UNOCAL CORP
Form 10-K
March 08, 2005
Table of Contents

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.

Table of Contents

UNOCAL CORPORATION

TABLE OF CONTENTS

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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**

Table of Contents

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		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**

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

-7-

Table of Contents

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.

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.

Table of Contents

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-

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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 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.

<u>The Federal Cases</u>

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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	

Table of Contents

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.

Table of Contents

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.

-30-

Table of Contents

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,

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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

	Years ended December 31,		
Millions of dollars	**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

-38-

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

-41-

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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).

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

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.

-50-

Table of Contents

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.

Table of Contents

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:

		Amount of Commitment Expiration				
Millions of dollars	Total	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.*

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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 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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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,

Table of Contents

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.

Table of Contents

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;

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.*

Table of Contents

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).*

Table of Contents

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.

Table of Contents

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 Chief Executive Officer	President and Chief Operating Officer

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

March 8, 2005

Table of Contents

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 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

Table of Contents

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Table of Contents

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)	$
Net earnings	$ 4.59	$ 2.49	$ 1.34
Diluted earnings per share of common stock:			
Continuing operations	$ 4.25	$ 2.66	$ 1.31
Discontinued operations	$ 0.23	$ 0.10	$ 0.03
Cumulative effect of accounting changes	$	$ (0.30)	$
Net earnings	$ 4.48	$ 2.46	$ 1.34

(a) Includes crude oil buy/sell transactions settled in cash of :	*$ 965*	*$ 820*	*$ 604*
(b) Net of capitalized interest of :	*$ 65*	*$ 60*	*$ 46*
(c) Net of tax expense of :	*$ 33*	*$ 13*	*$ 5*
(d) Net of tax expense of :	*$*	*$ 48*	*$*

See Notes to the Consolidated Financial Statements.

Table of Contents

CONSOLIDATED BALANCE SHEETS **UNOCAL CORPORATION**

Millions of dollars	At December 31, 2004	At December 31, 2003
Assets		
Current assets		
Cash and cash equivalents	$ 1,160	$ 404
Accounts and notes receivable - net (see notes 11 and 20)	1,423	1,292
Inventories	220	141
Deferred income taxes	88	119
Other current assets	39	35
Total current assets	2,930	1,991
Investments and long-term receivables - net (see notes 14 and 20)	777	892
Properties - net (see note 15)	8,819	8,324
Goodwill	136	131
Deferred income taxes	272	300
Other assets	167	160
Total assets	$ 13,101	$ 11,798
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 1,298	$ 1,072
Taxes payable	410	326
Dividends payable	53	52
Interest payable	38	43
Current portion of environmental liabilities	109	118
Current portion of long-term debt and capital leases	491	248
Other current liabilities	182	226
Total current liabilities	2,581	2,085
Long-term debt and capital leases	2,571	2,635
Deferred income taxes	839	704
Accrued abandonment, restoration and environmental liabilities	897	844
Other deferred credits and liabilities	969	960
Minority interests	27	39
Commitments and contingencies - (see note 23)		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures		522
Common stock ($1 par value, shares authorized: 750,000,000 (a))	280	271
Capital in excess of par value	1,304	1,031
Unearned portion of restricted stock issued	(23)	(13)
Retained earnings	4,453	3,456
Accumulated other comprehensive income	(160)	(298)
Notes receivable - key employees	(3)	(27)
Treasury stock - at cost (b)	(634)	(411)
Total stockholders equity	5,217	4,009
Total liabilities and stockholders equity	$ 13,101	$ 11,798

(a) Number of shares outstanding (in thousands)	*263,190*	*260,594*
(b) Number of shares (in thousands)	*16,538*	*10,623*

See Notes to the Consolidated Financial Statements.

Table of Contents

CONSOLIDATED CASH FLOWS **UNOCAL CORPORATION**

Millions of dollars	Years ended December 31, 2004	2003	2002
Cash Flows from Operating Activities			
Net earnings	$ 1,208	$ 643	$ 331
Adjustments to reconcile net earnings to net cash provided by operating activities			
Depreciation, depletion and amortization	997	988	973
Impairments	74	93	47
Dry hole costs	160	128	107
Amortization of exploratory leasehold costs	61	108	98
Deferred income taxes	134	56	22
Gain on sales of assets	(154)	(119)	(42)
Gain on disposal of discontinued operations	(86)	(25)	(2)
Pension expense net of contributions	(14)	58	22
Restructuring provisions net of payments	(24)	27	2
Cumulative effect of accounting changes		83	
Other	107	(3)	(73)
Working capital and other changes related to operations			
Accounts and notes receivable	(134)	(294)	(160)
Inventories	(79)	(44)	5
Accounts payable	226	48	196
Taxes payable	84	103	52
Other	(4)	99	(7)
Net cash provided by operating activities	2,556	1,949	1,571
Cash Flows from Investing Activities			
Capital expenditures (includes dry hole costs)	(1,744)	(1,718)	(1,670)
Proceeds from sales of assets	377	642	163
Proceeds from sales of discontinued operations	123	11	3
Return of capital from affiliate company	48		
Net cash used in investing activities	(1,196)	(1,065)	(1,504)
Cash Flows from Financing Activities			
Long-term borrowings	138	205	585
Reduction of long-term debt and capital lease obligations	(522)	(452)	(495)
Minority interests	(3)	(257)	(8)
Repurchases of common stock	(223)		
Proceeds from issuance of common stock	195	58	21
Dividends paid on common stock	(210)	(207)	(196)
Loans to key employees	25	11	6
Other	(4)	(6)	(2)
Net cash used in financing activities	(604)	(648)	(89)
Increase (decrease) in cash and cash equivalents	756	236	(22)
Cash and cash equivalents at beginning of year	404	168	190
Cash and cash equivalents at end of year	$ 1,160	$ 404	$ 168

Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 152	$ 199	$ 180
Income taxes (net of refunds)	$ 510	$ 364	$ 249

See Notes to the Consolidated Financial Statements.

Table of Contents

CONSOLIDATED STOCKHOLDERS EQUITY **UNOCAL CORPORATION**

Millions of dollars except per share amounts	At December 31, 2004	2003	2002
Common stock			
Balance at beginning of year	$ 271	$ 269	$ 255
Issuance of common stock for acquisition of Pure Resources minority interest			13
Issuance of common stock for exercised stock options	7	2	1
Issuance of common stock for conversions of Trust 6 1/4% convertible preferred securities	1		
Other issuance of common stock	1		
Balance at end of year	280	271	269
Capital in excess of par value			
Balance at beginning of year	1,031	962	551
Issuance of common stock for acquisition of Pure Resources minority interest			378
Issuance of common stock for exercised stock options	188	55	20
Issuance of common stock for conversions of Trust 6 1/4% convertible preferred securities	42		
Issuance of stock options and related tax benefit	24	12	2
Other issuance of common stock	19	2	11
Balance at end of year	1,304	1,031	962
Unearned portion of restricted stock and options issued			
Balance at beginning of year	(13)	(20)	(29)
Issuance of restricted stock and stock options	(22)	(1)	(3)
Amortization of restricted stock and stock options	12	8	12
Balance at end of year	(23)	(13)	(20)
Retained earnings			
Balance at beginning of year	3,456	3,021	2,888
Net earnings for year	1,208	643	331
Cash dividends declared on common stock ($0.80 per share)	(211)	(208)	(198)
Balance at end of year	4,453	3,456	3,021
Treasury stock			
Balance at beginning of year	(411)	(411)	(411)
Purchased at cost	(223)		
Balance at end of year	(634)	(411)	(411)
Notes receivable - Key employees			
Balance at beginning of year	(27)	(37)	(42)
Accrued interest on loans to key employees	(1)	(2)	(2)
Principal and interest payments received from key employees	25	12	7
Balance at end of year	(3)	(27)	(37)
Accumulated other comprehensive income (loss)			
Balance at beginning of year	(298)	(486)	(88)
Foreign currency translation adjustments	87	145	(15)
Deferred net gains (losses) on hedging instruments	39	15	(49)
Minimum pension liability adjustment	12	28	(334)
Balance at end of year (a)	(160)	(298)	(486)
Total stockholders equity	$ 5,217	$ 4,009	$ 3,298

(a) At year-end 2004, accumulated other comprehensive income was comprised of unrealized currency translation gains of $132 million, deferred net gains on hedging instruments of $6 million and a minimum pension liability adjustment of $298 million. At year-end 2003, acumulated other comprehensive income was comprised of unrealized currency translation gains of $45 million, deferred net losses on hedging instruments of $33 million and a minimum pension liability adjustment of $310 million. At year-end 2002, other comprehensive income was comprised of unrealized currency translation losses of $100 million, deferred net losses on hedging instruments of $48 million and a minimum pension liability adjustment of $338 million.

See Notes to the Consolidated Financial Statements.

Table of Contents

COMPREHENSIVE INCOME **UNOCAL CORPORATION**

Millions of dollars	Years ended December 31, 2004	2003	2002
Net earnings	$ 1,208	$ 643	$ 331
Change in unrealized gains (losses) on hedging instruments (a)	30	(6)	(57)
Reclassification adjustment for settled hedging contracts (b)	9	21	8
Unrealized foreign currency translation adjustments	87	145	(15)
Minimum pension liability adjustment (c)	12	28	(334)
Total comprehensive income (loss)	$ 1,346	$ 831	$ (67)
(a) Net of tax effect of:	*(18)*	*3*	*33*
(b) Net of tax effect of:	*(5)*	*(12)*	*(4)*
(c) Net of tax effect of:	*(7)*	*(17)*	*196*

See Notes to the Consolidated Financial Statements.

Table of Contents

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - Our consolidated financial statements include the accounts of subsidiaries in which a controlling interest is held and variable interest entities where we are the primary beneficiary. Investments in entities without a controlling interest are accounted for by the equity method or cost basis. Under the equity method, the investments are stated at cost plus our equity in undistributed earnings and losses after acquisition. Income taxes estimated to be payable when equity earnings are distributed are included in deferred income taxes. Under the cost method, the investments are recorded at cost, and we recognize as income dividends received that are distributed from net accumulated earnings of the investee since the date of acquisition.

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

Revenue Recognition Revenues associated with sales of crude oil, condensate, natural gas, natural gas liquids and other products are recorded when title passes to the customer. To market our domestic crude oil production, our marketing group generally enters into sale and purchase transactions, commonly know as buy/sell transactions, with unaffiliated oil and gas producing, refining, marketing and trading companies. A buy/sell transaction generally consists of the purchase and sale of crude oil from the same counterparty. In a typical buy/sell transaction, Company A enters into a contract to sell a particular grade of crude oil at a specified location to Company B on a future date, and simultaneously agrees to buy from Company B a particular grade of crude oil at a different location at the same or another specified date. We enter into buy/sell transactions to sell our crude oil production to local refiners or marketers at alternate locations closer to commercial market hubs with greater market liquidity. These transactions allow us to increase our margins by minimizing transportation costs that we would otherwise incur to physically transport our crude oil production to these markets for sale.

In accordance with established industry practice and more recently with the FASB s Emerging Issues Task Force (EITF) Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent* (Issue No. 99-19), our consolidated earnings statement includes the sales portions of these buy/sell transactions in the sales and operating revenues line while the purchases portions of these transactions are reported in the crude oil, natural gas and product purchases line. Sales of crude oil, natural gas or natural gas liquids purchased from third parties (i.e., non-buy/sell transactions or transactions purchased from one counter party and sold to a different counter party for arbitrage opportunities) are also included in our consolidated earnings statement in the sales and operating revenues line. Related purchases are reported in the crude oil, natural gas and product purchases line. Recently, the EITF has undertaken a review of buy/sell transactions with the same counterparty to determine if they should be reported on a gross or net basis (see discussion in note 2 Accounting Changes).

Natural gas sales revenues from properties in which we have an interest with other producers are recognized on the basis of our working interest (entitlement method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. Any amount received in excess of our share is treated as a liability. If we take less than we are entitled to, the under-delivery is recorded as a receivable. At December 31, 2004, our worldwide receivables and payables related to under and over liftings of natural gas with other producers was a net payable amount of $18 million.

Inventories Inventories are generally valued at the lower of cost or market. The costs of inventories are primarily determined using the last-in, first-out (LIFO) method or average costs method. Cost elements primarily consist of raw materials and production expenses.

Table of Contents

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

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

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

Asset Retirement Obligations (AROs) We recognize liabilities related to the legal obligations associated with the retirement of our tangible long-lived assets in the periods in which the obligations are incurred, which is typically when the assets are installed, if a reasonable estimate of fair value can be made. These obligations include the required decommissioning and removal of certain oil and gas platforms, plugging and abandonment of oil and gas wells and facilities, the closure of certain mining facilities, and the restoration of certain sites at the time of abandonment. We have interests in some long-lived assets, such as commercial natural gas storage facilities, commercial crude oil and products storage facilities and commercial pipelines where the operations are not tied to any particular operating field reserves. While some of these assets may have retirement obligations under SFAS No. 143, certain of those obligations have not been recognized due to the uncertainties of the settlement dates of the obligations. We monitor these assets for any changes to this position. Under SFAS No. 143, ARO liabilities are initially recorded at fair values and the carrying values of the related assets are increased by corresponding amounts. Over time, changes in the present value of the liabilities are accreted and expensed and the capitalized asset costs are depreciated over the useful lives of the corresponding assets. Recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as: (1) expected economic recoveries of crude oil and natural gas, (2) time to abandonment, (3) future inflation rates and (4) the risk free rate of interest adjusted for our credit costs. Future revisions to ARO estimates will impact the present value of existing ARO liabilities and corresponding adjustments will be made to the capitalized asset retirement costs balance.

Oil and Gas Exploration and Development Costs We follow the successful efforts method of accounting for our oil and gas activities. Acquisition costs of exploratory acreage are capitalized when incurred. Such costs related to the portion of properties expected to be non-commercial, based on exploratory experience and judgment, are amortized for impairment over the shorter of the exploratory period or the lease/concession holding period. This impairment amortization is reflected as a component of exploration expense on the consolidated earnings statement. Costs of successful leases are transferred to proved properties. Geological and geophysical costs for exploration and leasehold rentals for unproved properties are expensed.

Exploratory drilling costs are initially capitalized. If an exploratory well results in discovery of commercial reserves, the well investment is transferred to proved properties at the time reserves are booked. Exploratory wells that are non-commercial are expensed as dry holes. Costs of exploratory wells that have found commercially producible quantities of reserves that cannot be classified as proved remain capitalized while awaiting anticipated required major capital expenditures. Costs also remain capitalized for wells that have found sufficient quantities of reserves to justify their completion as long as we have firm plans to drill additional wells necessary to determine the existence of proved reserves. Costs of drilling other exploratory wells that do not require major expenditures are not carried on the books for more than one year following completion of drilling. See note 2 EITF Issue 04-9 and proposed FASB Staff Position (FSP) FAS 19-a for the current FASB deliberations regarding capitalization of suspended wells.

Development costs of proved properties, including unsuccessful development wells, are capitalized.

Depreciation, Depletion and Amortization Depreciation, depletion and amortization related to acquisition costs and development costs of proved properties, including capitalized abandonment and removal costs, are calculated at unit-of-production rates based upon total proved or proved developed reserves. Depreciation of other properties, including capitalized abandonment and removal costs, is generally on a straight-line method using various rates based on estimated useful lives.

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

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

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

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

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

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

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

Risk Management - Our risk management strategies include reducing the overall volatility of our cash flows, preserving revenues and exploiting anticipated opportunities arising from commodity price fluctuations. As part of our overall risk management strategy, we enter into various derivative instrument contracts to offset portions of our exposures to changes in interest rates, changes in foreign currency exchange rates, and fluctuations in crude oil and natural gas prices. In general, we enter into derivative instruments to hedge two types of exposures: cash flow exposures and fair value exposures. Hedges of cash flow exposures are generally undertaken to reduce cash flow volatility associated with forecasted transactions. They may also be used to reduce volatility associated with cash flows to be paid related to recognized liabilities. Hedges of fair value exposures are undertaken to hedge recognized assets or liabilities or unrecognized firm commitments against changes in value.

Interest Rates From time to time, we enter into interest rate swap contracts to manage the interest cost of our debt with the objective of minimizing the volatility and magnitude of our borrowing costs.

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

Commodities We use hydrocarbon derivatives such as futures, swaps, collars and options to mitigate our overall exposure to fluctuations in hydrocarbon commodity prices. We also trade hydrocarbon derivative financial instruments subject to certain limits.

In accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, all derivative instruments are recorded as assets or liabilities on the balance sheet at their fair values. We routinely enter into various purchase and sale contracts that will ultimately result in the physical delivery of hydrocarbon commodities. We have determined that the normal purchase and normal sale exception included in paragraph 10(b) of SFAS No. 133 applies to such contracts, so we do not account for them as derivatives pursuant to SFAS No.133.

At the inception of a derivative contract, we may choose to designate and document a derivative as a cash flow hedge or a fair value hedge. Changes in the values of derivatives not designated and documented as hedges are recorded in current-period earnings.

Changes in the values of derivatives that qualify for, and are designated and effective as, cash flow hedges are deferred and recorded as components of accumulated other comprehensive income until the hedged transactions occur and are then recognized in earnings. Any ineffectiveness that is related to changes in the values of cash flow hedge derivatives is recognized immediately in earnings as a component of sales revenues. Changes in the values of derivatives that qualify for, and are designated and effective as, fair value hedges are recognized in current-period earnings as components of the line items reflecting the underlying hedged transactions. Changes in the fair values of the underlying hedged items (e.g., recognized assets, liabilities or unrecognized firm commitments) are also recognized in current-period earnings and offset the changes in the values of the corresponding hedging derivatives. Any resulting fair value hedge ineffectiveness is recognized in current-period earnings as the difference between the offsetting changes in values of the derivative and the underlying hedged items.

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

Stock-Based Compensation - We began using the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, for all employee awards granted, modified or settled after December 31, 2002. Therefore, the cost related to stock-based employee compensation included in the determination of net earnings for 2004 and 2003 is less than that which would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS No. 123. Prior to 2003, we applied Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations in accounting for stock-based

Table of Contents

compensation. Accordingly, stock-based compensation expense recognized in our consolidated earnings prior to 2003 included expenses related to our various cash incentive plans that are paid to certain employees based upon defined measures of our common stock price performance and total shareholder return. Under APB Opinion No. 25, stock-based employee compensation cost was not recognized in earnings when stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant.

