnings by approximately $80 million, $35 million, $30 million, $30 million and $15 million, respectively, in 2003 compared with 2002. North America liquids production averaged 81,000 Bbl/d in 2003, down from 94,000 Bbl/d a year ago, while natural gas production averaged 763 MMcf/d down from 886 MMcf/d for 2002. Most of the production decline was due to the divestiture of various properties in the Gulf of Mexico, onshore U.S. and Canada and the natural declines in existing fields in the Gulf of Mexico. In addition, the Company s minerals operations recorded approximately $20 million after-tax in lower earnings for 2003 as compared to 2002 due primarily to lower mining margins and lower Brazil equity earnings.

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After-tax environmental and litigation expenses were $110 million in 2003, compared with $91 million in 2002, reflecting higher litigation expenses including related outside support costs. The 2003 results included the company-wide $24 million after-tax restructuring charge (see note 7 to the consolidated financial statements in Item 8 of this report), while the same period a year ago included $14 million in after-tax restructuring charges for the Gulf Region and Alaska business units.

Income taxes on earnings from continuing operations in 2003 were $522 million compared with $280 million for 2002. The effective income tax rate was approximately 42 percent for 2003 as compared to approximately 45 percent in 2002. The lower effective tax rate for 2003 as compared with 2002 reflects the aforementioned benefit from the Canadian statutory tax rate changes and the mix of positive domestic and foreign earnings in 2003 compared to the mix of domestic losses and foreign earnings in 2002. Foreign earnings are generally taxed at higher rates than domestic earnings. Those factors were partially offset by currency-related adjustments in Thailand and tax adjustments related to the sale of affiliate investments in 2003.

2002 vs. 2001   Earnings from continuing operations were $330 million in 2002, compared with $599 million in 2001. 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 from Ship Shoal 295 field (Muni) 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, $14 million in after-tax restructuring charges for the Gulf Region and Alaska business units, $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 common stock. The full-year results in 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 previous year, 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.

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Earnings From Discontinued Operations

Earnings from discontinued operations were $16 million in 2003, $1 million in 2002 and $17 million in 2001. The amounts in all three years primarily related to the Company s 1997 sale of its former West Coast refining, marketing and transportation assets. The sales agreement contained a provision calling for payments to the Company for price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. This provision of the agreement terminated at the end of 2003. See note 9 to the consolidated financial statements in Item 8 of this report for details on discontinued operations.

Cumulative Effect of Accounting Change

In 2003, the Company recorded a non-cash $83 million after-tax charge for the cumulative effect of a change in accounting principle related to the initial adoption of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations. The Company also increased its accrued abandonment and restoration liabilities by $268 million and increased its net properties by $138 million on the consolidated balance sheet as a result of the adoption of SFAS No. 143. In 2001, the Company recorded a one-time non-cash $1 million after-tax charge for the cumulative effect of a change in accounting principle related to the initial adoption of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities.

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Operating Highlights

	2003	2002	2001
North America Net Daily Production [a]			
Liquids (thousand barrels)			
U.S. Lower 48 [b]	43	52	59
Alaska	21	24	25
Canada	17	18	16
Total liquids	81	94	100
Natural gas - dry basis (million cubic feet)			
U.S. Lower 48 [b]	616	719	905
Alaska	57	76	103
Canada	90	91	101
Total natural gas	763	886	1,109
North America Average Prices (excluding hedging activities) [c] [d]			
Liquids (per barrel)			
U.S. Lower 48	$ 28.07	$ 22.85	$ 23.35
Alaska	$ 29.85	$ 24.21	$ 24.69
Canada	$ 24.76	$ 20.70	$ 18.53
Average	$ 27.84	$ 22.79	$ 22.90
Natural gas (per mcf)			
U.S. Lower 48	$ 5.18	$ 3.01	$ 4.14
Alaska	$ 1.31	$ 1.42	$ 1.37
Canada	$ 5.07	$ 2.67	$ 4.34
Average	$ 4.88	$ 2.83	$ 3.89
North America Average Prices (including hedging activities) [c] [d]			
Liquids (per barrel)			
U.S. Lower 48	$ 27.72	$ 22.87	$ 23.41
Alaska	$ 29.85	$ 24.21	$ 24.69
Canada	$ 24.76	$ 20.70	$ 18.53
Average	$ 27.66	$ 22.81	$ 22.93
Natural gas (per mcf)			
U.S. Lower 48	$ 5.07	$ 3.07	$ 4.23
Alaska	$ 1.31	$ 1.42	$ 1.37
Canada	$ 4.78	$ 2.66	$ 3.17
Average	$ 4.76	$ 2.88	$ 3.85

(a) Includes minority interests of :

Liquids		7	9
Natural gas	5	82	102
Barrels oil equivalent	1	21	26

(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.

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Operating Highlights (continued)

	2003	2002	2001
International Net Daily Production [e]			
Liquids (thousand barrels)			
Far East	59	53	51
Other [b]	20	20	19
Total liquids	79	73	70
Natural gas - dry basis (million cubic feet)			
Far East	877	847	829
Other [b]	88	93	65
Total natural gas	965	940	894
International Average Prices [f]			
Liquids (per barrel)			
Far East	$ 27.30	$ 22.88	$ 22.50
Other	$ 28.29	$ 25.47	$ 24.15
Average	$ 27.54	$ 23.57	$ 22.97
Natural gas (per mcf)			
Far East	$ 2.83	$ 2.75	$ 2.67
Other	$ 2.90	$ 2.72	$ 2.75
Average	$ 2.84	$ 2.75	$ 2.67
Worldwide Net Daily Production [a] [b] [e]			
Liquids (thousand barrels)	160	167	170
Natural gas - dry basis (million cubic feet)	1,728	1,826	2,003
Barrels oil equivalent (thousands)	448	471	504
Worldwide Average Prices (excluding hedging activities) [c] [d]			
Liquids (per barrel)	$ 27.70	$ 23.13	$ 22.93
Natural gas (per mcf)	$ 3.73	$ 2.79	$ 3.33
Worldwide Average Prices (including hedging activities) [c] [d]			
Liquids (per barrel)	$ 27.60	$ 23.14	$ 22.95
Natural gas (per mcf)	$ 3.66	$ 2.81	$ 3.31

[a] Includes minority interest shares of :			
Liquids		7	9
Natural gas	5	82	102
Barrels oil equivalent	1	21	26

[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.

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Sales and Operating Revenues

2003 vs. 2002 Sales and operating revenues in 2003 were $6.40 billion, which was an increase of $1.17 billion from 2002. The increase was primarily due to higher average hydrocarbon commodity prices. Sales and operating revenues from the Trade business segment were $2.92 billion in 2003, which was an increase of $395 million from 2002. During 2003 and 2002, approximately 23 percent and 25 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from others in connection with the Trade segment s marketing activities. These activities allow the Company to better manage its commodity-related risk and seek additional revenues beyond the market values available at producing locations by effectively transferring its production and commodity purchases to industry marketing centers with higher volumes of commercial activity and greater market liquidity.

2002 vs. 2001 Sales and operating revenues in 2002 were $5.22 billion, which was a decrease of $1.48 billion 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 $2.52 billion in 2002, which was a decrease of $1.33 billion 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 segment s marketing activities.

Sales of Assets

In 2003, the Company recorded pre-tax gains of $119 million from asset sales. The Company sold its equity interest shares held in Tom Brown and Matador, with a pre-tax gain of $100 million. The Company also completed the sale of various oil and gas properties in the Gulf of Mexico, onshore U.S. and Canada, which resulted in a net pre-tax gain of $8 million. The Company retained its deep mineral rights from a substantial portion of the properties sold in the Gulf of Mexico. The sale of various real estate and other miscellaneous properties resulted in pre-tax gains of $11 million. See note 4 in the consolidated financial statements in Item 8 of this report for a detailed discussion of the Company s asset sales.

Selected Costs and Other Deductions

	Years ended December 31,		
Millions of dollars	**2003**	**2002**	**2001**
Pre-tax costs and other deductions:			
Crude oil, natural gas and product purchases	$ 2,126	$ 1,701	$ 2,492
Operating expense	1,340	1,338	1,420
Administrative and general expense	260	151	122
Depreciation, depletion and amortization	988	973	967
Impairments	93	47	118
Dry hole costs	128	107	175
Exploration expense (see table below)	251	246	252
Interest expense	190	179	192

Years ended December 31,

Millions of dollars	2003	2002	2001
Exploration operations	$ 68	$ 80	$ 85
Geological and geophysical	63	53	56
Amortization of exploratory leases	108	98	95
Leasehold rentals	12	15	16
Exploration expense	$ 251	$ 246	$ 252

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2003 vs. 2002 Crude oil, natural gas and product purchases increased by $425 million in 2003. This increase was principally due to higher commodity prices. Administrative and general expense increased by $109 million in 2003. This increase primarily reflected $57 million of higher pension related expenses and the $38 million restructuring accrual in 2003 (see note 7 for details on restructuring). This higher level of pension related expenses is expected to continue for the next few years. The precise costs will depend primarily on future discount rates and the difference between the actual and expected return on plan assets. Depreciation, depletion and amortization expense was higher in 2003. This increase was primarily due to accretion on asset retirement obligations and increased DD&A rates per BOE from new higher cost fields. This increase in DD&A was partially offset by lower production from the Company s North America operations. Impairments in 2003 were $93 million, which primarily reflected asset write-downs, to fair market value, of certain oil and gas fields in the Gulf of Mexico region that were sold in 2003. Interest expense was $11 million higher in 2003 primarily due to the premium paid on the early retirement of certain long-term debt, partially offset by higher capitalized interest.

While overall exploration expense remained relatively unchanged in 2003, the Company recorded higher amortization of exploratory leases. This increase was primarily due to a $26 million pre-tax provision that was a result of the Company s relinquishment of 44 deepwater Gulf of Mexico blocks before their expiration dates. The Company intends to focus its deepwater Gulf of Mexico land position on those Outer Continental Shelf blocks that have more potential. This expense increase was partially offset by lower expenses of $18 million pre-tax, reflecting the relinquishment of certain exploration blocks in Gabon and Brazil in 2002.

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 expanded 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.

BUSINESS SEGMENT RESULTS

See note 31 to the consolidated financial statements in Item 8 of this report for a description of the Company s reportable segments. The following business segment results should be read in conjunction with the business and properties descriptions in Items 1 and 2 of this report. The Company is organized in the following business segments:

Exploration and Production

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

North America

2003 vs. 2002 After-tax earnings were $474 million in 2003 compared to $33 million in 2002. The increase was primarily due to higher natural gas and liquids prices, which increased net earnings by approximately $405 million. In addition, the Company recorded approximately $57 million after-tax in asset sale gains, primarily from the sale of Tom Brown and Matador common stock in 2003. In 2003, the Company recorded a $25 million deferred tax benefit adjustment related to statutory tax rate changes in Canada. In 2003, the results included after-tax gains of $4 million in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives recorded by Northrock, while the comparable period a year ago included an after-tax loss of $6 million. The 2002 results also included approximately $17 million in after-tax losses from asset sales, $14 million in after-tax restructuring charges in the Gulf Region and Alaska business units, $9 million after-tax for uninsured losses due to hurricane damage in the Gulf of Mexico, and $8 million in costs related to the acquisition of the outstanding minority interest in Pure common stock.

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These positive factors were partially offset by lower natural gas and liquids production, higher impairments, higher DD&A rates and higher exploration expenses including dry hole costs, which reduced after-tax earnings by approximately $80 million, $40 million, $25 million and $10 million, respectively. In 2003, asset impairments in the Gulf Region business unit totaled $52 million after-tax and were primarily related to the sale of certain Gulf of Mexico assets that were held for sale, compared to 2002 impairments that totaled $12 million. In 2002, the Company s Alaska business unit had an after-tax impairment of $15 million. Natural gas and liquids production was lower primarily due to a decrease in the Gulf of Mexico production from asset sales and natural field declines.

2002 vs. 2001 After-tax earnings were $33 million in 2002 compared to $440 million in 2001. 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. 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 production, 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. The 2002 results also included a $17 million after-tax loss in asset sales, a $15 million after-tax charge for impairments in Alaska, $14 million in after-tax restructuring charges for the Gulf Region and Alaska business units, $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. After-tax earnings in 2001 also included $17 million in after-tax gains on the sale of certain Gulf of Mexico production properties.

International

2003 vs. 2002 After-tax earnings totaled $561 million in 2003 compared to $503 million in 2002. The increase was primarily due to approximately $75 million in higher liquids and natural gas prices and $35 million in higher liquids and natural gas production. The higher natural gas production was primarily from increased demand tied to higher electric power needs in Thailand. Higher liquids production was due to the Yala-Plamuk and Pailin Phase 2 projects in Thailand and the start-up of the West Seno production in Indonesia. The 2003 exploration costs were $11 million after-tax lower than 2002 due to the relinquishment of exploration blocks in Gabon and Brazil that occurred in 2002. These positive factors were partially offset by approximately $25 million in higher DD&A expense (including asset retirement obligation accretion), $20 million in higher operating expenses primarily due to the new operations in Indonesia and $15 million in increased income taxes due to higher effective tax rates, primarily due to the weakening of the U.S. dollar against the Thai baht.

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.

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Trade

2003 vs. 2002 After-tax results were a $2 million loss in 2003 compared to after-tax earnings of $4 million in 2002. The decrease was primarily due to lower results related to domestic crude oil and natural gas marketing activities, which were negatively impacted by volatile commodity prices.

Sales and operating revenues were $2.92 billion in 2003 compared to $2.52 billion in the same period a year ago, which was an increase of $395 million. These revenues represented approximately 46 percent and 48 percent of the Company s total sales and operating revenues for 2003 and 2002, respectively. In 2003, natural gas revenues increased by approximately $420 million and crude oil revenues decreased by approximately $20 million. Both natural gas and crude oil revenues benefited from higher commodity prices, as compared to a year ago. However, lower volumes for natural gas partially offset the positive impact of higher natural gas prices, while lower crude oil volumes more than offset the impact of higher crude oil prices. Lower crude oil revenues reflect management s philosophy to decrease its outside crude oil purchases for resale due to continued volatility in the oil markets.

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 $2.52 billion in 2002 compared to $3.86 billion in 2001, which was a decrease of $1.34 billion. 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.

Midstream

2003 vs. 2002 After-tax earnings totaled $73 million in 2003 compared to $104 million in 2002. The decrease was due primarily to $30 million in after-tax gains from the sales of certain investment interests in nonstrategic pipelines in the U.S. that occurred in 2002. The decrease was also due to $3 million in higher after-tax expenses related to the BTC pipeline project and a $7 million after-tax impairment related to the Trans-Andean oil pipeline in Argentina, which was held for sale at the end of 2003. These negative results were partially offset by $6 million after-tax in higher results in the natural gas storage and pipelines businesses and by a benefit of $4 million related to statutory tax rate changes in Canada.

2002 vs. 2001 After-tax earnings totaled $104 million in 2002 compared to $54 million in 2001. The increase was due the aforementioned gains from asset sales. 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.

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Geothermal and Power Operations

2003 vs. 2002 After-tax earnings totaled $50 million in 2003 compared to $30 million in 2002. The current year results reflect $8 million in higher earnings due to improvements from the amended Salak agreements in Indonesia. In addition, the results in 2003 reflect $9 million in higher earnings from the Company s equity interests in gas-fired plants in Thailand due largely to favorable foreign exchange rates and $6 million in lower business development expenses as compared to 2002.

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 amended Salak agreements. This was partially offset by a decrease of $14 million from lower operational results in Indonesia and lower earnings results from the equity interests in the gas-fired power plants in Thailand.

Corporate and Other

2003 vs. 2002 The after-tax earnings effect for 2003 was a loss of $446 million compared to a loss of $344 million in the same period a year ago. The 2003 results included $24 million after-tax in restructuring charges and higher pension related expenses of approximately $35 million. Net interest expense was $17 million higher in 2003, reflecting the $30 million after-tax in premiums paid for the early redemption of long-term debt, which was partially offset by higher capitalized interest on development projects. Environmental and litigation expenses were $107 million after-tax in 2003 compared to $93 million after-tax in 2002, primarily reflecting higher litigation support costs. In addition, the Company s minerals operations recorded approximately $20 million after-tax in lower earnings for 2003 as compared to a year ago due primarily to lower mining margins and lower Brazil equity earnings.

2002 vs. 2001 The after-tax earnings effect for 2002 was a loss of $344 million compared to a loss of $355 million in 2001. 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.

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LIQUIDITY and CAPITAL RESOURCES

	At December 31,		
Millions of dollars except as indicated	2003	2002	2001
Current ratio	1.0:1	0.8:1	0.9:1
Total debt and capital leases	$ 2,883	$ 3,008	$ 2,906
Trust convertible preferred securities	522	522	522
Stockholders equity [(a)]	4,009	3,298	3,124
Total capitalization	7,414	6,828	6,552
Floating-rate debt/total debt [(b)]	8%	6%	8%

(a) 2003 reflects an increase of $145 million due to changes in foreign currency translation adjustments. 2002 included $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 U.S. Qualified Retirement Plan.

(b) Excludes interest rate swap derivatives. With the swaps included the ratios would be 8%, 5% and 7% for 2003, 2002 and 2001, respectively.

