UNOCAL CORP
Form 10-K
March 08, 2005
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004

Commission file number 1-8483

UNOCAL CORPORATION

(Exact name of registrant as specified in its charter)

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

2141 Rosecrans Avenue, Suite 4000, El Segundo, California 90245

(Address of principal executive offices)

(310) 726-7600

(Registrant s telephone number, including area code)

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

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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. ¨

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

The aggregate market value of the common stock held by non-affiliates of the registrant as of June 30, 2004 (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 $10.0 billion.

Shares of registrant s common stock outstanding as of February 28, 2005: 270,571,829

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive proxy statement for its 2005 annual meeting of stockholders (expected to be filed with the Securities and Exchange Commission on or about April 11, 2005) are hereby incorporated by reference into Part III hereof as indicated in Part III.

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GLOSSARY

Below are definitions of certain common industry terms that may be used in this Form 10-K:

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

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

Bilateral institution refers to a country specific institution that 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 crude oil and natural gas amounts using a standard measurement. Natural gas volumes are converted to barrels of oil equivalent on the basis of 6,000 cubic feet of natural 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 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 our share of the cost recovery revenue and the profit revenue is divided by market oil and gas prices and represents the volume to which we are entitled. 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 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 agrees to pay a portion of past or future costs. 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 field. Produced fluids are brought by flowlines to the vessel where they are separated, or treated, or stored and then offloaded to another vessel or pipeline for transportation.

Gross acres or gross wells are the total acres or wells in which we have a working interest.

Hydrocarbons are organic compounds of hydrogen and carbon atoms that form the basis of all petroleum products.

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Lifting is the amount of liquids each working-interest partner takes physically. The liftings may 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 pressurization 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 our working interest percentage in the properties.

Net pay is the amount of oil or gas saturated rock capable of producing oil or gas.

Net working interest is a working interest after deducting royalties and other economic interests payable to third parties. Our net working interest may vary over time due to changes in commodity prices, costs and other factors.

OPEC is the abbreviation for Organization of Petroleum Exporting Countries.

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.

Production Sharing Contract (PSC) is a contractual agreement between us and a host government whereby we, act as contractor, bear exploration, development and production costs in return for an agreed upon share of the proceeds from the sale of production.

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 crude 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 crude 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. In some contracts, 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/or prospects.

Working interest (WI) is the percentage of ownership we have in a joint venture, partnership, consortium, project or acreage. Our working interest does not necessarily equal our share of revenues or production. See Net working interest definition above.

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.

For the purpose of this report, the terms Unocal, Union Oil, we, our, its and the Company refer to Unocal Corporation (Unocal) and its consolidated subsidiaries, including Union Oil Company of California (Union Oil), unless the context otherwise provides.

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FORWARD-LOOKING STATEMENTS

This cautionary note is provided pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are included in this report and may be included in other public filings, press releases, our website and oral and written presentations by management. Statements other than historical facts are forward-looking and may be identified by words such as expects, anticipates, intends, plans, believes, estimates, fore could, will and words of similar meaning. Examples of these types of statements include those regarding:

- estimates of oil and gas reserves recoverable in future years and related future net cash flows,
- assessments of hydrocarbon formations and potential resources,
- exploration, development and other plans for future operations,
- production rates, timing and costs and sales volumes and prices,
- revenues, earnings, cash flows, liabilities, capital expenditures and other financial measures,
- anticipated liquidity,
- the amount and timing of environmental and other contingent liabilities, and
- other statements regarding future events, conditions or outcomes.

Although these statements are based upon our current expectations and beliefs, they are subject to known and unknown risks and uncertainties that could cause actual results and outcomes to differ materially from those described in, or implied by, the forward-looking statements. In that event, our business, financial condition, results of operations or liquidity could be materially adversely affected and investors in our securities could lose part or all of their investments. These risks and uncertainties include, for example:

- volatility in commodity prices,
- our ability to find or acquire commercially productive reservoirs and to develop and produce deepwater and other projects in a timely and cost-effective manner,
- the accuracy of our estimates and judgments regarding hydrocarbon resources and formations and reservoir performance,
- operational risks inherent in the exploration, development and production of oil and gas,

- the impact of environmental laws, permitting and licensing requirements and other regulations,
- international and domestic political and economic factors, and
- other factors discussed in our Risk Factors section in Part II, Item 7 of this report.

We undertake no obligation to update the forward-looking statements in this report or in other documents, our website or oral statements to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

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PART I

ITEMS 1 AND 2 - BUSINESS AND PROPERTIES.

Information required under Items 1 and 2 are presented together in the following discussion and should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in Item 7 of this report, including the Risk Factors, and the cautionary note under Forward-Looking Statements.

We make available free of charge on or through our Internet website our annual reports on Form 10-K, annual proxy statements, 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 or furnished to the Securities and Exchange Commission (SEC). Our Internet address is http://www.unocal.com. We will also make available to any stockholder, without charge, copies of our annual report on Form 10-K as filed with the SEC. For copies of this report, or any other filings, please contact: Unocal Stockholder Services, 2141 Rosecrans Avenue, Suite 4000, El Segundo, California 90245 or call (800) 252-2233.

Unocal Corporation was incorporated in Delaware in 1983 to operate as the parent entity of Union Oil Company of California, which was incorporated in California in 1890. Virtually all of our operations are conducted by Union Oil and its subsidiaries.

We are one of the world s leading independent oil and gas exploration and production companies, with principal operations in North America and Asia. We are 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 of hydrocarbon commodities.

STRATEGIC FOCUS

Our strategy is to create value for our stockholders by advancing worldwide oil and gas development projects and delivering successful exploration results through the drill bit. We seek to create stockholder value while maintaining a strong balance sheet. Key elements of our strategy include:

- maintaining focus on high-impact exploration and growth,
- maintaining capital discipline, controlling costs and improving efficiency across our businesses,
- achieving world-class status in our safety processes, systems and record,

leveraging advantaged positions in the Gulf of Thailand and deepwater Indonesia,

building large-scale businesses in Azerbaijan, Bangladesh and Vietnam,

pursuing Asian regional expansion via farm-ins, new PSCs and concession agreements and selective asset acquisitions,

continuing our exploration and development efforts in the Gulf of Mexico deepwater, and

maintaining a profitable and sustainable North American business.

SEGMENT AND GEOGRAPHIC INFORMATION

In 2004, we modified our reporting segments. In our reporting of the Exploration and Production segment: (1) we combined the Alaska business unit with the U.S. Lower 48 to form the U.S. geographic designation under North America and (2) we now present Asia and Other instead of the previous categories of Far East and Other under International. In addition, the former Trade segment has been combined with the Midstream segment to form the Midstream and Marketing segment. Financial information relating to our business segments, geographic areas of operations, and sales revenues by classes of products is presented in note 29 to the consolidated financial statements in Item 8 of this report and in the selected financial data section in Item 6 of this report.

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Exploration and Production

Our primary activities are oil and gas exploration, development and production. These operations are conducted in North America, Asia and other locations around the world. In 2004, our net worldwide average production was approximately 159 MBbl/d of liquids and 1,510 MMcf/d of natural gas, primarily from the Gulf of Thailand, offshore East Kalimantan, Indonesia, U.S. onshore, offshore in the U.S. Gulf of Mexico and Canada.

Approximately 33 percent of our worldwide production in 2004 and 26 percent of our worldwide proved oil and gas reserves at year-end 2004 were in the U.S. Exploration and production net properties accounted for approximately 91 percent of our total net properties at December 31, 2004. Exploration and production properties in the U.S., as a percentage of total exploration and production properties, were 36 percent at year-end 2004.

We report all reserve and production data pursuant to PSCs utilizing the economic interest method, which excludes host country shares. We also report 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 estimate data and the related estimated present value of future net cash flows from oil and gas operations is presented on pages 138 through 147 of this report. During 2004, certain of our estimates of U.S. underground oil and gas reserves as of December 31, 2003, were filed with the U.S. Department of Energy and various state agencies under the name of Union Oil. Such estimates were essentially identical to the corresponding estimates of such reserves at December 31, 2003, included in this report.

Estimated Net Proved Reserves

Our estimated net quantities of proved liquids and natural gas reserves at December 31, 2004, 2003 and 2002, including our proportional shares of the reserves of equity investees, were as follows:

	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2004							
Liquids - million barrels	218	60	**278**	177	204	**381**	**659**
Natural gas - billion cubic feet	1,377	297	**1,674**	4,812	82	**4,894**	**6,568**
Barrels oil equivalent - millions	447	110	**557**	980	217	**1,197**	**1,754**
2003							
Liquids - million barrels	211	57	**268**	220	187	**407**	**675**
Natural gas - billion cubic feet	1,578	315	**1,893**	4,532	80	**4,612**	**6,505**
Barrels oil equivalent - millions	474	109	**583**	975	200	**1,176**	**1,759**
2002							
Liquids - million barrels	239	56	**295**	203	183	**386**	**681**
Natural gas - billion cubic feet	2,076	306	**2,382**	4,093	84	**4,177**	**6,559**
Barrels oil equivalent - millions	585	107	**692**	885	197	**1,082**	**1,774**

There were de minimis amounts of proved reserves attributable to minority interests at December 31, 2004 and 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.

There were no amounts attributable to our proportional shares of reserves of equity investees at December 31, 2004. The year-end 2003 and 2002 proved reserves included amounts attributable to our proportional shares of equity investees of approximately 2 million and 7 million barrels of liquids, respectively, and 44 billion and 227 billion cubic feet of natural gas, respectively.

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

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Net Daily Production

Our net quantities of daily liquids and natural gas production for the years 2004, 2003 and 2002, including our proportional shares of production of equity investees, were as follows:

	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2004							
Liquids - thousand barrels	54	16	**70**	70	19	**89**	**159**
Natural gas - million cubic feet	495	83	**578**	912	20	**932**	**1,510**
Barrels oil equivalent - thousands	136	30	**166**	222	23	**245**	**411**
2003							
Liquids - thousand barrels	64	17	**81**	59	20	**79**	**160**
Natural gas - million cubic feet	673	90	**763**	941	24	**965**	**1,728**
Barrels oil equivalent - thousands	176	32	**208**	216	24	**240**	**448**
2002							
Liquids - thousand barrels	76	18	**94**	54	19	**73**	**167**
Natural gas - million cubic feet	795	91	**886**	920	20	**940**	**1,826**
Barrels oil equivalent - thousands	209	32	**241**	207	23	**230**	**471**

There were de minimis liquids volumes attributable to minority interests in 2004 and 2003. In 2002, the net daily production of liquids in the U.S. included volumes attributable to minority interests of approximately 7 MBbl/d. There were de minimis natural gas volumes attributable to minority interests for 2004 and 2003. In 2002, natural gas net daily production in the U.S. included volumes attributable to minority interests of approximately 82 MMcf/d.

Our liquids production included our proportional shares of equity investees of 1 MBbl/d, 2 MBbl/d and 3 MBbl/d in 2004, 2003 and 2002, respectively. In addition, our natural gas production included our proportional shares of equity investees of 10 MMcf/d, 46 MMcf/d and 58 MMcf/d in 2004, 2003 and 2002, respectively.

Oil and Gas Acreage

As of December 31, 2004, we held oil and gas rights acreage as follows:

	(Thousands of acres)			
	Proved Acreage		Prospective Acreage	
	Gross	Net	Gross	Net

United States	2,555	828	3,444	1,917
Canada	613	297	2,184	1,119
North America Total	**3,168**	**1,125**	**5,628**	**3,036**
Asia	1,314	803	23,019	10,565
Other	57	12	5,497	2,533
International Total	**1,371**	**815**	**28,516**	**13,098**
Worldwide	**4,539**	**1,940**	**34,144**	**16,134**

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Producible Oil and Gas Wells and Drilling in Progress

The numbers of oil and gas producible wells and the number of oil and gas wells in progress at December 31, 2004 were as follows:

	Drilling In Progress (a) (b)		Producible (c) Oil		Producible (c) Gas	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	60	39	5,297	2,533	1,876	1,043
Canada	20	9	1,222	618	618	323
North America Total	**80**	**48**	**6,519**	**3,151**	**2,494**	**1,366**
Asia	6	4	399	302	906	584
Other	12	1	111	41	7	4
International Total	**18**	**5**	**510**	**343**	**913**	**588**
Worldwide	**98**	**53**	**7,029**	**3,494**	**3,407**	**1,954**

(a) Excludes service wells in progress in Asia (2 gross and 0 net).
(b) We had one waterflood project under development in International Other at December 31, 2004.
(c) Includes 182 gross and 135 net producible wells with multiple completions.

Net Oil and Gas Wells Completed and Dry Holes

The following table shows the number of net productive and dry hole wells drilled to completion:

	Productive			Dry		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
Exploratory						
United States	14	9	25	4	8	20
Canada	10	14	20	7	4	9
North America Total	**24**	**23**	**45**	**11**	**12**	**29**
Asia	9	7	19	7	10	6
Other						

International Total	**9**	**7**	**19**	**7**	**10**	**6**
Worldwide	**33**	**30**	**64**	**18**	**22**	**35**
Development						
United States	91	78	56	3		1
Canada	31	51	56	4	3	8
North America Total	**122**	**129**	**112**	**7**	**3**	**9**
Asia	141	118	174	1	1	1
Other	1	4	3			
International Total	**142**	**122**	**177**	**1**	**1**	**1**
Worldwide	**264**	**251**	**289**	**8**	**4**	**10**

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Exploration and Production North America

Our E&P operations in North America are reported under United States and Canada. In 2004, North America production contributed 44 percent of our worldwide liquids production and 38 percent of our worldwide natural gas production.

United States

In 2004, U.S. E&P operations contributed 34 percent of our worldwide liquids production and 33 percent of our worldwide natural gas production. Over the past three years, our U.S. production has been declining because of asset sales and natural declines on the Gulf of Mexico shelf. These declines were a reflection of the highly prolific nature of the fields in the Gulf of Mexico shelf, which tend to have quick monetization timelines, and the effect of lower drilling activity. The increasing cost of finding new reserves has prompted us to scale back our exploration program in the shelf region, sell selected older properties and focus on a smaller group of more profitable and sustainable fields with more stable production and manageable capital requirements. Our exploration efforts in the Gulf of Mexico are now mainly focused on the deepwater areas. Our U.S. operations are grouped as follows:

Gulf of Mexico

Our Gulf of Mexico operations are primarily comprised of activities in the shelf and deepwater regions located off the coasts of Texas, Louisiana and Alabama. We hold approximately 1.1 million net acres of prospective land with nearly 96 percent of the prospective acreage located in federal offshore leases. We also hold approximately 240 thousand net acres of proved lands, of which approximately 85 percent are located in federal offshore leases. We currently hold an interest in 366 Gulf of Mexico leases including 237 deepwater exploratory leases, 62 shelf exploratory leases and 67 shelf development leases. Our deepwater exploratory leases are primarily in the Subsalt/Foldbelt trend, which lies beyond the Primary Basin deepwater trend, with a number of prospects in water depths of 5,000 feet and greater. Our net production in 2004, which was 73 percent weighted toward natural gas, averaged 54 MBOE/d. The average production in 2004 was approximately 40 percent lower than the previous year, principally as a result of the sale of non-core properties, which accounted for approximately 75 percent of the decline, with the remaining decrease due to natural field declines. A substantial portion of the crude oil and natural gas produced in the Gulf of Mexico is sold to our Midstream and Marketing business segment. The remaining production is sold to third-parties at spot market prices or under long-term contracts.

In 2004, development of the Mad Dog and K-2 fields continued on track toward completion. First production from the deepwater Mad Dog field, located in Green Canyon Block 782, began in January of 2005. We have a 15.6 percent working interest (13.3 percent net working interest) in the Mad Dog field, which is operated by BP PLC (BP). The K-2 discovery is located on Green Canyon Block 562. We hold a 12.5 percent working interest (10.9 percent net working interest) in the K-2 field, which is operated by Eni SpA (ENI). We anticipate first production in the second quarter of 2005. The estimate of initial net production for both the Mad Dog and K-2 fields combined is expected to average about 4 MBOE/d to 6 MBOE/d in the second quarter of 2005 rising to an average of 10 MBOE/d to 12 MBOE/d by the fourth quarter of 2005.

In 2004, our deepwater Gulf of Mexico drilling program completed a successful appraisal at the St. Malo discovery located on Walker Ridge Block 678. The appraisal well encountered more than 400 net feet of crude oil pay at depths greater than were encountered in the earlier discovery well in 2003. We are currently evaluating the results to optimize appraisal operations and the viability of development options, with the current objective of establishing potential commerciality in 2005. We expect to drill another appraisal of the St. Malo discovery in 2005. We are the operator at St. Malo and hold a 28.75 percent working interest.

In addition, our exploratory well at the Puma prospect, operated by BP, and located on Green Canyon Block 823, was a significant discovery in a hydrocarbon-rich area near existing developments. The well encountered approximately 500 net feet of crude oil pay in Miocene-age reservoirs. Two subsequent sidetracks encountered crude oil in reservoir intervals of a similar age. Initial indications of reservoir productivity are encouraging. As a result of the proximity of the Puma discovery to the Mad Dog field, we expect that any future development could be achieved by either a stand-alone development or a tie-back, depending on future appraisal results. The Puma discovery is structurally complex, which will require additional seismic data and appraisal drilling to determine the field s size. We hold a 15 percent working interest in the discovery.

In 2004, our exploratory well at the Tobago prospect located on Alaminos Canyon Block 859 was a discovery. The well, in which we have a 40.01 percent working interest, found about 50 net feet of crude oil pay. The discovery was one of several wells that have been drilled to date in the Alaminos Canyon area to evaluate the development potential for the Perdido Foldbelt. The Tobago discovery could become part of a larger development encompassing several recent industry discoveries, which include our nearby Trident discovery. We continue to study development options for our Trident and Tobago discoveries including discussing with other operators and our partners in the area development scenarios and joint development planning. The Trident prospect covers seven blocks in Alaminos Canyon. We are the operator of the Trident discovery and have a 59.5 percent working interest.

Drilling on several other prospects was not as successful. Our deepwater Myrtle Beach prospect located on Green Canyon Block 943 and our Sardinia prospect, a lower Tertiary test, located on Keathley Canyon Block 681, did not encounter commercial quantities of hydrocarbons. While the results of the Sardinia well were disappointing, we were encouraged by the thickness of the sandstones encountered in this lower Tertiary well. Our net costs on the Sardinia well were nominal as others paid a disproportionate share of the well cost. In addition, a second well at the Hawkes prospect on Mississippi Canyon Block 508 encountered non-commercial quantities of hydrocarbons and was plugged and abandoned.

In 2004, we drilled a deeper zone test well on the Sequoia prospect, which is located in Mississippi Canyon Block 947, below our Mirage discovery, which is located in Mississippi Canyon Block 941. The Sequoia well was a Miocene test and was a dry hole. We had hoped that a successful test of the deeper intervals at the Mirage discovery would lead to development, but the hydrocarbons encountered in the deeper interval were deemed to be noncommercial. We hold a 10 percent working interest in both the Sequoia and Mirage wells.

An appraisal well targeting the Mad Dog Southwest Ridge began drilling late in 2004. The well is testing Miocene targets downdip on the flank of the existing Mad Dog reservoir limits.

At year-end 2004, we also held a 30 percent working interest in the Champlain discovery, located in Atwater Block 63, discovered in 2003.

Onshore U.S.

Our onshore U.S. operations are primarily comprised of activity in the Permian Basin of west Texas and southeastern New Mexico, the San Juan Basin area of New Mexico and Colorado and activity in the East Texas area. Our net production in 2004, which was 61 percent weighted toward natural gas, averaged 54 MBOE/d. We have a large inventory of quality development and exploitation projects in this region that we believe will yield positive results for our onshore U.S. operations. We participated in drilling 169 gross wells in 2004 resulting in 43 natural gas wells and 119 crude oil wells.

Alaska

We operate ten platforms and five producing natural gas fields in the Cook Inlet. In the North Slope, we hold a 10.52 percent non-operating working interest in the Endicott field and a 4.95 percent non-operating working interest in the Kuparuk and Kuparuk satellite fields.

In 2004, net liquids production averaged approximately 19 MBbl/d of which about 57 percent was from the North Slope. All of our Alaska crude oil production is sold under contract to third parties at adjusted spot market prices.

In 2004, our net natural gas production from the Cook Inlet averaged 60 MMcf/d. Pursuant to the original gas sales agreement with Agrium, all of our natural gas production from selected fields was sold for feedstock to a fertilizer manufacturing operation in Nikiski, Alaska. As part of the settlement reached between Unocal and Agrium, we entered into a new gas sales agreement, which became effective in December 2004, with defined monthly gas delivery obligations that terminate on October 31, 2005. While Agrium has first call on natural gas from the previously dedicated fields, we can sell gas from those fields to other customers so long as (1) we are meeting the delivery requirements of the new agreement and (2) the sale would not reasonably be expected to materially affect our ability to meet the delivery requirements for the remaining term of the agreement.