The following table illustrates the effect on net earnings and earnings per share if the fair value based method had been applied to all outstanding and unvested awards in each period:

	Years Ended December 31,		
Millions of dollars except per share amounts	**2004**	**2003**	**2002**
Net earnings			
As reported	$ 1,208	$ 643	$ 331
Add: Stock-based employee compensation expense included in reported net earnings, net of related tax effects and minority interests	11	17	26
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects and minority interests	(14)	(22)	(56)
Pro forma net earnings	$ 1,205	$ 638	$ 301
Net earnings per share:			
Basic - as reported	$ 4.59	$ 2.49	$ 1.34
Basic - pro forma	$ 4.58	$ 2.47	$ 1.22
Diluted - as reported	$ 4.48	$ 2.46	$ 1.34
Diluted - pro forma	$ 4.47	$ 2.44	$ 1.21

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

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

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

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

Certain items in prior year financial statements have been reclassified to conform to the 2004 presentation.

NOTE 2   ACCOUNTING CHANGES

SFAS No. 132 (revised 2003): In 2003, we adopted SFAS No. 132, *Employers Disclosures about Pensions and Other Postretirement Benefits (revised 2003).* In accordance with this pronouncement, beginning in 2004, this Form 10-K includes certain future benefit-payment information.

FASB Interpretation No. 46 (revised December 2003): Effective January 1, 2004, we adopted FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* which clarifies the definition of a variable interest entity and provides a scope exception for certain entities that meet the Statement s definition of a business. This pronouncement resulted in the deconsolidation of the Trust. As a result, the $522 million obligation

Table of Contents

for the Trust s convertible preferred securities was removed from the consolidated balance sheet and replaced by an increase in long-term debt for the $538 million in 6 $^{1}/4$% convertible junior subordinated debentures of Unocal payable to the Trust. We also recorded a $16 million investment in the Trust on the consolidated balance sheet. The deconsolidation did not affect our consolidated net earnings. In 2004, we redeemed a portion of the debentures (see note 17 Variable Interest Entities).

FASB Staff Position No. 142-2: In 2004, the FASB issued Staff Position No. 142-2, *Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities,* that clarified that oil and gas drilling rights are tangible assets. This position is consistent with our classification of the cost of acquiring oil and gas drilling rights in property, plant and equipment on our consolidated balance sheet. Therefore, adoption of this rule had no impact on either our earnings or consolidated balance sheet.

FASB Staff Position No. 106-2: In December 2003, *The Medicare Prescription Drug, Improvement and Modernization Act of 2003* (the Act) was enacted, which introduces a prescription drug benefit under Medicare Part D. The availability of the new drug benefit could cause Medicare eligible plan participants to leave their current employer-sponsored plans (or cause employees to join such plans), depending on the drug benefits provided under those plans relative to the benefits provided by Medicare. The Act also provides that a non-taxable federal subsidy will be paid to sponsors of postretirement benefit plans that provide retirees with a drug benefit that is at least actuarially equivalent to the Medicare Part D benefit. The federal subsidy is not payable to a plan sponsor for retirees who leave their current employer-sponsored plan to participate in the Medicare drug program. As of January 1, 2004, the Act s subsidy reduced the Accumulated Postretirement Benefit Obligation (APBO) of our U.S. Postretirement Welfare Plan by $72 million, which will be amortized to future earnings as an actuarial experience gain. In accordance with FASB Staff Position No. 106-2, in 2004, we recorded a benefit of $11 million representing the estimated impact of the subsidy. This amount consisted of $4 million for the reduction in interest cost, $6 million for amortization of the actuarial gain and $1 million for the reduction in service cost.

EITF Issue 03-1: In March 2004, the EITF issued EITF Issue 03-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* The consensus provides new guidance for assessing impairment losses on debt and equity investments and includes new disclosure requirements for investments that are deemed temporarily impaired plus additional disclosures for cost method investments. Although the FASB has delayed the accounting recognition and measurement provisions of this consensus, the assessment and disclosure provisions remain effective for this Form 10-K as well as the obligation to recognize other-than-temporary impairments required by existing authoritative literature. We do not have any marketable securities subject to the provisions of SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities.* Our only investments subject to EITF Issue 03-1 are cost method investments, which were not material as of December 31, 2004.

EITF Issue 03-16: Beginning with the third quarter of 2004, EITF Issue 03-16, *Accounting for Investments in Limited Liability Companies (LLCs),* became effective. This pronouncement may cause some entities to be accounted for by the equity method rather than on a cost basis. Adoption of this pronouncement did not have an impact on either our earnings or consolidated balance sheet in 2004.

EITF Issue 04-9 and proposed FASB Staff Position (FSP) FAS 19-a: SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* requires the cost of drilling an exploratory well to be capitalized pending determination of whether the well has found proved reserves. If this determination cannot be made at the conclusion of drilling, SFAS No. 19 sets out additional requirements for continuing to carry the cost of the well as an asset. These requirements include firm plans for further drilling and a one-year time limitation on continued capitalization in certain instances. The EITF in their discussions of this issue noted that as a result of the increasing complexity of oil and gas projects due to drilling in remote and deepwater offshore locations, companies increasingly require more than one year to complete all of the activities that permit recognition of proved reserves. Furthermore, because of new technologies, additional exploratory wells may no longer be required before a project can commence. EITF Issue 04-9, Accounting for Suspended Well Costs, sought to determine whether SFAS No. 19 should be clarified to recognize the industry changes that have taken place in the past quarter century. This issue was discussed by the EITF and it was determined that a formal amendment to SFAS No. 19 would be required if the FASB concurs with broadening the requirements for continued capitalization of exploratory well costs. In the proposed FSP FAS 19-a, the FASB has tentatively decided to increase required disclosures and to allow continued capitalization when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. Most of the additional proposed FSP disclosures are presented in note 15-Properties and Capital leases. If this proposed FSP had been applied to 2004, 2003 and 2002, it would not have a material effect on our net earnings in any of those years.

American Jobs Creation Act: The American Jobs Creation Act of 2004 (the Act) was signed into law by the U.S. President on October 22, 2004. The Act contains numerous changes to U.S. tax law, both temporary and permanent in nature, including a potential tax deduction with respect to certain qualified domestic manufacturing activities, which will be phased in from 2005 through 2010. Under the guidance in FASB Staff Position No. FAS 109-1, *Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*, the deduction will be reported in the period in which the deduction is claimed on our tax return. Based on current earnings levels, we estimate the increase in net earnings generated by this deduction will be in the range of zero to $5 million in both calendar years 2005 and 2006 and in the range of zero to $20 million per year by the end of the phase-in period in 2010.

The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. Because we incur a foreign tax rate in excess of the 35 percent U.S. federal income tax rate, we do not pay incremental federal income tax on our foreign earnings due to excess foreign tax credits. Therefore, we do not anticipate repatriating higher amounts of foreign earnings under the Act since any such repatriations do not reduce federal income taxes. In addition, this Act includes changes in the carryback and carryforward utilization periods for foreign tax credits.

SFAS No. 151: In 2004, the FASB issued SFAS No. 151, *Inventory Costs an amendment of ARB No. 43, Chapter 4,* which is effective for inventory costs incurred after December 31, 2005. This statement requires that items such as idle facility expense, excessive spoilage, double freight, and rehandling costs be recognized as current-period charges regardless of whether they meet the criterion of so abnormal as stipulated in Chapter 4 of ARB No. 43. In addition, this statement requires that fixed production overhead allocated to inventory be based on the normal capacity of the production facilities. Adoption of this pronouncement is not expected to have a significant impact on either our earnings or consolidated balance sheet.

SFAS No. 123 (revised 2004): In 2004, the FASB issued SFAS No. 123 (revised 2004) *Share-Based Payment,* an amendment of FASB Statement Nos. 123 and 95, which is effective July 1, 2005. This pronouncement requires the fair value method to account for share-based awards and potentially increases the number of grants considered liability awards. In addition to more disclosures and a change in reporting the cash flows of certain stock option excess realized income tax benefits, it also requires liability awards to be reported at fair value rather than intrinsic value. Equity awards will continue to be recorded at grant-date fair value and recognized over the vesting period. Liability awards will be reported at fair value until settlement or expiration. Because we commenced in 2003 to prospectively expense new stock option grants, this standard is not expected to have a material impact on either our earnings or consolidated balance sheet.

SFAS No. 153: In 2004, the FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion No.29,* which is effective prospectively July 1, 2005. With certain exceptions, this will require exchanges of nonmonetary assets to be recorded at fair value. Currently these transactions are generally recorded at book value. This pronouncement will result in reporting in earnings, gains and losses on future exchanges of nonmonetary assets. Because we operate in a capital-intensive industry, future exchanges of nonmonetary assets may materially impact our future earnings or consolidated balance sheet.

EITF Issue No. 04-13: In 2004, the EITF initiated a review under Issue No. 04-13, *Accounting for Purchases and Sales Inventory with the Same Counterparty,* to determine if they should be reported on a gross basis or a net basis. For many years, we have used a type of transaction commonly called a buy/sell, which generally consists of the purchase and sale of crude oil from the same counterparty. In a typical buy/sell transaction, Company A enters into a contract to sell a particular grade of crude oil at a specified location to Company B on a future date, and simultaneously agrees to buy from Company B a particular grade of crude oil at a different location at the same or another specified date.

The characteristics of buy/sell transactions include gross invoicing reflecting the quality and location differences of the crude oil, physical delivery requirements and separate payment terms. Nonperformance by one party does not relieve the other party s obligation to perform under the contract except for events of force majeure. The risks and rewards of

Table of Contents

ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling and counterparty credit risk. Because of these characteristics, we, as well as many of our industry peers, report the sale of the barrels as gross revenues and the purchase of the barrels as gross purchases in accordance with EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*. These characteristics also provide evidence that these transactions are monetary in nature and thus outside the scope of APB Opinion No. 29.

We understand that some registrants in our industry may report buy/sell transactions on a net rather than a gross presentation. The EITF is reviewing these transactions to determine if more specific guidance is needed for determining a net rather than gross presentation in consolidated earnings. While a net presentation of this issue would reduce both our revenues and our purchases, our net earnings would not be impacted.

NOTE 3 - DISPOSITIONS OF ASSETS

Certain of our asset sales in 2004 are discussed below:

- We sold 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, for $67 million in cash plus possible future payments that are contingent on attainment of certain natural gas prices and/or volume thresholds. The underlying assets sold represented net production of approximately 4.5 MBOE/d and were our remaining oil and gas assets in Brazil. We recorded an after-tax gain of $1 million.

- We sold non-oil and gas property in Parachute, Colorado for $26 million in cash. We recorded an after-tax gain of $16 million.

- Our Pure subsidiary sold certain of its mineral fee lands it held in several states to Black Stone Minerals Company, LP. The sale involved Pure s royalty interests, overriding royalty interests and minor working interests. The $190 million sale price included approximately $75 million for the prospective portion of these mineral fee lands resulting in a $22 million after-tax gain. The net proceeds received were $176 million after sale price adjustments to reflect the effective date of the transaction as October 1, 2003. The sale of the producing portion of these lands was recorded as discontinued operations (see note 8 Discontinued Operations).

- Our subsidiary, Unocal North Sumatra Geothermal, Ltd. (UNSG), received about $60 million from PLN for the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia. PLN acquired UNSG s interest in the Joint Operation Contract with Pertamina and the Energy Sales Contract with PLN. We recorded a $21 million after-tax gain.

- Our Molycorp subsidiary sold down its interest of its equity investment in Companhia Brasileira de Metalurgia e Mineracao, a niobium operation in Brazil, from 44.59 percent to 40 percent for $27 million. We recorded an after-tax gain of $2 million.

- We sold non-oil and gas property in Simi Valley, California for $38 million in cash. We recorded an after-tax gain of $18 million.

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

In 2002, cash proceeds received from sales of assets totaled $163 million, with pre-tax gains of $42 million. The proceeds included $65 million from the sale of certain investment interests in nonstrategic pipelines in the U.S, with a pre-tax gain of $49 million. Cash proceeds of approximately $44 million were from the sale of real estate and other miscellaneous properties, with a pre-tax gain of $20 million, and $32 million were from the sale, by our Pure subsidiary, of oil and gas producing properties in the U.S, with a pre-tax gain of $4 million. Sale proceeds also included $22 million from various other oil and gas asset sales, with a pre-tax loss of $31 million.

Table of Contents

NOTE 4 - LEASE RENTAL OBLIGATIONS

We have operating leases for drilling rigs, office space and other property and equipment having initial or remaining noncancelable lease terms in excess of one year.

Future minimum rental payments for operating leases at December 31, 2004 were as follows:

Millions of dollars	
2005	$ 135
2006	40
2007	23
2008	17
2009	15
Thereafter	6
Total minimum lease rental payments (a)	$ 236

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(a) *Future minimum lease rental payments have not been reduced, in total, by minimum sublease rentals due in the future under non-cancelable subleases.*

We have a lease agreement relating to the *Discoverer Spirit* deepwater drillship, which is set to expire on September 18, 2005. The drillship has a current minimum daily rate of approximately $229,000. The future remaining minimum lease payment obligation was approximately $60 million at December 31, 2004.

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

	Years ended December 31,		
Millions of dollars	**2004**	**2003**	**2002**
Fixed rentals	$ 75	$ 79	$ 72
Sublease rental income	(2)	(6)	(4)
Net rental expense	$ 73	$ 73	$ 68

NOTE 5 - IMPAIRMENT OF ASSETS

As part of our periodic assessment, we review our developed and undeveloped oil and gas properties and other long-lived assets for possible impairment. We also review our properties as they are identified for sale.

In 2004, we recorded pre-tax impairment charges of $74 million ($54 million after-tax). Approximately $49 million pre-tax was attributable to oil and gas fields in the U.S., 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. In addition, we recorded an after-tax impairment of approximately $15 million relating to our Geothermal segment s equity investments in natural gas-fired power-plant projects and impairments of $5 million after-tax relating to our equity investment in an LPG terminal in China.

In 2003, we recorded pre-tax impairment charges of $93 million ($62 million after-tax). Approximately $85 million pre-tax was for oil and gas fields in the Gulf of Mexico region of the U.S. including the associated pipelines, which were part of the Midstream and Marketing segment that were sold in a divestment of non-core assets. The properties were low margin properties in the Gulf of Mexico region (see note 3 Dispositions of Assets). In addition, we recorded an after-tax charge of $6 million in our Midstream and Marketing segment due to the impairment of the Trans-Andean oil pipeline in Argentina.

In 2002, we recorded pre-tax impairment charges of $47 million ($30 million after-tax). Approximately $41 million pre-tax was for oil and gas fields in Alaska and the Gulf of Mexico region primarily due to lower reserve estimates, production forecasts and future expenses. The impairment in Alaska was $24 million pre-tax while the impairment for the Gulf of Mexico region was $17 million pre-tax.

Table of Contents

NOTE 6 - RESTRUCTURING COSTS

In 2003, we accrued $38 million pre-tax in restructuring charges and adopted a plan for streamlining our organizational structures in order to align them with our portfolio requirements and business needs. These charges, which were included in administrative and general expense on the consolidated earnings statement, represented the costs associated with eliminating 360 positions. During 2004, the plan was modified to reflect a reduction of 41 employees involved in the restructuring and the subsequent reversal of $3 million pre-tax in previously recognized costs. At December 31, 2004, 298 of 319 employees in the plan had been terminated. The remaining 21 individuals have been advised of their planned termination dates. The remaining liability of $5 million is expected to be paid in 2005. The following table reflects the 2004 plan activity.

Millions of dollars (except employees)	Number of Employees	Termination Costs	Training / Out-placement Costs
Liability at December 31, 2003	360	$ 24	$ 2
1st Quarter Payments		(7)	
Liability at March 31, 2004	360	17	2
2nd Quarter adjustments	(36)	(2)	
2nd Quarter payments		(4)	(1)
Liability at June 30, 2004	324	11	1
3rd Quarter payments		(4)	
Liability at September 30, 2004	324	7	1
4th Quarter adjustments	(5)		(1)
4th Quarter payments		(2)	
Liability at December 31, 2004	319	$ 5	$

Table of Contents

NOTE 7 - INCOME TAXES

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

Millions of dollars	Years ended December 31, 2004	2003	2002
Earnings (loss) from continuing operations before income taxes and minority interests (a)			
United States	$ 276	$ 229	$ (190)
Foreign	1,553	992	796
Earnings from continuing operations before income taxes and minority interests	$ 1,829	$ 1,221	$ 606
Income taxes (benefits)			
Current			
Federal	$ (30)	$ 60	$ (52)
State	(23)	18	7
Foreign	584	384	221
Total current taxes	531	462	176
Deferred			
Federal	33	37	(58)
State	5	(11)	
Foreign	104	26	159
Total deferred taxes	142	52	101
Total income taxes	$ 673	$ 514	$ 277

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

In 2004, the effective income tax rate was 37 percent as compared to 42 percent for 2003 and 45 percent for 2002. The lower effective tax rate in 2004 as compared to 2003 is due primarily to net tax benefits recorded in 2004 relating to settlements and assessments with various taxing authorities (see note 23 Commitments and Contingencies for details) and the lower tax effect of currency related adjustments in Thailand.

The lower effective tax rate in 2003 as compared with 2002 reflects the change in the Canadian statutory tax rate and the mix of positive domestic and foreign earnings in 2003 compared to the mix of domestic losses and foreign earnings in 2002. Foreign earnings are generally taxed at higher rates than domestic earnings. Those factors were partially offset by currency related adjustments in Thailand and tax adjustments related to the sale of affiliate investments in 2003.

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

	Years ended December 31,		
Millions of dollars	**2004**	**2003**	**2002**
Federal statutory rate	35%	35%	35%
Taxes on earnings from continuing operations before minority interests at statutory rate	$ 640	$ 427	$ 212
Taxes on foreign earnings in excess of statutory rate	124	105	66
Prior years tax settlements, assessments and adjustments	(87)	3	16
Change in Canadian statutory rate	(5)	(29)	
State taxes, net of federal benefit	16	8	5
Dividend exclusion	(13)	(16)	(15)
Other	(2)	16	(7)
Total	$ 673	$ 514	$ 277

Table of Contents

The significant components of deferred income tax assets and liabilities included in the consolidated balance sheets at December 31, 2004 and 2003 were as follows:

	At December 31,	
Millions of dollars	**2004**	**2003**
Deferred tax assets:		
Exploratory costs	$ 250	$ 299
Federal AMT and other tax credits	111	125
Foreign tax credits	251	215
Future abandonment costs	225	154
Litigation and environmental costs	113	113
Pension plans and postretirement benefit costs	130	132
Doubtful receivables	10	32
Forward sales of natural gas	18	22
Price risk and interest rate management activities		23
Other deferred tax assets	141	116
Total deferred tax assets	1,249	1,231
Valuation allowance	(251)	(215)
Net deferred tax assets	998	1,016
Deferred tax liabilities:		
Depreciation, depletion and intangible drilling costs	(1,366)	(1,151)
Investments in subsidiaries and affiliates	(39)	(47)
Other deferred tax liabilities	(72)	(103)
Total deferred tax liabilities	(1,477)	(1,301)
Total net deferred tax liabilities	$ (479)	$ (285)

The valuation allowance relates to foreign tax credit carryforwards which will more likely than not expire and the change in the valuation allowance relates to the expiration of foreign tax credits and the generation of additional foreign tax credits that will more likely than not expire. No deferred U.S. income tax liability has been recognized on the undistributed earnings of foreign subsidiaries that have been retained for reinvestment. If distributed, no additional U.S. tax is expected due to the availability of foreign tax credits. The undistributed earnings for tax purposes, excluding previously taxed earnings, were estimated at $2.9 billion as of December 31, 2004.