Liquidity is the Company s ability to generate sufficient cash flows from operating activities to meet obligations and commitments. Cash generated from operations is the Company s principal source of liquidity. The Company generally funds any additional liquidity requirements through debt issuance including commercial paper, the sale of a portion of its accounts receivable accounts through its receivable securitization program, and the use of revolving credit facilities to cover near-term borrowing requirements. Currently, the Company s liquidity needs arise primarily from capital expenditures, cash dividends, working capital requirements and debt service. Based on current commodity prices and current development project expenditures, the Company expects cash generated from operating activities, asset sales and cash on hand in 2004 to be sufficient to cover these requirements. Further, the Company has substantial borrowing capacity to enable it to meet unanticipated cash requirements.

Cash Flows from Operating Activities

Net cash provided by operating activities was $1.95 billion in 2003, $1.57 billion in 2002 and $2.13 billion in 2001.

2003 vs. 2002 Cash flows from operating activities increased by $378 million in 2003. The increase principally reflected the effects of higher worldwide commodity prices. In addition, the Company received $51 million in repayment of a loan made to PTT Exploration and Production Public Company Limited when the Company farmed into the Arthit field. The positive impact from higher prices was partially offset by higher income tax payments and higher interest paid compared to a year ago. In addition, cash flows from operating activities were reduced by the repayment of the outstanding balance under the Company s accounts receivable securitization program.

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 PT PLN (Persero) (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.

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Capital Expenditures

Millions of dollars	Estimated 2004	Years ended December 31, 2003	2002	2001
Exploration and production				
U.S. Lower 48 [a]	$ 480	$ 515	$ 544	$ 861
Alaska	65	41	72	81
Canada [b]	110	133	147	113
North America Total	655	689	763	1,055
Far East	885	573	626	425
Other	355	261	157	148
International Total	1,240	834	783	573
Total exploration and production	1,895	1,523	1,546	1,628
Midstream	60	138	71	41
Geothermal and power operations	30	21	14	7
Corporate and other	30	36	39	51
Total capital expenditures [c] [d]	$ 2,015	$ 1,718	$ 1,670	$ 1,727

(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.

(c) Estimated capital expenditures for 2004 exclude any possible major acquisitions.

(d) Includes capitalized interest of:	$ 80	$ 60	$ 46	$ 27

The Company expects its overall capital expenditures in 2004 to increase by 17 percent from the 2003 level. The major component of this increase is due to capital spending for development projects in Indonesia and Thailand (International Far East), which are expected to add approximately $170 million from the expenditure level in 2003. Another major factor contributing to the increase is the Xihu Trough project in China (International Far East), which is expected to total $130 million in 2004, up from $10 million in 2003. The Caspian crude oil development project (International Other) will remain a major portion of the capital expenditures in 2004 and is expected to total $295 million, up from $250 million in 2003. In addition, the Company expects its capital spending in Bangladesh (International Other), to increase by $45 million in 2004, reflecting the development of natural gas from the Moulavi Bazar field. The increase from the aforementioned factors will be partially offset by $90 million in lower expenditures from the BTC pipeline project (Midstream).

2003 vs. 2002 Capital expenditures for 2003 increased by 3 percent from 2002. Capital spending for large development projects, including the West Seno field in deepwater Indonesia (International Far East) and Mad Dog in the Gulf of Mexico (U.S. Lower 48), and the Caspian crude oil development (International Other), and the associated BTC pipeline project (Midstream) totaled $655 million, up from $430 million in 2002. This increase from large development projects was mostly offset by $145 million in lower other development capital in North America and $15 million in lower worldwide exploration capital expenditures.

In 2003, the Company s capital expenditures included approximately $770 million for the development of undeveloped proved oil and gas reserves, primarily in Indonesia, Azerbaijan, Thailand and the deepwater Gulf of Mexico.

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).

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Major Acquisitions

The Company did not make any significant acquisitions in 2003. 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 significant acquisitions in 2001 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.

Asset Sale Proceeds

In 2003, pre-tax proceeds from asset sales and discontinued operations were $653 million. The proceeds included approximately $361 million for the sale of various oil and gas properties in the Gulf of Mexico, onshore U.S. and Canada. The Company also received proceeds of $229 million from the sale of its equity interest shares held in Tom Brown and Matador. Cash proceeds also included approximately $52 million for the sale of various real estate and other miscellaneous properties. In addition, cash proceeds included $11 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 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., $54 million from the sale of oil and gas assets primarily in the U.S. and approximately $44 million from the sale of real estate and other miscellaneous properties. The cash proceeds also included $3 million related to the aforementioned participation payment from the Company s former West Coast refining, marketing and transportation assets.

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, $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.

Long-term Debt

The Company s long-term debt at year-end 2003, including the current portion, was $2.88 billion, approximately $125 million less than at the end of 2002. The Company retired $89 million in 9.25% debentures and paid down $10 million of medium-term notes that matured. The Company repurchased $194 million of debt principal through a tender offer, which included $115 million of the 7.20 percent notes due in 2005 and $79 million of the 6.50 percent notes due in 2008. The Company also repurchased $34 million of the 7.35% notes due in 2009, $34 million of the 9.125% debentures due in 2006, $27 million of the 6.375% notes due in 2004 and $26 million of medium-term notes in varying maturities. The Company also repaid $20 million of 6.20% Industrial Development Revenue Bonds due in 2008. In total, the Company paid approximately $35 million pre-tax ($30 million after-tax) in premiums for the early redemption of debt in 2003.

These decreases in debt were offset by $205 million drawn under the Overseas Private Investment Corporation (OPIC) Financing Agreement for the first phase of the West Seno development project in Indonesia. In addition, effective in the third quarter of 2003, the Financial Accounting

Standards Board (FASB) issued Financial Interpretation No. 46 (FIN 46), Consolidation of Variable Interest Entities, which required the Company to consolidate its Dayabumi Salak Pratama, Ltd. (DSPL) subsidiary, resulting in the reporting of $74 million as long-term debt on the consolidated balance sheet. In 2003, the Company paid off the $252 million limited partner interest in Spirit Energy 76 Development, L.P. of which $242 million would have been reclassified as long-term debt in 2003 pursuant to FASB Interpretation No. 46 (see note 19 for further detail on the Company s long-term debt).

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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.

Contractual Obligations

The following table outlines various financial contractual obligations of the Company:

		Amount of Obligation Expiration			
In Millions of Dollars	**Total**	**2004**	**2005-2006**	**2007-2008**	**Later years**
Long-term debt [(a) (k)]	$ 2,883	$ 248	$ 727	$ 175	$ 1,733
Trust convertible preferred securities [(b) (k)]	522				522
Non- cancelable operating leases [(c) (k)]	365	187	122	43	13
Purchase obligations [(d)]					
Development related expenditures	727	466	243	18	
Exploration related expenditures	234	216	18		
Other	121	118	3		
Asset retirement obligations [(e)]	710	21	74	46	569
Environmental liabilities [(f)]	252	118	102	32	
Postretirement medical benefits [(g)]	56	27	29		
Pension and other employee benefits [(h)]	260	25	74	144	17
Advances related to future production [(i)]	122	4	9	9	100
Derivative and commodity contract liabilities [(j) (k)]	218	167	26	25	
Other	202	43	66	30	63
Total	$ 6,672	$ 1,640	$ 1,493	$ 522	$ 3,017

(a) See note 19 for details on long-term debt.

(b) See note 25 for detail on the trust convertible securities.

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

(d) Includes both accrued and future expenditures for significant purchase obligations and commitments.

(e) See note 2 for detail on SFAS No. 143 adoption for asset retirement obligations.

(f) See note 20 and 24 for detail on environmental liabilities.

(g) Payments reflect an estimate of the mandated annual contributions in 2004 and 2005 to the U.S. postretirement medical plan. Not included in the above table are expected future employer contributions to the U.S. postretirement plan of $30 million in 2006 and $61 million in 2007-2008 plus $96 million in the out years reflecting the remainder of the actuarially computed balance.

(h) Reflects projected mandated minimum funding contributions by the Company for U.S. Qualified Retirement Plan in 2006-2008 plus anticipated payments in support of the Company's Supplemental Executive Retirement Plan and unfunded foreign pension plans.

(i) See note 21 for further detail.

(j) Includes interest rate, foreign exchange rate and hydrocarbon derivatives and forward natural gas sale. See discussion in Item 7A and note 29 for detail on derivatives and note 22 for forward sale.

(k) There are no credit rating triggers that would require pre-payment.

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Contractual Commitments

The Company has two credit facilities in place: a $400 million 364-day credit agreement which is due to terminate on September 30, 2004 and a $600 million credit agreement due to terminate on October 31, 2006. 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.

The Company also has a 3-year $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest. At December 31, 2003, the borrowings under the credit facility translated to $227 million, using applicable foreign exchange rates.

The Company also had in place a universal shelf registration statement as of December 31, 2003, with an unutilized balance of approximately $1.539 billion 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. Standard & Poor s and Moody s have a stable rating outlook for the Company s long-term debt, Prime-2 and A-2 commercial paper ratings. The Company does not believe it has a significant exposure to liquidity risk in the event of a credit rating downgrade.

In the normal course of business, the Company has performance obligations that 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. 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. See note 24 to the consolidated financial statements in Item 8 for a more detailed discussion of surety bonds, letters of credit and other guarantees.

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The following table outlines various financial commitments of the Company, including the potential effects in the event of a credit rating downgrade:

Other Financial Commitments (millions of dollars)	Total	Amount of Commitment Expiration 2004	2005-2006	2007-2008	After 5 Years	Recourse & Credit Rating Triggers
Unocal credit agreement expiring Oct. 31, 2006 - zero balance outstanding	$ 600	$	$ 600	$	$	Interest rate varies marginally based on rating. Ratings downgrade does not prevent drawdown or require pre-payment.
Unocal 364-day credit agreement expiring Sep. 30, 2004 - zero balance outstanding	400	400				Interest rate varies marginally based on rating. Ratings downgrade does not prevent drawdown or require pre-payment and the credit agreement allows Company to extend term yearly for an additional 364 day period.
Receivable securitization program [a] - zero balance outstanding at year-end						Sales of receivables prohibited if rating below Baa3 or BBB-
Standby letters of credit [b] [d]	44	44				None - one year term
Other financial assurances [b] [d]	553	553				Approx. $333 million would require bonds, letter of credit or trust funds if rating below Baa3 or BBB-
Performance bonds (with indemnity) [b][c][d]	191	122	33	36		Approx. $65 MM in bonds would require additional collateral if rating below Baa3 or BBB-
Guaranteed debt of equity investees [d]	19	19				Unocal guarantees are limited
Non-guaranteed debt of equity investees [e]						None
Environmental indemnification related to sold or formerly-operated properties [d]						None

(a) See note 12 for further details.

(b) 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.

(c) Includes $61 million of a performance bond for which a liability is included on the balance sheet in other current liabilities and other deferred credits.

(d) See note 24 for further details.

(e) See note 15 for further details.

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Off-Balance Sheet Arrangements

Guarantees Related to Assets or Obligations of Third Parties

The Company has guaranteed the debt of certain joint ventures accounted for by the equity method. The majority of this debt matures ratably through the year 2014. Extending guarantees to creditors allows the joint ventures to reduce their borrowing costs. The Company is not the primary beneficiary in any of these arrangements. The maximum amount of future payments the Company could be required to make is approximately $19 million. In addition to these guarantees, to facilitate sales of some property or as a condition of some property leases, the Company indemnified certain third parties for particular remediation costs.

See note 24 to the consolidated financial statements in Item 8 for a more detailed discussion of guarantees related to assets or obligations of third parties. These agreements are not critical to the Company s liquidity, credit risk or capital resources.

Sales of Accounts Receivables

The Company, through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation, has a sales agreement with an outside unrelated party that provides for the sale of up to $125 million of an undivided interest in domestic crude oil and natural gas trade receivables. The Company uses this program as a low cost and readily available source of working capital. Details of this arrangement are provided in Note 12 to the Company s financial statements. In the event receivables become uncollectible, the outside purchaser would participate in any losses that exceed reserves built into the program.

The arrangement also has a credit rating trigger whereby the sales of receivables are prohibited if the Company s long-term unsecured debt should be rated less than BBB- by Standard & Poor s or Baa3 by Moody s. In such an event, the purchaser would be repaid from its pro rata share of receivables as they are collected and the Company may find it necessary to use an alternative source of funds. In this case, the Company s accounts receivable balance would increase as well as the balance of debt on the Company s consolidated balance sheet. This program is not critical to the Company s liquidity or capital resources.

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Critical Accounting Policies and Estimates

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 represents management s view of accounting policies, practices and estimates 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.

See Note 1 to the consolidated financial statements in Item 8 of this report for the accounting policy description for Oil and Gas Exploration and Development Costs. 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 prospective depreciation and depletion expense or an immediate write-down of the property s book value (see impairments discussion below). If reserve estimates are revised upward, earnings could be affected by decreased prospective depreciation and depletion expense.

Exploratory drilling involves significant capital investment and considerable risk of dry holes or failure to find commercial quantities of hydrocarbons. See RISK FACTORS in Item 7 of this report for a discussion on Our drilling activities may not be productive. Exploratory wells that do not find commercial quantities of hydrocarbons are expensed as dry hole expense. Dry holes take place at unscheduled times and involve interpretation based on technical expertise and informed judgment. Material fluctuations in earnings may result from the recording of dry hole expense.

At the time exploratory acreage is acquired, the Company makes an initial assessment of the probability that the acreage will eventually lead to the discovery of commercial hydrocarbon reserves. The portion estimated not to find commercial reserves is amortized. The majority of properties have costs that are individually not significant and are amortized for impairment by groups. Additional attention is given to individually significant leases/concessions to ensure their probability-of-success factors and amortization periods are consistent with the latest developments. The methodology takes into consideration factors that indicate partial or full impairment.

Oil and Gas Reserves Estimates of physical quantities of oil and gas reserves are determined by Company engineers and in some cases verified by third-party experts. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that 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 resulting from future changes in economic and operating conditions. See RISK FACTORS in Item 7 of this report for a discussion on Our oil and gas reserve estimates are subject to change. 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.

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Impairment of Assets See note 1 to the consolidated financial statements in Item 8 of this report for the accounting policy description of Impairment of Assets. Commodity prices are difficult to predict and can change dramatically. Prices depend on market demand and supply, which can be influenced by factors such as OPEC production quotas, changes in climate conditions, government regulation, political instability, economic climates at both a local and a global basis, security and other factors. Different views of future commodity prices could have a significant impact on whether the Company records asset impairments. Field decline rates, increases in lifting and development costs or a downward revision of reserves could occur and result in asset impairment. See note 6 to the consolidated financial statements in Item 8 of this report for details on impairments.

Asset Retirement Obligations (AROs) See note 1 to the consolidated financial statements in Item 8 of this report for the accounting policy description of Asset Retirement Obligations. See note 2 for a discussion of the adoption of SFAS No. 143. Recognized ARO liability amounts are based upon future asset retirement cost estimates that are developed in large part from abandonment cost studies performed by independent third-party firms. The studies are then reviewed by the Company s technical, accounting and legal staff. Projecting future ARO cost estimates is difficult as it involves the estimation of many variables such as economic recoveries of future oil and gas reserves, future labor and equipment rates, future inflation rates, and the company s credit adjusted risk free interest rate. Future geopolitical, regulatory, technological, contractual, legal and environmental changes could also impact future ARO cost estimates. Because of the intrinsic uncertainties present when estimating asset retirement costs as well as asset retirement settlement dates, the Company s ARO estimates are subject to ongoing volatility.

Post-employment Benefits The Company utilizes U.S. 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, 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 for years 2000-2002 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 U.S. qualified plan, a 50 basis point (1/2 %) decrease in the discount rate, with all other assumptions held constant, would have increased the PBO by approximately $90 million at December 31, 2003 and would increase pre-tax pension expense for 2004 by approximately $11 million. For 2004, the expected rate of return on plan assets (ROA) is 8 percent, which 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 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 pre-tax pension expense approximately $5 million in 2004.

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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 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. In 2003, the Company made a $30 million voluntary contribution to the plan and the plan experienced favorable asset returns. As a result, the minimum pension liability was reduced by $12 million to $91 million, and the cumulative OCI after-tax charge decreased by $34 million to $300 million. The Company was not required to make any contributions to the plan in 2003 nor will it be required to make any contributions in 2004 or 2005. However, poor returns on plan assets could accelerate the requirement to make cash contributions to the plan after 2005. The Company may elect, however, to make voluntary cash contributions to the plan. See note 17 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 The Company s management 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 settlements. For environmental reserves, actual costs can differ from estimates because of changes in laws and regulations, discovery and analysis of actual site conditions and/or changes in clean-up technology. For additional details, refer to the ensuing Environmental Matters discussion and notes 20 and 24 to the consolidated financial statements in Item 8 of this report. Actual litigation costs can vary from estimates based on the facts and circumstances and 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.

		Years Ended December 31,		
	Estimated			
Millions of Dollars	**2004**	**2003**	**2002**	**2001**
Environmental related capital expenditures	$ 38	$ 24	$ 22	$ 19

The 2003 capital expenditures were higher than 2002 due to environmental capital expenditures that were incurred in 2003 to prepare properties owned by the Company for sale. Higher estimated 2004 capital expenditures are mainly attributed to various planned environmental projects related to process upgrades and expansion for ongoing operations, contractual requirements and regulatory compliance.