We also have an interest in the Ninilchik Unit, on the South Kenai Peninsula, which began first production from five wells in 2003. We are currently producing 10 MMcf/d net from the Ninilchik wells. We have a 40 percent non-operating interest in the unit. Our natural gas discovery at the Happy Valley field, which is approximately seven miles southeast of Ninilchik on Alaska s Kenai Peninsula, began first production in late 2004. Field production is expected to average about 12 MMcf/d gross during 2005. We hold a 100 percent working interest in the field.

We have a contract to sell up to 450 billion cubic feet of natural gas to an affiliate of ENSTAR Natural Gas Company and we began deliveries on the contract in 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.

We manage our gas supply and delivery obligations through coordinated production from various fields, direct sales to our customers, exchanges with other producers, and storage for later production to market, all of which are designed to meet the terms of our gas sales agreements.

Canada

Our operations in Canada are primarily carried out by our 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). Our Canadian production in 2004 averaged approximately 16 MBbl/d of liquids and 83 MMcf/d of natural gas. We participated in drilling 130 wells in 2004 resulting in 53 natural gas wells, 64 crude oil wells and 3 service wells.

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Exploration and Production International

Our international operations encompass oil and gas exploration and production activities outside of North America. Through our subsidiaries, we operate or participate in production operations in Thailand, Myanmar, Indonesia, Bangladesh, Azerbaijan, the Netherlands and the Democratic Republic of Congo. In 2004, international operations accounted for 62 percent and 56 percent of our worldwide natural gas and liquids production, respectively. International operations also include exploration activities and the development of energy projects primarily in Asia.

Oil and Gas Concessions and Production Sharing Contracts

Most of our international exploration and production activities are conducted pursuant to concessions and production sharing contracts with a host government. A PSC specifies terms under which we, as contractors, and the host government share production from the contract area. The PSC typically provides a mechanism for recovery of our costs, and then the remaining production is shared between the host government and us. As crude oil and natural gas prices increase, our share of production decreases and vice versa. A concession agreement, the most common alternative to a PSC, does not provide for cost recovery but typically allows us to sell all production and pay royalties and taxes. Listed below are our more important international oil and gas concessions and PSCs:

Country	Agreement Type	Area	Working Interest 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	28.26	2028	N(d)
Indonesia	Production Sharing Contract	East Kalimantan	92.5	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	10.28	2024	Y
Bangladesh	Production Sharing Contract	Blocks 13 & 14	98	2028	Y
	Production Sharing Contract	Block 12	98	2034	Y
Vietnam	Production Sharing Contract	Blocks B & 48/95	42.38	2026	Y
	Production Sharing Contract	Block 52/97	43.3	2029	Y

(a) *Share percentages rounded to the nearest whole number. Working interest and net working interest are defined in our glossary.*
(b) *Terms of agreement renewal are subject to negotiation. We cannot predict whether the concession or PSC will in fact be renewed.*

(c) We have a ten-year extension option.
(d) No renewal option specified in the PSC.

Asia

Thailand

Through our Unocal Thailand, Ltd. (Unocal Thailand) subsidiary, we currently conduct 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. We had 1,165 employees in our Thailand operations at year-end 2004 with Thai nationals making up approximately 92 percent of the total.

Thailand s electricity market continued to grow in 2004 due to the continued strengthening of the Thai economy. The strength of the market led to strong sales that capped off another record year for Unocal Thailand. New monthly and annual records were set for natural gas and liquids production during 2004. In 2004, gross natural gas production from Unocal s Gulf of Thailand operations averaged 1,181 MMcf/d or 642 MMcf/d net. 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. Our natural gas production currently is utilized in producing approximately 30 percent of Thailand s total electricity demand.

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We sell all of our Thailand 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. See note 29 to the consolidated financial statements for sales figures to PTT. We have typically supplied more natural gas to PTT than the minimum daily contract quantity provision of our GSAs. The minimum gross quantity of natural gas that PTT is contractually obligated to purchase from us and our co-venturers under the existing GSAs is 1,093 MMcf/d. Included in this total is the Pailin operational area where gross contracted natural gas sales volumes are currently 353 MMcf/d.

To meet growing demand for domestic natural gas in Thailand, we continued discussions, during 2004, to finalize the commercial arrangements required to extend our existing GSAs and expand contract quantities for two of our GSAs after PTT completes its expected installation in 2006 of a third pipeline to shore. In 2003, we signed a heads of agreement with PTT with a goal of amending and extending the two 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.

Gross crude oil and condensate production in 2004 averaged 63 MBbl/d or 35 MBbl/d net. The produced crude oil is sold to both domestic and export markets, and the condensate is sold primarily as a petrochemical feedstock. In 2004, the second phase of our offshore oil development in the Pattani field progressed on schedule. Phase 2 is designed to double gross crude oil production from the Yala and Plamuk operating areas. Upon expected completion early in the third quarter of 2005, this project is expected to add on average between 7 MBOE/d and 9 MBOE/d and average about 9 MBOE/d to 11 MBOE/d in the fourth quarter of 2005. We have a 71.25 percent working interest in the Yala and Plamuk operating areas or 62 percent net of royalty.

Our Thailand business conducted successful delineation drilling activities in 2004 in the South Gomin operating area, located in Block 13 in the Gulf of Thailand. The delineation-drilling program involved three follow-up wells that encountered 195 feet, 183 feet, and 95 feet of net natural gas pay. The South Gomin operating area was discovered in 1998 when the South Gomin-1 well was drilled and encountered a total of 269 feet of net natural gas and condensate pay. The first production from the South Gomin operating area is expected in late 2006.

We also have a 16 percent working interest in the Arthit field, which is operated by PTT Exploration and Production Public Company Limited. We signed a natural gas sales agreement and work began on design engineering in 2004 with first production anticipated by the operator in late 2006 or early 2007.

Myanmar

Through subsidiaries, we have 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 of our subsidiaries 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 primarily purchased by PTT and contributes to the fuel requirements of three major power plants in Thailand. Gross natural gas production averaged 652 MMcf/d or 79 MMcf/d net in 2004, which was more than the contract rate of 525 MMcf/d. See note 29 to the consolidated financial statements for sales figures to PTT from our Thailand and Myanmar operations.

We continue to believe that the Burmese Freedom and Democracy Act of 2003 and Executive Order 13310 signed by the President of the United States, expanding existing U.S. sanctions against Myanmar, will not have a material adverse effect on the revenues we receive from our interests in Myanmar.

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Indonesia

We hold varying interests in 12 offshore PSC areas, covering approximately 7 million acres, through various subsidiaries. Nine PSC areas including East Kalimantan, Ganal, Rapak, Makassar Strait, Muara Bakau, Popodi, Papalang, Donggala and Tanjung Aru are located offshore the island of Borneo, on the western side of the Makassar Strait, East Kalimantan. Three additional PSC areas, Bukat, Ambalat and East Ambalat, are located in the Tarakan Basin offshore Northeast Kalimantan. We had about 1,800 employees in our Indonesian oil and gas operations at year-end 2004, of which approximately 92 percent were Indonesian nationals.

Through our subsidiaries, we operate the East Kalimantan, Makassar Strait, East Ambalat, Rapak and Ganal PSCs. We hold working interests of 100 percent in the East Ambalat, 92.5 percent in the East Kalimantan, 90 percent in the Makassar Strait and 80 percent in the Rapak and Ganal PSCs. We also hold, through subsidiaries, a 24 percent non-operating working interest in the Popodi and Papalang PSCs and hold a 50 percent non-operating working interest in the Muara Bakau PSC area. We also hold a 19.55 percent non-operating working interest in the Donggala PSC, a 10 percent non-operating working interest in Tanjung Aru PSC, and a 33.75 percent non-operating working interest in the Bukat and Ambalat PSCs.

Our gross production averaged 62 MBbl/d of liquids and 232 MMcf/d of natural gas in 2004. The average net production under the PSCs was 35 MBbl/d of liquids and 136 MMcf/d of natural gas in 2004.

Shelf - We currently operate 11 producing oil and gas fields offshore East Kalimantan. We have a 92.5 percent working interest in 10 of the fields, and a 46.25 percent working interest in the Attaka field.

Crude oil and natural gas production from our northern fields are processed at our company-operated Santan terminal and liquids extraction plant, and the dry natural gas is transported by pipelines to an LNG plant, located nearby at Bontang, East Kalimantan. Dry natural 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.

Crude oil and natural gas from our southern fields are sent to the Lawe-Lawe terminal that we operate, located onshore south of Balikpapan. The stored crude oil is either exported by tanker or transported by pipeline to a refinery in Balikpapan owned by Pertamina, the Indonesian national petroleum company. The natural gas is transported by pipeline and sold as fuel gas to the Pertamina refinery. Under the terms of the Indonesia PSCs, we are required to sell a portion of our net entitlement crude oil production to the Indonesia government at reduced prices. For 2004, approximately 14 percent of our share of this production was sold to the government for an average price that was substantially lower than market.

Deep Water At the West Seno field located in the Makassar Strait PSC, we completed initial drilling activities late in 2004. There are currently 28 wells completed and gross production averaged 40 MBOE/d in December of 2004. The field is supplying natural gas to the Bontang LNG facility. Along with our co-venturers, we financed a portion of the initial total development costs through the Overseas Private Investment Corporation (OPIC). Bids were received for further development, including offshore installation and tension leg platform fabrication; however, the bid results were unacceptably high. Accordingly, extended reach drilling from the existing platform is being considered as a means to more cost effectively recover the resource in the southern portion of the field. Any potential production from future development will be after 2005 and will be less than originally expected.

We continue to work on solidifying our development plans for our other deepwater natural gas projects. In 2004, we selected a development concept for the Gendalo field in the Ganal PSC. Engineering design work will commence in the second quarter of 2005, along with the submittal of the plan of development to the government of Indonesia. The project will be designed to produce between 550 MMcf/d and 650 MMcf/d gross Bontang inlet natural gas and 20 MBbl/d to 25 MBbl/d gross of condensate. The project will target existing contract requirements for the Bontang natural gas market and new sales. We are estimating production startup between 2008-2010 depending on government approvals and market conditions.

Another development project is expected to be the Gehem-Ranggas oil and gas complex where first production could come on-line by 2011-2012 depending on government approvals and market conditions. The Gehem-

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Ranggas complex is expected to produce between 300 MMcf/d and 500 MMcf/d gross Bontang inlet natural gas and 25 MBbl/d to 40 MBbl/d gross of liquids. In 2004, we drilled a successful appraisal well at the Gehem field in the Ganal PSC. The Gehem-2 well results showed the primary zone of interest to have a single natural gas column of greater than 550 feet. The Gehem-2 well was drilled 300 feet downdip of Gehem-1 and encountered 240 feet of net natural gas pay in zones penetrated by Gehem-1. Beneath those zones, 55 feet of net crude oil pay was discovered in a single zone. The well is located 1.8 miles south of the Gehem-1 well in the Ganal PSC. Due to the Gehem discovery and its successful appraisal, we are considering a joint deepwater development with the nearby Ranggas field using a common host facility. Development concept investigation and engineering are in process for the joint development. New 3-D seismic acquisition across the two fields is underway for use in the development planning. We expect to submit a plan of development to the government for the Gehem Ranggas complex in 2005. In support of the joint development, we drilled the Gehem-3 and Ranggas-7 appraisal wells in 2004. The Gehem-3 well, located in the Rapak PSC, was drilled 1.7 miles north of the Gehem-1 discovery well and 3.2 miles northwest of the Gehem-2 well. The well primarily encountered 232 feet of net natural gas pay. The appraisal well results indicated consistent pressure across the entire primary reservoir pool in this field and a potential single hydrocarbon reservoir with high-quality rock. The Ranggas-7 well, in the Rapak PSC, was drilled 4.7 miles northeast of Gehem-3 in 2004. A total of 167 feet of net pay was encountered, including 52 feet of crude oil. The Ranggas-7 well was drilled to delineate the downdip and eastern limits of the primary Ranggas development area and to penetrate the deeper primary reservoir unit of the field. The appraisal well did not encounter hydrocarbons in the deeper zone. In the shallower zone, however, hydrocarbons were penetrated as far as 400 feet downdip of the Ranggas-1 well.

Additional appraisal activity in 2004 was also performed on the Gula structure located in the Ganal PSC area. The Gula-3 well was drilled 3.5 miles south of the Gula-1 discovery well. The well was drilled to a total depth that was more than 1,000 feet deeper than was drilled in the Gula-1 well. The Gula-3 well encountered 327 feet of net natural gas pay.

A three-well appraisal program was completed in late 2004 on the Sadewa prospect in the East Kalimantan PSC. The Sadewa prospect is a potential candidate for early natural gas development because of its proximity to the shelf. We are currently doing detailed subsurface mapping. The most likely development concept is a natural gas and crude oil development from a shallow-water platform with extended reach wells towards targets in deep water.

We continued our exploration and appraisal drilling in 2004 in the deep water Kutei Basin, which tested new prospects in recently awarded PSCs. We drilled a deepwater exploratory well in the Papalang PSC. The Pandu-1 well was drilled as a dry hole. Excellent reservoir quality sands were encountered, but they were water bearing. We also participated in drilling two exploratory wells in the Tarakan Basin on the Bukat PSC. Both wells discovered hydrocarbons but were non-commercial. The presence of hydrocarbons in both of these wells provides encouragement that the deepwater of the Tarakan Basin may still hold commercially viable prospects.

Bangladesh

Through our subsidiaries, we hold 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. We have a 98 percent working interest in Blocks 12, 13 and 14 and are the operator. Our working interest in Block 7 is 90 percent and we are the operator.

Gross production from the Jalalabad field on Block 13 averaged 184 MMcf/d (55 MMcf/d net) of natural gas and 1,800 Bbl/d (405 Bbl/d net) of liquids in 2004. Currently, the take-or-pay volume of natural gas from the Jalalabad field is 100 MMCf/d gross. In total, our subsidiaries currently supply to Bangladesh Oil, Gas & Mineral Corporation (Petrobangla), the state oil and gas company, almost 15 percent of Bangladesh s natural gas requirements and we expect this to increase to about 35 percent by 2008.

Facility construction and development drilling on the Moulavi Bazar field located in Block 14 is almost complete. First production from the Moulavi Bazar field is expected late in the first quarter of 2005 or early in the second quarter of 2005. Commencement of this new field is expected to increase our net production in the country by 20 MBOE/d to 24 MBOE/d in the second quarter and 20 MBOE/d to 32 MBOE/d in the third quarter of 2005. This production outlook reflects higher volumes due partially to the increase in cost recovery that we expect to receive from the Jalalabad field because of new production from the Moulavi Bazar field. We anticipate the net average incremental production in the fourth quarter of 2005 to be 9 MBOE/d to 15 MBOE/d due to the completion of cost recovery.

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In late 2004, we signed a third natural gas purchase and sales agreement to develop and produce natural gas from the Bibiyana field located on Block 12. Under the agreement, minimum production is expected to be 200 MMcf/d of natural gas from the field beginning in the fourth quarter of 2006. In the fourth quarter 2007 and in 2008, the take-or-pay production volumes under the agreement are expected to increase by 100 MMcf/d, raising total expected sales volumes from the field to 400 MMcf/d at the end of 2008. Total development cost for the project, including up to 15 development wells, is currently estimated at $230 million. We plan to build a natural gas processing plant with an initial capacity of 300 MMcf/d. The plant capacity is ultimately expected to expand to 600 MMcf/d as field production ramps up. The development program also includes a natural gas pipeline to connect the Bibiyana field to the national natural gas distribution grid and a condensate pipeline.

Vietnam

Through our subsidiaries, we operate two PSCs offshore southwest Vietnam in the northern part of the Malay Basin. We have a 42.38 percent working interest in one PSC, which includes Block B and Block 48/95, which covers 2.2 million acres. We made the initial natural gas discovery on the Kim Long prospect on Block B, which found 113 feet of natural gas pay. We also hold a 43.4 percent working interest in a PSC for Block 52/97, which covers 400,000 acres.

In 2004, we signed a Coordination Memorandum of Understanding with PetroVietnam for natural gas development and fulfilled our initial drilling commitments. In order to retain some prospective acreage in Block B, we committed to drill two additional wells by August 2008. In total we have drilled 17 successful wells offshore Vietnam, three of which were drilled in 2004. We continue to work towards commercializing our offshore natural gas resources and to bring natural gas to market. We are currently working on a feasibility study to develop the fields. We are also in discussions with PetroVietnam concerning a natural gas pipeline to serve power plants proposed for construction in southern Vietnam.

Our oil and gas operations in Southeast Asia did not sustain any damage by the tsunamis that hit 11 countries, following an earthquake in offshore Sumatra, Indonesia in December 2004. None of our employees or their immediate families sustained any major injuries.

Other

Azerbaijan

Through a subsidiary, we hold a 10.28 percent working interest in the Azerbaijan International Operating Company (AIOC) project that is producing and developing offshore oil reserves in the Caspian Sea from the Azeri Chirag Gunashli (ACG) project. In 2004, AIOC s gross crude oil production averaged 132 MBbl/d (12 MBbl/d net). AIOC currently has access to two pipelines to export its crude 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 2004, approximately 97 percent of production from the consortium was exported through the western pipeline and the remaining 3 percent through the northern pipeline. Through our AIOC participation, we have an equity interest in the development of a third pipeline from Baku to Ceyhan, Turkey (see the discussion under the Midstream and Marketing segment for further details on the Baku-Tbilsi-Ceyhan (BTC) pipeline).

Progress continued in 2004 on the development of the ACG crude oil project. Phase I, which is designed to develop an estimated 1.5 billion gross barrels of proved crude oil reserves, began first oil production in February 2005. The average net production rate for Phase I is expected to be approximately between 5 MBOE/d and 7 MBOE/d in the second quarter of 2005. Net production in the fourth quarter of 2005 is expected to increase to between 10 MBOE/d and 13 MBOE/d. Phase II of the project is expected to be larger in size to Phase I and is expected to begin production from two additional platforms in 2006 and 2007. In 2004, AIOC participant companies approved and sanctioned Phase 3 development of the ACG crude oil project. Phase 3, which is the deepwater portion of the project, is the final phase of full development. Gross production is expected to ramp up to more than 230 MBbl/d in 2005, rising to 670 MBbl/d in 2007 and over 1 million Bbl/d by 2009.

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The Netherlands

Through a subsidiary, we have interests ranging from 34 percent to 80 percent in four blocks in the Netherlands sector of the North Sea. Average gross production in 2004 was approximately 5 MBbl/d of crude oil (4 MBbl/d net) and 16 MMcf/d (10 MMcf/d net) of natural gas. We are the operator and have an average 70 percent working interest in the four blocks.

Democratic Republic of Congo

Through a subsidiary, we have a 17.7 percent non-operating working interest in a PSC with 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) from seven fields in 2004.

Australia

We hold interests in over 5 million acres in five blocks offshore Australia.

Through a subsidiary, we hold a 50 percent non-operating working interest in exploration Blocks T/35P and T/36P in the Otway and Sorrel Basins between Victoria and Tasmania off the coast of southeastern Australia. We also hold a 50 percent non-operating working interest in Block T/32P, which is located in the Sorell Basin, off the northwestern shore of Tasmania and a 33.33 percent non-operating working interest in Block VIC/P52, which is located in the Otway Basin, offshore Victoria. Through another subsidiary, we hold a 50 percent non-operating working interest in Block WA-274-P off the coast of Western Australia in the Browse Basin.

Midstream and Marketing

In 2004, we combined our former Trade segment with the Midstream segment to form the Midstream and Marketing segment. The Midstream and Marketing segment is comprised of our equity interests in certain petroleum pipeline companies, wholly-owned pipelines and terminals throughout the U.S., our North America natural gas storage business and the organization that markets the majority of our worldwide liquids production and North American natural gas production.

Pipelines

Our pipelines business principally includes equity interests in certain petroleum pipeline companies and wholly-owned pipeline systems throughout the U.S., including our pipeline investments in the Colonial Pipeline Company (Colonial Pipeline), in which we hold 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. We also have a 40 percent equity interest in the Kenai Kachemak Pipeline LLC, which operates a natural gas pipeline between Kenai and Ninilchik in Alaska.

Through an equity investee and our working interest in AIOC, we are 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 $3.5 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 93 percent complete. We have an 8.9 percent equity interest in the pipeline company and are one of eleven shareholders. Up to 70 percent of the pipeline s cost is covered under financing agreements with both bilateral and multilateral agencies and commercial lenders.

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We also hold a 27.75 percent equity interest in the Trans-Andean oil pipeline, which transports crude oil from Argentina to Chile.