At December 31, 2004, we estimate having $98 million of federal alternative minimum tax (AMT) credits which are available to reduce future U.S. federal income taxes on an indefinite basis. Realization of the aggregate deferred tax assets is dependent upon our ability to generate taxable income in the future. A valuation allowance against the AMT and other credit carryforwards has not been established as we believe that it is more likely than not that these assets will be realized.

NOTE 8 - DISCONTINUED OPERATIONS

In 2004, our Pure subsidiary sold certain of its prospective and producing mineral fee lands in the U.S., which included approximately 2 MBOE/d of production in Mississippi, Arkansas and Alabama. The $190 million sale price included approximately $115 million for the producing portion of these mineral fee lands, resulting in an after-tax gain of approximately $44 million on the producing portion of the sale. The gain on the producing portion of the sale plus the results of operations prior to the sale have been reported as discontinued operations in the consolidated earnings statement. These properties generated revenues of $12 million and net earnings of approximately $6 million in 2004 up to the sale date in June 2004. In 2003 and 2002, these properties generated revenues of $26 million and $22 million, respectively, and net earnings of approximately $11 million and $6 million, respectively.

We also sold our Cal Ven Pipeline system located in Alberta, Canada, for approximately $19 million in May 2004 and recorded an after-tax gain of approximately $13 million. The gain plus normal results of operations prior to the sale have been reported as discontinued operations in the consolidated earnings statement. The Cal Ven pipeline generated revenues of $1 million and net earnings of less than one million in 2004 up to the sale date. In 2003 and 2002, the Cal Ven pipeline generated revenues of $3 million and $2 million, respectively, and net earnings of approximately $1 million and $1 million, respectively.

Table of Contents

In 2003 and 2002, discontinued operations included pre-tax gains of $25 million and $2 million, respectively, relating 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. We recorded $14 million and $2 million pre-tax for this provision of the sales agreement in 2003 and 2002, respectively. In 2003, we also reduced our loss provisions for the disposal of the business by $11 million pre-tax, reflecting lower than anticipated charges relating to the sold properties. Cash proceeds related to the provision of the sales agreement were $3 million, $11 million and $3 million for 2004, 2003 and 2002, respectively. This provision in the sales agreement terminated at the end of 2003.

The following table summarizes the results from these discontinued operations:

Millions of dollars	2004	2003	2002
Revenues	$ 13	$ 29	$ 24
Total costs and other deductions	3	9	14
Earnings from discontinued operations before income taxes	10	20	10
Income taxes on discontinued operations	4	8	3
Earnings from discontinued operations	6	12	7
Gain on disposal of discontinued operations before income taxes	86	25	2
Income taxes on disposal of discontinued operations	29	9	1
Gain on disposal of discontinued operations	57	16	1
Total earnings from discontinued operations	$ 63	$ 28	$ 8

Table of Contents

NOTE 9 - EARNINGS PER SHARE

The following are reconciliations of the numerators and denominators of the basic and diluted EPS computations for earnings from continuing operations for the years 2004, 2003 and 2002:

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Year ended December 31, 2004			
Earnings from continuing operations	$ 1,145	263	
Basic EPS			$ 4.35
Effect of dilutive securities Options and common stock equivalents		2	
	1,145	265	$ 4.32
Interest on convertible debentures payable to trust (after-tax)	24	10	
Diluted EPS	$ 1,169	275	$ 4.25
Year ended December 31, 2003			
Earnings from continuing operations	$ 698	259	
Basic EPS			$ 2.70
Effect of dilutive securities			
Options and common stock equivalents		2	
	698	261	$ 2.68
Distributions on subsidiary trust preferred securities (after-tax)	28	12	
Diluted EPS	$ 726	273	$ 2.66
Year ended December 31, 2002			
Earnings from continuing operations	$ 323	247	
Basic EPS			$ 1.31
Effect of dilutive securities			
Options and common stock equivalents		1	
Diluted EPS	323	248	$ 1.31
Distributions on subsidiary trust preferred securities (after-tax)	28	12	
Antidilutive	$ 351	260	$ 1.35(a)

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

Certain options were not included in the computation of diluted EPS as the exercise prices were greater than the average market prices of the common shares during the respective years. Not included in the computation of diluted EPS at December 31, 2004, 2003 and 2002, were options outstanding to purchase approximately 0.2 million, 8.2 million and 7.6 million shares of common stock, respectively.

Table of Contents

NOTE 10 CASH AND CASH EQUIVALENTS

	At December 31,	
Millions of dollars	2004	2003
Cash	$ 243	$ 201
Time deposits	258	150
Marketable securities	659	53
Cash and cash equivalents	$ 1,160	$ 404

At December 31, 2004, our cash and cash equivalents had increased by $756 million from year-end 2003, reflecting the effect of stronger commodity prices during the year. At year-end 2004, marketable securities totaled $659 million reflecting our short-term investments primarily in high-grade commercial paper and money market funds that invest in U.S. Treasury and other U.S. government agency obligations, floating rate and variable rate demand notes of U.S. and foreign corporations and commercial paper. These short-term investments are rated in the highest category by Moody s Investor Services, Inc. (P1) and Standard & Poor s Ratings Services (A1), certificates of deposit and time deposits, asset backed securities and repurchase agreements. The funds are rated Aaa by Moody s Investors Service, Inc. and AAAm by Standard & Poor s Ratings Services. All short-term investments are highly liquid and are part of our cash management portfolio with original maturities of three months or less.

NOTE 11 ACCOUNTS RECEIVABLE

Through a bankruptcy remote wholly-owned subsidiary, 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. Under the terms of the agreement, the receivables are sold at a discount on a revolving basis and without recourse. The costs incurred under the agreement for the years ended December 31, 2004 and 2003, were de minimis and were charged to operating expense in the consolidated earnings statement. Amounts sold were reflected as a reduction of accounts and notes receivable in the consolidated balance sheet and in net cash provided by operating activities in the consolidated cash flows statement. We used this arrangement during 2004 and 2003, but had no outstanding balance at December 31, 2004 and 2003, respectively.

Our consolidated balance sheet included a note receivable from URC of approximately $238 million and $182 million at December 31, 2004 and 2003, respectively, representing the unsold balance of trade receivables transferred to URC.

Our accounts receivable are presented at their net realizable values, which includes allowances for doubtful accounts. Bad debt reserves are recorded for potential losses incurred from the sale of crude oil, natural gas and natural gas liquids and for potential losses incurred from certain joint venture exploration and production activities. Allowance estimates are based upon individual customer experience, as well as age of receivables and likelihood of collection. See Schedule II Valuation and Qualifying Accounts for details on the allowance for doubtful receivables.

NOTE 12 - INVENTORIES

Millions of dollars	At December 31, 2004	2003
Crude oil and natural gas	$ 156	$ 71
Carbon and mineral products	44	43
Materials, supplies and other	20	27
Total inventories	$ 220	$ 141

Inventories are generally valued at the lower of cost or market. Inventories using the LIFO cost method amounted to $12 million and $17 million as of December 31, 2004 and 2003, respectively. The remaining inventory balances were primarily valued using average cost. The current replacement cost of inventories exceeding the LIFO inventory values was $3 million at both December 31, 2004 and 2003.

Table of Contents

NOTE 13 ASSETS HELD FOR SALE

In 2004, we sold certain of our prospective mineral fee lands in North America (see note 8 Discontinued Operations) and our UNSG subsidiary sold its rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia (see note 3 Dispositions of Assets). These two assets were held for sale as of December 31, 2003.

NOTE 14 - EQUITY INVESTMENTS

Investments in companies accounted for by the equity method were $537 million, $651 million and $686 million at December 31, 2004, 2003 and 2002, respectively. These investments are reported in investments and long-term receivables on the consolidated balance sheet.

Dividends or cash distributions received from our equity investees were $124 million, $180 million and $132 million for the years 2004, 2003 and 2002, respectively. At December 31, 2004, 2003 and 2002, the excess of our investments in Colonial Pipeline and various other pipeline companies was $135 million, $139 million and $143 million, respectively. Our equity investees have approximately $3.38 billion of their own debt obligations that are either fully non-recourse or of limited recourse to Unocal. Colonial Pipeline, in which we hold a 23.44 percent equity interest, has $1.17 billion of debt that is non-recourse to Unocal. BTC Pipeline, in which we hold an 8.9 percent equity interest, has $1.92 billion of debt that is of limited recourse to Unocal. In connection with this BTC Pipeline debt, we have a construction completion guarantee (see note 23 for further details on the guarantee). Lastly, other equity investees have approximately $290 million of their own debt and all but $15 million of this debt is non-recourse to Unocal. At December 31, 2004, 2003 and 2002, our share of the net capitalized costs of other companies engaged in oil and gas exploration and production activities were $120 million, $178 million and $347 million, respectively.

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

	Years ended December 31,					
	2004		2003		2002	
Millions of dollars	Total	Unocal Share	Total	Unocal Share	Total	Unocal Share
Revenues	$ 1,690	$ 475	$ 2,148	$ 600	$ 1,965	$ 548
Costs and other deductions	1,173	335	1,425	408	1,419	394
Net earnings	$ 517	$ 140	$ 723	$ 192	$ 546	$ 154

	At December 31,		
	2004	2003	2002
Millions of dollars	Total	Total	Total

		Unocal Share		Unocal Share		Unocal Share
Current assets	$ 1,104	$ 242	$ 700	$ 239	$ 756	$ 248
Noncurrent assets	5,589	983	4,450	921	4,653	1,088
Current liabilities	918	189	695	197	787	257
Noncurrent liabilities	3,616	576	1,690	409	1,975	521
Net equity	2,159	460	2,765	554	2,647	558

Table of Contents

NOTE 15 PROPERTIES AND CAPITAL LEASES

Investments in owned and capitalized-leased properties are shown below. Accumulated depreciation, depletion and amortization for continuing operations were $12,597 million and $11,711 million at December 31, 2004 and 2003, respectively.

	At December 31,			
	2004		2003	
Millions of dollars	Gross	Net	Gross	Net
Owned Properties (at cost)				
Exploration and Production				
Exploration				
United States	$ 477	$ 301	$ 517	$ 377
Canada	298	163	269	166
North America Total	775	464	786	543
Asia	281	246	314	278
Other			61	
International Total	281	246	375	278
Production and Development				
United States	7,688	2,571	7,313	2,520
Canada	1,813	1,096	1,571	1,022
North America Total	9,501	3,667	8,884	3,542
Asia	7,209	2,674	6,602	2,440
Other	1,665	916	1,341	631
International Total	8,874	3,590	7,943	3,071
Total exploration and production	19,431	7,967	17,988	7,434
Midstream and Marketing	617	270	539	241
Geothermal	866	390	903	427
Corporate & Other	470	162	605	222
Total owned properties	21,384	8,789	20,035	8,324
Capitalized-leased properties	32	30		
Total properties and capital leases	$ 21,416	$ 8,819	$ 20,035	$ 8,324

The following table reconciles the amount of capitalized exploratory drilling costs for suspended wells, which are part of the exploration subtotals included in the above table. All wells included in the December 31, 2004 ending balance in the following table had drilling activity in the area during 2004. Those wells that have been suspended for more than one year at December 31, 2004 require major capital expenditures and have additional exploratory wells underway or firmly planned with the exception of four wells with an investment of $76 million where no further drilling is currently planned. However, another drilling opportunity in the area of the four wells is presently under consideration.

Capitalized Exploratory Drilling Costs - Suspended Wells

Millions of dollars	**2004**	**2003**	**2002**
Beginning balance at January 1	$ 364	$ 409	$ 334
Additions to capitalized exploratory well costs pending the determination of proved reserves	109	66	95
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(55)	(96)	(12)
Capitalized exploratory well costs charged to expense	(63)	(15)	(8)
Ending balance at December 31 (a)	$ 355	$ 364	$ 409
(a) Excludes costs of wells where drilling was in progress at December 31 of:	*$ 18*	*$ 51*	*$ 47*

-100-

Table of Contents

For exploratory well costs that continue to be capitalized for more than one year after completion of drilling at December 31, 2004, the following describes the activities that have been undertaken to evaluate the reserves and the projects and the information still required to classify the associated reserves as proved.

United States ($130 million, 10 wells)

In 2004, we continued our effort to further evaluate and advance the Trident discovery in the Perdido foldbelt of the deepwater Gulf of Mexico. In 2004, we drilled an additional successful well at the nearby Tobago prospect, which could allow for co-development of the two discoveries. We are in active discussions with all of the area operators and partners, all of which already have discoveries in the area, to determine the feasibility of various co-development options, which will be required before proved reserves can be booked. 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.

A successful appraisal well was drilled in 2004 on the St. Malo discovery that was made in 2003. An additional appraisal well is firmly planned for 2005. Well and seismic analysis is ongoing to move this project towards sanctioning and proved reserves booking.

An appraisal well is firmly planned for 2005 to further evaluate the 2004 Puma discovery. This prospect is near the Mad Dog field that began production in early 2005. Evaluation of the 2005 appraisal well and ongoing seismic analysis is needed to move this project toward sanctioning and reserve booking.

Indonesia ($153 million, 18 wells)

The Gendalo complex project encompasses three deepwater fields in the Kutei Basin, East Kalimantan, Indonesia. A plan of development covering this project is currently being prepared and is expected to be submitted to the Government of Indonesia in mid-2005.

The Gehem field will be developed as part of the Gehem-Ranggas complex, which is located in the Kutei Basin. Work continued in 2004 with the drilling of a successful appraisal well. A plan of development is expected to be submitted to our partner and the Government of Indonesia in 2005. Proved reserves for Gehem are expected to be booked after all the requisite approvals have been received.

A plan of development is expected to be submitted for the Bangka project, a satellite development to the West Seno producing operation, in 2006. Conceptual engineering work has started.

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.

Thailand ($42 million, 20 wells)

Efforts to bring the Gulf of Thailand Arthit project to development continued during 2004 including additional exploratory and delineation drilling to further evaluate this discovery. Further drilling is firmly planned for 2005. The expected completion of a third pipeline to shore in 2006 by PTT will provide capacity for Arthit s production. A gas sales contract was signed in 2004. Proved reserves are expected to be booked after additional drilling.

Vietnam ($24 million, 16 wells)

Additional successful exploratory drilling continued during 2004 to further appraise the discovery of natural gas reserves offshore of Vietnam. We are also committed to drilling two additional wells by 2008. We are currently working with the Vietnamese officials to finalize and obtain government approval for development plans to supply gas for power generation in the southwest part of the country. This work includes detailed engineering and economic analysis, which then will lead us into commercial negotiations. The timing for the booking of any proved reserves is dependent on finalizing remaining PSC requirements and concluding all commercial negotiations.

Canada ($6 million, 1 well) The suspended well was drilled in 2004.

Table of Contents

NOTE 16 - POSTEMPLOYMENT BENEFIT PLANS

We have numerous plans worldwide that provide employees with retirement benefits. We also have medical plans that provide health care benefits for eligible employees and many of our retired employees. Most of our plans covering employees outside of North America are unfunded and resulting liabilities are extinguished on a pay as you go basis.

The functional currency for all of our international plans, with the exception of Canada, is the U.S. dollar.

Prepaid pension costs are reported as a component of investments and long-term receivables on the consolidated balance sheet. Postemployment benefit liabilities, including pensions, postretirement medical benefits and other postemployment benefits, are reported as a component of other deferred credits and liabilities on the consolidated balance sheet. We use a December 31 measurement date for all of our postemployment benefit plans. The following table sets forth the postretirement benefit obligations recognized in the consolidated balance sheets at December 31, 2004 and 2003.

	Pension Benefits		Other Benefits	
Millions of dollars	**2004**	**2003**	**2004**	**2003**
Change in benefit obligation:				
Projected benefit obligation at January 1,	$ 1,381	$ 1,197	$ 431	$ 372
Service cost	36	31	4	4
Interest cost	83	83	20	25
Employee contributions			6	6
Disbursements	(122)	(117)	(28)	(28)
Actuarial losses (gains)	82	189	(93)	51
Plan amendments			(55)	
Curtailments and settlements		(7)		
Effect of foreign exchange rates	2	5		1
Projected benefit obligation at December 31,	$ 1,462	$ 1,381	$ 285	$ 431
Change in plan assets:				
Fair value of plan assets at January 1,	$ 999	$ 882	$	$
Actual return on plan assets	116	187		
Employer contributions	129	47	22	22
Employee contributions			6	6
Disbursements	(122)	(117)	(28)	(28)
Administrative expenses	(6)	(5)		
Effect of foreign exchange rates	2	5		
Fair value of plan assets at December 31,	$ 1,118	$ 999	$	$
Net amount recognized:				
Funded status	$ (344)	$ (382)	$ (285)	$ (431)
Unrecognized net obligation at transition	1	1		
Unrecognized prior service cost	31	38	(52)	4

Unrecognized net actuarial losses	679	689	86	186
Net amount recognized	$ 367	$ 346	$ (251)	$ (241)
Components of the above amounts consist of:				
Prepaid pension cost	$ 13	$ 11	$	$
Accrued benefit liability	(171)	(217)	(251)	(241)
Intangible asset	31	38		
Accumulated other comprehensive loss	494	514		
Net amount recognized	$ 367	$ 346	$ (251)	$ (241)

Table of Contents

The accumulated benefit obligation for our defined benefit pension plans was $1.27 billion and $1.20 billion at December 31, 2004, and 2003, respectively. The projected benefit obligations, accumulated benefit obligations and fair values of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were approximately $1.39 billion, $1.22 billion and $1.05 billion, respectively as of December 31, 2004 and approximately $1.32 billion, $1.16 billion and $937 million, respectively as of December 31, 2003.