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Amounts recorded for environmental related expenses, including provisions for remediation that were identified during the Company s ongoing review of its environmental obligations and operating, maintenance and administrative expenses, were approximately $140 million in 2003, $170 million in 2002 and $175 million in 2001. Lower expenses in 2003 versus 2002 were primarily due to higher remediation provisions recorded in 2002 for 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 and for the decommissioning and decontamination of the Company s Molycorp, Inc. (Molycorp) subsidiary closed molybdenum and rare earth processing facilities in Washington and York, Pennsylvania. Partially offsetting the higher 2002 expenses were higher remediation provisions recorded in 2003 for the Company s inactive Guadalupe oil field located on the central California coast and for remediation projects at the Company s former refinery in Beaumont, Texas. Lower expenses in 2002 versus 2001 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, 2003, the Company s reserves for environmental remediation obligations totaled $252 million, of which $118 million was included in current liabilities. During 2003, cash payments of $85 million were applied against the reserves and $92 million in provisions were added to the reserves. The Company may also incur additional liabilities 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 $205 million.

The reserve amounts and possible additional costs are grouped into the following four categories:

	At December 31, 2003	
Millions of dollars	**Reserve**	**Possible Additional Costs**
Superfund and similar sites	$ 15	$ 15
Active Company facilities	28	30
Company facilities sold with retained liabilities and former Company-operated sites	99	75
Inactive or closed Company facilities	110	85
Total	$ 252	$ 205

Also, see notes 20 and 24 to the consolidated financial statements in Item 8 of this report for additional information on environmental related matters.

During 2003, provisions of $46 million were recorded for the Company facilities sold with retained liabilities and former Company-operated sites category. These provisions included the estimated cleanup costs for oil fields located in Michigan and California that were formerly operated by the Company. The estimated costs are based on assessments recently performed at the sites, higher than anticipated volumes of contaminated soil at existing sites and higher remediation costs for soil excavation and disposal than originally anticipated. The provisions for this category of sites were also the result of revised remediation cost estimates that were identified during 2003 for service station sites and distribution facilities formerly operated by the Company.

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Provisions were also recorded for auto/truckstop sites that were sold by the Company in 1993. In December 2003, an agreement was reached with the owner of certain of these auto/truckstops indemnifying the Company from future remediation liabilities and obligations related to these sites in exchange for a cash payment and payment for insurance coverage for unforeseen future environmental exposure that may arise from contamination that existed prior to the original sale of the sites. The agreement was finalized in January 2004. In addition, the Company received revised remediation cost estimates 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.

In 2003, the Company accrued $38 million related to sites in the Inactive or closed Company facilities category primarily for the Guadalupe oil field located on the central California coast and for remediation projects at the Company s former refinery in Beaumont, Texas.

For the Guadalupe oil field site, it was determined that contaminated soil excavated from the site will be taken to an offsite landfill for disposal. The soil is contaminated with diluent, a kerosene-like additive used in the field s former operations. Previously, the Company had planned to remediate the soil on-site; however, a preliminary draft report for the ecological risk study being conducted indicates that on-site remediation is not feasible. The provisions recorded for the site include the costs for the offsite disposal alternative. The provisions recorded for the Guadalupe oil field also include estimated costs for remediation work that is ongoing at the site. This work includes groundwater monitoring, operation and maintenance of remedial systems, restoration, agency oversight, permitting, and site assessment. The provisions for these costs are based on data from various studies and assessments that have been completed for the site in conjunction with data provided by the project management system the Company has in place.

A provision was also recorded for the Company s former Beaumont, Texas refinery. The Company has been working with the Texas Commission on Environmental Quality (TCEQ) to develop plans for closing impoundments used in the site s former operations and for other remediation projects. In 2003, the Company recorded a provision for the revised estimated costs of the impoundment closure plan based on the TCEQ initial draft permit that was issued for the site.

The Company recorded provisions of $7 million during 2003 for the Active Company facilities category of sites. The provisions were primarily for the remedial investigation and feasibility study (RI/FS) being performed at a molybdenum mine located in Questa, New Mexico, that is owned by the Company s Molycorp subsidiary. Molycorp has been working closely with the U.S. Environmental Protection Agency and the State of New Mexico in conducting the RI/FS at the mine during the year. The RI/FS is being performed to determine if past mining operations have had an adverse impact on the environment. Numerous additions and changes to the RI/FS scope have been required by the agencies, which will require a higher level of effort than originally projected.

In 2003, estimated possible additional costs in excess of amounts included in the reserves for remediation obligations decreased by $40 million. The decrease was primarily for sites in the Active Company facilities category, as a result of the reclassification of costs to asset retirement obligations under SFAS No. 143 for the Company s Molycorp subsidiary (see note 2 for further detail). The decrease was also the result of the Company lowering its estimated costs for the Inactive or closed Company facilities category of sites by $20 million. These costs were included in the amounts added to the reserve for the Guadalupe oil field and the Beaumont Refinery sites as discussed above.

Partially offsetting the foregoing decreases was an increase of $5 million in possible additional costs for the Superfund and similar sites category. The increase is based on preliminary information that the Company has received regarding possible payments for remediation-related work for two sites located in California.

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At year-end 2003, estimated possible additional costs for the Company facilities sold with retained liabilities and former Company-operated sites category was $75 million; no change from year-end 2002. During 2003, possible additional costs for this category of sites increased for former Company-operated service stations and distribution facilities. The increase was based on revised cost estimates for remediation work that may be required for these sites. Possible additional costs also increased for a former oil field in Michigan where the company is in the process of determining the extent of cleanup that may be required. Offsetting the aforementioned increases were lower remediation costs based on estimates 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. During 2003, possible additional costs for this category also increased as the result of higher costs identified for auto\truckstop system sold by the Company in 1993. These costs were subsequently added to the remediation reserve and the estimated possible additional costs were concurrently reduced as a result of the agreement reached with the owner of certain of these sites indemnifying the Company from future remediation liabilities and obligations as previously discussed.

OUTLOOK

Realized prices for crude oil, natural gas liquids and North America natural gas are a significant driver of financial performance for the Company. Energy prices are expected to remain volatile due to a variety of fundamental and market perception factors including variability of the weather on a year to year basis, worldwide demand, crude oil and natural gas inventory levels, production quotas set by OPEC, current and future worldwide political instability, especially events concerning Iraq, worldwide security and other factors. The Company has secured fixed price hedges to mitigate some of that volatility, primarily relating to a portion of its 2004 North America natural gas production.

The economic situation in Asia, where most of the Company s international activity is centered, is showing positive signs. The Company looks at the natural gas market in Asia as one of its major strategic investments.

The Company s outlook of important 2004 activities is as follows;

Exploration and Production North America

U.S. Lower 48

In the deep water region of the Gulf of Mexico, the Mad Dog development project will be nearing completion by the end of 2004. Initial production is expected in early 2005. The Company has a 15.6 percent working interest. Another Gulf of Mexico deep water development moving forward in 2004 is the K-2 field, in which the Company has a 12.5 percent working interest. A decision is anticipated in 2004 on development of the Champlain project. The Company is the operator with a 30 percent working interest.

Gulf of Mexico exploration will be focused on the deep water as well as a re-tooled and smaller deep shelf program. The deep water program will be concentrated on three areas where the Company has participated in significant discoveries: Green Canyon Miocene (Mad Dog, K-2 and Puma), the Perdido Fold Belt (Trident), and the emerging Lower Tertiary play (Saint Malo). The deep shelf exploration program has a new management group which is responsible for both the deep shelf and the deep water Gulf of Mexico. This group is currently conducting a comprehensive evaluation of the deep shelf program.

Appraisal activities expected in 2004 include follow-up wells on the Company s Saint Malo and Puma discoveries in the deep water Gulf of Mexico.

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The Company s legacy Gulf of Mexico shelf operations have been concentrated into a new core of fields following the 2003 non-core divestitures. Activities on these traditional shelf fields will be focused on investing to promote proved undeveloped reserves into production. The Company anticipates that there are enough investment opportunities in this new core of fields to allow us to keep production declines in the intermediate future to less than 10 percent per year, without any significant contributions from the future deep shelf exploration program.

The most important onshore exploration activities conducted by the Company will be in West Texas on deep horizon tests of potentially significant gas accumulations from formations with longer reserve lives than the Gulf of Mexico. The Company expects production from the onshore business to be flat to slightly growing over the next few years.

The Company is negotiating the sale of its interests in certain prospective mineral fee lands in North America. The assets involved include working interests, royalty interests, overriding royalty interests and subsurface mineral rights on approximately 3.3 million net acres, primarily in Texas, Louisiana, Mississippi and Alabama.

The U.S. Lower 48 capital programs have a goal to add reserves with a finding and development cost of $8.00 per BOE or less.

Alaska

First production from the Company s Happy Valley discovery is planned for late 2004 upon completion of an extension of the Kenai Kachemak Pipeline. Happy Valley, which was discovered in November of 2003, will sell natural gas under a contact with ENSTAR, the local utility, at prices based on a 36-month trailing average for Henry Hub natural gas prices.

Other natural gas prospects in the southern Kenai Peninsula are targeted for exploration. The Company expects to drill two or three of them in 2004. Any additional natural gas found will also be marketed through the ENSTAR contract.

Canada

The Company s Canadian operations have two to three large potential, high-risk exploration tests planned in 2004. The primary focus in Canada will also be to promote proved undeveloped reserves into production and to replace production with new reserves. The Company sees investment opportunities in Canada that should result in slight production growth over the next few years. The Company s expectations for Canada s finding and development costs are also at $8.00 per BOE or below.

Exploration and Production International

Far East

Thailand:

Thailand s natural gas market continues to grow at around 5 to 6 percent per annum. The Company s operations have supplied natural gas to the Kingdom of Thailand at above contract minimum volumes for several years. In our existing Thailand natural gas operation the Company will continue to follow its program of just in time development, which allows it to be the swing natural gas producer without over-investing in new capacity.

Significant new crude oil production is anticipated from Phase 2 of the Platong, Yala, Surat, and Plamuk areas. Development work will advance in 2004, with an additional 20 MBbl/d of gross crude oil expected in mid-2005.

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The Company anticipates signing final agreements in 2004 for the extension of existing natural gas sales agreements and expansion of contract quantities by 15 percent by 2006, and another 50 percent by 2010-2012. Negotiations are expected to be completed in 2004 include the pricing of the new sales quantities.

The Arthit field s natural gas sales agreement has been signed and development work is expected during 2004 with first production anticipated in 2006.

Indonesia:

The West Seno field, which came on stream in 2003, is expected to continue ramping up during 2004 toward peak gross rates for Phase 1 of 35 to 45 MBOE/d.

Development and engineering activities are underway in 2004 for the West Seno Phase 2, Merah Besar, and Ranggas fields.

Parallel conceptual engineering activities will also move forward in 2004 for natural gas sales opportunities from either the Gehem or Gendalo fields. One of these projects is expected to emerge in the first half of 2004 as the first deep water development of natural gas production as soon as 2006. This natural gas will be available to the Bontang LNG facility as back-up capacity for current production commitments and to provide natural gas for potential spot sales opportunities of LNG.

Exploration and appraisal drilling will continue in 2004 in the deep water Kutei Basin. This drilling activity will test for crude oil in deeper horizons below the Company s past natural gas discoveries. These tests will also allow the Company to certify additional natural gas volumes, which will be used to secure increased allocations of the new Bontang sales contracts, the majority of which are anticipated in 2010 and beyond.

China:

Both development and exploration activity is expected in 2004 on the Company s PSC areas in the Xihu Trough off the coast of Shanghai.

Evaluation of technical information will proceed on existing wells that were drilled in the past. Once the evaluation is complete, a final development plan will be determined.

The Company is processing recently acquired seismic data and finalizing the drilling program. Exploration drilling is anticipated with up to six wildcat and appraisal wells expected in 2004. The first appraisal well was spud in mid-February 2004. A successful drilling campaign is essential to achieve minimum commercial reserves for the Phase I development. If the exploration and appraisal programs prove sufficient reserves, commercial natural gas production could begin in late 2005.

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Other International

Azerbaijan:

Continued progress is expected in 2004 on the development of the BP operated AIOC project. Gross production is expected to ramp up to more than 200 MBbl/d in 2005, rising to 700 MBbl/d in 2007 and over 1 million Bbl/d by 2009. The Company has a 10.28 percent working interest.

Bangladesh:

Construction and development drilling on the Moulavi Bazar field will progress during 2004, with first production in the first half of 2005. Moulavi Bazar is expected to have peak production of 70 to 100 MMcf/d. The Company signed a new natural gas sales agreement for Moulavi Bazar in 2003.

Unocal expects to make progress on a third natural gas sales agreement in Bangladesh covering the Bibiyana field. The Bibiyana field is capable of being developed in stages, which could provide Bangladesh with natural gas resources in the short, medium and long term time frames.

As Bangladesh makes progress on the program to electrify rural areas that do not currently have access to electrical power, demand for natural gas will continue to grow. The Company s past discoveries can lead to future proven reserves and developments without significant additional exploration spending.

Midstream

In parallel with the AIOC field development work in Azerbaijan in 2004, the BTC pipeline is expected to be operational in mid-2005. The Company s interest in this pipeline is 8.9 percent. The BTC pipeline will transport the crude oil from the AIOC field to the Turkish port of Ceyhan and will have a capacity of 1 million Bbl/d.

Geothermal and Power Operations

Indonesia:

The Company anticipates stable operations at the Gunung Salak, and DSPL steam and power projects for the foreseeable future. In February 2004, the Company sold its rights and interest in the Sarulla geothermal project on the island of Sumatra, Indonesia to PLN for $60 million.

Philippines:

The Company s Philippine Geothermal, Inc. (PGI) subsidiary anticipates that it will obtain final Philippine government and court approvals of a settlement for past contractual issues and agreement covering the ongoing operations of the steam resources at Tiwi and Mak-Ban. Under the settlement, PGI will be granted the right to operate the steam fields until at least 2021; and PGI will sell geothermal resources to the National Power Corporation (NPC), a Philippine government-owned corporation, and the Power Sector Assets and Liabilities Management Corporation at a renegotiated price to ensure base-load operation of the Tiwi and Mak-Ban power plants.

FUTURE ACCOUNTING CHANGES

See Note 2 to the consolidated financial statements for information about recent accounting pronouncements.

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RISK FACTORS

Our business activities and the value of 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. 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 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.

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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 estimates are subject to change.

Estimates of reserves by necessity are projections based on engineering and geoscience data, commodity prices, future rates of production and the amounts and timing of future expenditures. Our estimates of proved oil and gas reserves and projected future net revenues require substantial judgment on the part of the petroleum engineers, 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 operating performance that deviates significantly from reserve reports and future changes in economic conditions 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 decreases 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.

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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 60 percent of our oil and gas production in 2003 was outside the United States, and over 70 percent of our proved oil and gas reserves at December 31, 2003 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, or failing to extend or renew such 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.

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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

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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 24 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 international subsidiaries generate substantial foreign tax credits. Our ability to utilize these foreign tax credits is dependent on achieving a sufficient future level of taxable income in various jurisdictions over time and other factors and uncertainties, including tax law changes and the future level of commodity prices and operating costs. Failure to utilize these foreign tax credits over time could result in the future recognition of a valuation allowance in the applicable fiscal period and a higher effective tax rate, reducing stockholders equity and impacting earnings.

Our debt level may limit our financial flexibility.

As of December 31, 2003, our consolidated balance sheet showed $2.88 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. We may incur additional debt in the future, including in connection with acquisitions, recapitalizations and refinancings.

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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 substantial contractual obligations for non-cancelable operating leases, including drill ship leases, reimbursement obligations under standby letters of credit and performance bonds 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.

Furthermore, at year-end 2003, we had firmly committed to significant capital expenditures in 2004 for the development of offshore oil and gas fields, including related platforms, pipelines and other infrastructures. We expect 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 2004, 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 reduce discretionary capital expenditures, 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 amounts due under 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 Unocal, 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 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. In addition, certain of our employment and other agreements and severance plans covering most domestic employees and a limited number of non-U.S. employees provide for enhanced payments upon a termination of employment following 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, prohibiting stockholder action by written consent and 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.

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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.

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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, 2003. Assuming a ten percent decrease in the Company s weighted average borrowing costs at December 31, 2003 and 2002, 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 $93 million and $105 million at December 31, 2003 and 2002, respectively.

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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 and have outstanding Canadian-dollar denominated debt.

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, 2003, the Company had various foreign currency forward contracts outstanding related to operations in Thailand. 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, forward contracts and foreign-currency denominated debt. Assuming an adverse change of ten percent in foreign exchange rates at December 31, 2003 and 2002, the potential decrease in fair value of the foreign currency swaps, foreign currency forward contracts and foreign-currency denominated debt of the Company and its subsidiaries would have been approximately $37 million and $35 million at December 31, 2003 and 2002, respectively.

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 $26 million and $20 million at December 31, 2003 and 2002, respectively. The value at risk related to hydrocarbon derivatives held for non-hedging purposes was immaterial at December 31, 2003, and approximately $4 million at December 31, 2002.

In order to provide a more comprehensive view of the Company s commodity price risk, a tabular presentation of open hydrocarbon derivatives is also provided. The following table sets forth the future volumes and price ranges of hydrocarbon derivatives held by the Company at December 31, 2003, along with the fair values of those instruments.