Natural Gas Storage

We own varying interests in natural gas storage facilities in Canada and Texas. Through our Canadian subsidiaries, we hold a 94 percent interest in the Aitken Creek Gas Storage Reservoir in British Columbia, which has 48 BCF of capacity and 500 MMcf/d of deliverability. We also hold a 43 percent non-operating interest in the Alberta Hub natural gas storage facility in Alberta. In addition, we operate the Keystone Gas Storage Project in West Texas with a storage capacity of 3 BCF and hold a 100 percent interest in the project. Keystone is located in the Permian Basin near the Waha Hub.

Marketing

Marketing activities include transporting and selling our hydrocarbon production. To that end, the marketing group conducts the majority of our: (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 our U.S. production is sold on an intracompany basis from the Exploration and Production segment to the Midstream and Marketing segment at market prices and then is resold to third-party customers. However, because this production is sold at market prices, our marketing business is, consequently, a low-margin business. These intracompany sales and purchase transactions, including any intracompany profits and losses, are eliminated upon consolidation. To market our production, the marketing group 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 us to better manage our commodity-related risks. Currently, these sale and purchase transactions represent a significant portion of the Midstream and Marketing segment s U.S. crude oil sales and purchases.

Our non-U.S. crude oil and condensate production is typically sold by the Exploration and Production segment to the Midstream and Marketing segment at market prices and then is resold to third party customers. Intracompany profits and losses related to these marketing arrangements are eliminated upon consolidation.

The marketing group also purchases crude oil, condensate and natural gas for resale from certain of our royalty owners, joint venture partners and unaffiliated oil and gas producing, refining and trading companies.

The marketing group 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 our cash flows and preserving revenues. The marketing group enters into various hydrocarbon derivative financial instrument contracts, such as futures, swaps and options (derivative contracts), to hedge or offset portions of our exposures to commodity price changes for future sales transactions. Our commodity-risk management program is authorized by our senior management and board of directors.

The marketing group 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 marketing group 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 our potential loss from likely changes in market prices.

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Geothermal Operations

We are a producer of geothermal energy with experience in geothermal resource exploration, reservoir delineation and management and production operations. Through our subsidiaries, we operate major geothermal fields producing steam for power generation projects at Gunung Salak in Indonesia and at Tiwi and Mak-Ban in the Philippines. Together, these projects have a combined installed electrical generating capacity of 1,010 megawatts.

Indonesia

We develop and produce geothermal steam pursuant to the terms of exclusive Joint Operation contracts with Pertamina and sell 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 an Energy Sales Contract. In 2004, we acquired the remaining 50 percent interest in Dayabumi Salak Pratama, Ltd. (DSPL) and now own 100 percent of this subsidiary, which operates three other power generation plants with a total installed capacity of 197 megawatts also located within the Gunung Salak steam field. DSPL operates these power plants and sells electrical energy to PLN pursuant to the build-operate-transfer provisions of the current Energy Sales Contract. Title to geothermal resources rests with the Indonesian central government.

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. Unocal Philippines, Inc. (UPI), a wholly-owned subsidiary formerly known as Philippine Geothermal, Inc. (PGI), 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.

In 2004, UPI obtained final Philippine government and court approvals of a settlement for past contractual issues covering the ongoing operations of the steam resources at Tiwi and Mak-Ban and received the majority of all outstanding amounts owed by NPC and the Power Sector Assets and Liabilities Management Corporation (PSALM).

UPI had been operating the steam fields under an Interim Agreement with NPC while the parties were negotiating this settlement. The settlement provides 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 2006; UPI will be granted the right to operate the steam fields until at least 2021; and UPI will sell geothermal resources to NPC/PSALM at a negotiated price to ensure base-load operation of the Tiwi and Mak-Ban power plants.

Thailand

Through our subsidiaries, we have various equity interests in four natural gas-fired power plant projects in Thailand with combined installed generating capacity of 985 megawatts. In late 2004, we agreed to sell our equity interest in one of these power plants with installed generating capacity of 700 megawatts. We anticipate the sale to be completed in March 2005 subject to various approvals.

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Geothermal Reserves and Operating Data

Our geothermal reserves and operating data for 2004, 2003 and 2002 are summarized in the following table:

	2004	2003	2002
Net proved geothermal reserves at year end: (a)			
billion kilowatt-hours	145	150	155
million equivalent oil barrels	217	225	232
Net daily production			
million kilowatt-hours	14	12	13
thousand equivalent oil barrels	22	19	20
Net geothermal lands in thousand acres			
proved	9	6	9
prospective	314	314	314
Net producible geothermal wells	98	87	85

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

Geothermal energy reserves and production data are expressed as a capacity to generate electrical power in kilowatt-hours. To facilitate comparison with our oil and gas operations we also report 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 oil 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.

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PATENTS

We hold five U.S. patents resulting from our independent research on cleaner-burning reformulated gasolines (RFG). We have entered into nine licensing agreements that grant motor gasoline refiners, blenders and importers the right to make cleaner-burning gasolines using these formulations. We have 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 awarding us damages, the refiners appealed unsuccessfully to the U.S. Circuit Court of Appeals for the Federal Circuit. In 2000, we 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, we 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). We are 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. We are also seeking a mandatory licensing of our patents by Valero with respect to future activities. Proceedings in both of our lawsuits have been temporarily suspended pending the outcome of the reexamination of the patents discussed below.

In 2001, petitions were filed with the U.S. Patent and Trademark Office (PTO) by Washington, D.C., law firms, acting independently 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, we filed a response to this rejection, including an appeal within the PTO, which was followed by yet a third reexamination request of the 393 patent. That request was granted and the PTO merged the three 393 reexaminations. We are now awaiting a response from the PTO to our submission of March 2003.

A second reexamination request of the 126 patent was also granted and merged with the first, and yet a third request for reexamination of the 126 patent was filed in October 2004 and granted in January 2005. The completion of the reexamination processes, including appeals within the PTO, is expected to take some time, but we believe the claims of both patents are novel and non-obvious and expect 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 us 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 we had illegally monopolized, attempted to monopolize and otherwise engaged in unfair methods of competition with respect to California RFG. The complaint alleges that we made materially false and misleading statements to the California Air Resources Board (CARB) which resulted in regulations that benefited us and created anticompetitive effects. The complaint alleges that our failure to disclose our 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 we cease and desist from any efforts to continue or commence any actions with respect to infringement of our RFG patents for gasolines sold in California.

In November 2003, an Administrative Law Judge issued an initial decision granting our motion to dismiss the complaint on the basis of Noerr-Pennington immunity and the absence of jurisdiction by the FTC to resolve substantive patent

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issues. The complaint counsel appealed that decision to the FTC in December 2003. In July 2004, the FTC reversed the decision and remanded the matter to the Administrative Law Judge for trial. The subsequent trial commenced in October 2004 and concluded at the end of January 2005. After post-trial briefing and oral arguments, which are expected to be completed in early May 2005, the Administrative Law Judge will render a recommended decision.

In the fall of 2004 and early 2005, twelve separate putative class action lawsuits were filed in either state or federal courts in California. These cases have been brought on behalf of California motorists and allege essentially the same claims and theories currently before the FTC. The claims seek relief for California class members who purchased RFG from 1995 to the present for alleged violations of the Clayton Act, Cartwright Act, certain California Code sections and common antitrust law. All cases originally filed in state court were successfully removed to federal court with a view to consolidate all cases into federal multi-district litigation. A remand motion was heard on February 14, 2005 in the sole case where Plaintiff s counsel is challenging federal jurisdiction. We will continue to vigorously contest these actions and believe that we did not engage in misleading or deceptive practices before the CARB. If these lawsuits were to be certified as class actions and monetary damages were awarded to the plaintiffs, our results of operations could be adversely affected in the fiscal period during which we record such monetary damages, although we do not believe that our financial condition or liquidity would be materially adversely affected by the payment of any such monetary damages.

COMPETITION

The energy resource industry is very competitive around the world. As an independent oil and gas exploration and production company, we compete against major integrated oil and gas companies, other 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. 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 in our industry are oil and gas sales prices, demand, worldwide production levels, alternative fuels and government and environmental regulations. 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 carrying out these activities. Our geothermal operations are in competition with producers of other fuels (such as coal, hydro-electric, fossil fuels and nuclear energy) for the generation of electricity.

EMPLOYEES

As of December 31, 2004, Unocal and its subsidiaries had about 6,590 employees compared to 6,700 and 6,615 in 2003 and 2002, respectively. The number of employees in 2004 included approximately 215 employees in the United States who were represented by various labor unions, 420 employees in Thailand and 175 employees in the Philippines who were represented by a trade union.

GOVERNMENT REGULATION

As a lessee from the U.S. government, we are 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 legislation and regulation would, if enacted, significantly and adversely affect us as well as the other members of the petroleum industry. This legislation and regulation includes the imposition of additional taxes/fees, land use controls/restrictions, new operational controls, prohibitions against operating in certain foreign countries and restrictions on exploration and development.

Certain of our interstate crude oil pipeline subsidiaries are regulated (as common carriers) by the Federal Energy Regulatory Commission. The Railroad Commission of Texas regulates our Keystone Gas Storage Project as an intrastate facility.

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Federal 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. State regulations promulgated by a wide range of state agencies can also impose new requirements and cost on our business units. New regulations may be adopted. We 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 our 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 continue to impact our operations. Significant federal legislation applicable to our operations include 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 new environmental laws and regulations. We believe that we 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 us.

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 Unocal 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 storm water runoff. The act requires us 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 our 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 our monitoring, recording and reporting (MR&R) requirements. MR&R involves periodic reporting such as semi-annual monitoring reports, permit deviation reports and annual compliance certifications. Failure to properly file these reports may result in a Notice of Violation and possible fine. The Risk Management Plan regulations under the Clean Air Act require that any non-exempted facility that processes or stores a threshold amount of a regulated substance prepare and implement a risk management plan to detect, prevent and minimize accidental releases. The regulations require undertaking an offsite hazard assessment, preparing a response plan and communication with the local community. We have 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.

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The Solid Waste Disposal Act, as amended by 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 of our former 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. Our facilities generate and handle a number of wastes regulated by RCRA. We have facilities that have been used for the storage, handling or disposal of RCRA wastes that are subject to investigation and corrective action.

We must provide financial assurance for future closure and post-closure costs of our 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 our former service stations and other facilities.

CERCLA 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 2004, we have been identified as a Potentially Responsible Party (PRP) under CERCLA at approximately 22 sites by the EPA and various state agencies and private parties had identified us as a PRP at 23 other similar sites. A PRP has strict and joint and several liability for site remediation and agency oversight costs and so we may be required to assume, among other costs, all or portions of the shares attributed to insolvent, unidentified or other parties. We do not anticipate that our ultimate exposure at these sites individually, or in the aggregate, will have a material adverse impact on our financial condition or liquidity, but it could have a material adverse impact on results of operations.

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

Other regulations and requirements that may have material impacts on us include the following:

- The Toxic Substances Control Act of 1976, as amended in 1986, which 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, which requires us 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, which 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, which have a significant impact on the mining operations and former processing plants of our Molycorp, Inc. (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 us to provide financial assurances related to 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. We have been a party to a number of administrative and judicial

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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.

Greenhouse gas (GHG) emissions and their possible effect on the global climate have become a subject of growing public debate. Around the world, policymakers have been developing various regulatory and voluntary measures to address this issue. Most notably, the Kyoto Protocol of the United Nations Framework Convention on Climate Change set legally binding commitments for developed but not developing nations to reduce their GHG emissions by 2012. The Kyoto Protocol entered into force as a global treaty in February 2005. Among developed countries that are a party to the convention, we currently conduct operations in Canada and The Netherlands. The European Union GHG cap-and-trade Emissions Trading Scheme (EU ETS) started in January 2005 and our Netherlands subsidiaries are subject to it. Canada is expected to promulgate regulations to implement their Kyoto Protocol commitments in the near future. We also operate in some developing countries that are party to the Kyoto Protocol, primarily Thailand, Indonesia, Philippines and Bangladesh. The Kyoto Protocol does not require developing countries to reduce GHG emissions at least until 2012, though some countries may do so independent of the Kyoto agreement. The United States has indicated that it does not intend to ratify the Kyoto Protocol but rather encourages voluntary GHG emission reductions. Many U.S. states have either passed or proposed GHG-related legislation, including limited, but mandatory, emission reduction requirements typically focused on the power sector. No U.S. state-level requirements apply to us at this time. In addition, federal level GHG-related legislation is being considered. Given the fact that most of our business is conducted in countries without GHG constraints, we believe, at this point in time, these developments will not have a material impact on our financial results.

Given the trend toward emission limits, we should benefit from a general shift away from GHG emission-intensive fuels, such as coal, and toward relatively cleaner natural gas and geothermal power. In addition, the Kyoto Protocol and similar policy frameworks allow credits from qualifying GHG emission-reduction projects in developing countries to be sold to developed country entities seeking compliance with GHG regulations or other benefits. GHG emission-reduction projects include flaring and venting reduction and switching from coal-fired power systems to natural gas or geothermal power. Such credits provide an incentive for end-users to switch to our less emissions-intensive fuels as well as encourage efficiency within our operations. We continue to assess these developments and pursue opportunities as conditions warrant.

For information regarding our 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 19 and 23 to the consolidated financial statements in Item 8 of this report.

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ITEM 3 LEGAL PROCEEDINGS.

There is incorporated by reference: the information regarding environmental remediation reserves and possible additional remediation costs in notes 19 and 23 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 23 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 our patents for cleaner-burning gasolines. Set forth below is information with respect to certain additional legal proceedings pending or threatened against Unocal:

1. Since 1993, Unocal, 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, we are 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 was issued in August 2004, but must be adopted by the FERC before becoming effective. The FERC is fully authorized to adopt, revise, amend, reject or remand the Administrative Law Judge s decision. There is no time limit within which the FERC must issue its decision, but it is anticipated that FERC will issue its decision in mid- to late 2005. The FERC decision 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. (The issue of the proper methodology was bifurcated and will be decided in a later proceeding.) The FERC decision may be appealed to the U.S. Court of Appeals for the District of Columbia Circuit. Once the matter is finally determined, it is anticipated that the RCA will then adopt the FERC decision for intrastate transportation of ANS crude oil. We believe, based on our current assessment of the case, that the outcome is not likely to have a material adverse effect on our financial condition, liquidity or results of operations.

2. We have 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 us 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 Unocal.

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 Unocal, 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

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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. We have cooperated fully with the DOJ in connection with its investigations in both the *Wright* and *Grynberg* cases. To date, we have received no indication from the DOJ that it contemplates intervening against us 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 have been presented to the U.S. District Courts in Wyoming and Texarkana. The Court in the *Wright* case recently denied the defendants motions to dismiss and directed the parties to prepare an agreed upon scheduling order to govern further case proceedings. The motions to dismiss in the *Grynberg* case will be heard by the Court in March of 2005. All other aspects of the *Grynberg* case have been stayed pending resolution of the jurisdictional issues. We believe, based on our current assessment of the cases, that the outcomes are not likely to have a material adverse effect on our financial condition, liquidity or results of operations.

3. We are a defendant in lawsuits by anonymous residents and former residents of the Tenasserim region of Myanmar. The two 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 we were 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.

The Federal Cases

In 2000, the federal district court granted our motions for summary judgment in both actions, ordered the federal law claims dismissed and, after declining to exercise jurisdiction over the pendant state law claims, ordered them dismissed without prejudice.

The plaintiffs in both actions appealed the final judgments to the U.S. Court of Appeals for the Ninth Circuit (Case Nos. 00-56603 and 00-56628, respectively). In 2002, a three-judge panel of the Circuit Court issued an opinion that reversed in part and affirmed in part the District Court s ruling and remanded the case for further proceedings in the District Court. The panel held that, if proved at trial, the alleged conduct of the Myanmar military, consisting of alleged forced labor and certain alleged related violence, would constitute violations of international law actionable under the Alien Tort Statute (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 us and found sufficient disputed facts to warrant a trial. Subsequently, we were granted a rehearing by an 11-judge *en banc* panel of the Circuit Court in June 2003.

In June 2004, the United States Supreme Court issued its decision in *Sosa v. Alvarez-Machian (Alvarez)* a case that addressed private right of action under the Alien Tort Statute. In July 2004, the en banc Ninth Circuit panel asked parties to the Yadana litigation to submit supplemental briefs regarding any impact of Alvarez on the Yadadna case. The parties completed briefing last fall, and the United States submitted an amicus brief on our behalf. The en banc court then set December 13, 2004 as the date for oral argument, while also granting a request by the government to participate in the hearing. Before the hearing date, the parties apprised the court that they had reached a settlement in principle, and the court removed oral argument from its calendar. If a settlement is finalized, the parties will file a joint stipulation dismissing the federal court cases with prejudice.

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The State Cases

In 2000, the plaintiffs filed actions against us 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 our participation in the Yadana project, we are 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 our alleged intentional or negligent actions. The remaining causes of action in both state cases are all premised on whether we 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 Unocal 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.

After successfully disproving their alter ego status in the Phase I trial, defendants Union Oil and Unocal filed a motion for judgment. They argued that the Phase I victory as well as the Court s findings on summary judgment, plaintiffs expert admissions, and recent case law precluded the remaining claims. The Court heard argument in August of 2004. In September 2004, the court ruled that the Phase I trial did not preclude plaintiffs remaining claims from being tried in a Phase II trial. At the November 2004 status conference, Judge Chaney set a briefing schedule and trial date for the Phase II trial. Soon after these rulings were issued, the parties participated in a third-party mediation at which the parties agreed to a settlement in principle. We expect to reach final agreement on all terms of the settlement that will end the litigation. The court continued all scheduled matters in the case pending the finalization of settlement talks.

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

4. In June 2002, a lawsuit was filed against us 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, we 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). In addition, we initiated arbitration concerning the Gas Purchase and Sale Agreement (GPSA) between Agrium U.S. Inc. and us (AAA Case No. 70 198 00539 02) (the Arbitration).

In the Agrium Claim, Agrium sought damages, declaratory relief for the calculation of payments under a Retained Earnout covenant in the Purchase and Sale Agreement for the plant (the PSA), punitive damages, rescission of the sale of the fertilizer plant and attorneys fees. The Agrium Claim alleged numerous causes of action relating to Agrium s purchase from us of a nitrogen-based fertilizer plant on the Kenai Peninsula, Alaska, in September 2000. The primary allegations involved our obligation to supply natural gas to the plant pursuant to the GPSA. Agrium alleged that we misrepresented the amount of natural gas reserves available for sale to the plant as of the closing of the transaction and that we have failed to develop additional natural gas reserves for sale to the plant. Agrium also alleged that we misrepresented the condition of the general effluent sewer at the plant and made misrepresentations regarding other environmental matters. In September 2002, Agrium amended its complaint to add allegations that we breached certain conditions of the September 2000 closing, breached certain indemnification obligations, and violated the pertinent health and safety code.

In the Company Claim, we sought declaratory relief in our 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 also sought 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.

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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 commenced May 24, 2004. The arbitration panel issued its ruling on July 22, 2004. The arbitration panel agreed with us that the GPSA was a reserves-based contract. The panel s decision laid out the methodology for determining past and future gas delivery quantities and for calculating liquidated damages arising from underdeliveries of gas by us to the fertilizer plant. Using the methodology, the arbitration panel found we owed Agrium $36 million through April 2004 plus $2 million in interest through the arbitration ruling date for underdelivery of natural gas to the fertilizer plant. The arbitration panel did not rule on the enforceability of the $50 million GPSA liquidated damages cap because its award did not exceed the amount of the cap. The arbitration panel also ordered Agrium to reimburse us $5 million for excess royalties that have been paid by us to the state of Alaska. We paid Agrium $36 million plus $2 million in interest in September 2004.

On December 14, 2004, we reached a final settlement with Agrium on all issues arising from the litigation regarding the original sale of the fertilizer plant, the PSA and the GPSA. Under the settlement, all litigation, including the Agrium Claim and the Company Claim, were dismissed with prejudice. As part of the settlement, we have entered into a new gas sales agreement with Agrium, effective December 1, 2004, with defined monthly gas delivery obligations (rather than dedicated reserves) that terminate on October 31, 2005. We also paid Agrium a net amount of $25 million for early termination of the original GPSA (which originally terminated in June 2009), full release of Unocal of all environmental claims and resolution of all other issues, including certain contingent payments we were due under the PSA. The settlement payment is in addition to the remaining liquidated damages due under the original GPSA.

5. In July 2002, our subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. (Unocal Blocks 13 and 14 Ltd.) received a letter from Petrobangla claiming, on behalf of itself and the Bangladesh government, 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. Unocal and OBL believe that the claim vastly overstates the amount of recoverable natural 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, Unocal 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 our 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 or deemed commercial, from other commercial fields in the Moulavi Bazar ring-fenced area of Block 14. Consequently, Unocal 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. We were notified of the suit on May 26, 2003 when we 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 we believe the action is not well founded.