The components of net periodic benefit cost for our pension and postretirement medical plans were:

	Pension Benefits			Other Benefits		
Millions of dollars	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Service cost (net of employee contributions)	$ 36	$ 31	$ 24	$ 4	$ 4	$ 3
Interest cost	83	83	77	20	24	21
Expected return on plan assets	(80)	(81)	(105)			
Amortization of:						
Prior service cost	7	7	6		1	1
Net actuarial losses	62	68	33	7	10	5
Curtailment and settlement losses		4	5		1	
Net periodic pension and other benefit cost	$ 108	$ 112	$ 40	$ 31	$ 40	$ 30

In 2003, we recognized $5 million in curtailment costs related to our U.S. Qualified Retirement Plan and Postretirement Welfare plans covering current and former U.S. payroll employees as a result of asset sales and our 2003 restructuring plan.

In December 2003, The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was enacted. As of January 1, 2004, the Act s non-taxable federal subsidy reduced the Accumulated Postretirement Benefit Obligation (APBO) of our U.S. Postretirement Welfare Plan by $72 million, which will be amortized to future earnings as an actuarial gain. In keeping with the guidance provided by FASB Staff Position 106-2, we recorded a benefit of $11 million in 2004, representing the impact of the subsidy. This amount consisted of $4 million for the reduction in interest cost, $6 million for amortization of the actuarial experience gain and $1 million for the reduction in service cost.

On October 15, 2004, we amended our U.S. postretirement medical program to set a maximum amount to our contributions for retiree medical coverage. As a result of this revision, we were required to remeasure our postretirement benefit obligation as of October 15, 2004. This calculation resulted in a net reduction of $55 million to our accumulated postretirement benefit obligation and approximately $2 million in expense for 2004. This amount consisted of $1 million for the reduction of interest cost and $1 million reduction in prior service cost. It is estimated that these plan changes will decrease our future annual pre-tax postretirement expense by approximately $12 million.

Final detailed regulations specifying the manner in which actuarial equivalency is determined were issued by the U.S. Department of Health and Human Services Centers for Medicare and Medicaid Services in January 2005. The final regulations provide plan sponsors with additional flexibility regarding submission of Medicare subsidy eligible claims. As a result, our Plan will be eligible for the Medicare subsidy for a longer period of time. Accordingly, the APBO will be reduced by an additional $13 million effective January 1, 2005. In keeping with the guidance provided by paragraph 16 of FASB Staff Position 106-2, this change will be accounted for as an actuarial gain in 2005.

We amortize unrecognized actuarial gains and losses on a straight-line basis over the average remaining service period of active plan participants expected to receive benefits. We amortize the cost of plan amendments for our pension plans over the average remaining service period of active plan participants expected to receive benefits. However, we amortize the cost of plan amendments for our postretirement medical plans on a straight-line basis over the average remaining service period of active plan participants to their expected full eligibility date.

Table of Contents

The assumed weighted-average rates used to determine benefit obligations at December 31 were:

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Discount rates	5.74%	6.00%	6.74%	5.75%	6.00%	6.75%
Rates of salary increases	4.91%	4.91%	4.93%	4.99%	4.99%	4.99%

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

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Discount rates	6.00%	6.74%	7.24%	6.00%	6.75%	7.25%
Rates of salary increases	4.91%	4.93%	4.50%	4.99%	4.99%	4.50%
Expected returns on plan assets	8.00%	8.40%	9.33%	N/A	N/A	N/A

We employ a building block approach in determining the expected long-term rate of return for pension plan assets. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The overall expected long-term rate of return on assets assumption is calculated using pension plan target asset allocations, outside consultants capital markets return forecasts for the asset classes employed, expected premium returns for active management and estimated pension plan fees and expenses. Peer data and historical returns are utilized to validate projected long-term returns for reasonableness. The resulting weighted average expected long-term rate of return for our domestic and international pension plans were 8.0 percent and 8.0 percent at January 1, 2005 and 2004, respectively.

The following is a breakdown of the fair value of our pension plan assets by investment type at December 31, 2004 and 2003, respectively:

	U.S. Plan				Foreign Plans			
Millions of dollars	2004		2003		2004		2003	
U.S. Equity Securities	$ 505	48%	$ 432	46%	$ 3	4%	$ 4	6%
International Equity Securities	160	15%	162	17%	27	37%	21	34%
Debt Securities	351	34%	283	30%	43	59%	36	58%
Cash/Other	29	3%	60	7%			1	2%
Total assets	$ 1,045	100%	$ 937	100%	$ 73	100%	$ 62	100%

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

Type of Investment	Allocation Range
U.S. Equity Securities	42.0% to 52.0%
International Equity Securities	12.0% to 18.0%
Debt Securities	32.0% to 42.0%
Cash/Other	0% to 7.0%

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

In 2002, we had recognized a minimum pension liability of $103 million, for our U.S. Qualified Retirement Plan covering current and former U.S. payroll employees, reflecting the excess of the ABO over the fair value of plan assets at December 31, 2002. The recognition of this liability resulted in an after-tax charge of $334 million to OCI. In 2003,

Table of Contents

we recognized a minimum pension liability of $91 million reflecting the excess of the ABO over the fair value of plan assets at December 31, 2003. The recognition of this liability, which was a reduction of liability from the prior year, resulted in an after-tax credit of $34 million to the other comprehensive income component of stockholders equity in 2003. At December 31, 2004, the minimum pension liability had been reduced to $40 million. This net reduction was achieved in spite of using a lower discount rate to measure the liability at year-end 2004 and reflects the impact of our contributions and improved market returns on plan assets during 2003 and 2004. As a result, an after-tax credit of $13 million was recorded to the other comprehensive income component of stockholders equity in 2004. We made voluntary pre-tax contributions of $100 million and $30 million to our U.S. Qualified Retirement Plan in 2004 and 2003, respectively. Under existing pension funding regulations, we expect that mandated employer contributions to this plan will be payable no sooner than 2009.

We contributed approximately $150 million in support of our various postemployment benefit plans in 2004. This amount consisted of the previously mentioned $100 million contribution to the U.S. Qualified Retirement Plan, $8 million to our Supplemental Executive Retirement plans, approximately $20 million to our foreign pension plans and approximately $22 million to our worldwide postretirement medical plans. We anticipate that we will contribute approximately $5 million to our Supplemental Executive Retirement plans, approximately $17 million to our foreign pension plans and approximately $25 million to our worldwide postretirement medical plans in 2005.

The following benefit payments, which reflect expected future service, relate to all our pension and postemployment benefit plans and are expected to be paid as follows:

Millions of dollars	Pension Benefits	Other Benefits
Fiscal Year ended December 31, 2005	$ 80	$ 25
Fiscal Year ended December 31, 2006	$ 85	$ 23
Fiscal Year ended December 31, 2007	$ 106	$ 23
Fiscal Year ended December 31, 2008	$ 124	$ 23
Fiscal Year ended December 31, 2009	$ 138	$ 23
5 Fiscal Years ended December 31, 2014	$ 778	$ 107

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

	2004	2003	2002
Health care cost rate assumed for next year	10.00%	10.00%	9.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%
Year that rate reaches ultimate trend rate	2009	2008	2006

A one percentage-point change in the assumed health care cost trend rate would have had the following effects on 2004 service and interest cost and the accumulated postretirement benefit obligation at December 31, 2004:

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

We have a 401(k) defined contribution savings plan designed to supplement retirement income for our U.S. employees. Our contributions to this plan were $13 million, $13 million and $12 million in 2004, 2003 and 2002, respectively, which were used by the plan trustee to purchase shares of Unocal common stock in the open market. While historically trustee purchases of Unocal common stock have been made in the open market, we have the option to direct the trustee to purchase common stock directly from Unocal. Once our contributions have been used to purchase Unocal common stock, employees have the ability to sell the shares and reinvest the proceeds in a variety of mutual funds.

Table of Contents

We also provide benefits such as workers compensation and medical care to former or inactive employees after employment but before retirement. The accumulated postemployment benefit obligation was $14 million at December 31, 2004 and 2003.

NOTE 17 VARIABLE INTEREST ENTITIES

In 1996, Unocal exchanged 10,437,873 newly issued 6 1/4% trust convertible preferred securities of Unocal Capital Trust, a Delaware statutory trust, for shares of a then-outstanding issue of convertible preferred stock. Unocal acquired the convertible preferred securities, which had an aggregate liquidation value of $522 million, from the Trust, together with 322,821 common securities of the Trust, which had an aggregate liquidation value of $16 million, in exchange for $538 million principal amount of 6 1/4% convertible junior subordinated debentures of Unocal. Until the end of 2003, the Trust was accounted for as a 100 percent-owned consolidated finance subsidiary of Unocal, with the debentures and payments thereon by Unocal to the Trust eliminated in the consolidated financial statements. The trust convertible preferred securities have been fully and unconditionally guaranteed by Unocal in accordance with the terms of Unocal s guarantee agreement. The convertible preferred securities have a liquidation value of $50 per security and are convertible into shares of Unocal common stock at a conversion price of $42.56 per share, subject to adjustment upon the occurrence of certain events. Distributions on the convertible preferred securities are cumulative at an annual rate of 6.25 percent of their liquidation amount and are payable quarterly in arrears on March 1, June 1, September 1 and December 1 of each year to the extent that the Trust receives interest payments on the debentures. The debentures mature on September 1, 2026, and may be redeemed, in whole or in part, at the option of Unocal at a redemption price equal to 101.875 percent (since September 1, 2003), of the principal amount redeemed, declining annually to 100 percent of the principal amount redeemed on or after September 1, 2006, plus accrued and unpaid interest thereon to the redemption date. The debentures, and hence the convertible preferred securities, are redeemable at the option of Unocal upon the occurrence of certain special events or restructuring transactions. Upon repayment of the debentures by Unocal, whether at maturity, upon redemption or otherwise, the proceeds thereof must immediately be applied to redeem a corresponding amount of the convertible preferred securities and the common securities of the Trust.

Pursuant to FASB Interpretation No. 46 Consolidation of Variable Interest Entities as revised in December 2003 (see note 2 Accounting Changes), we deconsolidated the Trust in the first quarter of 2004. As a result, the $522 million obligation for the convertible preferred securities was removed from the consolidated balance sheet and replaced by $538 million in 6 1/4% convertible junior subordinated debentures of Unocal payable to the Trust. In addition, we recorded our $16 million investment in the Trust in investments and long-term receivables-net on the consolidated balance sheet. Effective in the first quarter of 2004, interest payments on the debentures are now recorded as interest expense on the consolidated earnings statement. In prior periods, payments to the holders of the preferred securities were reported as a separate line item on the consolidated earnings statement. Payments are subject to deferral under certain circumstances. If payments are deferred, Unocal would be prohibited from paying dividends on its common stock during the deferral period.

In 2004, the Trust called all of its outstanding convertible preferred securities. During 2004, holders converted 852,249 preferred securities into Unocal common stock and 4,914,302 convertible preferred securities were redeemed for $246 million, plus a $3 million premium. In connection with this redemption program, Unocal redeemed $296 million of its convertible junior subordinated debentures held by the Trust using cash on hand and by issuing $43 million in Unocal common stock. The Trust utilized the cash it received from Unocal to redeem the preferred securities and to retire the Trust s common securities, which Unocal held as an investment. At December 31, 2004, the Trust held 4,840,686 units of Unocal s convertible junior subordinated debentures valued at $242 million and Unocal held 170,805 common securities of the Trust, approximating an $8 million investment. The redemption of the remaining convertible preferred securities was completed in January 2005 (see note 30 Subsequent Events).

-106-

Table of Contents

NOTE 18 - LONG-TERM DEBT AND CREDIT AGREEMENTS

The following table summarizes our long-term debt and capital leases:

Millions of dollars	At December 31, 2004	2003
Bonds and debentures		
9 1/8% Debentures due 2006	166	166
7% Debentures due 2028	200	200
7 1/2% Debentures due 2029	350	350
Notes		
Medium-term notes due 2004 to 2015 (8.10%) and (7.96%) (a)	273	294
6 3/8% Notes due 2004		173
7 1/5% Notes due 2005	85	85
6 1/2% Notes due 2008	21	21
7.35% Notes due 2009	316	316
5.05% Notes due 2012	400	400
Other		
6 1/4% convertible securities	242	
Canadian Bank Credit Agreement	245	227
Pure consolidated debt (b)	350	350
Bangladesh Bibiyana 7% note (c)	30	
Azerbaijan Early Oil loan (c)		24
Azerbaijan Phase 1 loan (c)	40	
West Seno - OPIC loan (c)	259	205
DSPL debt (b)	57	74
Other miscellaneous debt	2	1
Bond (discount) premium	(4)	(3)
Capital leases	30	
Total debt and capital leases	3,062	2,883
Less current portion of long-term debt and capital leases	491	248
Total long-term debt and capital leases	$ 2,571	$ 2,635

(a) *Weighted average interest rate at December 31, 2004 and 2003, respectively.*
(b) *Non-Recourse debt.*
(c) *Limited-Recourse debt.*

At December 31, 2004, the amounts of annual maturities on long-term debt and capital leases for the next five years were:

Millions of dollars	Long-Term Debt	Capital Leases
2005	488	3

2006	298	3
2007	133	3
2008	81	3
2009	590	3
Thereafter	1,442	15

Effective January 1, 2004, we adopted FASB Interpretation No. 46 (revised December 2003) that resulted in us removing from our consolidated balance sheet the $522 million obligation for the Trust s convertible preferred securities and replaced it with $538 million in 6 1/4% convertible junior subordinated debentures of Unocal payable to the Trust. During 2004, we redeemed $296 million of our convertible junior subordinated debentures held by the Trust using cash on hand and by issuing $43 million in Unocal common stock (see note 17 Variable Interest Entities).

-107-

Table of Contents

During 2004, we retired $173 million in 6.375 percent notes and $21 million of medium-term notes that matured in 2004. We also made principal payments of $41 million 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. In 2004, we also repaid the $24 million outstanding on our Azerbaijan Early Oil limited recourse loan. We had completed the limited recourse project financing for our separate share of the AIOC Early Oil Project under an International Finance Corporation and European Bank for Reconstruction and Development loan structure in 1998 for up to $77 million. Finally, our DSPL subsidiary repaid $17 million of its outstanding debt that matured in 2004.

These decreases were partially offset by $40 million in new borrowing relating to 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 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.

At December 31, 2004, consolidated debt included $350 million in unsecured senior notes, which bear interest at 7.125 percent and mature in 2011 that relates to our Pure subsidiary. The notes were issued at a discount to their face value. Neither Unocal nor Union Oil guarantees any of Pure s debt.

In addition, consolidated debt included $259 million drawn under the OPIC Financing Agreement, a limited recourse loan, for the West Seno project in Indonesia. The outstanding $259 million was comprised of $38 million with a floating rate that is adjusted weekly, which as of December 31, 2004 was set at 2.4 percent. The remaining $221 million was made up of four other draw downs that carry fixed rates ranging from 2.41 percent to 4.78 percent. Principal payments on these four fixed rate draw downs are scheduled semiannually until June 2008.

At December 31, 2004, consolidated debt included $57 million related to our DSPL subsidiary. Neither Unocal Geothermal of Indonesia, Ltd. nor Unocal has guaranteed DSPL s debt obligations, which are non-recourse.

In November 2004, two of our wholly owned subsidiaries signed a natural gas purchase and sales agreement with Petrobangla to develop and produce natural gas from the Bibiyana field in Bangladesh. The agreement triggered an obligation to make payments to a former co-venturer in our Bangladesh operations of a $30 million note that was entered into in 1999 as part of the purchase agreement for the co-venturer s share. The principal plus simple interest at 7 percent per annum is payable quarterly in amounts equal to 10 percent of our profit petroleum revenues received during the twelve years ending September 30, 2011, or sooner in the event principal and interest have been fully repaid. Any principal and interest amounts that remain unpaid at September 30, 2011 shall cease to be payable on that date.

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 have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade. The credit agreement does not contain a material adverse change or MAC clause test that would impair our ability to borrow under it.

In November 2004, our wholly owned subsidiaries, Unocal Canada Limited and Northrock Resources Ltd., entered into a new $295 million Canadian dollar-denominated credit agreement with five commercial banks with a maturity date of November 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.

Table of Contents

During 2004, a capital lease of $32 million for a 10-year lease agreement on a floating storage unit for our Thailand production operations was added to our consolidated debt. The interest rate of this lease agreement is 4.01 percent. In 2004, $2 million was amortized and charged to interest expense under this capital lease. The lease agreement has an extension option for an additional 5 years.

We have undrawn letters of credit at year-end 2004 that approximated $105 million, the majority of which are maintained for operational needs and are renewed yearly.

NOTE 19 ASSET RETIREMENT AND ENVIRONMENTAL LIABILITIES

At December 31, 2004, we had accrued $762 million in estimated asset retirement obligations, and at December 31, 2003, we had accrued $710 million. The following table details the changes in the liabilities accounts:

Millions of dollars	2004	2003
Asset retirement obligations as of January 1,	$ 710	$ 758
Liabilities settled during the year	(28)	(21)
Liabilities related to sold assets	(2)	(86)
Accretion expense	44	44
Revisions recorded during the year	27	
New liabilities recorded during the year	11	15
Asset retirement obligations as of December 31,	$ 762	$ 710

Our reserve for environmental remediation obligations at December 31, 2004 totaled $244 million, of which $109 million was included in current liabilities. This compared with $252 million at December 31, 2003, of which $118 million was included in current liabilities. The following table details the environmental remediation obligations into 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

NOTE 20 - OTHER FINANCIAL INFORMATION

The consolidated balance sheet included the following:

	At December 31,	
Millions of dollars	**2004**	**2003**
Other deferred credits and liabilities:		
Postretirement medical benefits	$ 251	$ 242
Pension and other employee benefits	153	194
Reserves for litigation and other claims	114	129
Advances related to future production	134	122
Derivative and commodity contract liabilities	132	122
Other	185	151
Total other deferred credits and liabilities	$ 969	$ 960
Allowances for doubtful accounts and notes receivables	$ 5	$ 88
Allowances for investments and long-term receivables	$ 32	$ 11

Table of Contents

Pension and other employee benefits included $40 million and $91 million at December 31, 2004 and 2003, respectively, to recognize the minimum pension liability for our U.S. Qualified Retirement Plan. These amounts reflect the excess of the accumulated benefit obligation for vested current and former employees over the fair value of plan assets. The decrease reflects our voluntary pre-tax contribution of $100 million to the plan and favorable asset returns. See note 16 Postemployment Benefit Plans for a full discussion of the minimum pension liability for our U.S. Qualified Retirement Plan. See Schedule II Valuation and Qualifying Accounts for details on the allowances for doubtful receivables and investments.