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Open Hydrocarbon Hedging Derivative Instruments [a]

	2004	2005	2006	2007-2008	(Thousands of dollars) Fair Value Asset (Liability) [b][c]
Natural Gas Futures Positions					
Volume (MMBtu)	4,120,000	30,000			$ 2,969
Average price, per MMBtu	$ 5.34	$ 5.01			
Volume (MMBtu)	(19,220,000)				$ 3,325
Average price, per MMBtu	$ 6.12				
Natural Gas Swap Positions					
Pay fixed price					
Volume (MMBtu)	20,419,500	10,143,000	7,218,000	14,459,000	$ 89,522
Average swap price, per MMBtu	$ 4.13	$ 3.13	$ 2.42	$ 2.50	
Receive fixed price					
Volume (MMBtu)	28,630,000				$ 584
Average swap price, per MMBtu	$ 5.49				
Natural Gas Basis Swap Positions					
Volume (MMBtu)	14,560,000				$ 1,795
Average price received, per MMBtu	$ 5.53				
Average price paid, per MMBtu	$ 5.41				
Natural Gas Collar Positions					
Volume (MMBtu)	1,200,000				$ (119)
Average ceiling price, per MMBtu	$ 5.76				
Average floor price, per MMBtu	$ 4.65				
Crude Oil Future position					
Volume (Bbls)	(3,839,000)				$ (11,406)
Average price, per Bbl	$ 29.95				
Crude Oil Collar Positions					
Volume (Bbls)	720,000				$ (2,993)
Average ceiling price, per Bbl	$ 28.40				
Average floor price, per Bbl	$ 24.00				

(a) Positions reflect long (short) volumes.

(b) Net claims against counterparties with non-investment grade credit ratings are immaterial.

(c) Includes $3,541 thousand in assumed liabilities which were capitalized as acquisition costs.

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Open Hydrocarbon Non-Hedging Derivative Instruments [a]

	2004	(Thousands of dollars) Fair Value Asset (Liability) [b]
Natural Gas Futures Positions		
Volume (MMBtu)	6,440,000	$ (8,886)
Average price, per MMBtu	$ 6.58	
Volume (MMBtu)	(5,450,000)	$ 6,060
Average price, per MMBtu	$ 6.49	
Natural Gas Swap Positions		
Pay fixed price		
Volume (MMBtu)	5,555,000	$ (298)
Average swap price, per MMBtu	$ 5.13	
Receive fixed price		
Volume (MMBtu)	5,580,437	$ (3,324)
Average swap price, per MMBtu	$ 4.86	
Natural Gas Spread Swap Positions		
Volume (MMBtu)	46,035,000	$ 14,755
Average price paid, per MMBtu	$ 0.69	
Volume (MMBtu)	45,135,000	$ (11,291)
Average price received, per MMBtu	$ 0.68	
Natural Gas Option (Listed & OTC)		
Call Volume (MMBtu)	3,200,000	$ (4,658)
Average Call price	$ 8.41	
Call Volume (MMBtu)	(6,120,000)	$ 4,415
Average Call price	$ 7.67	
Put Volume (MMBtu)	7,080,000	$ (3,007)
Average Put Price	$ 4.25	
Put Volume (MMBtu)	(8,280,000)	$ 3,788
Average Put Price	$ 4.29	
Crude Oil Future position		
Volume (Bbls)	4,442,000	$ 20,413
Average price, per Bbl	$ 30.17	
Volume (Bbls)	(4,142,000)	$ (18,287)
Average price, per Bbl	$ 30.41	
Crude Oil Option (Listed & OTC)		
Call Volumes (Bbls)	150,000	$ (98)
Average price, per Bbl	$ 34.67	
Call Volumes (Bbls)	(450,000)	$ 342
Average price, per Bbl	$ 35.39	
Put Volume (Bbls)	100,000	$ (181)
Average price, per Bbl	$ 32.00	
Put Volume (Bbls)	(720,000)	$ 921
Average price, per Bbl	$ 20.00	
Crude Oil Swap Positions		

Pay fixed price		
Volume (Bbls)	5,065,000	$ 16,163
Average swap price, per Bbl	$ 28.04	
Receive fixed price		
Volume (Bbls)	5,315,001	$ (17,179)
Average swap price, per Bbl	$ 28.02	

(a) Positions reflect long (short) volumes.

(b) Includes $5,034 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).

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ITEM 8 - FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Index to the Consolidated Financial Statements and Financial Statement Schedule

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

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REPORT ON MANAGEMENT S RESPONSIBILITIES

To the Stockholders of Unocal Corporation:

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

The financial statements have been audited by the independent auditing 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 auditors 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 auditors, and the internal audit function. The Audit Committee is also responsible for the appointment of the independent auditors (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 auditors 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.

/s/ CHARLES R. WILLIAMSON	/s/ TERRY G. DALLAS	/s/ SAMUEL H. GILLESPIE, III	/s/ JOE D. CECIL
Charles R. Williamson	Terry G. Dallas	Samuel H. Gillespie, III	Joe D. Cecil
Chairman of the Board,	Executive Vice	Senior Vice President,	Vice President and Comptroller
Chief Executive Officer	President and Chief Financial Officer	Chief Legal Officer,	
and President		General Counsel and Corporate Secretary	

March 11, 2004

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REPORT OF INDEPENDENT AUDITORS

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, 2003 and 2002, 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, 2003 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 135 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, 2003 and 2002 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, 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.

As discussed in Note 2 to the consolidated financial statements, Unocal Corporation changed its method of accounting for asset retirement costs as of January 1, 2003.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

February 17, 2004

cLos Angeles, California

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CONSOLIDATED EARNINGS **UNOCAL CORPORATION**

Millions of dollars except per share amounts	Years ended December 31, 2003	2002	2001
Revenues			
Sales and operating revenues	$ 6,395	$ 5,224	$ 6,708
Interest, dividends and miscellaneous income	25	31	64
Gain on sales of assets	119	42	24
Total revenues	6,539	5,297	6,796
Costs and other deductions			
Crude oil, natural gas and product purchases	2,126	1,701	2,492
Operating expense	1,340	1,338	1,420
Administrative and general expense	260	151	122
Depreciation, depletion and amortization	988	973	967
Impairments	93	47	118
Dry hole costs	128	107	175
Exploration expense	251	246	252
Interest expense [(a)]	190	179	192
Property and other operating taxes	81	60	77
Distributions on convertible preferred securities of subsidiary trust	33	33	33
Total costs and other deductions	5,490	4,835	5,848
Earnings from equity investments	192	154	144
Earnings from continuing operations before income taxes and minority interests	1,241	616	1,092
Income taxes	522	280	452
Minority interests	9	6	41
Earnings from continuing operations	710	330	599
Earnings from discontinued operations [(b)]	16	1	17
Cumulative effect of accounting change	(83)		(1)
Net earnings	$ 643	$ 331	$ 615
Basic earnings per share of common stock:			
Continuing operations	$ 2.75	$ 1.34	$ 2.45
Discontinued operations	$ 0.06	$	$ 0.07
Cumulative effect of accounting change	$ (0.32)	$	$
Net earnings	$ 2.49	$ 1.34	$ 2.52
Diluted earnings per share of common stock:			
Continuing operations	$ 2.70	$ 1.34	$ 2.43
Discontinued operations	$ 0.06	$	$ 0.07
Cumulative effect of accounting change	$ (0.30)	$	$
Net earnings	$ 2.46	$ 1.34	$ 2.50

(a)	Net of capitalized interest of :	$	60	$	46	$	27
(b)	Net of tax expense of :	$	9	$	1	$	10

See Notes to the Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS **UNOCAL CORPORATION**

Millions of dollars	At December 31, 2003	2002
Assets		
Current assets		
Cash and cash equivalents	$ 404	$ 168
Accounts and notes receivable - net	1,292	994
Inventories	141	97
Deferred income taxes	119	90
Other current assets	35	26
Total current assets	1,991	1,375
Investments and long-term receivables - net	892	1,044
Properties - net	8,324	7,879
Goodwill	131	122
Deferred income taxes	300	273
Other assets	160	153
Total assets	$ 11,798	$ 10,846
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 1,072	$ 1,024
Taxes payable	326	223
Dividends payable	52	51
Interest payable	43	50
Current portion of environmental liabilities	118	113
Current portion of long-term debt and capital leases	248	6
Other current liabilities	226	165
Total current liabilities	2,085	1,632
Long-term debt and capital leases	2,635	3,002
Deferred income taxes	704	593
Accrued abandonment, restoration and environmental liabilities	844	622
Other deferred credits and liabilities	960	902
Minority interests	39	275
Commitments and contingencies - Note 24		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	522	522
Common stock ($1 par value, shares authorized: 750,000,000 [(a)])	271	269
Capital in excess of par value	1,031	962
Unearned portion of restricted stock issued	(13)	(20)
Retained earnings	3,456	3,021
Accumulated other comprehensive income	(298)	(486)
Notes receivable - key employees	(27)	(37)
Treasury stock - at cost [(b)]	(411)	(411)
Total stockholders equity	4,009	3,298
Total liabilities and stockholders equity	$ 11,798	$ 10,846

(a)	Number of shares outstanding (in thousands)	260,594	257,980
(b)	Number of shares (in thousands)	10,623	10,623

The Company follows the successful efforts method of accounting for its oil and gas activities.

See Notes to the Consolidated Financial Statements.

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CONSOLIDATED CASH FLOWS **UNOCAL CORPORATION**

	Years ended December 31,		
Millions of dollars	2003	2002	2001
Cash Flows from Operating Activities			
Net earnings	$ 643	$ 331	$ 615
Adjustments to reconcile net earnings to net cash provided by operating activities			
Depreciation, depletion and amortization	988	973	967
Asset impairments	93	47	118
Dry hole costs	128	107	175
Amortization of exploratory leasehold costs	108	98	95
Deferred income taxes	56	22	81
Gain on sales of assets	(119)	(42)	(24)
Gain on disposal of discontinued operations	(25)	(2)	(27)
Pension expense net of contributions	58	22	(12)
Restructuring provisions net of payments	27	2	(6)
Cumulative effect of accounting changes	83		1
Other	(3)	(73)	89
Working capital and other changes related to operations			
Accounts and notes receivable	(294)	(160)	462
Inventories	(44)	5	(14)
Accounts payable	48	196	(273)
Taxes payable	103	52	(33)
Other	99	(7)	(89)
Net cash provided by operating activities	1,949	1,571	2,125
Cash Flows from Investing Activities			
Capital expenditures (includes dry hole costs)	(1,718)	(1,670)	(1,727)
Major acquisitions			(646)
Proceeds from sales of assets	642	163	81
Proceeds from sales of discontinued operations	11	3	25
Net cash used in investing activities	(1,065)	(1,504)	(2,267)
Cash Flows from Financing Activities			
Long-term borrowings	205	585	519
Reduction of long-term debt and capital lease obligations	(452)	(495)	(225)
Minority interests	(257)	(8)	(17)
Proceeds from issuance of common stock	58	21	15
Dividends paid on common stock	(207)	(196)	(195)
Loans to key employees	11	6	
Other	(6)	(2)	
Net cash provided by (used in) financing activities	(648)	(89)	97
Increase (decrease) in cash and cash equivalents	236	(22)	(45)
Cash and cash equivalents at beginning of year	168	190	235
Cash and cash equivalents at end of year	$ 404	$ 168	$ 190

Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 199	$ 180	$ 195
Income taxes (net of refunds)	$ 364	$ 249	$ 368

See Notes to the Consolidated Financial Statements.

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CONSOLIDATED STOCKHOLDERS EQUITY **UNOCAL CORPORATION**

Millions of dollars except per share amounts	At December 31, 2003	2002	2001
Common stock			
Balance at beginning of year	$ 269	$ 255	$ 254
Issuance of common stock for acquisition of Pure Resources minority interest		13	
Other issuance of common stock	2	1	1
Balance at end of year	271	269	255
Capital in excess of par value			
Balance at beginning of year	962	551	522
Issuance of common stock for acquisition of Pure Resources minority interest		378	
Other issuance of common stock	57	31	28
Issuance of stock options and related tax benefit	12	2	1
Balance at end of year	1,031	962	551
Unearned portion of restricted stock and options issued			
Balance at beginning of year	(20)	(29)	(21)
Issuance of restricted stock and stock options	(1)	(3)	(18)
Amortization of restricted stock and options	8	12	10
Balance at end of year	(13)	(20)	(29)
Retained earnings			
Balance at beginning of year	3,021	2,888	2,468
Net earnings for year	643	331	615
Cash dividends declared on common stock ($0.80 per share)	(208)	(198)	(195)
Balance at end of year	3,456	3,021	2,888
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	(37)	(42)	(40)
Accrued interest on loans to key employees	(2)	(2)	(2)
Principal and interest payments received from key employees	12	7	
Balance at end of year	(27)	(37)	(42)
Accumulated other comprehensive income (loss)			
Balance at beginning of year	(486)	(88)	(53)
Foreign currency translation adjustments	145	(15)	(40)
Deferred net gains (losses) on hedging instruments	15	(49)	60
Cumulative effect of accounting change			(59)
Minimum pension liability adjustment	28	(334)	4
Balance at end of year [(a)]	(298)	(486)	(88)
Total stockholders equity	$ 4,009	$ 3,298	$ 3,124

[a] At year-end 2003, other comprehensive income was comprised of unrealized currency translation gains of $45 million, deferred net losses on hedging instruments of $33 million and minimum pension liability adjustment of $310 million. 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.

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COMPREHENSIVE INCOME **UNOCAL CORPORATION**

Millions of dollars	**2003**	**2002**	**2001**
	Years ended December 31,		
Net earnings	$ 643	$ 331	$ 615
Cumulative effect of change in accounting principle - SFAS No. 133 adoption [a]			(59)
Change in unrealized gains (losses) on hedging instruments [b]	(6)	(57)	32
Reclassification adjustment for settled hedging contracts [c]	21	8	28
Unrealized foreign currency translation adjustments	145	(15)	(40)
Minimum pension liability adjustment [d]	28	(334)	4
Total comprehensive income	$ 831	$ (67)	$ 580

(a) Net of tax effect of:			36
(b) Net of tax effect of:	3	33	(19)
(c) Net of tax effect of:	(12)	(4)	(16)
(d) Net of tax effect of:	(17)	196	(2)

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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 and variable interest entities where the Company is the primary beneficiary. 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, 2003 and 2002, 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 $22 million and $29 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 or fair values. These expected future cash flows are estimated based on management s plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on management s best estimate of future oil and gas prices using market-based information. The estimated future level of production is based on assumptions surrounding future commodity prices, lifting and development costs, field decline rates, market demand and supply, the economic regulatory climates and other factors.

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

Goodwill is not amortized but is reviewed for impairment on an annual basis and at other times when an event occurs or circumstances change that could negatively impact the fair value of a reporting unit. For purposes of goodwill, a reporting unit is the same as or one level below the Company s operating segment. Fair value is determined by taking into consideration such factors as current commodity prices in cases where the present value of discounted cash flows are used in the valuation as well as externally available valuation data for similar operations in like geographic areas. If the carrying amount of a reporting unit exceeds its fair value, a purchase price type allocation is made to the identifiable assets and liabilities of the reporting unit as if acquired in a business combination and the remaining unallocated value is compared to recorded goodwill to determine if a write-down is required.

Asset Retirement Obligations (AROs) Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, (see note 2 for further details). This Statement requires that the Company recognize liabilities related to the legal obligations associated with the retirement of its tangible long-lived assets in the periods in which the obligations are incurred (typically when the assets are installed) if a reasonable estimate of fair value can be made. These obligations include the required decommissioning and removal of certain oil and gas platforms, plugging and abandonment of oil and gas wells and facilities, the closure of certain mining facilities, and the restoration of certain sites at the time of abandonment. The Company has interests in some long-lived assets, such as commercial natural gas storage facilities, commercial crude oil and products storage facilities and commercial pipelines where the operations are not tied to any particular operating field reserves. While these assets have retirement obligations under SFAS No. 143, certain of those obligations have not been recognized due to the uncertainties of the settlement dates of the obligations. The Company will continue to monitor these assets for any changes to this position.

Under SFAS No. 143, liabilities for asset retirement obligations are initially recorded at fair values and the carrying values of the related assets are increased by corresponding amounts. Over time, changes in the present value of the liabilities are accreted and expensed and the capitalized asset costs are depreciated over the useful lives of the corresponding assets. Recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as expected economic recoveries of crude oil and natural gas, time to abandonment, future inflation rates and the risk free rate of interest adjusted for the Company s credit costs. Future revisions to ARO estimates will impact the present value of existing ARO liabilities and corresponding adjustments will be made to the capitalized asset retirement costs balance.

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. Costs of exploratory wells that have found commercially producible quantities of reserves that cannot be classified as proved remain capitalized while awaiting anticipated required major capital expenditures. Costs also remain capitalized for wells that have found sufficient quantities of reserves to justify their completion as long as the Company has firm plans to drill additional wells necessary to determine the existence of proved reserves. 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, including capitalized abandonment and removal costs, are calculated at unit-of-production rates based upon total proved and proved developed reserves, respectively. Depreciation of other properties, including capitalized abandonment and removal costs, is generally on a straight-line method using various rates based on estimated useful lives.