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Certain Environmental Matters Involving Civil Penalties

On February 13, 2004, the U.S. Coast Guard provided Unocal, 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. In April of 2004, we signed a settlement agreement with the Coast Guard that called for a fine of $137,500 in exchange for complete release of any claim arising from the discharge. The settlement specifically states that it does not relieve Unocal of compliance with applicable laws and therefore we could have a remediation obligation. The settlement was published in the Federal Register on March 1, 2005. Those who are interested can file comments with the Coast Guard no later than March 31, 2005. Upon receipt of one or more petitions, the Coast Guard has discretion to withdraw from the settlement or request us to modify the settlement in reaction to the comments in the petitions. The Alaska Department of Environmental Conservation (DEC) also asserted jurisdiction over the discharge. On July 16, 2004, Unocal executed a settlement agreement with the State of Alaska that called for a fine of approximately $26,300 in exchange for complete release of any claim arising from the discharge. Unocal has paid the fine. The State of Alaska has taken the position that further enforcement action may be undertaken by the Alaska Oil and Gas Conservation Commission (AOGCC), but to date AOGCC has not asserted a claim against us.

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

No matters were submitted to a vote of our security holders during the fourth quarter of 2004.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following is a list of our executive officers as of February 28, 2005, showing their ages, present positions and their business experience during the past five or more years. Our bylaws provide that each executive officer shall hold office until the annual organizational meeting of our board of directors, to be held May 23, 2005, and until his/her successor shall be elected and qualified, unless he/she shall resign or shall be removed or otherwise disqualified to serve. Officers serve at the discretion of our board.

Name, age and present positions with Unocal	Recent business experience
CHARLES R. WILLIAMSON, 56 Chairman of the Board and Chief Executive Officer Chairman of Management Committee	Mr. Williamson has been Chairman of the Board since October 2001 and Chief Executive Officer since January 2001. He served as President from February 2004 to September 1, 2004. He has served as a director since January 2000. He was Executive Vice President, International Energy Operations, during 1999 and 2000.
JOSEPH H. BRYANT, 49 President and Chief Operating Officer Member of Management Committee	Mr. Bryant joined Unocal on September 1, 2004. Mr. Bryant has more than 27 years of experience in the oil and gas industry, both domestic and international. Prior to joining Unocal, Mr. Bryant was President of BP Angola, one of BP s largest exploration and development operations. From 1997-2000, Mr. Bryant was President, Amoco Canada, and subsequently was named president, BP Canada.
TERRY G. DALLAS, 54 Executive Vice President and Chief Financial Officer Member of 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, 62 Senior Vice President, Chief Legal Officer,	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

and General Counsel Member of Management Committee	Senior Vice President and General Counsel with Mobil Corporation, where he worked for 20 years.
RANDOLPH L. HOWARD, 54 Senior Vice President, Global Gas	Mr. Howard became Senior Vice President of Global Gas effective July 1, 2004. Mr. Howard served as Vice President, International Energy Operations, Myanmar, Thailand and Vietnam, and President, Unocal Thailand, during the period from 1999 until 2004.
JOE D. CECIL, 56 Vice President and Comptroller	Mr. Cecil has been Vice President and Comptroller since December 1997. Mr. Cecil has announced his intention to retire from Unocal effective April 1, 2005.
DOUGLAS M. MILLER, 45 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 AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Information Regarding Unocal Common Stock

Our common stock is listed for trading on the New York Stock Exchange (NYSE). The following table presents a two-year history of the high and low stock prices for our common stock, as reported by the New York Stock Exchange Composite Transactions listing:

	2004 Quarters				2003 Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Market price per share of common stock								
- High	$ 39.40	$ 39.70	$ 43.50	$ 46.50	$ 31.76	$ 31.38	$ 32.45	$ 37.08
- Low	$ 35.12	$ 34.18	$ 34.65	$ 40.56	$ 24.97	$ 26.14	$ 27.79	$ 30.72
Cash dividends paid per share of common stock	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20

On February 28, 2005, the high price per share was $55.26 and the low price per share was $53.00.

As of February 28, 2005, the number of holders of record of our common stock was 18,878 and the number of shares outstanding was 270,571,829.

Unocal s quarterly dividend declared has been $0.20 per common share since the third quarter of 1993. We have paid a quarterly dividend for 89 consecutive years.

Unregistered Sales of Equity Securities

In 2004, 1,002,012 shares of our common stock, together with cash in lieu of fractional shares, were issued upon conversion of 852,922 of the 6 1/4% convertible preferred securities of Unocal Capital Trust (the Trust). The shares of common stock were not registered under the Securities Act of 1933, as amended (the 1933 Act), in reliance upon the exemption from registration afforded by Section 3(a)(9) of the 1933 Act, together with interpretations thereof by the staff of the Division of Corporation Finance of the SEC, for a security exchanged by the issuer with its existing security holders, of those of a subsidiary where no commission or other remuneration is paid or given directly or indirectly for soliciting such exchange.

Unocal Purchases of Equity Securities

The following table shows information regarding repurchases we made of our shares of common stock during the fourth quarter of 2004:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
October 1 through October 31, 2004	22,626	$ 42.06	None	
November 1 through November 30, 2004	22,530	$ 42.89	None	(2) (3)
December 1 through December 31, 2004	1,266,717	$ 42.99	1,246,000	
Total	1,311,873	$ 42.97	1,246,000	

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1. During the fourth quarter, we cancelled 1,056 shares repurchased for the payment of withholding taxes due on restricted stock that vested under various employee restricted stock plans.

During the fourth quarter, we purchased 64,817 shares in the open market and distributed these shares to employee participants in Unocal s savings plans, which are defined contribution plans with 401(k) features.

2. In December 1996, our board of directors authorized the repurchase of $400 million of our common stock. In January 1998, our board extended the stock repurchase program, increasing the authorized amount by $200 million. At the beginning of 2004, we had a balance of $189 million remaining for additional repurchases. In August 2004, we purchased approximately $150 million of our common stock under this program, resulting in a balance of approximately $39 million for additional purchases. In December 2004, our board of directors authorized the repurchase of up to $200 million of our common stock (including the $39 million balance remaining from its previous authority) plus shares of common stock up to the dollar amount not spent by us to redeem preferred securities of the Trust due to the conversion of those securities into shares of common stock. Because of the conversion of preferred securities, an additional $259 million became available to repurchase additional shares of our common stock, raising the total authorized common stock repurchase program limit to $459 million. There is no expiration date to this repurchase program.

3. In October 2004, our board of directors authorized the repurchase from time to time of shares of our common stock in order to offset the net number of shares of common stock issued by us upon the exercise or granting, as the case may be, of existing or subsequently issued stock options or shares of our restricted common stock. There is no expiration date to the repurchase program. The board authorized management to determine whether, and when, to effect any repurchases under this program and did not limit the aggregate dollar amount for any such repurchases. In 2004, we repurchased approximately $54 million of our common stock under this program. As of February 28, 2005, we had approximately 1.5 million shares that were authorized for repurchase under this program.

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ITEM 6 - SELECTED FINANCIAL DATA.

The following table presents selected consolidated financial data for the past five completed fiscal years and should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and the consolidated financial statements and notes thereto in Item 8 of this report.

	Years Ended December 31,				
Millions of dollars except as indicated	**2004**	**2003**	**2002**	**2001**	**2000**
Revenue Data					
Sales					
Crude oil, condensate and natural gas liquids (a)	$ 4,003	$ 2,751	$ 2,466	$ 3,042	$ 5,872
Natural gas	3,309	3,139	2,356	3,055	2,526
Geothermal steam	239	133	100	160	161
Petroleum products	45	52	50	203	286
Minerals	60	25	31	28	29
Other	187	95	55	68	137
Total sales revenues	7,843	6,195	5,058	6,556	9,011
Operating revenues	160	173	142	126	(58)
Other revenues (b)	201	144	73	88	261
Total revenues from continuing operations	$ 8,204	$ 6,512	$ 5,273	$ 6,770	$ 9,214
Earnings Data					
Earnings from continuing operations	$ 1,145	$ 698	$ 323	$ 591	$ 722
Earnings from discontinued operations (net of tax)	63	28	8	25	38
Cumulative effect of accounting changes (net of tax)		(83)		(1)	
Net earnings	$ 1,208	$ 643	$ 331	$ 615	$ 760
Diluted earnings (loss) per share:					
Continuing operations	$ 4.25	$ 2.66	$ 1.31	$ 2.40	$ 2.93
Discontinued operations	0.23	0.10	0.03	0.10	0.15
Cumulative effect of accounting changes		(0.30)			
Net earnings per share	$ 4.48	$ 2.46	$ 1.34	$ 2.50	$ 3.08
Share Data					
Cash dividends declared on common stock	$ 211	$ 208	$ 198	$ 195	$ 194
Per share	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80
Number of common stockholders of record at year end	19,095	20,735	21,870	23,213	24,910
Weighted average common shares - thousands	262,973	258,563	246,759	243,568	242,863
Balance Sheet Data At December 31,					
Current assets	$ 2,930	$ 1,991	$ 1,375	$ 1,295	$ 1,802
Current liabilities	2,581	2,085	1,632	1,422	1,845
Working capital	349	(94)	(257)	(127)	(43)
Ratio of current assets to current liabilities	1.1:1	1.0:1	0.8:1	0.9:1	1.0:1
Total assets	13,101	11,798	10,846	10,491	10,066

Total debt and capital leases	3,062	2,883	3,008	2,906	2,506
Trust convertible preferred securities		522	522	522	522
Total stockholders equity	5,217	4,009	3,298	3,124	2,719
Stockholders equity - per common share	19.82	15.39	12.78	12.80	11.19
Return on average stockholders equity from:					
Earnings from continuing operations	24.8%	19.1%	10.1%	20.2%	29.5%
Net Earnings	26.2%	17.6%	10.3%	21.1%	31.0%

(a) Includes crude oil buy/sell transactions settled in cash of:	$ 965	$ 820	$ 604	$ 601	$ 533

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

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

Our reporting segments were modified effective January 1, 2004. In our Exploration and Production segment: (1) we combined the Alaska business unit with the U.S. Lower 48 to form the United States geographic designation under North America and (2) we now present Asia and Other instead of the previous categories of Far East and Other under International. In addition, the former Trade segment has been combined with the Midstream segment to form the Midstream and Marketing segment. These changes were made to recognize the sale of many of our oil and gas properties in the U.S. Lower 48 during 2003, which altered that business unit s earnings contribution to our overall consolidated results. The new categories in our International business reflect a more appropriate geographic split of our current core international operating areas. Finally, the combination of our former Trade segment into the Midstream and Marketing segment reflects our de-emphasis of commodity trading activities and our increased focus on marketing and natural gas storage. Historical segment results have been reclassified to conform to the 2004 presentation. See note 29 to the consolidated financial statements in Item 8 of this report for revisions to our reportable segments.

OVERVIEW

Unocal s primary line of business is the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids. Our principal operations are in North America and Asia. We are also a leading producer of geothermal energy in Asia. Other activities include ownership in proprietary and common carrier pipelines, natural gas storage facilities and the marketing of hydrocarbon commodities. Our strategy is to create value for our stockholders by advancing worldwide oil and gas development projects and delivering successful exploration results through the drill bit. Fluctuations in hydrocarbon commodity prices and the resulting impact on our realized prices for liquids and North America natural gas are a significant driver of our financial performance.

2004 Highlights

Some of our more significant operational highlights and other activities during the year are listed below:

- drilled deepwater discoveries in the Gulf of Mexico on the Puma and Tobago prospects that were both near prior discoveries and/or developments,
- encountered hydrocarbons on several appraisal wells: the St. Malo prospect in the Gulf of Mexico and the deepwater Ranggas, Gehem and Gula prospects in Indonesia,
- continued development of Phase 1 and 2 of the ACG crude oil project in the Azerbaijan sector of the Caspian Sea with first oil, from Phase I, beginning in February 2005,
- received AIOC participant companies approval and sanction of Phase 3 development of the ACG crude oil project,
- completed construction on 93 percent of the BTC crude oil export pipeline from the Caspian Sea to Turkey,

continued second phase of offshore crude oil development from the Pattani field in the Gulf of Thailand on schedule,

completed successful delineation drilling in the South Gomin operating area in the Gulf of Thailand,

substantially completed facility construction and development drilling on the Moulavi Bazar field in Bangladesh with first production expected late in the first quarter or early in the second quarter of 2005,

signed a third GSA in Bangladesh covering the Bibiyana field with first production expected in late 2006,

reached agreement to settle an eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines,

completed development of the Mad Dog field in the Gulf of Mexico in 2004 and began first production in January 2005,

progress continued on developing the K-2 field in the Gulf of Mexico, which is expected to begin production in the second quarter of 2005,

completed the buyback of \$200 million of Unocal common stock, redeemed \$296 million of our outstanding 6 $^{1}/4$% convertible junior subordinated debentures and made a contribution of \$100 million to our U.S. Qualified Retirement Plan,

sold certain mineral fee lands in the United States for \$190 million, received $67 million in cash from the sale of our 50 percent equity interest in a jointly held project company that owned UnoPaso Exploração e Produção de Petróleo e Gás Ltda., a Brazilian exploration and production venture that owned our remaining oil and gas assets in Brazil,

received $60 million in cash from the sale of the Sarulla geothermal project to Indonesia s state electric utility, and

settled a dispute over our natural gas deliveries to Agrium s Kenai, Alaska nitrogen-based fertilizer plant and Agrium s obligation to reimburse us for participation payments on the supplied natural gas.

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

drilled several unsuccessful deepwater Gulf of Mexico wells that did not find commercial quantities of hydrocarbons, but we gained more knowledge in our overall exploration efforts in the deepwater Gulf of Mexico,

experienced slower than anticipated ramp-up of production at our West Seno field in Indonesia; however, ramp-up of production continued and drilling performance improved; the field s gross production was about 40 MBOE/d at year-end,

determined that any potential production from future development of the West Seno field will be after 2005 and will be less than originally expected due to bid results being unacceptably high, and

elected not to proceed with our participation in five contracts to explore for, develop and market natural gas resources in the Xihu Trough off the coast of Shanghai, in the East China Sea.

Commodity Prices

We benefited from higher commodity prices, which continued an upward trend in 2004. Crude oil and natural gas prices are key variables that drive industry performance and can vary significantly. Crude oil prices reached historical highs in October before trending downward in November and December. The sharp decline in crude oil inventories in the United States, precipitated by production disruptions brought on by hurricanes in the Gulf of Mexico and fear about the reliability of oil supplies due to unrest in the Middle East and Africa were the main drivers behind this new historical high. As the table below demonstrates, the 2004 average WTI crude oil price and the Henry Hub natural gas price were higher by 34 percent and 7 percent, respectively, from 2003. This follows a 19 percent and 63 percent increase in the average WTI and Henry Hub prices, respectively, in 2003 compared to 2002.

	2004	% Increase Over	2003	% Increase Over	2002
WTI crude oil - dollars per barrel	$ 41.51	*34%*	$ 31.06	*19%*	$ 26.17
Henry Hub natural gas - dollars per Mcf	$ 5.90	*7%*	$ 5.49	*63%*	$ 3.37

Operation Results

Our worldwide production declined 8 percent in 2004 primarily due to asset sales and natural declines in existing fields in North America. These declines were a reflection of the highly prolific nature of the fields in the Gulf of Mexico shelf, which tend to have quick monetization timelines and the effect of lower drilling activity. Our production in North America declined approximately 20 percent in 2004. This decline was partially offset by higher liquids production in Thailand and the effect of a full year s production from the West Seno project in Indonesia. Our year-end 2004 proved oil and gas reserves were 1.754 billion BOE, compared with 1.759 billion BOE at the end of 2003. In 2004, we added 149 million BOE to reserves through discoveries and extensions, net purchases and sales and performance, price and other revisions. Rising production costs remain a challenge and in 2005, we will continue to focus on improving production and finding and development costs, especially in our North American operations.

Our oil and gas operations in Southeast Asia did not sustain any damage by the tsunamis that hit 11 countries, following an earthquake in Sumatra, Indonesia in December 2004. None of our employees or their immediate families sustained any major injuries.

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The following table summarizes our net daily production and average prices for our North America and International Exploration and Production business units:

	2004	2003	2002
North America Net Daily Production			
Liquids (thousand barrels)			
U.S. (a)	54	64	76
Canada	16	17	18
Total liquids	70	81	94
Natural gas - dry basis (million cubic feet)			
U.S. (a)	495	673	795
Canada	83	90	91
Total natural gas	578	763	886
North America Average Prices (excluding hedging activities) (b)			
Liquids (per barrel)			
U. S.	$ 37.82	$ 28.67	$ 23.29
Canada	$ 32.31	$ 24.76	$ 20.70
Average	$ 36.57	$ 27.84	$ 22.79
Natural gas (per mcf)			
U. S.	$ 5.33	$ 4.85	$ 2.85
Canada	$ 5.48	$ 5.07	$ 2.67
Average	$ 5.35	$ 4.88	$ 2.83
North America Average Prices (including hedging activities) (b)			
Liquids (per barrel)			
U. S.	$ 33.45	$ 28.43	$ 23.30
Canada	$ 32.31	$ 24.76	$ 20.70
Average	$ 33.19	$ 27.66	$ 22.81
Natural gas (per mcf)			
U. S.	$ 5.23	$ 4.75	$ 2.91
Canada	$ 5.24	$ 4.78	$ 2.66
Average	$ 5.23	$ 4.76	$ 2.88

(a) Includes proportional interests in production of equity investees of:

Liquids		*1*	*2*
Natural gas		*29*	*45*

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

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Operating Results (Continued)

	2004	2003	2002
International Net Daily Production (a)			
Liquids (thousand barrels)			
Asia	70	59	54
Other (b)	19	20	19
Total liquids	89	79	73
Natural gas - dry basis (million cubic feet)			
Asia	912	941	920
Other (b)	20	24	20
Total natural gas	932	965	940
International Average Prices (c)			
Liquids (per barrel)			
Asia	$ 37.76	$ 27.30	$ 22.88
Other	$ 38.64	$ 28.31	$ 25.57
Average	$ 37.94	$ 27.54	$ 23.57
Natural gas (per mcf)			
Asia	$ 3.17	$ 2.82	$ 2.74
Other	$ 4.32	$ 4.38	$ 3.35
Average	$ 3.19	$ 2.84	$ 2.75

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

(b) Includes proportional interests in production of equity investees of:

Liquids	*1*	*1*	*1*
Natural gas	*10*	*17*	*13*

(c) International did not have any hedging activities.

	2004	2003	2002
Worldwide Net Daily Production (d)			
Liquids (thousand barrels)	159	160	167
Natural gas - dry basis (million cubic feet)	1,510	1,728	1,826
Barrels oil equivalent (thousands)	411	448	471
Worldwide Average Prices (excluding hedging activities) (e)			
Liquids (per barrel)	$ 37.33	$ 27.70	$ 23.13
Natural gas (per mcf)	$ 4.02	$ 3.73	$ 2.79
Worldwide Average Prices (including hedging activities) (e)			
Liquids (per barrel)	$ 35.84	$ 27.60	$ 23.14
Natural gas (per mcf)	$ 3.98	$ 3.66	$ 2.81

(d) Includes proportional interests in production of equity investees of:

Liquids	*1*	*2*	*3*
Natural gas	*10*	*46*	*58*
Barrels oil equivalent	*2*	*10*	*13*

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

Additional information regarding oil and gas financial and reserve data is presented on pages 142 through 144 of this report.

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CONSOLIDATED RESULTS

Our consolidated results are driven primarily by the results of our oil and gas exploration and production business segment. The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes in Item 8 of this report, as well as the business and properties descriptions in Items 1 and 2 of this report. Our financial performance is highly dependent on commodity prices, our exploration success and our ability to develop and produce our proved reserves. Other factors such as, but not limited to, asset sales, insurance settlements, environmental and litigation costs may, from time to time, be important factors that impact our financial performance. The following table summarizes our consolidated net earnings for the years ended December 31, 2004, 2003 and 2002:

	Years ended December 31,		
Millions of dollars	**2004**	**2003**	**2002**
Earnings from continuing operations (a)	$ 1,145	$ 698	$ 323
Earnings from discontinued operations	63	28	8
Cumulative effect of accounting changes		(83)	
Net Earnings	$ 1,208	$ 643	$ 331

(a) Includes minority interests of:	$ (11)	$ (9)	$ (6)

Earnings From Continuing Operations

2004 earnings increased $447 million, or 64 percent, vs. 2003 primarily due to the following factors:

Positive Variance Factors

Higher worldwide commodity prices in 2004 increased net earnings by approximately $400 million.

International production was higher in 2004 and contributed about $60 million in higher earnings, primarily from Indonesia and Thailand liquids production due to a full year of production from the West Seno project and higher Thailand offshore crude oil development.

Exploration expenses were lower in 2004 primarily due to lower amortization of exploratory leasehold costs, which increased net earnings by approximately $35 million.

Our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban steam fields in the Philippines and recorded an after-tax settlement gain of $46 million in 2004.