NOTE 21 ADVANCE SALES OF NATURAL GAS

We entered into a long-term fixed price natural gas sales contract for the delivery of approximately 72 billion cubic feet of natural gas over a ten-year period beginning in January 1999 and ending in December 2008. In January 1999, we received a non-refundable payment of approximately $120 million pursuant to the contract. We are also receiving a fixed monthly reservation fee over the life of the contract. We entered into a ten-year natural gas price swap agreement, which effectively refloated the fixed price that we received under the long-term natural gas sales contract. We did not dedicate a portion of our natural gas reserves to the contract and we have the option to satisfy contract delivery requirements with natural gas purchased from third parties. Accordingly, the obligation associated with the future delivery of the natural gas has been recorded as deferred revenue and is being amortized into revenue as scheduled deliveries of natural gas are made throughout the contract period. As of December 31, 2004, we have delivered approximately 43 billion cubic feet of natural gas since the contract began in January 1999. Of the remaining unamortized balance at year-end 2004, approximately $37 million related to deliveries scheduled to be made in the years 2006 through 2008 and was recorded in other deferred credits and liabilities on the consolidated balance sheet. Approximately $12 million was included in other current liabilities on the consolidated balance sheet, representing deliveries to be made in 2005. At December 31, 2004, we had in place an irrevocable surety bond for $66 million and letters of credit for $13 million, both securing our performance under the sales contract.

NOTE 22 MINORITY INTERESTS

At December 31, 2004, minority interests on our consolidated balance sheet were $27 million, a decrease of $12 million from 2003. This decrease was primarily due to the purchase by one of our subsidiaries of the remaining 50 percent minority interest related to DSPL, a geothermal subsidiary in Indonesia, and the purchase by one of our subsidiaries of the 25 percent minority interest related to our carbon business. In 2004, as required by FASB Interpretation No. 46 (revised December 2003), we consolidated a domestic pipeline company and recorded the amount of minority interests related to the outside interest. The $27 million balance at December 31, 2004, included $9 million relating to the outside interests of certain oil and gas subsidiaries, $6 million relating to the domestic pipeline company and $12 million relating to a real estate subsidiary.

Table of Contents

NOTE 23 COMMITMENTS AND CONTINGENCIES

Unocal has contingent liabilities for existing or potential claims, lawsuits and other proceedings, including those involving environmental, tax, guarantees and other matters, some of which are discussed more specifically below. We accrue liabilities when it is probable that future costs will be incurred and these costs can be reasonably estimated. Accruals are based on developments to date, our estimates of the outcomes of these matters and our experience in contesting, litigating and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which could have a material effect on our future results of operations, financial condition or liquidity.

Environmental matters

We continue to move forward to address environmental issues for which we are responsible. In cooperation with regulatory agencies and others, we follow procedures that we have established to identify and cleanup contamination associated with past operations. We are subject to loss contingencies pursuant to federal, state, local and foreign environmental laws and regulations. These include existing and possible future obligations to investigate the effects of the release or disposal of certain petroleum, chemical and mineral substances at various sites; to remediate or restore these sites; to compensate others for damage to property and natural resources, for remediation and restoration costs and for personal injuries; and to pay civil penalties and, in some cases, criminal penalties and punitive damages. These obligations relate to sites owned by us or owned by others and are associated with past and present operations, including sites at which we have been identified as a potentially responsible party (PRP) under the federal Superfund laws and comparable state laws.

Liabilities are accrued when it is probable that future costs will be incurred and such costs can be reasonably estimated. However, in many cases, investigations are not yet at a stage where we are able to determine whether we are liable or, even if liability is determined to be probable, to quantify the liability or estimate a range of possible exposure. In such cases, the amounts of our liabilities are indeterminate due to the potentially large number of claimants for any given site or exposure, the unknown magnitude of possible contamination, the imprecise and conflicting engineering evaluations and estimates of proper clean-up methods and costs, the unknown timing and extent of the corrective actions that may be required, the uncertainty attendant to the possible award of punitive damages, the recent judicial recognition of new causes of action, the present state of the law, which often imposes joint and several and retroactive liabilities on PRPs, the fact that we are usually just one of a number of companies identified as a PRP, or other reasons.

Assessment and Remediation

As disclosed in note 19, at December 31, 2004, we had accrued $244 million for estimated future environmental assessment and remediation costs at various sites where liabilities for such costs are probable and reasonably estimable. The amount accrued represents our reserve for assessment and remediation obligations based on currently available facts, existing technology and presently enacted laws and regulations. The remediation cost estimates, in many cases, are based on plans recommended to the regulatory agencies for approval and are subject to future revisions. The ultimate costs to be incurred could exceed the total amounts reserved. We may also incur additional liabilities in the future at sites where remediation liabilities are probable but future environmental costs are not presently reasonably estimable because the sites have not been assessed or the assessments have not advanced to the stage where costs are reasonably estimable. At those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately $215 million. The amount of such possible additional costs reflects the aggregate of the high ends of the ranges of costs of feasible alternatives that we identified for those sites with respect to which investigation or feasibility studies have advanced to the stage of analyzing such alternatives. However, such estimated possible additional costs are not an estimate of the total remediation costs beyond the amounts reserved, because there are sites where we are not yet in a position to estimate all, or in some cases any, possible additional costs. Both the amounts reserved and estimates of possible additional costs will be adjusted, as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties. Therefore, the amounts reserved and the possible additional estimated costs may change in the near term, and in some cases could change substantially.

Table of Contents

During 2004, cash payments of $102 million were applied against the reserves and $94 million was added to the reserves. Possible additional remediation costs increased by $10 million during 2004. The accrued costs and the estimated possible additional costs are shown below for four categories of sites:

	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

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

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

Superfund and similar sites

Contamination at the sites of the Superfund and similar sites category was the result of the disposal of substances at these sites by one or more PRPs. Contamination of these sites could be from many sources, of which we may be one. We have been notified that we are a PRP at the sites included in this category. At the sites where we have not denied liability, our contribution to the contamination at these sites was primarily from operations in the other categories described below. Included in this category of sites are:

- the McColl site in Fullerton, California

- the Operating Industries site in Monterey Park, California the Casmalia Waste site in Casmalia, California.

At December 31, 2004, we have received notifications from the EPA that we may be a PRP at 22 sites and may share certain liabilities at these sites. Of the total, four sites are under investigation and/or litigation, and our potential liability is not presently determinable; and for two sites, our potential liability appears to be de minimis. Of the remaining 16 sites, where we have concluded that liability is probable and to the extent costs can be reasonably estimated, a reserve of $10 million has been established for future remediation and settlement costs.

Various state agencies and private parties had identified 23 other similar PRP sites. Four sites are under investigation and/or litigation, and our potential liability is not presently determinable; and at three sites, our potential liability appears to be de minimis. Where we have concluded that liability is probable and to the extent costs can be reasonably estimated at the remaining 16 sites, a reserve of $4 million has been established for future remediation and settlement costs.

Table of Contents

The sites discussed above exclude 129 sites where our liability has been settled, or where we have no evidence of liability and there has been no further indication of liability by government agencies or third parties for at least a 12-month period.

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

Active Company facilities

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

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

We have a reserve of $30 million for estimated future costs of remedial orders, corrective actions and other investigation, remediation and monitoring obligations at certain operating facilities and producing oil and gas fields. We recorded provisions of $9 million during 2004. 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, we made payments of $7 million for this category of sites.

Company facilities sold with retained liabilities and former Company operated sites

The Company facilities sold with retained liabilities and former Company-operated sites category includes our former refineries, transportation and distribution facilities and service stations. The required remediation of these sites is mainly for petroleum hydrocarbon contamination as the result of leaking tanks, pipelines or other equipment or impoundments that were used in these operations. Also included in this category are former oil and gas fields that we no longer operate. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at other sites in these categories of sites was the result of former industrial chemical and polymers manufacturing and distribution facilities and agricultural chemical retail businesses. Included in this category are:

- West Coast refining, marketing and transportation sites auto/truckstop facilities in various locations in the U.S.

industrial chemical and polymer sites in the South, Midwest and California

agricultural chemical sites in the West and Midwest.

In each sale, we retained a contractual remediation or indemnification obligation and are responsible only for certain environmental issues that resulted from operations prior to the sale. The reserve represents estimated future costs for remediation work: identified prior to the sale of these sites; included in negotiated agreements with the buyers of these sites where we retained certain levels of remediation liabilities; and/or identified in subsequent claims made by buyers of the properties. Our former operated sites include service stations, distribution facilities and oil and gas fields that we previously operated but did not own.

Table of Contents

We have an aggregate reserve of $101 million for this group of sites. During 2004, provisions of $74 million for this category were recorded. These provisions were primarily 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 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 cleanup. Payments of $72 million were made during 2004 for sites in this category.

Inactive or closed Company facilities

The Inactive or closed Company facilities category includes former oil and gas fields and other locations that are no longer operating. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Other sites in this category were contaminated from former ferromolybdenum production operations. Included in this category are:

- the Guadalupe oil field on the central California coast
- the Molycorp Washington facility in Pennsylvania
- the Beaumont Refinery in Texas.

A reserve of $99 million has been established for these types of facilities. During 2004, we accrued $9 million related to sites in this category primarily for the Beaumont Refinery site and for a former terminal site in Edmonds, Washington. A provision was recorded for the updated cost estimates to close impoundments used in our 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. Payments of $20 million were made during 2004 for sites in this category.

Legal Compliance

We are subject to federal, state and local environmental laws and regulations, including CERCLA, as amended, RCRA and laws governing low-level radioactive materials. Under these laws, we are subject to existing and/or possible obligations to remove or mitigate the environmental effects of the disposal or release of certain chemical, petroleum and radioactive substances at various sites. Corrective investigations and actions pursuant to RCRA and other federal, state and local environmental laws are being performed at our facility in Beaumont, Texas, a former agricultural chemical facility in Corcoran, California, Molycorp s facility in Washington, Pennsylvania and other facilities. In addition, Molycorp is required to decommission its Washington facility in Pennsylvania pursuant to the terms of its radioactive source materials license and decommissioning plan.

We also must provide financial assurance for future closure and post-closure costs of our RCRA-permitted facilities and for decommissioning costs at Molycorp s Washington Pennsylvania facility under its radioactive source materials license. Pursuant to a 1998 settlement agreement between us and the State of California (and the subsequent stipulated judgment entered by the Superior Court), we must provide financial assurance for anticipated costs of remediation activities at our former Guadalupe oil field. As previously discussed, remediation reserves for these sites are included in the Inactive or closed Company facilities category and totaled $86 million at December 31, 2004. At those sites where investigations or feasibility studies have advanced to the stage of analyzing alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately $63 million. Although any possible additional costs for these sites are likely to be incurred at different times and over a period of many years, we believe that these obligations could have a material adverse effect on our results of operations but are not expected to be material to our consolidated financial condition or liquidity.

Table of Contents

Insurance

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

Certain Litigation and Claims

Petrobangla Claim: 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.

Tax Matters

We believe we have adequately provided in our accounts for tax items and issues not yet resolved. Several prior material tax issues are unresolved. Resolution of these tax issues affects not only the year in which the items arose, but also our tax situation in other tax years.

With respect to the 1979-1994 taxable years, the Joint Committee on Taxation of the U.S. Congress reviewed and approved the settlement of all issues for these years, including the carryback of a 1993 net operating loss to taxable year 1984 and resultant credit adjustments, as previously agreed with the Appeals division of the Internal Revenue Service (IRS). This settlement and corresponding recalculation of taxable income and credits for this period resulted in an overpayment of taxes. We received cash refunds of $72 million in 2004, representing overpaid taxes plus interest thereon. A small additional refund is anticipated in the first quarter of 2005. Taxable years 1979-1984 are now closed and barred from additional assessment of federal income taxes. Although the IRS has completed its audit of Unocal for taxable years 1985-1994 and a settlement has been reached for all such years, these years cannot be formally closed until a separate audit by the IRS of the Alaska Kuparuk River Unit tax partnership is closed. The Kuparuk tax partnership audit has been completed and is in the process of being closed. No material adjustments to taxable income are required. However, until this tax partnership audit is formally closed, our corporate tax audit remains technically open.

Table of Contents

Accordingly, the IRS refers to the 1985-1994 taxable years as partially closed. All such developments have been considered in our accounts.

With respect to the 1995-1997 taxable years, a settlement of all issues was reached with the Appeals division of the IRS. Although the IRS has completed its audit of Unocal for taxable years 1995-1997 and a settlement has been reached for all such years, these years cannot be formally closed until a separate audit by the IRS of the Alaska Kuparuk River Unit tax partnership is closed. The Kuparuk tax partnership audit has been completed and is in the process of being closed. No material adjustments to taxable income are required. However, until this tax partnership audit is formally closed, our corporate tax audit remains technically open. Accordingly, the IRS refers to the 1995-1997 taxable years as partially closed. All such developments have been considered in our accounts.

The 1998-2001 taxable years are before the Exam division of the IRS.

With respect to state tax matters, settlements were reached with the Franchise Tax Board of the state of California with respect to taxable years 1989-1994. We received cash refunds of $71 million in 2004, representing overpaid taxes plus interest thereon.

Guarantees Related to Assets or Obligations of Third Parties

Future Remediation Costs

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

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

We have accrued probable and reasonably estimable assessment and remediation costs for the locations covered under these guarantees. These amounts are included in the Company facilities sold with retained liabilities and former Company-operated sites category of our reserve for environmental remediation obligations.

At December 31, 2004, the reserve for this category totaled $101 million. For 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 $70 million.

BTC Construction Completion Guarantee

We have a construction completion guarantee related to debt financing arrangements for the BTC crude oil pipeline project. We have an equity interest in the development of this pipeline from Baku, Azerbaijan through Georgia to the Mediterranean port of Ceyhan, Turkey. Our maximum potential future payments under the guarantee are estimated to be $310 million. The debt is secured by transportation proceeds from production of the Azeri field in the Caspian Sea. The debt is non-recourse upon financial completion certification, which is expected by 2009. As of December 31, 2004, we have recorded a liability of $19 million as the estimated value of this guarantee.

Table of Contents

Other Guarantees and Indemnities

We have also guaranteed the debt of certain other entities accounted for by the equity method. The majority of this debt matures ratably through the year 2014. The maximum potential amount of future payments we could be required to make is approximately $15 million.

In the ordinary course of business, we have agreed to indemnify cash deficiencies for certain domestic pipeline joint ventures, which we account for on the equity method. These guarantees are considered in our analysis of overall risk. Because most of these agreements do not contain spending caps, it is not possible to quantify the amount of maximum payments that may be required. Nevertheless, we believe the payments would not have a material adverse impact on our financial condition or liquidity.

Financial Assurance for Unocal Obligations

Surety Bonds and Letters of Credit

In the normal course of business, we 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 are required to be reimbursed by us if drawn upon. At December 31, 2004, we had obtained various surety bonds for $178 million. These surety bonds included a bond for $66 million securing our performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of natural gas over a ten-year period that began in January of 1999 and will end in December of 2008 and $112 million in various other routine performance bonds held by local, city, state and federal agencies. We also had obtained $105 million in standby letters of credit at December 31, 2004, of which $31 million represented letters of credit with the revenue department in Thailand relating to a tax appeal, $24 million represented letters of credit for margin requirements for natural gas purchases in Canada and $13 million represented additional collateral related to the aforementioned bond for the fixed price natural gas sales contract. We have entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit.

Other Guarantees and Credit Rating Triggers

We have various other guarantees for approximately $525 million. Approximately $134 million of the $525 million in guarantees represent financial assurance we gave on behalf of our Molycorp subsidiary relating to permits covering operations and discharges from Molycorp s Questa, New Mexico, molybdenum mine. Our financial assurance is for the completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. The costs associated with the financial assurance are based on estimations provided by agencies of the state of New Mexico.

Guarantees for approximately $305 million of the $525 million would require us to obtain a surety bond or a letter of credit or establish a trust fund if our credit rating were to drop below investment grade that is BBB- or Baa3 from Standard & Poor s Ratings Services and Moody s Investors Service, Inc., respectively.

Classification on Balance Sheet

Approximately $250 million of the surety bonds, letters of credit and other guarantees that we are required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note.

Other Matters

Our lease agreement for the *Discoverer Spirit* deepwater drillship has a current minimum daily rate of approximately $229,000. The future remaining minimum lease payment obligation was approximately $60 million at December 31, 2004. The contract will expire on September 18, 2005.

Table of Contents

We also have other contingent liabilities for litigation, claims and contractual agreements arising in the ordinary course of business. Based on management s assessment of the ultimate amount and timing of possible adverse outcomes and associated costs, none of these other matters is presently expected to have a material adverse effect on our consolidated financial condition, liquidity or results of operations.

NOTE 24 - CAPITAL STOCK

Common Stock

Authorized - 750,000,000

$1.00 Par value per share

	At December 31,		
Thousands of shares	**2004**	**2003**	**2002**
Outstanding at beginning of year	260,594	257,980	243,998
Issuance of common stock in exchange for Pure Resources, Inc. common stock			13,247
Issuance of common stock for conversions of Trust 6 1/4% convertible preferred securities (a)	1,002		
Other issuances of common stock (b)	7,509	2,614	735
Repurchases of common stock - Treasury Stock	(5,915)		
Outstanding at end of year	263,190	260,594	257,980

(a) See note 17 - Variable Interest Entities for further details
(b) Includes issuances under our various stock-based compensation plans, net of cancellations

At December 31, 2004, there were approximately 5.5 million shares that remained reserved for the conversion of Unocal Capital Trust convertible preferred securities, 23.5 million shares for our employee benefit plans and Directors plans and 2.5 million shares for our Dividend Reinvestment and Common Stock Purchase Plan.

Treasury Stock

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 purchased balance of $411 million and a balance of $189 million remaining for additional repurchases. In August 2004, we purchased 4,130,000 common shares at a cost of approximately $150 million under this program, resulting in a balance of approximately $39 million for additional purchases. In December 2004, our board of directors authorized the additional 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 on a buyback program for preferred securities of the Trust due to the conversion of those securities into shares of common stock. There was no expiration date to this repurchase program.

Our board of directors also 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 1,246,000 common shares at a cost of approximately $54 million under this program.

In February 2004, we repurchased 539,208 shares of our common stock from four of the original participants of the Executive Stock Purchase Program (the Program) of 2000 at market prices. The purchases, which aggregated to approximately $20 million, were accounted for as treasury stock on the consolidated balance sheet. The recipients used the proceeds to repay the loans made by Unocal for the original acquisition of the shares (see note 25 Loans to Certain Officers and Key Employees).