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Maintenance and Repairs Expenditures for maintenance and repairs are expensed. In general, improvements are capitalized 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.

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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 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. 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.

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Stock-Based Compensation Prior to 2003, the Company applied Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations in accounting for stock-based compensation. Accordingly, stock-based compensation expense recognized in the Company s consolidated earnings included 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 included expenses related to the Company s Pure Resources, Inc. (Pure) subsidiary, which had its own stock-based compensation plans. Under APB Opinion No. 25, stock-based employee compensation cost was not recognized in earnings when stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant.

Effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, prospectively to all employee awards granted, modified, or settled after December 31, 2002. Therefore, the cost related to stock-based employee compensation included in the determination of net earnings for 2003 is less than that which would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS No. 123. The following table illustrates the effect on net earnings and earnings per share if the fair value based method had been applied to all outstanding and unvested awards in each period:

	Years Ended December 31,		
Millions of dollars except per share amounts	**2003**	**2002**	**2001**
Net earnings			
As reported	$ 643	$ 331	$ 615
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects and minority interests	17	26	9
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects and minority interests	(22)	(56)	(21)
Pro forma net earnings	$ 638	$ 301	$ 603
Net earnings per share:			
Basic - as reported	$ 2.49	$ 1.34	$ 2.52
Basic - pro forma	$ 2.47	$ 1.22	$ 2.48
Diluted - as reported	$ 2.46	$ 1.34	$ 2.50
Diluted - pro forma	$ 2.44	$ 1.21	$ 2.45

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 2003 presentation.

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NOTE 2 - ACCOUNTING CHANGES

SFAS No. 132 (revised 2003): In 2003, the Company adopted SFAS No. 132, Employers Disclosures about Pensions and Other Postretirement Benefits (revised 2003). This Statement requires additional disclosures to those required in the original Statement relating to the assets, obligations, cash flows and net periodic benefit costs of defined benefit pension plans and other defined benefit postretirement plans. The adoption of the revised Statement did not have an effect on the Company s financial position or results of operations. In accordance with this pronouncement, the benefit payment information will be included in the Company s 2004 Form 10-K.

SFAS No. 143: Effective January 1, 2003, the Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations. If a reasonable estimate of fair value can be made, this Statement requires that the Company recognize liabilities related to the legal obligations associated with the retirement of its tangible long-lived assets 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. The recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as expected economic recoveries of crude oil and natural gas, time to abandonment, future inflation rates and the risk free rate of interest adjusted for the Company s credit costs.

The Company has interests in some long-lived assets, such as commercial natural gas storage facilities, commercial crude oil and products storage facilities, commercial pipelines, etc. where the operations are not tied to any particular operating field reserves. As the Company expects these assets to continue operations for the foreseeable future, it cannot reasonably estimate when, or if, these facilities will be abandoned. Accordingly, the Company has not accrued abandonment and restoration liabilities for these assets. The Company will continue to monitor these assets for any changes to this position.

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 using the units-of-production method. 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 their fair value, 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.

APB Opinion 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 Opinion 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 includes 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 also includes 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 also includes the impact related to the Company s mining operations under SFAS No. 143.

In the first quarter of 2003, the Company recognized a one time after-tax charge of $83 million as the cumulative effect of an accounting change related to the adoption of SFAS No. 143. The Company also increased its accrued abandonment and restoration liabilities by $268 million and increased its net properties by $138 million on the consolidated balance sheet as a result of the adoption of SFAS No. 143 as of January 1, 2003. The impact of adopting SFAS No. 143 on its 2003 operating earnings was an incremental charge of approximately $18 million after tax. The change in the asset retirement obligation during 2003 is discussed in note 20. The following table presents the pro-forma effects of SFAS No. 143 on the liability balance for December 31, 2002 and 2001, and the pro-forma earnings information for the periods ended December 31, 2003, 2002 and 2001:

Pro Forma SFAS No. 143 Liability	At December 31,	
(Millions of dollars)	2002	2001
Carrying amount of liability at beginning of year	$ 713	$ 661
Carrying amount of liability at end of period	$ 758	$ 713

Millions of dollars	For the years ended December 31,		
(except per share amounts)	2003	2002	2001
Net income [(a)]	$ 726	$ 312	$ 596
Earnings per share as reported:			
Basic	$ 2.81	$ 1.26	$ 2.44
Diluted	$ 2.76	$ 1.26	$ 2.42

(a) Net earnings of $643 million for 2003 has been adjusted to remove the $83 million cumulative effect of accounting change attributable to SFAS No. 143.

SFAS No. 146: Effective January 1, 2003, the Company adopted 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. The adoption of the Statement did not have a material effect on the Company s financial position or results of operations.

SFAS No. 148: Effective January 1, 2003, the Company adopted 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 amended 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 were adopted in the Company s 2002 Annual Report on Form 10-K. The Company adopted the fair value recognition provisions of SFAS No. 123, on a prospective basis, effective January 1, 2003 (see note 28 for further details). This change decreased 2003 after-tax income by $5 million. Adoption of the fair value recognition provisions did not have a material effect on the Company s 2003 financial position.

SFAS No. 149: Effective July 1, 2003, the Company adopted SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This Statement amends and clarifies accounting for derivative instruments including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. The adoption of the Statement did not have a material effect on the Company s financial position or results of operations.

SFAS No. 150: Effective April 1, 2003, the Company adopted SFAS No. 150, Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 requires that the Company classify a financial instrument that is within its scope, which may have previously been reported as equity, as a liability or an asset in some circumstances. The adoption of the Statement did not have an effect on the Company s 2003 financial position.

FASB Interpretation No. 45: Effective January 1, 2003, the Company adopted Financial Accounting Standards Board (FASB) 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 24. The adoption of this Interpretation did not have an effect on the Company s financial position or results of operations.

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FASB Interpretation No. 46: FASB Interpretation No. 46, Consolidation of Variable Interest Entities (VIE) requires the consolidation of certain entities that generally lack sufficient equity to finance their own activity without support from others or where there is an absence of control by equity investors. Although this Interpretation was effective for new variable interest entities as of February 1, 2003, the Company did not participate in any new VIEs in 2003. Pursuant to the recognition requirements of FASB Interpretation No. 46, the Company consolidated in the third quarter of 2003 the long-term debt of an affiliate that operates geothermal steam-fired power plants in Indonesia. At December 31, 2003, the balance sheet includes $74 million related to this debt (see note 19 for further details). An additional $242 million, classified as minority interests as of June 30, 2003, related to a partnership interest in Spirit Energy 76 Development, L.P. (Spirit LP), would have been required to be consolidated as long-term debt under this Interpretation had it not been paid in July 2003. FASB Staff Position No. FIN 46-6, delayed mandatory adoption of this rule until December 31, 2003, and permitted adoption on an entity-by-entity basis.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003) which clarifies the definition of a VIE and provides a scope exception for certain entities that meet the Statement s definition of a business. The Company will adopt this Standard in the first quarter of 2004, which will result in the deconsolidation of the Unocal Capital Trust (see note 25 for further details). As a result, the $522 million obligation for the convertible preferred securities will be removed from the consolidated balance sheet and replaced by a non-current liability for the $538 million in 6-1/4% convertible junior subordinated debentures of Unocal payable to the Trust. The Company will also record its $16 million investment in the Trust on the consolidated balance sheet. The deconsolidation will not effect consolidated net earnings. Because of its complexities, the Company continues to review the revised Statement and may find additional material interests in entities which could require recognition or disclosure in the first quarter 2004 financial statements.

Other Matters: The Company has classified the cost of acquiring oil and gas drilling rights in property, plant and equipment. The FASB s Emerging Issues Task Force (EITF) has on their agenda Issue No. 03-S, Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies. This issue addresses whether oil and gas drilling rights are intangible assets, and whether those assets are subject to classification and disclosure provisions of SFAS No. 142. The resolution of this issue will have no impact on the Company s results of operations and statement of cash flows. If the EITF determines that the cost of oil and gas drilling rights should be classified as intangible assets, it would result in additional disclosures and a balance sheet reclassification of these assets from Properties-net to Intangible Assets amounting to approximately $1,527 million and $1,746 million at December 31, 2003 and 2002, respectively.

In December 2003, The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was enacted, which introduces a prescription drug benefit under Medicare Part D. The availability of the new drug benefit could cause medicare eligible plan participants to leave their current employer-sponsored plans (or cause employees to join such plans), depending on the drug benefits provided under those plans relative to the benefits provided by Medicare. The Act also provides that a non-taxable federal subsidy will be paid to sponsors of postretirement benefit plans that provide retirees with a drug benefit that is at least actuarially equivalent to the Medicare Part D benefit. In accordance with FASB Staff Position 106-1, the Company has deferred the accounting for this Act and thus any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost in the consolidated financial statements or accompanying notes do not reflect the effects of the Act on the plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require the sponsor to change previously reported information. The Company is studying the Act to determine its economic impact. The federal subsidy is not payable to a plan sponsor for retirees who leave their current employer-sponsored plan to participate in the Medicare drug program. Detailed regulations specifying the manner in which actuarial equivalency must be determined and the evidence required to demonstrate it are not yet available. It is not known whether the Company will amend the plan in response to the new legislation.

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NOTE 3 - ACQUISITIONS

The Company did not make any significant acquisitions in 2003. In 2002, the Company exchanged shares of its common stock for the remaining shares of Pure that it did not already own. 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. At December 31, 2002, as a result of the transaction, properties increased by $121 million, goodwill increased by $80 million representing the excess of cost over fair values 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. As a result of the transaction, a minority interest liability of $151 million and a $112 million obligation for Subsidiary stock subject to repurchase were eliminated from the Company s consolidated balance sheet.

NOTE 4 - DISPOSITIONS OF ASSETS

In 2003, pre-tax proceeds from sales of assets totaled $642 million, with pre-tax gains of $119 million. The proceeds included approximately $361 million for the sale of various oil and gas properties in the Gulf of Mexico, onshore U.S. and Canada with a pre-tax gain of $8 million. In the Gulf of Mexico, the Company retained its deep mineral rights from a substantial number of the properties sold. The Company also received proceeds of $229 million from the sale of its equity interest shares held in Tom Brown Inc. and Matador Petroleum Corporation, with a pre-tax gain of $100 million. Cash proceeds also included approximately $52 million with a pre-tax gain of $11 million for the sale of various real estate and other miscellaneous properties.

In 2002, cash proceeds received from sales of assets totaled $163 million, with pre-tax gains of $42 million. The proceeds included $65 million from the sale of certain investment interests in nonstrategic pipelines in the U.S, with a pre-tax gain of $49 million. Cash proceeds of approximately $44 million were from the sale of real estate and other miscellaneous properties, with a pre-tax 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 U.S, with a pre-tax gain of $4 million. Sale proceeds also included $22 million from various other oil and gas asset sales, with a pre-tax loss of $31 million.

In 2001, cash proceeds received from sales of assets totaled $81 million, with pre-tax gains of $24 million. The Company received $63 million from the sale of certain oil and gas properties, primarily located in the U.S. Gulf of Mexico, with a pre-tax gain of $21 million. In addition, the Company received $18 million from the sale of real estate and other assets, with a pre-tax gain of $3 million.

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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, 2003 were as follows:

Millions of dollars	
2004	$ 187
2005	93
2006	29
2007	26
2008	17
Thereafter	13
Total minimum lease rental payments	$ 365

The Company has a lease agreement relating to the *Discoverer Spirit* deepwater drillship, with a remaining term of approximately 21 months at December 31, 2003. The drillship has a current minimum daily rate of approximately $226,000. The future remaining minimum lease payment obligation was approximately $140 million at December 31, 2003.

The future minimum lease rental payments have not been reduced, in total, by minimum sublease rentals due in the future under non-cancelable subleases.

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

	Years ended December 31,		
Millions of dollars	**2003**	**2002**	**2001**
Fixed rentals	$ 79	$ 72	$ 58
Sublease rental income	(6)	(4)	(3)
Net rental expense	$ 73	$ 68	$ 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. It also reviewed its properties as they were identified for sale.

In 2003, the Company recorded pre-tax impairment charges of $85 million ($53 million after-tax) for oil and gas fields (E&P North America U.S. Lower 48) and associated pipelines (Midstream) in the Gulf of Mexico region that were targeted and sold in a divestment of non-core assets. The properties targeted were low margin properties in the Gulf of Mexico region (see note 4). In addition, the Company recorded an after-tax charge of $6 million in its Midstream segment due to the impairment of the Trans-Andean oil pipeline in Argentina, which was held for sale at the end of 2003.

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 pre-tax. The Company also recorded a pre-tax charge of $4 million, for the impairment of its investment in a U.S. pipeline company that was being held for sale, carried in its Midstream segment as an equity affiliate. Lastly, the Company recorded a pre-tax charge of $2 million to impair its investment in an electronic commerce provider.

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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.

NOTE 7 - RESTRUCTURING COSTS

In June 2003, the Company accrued a $27 million pre-tax restructuring charge and adopted a plan for streamlining the organizational structures in order to align them with the Company s portfolio requirements and business needs. In the third quarter of 2003, the Company accrued an additional $10 million pre-tax restructuring charge to reflect continued streamlining of the organizational structures. An additional $1 million pre-tax charge was accrued in the fourth quarter when benefits for the additional participants became probable. These charges are included in administrative and general expense on the consolidated earnings statement. The following table reflects the 2003 restructuring activity by quarter. The majority of the remaining liability is expected to be paid in 2004. At December 31, 2003, 335 of 360 employees had been terminated or had been advised of planned termination dates as a result of the plan.

Millions of dollars (except employees)	**# Employees added to restructuring plan**	**Termination Costs**	**Training / Out-placement Costs**	**Post-retirement Benefit Costs**
1st Quarter Accrual				
1st Quarter Payments				
Liability at March 31, 2003				
2nd Quarter Accrual	219	$ 21	$ 2	$ 4
2nd Quarter Payments				
Liability at June 30, 2003		$ 21	$ 2	$ 4
3rd Quarter Accrual	127	9		1
3rd Quarter Payments		(2)		
Liability at September 30, 2003		$ 28	$ 2	$ 5
4th Quarter Accrual	14	1		
4th Quarter Payments		(5)		(5)
Liability at December 31, 2003		$ 24	$ 2	

In June 2002, the Company s Gulf Region business unit, which is part of the U.S. Lower 48 operations in the Exploration and Production segment, adopted a restructuring plan that resulted in the accrual of a $19 million pre-tax restructuring charge. The charge reflected the costs of terminating 202 employees. At year-end 2003, the restructuring costs had been paid and charged against the liability.

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 reflected the costs of terminating 46 employees. The plan was completed in 2003.

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NOTE 8 - INCOME TAXES

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

	Years ended December 31,		
Millions of dollars	**2003**	**2002**	**2001**
Earnings (loss) from continuing operations before income taxes and minority interests [a]			
United States	$ 247	$ (181)	$ 409
Foreign	994	797	683
Earnings from continuing operations before income taxes and minority interests	$ 1,241	$ 616	$ 1,092
Income taxes			
Current			
Federal	$ 67	$ (47)	$ 8
State	18	7	12
Foreign	384	221	351
Total current taxes	469	181	371
Deferred			
Federal	37	(60)	68
State	(11)		(1)
Foreign	27	159	14
Total deferred taxes	53	99	81
Total income taxes	$ 522	$ 280	$ 452

[a] Amounts attributable to the Corporate and Other segment are allocated.

In 2003, the Company elected to carry the U.S. federal net operating loss incurred in 2002 forward into 2003 to reduce federal taxable income. In addition, in 2003 the Company expects to utilize a portion of the past net operating loss carryforwards generated by its Pure subsidiary. The 2002 provision 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.

Millions of dollars	Years ended December 31, 2003	2002	2001
Federal statutory rate	35%	35%	35%
Taxes on earnings from continuing operations before minority interests at statutory rate	$ 434	$ 216	$ 382
Taxes on foreign earnings in excess of statutory rate	112	73	73
Change in Canadian statutory rate	(29)		
Dividend exclusion	(16)	(15)	(17)
Other	21	6	14
Total	$ 522	$ 280	$ 452

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The significant components of deferred income tax assets and liabilities included in the consolidated balance sheet at December 31, 2003 and 2002 were as follows:

	At December 31,	
Millions of dollars	**2003**	**2002**
Deferred tax assets:		
Exploratory costs	$ 299	$ 285
Federal AMT and other tax credits	125	209
Future abandonment costs	154	139
Litigation and environmental costs	113	107
Pension plans and postretirement benefit costs	132	110
Doubtful receivables	32	14
Forward sales of natural gas	22	27
Price risk and interest rate management activities	23	41
Other deferred tax assets	129	153
Total deferred tax assets	1,029	1,085
Deferred tax liabilities:		
Depreciation, depletion and intangible drilling costs	(1,164)	(1,153)
Investment in subsidiaries and affiliates	(47)	(79)
Other deferred tax liabilities	(103)	(83)
Total deferred tax liabilities	(1,314)	(1,315)
Total net deferred tax liabilities	$ (285)	$ (230)

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 $2.4 billion as of December 31, 2003. The Company estimates that approximately $215 million of unused foreign tax credits will be available after the filing of the 2003 consolidated tax return, with various expiration dates through the year 2008. No deferred tax asset for these foreign tax credits has been recognized for financial statement purposes.