We recorded net tax benefits of $82 million related primarily to settlements and assessments with various taxing authorities in 2004 and had $14 million in lower tax expenses primarily due to currency related adjustments in Thailand during 2004.

Our 2004 results included a $2 million after-tax benefit from an adjustment to the 2003 company-wide restructuring plan, which was recorded originally as a $24 million restructuring charge in 2003 (see note 6 to the consolidated financial statements in Item 8 of this report).

We recorded $31 million in after-tax asset impairments for North America operations in 2004 as compared to $53 million in 2003. The higher impairments in 2003 related to the Gulf of Mexico non-core property divestitures.

Our minerals operations recorded approximately $20 million in higher net earnings for 2004 as compared to 2003 due primarily to higher molybdenum margins.

The 2004 results included a $15 million after-tax litigation settlement gain related to a previous asset sale.

Pension and retiree medical related expenses were lower by $10 million after-tax due primarily to recognition in 2004 of the federal subsidy provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 and the impact of our $100 million contribution to our U.S. Qualified Retirement Plan.

Our results included approximately $92 million in after-tax gains from asset sales in 2004, primarily from the sale of certain of our exploratory mineral fee lands in the United States, the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia, the sale of non-oil and gas property in Parachute, Colorado and other miscellaneous real estate properties.

After-tax environmental and litigation expenses were $107 million in 2004, compared with $110 million in 2003.

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Negative Variance Factors

Lower North America production reduced net earnings by about $210 million in 2004 due mostly to divestitures of lower margin properties in the Gulf of Mexico, onshore United States and Canada in 2003 and natural production declines.

We recorded a charge of $43 million after-tax, associated with the settlements in 2004 regarding Agrium s Kenai, Alaska nitrogen-based fertilizer plant and our obligations to supply natural gas to the plant.

We recorded a provision of $21 million after-tax in 2004 for a retrospective liability increase related to our membership in Oil Insurance Limited (OIL).

Higher dry hole costs in 2004 reduced net earnings by approximately $20 million, primarily from Indonesia, Canada and Australia.

In 2003, asset sales added after-tax gains of approximately $65 million, which included the sale of our equity interests in Matador Petroleum Corporation (Matador) and Tom Brown, Inc. (Tom Brown) and other asset divestitures in North America.

The 2003 results also benefited from Canadian statutory tax rate changes, which added $29 million to net earnings.

2003 earnings increased $375 million, or 116 percent, vs. 2002 primarily due to the following factors:

Positive Variance Factors

Higher worldwide commodity prices increased net earnings by approximately $480 million.

International production increases also contributed about $35 million in higher earnings, primarily from higher Indonesia and Thailand liquids and natural gas production due to the start of production at the West Seno field in 2003, ramp-up of Thailand s Phase 1 crude oil production and an increase in gas demand in Thailand.

In 2003, asset sales added after-tax gains of approximately $65 million, which included the sale of our equity interests in Matador and Tom Brown and other asset divestitures in North America, compared to gains of approximately $26 million in 2002.

The Geothermal segment results improved net earnings by $20 million in 2003 as compared to 2002, primarily due to the amended Geothermal Salak energy sales agreements in Indonesia and higher earnings from our equity interests in natural 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 our Northrock subsidiary in Canada, compared with a $6 million after-tax loss in 2002.

The 2003 results also benefited from Canadian statutory tax rate changes, which added $29 million to net earnings.

We 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.

Negative Variance Factors

Lower North America production reduced net earnings by approximately $80 million.

Higher pension related expenses reduced net earnings by approximately $35 million due to the decline in interest rates and lower market returns on plan assets for years 2000-2002.

Higher asset impairments primarily related to the Gulf region non-core property divestitures reduced net earnings by approximately $30 million.

The premiums paid for the early redemption of long-term debt reduced net earnings by approximately $30 million.

Higher exploration expenses including dry hole costs reduced net earnings by approximately $15 million, primarily due to higher dry hole costs in 2003 in the Gulf of Mexico.

Our minerals operations recorded approximately $20 million in lower net earnings for 2003 as compared to 2002 due primarily to lower mining margins and lower Brazil equity earnings.

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.

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The 2003 results included our company-wide $24 million after-tax restructuring charge, while the 2002 period included $14 million in after-tax restructuring charges for the Gulf of Mexico region and Alaska business units.

Sales and Operating Revenues

Millions of dollars	**2004**	**2003**	**2002**
Sales and operating revenues (a)	$ 8,003	$ 6,368	$ 5,200
(a) *Includes crude oil buy/sell transactions settled in cash of:*	$ 965	$ 820	$ 604

2004 sales and operating revenues increased by $1.64 billion, or 26 percent, vs. 2003 primarily due to the following factors:

Higher average commodity prices from our exploration and production activities increased sales revenues. Our worldwide average realized liquids price was $35.84 per Bbl, which was an increase of $8.24 per Bbl, or 30 percent, from 2003. Our average realized liquids price included losses from our hedging activities of $1.49 per Bbl and 10 cents per Bbl in 2004 and 2003, respectively. Our worldwide average realized natural gas price was $3.98 per Mcf in 2004, which was an increase of 32 cents per Mcf, or 9 percent, from the $3.66 per Mcf, from 2003. Our average worldwide natural gas price included losses from our hedging activities of 4 cents per Mcf and 7 cents per Mcf in 2004 and 2003, respectively.

Sales and operating revenues from marketing activities were $3.7 billion in 2004, which was an increase of $778 million from 2003. During 2004 and 2003, approximately 26 percent and 23 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from outside parties by our Midstream and Marketing segment. These percentages in both years included crude oil buy/sell transactions. Increases in crude oil buy/sell amounts were primarily due to crude oil price increases as the volumes associated with these transactions remained relatively constant for the years shown (see crude oil buy/sell discussions in Item 8 of this report in the consolidated financial statements under notes 1 and 2). These marketing activities allowed us to better manage commodity-related risk by effectively transferring our production and commodity purchases to industry marketing centers with higher volumes of commercial activity and greater market liquidity.

Higher International liquids production increased sales revenues primarily due to a full year of production at the West Seno field in Indonesia and offshore crude oil development in Thailand.

In North America, lower natural gas and liquids production reduced sales revenues. Most of the production decline in 2004 was due to the divestiture of various properties in the Gulf of Mexico, onshore United States and Canada in 2003 and natural production decline.

2003 sales and operating revenues increased by $1.17 billion, or 22 percent, vs. 2002 primarily due to the following factors:

Higher average commodity prices from our exploration and production activities increased sales revenues. Our 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, our worldwide average realized liquids price was $27.60 per Bbl, which was an increase of $4.46 per Bbl, or 19 percent, from 2002. Our 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.

Sales and operating revenues from marketing related activities 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 outside parties by our Midstream and Marketing segment.

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Gain on Sales of Assets

In 2004, we recorded pre-tax gains of $154 million due primarily to the following asset sales from continuing operations.

Our Pure subsidiary sold certain of its mineral fee lands in the United States and recorded a pre-tax gain of $35 million relating to the prospective portion of these mineral fee lands.

Our subsidiary sold our rights and interests in the Sarulla geothermal project in Indonesia and recorded a pre-tax gain of $33 million.

Our Molycorp subsidiary sold down its interest in its equity investment in Companhia Brasileira de Metalurgia e Mineracao, a niobium operation in Brazil, from 44.59 percent to 40 percent and recorded a pre-tax gain of $15 million.

We recorded pre-tax gains of $52 million from the sale of real estate properties including the sale of non-oil and gas property in Parachute, Colorado and Simi Valley, California.

We recorded pre-tax gains of $13 million, which included the sale of our equity interest in a Brazilian exploration and production venture and the sale of various oil and gas properties, primarily in the Gulf of Mexico.

See note 3 in the consolidated financial statements in Item 8 of this report for a detailed discussion of our asset sales.

In 2003, we recorded pre-tax gains of $119 million due primarily to the following asset sales from continuing operations.

We sold our equity interest shares held in Tom Brown and Matador, with a pre-tax gain of $100 million.

We completed the sale of various oil and gas properties in the Gulf of Mexico, onshore United States and Canada, which resulted in a net pre-tax gain of $8 million while retaining our deep mineral rights from a substantial portion of the properties sold in the Gulf of Mexico.

We sold various real estate and other miscellaneous properties, which resulted in pre-tax gains of $11 million.

In 2002, we recorded pre-tax gains of $42 million due primarily to the following asset sales from continuing operations.

We sold certain investment interests in nonstrategic pipelines in the U.S, which added pre-tax gains of $49 million.

We sold real estate and other miscellaneous properties which added pre-tax gains of $20 million.

We sold various nonstrategic oil and gas assets in the U.S., which amounted to a pre-tax loss of $27 million.

Selected Costs and Other Deductions

Millions of dollars	Years ended December 31, 2004	2003	2002
Pre-tax costs and other deductions:			
Crude oil, natural gas and product purchases (a)	$ 3,202	$ 2,126	$ 1,701
Operating expense	1,435	1,340	1,338
Administrative and general expense	202	260	151
Depreciation, depletion and amortization	997	988	973
Impairments	74	93	47
Dry hole costs	160	128	107
Exploration expense (see components below)	201	251	246
Interest expense	160	190	179
Property and other operating taxes	84	81	60
(a) Includes crude oil buy/sell transactions settled in cash of:	*$ 965*	*$ 820*	*$ 604*
Exploration operations	$ 71	$ 68	$ 80
Geological and geophysical	57	63	53
Amortization of exploratory leases	61	108	98
Leasehold rentals	12	12	15
Exploration expense	$ 201	$ 251	$ 246

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2004 vs. 2003

Crude oil, natural gas and product purchases increased by $1.08 billion in 2004 due mostly to higher commodity prices and $205 million from higher volumes purchased primarily for International crude oil marketing. Increases in crude oil buy/sell amounts were primarily due to crude oil price increases as the volumes associated with these transactions remained relatively constant for the years shown (see crude oil buy/sell discussions in Item 8 of this report in the consolidated financial statements under notes 1 and 2).

Operating expense was $95 million higher in 2004. The increase was mainly due to $69 million related to the Agrium settlements; $34 million related to the OIL retrospective liability increase and higher expenses in Indonesia reflecting full-year operations at the West Seno field. The 2004 results also reflected lower Gulf of Mexico expenses due to the divestiture of various non-core properties in 2003.

Administrative and general expense decreased by $58 million in 2004. This decrease primarily reflected the $38 million restructuring accrual recorded in 2003 (see note 6 to the consolidated financial statements in Item 8 of this report).

Depreciation, depletion and amortization expense was slightly higher in 2004. The 2004 results reflected lower DD&A amounts from the divestiture of various non-core properties, primarily in the Gulf of Mexico, in 2003 and overall lower production from North America, which was offset by higher Indonesia DD&A amounts reflecting full-year operations at the West Seno field.

Impairments in 2004 were $74 million, with approximately $49 million attributable to oil and gas fields in the United States, which included $26 million related to an impairment of East Texas properties and $11 million for impairment of drilling related warehouse stock for the Gulf of Mexico region. We also recorded impairments of approximately $15 million relating to our Geothermal segment s equity investments in natural gas-fired power-plant projects and impairments of $5 million relating to our equity investment in an LPG terminal in China.

Dry hole costs were $32 million higher in 2004, reflecting higher exploration activity primarily in Indonesia, Canada and Australia, which amounted to $9 million, $8 million and $5 million, respectively.

Exploration expense decreased by $50 million in 2004, which was primarily due to lower amortization of exploratory leases. In 2003, we relinquished 44 deepwater Gulf of Mexico blocks before the end of their lease term and recorded a pre-tax provision of $26 million. The remaining decrease in the amortization of exploratory leasehold costs for 2004 is principally due to lower amortization for U.S. operations due to the divestiture of various properties in the Gulf of Mexico and onshore United States.

Interest expense was $30 million lower in 2004 primarily due to the premium paid on the early retirement of certain long-term debt in 2003, partially offset by the recognition of interest expense on the 6 $^{1}/4$% convertible junior subordinated debentures of Unocal payable to the Trust.

2003 vs. 2002

Crude oil, natural gas and product purchases increased by $425 million in 2003 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 due to the decline in interest rates and lower market returns on plan assets for years 2000-2002 and the $38 million restructuring charge in 2003.

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 our 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. In 2002, impairments were $47 million, which primarily reflected asset write-downs of certain oil and gas fields in Alaska and the Gulf of Mexico region.

Exploration expense remained relatively unchanged in 2003. We recorded higher amortization of exploratory leases due to our relinquishment of 44 deepwater Gulf of Mexico blocks, which was partially offset by lower expenses of $18 million, reflecting the relinquishment of certain exploration blocks in Gabon and Brazil in 2002.

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.

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Income Taxes

Income taxes on earnings from continuing operations in 2004 were $673 million compared with $514 million in 2003. The effective income tax rate for 2004 was approximately 37 percent as compared to approximately 42 percent in 2003. The overall lower effective tax rate for 2004 as compared with 2003 was due primarily to a $82 million net tax benefit in 2004 relating to settlements and assessments with various taxing authorities and $14 million in lower tax expenses primarily due to currency related adjustments in Thailand during 2004.

Income taxes on earnings from continuing operations in 2003 were $514 million compared with $277 million for 2002. The effective income tax rate for 2003 was approximately 42 percent as compared to approximately 45 percent in 2002. The overall lower effective tax rate for 2003 as compared with 2002 reflected a $29 million net tax benefit from Canadian statutory tax rate changes. In addition, the lower effective tax rate in 2003 reflected the mix of positive domestic and foreign earnings in 2003 compared to the mix of domestic losses and foreign earnings in 2002. Those factors were partially offset by currency-related adjustments in Thailand and tax adjustments related to the sale of affiliate investments in 2003.

Earnings From Discontinued Operations

Earnings from discontinued operations were $63 million, $28 million and $8 million in 2004, 2003 and 2002, respectively. See note 8 to the consolidated financial statements in Item 8 of this report for details on discontinued operations.

The 2004 results included an after-tax gain of approximately $44 million from our sale of certain mineral fee producing properties in the United States and $13 million after-tax gain from our sale of the Cal Ven pipeline located in Alberta, Canada. The remaining amounts in 2004 reflected after-tax operating earnings of $6 million from these mineral fee producing properties and the Cal Ven pipeline prior to the sale.

The 2003 results included an after-tax gain of $16 million related to the 1997 sale of our former West Coast refining, marketing and transportation assets. The sales agreement contained a provision calling for payments to us 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. In addition, the 2003 results included after-tax operating earnings of approximately $11 million and $1 million from the mineral fee producing properties and the Cal Ven pipeline, respectively.

The 2002 results included after-tax operating earnings of approximately $6 million and $1 million from the mineral fee producing properties and the Cal Ven pipeline, respectively. In addition, the 2002 results included an after-tax gain of $1 million related to the 1997 sale of our former West Coast refining, marketing and transportation assets.

Cumulative Effect of Accounting Changes

In 2003, we 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. We also increased our accrued abandonment and restoration liabilities by $268 million and increased our net properties by $138 million on the consolidated balance sheet as a result of the adoption of SFAS No. 143.

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BUSINESS SEGMENT RESULTS

See note 29 to the consolidated financial statements in Item 8 of this report for a description of our reportable segments. The following business segment results should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes in Item 8 of this report, the consolidated results discussed earlier in this Item 7 and the business and properties descriptions in Items 1 and 2 of this report. Our operations are organized in the following business segments:

Exploration and Production

North America *Included in this category are our oil and gas operations in the United States and Canada.*

2004 vs. 2003 After-tax earnings were $452 million in 2004 compared to $463 million in 2003. Higher natural gas and liquids prices increased net earnings by approximately $185 million in 2004 compared with 2003. In addition, exploration expenses and dry hole costs were lower in 2004 compared with 2003, primarily due to lower amortization of exploratory leasehold costs and lower drilling activity, which increased net earnings by approximately $30 million. After-tax impairments were approximately $31 million in 2004 compared to $53 million in 2003. This decrease was primarily due to the impairments in 2003 related to the assets that were held for sale in the Gulf of Mexico and subsequently sold. In 2004, we recorded a $15 million after-tax litigation settlement gain related to a previous asset sale.

These positive factors were offset by lower natural gas and liquids production in 2004 compared with 2003, which reduced net earnings by about $210 million. Most of the production decline was due to the divestiture of various properties in the Gulf of Mexico, onshore United States and Canada in 2003. The 2004 results included approximately $27 million after-tax in asset sale gains, primarily from the sale of certain of our exploratory mineral fee lands in the United States. The 2003 results included $57 million after-tax in asset sale gains, primarily from the sale of all of our stock holdings in Matador and Tom Brown and miscellaneous property in Canada. The sale of our equity investments in Matador and Tom Brown in 2003 also reduced earnings from equity investees by $10 million in 2004 as compared to 2003. In addition, we recorded a $25 million deferred tax benefit adjustment related to statutory tax rate changes in Canada for 2003.

2003 vs. 2002 After-tax earnings were $463 million in 2003 compared to $27 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, we recorded approximately $57 million after-tax in asset sale gains, primarily from the sale of Tom Brown and Matador common stock in 2003. We also recorded a $25 million deferred tax benefit adjustment related to statutory tax rate changes in Canada for 2003. The 2002 results included about $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.

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 net earnings by approximately $80 million, $40 million, $25 million and $10 million, respectively. North America liquids production averaged 81 MBbl/d in 2003, down from 94 MBbl/d in 2002, while natural gas production averaged 763 MMcf/d in 2003 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 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 impairments in 2002 that totaled $12 million. In 2002, our Alaska business unit had an after-tax impairment of $15 million.

International *Our International operations encompass oil and gas operations outside of North America.*

2004 vs. 2003 After-tax earnings totaled $779 million in 2004 compared to $561 million in 2003. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately $220 million. Production was higher in 2004 than 2003 primarily due to higher liquids production attributable to a full-year of production from the West Seno field in Indonesia and higher Thailand liquids production due to offshore crude oil development, which increased net earnings by $60 million. The 2004 results reflected higher operating expenses, primarily from a full-year of operations at the West Seno field in Indonesia, as compared to 2003, which reduced net earnings by $25 million. Higher dry hole costs in 2004, primarily from Indonesia and Australia, reduced net earnings by approximately $15 million. In addition, the 2004 results included $10 million in after-tax charges related to the termination of our participation in the exploration and development of the Xihu Trough in China.

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 field 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 about $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.

Midstream and Marketing

The Midstream and Marketing segment is comprised of our equity interests in certain petroleum pipeline companies, wholly-owned pipelines and terminals throughout the United States, our North America natural gas storage business and the organization that markets the majority of our worldwide liquids production and North American natural gas production. To market our U.S. production, the segment enters into various sale and purchase transactions, including crude oil buy/sell transactions, with unaffiliated oil and gas producing, refining, marketing and trading companies (see crude oil buy/sell discussions in Item 8 of this report in the consolidated financial statements under notes 1 and 2). 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 us to better manage our commodity-related risks. Currently, these sale and purchase transactions represent a significant portion of the segment s U.S. crude oil sales and purchases. This marketing organization is also responsible for implementing commodity specific risk management activities on behalf of our exploration and production segment, and it conducts our trading activities involving hydrocarbon derivative instruments.

2004 vs. 2003 After-tax earnings totaled $79 million in 2004 compared to $70 million in 2003. The higher 2004 results reflected gains from crude oil and natural gas trading activities, which were positively impacted by volatile commodity prices. In addition, the 2003 results included gains on the sale of certain pipeline assets.

The segment s sales and operating revenues were $4.41 billion in 2004 compared to $3.47 billion in 2003. Included in these totals were sales from marketing activities totaling $3.7 billion in 2004 compared to $2.92 billion in 2003, representing approximately 46 percent of our total consolidated sales and operating revenues for both 2004 and 2003. Sales from marketing activities include buy/sell transactions. The increase in sales from marketing activities was primarily due to higher international and domestic crude oil revenues resulting from higher crude oil prices, which increased revenues by approximately $934 million. This was partially offset by lower domestic natural gas revenues resulting from lower volumes attributable mainly to property sales in the Gulf of Mexico in 2003, which decreased revenues by approximately $159 million.

2003 vs. 2002 After-tax earnings totaled $70 million in 2003 compared to $107 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 United States that occurred in 2002. The decrease was also due to $3 million in higher after-tax expenses related to the BTC crude oil pipeline project and a $7 million after-tax impairment related to the Trans-Andean oil pipeline in Argentina. 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.

The segment s sales and operating revenues were $3.47 billion in 2003 compared to $2.80 billion in 2002. Included in these totals were sales from marketing activities totaling $2.92 billion in 2003 compared to $2.52 billion in 2003, representing approximately 46 percent and 48 percent of our total consolidated sales and operating revenues for 2003 and 2002, respectively. In 2003, natural gas revenues increased by about $420 million and crude oil revenues decreased

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by about $20 million. Both natural gas and crude oil revenues benefited from higher commodity prices, as compared to 2002. 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 reflected our strategy to decrease our outside crude oil purchases for resale due to continued volatility in the oil markets.