At December 31, 2004, we held 16,537,992 common shares as treasury stock at a cost of $634 million. At December 31, 2003, we held 10,622,784 common shares at a cost of $411 million.

Table of Contents

Preferred Stock

We have authorized 100,000,000 shares of preferred stock with a par value of $0.10 per share. No shares of preferred stock were issued at December 31, 2004, 2003 or 2002. See Stockholder Rights Plan below with respect to shares of preferred stock reserved for issuance.

Stockholder Rights Plan

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

The 2000 Rights Plan, as amended, provides that in the event any person or group of affiliated persons (a) becomes, or (b) commences a tender offer or exchange offer pursuant to which such person or group would become, an acquiring person by virtue of obtaining the beneficial ownership of 15 percent or more (30 percent or more in the case of Qualified Institutional Investors) of the outstanding common shares, each Right (other than Rights held by the acquiring person) will be exercisable on and after the close of business on the tenth day or the tenth business day following the public announcement of such events, respectively, unless the Rights are redeemed by the board of directors, to purchase one one-hundredth of a share of Series B preferred stock for $180. If such a person or group becomes such an acquiring person, each Right (other than Rights held by the acquiring person) will be exercisable to purchase, for $180, shares of common stock with a market value of $360, based on the market price of the common stock prior to such acquisition.

If Unocal is acquired in a merger or similar transaction following the date the Rights become exercisable, each Right (other than Rights held by the acquiring person) will become exercisable to purchase, for $180, shares of the acquiring corporation with a market value of $360, based on the market price of the acquiring corporation s stock prior to such merger. The board of directors may reduce the 15 percent beneficial ownership threshold to not less than 10 percent.

The Rights will expire on January 29, 2010, unless previously redeemed by the board of directors, which the board may do, at a price of $.001 per Right, at any time before any person or group becomes an acquiring person. The Rights do not have voting or dividend rights and, until they become exercisable, have no diluting effect on our earnings per share.

NOTE 25 LOANS TO CERTAIN OFFICERS AND KEY EMPLOYEES

In March 2000, we entered into loan agreements with ten of our officers pursuant to our 2000 Executive Stock Purchase Program (the Program). The Program was approved by our board of directors and by our stockholders at the annual stockholders meeting in May 2000. The loans were granted to the officers to enable them to purchase shares of Unocal stock in the open market. The loans, which except under certain limited circumstances are full recourse to the officers, mature on March 16, 2008, and bear interest at the rate of 6.8 percent per annum. During 2004, we accrued interest of $1 million on the loans. In 2004, we repurchased 539,208 shares from four of the original participants in the Program at market price for approximately $20 million. The purchase of this number of shares was approved by our board of directors in February 2004. The four recipients used $18 million of the proceeds to repay their loans in full. We also received approximately $7 million from other former officers in payment of principal and accrued interest. The balance of the loans under this Program, including accrued interest, totaled $3 million at December 31, 2004 and $27 million at December 31, 2003, and was reflected as a reduction to stockholders equity on the consolidated balance sheet.

Table of Contents

NOTE 26 - STOCK-BASED COMPENSATION PLANS

We have adopted incentive programs for executives, directors and certain employees to provide incentives and rewards to strengthen their commitment to maximizing our profitability and increasing stockholder value.

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

In 2004, stockholders approved the 2004 Management Incentive Program authorizing the issuance of up to 12 million shares of common stock for stock options, restricted stock, performance restricted stock and performance share awards. Stockholders also approved the 2004 Directors Deferred Compensation and Restricted Stock Unit Award Plan authorizing the issuance of up to 500,000 shares of common stock.

All employee and director stock options are nonqualified with a maximum term of ten years. Director options vest ratably over three years for initial grants and over two years for annual grants. Employee stock options issued prior to 2004 vest over a three-year period at a rate of 50 percent the first year and 25 percent per year in each of the two succeeding years. Employee stock options issued in 2004 vest ratably over a three-year period.

Restrictions were imposed for a period of five years on certain shares acquired through the exercise of options granted from 1991 through 1996 under the Management Incentive Program of 1991. Stock options issued prior to 2004 cease to vest upon termination of employment and vested options generally may be exercised for up to three years (depending upon the terms of the individual award agreements), or the original expiration date, whichever is earlier, from the date of death, disability, or termination of employment other than for cause or resignation.

Stock options issued in 2004 under the 2004 Management Incentive Program cease to vest upon termination of employment except upon death or a change in control event. Vested options are canceled or exercisable for either three years or until the end of the option term, depending on the age of the employee, vesting status in the employee retirement plan, and whether employment was terminated at our convenience or not. In the event of an employee s death, or a change in control, stock options issued under the 2004 Management Incentive Program will immediately vest and remain exercisable until the end of the normal option term. Stock options issued under all incentive programs are generally nontransferable except in the event of an employee s death or pursuant to a court order.

All outstanding performance share awards issued prior to 2004 have four-year terms and can be paid out in common stock and/or cash. The amount of the payout for these awards is based on a percentile ranking of our common stock total return relative to the total returns on the common stocks of a peer group of companies. Outstanding performance share awards issued in 2004 under the 2004 Management Incentive Program have three-year terms and can be paid out in common stock and/or cash. The payout for the 2004 awards is based on a composite percentile ranking of five of our financial and operational performance measures relative to the same performance measures for a peer group of companies. The performance measures consist of and are weighted 50 percent for comparative return to stockholders, 12.5 percent for comparative discretionary cash flow per debt adjusted share, 12.5 percent for comparative production growth per debt adjusted share, 12.5 percent for comparative finding and development costs per BOE added, and 12.5 percent for comparative production and G&A costs per unit of production. Payouts under all performance share awards are subject to downward adjustments at the discretion of the Management Development and Compensation Committee.

Directors stock units and directors restricted stock units represent unfunded bookkeeping entries that are paid out in an equal number of shares of common stock at the end of the applicable deferral period. The unit holders do not have any voting rights until the common shares are issued. Dividend equivalents are credited to the unit holders as additional units. Directors restricted stock units issued under the 2004 Directors Deferred Compensation and Restricted Stock Unit Award Plan vest ratably over a two- or three-year vesting period.

Table of Contents

Holders of restricted stock are entitled to vote the shares and receive dividends, except that dividends for restricted stock granted under the Union Oil Restricted Stock Plan are accumulated and paid out when the shares vest. Restricted stock is not delivered until the end of the restriction period, which does not exceed ten years. Upon a qualified termination, restrictions are lifted on all or a portion of the shares granted (depending on the terms of the individual award agreements). Restricted stock is subject to forfeiture if the holder terminates employment during the restriction period for reasons other than for the convenience of Unocal, death, disability or upon reaching normal retirement age.

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

A summary of our stock and option plans for the last three years is presented below:

	Number of Options/Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Market Price Per Share
Options outstanding at January 1, 2002	10,997,777	$ 33.85	$
Options granted during year	1,710,027	34.68	34.68
Options assumed from Pure Resources	4,325,436	18.94	
Options exercised during year	(791,428)	27.98	
Options canceled/forfeited during year	(462,766)	35.10	
Options outstanding at December 31, 2002	15,779,046	30.11	
Options exercisable at December 31, 2002	12,437,204	29.07	
Restricted stock awarded during year	60,957		33.06
Performance shares awarded during year	224,672	$	$ 33.88
Options outstanding at January 1, 2003	15,779,046	30.11	
Options granted during year	2,327,270	27.07	27.07
Options exercised during year	(2,650,973)	22.37	
Options canceled/forfeited during year	(1,125,565)	34.59	
Options outstanding at December 31, 2003	14,329,778	30.70	
Options exercisable at December 31, 2003	11,199,831	30.70	
Restricted stock awarded during year	51,003		30.07
Performance shares awarded during year	250,024		30.39
Options outstanding at January 1, 2004	14,329,778	$ 30.70	$
Options granted during year	1,163,000	36.92	36.92
Options exercised during year	(7,050,710)	28.02	
Options canceled/forfeited during year	(537,483)	34.96	
Options outstanding at December 31, 2004	7,904,585	33.77	
Options exercisable at December 31, 2004	5,578,781	34.28	
Restricted stock awarded during year	656,642		37.19
Performance shares awarded during year	279,911		36.93

Table of Contents

Significant option groups outstanding at December 31, 2004 and related weighted average price and life information follows:

	Options Outstanding			Options Exercisable	
Range of Exercise prices	Number Outstanding	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$11.59 -$25.26	102,530	5.5	$ 22.49	102,530	$ 22.49
$26.08 -$29.99	1,903,031	7.0	$ 27.37	935,040	$ 27.68
$30.39 -$36.88	4,288,058	6.7	$ 35.17	2,991,337	$ 34.66
$37.03 -$45.25	1,610,966	3.6	$ 38.30	1,549,874	$ 38.32

The estimated fair value at date of grant of options for common stock granted in 2004, 2003 and 2002, using the Black-Scholes option pricing model is as follows:

	2004	2003	2002
Weighted-average fair value of common stock options granted during the year	**$ 7.98**	**$ 6.20**	**$ 9.35**
Assumptions:			
Expected life (years)	4.4	4.5	4.5
Expected volatility	27.4%	31.7%	32.7%
Expected dividend yield	2.2%	3.0%	2.2%
Risk-free interest rate	2.9%	2.9%	4.3%

See note 1 Summary of Significant Accounting Policies for pro-forma stock-based compensation expense if we had used the fair value accounting method recommended by SFAS No. 123.

NOTE 27 - FINANCIAL INSTRUMENTS AND COMMODITY HEDGING

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

Interest rate contracts We enter into interest rate swap contracts to manage our debt with the objective of minimizing the volatility and magnitude of our borrowing costs. We may also enter into interest rate option contracts to protect our interest rate positions, depending on market conditions. At December 31, 2004, we had approximately $20 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges of interest rate exposures through September 2012. Of this amount, approximately $3 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Foreign currency contracts From time to time, various foreign exchange currency forward, option and swap contracts are entered into to manage our exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions. At December 31, 2004, we had no deferred amounts in accumulated other comprehensive income on the consolidated balance sheet related to foreign currency contracts.

Commodity hedging activities We use hydrocarbon derivatives to mitigate our overall exposure to fluctuations in hydrocarbon commodity prices. We reported a gain of $1 million in 2004 due to ineffectiveness for cash flow and fair value hedges. At December 31, 2004, we had approximately $25 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future commodity sales for the period beginning January 2005 through December 2005. All of these after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Table of Contents

Fair values for debt and other long-term instruments The estimated fair values of our long-term debt were $3.33 billion and $3.17 billion at December 31, 2004 and 2003, respectively. Fair values were based on the discounted amounts of future cash outflows using the rates offered to us for debt with similar remaining maturities.

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

The majority of our trade receivables balance at December 31, 2004, was attributable to the sale of crude oil and natural gas we produce or that we purchase for resale. We have receivable concentrations for our crude oil and natural gas sales and geothermal steam and related electricity sales in certain Asian countries that are subject to currency fluctuations and other factors affecting the region.

At December 31, 2004, we had a $238 million note receivable from URC (see note 11 Sales of Accounts Receivable). Our highest accounts receivable balance with one customer, PTT in Thailand, was approximately $113 million, or approximately 10 percent of our consolidated net trade receivable balance at December 31, 2004. This amount primarily represented payments due for sales of natural gas and crude oil from our Gulf of Thailand and offshore Myanmar operations.

Table of Contents

NOTE 28 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

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

As a result of adopting FASB Interpretation No. 46 (revised December 2003) (see note 2 Accounting Changes and note 17 Variable Interest Entities), we deconsolidated Unocal Capital Trust effective January 1, 2004.

The following tables present condensed consolidating financial information for (a) Unocal (Parent), (b) Union Oil (Parent) and (c) on a combined basis, the subsidiaries of Union Oil (non-guarantor subsidiaries). Virtually all of our operations are conducted by Union Oil and its subsidiaries. The 2003 and 2002 tables also present the Trust, as part of the condensed consolidating financial information.

CONDENSED CONSOLIDATED EARNINGS STATEMENT

For the Year Ended December 31, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues					
Sales and operating revenues	$	$ 1,411	$ 7,589	$ (997)	$ 8,003
Interest, dividends and miscellaneous income	1	21	32	(7)	47
Gain on sales of assets		33	121		154
Total revenues	1	1,465	7,742	(1,004)	8,204
Costs and other deductions					
Purchases, operating and other expenses	12	1,220	4,892	(1,000)	5,124
Depreciation, depletion and amortization		259	738		997
Impairments		21	53		74
Dry hole costs		85	75		160
Interest expense	34	100	33	(7)	160
Total costs and other deductions	46	1,685	5,791	(1,007)	6,515
Equity in earnings of subsidiaries	1,245	1,310		(2,555)	
Earnings from equity investments		5	137	(2)	140
Earnings from continuing operations before income taxes and minority interests	1,200	1,095	2,088	(2,554)	1,829
Income taxes	(8)	(152)	833		673
Minority interests			10	1	11
Earnings from continuing operations	1,208	1,247	1,245	(2,555)	1,145
Earnings from discontinued operations		(2)	65		63

Net earnings	$ 1,208	$ 1,245	$ 1,310	$ (2,555)	$ 1,208

Table of Contents

CONDENSED CONSOLIDATED EARNINGS STATEMENT

For the Year Ended December 31, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues						
Sales and operating revenues	$	$	$ 1,566	$ 5,938	$ (1,136)	$ 6,368
Interest, dividends and miscellaneous income		34	25	3	(37)	25
Gain on sales of assets			22	91	6	119
Total revenues		34	1,613	6,032	(1,167)	6,512
Costs and other deductions						
Purchases, operating and other expenses	10		1,166	4,008	(1,130)	4,054
Depreciation, depletion and amortization			314	671		985
Impairments			22	71		93
Dry hole costs			79	49		128
Interest expense	33	1	160	33	(37)	190
Distributions on convertible preferred securities		33				33
Total costs and other deductions	43	34	1,741	4,832	(1,167)	5,483
Equity in earnings of subsidiaries	677		857		(1,534)	
Earnings from equity investments			7	185		192
Earnings from continuing operations before income taxes and minority interests	634		736	1,385	(1,534)	1,221
Income taxes	(9)		20	503		514
Minority interests				9		9
Earnings from continuing operations	643		716	873	(1,534)	698
Earnings from discontinued operations			16	12		28
Cumulative effect of accounting change			(55)	(28)		(83)
Net earnings	$ 643	$	$ 677	$ 857	$ (1,534)	$ 643

-125-

Table of Contents

CONDENSED CONSOLIDATED EARNINGS STATEMENT

For the Year Ended December 31, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues						
Sales and operating revenues	$	$	$ 1,098	$ 4,928	$ (826)	$ 5,200
Interest, dividends and miscellaneous income	1	34	(61)	94	(37)	31
Gain on sales of assets			4	38		42
Total revenues	1	34	1,041	5,060	(863)	5,273
Costs and other deductions						
Purchases, operating and other expenses	5		699	3,612	(826)	3,490
Depreciation, depletion and amortization			342	623		965
Impairments			41	6		47
Dry hole costs			33	74		107
Interest expense	34	1	144	37	(37)	179
Distributions on convertible preferred securities		33				33
Total costs and other deductions	39	34	1,259	4,352	(863)	4,821
Equity in earnings of subsidiaries	355		519		(874)	
Earnings from equity investments			4	150		154
Earnings from continuing operations before income taxes and minority interests	317		305	858	(874)	606
Income taxes	(14)		(50)	341		277
Minority interests				6		6
Earnings from continuing operations	331		355	511	(874)	323
Earnings from discontinued operations				8		8
Net earnings	$ 331	$	$ 355	$ 519	$ (874)	$ 331

-126-

Table of Contents

CONDENSED CONSOLIDATED BALANCE SHEET

At December 31, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets					
Cash and cash equivalents	$	$ 691	$ 469	$	$ 1,160
Accounts and notes receivable - net	55	239	1,184	(55)	1,423
Inventories		8	289	(77)	220
Other current assets		101	26		127
Total current assets	55	1,039	1,968	(132)	2,930
Properties - net		1,935	6,887	(3)	8,819
Other assets including goodwill	6,095	5,713	430	(10,886)	1,352
Total assets	$ 6,150	$ 8,687	$ 9,285	$ (11,021)	$ 13,101
Liabilities and Stockholders Equity					
Current liabilities					
Accounts payable	$	$ 278	$ 1,074	$ (54)	$ 1,298
Current portion of long-term debt	242	162	87		491
Other current liabilities	54	244	496	(2)	792
Total current liabilities	296	684	1,657	(56)	2,581
Long-term debt and capital leases		1,648	923		2,571
Deferred income taxes		(156)	995		839
Accrued abandonment, restoration and environmental liabilities		373	524		897
Other deferred credits and liabilities		663	309	(3)	969
Minority interests			15	12	27
Stockholders equity	5,854	5,475	4,862	(10,974)	5,217
Total liabilities and stockholders equity	$ 6,150	$ 8,687	$ 9,285	$ (11,021)	$ 13,101

Table of Contents

CONDENSED CONSOLIDATED BALANCE SHEET

At December 31, 2003

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

Table of Contents

CONDENSED CONSOLIDATED CASH FLOWS

Year Ended December 31, 2004

Millions of dollars	**Unocal (Parent)**	**Union Oil (Parent)**	**Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
Cash Flows from Operating Activities					
Net cash provided by operating activities	$ 458	$ 1,111	$ 987	$	$ 2,556
Cash Flows from Investing Activities					
Capital expenditures and acquisitions (includes dry hole costs)		(377)	(1,367)		(1,744)
Proceeds from sales of assets and discontinued operations		107	393		500
Return of capital from affiliate company			48		48
Net cash used in investing activities		(270)	(926)		(1,196)
Cash Flows from Financing Activities					
Change in long-term debt	(246)	(193)	55		(384)
Dividends paid on common stock	(210)				(210)
Proceeds from issuance of common stock	195				195
Repurchases of common stock	(223)				(223)
Other	25	(2)	(5)		18
Net cash provided by (used in) financing activities	(459)	(195)	50		(604)
Increase (decrease) in cash and cash equivalents	(1)	646	111		756
Cash and cash equivalents at beginning of period	1	45	358		404
Cash and cash equivalents at end of period	$	$ 691	$ 469	$	$ 1,160

-129-

Table of Contents

CONDENSED CONSOLIDATED CASH FLOWS

Year ended December 31, 2003

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

CONDENSED CONSOLIDATED CASH FLOWS

Year ended December 31, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flows from Operating Activities						
Net cash provided by operating activities	$ 175	$	$ 92	$ 1,304	$	$ 1,571
Cash Flows from Investing Activities						
Capital expenditures and acquisitions (includes dry hole costs)			(446)	(1,224)		(1,670)
Proceeds from sales of assets and discontinued operations			50	116		166
Net cash used in investing activities			(396)	(1,108)		(1,504)

Cash Flows from Financing Activities						
Change in long-term debt and capital leases			225	(135)		90
Dividends paid on common stock	(196)					(196)
Minority interests				(8)		(8)
Other	21		(1)	5		25
Net cash provided by (used in) financing activities	(175)		224	(138)		(89)
Increase (decrease) in cash and cash equivalents			(80)	58		(22)
Cash and cash equivalents at beginning of year			62	128		190
Cash and cash equivalents at end of year	$	$	$ (18)	$ 186	$	$ 168

-130-

Table of Contents

NOTE 29 SEGMENT AND GEOGRAPHIC DATA

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 increased focus on marketing and natural gas storage. Our reportable segments are: (1) Exploration and Production, (2) Midstream and Marketing, and (3) Geothermal. Historical segment results have been reclassified to conform to the 2004 presentation.