At December 31, 2003, the Company had $106 million of federal alternative minimum tax credits which are available to reduce future U.S. federal income taxes on an indefinite basis. At December 31, 2003, the Company had net operating loss carryforwards of approximately $9 million, which are available to offset future taxable income subject to annual limitations. The loss carryforwards begin to expire in 2019, and the tax effect of those carryforwards are included in other deferred tax assets.

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NOTE 9 - DISCONTINUED OPERATIONS

Millions of dollars	Years ended December 31, 2003	2002	2001
Gain on disposal before income taxes [(a)]	$ 25	$ 2	$ 27
Income taxes	9	1	10
Total earnings from discontinued operations	$ 16	$ 1	$ 17

(a) Gain on disposal in 2003, 2002 and 2001 is related to the former refining, marketing and transportation business.

In 2003, discontinued operations included a $25 million pre-tax gain relating to the Company s 1997 sale of its former West Coast refining, marketing and transportation assets. The sales agreement contained a provision calling for payments to the Company for price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. In 2003, the Company recorded $14 million pre-tax for this provision. The gains in 2002 and 2001 were also related to this agreement. The Company s cash proceeds related to the agreement were $11 million, $3 million and $25 million for 2003, 2002 and 2001, respectively. This provision in the agreement terminated at the end of 2003. In addition, the Company also reduced its loss provisions for the disposal of the business by $11 million pre-tax, reflecting lower than anticipated charges relating to the sold properties.

NOTE 10 - EARNINGS PER SHARE

The following table includes a reconciliation of the numerators and denominators of the basic and diluted EPS computations for earnings from continuing operations for the years 2003, 2002 and 2001.

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Year ended December 31, 2003			
Earnings from continuing operations	$ 710	259	
Basic EPS			$ 2.75
Effect of dilutive securities			
Options and common stock equivalents		2	
	710	261	$ 2.72
Distributions on subsidiary trust preferred securities (after-tax)	28	12	
Diluted EPS	$ 738	273	$ 2.70

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

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

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Not included in the computation of diluted EPS at December 31, 2003, 2002 and 2001, were options outstanding to purchase approximately 8.2 million, 7.2 million and 6.2 million shares of common stock, respectively. 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.

NOTE 11 - CASH AND CASH EQUIVALENTS

	At December 31,	
Millions of dollars	2003	2002
Cash	$ 201	$ 58
Time deposits	150	110
Marketable securities	53	
Cash and cash equivalents	$ 404	$ 168

At December 31, 2003, the Company s cash and time deposits had increased by $183 million from year-end 2002, reflecting the effect of stronger commodity prices during the year. At year-end 2003, marketable securities totaled $53 million reflecting the Company s short-term investment in two money market funds that invest in U.S. Treasury and other U.S. government agency obligations, floating rate and variable rate demand notes of U.S. and foreign corporations, commercial paper rated in the highest category by Moody s Investor Services, Inc. (P1) and Standard & Poor s Ratings Services (A1), certificates of deposit and time deposits, asset backed securities and repurchase agreements. The funds are rated Aaa by Moody s Investors Service, Inc. and AAAm by Standard & Poor s Ratings Services.

NOTE 12 - SALES OF ACCOUNTS RECEIVABLE

The Company, through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation (URC), has a sales agreement with an outside unrelated party that provides for the sale of up to $125 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, 2003 and 2002, were $1 million and $2 million, respectively, and were 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. The Company used this arrangement throughout 2003 but had no outstanding balance at December 31, 2003. At year-end 2002, the Company had sold $108 million of its domestic trade receivables under this agreement.

The Company s consolidated balance sheet included a note receivable from URC of approximately $182 million and $66 million at December 31, 2003 and 2002, respectively, representing the unsold balance of trade receivables transferred to URC.

NOTE 13 - INVENTORIES

	At December 31,	
Millions of dollars	2003	2002
Crude oil and other petroleum products	$ 71	$ 43
Carbon and mineral products	43	34
Materials, supplies and other	27	20
Total inventories	$ 141	$ 97

Inventories are generally valued at the lower of cost or market. Inventories using the LIFO cost method amounted to $17 million and $12 million as of December 31, 2003 and 2002, respectively. The remaining inventory balances were primarily valued using average cost. The current replacement cost of inventories exceeding the LIFO inventory values was $3 million and $4 million at December 31, 2003 and 2002, respectively.

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NOTE 14 - ASSETS HELD FOR SALE

At December 31, 2003, the Company was in the process of selling certain of its prospective mineral fee lands in North America. The assets involved in the proposed sale included approximately 3.2 million net acres, primarily in Texas, Louisiana, Mississippi and Alabama.

At December 31, 2003, the Company s Unocal North Sumatra Geothermal, Ltd. subsidiary had agreed to sell its rights and interest in the Sarulla geothermal project on the island of Sumatra, Indonesia to the state electricity company of Indonesia. The sales price was $60 million and the transaction closed in February 2004 (see note 32 Subsequent Event).

The Company is in the process of selling its interests in the Trans-Andean oil pipeline, which transports crude oil from Argentina to Chile. The Company recorded an after-tax impairment on the transaction of approximately $6 million in 2003.

Details of the assets classified as held for sale, as of December 31, 2003, are presented below:

Millions of dollars	E&P N.A.	Midstream	Geothermal	Total
Assets				
Properties - net	$ 67	$	$ 26	$ 93
Other assets		38	1	39
Total assets	$ 67	$ 38	$ 27	$ 132

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NOTE 15 - EQUITY INVESTMENTS

Investments in companies accounted for by the equity method were $651 million, $686 million and $625 million at December 31, 2003, 2002 and 2001, 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 $180 million, $132 million and $211 million for the years 2003, 2002 and 2001, respectively. At December 31, 2003, 2002 and 2001, the excess of the Company s investments in Colonial Pipeline Company and various other pipeline companies was $139 million, $143 million and $153 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 $19 million of the $1.5 billion total. At December 31, 2003, 2002 and 2001, the Company s shares of the net capitalized costs of other companies engaged in oil and gas exploration and production activities were $178 million, $347 million and $309 million, respectively.

Summarized financial information for these investments and the Company s equity shares are presented in the table below.

	Years ended December 31,					
	2003		**2002**		**2001**	
Millions of dollars	**Total**	**Unocal Share**	**Total**	**Unocal Share**	**Total**	**Unocal Share**
Revenues	$ 2,148	$ 600	$ 1,965	$ 548	$ 2,429	$ 515
Costs and other deductions	1,425	408	1,419	394	1,684	371
Net earnings	$ 723	$ 192	$ 546	$ 154	$ 745	$ 144

	At December 31,					
	2003		**2002**		**2001**	
Millions of dollars	**Total**	**Unocal Share**	**Total**	**Unocal Share**	**Total**	**Unocal Share**
Current assets	$ 700	$ 239	$ 756	$ 248	$ 873	$ 324
Noncurrent assets	4,450	921	4,653	1,088	4,069	1,084
Current liabilities	695	197	787	257	1,429	453
Noncurrent liabilities	1,690	409	1,975	521	1,753	475
Net equity	2,765	554	2,647	558	1,760	480

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NOTE 16 - PROPERTIES AND CAPITAL LEASES

Investments in owned and capitalized-leased properties are shown below. Accumulated depreciation, depletion, and amortization for continuing operations were $11,711 million and $12,277 million at December 31, 2003 and 2002, respectively.

	At December 31,			
	2003		2002	
Millions of dollars	Gross	Net	Gross	Net
Owned Properties (at cost)				
Exploration and Production				
Exploration				
Lower 48	$ 512	$ 373	$ 527	$ 381
Alaska	5	4	5	5
Canada	269	166	206	137
North America Total	786	543	738	523
Far East	250	222	275	250
Other	125	56	147	82
International Total	375	278	422	332
Production				
Lower 48	5,845	2,263	7,548	2,656
Alaska	1,468	257	1,410	254
Canada	1,571	1,022	1,183	837
North America Total	8,884	3,542	10,141	3,747
Far East	6,453	2,328	5,811	2,002
Other	1,490	743	1,185	521
International Total	7,943	3,071	6,996	2,523
Total exploration and production	17,988	7,434	18,297	7,125
Trade	7	1	7	2
Midstream	532	240	496	221
Geothermal & Power Operations	903	427	658	279
Corporate & Other	605	222	693	247
Total owned properties	20,035	8,324	20,151	7,874
Capitalized-leased properties			5	5
Total properties and capital leases	$ 20,035	$ 8,324	$ 20,156	$ 7,879

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NOTE 17 - 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. Most of the Company s plans covering employees outside of North America are unfunded and resulting liabilities are extinguished on a pay as you go basis. The functional currency for all of the Company s international plans, with the exception of Canada, is the U.S. dollar.

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. The Company uses a December 31 measurement date for all of its postemployment benefit plans. The following table sets forth the postretirement benefit obligations recognized in the consolidated balance sheet at December 31, 2003 and 2002.

	Pension Benefits		Other Benefits	
Millions of dollars	2003	2002	2003	2002
Change in benefit obligation:				
Projected benefit obligation at January 1,	$ 1,197	$ 1,065	$ 372	$ 306
Service cost	31	24	4	3
Interest cost	83	77	25	22
Employee contributions			6	5
Disbursements	(117)	(115)	(28)	(29)
Actuarial losses	189	143	51	69
Plan amendments		13		
Curtailments and settlements	(7)	(11)		(4)
Divestitures		1		
Effect of foreign exchange rates	5		1	
Projected benefit obligation at December 31,	$ 1,381	$ 1,197	$ 431	$ 372
Change in plan assets:				
Fair value of plan assets at January 1,	$ 882	$ 1,026	$	$
Actual return on plan assets	187	(40)		
Employer contributions	47	1	22	24
Employee contributions			6	5
Disbursements	(117)	(100)	(28)	(29)
Administrative expenses	(5)	(5)		
Settlements				
Divestitures				
Effect of foreign exchange rates	5			
Fair value of plan assets at December 31,	$ 999	$ 882	$	$
Net amount recognized:				
Funded status	$ (382)	$ (315)	$ (431)	$ (372)
Unrecognized net obligation at transition	1	1		
Unrecognized prior service cost	38	48	4	4
Unrecognized net actuarial losses (gains)	689	676	186	145

Net amount recognized	$ 346	$ 410	$ (241)	$ (223)
Components of the above amounts consist of:				
Prepaid pension cost	$ 11	$ 9	$	$
Accrued benefit liability	(217)	(193)	(241)	(223)
Intangible asset	38	45		
Accumulated other comprehensive loss	514	549		
Net amount recognized	$ 346	$ 410	$ (241)	$ (223)

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The accumulated benefit obligation for the Company s defined benefit pension plans was $1,203 million and $1,055 million at December 31, 2003, and 2002, respectively. The projected benefit obligations, accumulated benefit obligations and fair values of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were approximately $1,323 million, $1,155 million and $937 million, respectively as of December 31, 2003 and approximately $1,152 million, $1,019 million and $833 million, respectively as of December 31, 2002.

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

	Pension Benefits			Other Benefits		
Millions of dollars	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Service cost (net of employee contributions)	$ 31	$ 24	$ 20	$ 4	$ 3	$ 2
Interest cost	83	77	75	24	21	19
Expected return on plan assets	(81)	(105)	(111)			
Amortization of:						
Transition obligation						
Prior service cost	7	6	6	1	1	1
Net actuarial (gains) losses	68	33	2	10	5	1
Curtailment and settlement (gains) losses	4	5	7	1		
Cost of special separation benefits						
Net periodic pension and other benefit cost (credit)	$ 112	$ 40	$ (1)	$ 40	$ 30	$ 23

The Company recognized $5 million in curtailment costs related to its U.S. Qualified Retirement Plan and Postretirement Welfare plans covering current and former U.S. payroll employees as a result of asset sales and the Company s 2003 restructuring plan. 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 assumed weighted-average rates used to determine benefit obligations at December 31 were:

	Pension Benefits			Other Benefits		
Weighted-average assumptions	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Discount rates	6.00%	6.74%	7.24%	6.00%	6.75%	7.25%
Rates of salary increases	4.91%	4.93%	4.50%	4.99%	4.99%	4.50%

For the years ended December 31, the assumed weighted average rates used to determine net periodic benefit cost were:

Weighted-average assumptions	Pension Benefits 2003	2002	2001	Other Benefits 2003	2002	2001
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 Company employs a building block approach in determining the expected long-term rate of return for pension plan assets. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The overall expected long-term rate of return on assets assumption is calculated using pension plan target asset allocations, outside consultants capital markets return forecasts for the asset classes employed, expected premium returns for active management and estimated pension plan fees and expenses. Peer data and historical returns are utilized to validate projected long-term returns for reasonableness. The resulting weighted average expected long-term rate of return for the Company s domestic and international pension plans were 8.0 percent and 8.4 percent at January 1, 2004 and 2003, respectively.

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The following is a breakdown of the fair value of the Company s pension plan assets by investment type at December 31, 2003 and 2002, respectively:

	U.S. Plan				Foreign Plans			
Millions of Dollars	2003		2002		2003		2002	
U.S. Equity Securities	$ 432	46.1%	$ 364	43.7%	$ 4	6.4%	$ 3	6.1%
International Equity Securities	162	17.3%	127	15.2%	21	33.9%	14	28.6%
Debt Securities	283	30.2%	319	38.3%	36	58.1%	27	55.1%
Cash/Other	60	6.4%	23	2.8%	1	1.6%	5	10.2%
Total Assets	$ 937	100%	$ 833	100%	$ 62	100%	$ 49	100%

The investment objective is to maximize investment earnings and capital appreciation on plan assets and to preserve capital over a long-term horizon. This objective is achieved by investing in equities and other asset classes with differing rates of return, return variances and correlation so as to provide diversification and to mitigate risks. The Company s current asset allocation policy for its U.S. Qualified Retirement Plan is set forth below:

Type of Investment	Allocation Range		
U.S. Equity Securities	42.0%	to	52.0%
International Equity Securities	12.0%	to	18.0%
Debt Securities	32.0%	to	42.0%
Cash/Other	0%	to	5.0%

Asset allocations are reviewed periodically to ascertain that the desired asset mix is being maintained based on the return potential and risk factors associated with each asset class. Outside investment advisors are hired to manage plan assets and are selected based on their particular investment style, philosophy and past performance. Specific guidelines are in place for each investment advisor and are strictly enforced. Other than through index funds none of the plans hold shares of the Company s common stock.

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 U.S. 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. At December 31, 2003 the minimum pension liability reflecting the excess of the accumulated benefit obligation over the fair value of plan assets for the Company s U.S. Qualified Retirement Plan had been reduced to $91 million. This net reduction was achieved in spite of using a lower discount rate to measure the liability at year-end 2003 and reflects the improved market returns on plan assets during 2003. As a result, an after-tax credit of $34 million was recorded to the other comprehensive income component of stockholders equity in 2003.

The Company made a voluntary $30 million cash contribution to its U.S. Qualified Retirement Plan in the fourth quarter of 2003. The Company will not be required under existing funding or tax regulations to make any cash contributions to its U.S. Qualified Retirement Plan during 2004. The Company anticipates that it will contribute approximately $4 million to its Supplemental Executive Retirement plans, approximately $17 million to its foreign pension plans and approximately $27 million to its worldwide postretirement medical plans in 2004.

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Health care cost trend rates used in measuring the benefit obligation for the U.S. medical plans at December 31 are set forth as follows:

	2003	2002	2001
Health care cost rate assumed for next year	10.00%	9.00%	8.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%
Year that rate reaches ultimate trend rate	2008	2006	2004

A one percentage-point change in the assumed health care cost trend rate would have had the following effects on 2003 service and interest cost and the accumulated postretirement benefit obligation at December 31, 2003:

Millions of dollars	One percent Increase	One percent Decrease
Effect on total of service and interest cost components of net periodic expense	$ 4	$ (3)
Effect on postretirement benefit obligation	$ 46	$ (39)

In December 2003, the U.S. Congress passed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Company is still in the process of evaluating the impact of the Act on its U.S. Postretirement Welfare plan. In keeping with the guidance provided by the Financial Accounting Standards Board in its FASB Staff Position No. FAS 106-1, the Company has elected to defer accounting for the effects of the Act (see note 2 for further details). Accordingly, the accumulated postretirement benefit obligation and net periodic benefit cost reported in the Company s financial statements for the period ended December 31, 2003 do not reflect the effects of the Act. In addition, specific authoritative guidance on the accounting for the federal subsidy to qualifying plans is still pending and that guidance, when issued, could require the Company to change previously reported information.

The Company has a 401(k) defined contribution savings plan designed to supplement retirement income for its U.S. employees. The Company s contributions to the plan were $13 million, $12 million and $11 million in 2003, 2002 and 2001 respectively, which were used by the plan trustee to purchase shares of Unocal common stock in the open market. While historically trustee purchases of Unocal common stock have been made in the open market the Company has the option to direct the trustee to purchase common stock directly 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 and 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 $14 million and $15 million at December 31, 2003 and 2002, respectively.

NOTE 18 - VARIABLE INTEREST ENTITIES

Dayabumi Salak Pratama, Ltd. (DSPL) is a variable interest entity formed for the purpose of building and operating a geothermal energy fueled power generating facility in Indonesia. Under a long-term electricity sales contract, DSPL 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 $74 million at December 31, 2003. Neither UGI nor the Company has guaranteed DSPL s debt obligations, which are non-recourse. The Company consolidated DSPL commencing in the third quarter of 2003 in accordance with FASB Interpretation No. 46 (see note 2 for further details). See note 25 Trust Convertible Preferred Securities for discussion of an additional variable interest entity.