Geothermal

The Geothermal segment includes geothermal steam production for power generation, with operations in the Philippines and Indonesia. Geothermal activities also include the operation of geothermal steam-fired power plants in Indonesia and equity interests in natural gas-fired power plants in Thailand.

2004 vs. 2003 After-tax earnings totaled $119 million in 2004 compared to $50 million in 2003. The current year results included a $46 million after-tax gain from the settlement of the outstanding contract dispute in our Philippines operations (see Philippines Settlement below for further detail) and a $21 million after-tax gain from the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia. Improved results from our operations at Gunung Salak, Indonesia and the Philippines added approximately $23 million to our after-tax earnings. Most of this increase was attributable to higher revenues and lower costs that were the result of lost generation and additional repair costs associated with damage caused by landslides at Gunung Salak in 2003, the positive effect of a full year of earnings related to our DSPL subsidiary in Indonesia and improved Philippines results attributable to the new contract. These positive factors were mostly offset by lower earnings from our equity interests in natural gas-fired plants as compared to 2003, primarily due to an after-tax impairment of $15 million recorded in 2004 relating to the value of our investment and losses in 2004 compared to gains in 2003 relating to the operations of these power plants, which reduced after-tax earnings by $7 million.

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

Philippines Settlement: Our UPI subsidiary, formerly known as PGI, obtained final Philippine government and court approvals in June 2004 of a settlement for past contractual issues covering the ongoing operations of the steam resources at Tiwi and Mak-Ban on the island of Luzon. In July 2004, UPI received $50 million in cash for this settlement from NPC and PSALM. At year-end 2004, there was a $25 million after-tax receivable related to the settlement. In February 2005, we received $24 million in cash related to this receivable.

Corporate and Other

Corporate and Other includes general corporate overhead, miscellaneous operations (including real estate, carbon and mineral businesses), other corporate unallocated costs (including environmental and litigation expenses) and net interest expense.

2004 vs. 2003 The after-tax earnings effect for 2004 was a loss of $284 million compared to a loss of $446 million in 2003. After-tax expenses for environmental and litigation matters for 2004 were $105 million compared to $107 million for 2003. The 2004 results included net tax benefits of $82 million relating primarily to settlements and assessments with various taxing authorities. The 2004 results included $43 million after-tax associated with the settlements regarding Agrium s Kenai, Alaska nitrogen-based fertilizer plant, and our obligations to supply natural gas to the plant. The 2004 results also included an after-tax gain of $33 million from the sale of non-oil and gas property in Parachute, Colorado and Simi Valley, California. In addition, the 2004 results reflected approximately $20 million after-tax in higher results from our minerals business due to higher margins attributable to molybdenum prices and $10 million after-tax in lower pension and retiree medical related expenses due primarily to recognition in 2004 of the federal subsidy provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 and the impact of our $100 million contribution to our U.S. Qualified Retirement Plan. The 2004 results included a $2 million after-tax benefit from the adjustment to the 2003 company-wide restructuring, for which we recorded charges totaling $24 million in 2003.

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2003 vs. 2002 The after-tax earnings effect for 2003 was a loss of $446 million compared to a loss of $344 million in 2002. The 2003 results included $24 million after-tax in restructuring charges and higher pension related expenses of approximately $35 million due to the decline in interest rates and lower market returns on plan assets for years 2000-2002. 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, our minerals operations recorded approximately $20 million after-tax in lower earnings for 2003 as compared to 2002, primarily due to lower mining margins and lower Brazil equity earnings.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table shows certain measures of our financial condition as of the end of each of our last three completed fiscal years:

	At December 31,		
Millions of dollars except as indicated	**2004**	**2003**	**2002**
Current ratio (a)	1.1:1	1.0:1	0.8:1
Cash and cash equivalents	$ 1,160	$ 404	$ 168
Total debt and capital leases (b)	3,062	2,883	3,008
Trust convertible preferred securities (b)		522	522
Stockholders equity (c)	5,217	4,009	3,298
Total capitalization	8,279	7,414	6,828
Floating-rate debt/total debt (d)	8%	8%	6%

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(a) Ratio of total current assets to total current liabilities.

(b) With the adoption of FASB Interpretation No. 46 (Revised December 2003), Consolidation of Variable Interest Entities, the Trust redeemable preferred securities were deconsolidated and replaced by $538 million in debt effective January 1, 2004.

(c) 2004 and 2003 included increases of $87 million and $145 million, respectively, 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 a $334 million after-tax charge to other comprehensive income to recognize the minimum pension liability for our U.S. Qualified Retirement Plan.

(d) 2002 excluded interest rate swap derivatives. With the swaps included, the 2002 ratio would have been 5%.

Liquidity is defined as our ability to generate sufficient cash flows from operating activities and other available sources to meet obligations and commitments. Cash generated from operations is our principal source of liquidity. We generally fund any additional liquidity requirements through debt issuance including commercial paper, the sale of a portion of our accounts receivable accounts through our receivable securitization program, and the use of revolving credit facilities to cover near-term borrowing requirements. Currently, our liquidity needs arise primarily from capital expenditures, cash dividends, working capital requirements and debt service.

Cash and cash equivalents on hand totaled $1.16 billion at December 31, 2004, up from $404 million at the end of 2003. We have announced our intention to repurchase up to $459 million of our common stock by the end of the second quarter of 2005, depending on market conditions and other factors. Based on current commodity prices and current development projects, we expect cash generated from operating activities, asset sales and cash on hand to be sufficient in 2005 to cover our operating and capital spending requirements and to make expected dividend payments and to pay down scheduled debt. In addition, we believe that our available borrowing capacity is sufficient to enable us to meet unanticipated cash requirements if needed. As of the date of this report, there are no material restrictions imposed by credit agreements or other contracts to which Unocal or its subsidiaries is a party that would restrict inter-company loans, capital contributions, dividends or other distributions of cash among Unocal and its consolidated subsidiaries, equity investees or variable interest entities.

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Cash Flows from Operating Activities

Net cash provided by operating activities was $2.56 billion in 2004, $1.95 billion in 2003 and $1.57 billion in 2002.

2004 vs. 2003 Cash flows from operating activities increased by $607 million in 2004. The increase principally reflected the effects of higher worldwide commodity prices. The positive impact from higher prices was partially offset by the contribution of $100 million to our U.S. Qualified Retirement Plan, the negative impact from lower North America production, compared to 2003, and settlement payments made to Agrium. The 2004 results reflected higher tax payments net of refunds. Refunds included the receipt of $35 million relating to a federal income tax refund for the 2003 tax year and the receipt of payment from the Indonesian government in settlement of disputed value added taxes we paid in prior years. We also received approximately $143 million relating to federal and state income tax refunds for multiple tax years (see Tax Matters in note 23 to the consolidated financial statements in Item 8 of this report).

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, we received $51 million in repayment of a loan made to PTT when we farmed into the Arthit field in Thailand. The positive impact from higher prices was partially offset by higher income tax payments and higher interest paid compared to 2002. In addition, cash flows from operating activities were reduced by the repayment of the outstanding balance under our accounts receivable securitization program.

Capital Expenditures

		Years ended December 31,		
Millions of dollars	**Estimated 2005 (a)**	**2004**	**2003**	**2002**
Exploration and production				
North America				
United States	$ 500	$ 565	$ 556	$ 616
Canada	115	136	133	147
North America Total	615	701	689	763
International				
Asia	785	598	576	627
Other	320	327	258	156
International Total	1,105	925	834	783
Total exploration and production	1,720	1,626	1,523	1,546
Midstream and marketing	85	44	138	71
Geothermal operations	20	47	21	14
Corporate and other	30	27	36	39
Total capital expenditures (b)	$ 1,855	$ 1,744	$ 1,718	$ 1,670

(a)	*Estimated capital expenditures for 2005 exclude any possible major acquisitions.*							
(b)	*Includes capitalized interest of:*	*$*	*55*	*$*	*65*	*$*	*60*	*$* *46*

We expect our capital expenditures in 2005 to increase by 6 percent from the 2004 level. The major component of this increase is due to higher capital spending for development projects in Thailand and Bangladesh (International Asia). In Thailand, we expect to spend an additional $160 million relating to Phase 2 development of the crude oil project and the development of the Arthit field. In Bangladesh, we expect to spend an additional $90 million primarily for development of the Moulavi Bazar and Bibiyana fields. These increases will be mostly offset by $65 million in lower capital expenditures in the United States primarily due to lower Gulf of Mexico development activities relating to the Mad Dog field and $70 million in lower development capital in Indonesia (International Asia) due to the completion of the initial portion of the West Seno field project.

2004 vs. 2003 Capital expenditures for 2004 were $26 million higher than 2003. This year s expenditures level primarily reflected lower exploratory capital requirements in the Gulf of Mexico, which was offset by higher capital expenditures in the United States onshore Permian Basin. Last year, capital expenditures in our Midstream and Marketing segment included the BTC crude oil pipeline project expenditures prior to its financing by the BTC Pipeline Company. The current year reflects higher expenditures related to the development of the ACG crude oil project (International Other).

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In 2004, our capital expenditures included approximately $670 million for the development of undeveloped proved oil and gas reserves, primarily in Indonesia, Azerbaijan, Thailand and the deepwater Gulf of Mexico. In 2003, our capital expenditures included approximately $770 million for the development of undeveloped proved oil and gas reserves, primarily in the same areas.

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 and Mad Dog in the Gulf of Mexico, and the ACG crude oil project in the Caspian Sea, and the associated BTC crude oil pipeline project 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.

Asset Sale Proceeds

In 2004, pre-tax proceeds from asset sales relating to continuing and discontinued operations were $500 million. Our net proceeds included $176 million from the sale of certain of our mineral fee lands in the United States and $67 million from the sale of our 50 percent equity interest in a Brazilian exploration and production venture that owned our remaining oil and gas assets in Brazil. Pre-tax net proceeds included about $60 million from the sale of our rights and interests in the Sarulla geothermal project in Indonesia and $19 million from the sale of the Cal Ven Pipeline system in Canada. Our Molycorp subsidiary sold down its interest of its equity investment in a niobium operation in Brazil, from 44.59 percent to 40 percent for $27 million in cash. We also received approximately $84 million from the sale of real estate properties, which included the sale of non-oil and gas property in Parachute, Colorado for $26 million and real estate property in Simi Valley, California for $38 million. We also received about $47 million from the sale of various oil and gas properties, with $26 million from Gulf of Mexico properties. Lastly, we received pre-tax proceeds of $27 million from the sale of other miscellaneous assets, which included $16 million from the sale of assets in our carbon business.

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 United States and Canada. We also received proceeds of $229 million from the sale of our 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 our 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 United States, $54 million from the sale of oil and gas assets primarily in the United States 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 our former West Coast refining, marketing and transportation assets.

Other Investing Activities

In 2004, cash flows from investing activities included $48 million representing a return of capital from the completion of the BTC financing which closed in February 2004. The BTC Pipeline Company is financing up to 70 percent of the pipeline s cost. We have an 8.9 percent equity interest in the pipeline company.

Long-term Debt Financing Activities

During 2004, we reduced our outstanding balance on the 6-1/4% convertible junior subordinated debentures by $296 million and retired $173 million in 6.375 percent notes and $20 million of medium-term notes that matured. In addition, we retired the remaining $24 million limited recourse loan balance under the AIOC Early Oil Project in 2004. We also made $41 million in principal payments on the variable rate portion of the OPIC Financing Agreement for the West Seno project in Indonesia, which is scheduled to mature in June 2009. These decreases were partially offset by $40 million in new borrowing relating to AIOC Phase 1 development of the ACG crude oil project, scheduled for repayment semiannually from June 2006 through December 2015, and $95 million drawn under two new loans from the OPIC Financing Agreement, both limited recourse loans, for the West Seno project in Indonesia. One loan was drawn for $50 million and the other was drawn for $45 million, and they carry fixed rates of 3.61 percent and 4.78 percent, respectively. Principal payments on the $50 million loan are scheduled semiannually from June 2005 to December 2007, and on the $45 million loan payments are scheduled from June 2005 to June 2008.

During 2003, we retired $89 million in 9.25 percent debentures and $10 million of medium-term notes that matured. We also 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. In addition, we repurchased $34 million of the 7.35 percent notes due in 2009, $34 million of the 9.125 percent debentures due in 2006, $27 million of the 6.375 percent notes due in 2004 and $26 million of medium-term notes in varying maturities. We repaid $20 million of 6.20 percent Industrial Development Revenue Bonds due in 2008. In total, we 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 OPIC Financing Agreement for the West Seno project in Indonesia. In 2003, we 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 the Financial Accounting Standards Board (FASB) Interpretation No. 46 (see note 18 for further detail on our long-term debt).

Other Financing Activities

In 2004, we repurchased 5,915,208 shares of our common stock at a cost of approximately $223 million utilizing cash on hand. See Treasury Stock discussion in note 24 to the consolidated financial statements in Item 8 of this report for a detailed discussion of the repurchased common stock.

In 2004, we received $195 million from the issuance of 6,962,654 shares of our common stock related to the exercise of existing stock options.

Credit Facilities and Other Financing Sources

Revolving Credit Facility

General

In August 2004, our wholly owned subsidiary, Union Oil Company of California, entered into a $1.0 billion revolving credit agreement with a group of 29 commercial banks with a maturity date of August 12, 2009, and terminated its $600 million and $400 million credit facilities. Unocal guaranteed the obligations of Union Oil under the credit agreement. The credit agreement provides for the lenders to make up to $500 million of the $1.0 billion available in the form of letters of credit.

As of December 31, 2004, there were no borrowings outstanding under the credit agreement. Our ability to borrow at any particular time under the credit agreement is subject to the accuracy of certain representations and warranties and the absence of any defaults or events of default that we believe are customary for such a facility. The credit agreement does not contain a material adverse change or MAC clause test that would impair our ability to borrow under it.

The following is a summary of certain provisions of our credit agreement. It is not a complete discussion of all provisions or terms of the credit agreement. Please refer to the complete agreement, which we have filed as Exhibit 10 to our Form 8-K filed August 18, 2004.

Interest Rates

The interest rate for any borrowing under the credit agreement is determined at our option as follows:

Eurodollar loans for specified periods at the applicable LIBOR rate plus an applicable borrowing spread; or

competitive bid loans provided by any or all of the lenders through a competitive process; or

a rate established each day as the greater of the prime rate or the federal funds rate plus a half percent.

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Credit Rating Triggers

The applicable rate for Eurodollar revolving loans and the applicable facility fees vary in accordance with Unocal s credit ratings. Lower credit ratings result in higher facility fees and Eurodollar loan rates and higher credit ratings result in lower facility fees and Eurodollar loan rates. The credit agreement does not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade.

Mandatory Prepayments

The credit agreement provides for termination of the loan commitments and mandatory prepayments of any borrowings, interest and fees under certain specified events, including if (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 cease to constitute at least a majority of Unocal s board of directors.

Negative Covenants

The credit agreement contains financial and other covenants, including covenants that limit our and certain of our subsidiaries abilities to, among other things:

- incur liens upon any of our existing or future property or assets, other than permitted liens allowed by the credit agreement; and
- exceed a total debt to total capitalization ratio of 0.70 to 1.0 (total capitalization is defined as total debt plus total equity, with the convertible junior subordinated debentures excluded from total debt and included as equity in the ratio calculation). At December 31, 2004, this ratio was calculated to be 0.34 to 1.0.

Events of Default

The credit agreement includes events of default relating to:

- failure to pay amounts due in accordance with the terms of the credit agreement;
- failure to observe or perform any other affirmative covenants or other agreements under the credit agreement that remains uncured for thirty days after receipt of a notice of default;
- failure to observe or perform any negative covenants under the credit agreement;

accuracy of representations and warranties;

defaults and accelerations of other material indebtedness or material guarantee obligations;

bankruptcy, insolvency, reorganization and other similar proceedings and actions;

certain Employee Retirement Income Security Act (ERISA) matters;

material non-payment or non-appeal of judgments and decrees;

failure to own 100 percent of Union Oil or the majority of each borrowing subsidiary; and

unenforceability of any guarantees under the credit agreement.

The occurrence of an event of default may result in the termination of the loan commitments and require prepayments of any borrowings, interest and fees.

Canadian Revolving Credit Facility

In November 2004, two of our wholly owned Canadian subsidiaries entered into a new $295 million Canadian dollar-denominated credit agreement with five commercial banks with a maturity date of December 2009. The credit agreement is composed of a $200 million Canadian dollar-denominated term loan and a $95 million Canadian dollar-denominated revolving loan facility. Both loans provide for the payment of a variable rate of interest on borrowed amounts. This new agreement replaced the $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest, which was terminated before it was due to expire on December 19, 2005. At December 31, 2004, the borrowing under the Canadian credit facility translated to $245 million, using the applicable foreign exchange rate.

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Commercial Paper; Accounts Receivable Securitization; Universal Shelf

In addition to our revolving credit agreement, we have relied on the commercial paper market and our accounts receivable securitization program to cover near-term borrowing requirements (see Off-Balance Sheet Arrangements for further detail on page 53). At December 31, 2004, we had no outstanding balance under the commercial paper or accounts receivable securitization programs. We also have in place a universal shelf registration statement as of December 31, 2004, with an unutilized balance of approximately $1.539 billion, which is available for the future issuance of other debt and/or equity securities depending on our needs and market conditions. From time to time, we may also look to fund some of our long-term projects using other financing sources, including multilateral and bilateral agencies.

Credit Ratings

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 our ability to raise short-term and long-term financing. As a result of our current investment grade ratings, we have access to both the commercial paper and bank loan markets. We currently have a BBB+ / Baa2 credit rating by Standard & Poor s and Moody s, respectively, and an A-2 / Prime-2 for our commercial paper ratings. Moody s and Standard & Poor s outlooks, as of the date of the filing of this report, remained stable for our long term debt and commercial paper ratings. In the event that our credit ratings were downgraded to below investment grade, our ability to access additional short and long-term financing sources and the terms of any such financing would be adversely impacted. However, based on current commodity prices, we believe that cash generated from operating activities, asset sales and cash on hand would be sufficient for the remainder of 2005 to cover our operating and capital spending requirements for current development projects and to make expected dividend payments and to pay scheduled debt maturities. We also believe that our available borrowing capacity under our revolving credit agreement would be sufficient to enable us to meet unanticipated cash requirements if needed.

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Contractual Obligations and Commitments

The following table outlines certain of our financial contractual obligations. Some of these contractual obligations are reflected in our balance sheet, while others are disclosed as future obligations under accounting principles generally accepted in the United States.

		Amount of Obligation Expiration			
Millions of dollars	**Total**	**2005**	**2006 - 2007**	**2008 - 2009**	**Later years**
Long-term debt (a) (i) (j)	$ 3,032	$ 488	$ 431	$ 671	$ 1,442
Capital leases (a)	30	3	6	6	15
Non - cancelable operating leases (b) (i)	236	135	63	32	6
Purchase obligations (c)					
Development related expenditures	1,161	582	520	59	
Exploration related expenditures	125	120	5		
Other	240	228	8	3	1
Asset retirement obligations (d)	762	61	63	75	563
Environmental liabilities (d)	244	109	127	3	5
Postretirement medical benefits (e)	48	25	23		
Pension and other employee benefits (f)	253	22	41	45	145
Advances related to future production (g)	134	26	16	9	83
Derivative and commodity contract liabilities (h) (i)	225	94	80	51	
Other	419	259	68	34	58
Total	$ 6,909	$ 2,152	$ 1,451	$ 988	$ 2,318

(a) See note 18 for details on long-term debt.
(b) See note 4 for detail on non-cancelable operating leases.
(c) Includes both accrued and future expenditures for significant purchase obligations and commitments.
(d) See notes 19 and 23 for detail on environmental liabilities and note 19 for asset retirement obligations.
(e) Payments reflect an estimate of the mandated annual contributions in 2005 and 2006 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 $23 million in 2007 and $46 million in 2008-2009 plus $107 million in the out years reflecting the remainder of the actuarially computed balance.
(f) Reflects anticipated payments in support of our Supplemental Executive Retirement Plan and unfunded foreign pension plans. We expect that mandated employer contributions to the U.S. Qualified Retirement Plan will be payable no sooner than 2009 and thus have not included any potential contribution amount in the table.
(g) See note 20 for further detail.
(h) Includes interest rate, foreign exchange rate and hydrocarbon derivatives and forward natural gas sale.
See discussion in Item 7A and note 27 for detail on derivatives and note 21 for the forward natural gas sale.

Excludes derivative assets of $217 million.

(i) There are no credit rating triggers that would require pre-payment.
(j) Interest payments on our debt are currently estimated to be $173 million in 2005, $291 million in 2006-2007, $245 million in 2008-2009 and $891 million in the years thereafter. These amounts are excluded from the above table.