Exploration and Production Segment - This segment includes our North American and International oil and gas operations. North America includes the United States and Canada oil and gas operations. International operations include activities outside of North America and are categorized under the Asia and Other international geographic categories. The Asia category includes production and/or exploration activities in Thailand, Myanmar, Indonesia, Philippines, Bangladesh and Vietnam. The Other International category includes production and/or exploration activities in Azerbaijan, The Netherlands, the Democratic Republic of Congo and Australia. In 2004, $1.03 billion, or approximately 13 percent, of our total external sales and operating revenues were attributable to the sale of natural gas and condensate, produced offshore Thailand and Myanmar, to PTT.

At the end of 2004, we had $136 million of goodwill recorded on our consolidated balance sheet. This amount included $81 million in conjunction with the acquisition of the minority interests of Pure in 2002. The remaining $55 million in goodwill related to acquisitions by our Canadian subsidiary. We test goodwill for impairments annually or sooner if circumstances warrant. As of December 31, 2004, no such impairments have been recorded.

Midstream and Marketing Segment - This 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. To market our 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 under notes 1 and 2). These transactions, including crude oil buy/sell transactions, effectively transfer the commodities from production locations to various industry marketing locations with higher volumes of commercial activity and greater market liquidity and allow us to better manage our commodity-related risks. Our crude oil buy/sell transactions amounted to $965 million, $820 million and $604 million in 2004, 2003 and 2002, respectively, and were recorded on a gross basis in sales revenues and purchases on our consolidated earnings statement.

In addition, the marketing organization conducts our hedging activities involving hydrocarbon derivative instruments to mitigate commodity price volatility for which hedge accounting is used, as well as our trading activities including hydrocarbon derivative instruments to exploit anticipated opportunities arising from commodity price fluctuations, for which hedge accounting is not used. The marketing organization also purchases limited amounts of physical inventories for energy trading purposes when arbitrage opportunities arise. These commodity risk-management and trading activities are subject to internal restrictions, including value at risk limits, which measure our potential loss from likely changes in market prices.

Geothermal Segment This 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.

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

Table of Contents

The following tables present our geographic area of operations and financial data by business segment. Intersegment revenues, which are eliminated upon consolidation, in business segment data are primarily sales from the Exploration and Production segment to the Midstream and Marketing segment. Intersegment sales prices approximate market prices.

GEOGRAPHIC INFORMATION

The revenues presented in the following table primarily represent sales of crude oil and natural gas within the countries or regions shown.

2004 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	All Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations (a)	$ 3,851	$ 956	$ 1,187	$ 1,048	$ 930	$ 31	$ 8,003
Properties:							
Gross	8,943	2,274	3,895	3,704	2,456	144	21,416
Net	3,124	1,376	1,310	1,640	1,304	65	8,819

2003 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	All Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations (a)	$ 3,517	$ 686	$ 931	$ 702	$ 503	$ 29	$ 6,368
Properties:							
Gross	8,680	1,993	3,584	3,548	2,091	139	20,035
Net	3,174	1,299	1,173	1,655	947	76	8,324

2002 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	All Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations (a)	$ 2,763	$ 440	$ 789	$ 644	$ 535	$ 29	$ 5,200
Properties:							
Gross	10,389	1,511	3,316	2,887	1,876	177	20,156
Net	3,595	1,064	1,123	1,278	736	83	7,879

(a) U.S. includes crude oil buy/sell transactions settled in cash of $965 million, $820 million and $604 million for 2004, 2003 and 2002 respectively.

Table of Contents

Segment Information

For the Year Ended

December 31, 2004

Millions of dollars	Exploration and Production						
	North America			International			
	U.S.	Canada	Total N.A.	Asia	Other	Total Int l	Total E&P
Sales & operating revenues	$ 938	$ 306	$ 1,244	$ 1,519	$ 289	$ 1,808	$ 3,052
Other income (loss) (a)	43		43	(11)	15	4	47
Inter-segment revenues	994	137	1,131	592		592	1,723
Total	1,975	443	2,418	2,100	304	2,404	4,822
Depreciation, depletion & amortization	372	121	493	390	41	431	924
Impairments	49		49		5	5	54
Dry hole costs	91	14	105	50	5	55	160
Exploration expense							
Amortization of exploratory leases	33	22	55	10	(5)	5	60
Earnings from equity investments				47	3	50	50
Earnings (loss) from continuing operations before income taxes and minority interests	630	93	723	1,178	155	1,333	2,056
Income taxes (benefit)	233	36	269	507	47	554	823
Minority interests	2		2				2
Earnings (loss) from continuing operations	395	57	452	671	108	779	1,231
Earnings from discontinued operations (net)	50		50				50
Net earnings (loss)	445	57	502	671	108	779	1,281
Capital expenditures and acquisitions	565	136	701	598	327	925	1,626
Assets	3,307	1,376	4,683	3,661	1,007	4,668	9,351
Equity investments				103	16	119	119

			Corporate and Other				
	Midstream and Marketing (b)	Geothermal	Admin & General	Net Interest Expense	Environ-mental & Litigation	Other (c)	Total
Sales & operating revenues	$ 4,409	$ 249	$	$	$	$ 293	$ 8,003
Other income (loss) (a)	12	51		18		73	201
Inter-segment revenues	11					(1,734)	
Total	4,432	300		18		(1,368)	8,204
Depreciation, depletion & amortization	14	31				28	997
Impairments		15				5	74
Dry hole costs							160
Exploration expense							
Amortization of exploratory leases		1					61
Earnings from equity investments	48	1				41	140

Earnings (loss) from continuing operations before income taxes and minority interests	112	212	(132)	(141)	(144)	(134)	1,829
Income taxes (benefit)	29	88	(37)	(30)	(50)	(150)	673
Minority interests	4	5					11
Earnings (loss) from continuing operations	79	119	(95)	(111)	(94)	16	1,145
Earnings from discontinued operations (net)	13						63
Net earnings (loss)	92	119	(95)	(111)	(94)	16	1,208
Capital expenditures and acquisitions	44	47				27	1,744
Assets	1,303	573				1,874	13,101
Equity investments	283	42				93	537

(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets.
(b) Includes $965 million of crude oil buy/sell transactions settled in cash in sales & operating revenues.
(c) Includes eliminations and consolidation adjustments.

Table of Contents

Segment Information

For the Year Ended

December 31, 2003

Millions of dollars	Exploration and Production						
	North America			International			
	U.S.	Canada	Total N.A.	Asia	Other	Total Int l	Total E&P
Sales & operating revenues	$ 857	$ 176	$ 1,033	$ 1,326	$ 211	$ 1,537	$ 2,570
Other income (loss) (a)	96	12	108	(1)	(1)	(2)	106
Inter-segment revenues	1,128	145	1,273	293		293	1,566
Total	2,081	333	2,414	1,618	210	1,828	4,242
Depreciation, depletion & amortization	455	117	572	298	50	348	920
Impairments	83		83	2		2	85
Dry hole costs	91	6	97	31		31	128
Exploration expense							
Amortization of exploratory leases	82	19	101	5	2	7	108
Earnings from equity investments	14		14	41	5	46	60
Earnings (loss) from continuing operations before income taxes and minority interests	629	103	732	860	94	954	1,686
Income taxes (benefit)	240	24	264	363	30	393	657
Minority interests	5		5				5
Earnings (loss) from continuing operations	384	79	463	497	64	561	1,024
Earnings from discontinued operations (net)	11		11				11
Cumulative effect of accounting changes	(32)	5	(27)	12		12	(15)
Net earnings (loss)	363	84	447	509	64	573	1,020
Capital expenditures and acquisitions	556	133	689	576	258	834	1,523
Assets	3,315	1,324	4,639	3,377	765	4,142	8,781
Equity investments				98	71	169	169

			Corporate and Other				
	Midstream and Marketing (b)	Geothermal	Admin & General	Net Interest Expense	Environ-mental & Litigation	Other (c)	Total
Sales & operating revenues	$ 3,467	$ 149	$	$	$	$ 182	$ 6,368
Other income (loss) (a)	5	2		8		23	144
Inter-segment revenues	15					(1,581)	
Total	3,487	151		8		(1,376)	6,512
Depreciation, depletion & amortization	12	24				32	988
Impairments	8						93
Dry hole costs							128
Exploration expense							
Amortization of exploratory leases							108

Earnings from equity investments	67	12				53	192
Earnings (loss) from continuing operations before income taxes and minority interests	80	83	(128)	(181)	(151)	(168)	1,221
Income taxes (benefit)	10	27	(36)	(36)	(49)	(59)	514
Minority interests		6				(2)	9
Earnings (loss) from continuing operations	70	50	(92)	(145)	(102)	(107)	698
Earnings from discontinued operations (net)	1					16	28
Cumulative effect of accounting changes	(2)					(66)	(83)
Net earnings (loss)	69	50	(92)	(145)	(102)	(157)	643
Capital expenditures and acquisitions	138	21				36	1,718
Assets	1,097	611				1,309	11,798
Equity investments	334	67				80	650

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

(b) Includes $820 million of crude oil buy/sell transactions settled in cash in sales & operating revenues.

(c) Includes eliminations and consolidation adjustments.

Table of Contents

Segment Information **For the Year Ended** **December 31, 2002** *Millions of dollars*	**Exploration and Production**						
	North America			**International**			
	U.S.	**Canada**	**Total N.A.**	**Asia**	**Other**	**Total Int l**	**Total E&P**
Sales & operating revenues	$ 738	$ 207	$ 945	$ 1,138	$ 75	$ 1,213	$ 2,158
Other income (loss) (a)	(27)	(1)	(28)		2	2	(26)
Inter-segment revenues	825		825	238	116	354	1,179
Total	1,536	206	1,742	1,376	193	1,569	3,311
Depreciation, depletion & amortization	535	97	632	247	40	287	919
Impairments	41		41				41
Dry hole costs	70	9	79	23	5	28	107
Exploration expense							
Amortization of exploratory leases	56	18	74	2	22	24	98
Earnings (loss) from equity investments	2		2	33	7	40	42
Earnings (loss) from continuing operations before income taxes and minority interests	49	3	52	780	54	834	886
Income taxes (benefit)	7	3	10	319	12	331	341
Minority interests	15		15				15
Earnings (loss) from continuing operations	27		27	461	42	503	530
Earnings from discontinued operations (net)	6		6				6
Net earnings (loss)	33		33	461	42	503	536
Capital expenditures and acquisitions	616	147	763	626	157	783	1,546
Assets	3,684	1,113	4,797	3,096	586	3,682	8,479
Equity investments	146		146	115	83	198	344

			Corporate and Other				
	Midstream and Marketing (b)	**Geothermal**	**Admin & General**	**Net Interest Expense**	**Environ-mental & Litigation**	**Other (c)**	**Total**
Sales & operating revenues	2,798	$ 120	$	$	$	$ 124	$ 5,200
Other income (loss) (a)	51	(3)		17		34	73
Inter-segment revenues	13					(1,192)	
Total	2,862	117		17		(1,034)	5,273
Depreciation, depletion & amortization	11	18				17	965
Impairments	4					2	47
Dry hole costs							107
Exploration expense							
Amortization of exploratory leases							98

Earnings (loss) from equity investments	65	(1)				48	154
Earnings (loss) from continuing operations before income taxes and minority interests	148	51	(120)	(163)	(119)	(77)	606
Income taxes (benefit)	41	21	(38)	(29)	(43)	(16)	277
Minority interests				(6)		(3)	6
Earnings (loss) from continuing operations	107	30	(82)	(128)	(76)	(58)	323
Earnings from discontinued operations (net)	1					1	8
Net earnings (loss)	108	30	(82)	(128)	(76)	(57)	331
Capital expenditures and acquisitions	71	14				39	1,670
Assets	815	526				1,026	10,846
Equity investments	229	36				78	687

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

(b) Includes $604 million of crude oil buy/sell transactions settled in cash in sales & operating revenues.

(c) Includes eliminations and consolidation adjustments.

Table of Contents

NOTE 30 SUBSEQUENT EVENTS

In January 2005, the Trust completed the redemption of its outstanding convertible preferred securities. Holders converted 4,550,738 preferred securities into Unocal common stock and 119,143 convertible preferred securities were redeemed for $6 million. Including the 1.25-percent redemption premium and unpaid distributions, the total cash cost of the redemption program was $6.1 million. In connection with the redemption program completion, Unocal redeemed $242 million of its convertible junior subordinated debentures held by the Trust using cash on hand and by issuing Unocal common stock in January 2005. The Trust utilized the cash it received from Unocal to redeem the preferred securities and to retire the Trust s common securities, which Unocal held as an investment.

In February 2005, we sold our Unocal Bharat Limited subsidiary, which held our 26 percent equity interest in Hindustan Oil Exploration Company (HOEC) and received $25 million in net cash proceeds. HOEC is India s only publicly traded oil and gas exploration and production company outside the state controlled sector. We expect to record an after-tax gain of approximately $20 million in the first quarter of 2005.

QUARTERLY FINANCIAL DATA (Unaudited)

	2004 Quarters			
Millions of dollars except per share amounts	**1st**	**2nd**	**3rd**	**4th**
Total revenues	$ 1,885	$ 1,980	$ 1,993	$ 2,346
Earnings from equity investments	37	38	31	34
Total costs, including minority interests and income taxes	1,656	1,736	1,695	2,112
Earnings from continuing operations	266	282	329	268
Earnings from discontinued operations	3	59	1	
Net earnings	$ 269	$ 341	$ 330	$ 268
Basic earnings per share of common stock (a)				
Continuing operations	$ 1.02	$ 1.07	$ 1.25	$ 1.02
Discontinued operations	0.01	0.22	0.01	
Basic earnings per share of common stock	$ 1.03	$ 1.29	$ 1.26	$ 1.02
Diluted earnings per share of common stock (a)				
Continuing operations	$ 0.99	$ 1.04	$ 1.22	$ 1.00
Discontinued operations	0.01	0.21	0.01	
Diluted earnings per share of common stock	$ 1.00	$ 1.25	$ 1.23	$ 1.00
Net sales and operating revenues	$ 1,830	$ 1,921	$ 1,961	$ 2,291
Gross margin (b)	$ 399	$ 374	$ 480	$ 395

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

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

Table of Contents

QUARTERLY FINANCIAL DATA (continued)

Millions of dollars except per share amounts	2003 Quarters 1st	2nd	3rd	4th
Total revenues	$ 1,782	$ 1,613	$ 1,535	$ 1,582
Earnings from equity investments	43	53	54	42
Total costs, including minority interests and income taxes	1,611	1,501	1,439	1,455
Earnings from continuing operations	214	165	150	169
Earnings from discontinued operations	3	12	2	11
Cumulative effect of accounting changes (net of tax)	(83)			
Net earnings	$ 134	$ 177	$ 152	$ 180
Basic earnings per share of common stock (a)				
Continuing operations	$ 0.83	$ 0.65	$ 0.58	$ 0.65
Discontinued operations	0.01	0.04	0.01	0.04
Cumulative effect of accounting changes	(0.32)			
Basic earnings per share of common stock	$ 0.52	$ 0.69	$ 0.59	$ 0.69
Diluted earnings per share of common stock (a)				
Continuing operations	$ 0.81	$ 0.64	$ 0.57	$ 0.64
Discontinued operations	0.01	0.04	0.01	0.04
Cumulative effect of accounting changes	(0.30)			
Diluted earnings per share of common stock	$ 0.52	$ 0.68	$ 0.58	$ 0.68
Net sales and operating revenues	$ 1,768	$ 1,557	$ 1,472	$ 1,571
Gross margin (b)	$ 371	$ 233	$ 235	$ 269

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

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

Table of Contents

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

Results of Operations

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

Millions of dollars	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2004							
Sales							
To public	$ 637	$ 212	$ 849	$ 1,414	$ 269	$ 1,683	$ 2,532
Intercompany	994	137	1,131	592		592	1,723
Other revenues	57		57	4	11	15	72
Total	1,688	349	2,037	2,010	280	2,290	4,327
Production costs	304	64	368	205	42	247	615
Exploration expenses	190	45	235	114	9	123	358
Depreciation, depletion and amortization	421	121	542	390	46	436	978
Other operating expenses	143	26	169	170	31	201	370
Pre-tax results of operations	630	93	723	1,131	152	1,283	2,006
Income taxes	233	36	269	507	47	554	823
Results of operations	$ 397	$ 57	$ 454	$ 624	$ 105	$ 729	$ 1,183
Results of equity investees (a)				47	3	50	50
2003							
Sales							
To public	$ 611	$ 168	$ 779	$ 1,263	$ 204	$ 1,467	$ 2,246
Intercompany	1,128	145	1,273	293		293	1,566
Other revenues	128	13	141		4	4	145
Total	1,867	326	2,193	1,556	208	1,764	3,957
Production costs	340	58	398	204	36	240	638
Exploration expenses	249	32	281	88	10	98	379
Depreciation, depletion and amortization	536	117	653	300	50	350	1,003
Other operating expenses	126	24	150	147	23	170	320
Pre-tax results of operations	616	95	711	817	89	906	1,617
Income taxes	241	24	265	364	30	394	659

Results of operations	$ 375	$ 71	$ 446	$ 453	$ 59	$ 512	$ 958
Results of equity investees (a)	14		14	41	5	46	60

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

Table of Contents

Results of Operations (continued)

Millions of dollars	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2002							
Sales							
To public	$ 565	$ 217	$ 782	$ 1,138	$ 59	$ 1,197	$ 1,979
Intercompany	825		825	238	116	354	1,179
Other revenues	7		7	2	3	5	12
Total	1,397	217	1,614	1,378	178	1,556	3,170
Production costs	340	52	392	182	40	222	614
Exploration expenses	213	34	247	59	46	105	352
Depreciation, depletion and amortization	576	97	673	247	40	287	960
Other operating expenses	221	17	238	143	7	150	388
Pre-tax results of operations	47	17	64	747	45	792	856
Income taxes	6	7	13	304	12	316	329
Results of operations	$ 41	$ 10	$ 51	$ 443	$ 33	$ 476	$ 527
Results of equity investees (a)	2		2	33	7	40	42

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

-139-

Table of Contents

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities, both capitalized and charged to expense, are shown below. Data for our capitalized costs related to oil and gas exploration and production activities are presented in note 15 Properties and Capital Leases.