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NOTE 19 - LONG-TERM DEBT AND CREDIT AGREEMENTS

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

	At December 31,	
Millions of dollars	**2003**	**2002**
Bonds and debentures		
9-1/4% Debentures due 2003	$	$ 89
9-1/8% Debentures due 2006	166	200
6-1/5% Industrial Development Revenue Bonds due 2008		20
7% Debentures due 2028	200	200
7-1/2% Debentures due 2029	350	350
Notes		
Medium-term notes due 2004 to 2015 (7.96%) and (7.84%) [a]	294	330
6-3/8% Notes due 2004	173	200
7-1/5% Notes due 2005	85	200
6-1/2% Notes due 2008	21	100
7.35% Notes due 2009	316	350
5.05% Notes due 2012	400	400
Other		
Canadian Bank Credit Agreement	227	186
Capital leases		6
Pure consolidated debt [b]	350	351
Azerbaijan loan [c]	24	28
West Seno - OPIC loan [c]	205	
DSPL debt [b]	74	
Other miscellaneous debt	1	1
Bond (discount) premium	(3)	(3)
Total debt and capital leases	2,883	3,008
Less current portion of long-term debt and capital leases	248	6
Total long-term debt and capital leases	$ 2,635	$ 3,002

(a) Weighted average interest rate at December 31, 2003 and 2002, respectively.

(b) Non-Recourse debt.

(c) Limited-Recourse debt.

At December 31, 2003, the amounts of debt and capital leases maturing in 2004, 2005, 2006, 2007 and 2008 were $248 million, $460 million, $267 million, $110 million and $65 million, respectively.

In 2003, the Company s consolidated debt, including the current portion, decreased by $125 million. The Company retired $89 million in 9.25% debentures and paid down $10 million of medium-term notes that matured. The Company repurchased $194 million of debt principal through a tender offer, which included $115 million of the 7.20 percent notes due in 2005 and $79 million of the 6.50 percent notes due in 2008. The Company also repurchased $34 million of the 7.35% notes due in 2009, $34 million of the 9.125% debentures due in 2006, $27 million of the 6.375% notes due in 2004 and $26 million of medium-term notes in varying maturities. The Company also repaid $20 million of 6.20% Industrial Development Revenue Bonds due in 2008. In total, the Company paid approximately $35 million pre-tax ($30 million after-tax) in premiums for the early redemption of debt in 2003.

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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 LP. 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. In June, 2003 the Company entered into an agreement to pay the limited partner for its minority interest in Spirit LP, the amount of which was $252 million. In July, 2003 the agreement was executed and the payment was made. In the third quarter of 2003, FASB Interpretation No. 46 would have required the Company to consolidate the limited partner, an unaffiliated investor, which would have resulted in a reclassification of $242 million of minority interests to long-term debt.

These decreases in debt and other financings were partially offset by $205 million drawn under the Overseas Private Investment Corporation (OPIC) Financing Agreement, a limited recourse loan, for the first phase of the West Seno project in Indonesia. The Company and its co-venturer completed financing arrangements for a portion of the total costs of the project through two loans arranged with OPIC. One loan is for $300 million and covers the first phase, and the other loan is for $50 million and is for the second phase. The second phase loan will be subject to further due diligence by the lender. The initial draw down of $79 million has a floating rate that is adjusted weekly, which as of December 31, 2003 was set at 1.10 percent. Subsequent 2003 draw downs of $75 million and $51 million carry fixed rates that were 2.41 percent and 2.89 percent, respectively.

At December 31, 2003, the Company had $24 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.

At December 31, 2003, consolidated debt included $350 million in unsecured senior notes, which bear interest at 7.125 percent and mature in 2011 that relates to the Company s Pure subsidiary. The notes were issued at a discount to their face value. Neither Unocal nor Union Oil guarantees any of Pure s debt.

Effective in the third quarter of 2003, FASB Interpretation No. 46 (see note 2 for further details) required the Company to consolidate assets and liabilities and results of operations of DSPL, resulting in the reporting of an additional $74 million as long-term debt on the consolidated balance sheet. Neither UGI nor the Company has guaranteed DSPL s debt obligations, which are non-recourse.

The Company has two credit facilities in place: a $400 million 364-day credit agreement, which is due to terminate on September 30, 2004 and a $600 million credit agreement due to terminate on October 31, 2006. 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 2003.

The Company also has a 3-year $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest. At December 31, 2003, the borrowings under the credit facility translated to $227 million, using applicable foreign exchange rates, compared to

$186 million at year-end 2002.

The Company had undrawn letters of credit at year-end 2003 that approximated $44 million. The majority of these letters of credit are maintained for operational needs and are renewed yearly.

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NOTE 20 - ACCRUED ABANDONMENT, RESTORATION AND ENVIRONMENTAL LIABILITIES

Effective January 1, 2003, the Company adopted SFAS No. 143 which increased its accrued abandonment and restoration liabilities by $268 million (see note 2 for further detail). At January 1, 2003 and December 31, 2003, the Company had accrued $758 million and $710 million, respectively, in estimated abandonment and restoration costs as liabilities. The decrease in the liability account from January 1, 2003 was primarily due to $86 million associated with assets sold during the year and settlements that totaled $21 million. This was offset by accrued pre-tax accretion expense of $44 million and by $15 million in new abandonment liabilities recorded during the year. There were no material revisions to existing abandonment and restoration liabilities during 2003. The year-end 2003 liability amount represented approximately one-half of the Company s determinable abandonment and restoration costs adjusted for inflation.

At December 31, 2003 and 2002, the Company s reserve for environmental remediation obligations totaled $252 million and $245 million, respectively, of which $118 million at year-end 2003 and $113 million at year-end 2002 were included in current liabilities. The reserve, at December 31, 2003 and 2002, included estimated probable future costs of $15 million and $17 million, respectively, for federal Superfund and comparable state-managed multi-party disposal sites; $28 million and $37 million, respectively, for active sites owned and/or controlled by the Company and utilized in its present operations; $99 million and $104 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 $110 million and $87 million, respectively, for Company-owned or controlled sites where facilities have been closed or operations shut down.

NOTE 21 - OTHER FINANCIAL INFORMATION

The consolidated balance sheet included the following:

	At December 31,	
Millions of dollars	**2003**	**2002**
Other deferred credits and liabilities:		
Postretirement medical benefits	$ 242	$ 223
Pension and other employee benefits	194	182
Advances related to future production	122	110
Reserves for litigation and other claims	129	131
Derivative and commodity contract liabilities	122	150
Other	151	106
Total other deferred credits and liabilities	$ 960	$ 902
Allowances for doubtful accounts and notes receivables	$ 88	$ 26
Allowances for investments and long-term receivables	$ 11	$ 3

Pension and other employee benefits included $91 million and $103 million at December 31, 2003 and 2002, respectively, to recognize the minimum pension liability for the Company s U.S. Qualified Retirement Plan. These amounts reflect the excess of the accumulated benefit obligation for vested current and former employees over the fair value of plan assets. See note 17 for a full discussion of the minimum pension liability for the Company s U.S. Qualified Retirement Plan.

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NOTE 22 - 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 2003, approximately $49 million related to deliveries scheduled to be made in the years 2005 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 2004. At December 31, 2003, the Company had in place an irrevocable surety bond in the amount of $80 million and letters of credit in the amount of $16 million, securing its performance under the sales contract.

NOTE 23 - MINORITY INTERESTS

At December 31, 2003, the Company s minority interests on the consolidated balance sheet were $39 million, a decrease of $236 million from 2002. This decrease was primarily due to the payment of the limited partner s minority interest in Spirit LP in July 2003 for $252 million. Spirit LP was formed in 1999 when the Company contributed fixed-price overriding royalty interests, valued at $304 million, from its working interest shares in certain oil and gas producing properties in the Gulf of Mexico to the partnership. An unaffiliated investor contributed $250 million in cash to the partnership and received a priority allocation of profits and cash distributions.

At December 31, 2003, the $39 million reflected in minority interests included amounts relating to the outside interests of certain oil and gas, carbon, and real estate entities. Along with these entities, the amount in minority interests included the outside interest in DSPL, which was consolidated in the third quarter of 2003 as required by FASB Interpretation No. 46 (see notes 2 and 18 for further details).

NOTE 24 - 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 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 20, at December 31, 2003, the Company had accrued $252 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 $205 million. The amount of such possible additional costs reflects the aggregate of the high ends of the ranges of costs of feasible alternatives identified by the Company for those sites with respect to which investigation or feasibility studies have advanced to the stage of analyzing such alternatives. However, such estimated possible additional costs are not an estimate of the total remediation costs beyond the amounts reserved, because there are sites where the Company is not yet in a position to estimate all, or in some cases any, possible additional costs. Both the amounts reserved and estimates of possible additional costs may change in the near term, and in some cases could change substantially, as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties.

During 2003, cash payments of $85 million were applied against the reserves and $92 million in provisions were added to the reserves. Possible additional remediation costs decreased by $40 million in 2003. The accrued costs and the possible additional costs are shown below for four categories of sites:

	At December 31, 2003	
Millions of dollars	**Reserve**	**Possible Additional Costs**
Superfund and similar sites	$ 15	$ 15
Active Company facilities	28	30
Company facilities sold with retained liabilities and former Company-operated sites	99	75
Inactive or closed Company facilities	110	85
Total	$ 252	$ 205

The time frames 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 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.

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At the sites where the Company has contractual agreements to share remediation costs with third parties, the reserve reflects the Company s estimated shares 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 sites. In many cases where the Company sold facilities or a business to a third party, sharing of remediation costs for those sites may be included in the sales agreement.

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

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

The Company facilities sold with retained liabilities 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 these categories of sites was the result of former industrial chemical and polymers manufacturing and distribution facilities, agricultural chemical retail businesses and ferromolybdenum production operations.

Superfund and similar sites - 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 December 31, 2003, the Company had received notifications 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, six 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 s potential liability appears to be de minims. Of the remaining 18 sites, where the Company has concluded that liability is probable and to the extent costs can be reasonably estimated, a reserve of $11 million has been established for future remediation and settlement costs.

Various state agencies and private parties had identified 20 other similar PRP sites. Six sites are under investigation and/or litigation and the Company s potential liability is not presently determinable and at three sites the Company s potential liability appears to be de minimis. Where the Company has concluded that liability is probable and to the extent costs can be reasonably estimated at the remaining 11 sites, a reserve of $4 million has been established for future remediation and settlement costs.

The sites discussed above exclude 123 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.

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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 $28 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. The Company recorded provisions of $7 million during 2003 for the Active Company facilities category of sites. The provisions were primarily for the remedial investigation and feasibility study (RI/FS) being performed at a molybdenum mine located in Questa, New Mexico, that is owned by the Company s Molycorp, Inc. (Molycorp) subsidiary. Molycorp has been working closely with the U.S. Environmental Protection Agency and the State of New Mexico in conducting the RI/FS at the mine during the year. The RI/FS is being performed to determine if past mining operations have had an adverse impact on the environment. Numerous additions and changes to the RI/FS scope have been required by the agencies, which will require a higher level of effort than originally projected.

The Company made payments of $13 million for this category of sites in 2003.

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 reserve represents 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 $99 million for this group of sites. During 2003, provisions of $46 million for the Company facilities sold with retained liabilities and former Company-operated sites category were recorded. These provisions included the estimated cleanup costs for oil fields located in Michigan and California that were formerly operated by the Company. The estimated costs are based on assessments recently performed at the sites, higher than anticipated volumes of contaminated soil at existing sites and higher remediation costs for soil excavation and disposal than originally anticipated. The provisions for this category of sites were also the result of revised remediation cost estimates that were identified during 2003 for service station sites and distribution facilities formerly operated by the Company.

Provisions were also recorded for auto/truckstop sites that were sold by the Company in 1993. In December 2003, an agreement was reached with the owner of certain of these auto/truckstops indemnifying the Company from future remediation liabilities and obligations related to these sites in exchange for a cash payment and payment for insurance coverage for unforeseen future environmental exposure that may arise from contamination that existed prior to the original sale of the sites. The agreement was finalized in January 2004. In addition, the Company received revised remediation cost estimates 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.

Payments of $53 million were made during 2003 for sites in this category.

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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.

A reserve of $110 million has been established for these types of facilities. During 2003, the Company accrued $38 million related to sites in this category primarily for the Guadalupe oil field and for remediation projects at the Beaumont Refinery. For the Guadalupe oil field site, it was determined that contaminated soil excavated from the site will be taken to an offsite landfill for disposal. The soil is contaminated with diluent, a kerosene-like additive used in the field s former operations. Previously, the Company had planned to remediate the soil on-site; however, a preliminary draft report for the ecological risk study being conducted indicates that on-site remediation is not viable. The provisions recorded for the site include the costs for the offsite disposal alternative. The provisions recorded for the Guadalupe oil field also include estimated costs for remediation work that is ongoing at the site. This work includes groundwater monitoring, operation and maintenance of remedial systems, restoration, site assessment and regulatory agency oversight and permitting procedures. The provisions for these costs are based on data from various studies and assessments that have been completed for the site in conjunction with data provided by the project management system the Company has in place.

A provision was also recorded for the Company s former Beaumont, Texas refinery. The Company has been working with the Texas Commission on Environmental Quality (TCEQ) to develop plans for closing impoundments used in the site s former operations and for other remediation projects. In 2003, the Company recorded a provision for the revised estimated costs of the impoundment closure plan based on the TCEQ initial draft permit that was issued for the site.

Payments of $17 million were made during 2003 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 facility in Beaumont, Texas, a former agricultural chemical facility in Corcoran, California, and Molycorp s facility in Washington, Pennsylvania. 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. As previously discussed, remediation reserves for these sites are included in the Active Company facilities and Inactive or closed Company facilities categories and total $113 million at

December 31, 2003. 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 $55 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 represents 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

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 natural 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 in the Purchase and Sale Agreement for the plant (the PSA) 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 addition, Agrium seeks a declaration by the arbitral panel that has been convened (see below) that natural gas from Unocal s Ninilchik, Happy Valley fields or elsewhere should be delivered to the plant to meet Unocal s alleged obligations under the GPSA.

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 $17 million plus interest accrued

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subsequent to May 2002. Unocal is also seeking over $900,000 in reliability bonuses due under the GPSA and reimbursement of over $5 million in royalties paid to the State of Alaska.

The GPSA contains a contractual limit on liquidated damages of $25 million per year, not to exceed a total of $50 million over the life of the agreement. In addition, the PSA contains a limit on damages of $50 million. The Company believes it has a meritorious defense to each of the Agrium claims, but that in any event its exposure to damages for all disputes is limited by the agreements. Agrium alleges that it is entitled to recover damages in excess of those amounts. On July 16, 2003, the court approved an agreed stipulation between the parties to submit all issues under the GPSA to arbitration. The arbitration proceedings are scheduled to commence May 24, 2004. Discovery is now proceeding.

Petrobangla Claim:

In July 2002, the Company s subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. (Unocal Blocks 13 and 14 Ltd.) received a letter from the Bangladesh Oil, Gas & Mineral Corporation (Petrobangla) 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 Occidental Petroleum Corporation (known at that time in Bangladesh as Occidental of Bangladesh Ltd.) (OBL), as operator, of the Moulavi Bazar #1 (MB #1) exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout.

Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractor s 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 (the Supplemental Agreement), 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 (Unocal Bangladesh)) of entitlement to the recovery of costs incurred in the drilling of the MB #1 and 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 present or development is not feasible deemed commercial, from other commercial fields in the Moulavi Bazar ring-fenced area of Block 14. Consequently, the Company and OBL consider the matter closed and Unocal Blocks 13 and 14 Ltd. has advised Petrobangla that no additional compensation is warranted. By Writ Petition Affidavit dated March 24, 2003, a concerned citizen filed suit in the Bangladesh lower court (*Alam v. Bangladesh, Petrobangla, Department of Environment, and Unocal Bangladesh, Ltd.*, Supreme Court of Bangladesh, High Court Division, Writ Petition No. 2461 of 2003) on the basis of the MB #1 blowout. The Company was notified of the suit on May 26, 2003 when it received the court s order to show cause why the Supplemental Agreement should not be declared illegal and cancelled on account of its having been executed without lawful authority, and why Unocal Bangladesh should not be directed to stop exploration until it compensates for the MB#1 blowout. No hearing is currently scheduled on the matter, and the Company believes the action is not well founded.

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. On June 30, 2003, Nuevo filed suit against Unocal in the U.S. District Court for the Central District of California, Case No. 03-4664 (RCx). Nuevo seeks $10.8 million, the amount Nuevo alleges it paid Unocal in error. Nuevo also seeks a declaratory judgment regarding its right to take deductions in calculating the contingent payment in the future. Unocal has counterclaimed, seeking in excess of $16 million for amounts owed from 2002 under the contingent payment agreement and for a declaratory judgment regarding the rights and relations of Unocal and Nuevo under that agreement. The case is scheduled to go to trial May 11, 2004.