We have other liabilities reflected in our balance sheet, including current and deferred income taxes and pension and postretirement healthcare liabilities. The payment obligations associated with these liabilities, in some instances, are not reflected in the table above due to the absence of scheduled maturities; therefore, the timing of these payments cannot be determined. The amounts reflected in the table above for purchase obligations represent noncancelable agreements to purchase goods or services. Open purchase orders that are cancelable are not considered unconditional purchase obligations for financial reporting purposes and are not included in the table above. Such purchase orders often represent authorizations to purchase rather than binding agreements.

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The following table shows the amounts of what we believe to be our existing principal commitments and the amounts of our expected future remaining expenditures for the following projects: the ACG crude oil project in the Caspian, the development of the Moulavi Bazar and Bibiyana fields in Bangladesh, development of the crude oil project in Thailand and the Arthit field project in Thailand. The amounts reflected in the following table are a subset of the Contractual Obligations and Commitments table on page 50.

Millions of dollars	Aggregate Amount Committed	Remaining Expenditures at December 31, 2004
AIOC		
ACG crude oil - Phase 2	$ 780	$ 284
ACG crude oil - Phase 3	$ 420	$ 396
Bangladesh		
Moulavi Bazar development project	$ 43	$ 20
Bibiyana development project	$ 221	$ 218
Thailand		
Pattani crude oil project	$ 67	$ 17
Arthit project	$ 102	$ 93

In the normal course of business, we also have 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, if drawn upon, we are required to reimburse the financial institutions. We have entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit. In addition, we have various other outstanding guarantees. See note 23 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 shows our financial commitments for the categories specified in the table, including the potential effects in the event of a credit rating downgrade:

Millions of dollars	Total	Amount of Commitment Expiration 2005	2006-2007	2008-2009	Later years	Recourse & Credit Rating Triggers
Revolving credit agreement expiring Aug. 12, 2009 - zero balance outstanding	$ 1,000	$		$ 1,000	$	Interest rate varies marginally based on rating. Ratings downgrade does not prevent drawdown or require pre-payment
Receivable securitization program (a) - zero balance outstanding at year-end						Sales of receivables prohibited if rating below Baa3 or BBB-
Standby letters of credit & bank guarantees (b) (d)	105	105				None - primarily one year term
Other financial assurances (b) (d)	525	525				Approx. $305 million would require bonds, letter of credit or trust funds if rating below Baa3 or BBB-
Performance bonds (with indemnity) (b)(c)(d)	178	178				Approx. $67 MM in bonds would require additional collateral if rating below Baa3 or BBB-
Guaranteed debt of equity investees (d)						None
Non-guaranteed debt of equity investees (e)						None
Environmental indemnification related to sold or formerly-operated properties (d)						None

(a) *See note 11 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 $84million 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 23 for further details.*
(e) *See note 14 for further details.*

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Off-Balance Sheet Arrangements

Guarantees Related to Assets or Obligations of Third Parties

We have guaranteed the debt of certain other entities 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. We are not the primary beneficiary in any of these arrangements. The maximum amount of future payments that we could be required to make is approximately $15 million. In addition to these guarantees, to facilitate sales of some property or as a condition of some property leases, we indemnified certain third parties for particular remediation costs.

We also have a construction completion guarantee related to debt financing associated with our equity interest in the development of the BTC crude oil pipeline project. The maximum potential future payments under the guarantee are estimated to be $310 million. Extending guarantees to creditors allows the project to reduce its borrowing costs. We are not the primary beneficiary in this arrangement. See note 23 to the consolidated financial statements for a detailed discussion.

See note 23 to the consolidated financial statements in Item 8 of this report for a more detailed discussion of guarantees related to assets or obligations of third parties. We do not believe these agreements are material to our liquidity, credit risk or capital resources.

Sales of Accounts Receivables

Through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation (URC), we have 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. We use this program as a low cost and readily available source of working capital. Details of this arrangement are provided in note 11 to the consolidated financial statements in Item 8. In the event receivables become uncollectible, the outside purchaser would participate in any losses that exceed reserves built into the program. At December 31, 2004 and 2003, we had no outstanding balance under this program.

The arrangement also has a credit rating trigger whereby the sales of receivables are prohibited if our 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 we may find it necessary to use an alternative source of funds. In this case, our accounts receivable balance would increase as well as the balance of debt on our consolidated balance sheet. We do not believe this program to be material to our liquidity or capital resources.

Environmental Matters

We are committed to operating our business in a manner that is environmentally responsible. This commitment is fundamental to our core values. As part of this commitment, we have procedures in place to audit and monitor our environmental performance. In addition, we have implemented programs to identify and address environmental risks throughout Unocal. Consequently, we continue to incur substantial capital and operating expenditures for environmental protection and to comply with federal, state and local laws, as well as foreign laws, regulating the discharge of materials into the environment and management of hazardous and other waste materials. In many cases, investigatory or remedial work is now required at various sites even though past operations followed practices and procedures that were considered acceptable under environmental laws and regulations, if any, existing at the time.

	Estimated	**Years Ended December 31,**		
Millions of dollars	**2005**	**2004**	**2003**	**2002**
Environmental related capital expenditures	$ 38	$ 29	$ 24	$ 22

Capital expenditures in 2004 were higher than 2003 primarily due to expenditures for waste handling, treatment and disposal. Our estimated 2005 capital expenditures are higher than 2004 expenditures primarily due to new waste handling and processing facilities that will be installed in 2005 for our ongoing operations in Thailand.

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Amounts recorded for environmental related expenses, including provisions for remediation that were identified during our ongoing review of environmental obligations and operating, maintenance and administrative expenses, were approximately $145 million in 2004, $140 million in 2003 and $170 million in 2002. Higher expenses in 2004 versus 2003 were primarily due to new processes and increased costs for waste material handling, treatment and disposal. Partially offsetting these higher expenses were lower remediation provisions recorded in 2004. Higher 2003 remediation provisions were primarily the result of recording the remediation provision for the former Guadalupe oil field as described below. 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 our former West Coast refining, marketing and transportation assets sold in 1997 and for the decommissioning and decontamination, by our Molycorp subsidiary, of a 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 our former Guadalupe oil field located on the central California coast and for remediation projects at our former refinery in Beaumont, Texas.

Probable costs associated with identified and reasonably estimable environmental obligations have been accrued in a reserve for such obligations. Accruals are based on developments to date, our estimates of the outcomes of these matters and our experience in addressing these matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which could have a material effect on our future results of operations, financial condition or liquidity. At December 31, 2004, our reserves for environmental remediation obligations totaled $244 million, of which $109 million was included in current liabilities. In 2004, cash payments of $102 million were applied against the reserves and $94 million was added to the reserves. We 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, we estimate that we could incur possible additional remediation costs aggregating approximately $215 million.

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

	At December 31, 2004	
Millions of dollars	**Reserve**	**Possible Additional Costs**
Superfund and similar sites	$ 14	$ 15
Active Company facilities	30	35
Company facilities sold with retained liabilities and former Company-operated sites	101	70
Inactive or closed Company facilities	99	95
Total	$ 244	$ 215

Also, see notes 19 and 23 to the consolidated financial statements in Item 8 of this report for additional information on environmental related matters.

We recorded provisions of $9 million during 2004 for the Active Company facilities category of sites. The provisions were primarily for the estimated additional costs of the remedial investigation and feasibility study (RI/FS) that is continuing at a molybdenum mine located in Questa, New Mexico, which is owned by our Molycorp subsidiary. The estimated additional costs are based on an evaluation that Molycorp performed in 2004 of the remaining work that will be required to complete the RI/FS. Molycorp has been conducting the RI/FS cooperatively with the EPA to determine what, if any, adverse impacts past mining operations may have had on the environment.

During 2004, provisions of $74 million were recorded for the Company facilities sold with retained liabilities and former Company-operated sites category. These provisions were for approximately 270 sites where we had operated service stations, bulk plants or terminals. The provisions were based on new and revised cost estimates that were developed for these sites in 2004. In 2004, we received revised remediation cost estimates from the purchaser of service stations, bulk plants, terminals, refineries and pipelines that were part of our former West Coast refining, marketing and transportation assets sold in 1997. We recorded a provision for our estimated share of these revised costs. The provisions were also for new and revised cost estimates for the assessment and remediation of oil fields in Michigan and California. We will perform assessments on certain areas within these fields to determine if they have been contaminated by our former operations. We have determined that other areas within these sites are contaminated and will require remediation.

The reserve related to sites in the Inactive or closed Company facilities category was increased by $9 million during 2004. The increase was primarily for our former refinery in Beaumont, Texas and a former terminal in Edmonds, Washington. A provision was recorded for the updated cost estimates to close impoundments used in the former operations at the Beaumont, Texas site. In 2004, final design work and related detailed cost estimates to close these impoundments were completed. We also received final approval of a permit for these projects from the Texas Commission on Environmental Quality. The reserve for this category of sites was also increased for the estimated cost of cleanup work at a shutdown terminal in Edmonds, Washington. The cost includes the implementation and operation of a system to remediate petroleum hydrocarbon contamination caused by our former petroleum products storage and transportation operation at the facility.

In 2004, estimated possible additional costs in excess of amounts included in the reserves for remediation obligations increased by $10 million.

Possible additional costs for the Active Company facilities category of sites increased by $5 million in 2004. These costs are primarily to close two impoundments and remove a pipeline at our Molycorp subsidiary s lanthanide mine in California. Releases from the impoundments and pipeline of wastewater and tailings generated by the mining and milling operation had caused soil and groundwater contamination at the facility.

During 2004, possible additional costs for the Company facilities sold with retained liabilities and former Company-operated sites category decreased by $5 million. The lower costs were primarily for former service station, bulk plant and terminal sites at various locations. Some of the amounts previously included in the possible additional costs were added to the reserve for these sites as discussed above. Lower possible additional costs for these sites are also the result of revised estimates of the upper end of remediation costs ranges that were developed during 2004. Partially offsetting the aforementioned decreases were higher remediation costs based on estimates received from the purchaser of service stations, bulk plants, terminals, refineries and pipelines that were part of our former West Coast refining, marketing and transportation assets sold in 1997.

Possible additional costs for the Inactive or closed Company facilities category increased by $10 million. The increase is primarily for a molybdenum processing facility in Washington, Pennsylvania, which is owned by our Molycorp subsidiary. The remediation that may be required is for tar-contaminated soil caused by the operations of the former owner of the property.

Litigation and Other Contingencies

We are also subject to contingent liabilities for existing and potential claims, lawsuits and other proceedings and tax and other matters. For a more detailed discussion on these matters, see Item 3 in Part I and note 23 to the consolidated financial statements included in Item 8 of Part II of this report.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

A critical accounting policy is one that is important to the portrayal of our 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 our management s view of the critical accounting policies, practices and estimates.

Oil and Gas Accounting We follow the successful efforts method of accounting for our 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 or proved developed reserves. The calculation of unit-of-production depreciation and depletion is the ratio of (1) asset cost to (2) total proved or total proved developed reserves applied to actual volumes produced. The volumes produced and asset costs are known, and while proved reserves have a higher probability of recoverability, they are based on estimates that are subject to variability. 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.

Exploratory drilling capital in the years 2004, 2003 and 2002 was $243 million, $271 million and $291 million, respectively. Dry hole costs in years 2004, 2003 and 2002 were $160 million, $128 million and $107 million, respectively. Exploration expense, excluding dry hole costs and amortization of unproved leaseholds, in the years 2004, 2003 and 2002 was $139 million, $143 million and $147 million, respectively.

At the end of 2004, 2003 and 2002, the book values of suspended exploratory well costs were $355 million, $364 million and $409 million, respectively. Dry hole costs in 2004, 2003 and 2002 included $63 million, $15 million and $8 million, respectively, of write-offs of exploratory well investments that had been incurred and suspended in a prior year. See notes 15 and 29 of Item 8 of this report for amounts and geographic locations of costs on the balance sheet related separately to exploration and production activities including additional information on suspended exploratory wells. Also, see the Supplemental Information on Oil and Gas Exploration and Production Activities in Item 8 of this report for disclosures about results of operations, costs incurred and the number of wells completed.

At the time exploratory acreage is acquired, we make 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 our 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 additional discussion on how reserves are determined in the Oil and Gas Reserve Data section in the Supplemental Information on Oil and Gas Exploration and Production Activities in Item 8 of this report. See RISK FACTORS in Item 7 of this report for a discussion on Our oil and gas reserve estimates are subject to change. Based on data presented in the Supplemental Information on Oil and Gas Exploration and Production Activities in Item 8 of this report, the average

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quantity of revisions to proved reserves for the three years ended December 31, 2004 was negative 0.2 percent. This net negative revision primarily resulted from increased commodity prices and their inverse relationship with PSC reserves discussed below.

Significant portions of our 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. We report all reserves held under PSCs utilizing the economic interest or net interest method, which excludes host country shares. Estimated quantities for PSCs reported under the economic interest or net 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 our net equity (profit) share.

At year-end 2004, the net book value of productive exploration and production property, plant and equipment subject to a unit-of-production calculation was approximately $6 billion. The estimated proved developed oil and gas reserves on these fields were 885 million barrels-of-oil-equivalent at the beginning of 2004 and were 905 million barrels-of-oil-equivalent at the end of 2004. If the estimates of total proved developed reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, pre-tax depreciation, depletion and amortization in 2004 would have been increased by an estimated $65 million.

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 we record asset impairments. Field decline rates, increases in lifting and development costs or a downward revision of reserves could occur and result in asset impairment. Impairments of producing oil and gas properties in 2004, 2003 and 2002 totaled $54 million, $85 million and $41 million, respectively. Of these writedowns, $3 million in 2004, $9 million in 2003 and $8 million in 2002 were due to downward revisions of proved reserves.

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. 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 our 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 our 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, our ARO estimates are subject to ongoing volatility.

Post-employment Benefits We utilize accounting principles generally accepted in the United States, as promulgated by the FASB, 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, we engage the services of outside actuarial firms to assist in the determination of these obligations and their related costs.

Along with our actuaries, we utilize both forecasted and historical data to adjust assumptions. Assumed interest (discount) rates reflect the rates at which pension benefits can be effectively settled. We have 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 future pension expense. For our U.S. Qualified Retirement Plan, a 50 basis point (1/2 of one percent) decrease in the discount rate, with all other assumptions held constant, would have increased the PBO by approximately $100 million at December 31, 2004 and would increase pre-tax pension expense for 2005 by approximately $12 million. For 2005, 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. We consider expected asset allocations as well as historical and forecasted returns on all categories of plan assets when selecting a ROA. A 50 basis point decrease in the expected return on the assets of our principal pension plans with all other assumptions held constant would increase pre-tax pension expense approximately $5 million in 2005.

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. We made voluntary pre-tax contributions of $100 million and $30 million to our U.S. Qualified Retirement Plan in 2004 and 2003, respectively. The plan experienced favorable asset returns in 2004 and 2003. As a result, the minimum pension liability was reduced by $51 million and $12 million to $40 million and $91 million, respectively. The cumulative other comprehensive income (OCI) component of stockholders equity decreased by $13 million and $34 million to $287 million and $300 million, respectively. In 2002, we had 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 our 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 OCI. Based on existing regulations, we expect that mandated employer contributions to the plan will not be payable until 2009. However, less than expected future returns on plan assets or a decrease in the discount rate could accelerate the requirement to make cash contributions to the plan before 2009. See note 16 to the consolidated financial statements in Item 8 of this report for additional disclosures on our various post-employment benefit plans.

Environmental and Litigation Our 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 Environmental Matters discussion and notes 19 and 23 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.

OPERATIONS OUTLOOK

The following operations outlook is based upon our current expectations and beliefs. These statements are subject to a number of known and unknown risks and uncertainties that could cause actual results to differ materially from those described. Please see the cautionary statement under Forward-Looking Statements on page iii of this report and the Risk Factors in this Item 7 of Part II of this report. This outlook discusses our current expectations regarding certain important operational activities for the remainder of 2005 and for other future time periods. It is not intended to be a complete discussion of all future operational activities.

Our profitability will be significantly affected by crude oil and natural gas commodity prices. We expect energy prices 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, worldwide security and other factors. We have secured fixed price hedges to seek to mitigate some of that volatility, primarily relating to a portion of our 2005 North America natural gas and crude oil production.

In 2005, we expect five key development projects will continue to move forward on schedule. The projects discussed in more detail below are in the Gulf of Mexico deepwater, Thailand, Bangladesh and Azerbaijan. Our natural gas position in Asia encompasses our next tier of potential growth projects in Thailand, Indonesia, Bangladesh and Vietnam. We believe that market demand in Asia continues to grow, and our natural gas position is a key component of our future growth strategy.

In the United States, as the size of new drilling prospects continues to fall, especially in the shelf and onshore areas of the Gulf of Mexico, we expect the upward pressure on exploratory and development costs to increase significantly. We will monitor our drilling results and costs, and if we can not find projects that generate attractive returns, we will reduce our capital spending in those areas. Such a capital reduction could result in increased production declines. New projects in the deep water Gulf of Mexico may help to offset all or some of the declines.

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Exploration and Production North America

United States

The Mad Dog field in the Gulf of Mexico, operated by BP, began production in January 2005. The K-2 field in the Gulf of Mexico, operated by Eni, is expected to begin production in the second quarter of 2005. The estimate of initial net production for both the Mad Dog field and K-2 fields combined is expected to average about 4 MBOE/d to 6 MBOE/d in the second quarter of 2005 rising to an average of 10 MBOE/d to 12 MBOE/d by the fourth quarter of 2005. We have a 15.6 percent working interest in the Mad Dog field and a 12.5 percent working interest in the K-2 field.

Evaluation of the extensive well data collected from the St. Malo discovery well and the Dana Point deepening appraisal well on Walker Ridge Block 678 continues. We are also reviewing well data from a nearby BP discovery, which we expect will play a key role in our appraisal and development planning for St. Malo. The evaluation will focus on productivity, additional appraisal operations and the viability of development options. We expect to drill an appraisal well in 2005. Booking of proved reserves is currently expected to occur in 2007. We have a 28.75 percent working interest in the St. Malo discovery.

Our deepwater Gulf of Mexico exploration and appraisal program will continue in 2005. We are currently drilling the Southwest Ridge appraisal well on the Mad Dog structure. In addition, we are currently planning to participate in drilling a Miocene test on the Chilkoot prospect in Green Canyon Block 320, operated by Kerr McGee Corporation. Other deep water Gulf of Mexico drilling activities expected include the Knottyhead prospect in Green Canyon Block 512, a Miocene test, where we plan to drill the well for the operator of record and will have a 25 percent working interest in the well. We also plan to participate in a follow-up well on the Puma discovery in Green Canyon Block 823 and a Mad Dog Deep well in Green Canyon Block 826, both operated by BP, in the second quarter of 2005. Once the Puma follow-up well is completed, evaluation will be needed to move the project toward sanctioning and reserve booking, which is currently expected to occur in 2007.

We plan to continue our discussions with all of the area operators and partners about development scenarios and joint development options for our Tobago and Trident prospects, which will be required before proved reserves can be booked. Both prospects lie in the Lower Tertiary trend, one of the most active exploration areas in the deepwater Gulf of Mexico. Booking of proved reserves is currently expected to occur by 2007. Additional exploratory drilling opportunities are currently being planned in the area and may occur as early as 2005. Any additional exploratory discoveries in the area are expected to become part of the overall co-development of our Trident and Tobago discoveries.

We monetized our interest in the Champlain project rather than move forward in development as operator, so that we can focus on projects with higher impact for us. We had a 30 percent working interest in the discovery.

Exploration in the deep shelf area remains suspended in early 2005. We anticipate making a drilling program recommendation in the middle of 2005.

Our Pure subsidiary plans to continue development activities in 2005.

Canada

Our Northrock subsidiary will continue its exploration in the Northwest Territory.

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Exploration and Production International

Asia

Thailand:

Thailand s electricity market is expected to continue growing in 2005. Additional supplies of natural gas to meet that growth have been constrained by pipeline capacity. De-bottlenecking activities on the two existing pipelines in the Gulf of Thailand should allow us an opportunity for increased production in 2005, prior to the expected completion of a third pipeline in 2006.

Start up of the Phase 2 development of the Thailand crude oil project is expected late in the second quarter of 2005 or early in the third quarter of 2005. The average net production rate is expected to be between 5 MBOE/d and 7 MBOE/d in the second quarter of 2005. The estimate of average production in the fourth quarter of 2005 is expected to climb to between 10 MBOE/d and 13 MBOE/d.

Further drilling on the Arthit field is firmly planned for 2005. Proved reserves are currently expected to be booked after the additional drilling is complete. Natural gas production from the Arthit field is anticipated in late 2006 or early 2007. We have a 16 percent working interest in the Arthit field, which is operated by PTT.

Subject to reaching final agreements with PTT relating to two of our GSAs on timing and volumes, we anticipate executing an accelerated delineation-drilling program in the Gulf of Thailand of 30 to 45 wells over the period 2005 to 2007.