Millions of dollars	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2004							
Property acquisition							
Proved	$ 7	$ 6	$ 13	$	$	$	$ 13
Unproved	35	12	47				47
Exploration	165	42	207	158	17	175	382
Development (a)	411	85	496	557	320	877	1,373
Sub-total	$ 618	$ 145	$ 763	$ 715	$ 337	$ 1,052	$ 1,815
Asset retirement obligations (SFAS No. 143)	8	5	13	17	3	20	33
Total Costs Incurred	$ 626	$ 150	$ 776	$ 732	$ 340	$ 1,072	$ 1,848
Costs incurred by equity investees (b)							
2003							
Property acquisition							
Proved	$ 12	$ 17	$ 29	$	$	$	$ 29
Unproved	30	7	37	10		10	47
Exploration	255	36	291	123	7	130	421
Development (a)	345	80	425	543	258	801	1,226
Sub-total	$ 642	$ 140	$ 782	$ 676	$ 265	$ 941	$ 1,723
Asset retirement obligations (SFAS No. 143)	17	2	19	14		14	33
Total Costs Incurred	$ 659	$ 142	$ 801	$ 690	$ 265	$ 955	$ 1,756
Costs incurred by equity investees (b)	27		27				27
2002							
Property acquisition							
Proved (c)	$ 110	$ 45	$ 155	$	$	$	$ 155
Unproved (d)	59	5	64	22	3	25	89
Exploration	262	31	293	107	25	132	425
Development	349	79	428	567	144	711	1,139
Total Costs Incurred	$ 780	$ 160	$ 940	$ 696	$ 172	$ 868	$ 1,808
Costs incurred by equity investees (b)	48		48		3	3	51

(a) Includes capital to develop proved undeveloped reserves 2004:	*$ 126*	*$ 3*	*$ 129*	*$ 289*	*$ 252*	*$ 541*	*$ 670*
2003:	*$ 155*	*$ 10*	*$ 165*	*$ 374*	*$ 227*	*$ 601*	*$ 766*

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

(c) United States includes $73 million for the increased proved property basis resulting from the acquisition of the Pure minority interest shares.

(d) United States includes $48 million for the increased unproved property basis resulting from the acquisition of the Pure minority interest shares.

Table of Contents

Average Prices and Production Costs per Unit (Unaudited)

The average sales price is based on sales revenues and volumes attributable to net working interest production. Where intersegment sales occur, intersegment sales prices approximate market prices. The average production costs are stated on a BOE basis, which includes natural gas that is converted at a ratio of 6.0 Mcf to one BOE, which represents the approximate energy content of the natural gas. Production costs are disclosed in the Results of Operations tables on pages 138 and 139.

	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2004 Average prices: (a) (b)							
Liquids - per barrel	$ 33.45	$ 32.31	$ 33.19	$ 37.76	$ 38.64	$ 37.94	$ 35.84
Natural gas - per mcf	5.23	5.24	5.23	3.17	4.32	3.19	3.98
Average production costs per BOE	6.10	5.89	6.06	2.52	5.73	2.79	4.12
2003 Average prices: (a) (b)							
Liquids - per barrel	$ 28.43	$ 24.76	$ 27.66	$ 27.30	$ 28.31	$ 27.54	$ 27.60
Natural gas - per mcf	4.75	4.78	4.76	2.82	4.38	2.84	3.66
Average production costs per BOE	5.50	4.97	5.42	2.59	4.91	2.79	4.01
2002 Average prices: (a) (b)							
Liquids - per barrel	$ 22.87	$ 20.70	$ 22.81	$ 22.88	$ 25.57	$ 23.57	$ 23.14
Natural gas - per mcf	3.07	2.66	2.88	2.74	3.35	2.75	2.81
Average production costs per BOE	4.73	4.45	4.69	2.41	5.62	2.68	3.70

(a) Average prices include hedging gains and losses but exclude gains or losses on derivative positions not accounted for as hedges and ineffective portions of hedges.
(b) Hedging gains (losses) included in average prices:

2004							
Liquids - per barrel	*$ (4.37)*	*$*	*$ (3.38)*	*$*	*$*	*$*	*$ (1.49)*
Natural gas - per mcf	*(0.10)*	*(0.24)*	*(0.12)*				*(0.04)*
2003							
Liquids - per barrel	*$ (0.35)*	*$*	*$ (0.18)*	*$*	*$*	*$*	*$ (0.10)*
Natural gas - per mcf	*(0.11)*	*(0.29)*	*(0.12)*				*(0.07)*
2002							
Liquids - per barrel	*$ 0.02*	*$*	*$ 0.02*	*$*	*$*	*$*	*$ 0.01*
Natural gas - per mcf	*0.06*	*(0.01)*	*0.05*				*0.02*

Table of Contents

Oil and Gas Reserve Data (Unaudited)

We estimated our proved oil and gas reserves in accordance with the SEC definitions in Rule 4-10 of Regulation S-X. These definitions can be found on the SEC website at http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

We maintain procedures designed to provide reasonable assurance regarding the reliability of our estimates of proved oil and gas reserves in accordance with applicable SEC rules. Our process includes both internal and third party participants: (1) degreed engineering and geology professionals from our exploration and production business units, (2) a corporate reserves audit team comprised of individuals who are not part of the business unit under review and (3) a member of a leading third party oil and gas engineering firm, who is part of our corporate reserves audit team. We also maintain written guidelines that are reviewed and updated as deemed appropriate to help ensure that these participants in our reserves estimation process employ a common set of terms and standards. Our process is reviewed with the Audit Committee of our Board of Directors, which is comprised exclusively of independent directors as defined under applicable NYSE and SEC rules.

Estimates of physical quantities of proved oil and gas reserves as determined by our engineers for the years 2004, 2003 and 2002 are presented on pages 143 and 144. 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. Refer to the risk factor entitled Our oil and gas estimates are subject to change in Part II, Item 7 of this report. Significant portions of our proved undeveloped reserves, principally in offshore areas, require the installation or completion of related infrastructure facilities such as platforms, pipelines, and the drilling of development wells. Proved reserve quantities exclude royalty and other interests owned by others, as well as volumes we received from our owned natural gas plants in lieu of processing fees. We report all reserves held under PSCs in Indonesia, Myanmar, Bangladesh, Azerbaijan and a concession in the Democratic Republic of Congo utilizing the economic interest method, which excludes host country shares. Estimated quantities for PSCs reported under the economic interest method are subject to fluctuations in the prices of crude oil and natural 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 could be partially offset by a change in our net equity (profit) share. The reserve quantities also include barrels of oil that we are contractually obligated to sell in Indonesia at prices substantially below market.

We report natural gas reserves on a dry basis, as sold or consumed in the course of operations. Natural gas liquids are presented with crude oil and condensate reserves. For informational purposes, natural gas liquids reserves are estimated to be 25 million, 27 million and 30 million barrels at December 31, 2004, 2003, and 2002, respectively. Of the aforementioned totals, 11 million, 11 million and 12 million barrels, for the respective periods, are located in the U.S.

Table of Contents

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

Millions of barrels	United States	Canada	Total North America	Asia (c)	Other International (c)	Total International (c)	Worldwide (c)
As of December 31, 2001	235	51	286	211	196	407	693
Revisions of estimates	22		22	(7)	(6)	(13)	9
Improved recovery	6		6	1		1	7
Discoveries and extensions	7	9	16	25		25	41
Purchases (d)	1	3	4				4
Sales (d)	(5)		(5)	(7)		(7)	(12)
Production	(27)	(7)	(34)	(20)	(7)	(27)	(61)
As of December 31, 2002	239	56	295	203	183	386	681
Revisions of estimates	(3)	2	(1)	5	12	17	16
Improved recovery	5		5	1		1	6
Discoveries and extensions	13	7	20	34		34	54
Purchases (d)	1	2	3				3
Sales (d)	(21)	(4)	(25)				(25)
Production	(23)	(6)	(29)	(23)	(8)	(31)	(60)
As of December 31, 2003	211	57	268	220	187	407	675
Revisions of estimates	17	3	20	(25)	(20)	(45)	(25)
Improved recovery							
Discoveries and extensions	11	5	16	8	45	53	69
Purchases (d)	1	1	2				2
Sales (d)	(2)		(2)		(2)	(2)	(4)
Production	(20)	(6)	(26)	(26)	(6)	(32)	(58)
As of December 31, 2004	218	60	278	177	204	381	659
Proved Developed Reserves at:							
December 31, 2001:	171	46	217	54	44	98	315
December 31, 2002:	176	52	228	53	32	85	313
December 31, 2003:	153	53	206	70	28	98	304
December 31, 2004:	165	56	221	84	40	124	345

(a) Includes reserves attributable to minority interests in consolidated subsidiaries of 0,0,2 and 32 for 2004, 2003, 2002 and 2001, respectively.

(b) Includes proportional shares of reserves of investees accounted for by the equity method of 0, 2, 7 and 9 for 2004, 2003, 2002 and 2001, respectively.

(c) Quantities under production sharing contracts are calculated utilizing the economic interest method, which excludes host countries shares. Quantities under production sharing contracts comprised 40 percent of the worldwide liquid reserves at December 31, 2004.

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

-143-

Table of Contents

Estimated Proved Reserves of Natural Gas (a) (b) (c) (d)

Billions of cubic feet	United States	Canada	Total North America	Asia (e)	Other International (e)	Total International (e)	Worldwide (e)
As of December 31, 2001	2,177	289	2,466	4,194	89	4,283	6,749
Revisions of estimates	(36)	1	(35)	(55)	(4)	(59)	(94)
Improved recovery	2		2	31		31	33
Discoveries and extensions	241	43	284	296	8	304	588
Purchases (f)	29	10	39				39
Sales (f)	(30)		(30)	(34)		(34)	(64)
Production	(307)	(37)	(344)	(339)	(9)	(348)	(692)
As of December 31, 2002	2,076	306	2,382	4,093	84	4,177	6,559
Revisions of estimates	15	(6)	9	87	6	93	102
Improved recovery				29		29	29
Discoveries and extensions	164	58	222	674		674	896
Purchases (f)	12	2	14				14
Sales (f)	(426)	(10)	(436)				(436)
Production	(263)	(35)	(298)	(351)	(10)	(361)	(659)
As of December 31, 2003	1,578	315	1,893	4,532	80	4,612	6,505
Revisions of estimates	(87)	(21)	(108)	2	31	33	(75)
Improved recovery							
Discoveries and extensions	99	35	134	626	19	645	779
Purchases (f)	1	1	2				2
Sales (f)	(19)	(1)	(20)		(40)	(40)	(60)
Production	(195)	(32)	(227)	(348)	(8)	(356)	(583)
As of December 31, 2004	1,377	297	1,674	4,812	82	4,894	6,568
Proved Developed Reserves at:							
December 31, 2001:	1,720	218	1,938	1,739	66	1,805	3,743
December 31, 2002:	1,614	273	1,887	1,669	49	1,718	3,605
December 31, 2003:	1,267	271	1,538	1,895	53	1,948	3,486
December 31, 2004:	1,142	247	1,389	1,949	21	1,970	3,359

(a) Includes reserves attributable to minority interests in consolidated subsidiaries of 0, 0, 29, and 397 for 2004, 2003, 2002 and 2001, respectively.

(b) Includes proportional shares of reserves of investees accounted for by the equity method of 0, 44, 227 and 232 for 2004, 2003, 2002 and 2001, respectively.

(c) Estimates are on a Dry Gas basis, as sold or consumed in the course of operations. December 31, 2004 estimate includes fuel gas equating to approximately 7 percent of the worldwide total.

(d) Natural gas is normally sold on a Btu or heating value basis with a referenced heating value of 1,000 Btu per cubic foot of natural gas. The worldwide average of the heating value of our natural gas was approximately 1,010 Btu per cubic foot at December 31, 2004.

(e) Quantities under production sharing contracts are calculated utilizing the economic interest method, which excludes host countries shares. Quantities under production sharing contracts comprised 37 percent of the worldwide gas reserves at December 31, 2004.

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

Table of Contents

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The standardized measure of discounted future net cash flows from proved oil and gas reserves for the years 2004, 2003 and 2002 are presented on page 146. Revenues are based on estimated production of proved reserves from existing and planned facilities and on prices of oil and gas at year-end 2004. Development and production costs related to future production are based on year-end cost levels and assume continuation of existing economic conditions. Income tax expense is computed by applying the appropriate year-end statutory tax rates to pre-tax future cash flows less recovery of the tax basis of proved properties and reduced by applicable tax credits.

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

As set forth in note (a) to the table on page 146, the year-end prices required to be used in the calculations are highly volatile. Price changes have a significant impact on the calculated present values of proved oil and gas reserves. See *Changes in Standardized Measure of Discounted Future Net Cash Flows* table on page 147 for the aggregate changes and significant components of such changes for the last three calendar years.

Probable and possible reserves and the value of exploratory acreage that may be developed in the future have not been included in the calculation of the data presented on pages 146 and 147. Likewise, future realized prices are expected to vary significantly from the mandated year-end prices utilized in the determination of the revenues included in the calculations. While we have exercised due care in the preparation of the data, we do not warrant that this data represents the fair market value of our oil and gas properties or an estimate of the discounted present value of cash flows to be obtained from their development and production.

Table of Contents

Standardized Measure of Discounted Future Net Cash Flows

Millions of dollars	United States	Canada	Total North America	Asia	Other International	Total International	Worldwide
2004							
Revenues (a)	$ 15,202	$ 3,739	$ 18,941	$ 20,972	$ 8,387	$ 29,359	$ 48,300
Production costs	4,677	809	5,486	3,172	1,319	4,491	9,977
Development costs (b)	1,216	93	1,309	4,083	1,487	5,570	6,879
Income tax expense	2,963	897	3,860	5,156	1,376	6,532	10,392
Future net cash flows	6,346	1,940	8,286	8,561	4,205	12,766	21,052
10% annual discount	2,570	876	3,446	3,512	1,781	5,293	8,739
Present values of future net cash flows	$ 3,776	$ 1,064	$ 4,840	$ 5,049	$ 2,424	$ 7,473	$ 12,313
Our share of present values of future net cash flows of equity investees (c)	$	$	$	$ 482	$	$ 482	$ 482
2003							
Revenues (a)	$ 14,468	$ 3,042	$ 17,510	$ 18,343	$ 5,816	$ 24,159	$ 41,669
Production costs	3,954	684	4,638	3,400	1,208	4,608	9,246
Development costs (b)	1,027	96	1,123	3,546	943	4,489	5,612
Income tax expense	2,958	648	3,606	4,260	916	5,176	8,782
Future net cash flows	6,529	1,614	8,143	7,137	2,749	9,886	18,029
10% annual discount	2,798	714	3,512	3,490	1,266	4,756	8,268
Present values of future net cash flows	$ 3,731	$ 900	$ 4,631	$ 3,647	$ 1,483	$ 5,130	$ 9,761
Our share of present values of future net cash flows of equity investees (c)	$	$	$	$ 372	$ 75	$ 447	$ 447
2002							
Revenues (a)	$ 14,271	$ 2,651	$ 16,922	$ 16,026	$ 4,983	$ 21,009	$ 37,931
Production costs	4,107	541	4,648	3,468	527	3,995	8,643
Development costs (b)	1,175	62	1,237	2,686	1,100	3,786	5,023
Income tax expense	2,692	654	3,346	3,975	834	4,809	8,155
Future net cash flows	6,297	1,394	7,691	5,897	2,522	8,419	16,110
10% annual discount	2,442	577	3,019	2,617	1,310	3,927	6,946
Present values of future net cash flows (d)	$ 3,855	$ 817	$ 4,672	$ 3,280	$ 1,212	$ 4,492	$ 9,164
Our share of present values of future net cash flows of equity investees (c)	$ 238	$	$ 238	$ 355	$ 76	$ 431	$ 669

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

Liquids per barrel	*2004*	*$ 33.99*	*$ 35.63*	*$ 34.34*	*$ 39.13*	*$ 41.11*	*$ 40.18*	*$ 37.72*
		$ 28.86	*$ 25.98*	*$ 28.26*	*$ 29.43*	*$ 31.14*	*$ 30.21*	*$ 29.44*
	2003	*$ 27.57*	*$ 25.85*	*$ 27.24*	*$ 27.78*	*$ 27.40*	*$ 27.60*	*$ 27.45*

2002														
Natural gas, per mcf 2004														
2003	*$*	*6.24*	*$*	*5.77*	*$*	*6.15*	*$*	*3.42*	*$*	*5.10*	*$*	*3.42*	*$*	*4.10*
	$	*5.70*	*$*	*5.03*	*$*	*5.58*	*$*	*3.02*	*$*	*2.60*	*$*	*3.01*	*$*	*3.75*
2002	*$*	*4.45*	*$*	*3.97*	*$*	*4.39*	*$*	*2.99*	*$*	*2.66*	*$*	*2.99*	*$*	*3.50*

(b) Includes dismantlement and abandonment costs. Future development costs include $4,125 million, $3,911 million and $3,472 million at December 31, 2004, 2003 and 2002, respectively, required to promote proved undeveloped reserves.

(c) Represents proportional shares of investees accounted for under the equity method. Under Asia, the amount shown reflects the value assigned to the dedicated noncommon carrier pipeline related to our offshore operations, which is recorded through an equity investee.

(d) Included in United States is the present value of Spirit Energy 76 Development, L. P., a consolidated subsidiary, in which there was a minority interest share representing approximately $69 million.

Table of Contents

Changes in Standardized Measure of Discounted Future Net Cash Flows

Millions of dollars	2004	2003	2002
Present value at beginning of year	$ 9,761	$ 9,164	$ 5,203
Discoveries and extensions, net of estimated future costs	1,795	947	1,103
Net purchases and sales of proved reserves (a)	(65)	(741)	8
Revisions to prior estimates:			