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 impacts not only the year in which the items arose, but also the Company s tax situation in other tax years. With respect to 1979-1994 taxable years, all issues raised for these years have now been tentatively settled with the Appeals division of the Internal Revenue Service (IRS) as well as the Tax Court, including the carryback of a 1993 net operating loss (NOL) to tax year 1984 and resultant credit adjustments. The 1993 NOL resulted from certain specified liability losses described in Internal Revenue Code Section 172. Since the audit of the 1979-1994 taxable years resulted in a net overpayment of income taxes for the period, the Joint Committee on Taxation of the U.S Congress must review the claim. Once notification from the Joint Committee is received, taxable years 1979-1994 will be effectively closed as a single package, pending entry of final decisions in Tax Court for the docketed years, to assure that interest is properly computed under the complex rules, which govern netting of interest. All such developments have been considered in the Company s accounts. The 1995-1997 taxable years are before the Appeals division of the IRS. The 1998- 2001 taxable years are now before the Exam division of the IRS.

Guarantees Related to Assets or Obligations of Third Parties

The Company has agreed to indemnify 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 the fact that 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, 2003, the reserve for this category totaled $99 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 ratably through the year 2014. The maximum potential amount of future payments the Company could be required to make is approximately $19 million.

In the ordinary course of business, the Company has agreed to indemnify 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.

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Financial Assurance for Unocal Obligations

In the normal course of business, the Company has performance obligations that 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 and are required to be reimbursed by the Company if drawn upon. At December 31, 2003, the Company had obtained various surety bonds for approximately $191 million. These surety bonds included a bond for $80 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 $111 million in various other routine performance bonds held by local, city, state and federal agencies. The Company also had obtained approximately $44 million in standby letters of credit at December 31, 2003, of which $16 million represented additional collateral related to the aforementioned fixed price natural gas sales contract. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit.

The Company has various other guarantees for approximately $553 million. Approximately $134 million of the $553 million in guarantees represent 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.

Guarantees for approximately $333 million of the $553 million 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 $155 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.

Other matters

The Company has a lease agreement relating to the *Discoverer Spirit* deepwater drillship, with a current minimum daily rate of approximately $226,000. The future remaining minimum lease payment obligation was approximately $140 million at December 31, 2003. The contract will expire on September 18, 2005.

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.

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NOTE 25 - 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 common securities of the Trust, which have been retained by Unocal, and the convertible preferred securities represent undivided beneficial interests in the debentures, which constitute substantially all of the assets of the Trust. The numbers of convertible preferred securities outstanding were 10,437,105 on December 31, 2003 and December 31, 2002.

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 101.875 percent (since September 1, 2003), 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.

Pursuant to FASB Interpretation No. 46, Consolidation of Variable Interest Entities, as revised in December 2003, the Company will be required to deconsolidate the Trust in the first quarter of 2004. As a result, the $522 million obligation for the convertible preferred securities will be removed from the consolidated balance sheet and replaced by a non-current liability for the $538 million in 6-1/4% convertible junior subordinated debentures of Unocal payable to the Trust. In addition, the Company will also record its $16 million investment in the Trust in investments and long-term receivables-net on the consolidated balance sheet. Interest payments on the debentures will be recorded as interest expense on the consolidated earnings statement in 2004. See note 2 for additional information regarding the Trust and the accounting change.

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NOTE 26 - CAPITAL STOCK

Common Stock

Authorized - 750,000,000

$1.00 Par value per share

Thousands of shares	At December 31, 2003	2002	2001
Outstanding at beginning of year	257,980	243,998	243,044
Issuance of common stock in exchange for Pure Resources, Inc. common stock		13,247	
Other issuances of common stock [(a)]	2,614	735	954
Outstanding at end of year	260,594	257,980	243,998

(a) net of cancellations

At December 31, 2003, there were approximately 12.3 million shares reserved for the conversion of Unocal Capital Trust convertible preferred securities, 22.6 million shares for the Company s employee benefit plans and Directors plans and 2.6 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, 2003, 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, 2003, 2002 or 2001. 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 through 2003, 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 (30 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 27 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 $27 million at December 31, 2003 and $35 million at December 31, 2002, and was reflected as a reduction to stockholders equity on the consolidated balance sheet. During 2003, accrued interest of $2 million was offset by payments from the officers of $10 million.

The Company s Pure subsidiary also had a loan program for certain of its officers and key employees, with a balance of $2 million at December 31, 2002. These loans were repaid during 2003.

NOTE 28 - 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 2,481,774 shares with a weighted average exercise price of $18.50 and a weighted average remaining life of 6 years were outstanding at December 31, 2003. 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.

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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 the Company s Pure subsidiary 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.

Performance share awards outstanding at year-end 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, unless distributed upon a qualified termination. 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, death, disability or upon reaching normal retirement age.

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.

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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, 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
Options outstanding at January 1, 2003	15,779,046	$ 30.11	$
Options granted during year	2,327,270	27.07	27.07
Options exercised during year	(2,650,973)	22.37	
Options canceled/forfeited during year	(1,125,565)	34.59	
Options outstanding at December 31, 2003	14,329,778	30.70	
Options exercisable at December 31, 2003	11,199,831	30.70	
Restricted stock awarded during year	51,003		30.07
Performance shares awarded during year	250,024		30.39

Significant option groups outstanding at December 31, 2003 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	1,241,805	5.8	$ 12.83	1,241,805	$ 12.83

$19.82 - $24.99	1,057,797	6.3	$ 23.50	1,057,797	$ 23.50
$25.18 - $30.94	3,843,138	7.3	$ 27.54	2,168,593	$ 27.89
$31.07 - $36.88	5,455,279	6.7	$ 34.63	4,024,541	$ 34.59
$37.03 - $45.25	2,731,759	4.0	$ 38.19	2,707,095	$ 38.18

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The estimated fair value at date of grant of options for common stock granted in 2003, 2002 and 2001, using the Black-Scholes option pricing model is as follows:

	2003	2002	2001
Weighted-average fair value of common stock options granted during the year	**$ 6.20**	**$ 9.35**	**$ 9.22**
Assumptions:			
Expected life (years)	4.5	4.5	4.5
Expected volatility	31.7%	32.7%	30.5%
Expected dividend yield	3.0%	2.2%	2.2%
Risk-free interest rate	2.9%	4.3%	4.6%

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 29 - 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, 2003, the Company had approximately $22 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, $3 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, 2003, the Company had no deferred amounts in accumulated other comprehensive income on the consolidated balance sheet related to foreign currency contracts.

Commodity hedging activities The Company uses hydrocarbon derivatives to mitigate its overall exposure to fluctuations in hydrocarbon commodity prices. The Company recognized $2 million of gains due to ineffectiveness for cash flow and fair value hedges in 2003. At December 31, 2003, the Company had approximately $10 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 2004 through December 2004. All of the 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 $3.17 billion and $3.35 billion at year-end 2003 and 2002, 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 $532 million and $535 million at year-end 2003 and 2002, respectively. Fair values were based on the trading prices of the preferred securities on December 31, 2003 and 2002.

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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 2003, 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, 2003, 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, 2003, the Company had a $182 million note receivable from URC (see note 12 for further details). The Company did not have any customers that accounted for 10 percent or more of its consolidated net trade receivable balance, excluding the URC note, at December 31, 2003. The Company s highest account receivable balance with one customer was approximately $95 million from PTT Public Co., Ltd. This amount primarily represented payments due for sales of natural gas and crude oil from the Company s Gulf of Thailand and offshore Myanmar operations.

At December 31, 2003, the Company s business unit in Bangladesh had a gross receivable balance of approximately $26 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 March 2003 through November 2003. The Company continues to work with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables.

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NOTE 30 - SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiaries Unocal Capital Trust (see note 25 for further details) 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 2003, 2002 and 2001 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, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non - Guarantor Subsidiaries	Eliminations	Consolidated
Revenues						
Sales and operating revenues	$	$	$ 1,566	$ 5,965	$ (1,136)	$ 6,395
Interest, dividends and miscellaneous income		34	25	3	(37)	25
Gain (loss) on sales of assets			22	91	6	119
Total revenues		34	1,613	6,059	(1,167)	6,539
Costs and other deductions						
Purchases, operating and other expenses	10		1,166	4,012	(1,130)	4,058
Depreciation, depletion and amortization			314	674		988
Impairments			22	71		93
Dry hole costs			79	49		128
Interest expense	33	1	160	33	(37)	190
Distributions on convertible preferred securities		33				33
Total costs and other deductions	43	34	1,741	4,839	(1,167)	5,490
Equity in earnings of subsidiaries	677		857		(1,534)	
Earnings from equity investments			7	185		192
Earnings from continuing operations before income taxes and minority interests	634		736	1,405	(1,534)	1,241
Income taxes	(9)		20	511		522
Minority interests				9		9
Earnings from continuing operations	643		716	885	(1,534)	710
Earnings from discontinued operations			16			16
Cumulative effect of accounting change			(55)	(28)		(83)
Net earnings	$ 643	$	$ 677	$ 857	$ (1,534)	$ 643

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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

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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

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CONDENSED CONSOLIDATED BALANCE SHEET

At December 31, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non - Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash and cash equivalents	$ 1	$	$ 45	$ 358	$	$ 404
Accounts and notes receivable - net	94		360	946	(108)	1,292
Inventories			15	205	(79)	141
Other current assets	(1)		127	28		154
Total current assets	94		547	1,537	(187)	1,991
Properties - net			2,012	6,315	(3)	8,324
Other assets including goodwill	4,645	541	5,433	1,564	(10,700)	1,483
Total assets	$ 4,739	$ 541	$ 7,992	$ 9,416	$ (10,890)	$ 11,798
Liabilities and Stockholders Equity						
Current liabilities						
Accounts payable	$	$	$ 335	$ 831	$ (94)	$ 1,072
Current portion of long-term debt and capital leases			193	55		248
Other current liabilities	52	3	299	427	(16)	765
Total current liabilities	52	3	827	1,313	(110)	2,085
Long-term debt and capital leases			1,811	824		2,635
Deferred income taxes			(184)	888		704
Accrued abandonment, restoration and environmental liabilities			390	454		844
Other deferred credits and liabilities			654	309	(3)	960
Minority interests				32	7	39
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures		522				522
Stockholders equity	4,687	16	4,494	5,596	(10,784)	4,009
Total liabilities and stockholders equity	$ 4,739	$ 541	$ 7,992	$ 9,416	$ (10,890)	$ 11,798

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CONDENSED CONSOLIDATED BALANCE SHEET

At December 31, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union 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
Properties - net			2,255	5,624		7,879
Other assets including goodwill	4,024	541	4,955	1,076	(9,004)	1,592
Total assets	$ 4,079	$ 541	$ 7,563	$ 7,741	$ (9,078)	$ 10,846
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			594	312	(4)	902
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
Total liabilities and stockholders equity	$ 4,079	$ 541	$ 7,563	$ 7,741	$ (9,078)	$ 10,846

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CONDENSED CONSOLIDATED CASH FLOWS

Year ended December 31, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non - Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flows from Operating Activities	$ 150	$	$ 565	$ 1,234	$	$ 1,949
Cash Flows from Investing Activities						
Capital expenditures and acquisitions (includes dry hole costs)			(467)	(1,251)		(1,718)
Proceeds from sales of assets and discontinued operations			377	276		653
Net cash used in investing activities			(90)	(975)		(1,065)
Cash Flows from Financing Activities						
Change in long-term debt and capital leases			(414)	167		(247)
Dividends paid on common stock	(207)					(207)
Minority interests				(257)		(257)
Other	58		2	3		63
Net cash used in financing activities	(149)		(412)	(87)		(648)
Increase in cash and cash equivalents	1		63	172		236
Cash and cash equivalents at beginning of year			(18)	186		168
Cash and cash equivalents at end of year	$ 1	$	$ 45	$ 358	$	$ 404

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

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CONDENSED CONSOLIDATED CASH FLOWS

Year ended December 31, 2001

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

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NOTE 31 - 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 2003, $860 million, or approximately 13 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.

At the end of 2003, the Company had $131 million of goodwill recorded in its consolidated balance sheet. This amount included $92 million related to two acquisitions in North America made in 2002, which included $80 million in conjunction with the acquisition of the minority interests of Pure. The Company also 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, 2003, no such impairments had been recorded.

Trade Segment - The Trade segment externally markets most of the Company s worldwide liquids production and North American natural gas production, excluding production of 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 liquids 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 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.

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 U.S., 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 geothermal steam-fired power plants in Indonesia and equity interests in three 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.

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

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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

2003 Segment Information	**Exploration & Production**							
Millions of dollars	**North America**				**International**			
	U.S. Lower 48	**Alaska**	**Canada**	**Total N.A.**	**Far East**	**Other**	**Total Int l**	**Total E&P**
Sales & operating revenues	$ 622	$ 258	$ 176	$ 1,056	$ 1,256	$ 281	$ 1,537	$ 2,593
Other income (loss) [(a)]	96		12	108	(1)	(1)	(2)	106
Inter-segment revenues	1,128		145	1,273	293		293	1,566
Total	1,846	258	333	2,437	1,548	280	1,828	4,265
Depreciation, depletion & amortization	402	53	117	572	290	58	348	920
Impairments	83			83	2		2	85
Dry hole costs	89	2	6	97	31		31	128
Exploration expense								
Amortization of exploratory leases	82		19	101	4	3	7	108
Earnings (loss) from equity investments	14			14	40	6	46	60
Earnings (loss) from continuing operations before income taxes and minority interests	557	90	103	750	814	140	954	1,704
Income taxes (benefit)	214	33	24	271	348	45	393	664
Minority interests	5			5				5
Earnings (loss) from continuing operations	338	57	79	474	466	95	561	1,035
Discontinued operations (net)								
Cumulative effect of accounting changes	11	(43)	5	(27)	12		12	(15)
Net earnings (loss)	349	14	84	447	478	95	573	1,020
Capital expenditures and acquisitions	515	41	133	689	573	261	834	1,523
Assets	2,969	346	1,324	4,639	3,146	996	4,142	8,781
Equity investments					18	151	169	169

	Trade	**Midstream**	**Geothermal & Power Operations**	**Corporate & Other**				**Total**
				Admin & General	**Net Interest Expense**	**Environmental & Litigation**	**Other** [(b)]	

Sales & operating revenues	$ 2,919	$ 552	$ 149	$	$	$	$ 182	$ 6,395
Other income (loss) [a]	(2)	7	2		8		23	144
Inter-segment revenues	6	9					(1,581)	
Total	2,923	568	151		8		(1,376)	6,539
Depreciation, depletion & amortization	1	11	24				32	988
Impairments		8						93
Dry hole costs								128
Exploration expense								
Amortization of exploratory leases								108
Earnings (loss) from equity investments	2	65	12				53	192
Earnings (loss) from continuing operations before income taxes and minority interests	(4)	86	83	(128)	(181)	(151)	(168)	1,241
Income taxes (benefit)	(2)	13	27	(36)	(36)	(49)	(59)	522
Minority interests			6				(2)	9
Earnings (loss) from continuing operations	(2)	73	50	(92)	(145)	(102)	(107)	710
Discontinued operations (net)							16	16
Cumulative effect of accounting changes		(2)					(66)	(83)
Net earnings (loss)	(2)	71	50	(92)	(145)	(102)	(157)	643
Capital expenditures and acquisitions		138	21				36	1,718
Assets	395	702	611				1,309	11,798
Equity investments	16	318	67				80	650

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

(b) Includes eliminations and consolidation adjustments.

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SEGMENT DATA (continued)

2002 Segment Information

Millions of dollars

	Exploration & Production							
	North America				International			
	U.S. Lower 48	Alaska	Canada	Total N.A.	Far East	Other	Total Int l	Total E&P
Sales & operating revenues	$ 509	$ 251	$ 207	$ 967	$ 1,062	$ 151	$ 1,213	$ 2,180
Other income (loss) [a]	(27)		(1)	(28)	1	1	2	(26)
Inter-segment revenues	825			825	238	116	354	1,179
Total	1,307	251	206	1,764	1,301	268	1,569	3,333
Depreciation, depletion & amortization	479	63	97	639	239	48	287	926
Impairments	17	24		41				41
Dry hole costs	53	17	9	79	23	5	28	107
Exploration expense								
Amortization of exploratory leases	55	1	18	74	1	23	24	98
Earnings (loss) from equity investments	2			2	33	7	40	42
Earnings (loss) from continuing operations before income taxes and minority interests	58		3	61	731	103	834	895
Income taxes (benefit)	10		3	13	300	31	331	344
Minority interests	15			15				15
Earnings (loss) from continuing operations	33			33	431	72	503	536
Discontinued operations (net)								
Cumulative effect of accounting changes								
Net earnings (loss)	33			33	431	72	503	536
Capital expenditures and acquisitions	544	72	147	763	626	157	783	1,546
Assets	3,358	326	1,113	4,797	2,861	821	3,682	8,479
Equity investments	146			146	23	174	197	343

				Corporate & Other				
	Trade	Midstream	Geothermal & Power Operations	Admin & General	Net Interest Expense	Environmental & Litigation	Other [b]	Total
Sales & operating revenues	$ 2,524	$ 276	$ 120	$	$	$	$ 124	$ 5,224
Other income (loss) [a]	(1)	52	(3)		17		34	73

Inter-segment revenues	1	12					(1,192)	
Total	2,524	340	117		17		(1,034)	5,297
Depreciation, depletion & amortization	1	11	18					