Myanmar:

Beginning in 2005, a competing field in the Andaman Sea will receive an increase in its daily contract quantity. Accordingly, our gross production from the Yadana field will decrease to 600 MMcf/d from the 2004 average production of 652 MMcf/d.

Indonesia:

We are continuing to work on solidifying our development plans for our deepwater natural gas projects. Development will likely be around two major hubs. First production is expected in late 2008-2010 from the Gendalo field where engineering design work will commence in the second quarter of 2005 along with the submittal of the plan of development to the Government of Indonesia. Proved reserves are currently expected to be booked after all the requisite approvals have been received by 2008. The second development project is expected to be the Gehem-Ranggas oil and gas complex where first production could come on-line by 2011-2012. A plan of development for Gehem-Ranggas is expected to be submitted to our partner and the Government of Indonesia in 2005. Proved reserves for this project are currently expected to be booked after all the requisite approvals have been received by 2009.

We are also continuing to work on our evaluation for development feasibility at the Sadewa field. The Sadewa prospect is a candidate for early natural gas development because of its proximity to the shelf. We are currently doing detailed subsurface mapping. The most likely development concept is a natural gas and crude oil development from a shallow-water platform with extended reach wells towards targets in deep water.

We expect exploration and appraisal drilling to continue in the first half of 2005 in the deep water Kutei and Tarakan Basin. This drilling activity will test new prospects in the deep water.

A plan of development is currently expected to be submitted for the Bangka project, a satellite development to the West Seno producing operation, in 2006. Conceptual engineering work has started. Proved reserves are currently expected to be booked after all the requisite approvals have been received by 2008.

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Appraisal of the Gula discovery wells continued in 2004 with the drilling of an appraisal well. Further drilling is planned for 2006. Conceptual engineering, economic analysis and project approval will be necessary before proved reserves can be booked. This work will likely be completed by 2010.

The bids for fabrication and installation of a tension leg platform and infield pipelines for additional West Seno field development were unacceptably high, and we are evaluating extended reach drilling from the existing platform as a means to more cost effectively recover the resource in the southern portion of the field. Potential production from any additional development will be after 2005 and will be less than originally expected.

Bangladesh:

Facility construction and development drilling on the Moulavi Bazar field is nearly complete. First production from Moulavi Bazar field is expected late in the first quarter or early in the second quarter of 2005. Commencement of this new field is expected to increase our net average production in the country by 20 MBOE/d to 24 MBOE/d in the second quarter and 20 MBOE/d to 32 MBOE/d in the third quarter of 2005. This production outlook reflects higher volumes due partially to an increase in cost recovery that we expect to receive from the Jalalabad field because of new production from the Moulavi Bazar field. We anticipate the net average incremental production in the fourth quarter of 2005 to be 9 MBOE/d to 15 MBOE/d due to the completion of cost recovery.

We finalized the gas purchase and sales agreement with Petrobangla for the Bibiyana field in the fourth quarter of 2004. The Bibiyana field will be developed in stages, which could provide Bangladesh with natural gas resources in the short, medium and long-term time frames. We currently expect first production by the end of 2006.

Vietnam:

Work will continue on bringing Vietnam natural gas to market. We expect to submit field development plans after the outline development plan is approved by the government. We are also committed to drilling two additional wells in 2008. The timing for the booking of any proved reserves is dependent on finalizing remaining PSC requirements and concluding all commercial negotiations. This work is currently expected to occur by 2010 to 2012.

Other International

Azerbaijan:

Production from Phase 1 of the AIOC operated ACG crude oil project is expected to ramp up throughout 2005. The average net production rate from Phase 1 is expected to be approximately between 5 MBbl/d and 7 MBbl/d in the second quarter of 2005. Average net production in the fourth quarter is expected to climb to between 10 MBbl/d and 13 MBbl/d.

Development on Phases 2 and 3 of the ACG crude oil project will continue to progress in 2005. Gross production from the ACG crude oil project is expected to ramp up to more than 200 MBbl/d in 2005, rising to 670 MBbl/d by the end of 2007 and over 1 million Bbl/d by 2009. We have a 10.28 percent working interest in the AIOC project.

The Netherlands:

We will begin to develop the first of three discovered offshore natural gas fields in the North Sea, off the coast of the Netherlands, once the production license has been awarded and all conditions precedent of the acquisition of these fields are fulfilled, expected in the second quarter of 2005. We expect first production from these fields in the fourth quarter of 2006. We have approved approximately $75 million to develop the project. We have a 34.13 percent operating interest.

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Midstream and Marketing

In parallel with the ACG crude oil project, the BTC crude oil pipeline is expected to be fully operational in the second half of 2005. The portions of the pipeline through Azerbaijan and Georgia are expected to be complete and ready for line-fill in the second quarter of 2005. The BTC pipeline will transport the crude oil from the ACG crude oil project to the Turkish port of Ceyhan and will have a capacity of 1 million Bbl/d. Our interest in this pipeline is 8.9 percent.

Geothermal

In Thailand, we expect to complete the sale of our equity interest in a natural gas-fired power plant project with installed capacity of 700 megawatts in the first quarter of 2005. The sale is pending final approvals.

FUTURE ACCOUNTING CHANGES

See note 2 to the consolidated financial statements in Item 8 of this report 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 these events should occur, our business, financial condition, liquidity or results of operations could be materially adversely affected and investors in our securities could lose part or all of their investments. Also refer to the cautionary note under Forward Looking Statements on page iii of this report.

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 trading 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, and between budgeted and actual costs, 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. In addition, whether due to inflation or inaccurate estimates, actual costs for drilling rigs and other oilfield services, steel prices and other items may be substantially higher than budgeted costs. Delays and differences between estimated and actual timing of critical events and between budgeted and actual costs may adversely affect the completion of and commencement of production from such projects and 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 crude 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, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves most likely will vary from our estimates.

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

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

The rate of production from oil and gas properties generally declines as reserves are depleted. Actual decline rates are inherently uncertain and therefore difficult to predict. 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.

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

Acquisitions of producing oil and gas properties are a key element of maintaining and growing reserves and production. 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 and other international risks may impact our operations.

Political and economic factors in international markets and other international risks may have a material adverse effect on our operations. On an equivalent-barrel basis, approximately 67 percent of our oil and gas production in 2004 was outside the United States, and approximately 74 percent of our proved oil and gas reserves at December 31, 2004 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, civil unrest 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 and the impact of any local economic growth, or the absence thereof, on that demand. In addition, oil and gas production facilities, transportation systems and storage facilities could be targets of terrorist attacks, which could have a material adverse impact on our results of operations and cash flows if any oil and gas infrastructure integral to our operations were destroyed or damaged.

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 United States. Various agencies of the United States and other governments have from time to time imposed restrictions which have limited our ability to gain attractive opportunities or even operate in various countries. These restrictions have in the past limited our foreign opportunities and may continue to do so in the future.

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

Strong competition exists in all sectors of the oil and gas exploration and production industry and, in particular, in the exploration and development of new reserves. We compete with major integrated oil and gas companies, other 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. 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. 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 carrying out these activities. In addition,

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many of our larger competitors may have a competitive advantage when responding to factors that affect the demand for crude 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 have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

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

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

Our past and present operations and those of companies we have acquired expose us to civil claims by third-parties for alleged liability resulting from contamination of the environment or personal injuries caused by releases of hazardous substances. For example: we are investigating or remediating contamination at a large number of formerly and currently owned or operated sites and have recently recorded additional liabilities relating to some of these sites; and we have been identified as a potentially responsible party at several Superfund and other multi-party sites where we or our predecessors are alleged to have disposed of wastes in the past.

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

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

- some potentially contaminated sites are in the early stages of investigation, and other sites may be identified in the future;
- cleanup requirements are difficult to predict at sites where remedial investigations have not been completed or final decisions have not been made regarding cleanup requirements, technologies or other factors that bear on cleanup costs;

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

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

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

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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 23 to the consolidated financial statements in Item 8 of this report.

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, to satisfy our guarantees of debt securities of Union Oil and to pay dividends on our common stock and any preferred stock we may issue.

Our international subsidiaries generate substantial foreign tax credits. In the future, our ability to utilize these foreign tax credits is dependent on achieving a sufficient 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 a higher effective tax rate.

Our debt level may limit our financial flexibility.

As of December 31, 2004, our consolidated balance sheet showed $3.06 billion of total debt outstanding. We may incur additional debt in the future, including in connection with acquisitions, recapitalizations and refinancings.

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

- a significant portion of our cash flow from operations will be applied to the payment of principal and interest on the debt and will not be available for other purposes;

- credit rating agencies have changed, and may continue to change, their ratings of our debt and other obligations as a result of changes in our debt level, financial condition, earnings and cash flow, which in turn impacts the costs, terms and conditions and availability of financing;

- covenants contained in our existing and future debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- our ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate and other purposes may be limited or burdened by increased costs or more restrictive covenants;

- we may be at a competitive disadvantage to similar companies that have less debt; and

- our vulnerability to adverse economic and industry conditions may increase.

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

In the normal course of business we and our subsidiaries incur 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 2004, we had firmly committed to significant capital expenditures in 2005 for the development of 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 2005, 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, or to seek to sell additional assets, incur significant additional debt or issue other securities to obtain the necessary funds.

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

Our revolving credit facility guaranteed by Unocal, under which Union Oil can borrow an aggregate of up to $1.0 billion, provides for the termination of loan commitments and requires the prepayment of all outstanding borrowings under the facility 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 this credit facility. 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-United States 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.

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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.

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ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to market risks, which may give rise to losses from adverse changes in market prices and rates. The primary market risks to which we are exposed are: (1) commodity prices, (2) interest rates and (3) foreign currency exchange rates.

As part of our overall risk management strategies, we use derivative financial instruments to manage and seek to reduce risks associated with these factors. We also trade hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations. To the extent that we engage in hedging activities to seek 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, speculative trading in hydrocarbon commodities and derivative instruments in connection with our risk management activities subjects us to additional risk.

We determine the fair values of our 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 we feel that current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors to measure the fair value of our longer termed derivative instruments, other pricing assumptions or methodologies may lead to materially different results in some instances.

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

We use a variance-covariance value at risk model to assess the market risk of our hydrocarbon derivatives. Value at risk represents the potential loss in fair value we would experience on our hydrocarbon derivatives, as a result of commodity price changes using calculated volatilities and correlations over a specified time period with a given confidence level. Our 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 our fixed price pre-paid crude oil and pre-paid natural gas sales. The model also includes our net interests in our subsidiaries crude oil and natural gas hydrocarbon derivatives and forward sales contracts. Based upon our risk model, the value at risk related to hydrocarbon derivatives held for hedging purposes was approximately $23 million and $26 million at December 31, 2004 and 2003, respectively. Value at risk related to hydrocarbon derivatives held for non-hedging purposes was approximately $2 million at December 31, 2004 and was immaterial at December 31, 2003. See Hydrocarbon Derivatives Tables.

Interest Rate Risk From time to time, we temporarily invest our excess cash in short-term interest-bearing securities issued by high-quality issuers. Our 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 us. Our primary market risk exposure to changes in interest rates relates to our long-term debt obligations. We manage our exposure to changing interest rates principally with 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.

We evaluated the potential effect that near term changes in interest rates would have had on the fair value of our interest rate risk sensitive financial instruments at December 31, 2004. Assuming a ten percent decrease in our weighted average borrowing costs at December 31, 2004 and 2003, respectively, the potential increase in the fair value of our debt obligations and associated interest rate derivative instruments, including the debt obligations and associated interest rate derivative instruments of our subsidiaries, would have been approximately $88 million and $93 million at December 31, 2004 and 2003, respectively.

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Foreign Exchange Rate Risk We conduct business in various parts of the world and in various foreign currencies. To limit our foreign currency exchange rate risk related to operating income, foreign sales agreements generally contain price provisions designed to insulate our 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, we are 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. Our 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, we may purchase foreign currency options or enter into foreign currency swap or foreign currency forward contracts to limit the exposure related to our foreign currency debt or other obligations. At December 31, 2004, we had various foreign currency forward contracts outstanding related to operations in Thailand. We evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of our combined foreign currency position related to our 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, 2004 and 2003, the potential decrease in fair value of the foreign currency swaps, foreign currency forward contracts and foreign-currency denominated debt for us would have been approximately $43 million and $37 million at December 31, 2004 and 2003, respectively.

Hydrocarbon Derivatives Tables The following tables set forth the future volumes and price ranges of hydrocarbon derivatives we held at December 31, 2004, along with the fair values of those instruments.

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Open Hydrocarbon Hedging Derivative Instruments (a)

	2005	2006	2007	2008	Fair Value Asset (Liability) (b) (Thousands of dollars)
Natural Gas Futures Positions					
Volume (MMBtu)	640,000				$ (978)
Average price, per MMBtu	$ 6.75				
Volume (MMBtu)	(13,710,000)				$ 22,934
Average price, per MMBtu	$ 7.40				
Natural Gas Swap Positions					
Pay fixed price					
Volume (MMBtu)	13,016,000	8,568,000	7,218,000	7,241,000	$ 112,255
Average swap price, per MMBtu	$ 3.91	$ 3.05	$ 2.47	$ 2.52	
Receive fixed price					
Volume (MMBtu)	14,800,000				$ 7,216
Average swap price, per MMBtu	$ 6.35				
Natural Gas Basis Swap Positions					
Volume (MMBtu)	2,655,000				$ (606)
Average price received, per MMBtu	$ 5.52				
Average price paid, per MMBtu	$ 5.43				
Crude Oil Futures Positions					
Volume (Bbls)	(2,140,000)				$ 10,240
Average price, per Bbl	$ 47.04				

(a) *Futures positions reflect long (short) volumes.*
(b) *Net claims against counterparties with non-investment grade credit ratings are immaterial.*

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Open Hydrocarbon Non-Hedging Derivative Instruments (a)

(Thousands of dollars)

	2005	2006	Fair Value Asset (Liability) (b)
Natural Gas Futures Positions			
Volume (MMBtu)	2,310,000		$ (5,931)
Average price, per MMBtu	$ 6.75		
Volume (MMBtu)	(4,330,000)		$ 8,341
Average price, per MMBtu	$ 6.97		
Natural Gas Swap Positions			
Pay fixed price			
Volume (MMBtu)	4,370,000		$ (2,747)
Average swap price, per MMBtu	$ 6.56		
Receive fixed price			
Volume (MMBtu)	2,210,000		$ 987
Average swap price, per MMBtu	$ 6.14		
Natural Gas Spread Swap Positions			
Volume (MMBtu)	50,410,000	4,975,000	$ (603)
Average price paid, per MMBtu	$ 0.46	$ 0.65	
Volume (MMBtu)	50,410,000	4,975,000	$ 871
Average price received, per MMBtu	$ 0.46	$ 0.67	
Natural Gas Option (Listed & OTC)			
Call Volume -Buy-(MMBtu)			$ (438)
Average Call price	$		
Call Volume -Sell-(MMBtu)	(560,000)		$ 492
Average Call price	$ 8.00		
Put Volume -Buy-(MMBtu)			$
Average Put Price	$		
Put Volume -Sell-(MMBtu)	(3,000,000)		$ 212
Average Put Price	$ 4.93		
Natural Gas Spread Option (Over the Counter)			
NYMEX / IFERC (c)			
Call Volume (MMBtu)			$
Average Strike price	$		
Put Volume (MMBtu)	1,000,000		$ 17
Average Strike price	$ 0.50		
Crude Oil Futures Positions			
Volume (Bbls)	4,125,000		$ (13,224)
Average price, per Bbl	$ 43.63		
Volume (Bbls)	(3,905,000)		$ 16,483
Average price, per Bbl	$ 43.76		
Crude Oil Option (Listed & OTC)			
Call Volumes -Buy-(Bbls)	100,000		$ (218)
Average price, per Bbl	$ 55.00		
Call Volumes -Sell-(Bbls)	(200,000)		$ 463
Average price, per Bbl	$ 52.50		
Put Volume -Buy-(Bbls)	100,000		$ (304)
Average price, per Bbl	$ 41.50		
Put Volume -Sell-(Bbls)	(100,000)		$ 376

Average price, per Bbl	$	39.00				
Crude Oil Swap Positions						
Pay fixed price						
Volume (Bbls)		6,271,360		288,640	$	1,443
Average swap price, per Bbl	$	34.75	$	36.31		
Receive fixed price						
Volume (Bbls)		6,194,080		315,920	$	(5,118)
Average swap price, per Bbl	$	34.68	$	34.65		

(a) *Futures positions reflect long (short) volumes.*

(b) *Includes $4,648 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 TO STOCKHOLDERS ON MANAGEMENT S RESPONSIBILITIES

We are 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 our informed judgments and estimates. The financial statements have been audited by the independent registered public accounting firm of PricewaterhouseCoopers LLP (the independent auditor). We have made available to the independent auditor all of our financial records and related data, minutes of the meetings of our board of directors and its executive committee and of the management committee and all internal audit reports.

Our internal control over financial reporting is supported by written policies and procedures and by an appropriate segregation of responsibilities and duties. We maintain an extensive internal auditing program that independently assesses the effectiveness of these internal controls with written reports and recommendations issued to appropriate levels of management.

The 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 our financial reporting; 2) our compliance with legal and regulatory requirements; 3) the adequacy of our internal operating policies and controls; and 4) the quality and performance of combined management, the independent auditor, and the internal audit function. The audit committee is also responsible for the appointment and oversight of the independent auditor (which in turn is submitted to the stockholders for ratification) and reviewing their independence from us; and initiating special investigations as deemed necessary. The independent auditor 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 appropriate matters.

MANAGEMENT S REPORT TO STOCKHOLDERS ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Internal control over financial reporting is a process designed by, or under the supervision of, the chief executive officer and chief financial officer and effected by our board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

We are responsible for establishing and maintaining adequate internal control over financial reporting. We have used the framework set forth in the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission to assess our internal control over financial reporting. Based upon this assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2004. PricewaterhouseCoopers LLP, the independent auditor, audited our financial statements included in this annual report on Form 10-K and has audited our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 as stated in their report which appears on pages 76 and 77.

/s/ Charles R. Williamson	/s/ Joseph H. Bryant
Charles R. Williamson	Joseph H. Bryant

Chairman of the Board and	President and
Chief Executive Officer	Chief Operating Officer

/s/ Terry G. Dallas	/s/ Samuel H. Gillespie, III	/s/ Joe D. Cecil
Terry G. Dallas Executive Vice President and	Samuel H. Gillespie, III Senior Vice President,	Joe D. Cecil Vice President and
Chief Financial Officer	Chief Legal Officer and	Comptroller
	General Counsel	

March 8, 2005

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Unocal Corporation:

We have completed an integrated audit of Unocal Corporation s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Unocal Corporation and its subsidiaries at December 31, 2004 and 2003 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 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. These financial statements and financial statement schedule are the responsibility of the Company 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 of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in note 2 to the consolidated financial statements, Unocal Corporation adopted FASB Interpretation 46R, *Consolidation of Variable Interest Entities* which resulted in the deconsolidation of Unocal Capital Trust as of January 1, 2004. In addition, Unocal Corporation changed its method of accounting for asset retirement costs as of January 1, 2003.

Internal control over financial reporting

Also, in our opinion, management s assessment, included in Management s Report to Stockholders on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control Integrated Framework* issued by COSO. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the

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transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers

PricewaterhouseCoopers LLP

March 8, 2005

Los Angeles, California

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CONSOLIDATED EARNINGS **UNOCAL CORPORATION**

Millions of dollars except per share amounts	Years ended December 31, 2004	2003	2002
Revenues			
Sales and operating revenues (a)	$ 8,003	$ 6,368	$ 5,200
Interest, dividends and miscellaneous income	47	25	31
Gain on sales of assets	154	119	42
Total revenues	8,204	6,512	5,273
Costs and other deductions			
Crude oil, natural gas and product purchases (a)	3,202	2,126	1,701
Operating expense	1,435	1,336	1,332
Administrative and general expense	202	260	151
Depreciation, depletion and amortization	997	985	965
Impairments	74	93	47
Dry hole costs	160	128	107
Exploration expense	201	251	246
Interest expense (b)	160	190	179
Property and other operating taxes	84	81	60
Distributions on convertible preferred securities of subsidiary trust		33	33
Total costs and other deductions	6,515	5,483	4,821
Earnings from equity investments	140	192	154
Earnings from continuing operations before income taxes and minority interests	1,829	1,221	606
Income taxes	673	514	277
Minority interests	11	9	6
Earnings from continuing operations	1,145	698	323
Earnings from discontinued operations (c)	63	28	8
Cumulative effect of accounting changes (d)		(83)	
Net earnings	$ 1,208	$ 643	$ 331
Basic earnings per share of common stock:			
Continuing operations	$ 4.35	$ 2.70	$ 1.31
Discontinued operations	$ 0.24	$ 0.11	$ 0.03
Cumulative effect of accounting changes	$	$ (0.32)	