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

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004

Commission file number 1-8483

UNOCAL CORPORATION

(Exact name of registrant as specified in its charter)

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

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

(Address of principal executive offices)

(310) 726-7600

(Registrant s telephone number, including area code)

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

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

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

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

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant as of June 30, 2004 (based upon the average of the high and low prices of these shares reported in the New York Stock Exchange Composite Transactions listing for that date) was approximately $10.0 billion.

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

DOCUMENTS INCORPORATED BY REFERENCE

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

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GLOSSARY

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

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

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

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

BOE is a term used to quantify crude oil and natural gas amounts using a standard measurement. Natural gas volumes are converted to barrels of oil equivalent on the basis of 6,000 cubic feet of natural gas equals one barrel of oil equivalent.

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

Delineation or appraisal well is a well drilled in an unproven area adjacent to a discovery well to define the boundaries of the reservoir.

Development well is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Dry hole is a well incapable of producing hydrocarbons in sufficient commercial quantities to justify future capital expenditures for completion and additional infrastructure.

Economic interest method pursuant to production sharing contracts is a method by which our share of the cost recovery revenue and the profit revenue is divided by market oil and gas prices and represents the volume to which we are entitled. The lower the commodity price, the higher the volume entitlement, and vice versa.

Exploratory well is a well drilled to find and produce oil or gas reserves that is not a development well.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who agrees to pay a portion of past or future costs. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Floating Production, Storage and Offloading (FPSO) technology refers to the use of a vessel that is stationed above or near an offshore field. Produced fluids are brought by flowlines to the vessel where they are separated, or treated, or stored and then offloaded to another vessel or pipeline for transportation.

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

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

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Lifting is the amount of liquids each working-interest partner takes physically. The liftings may be more or less than actual entitlements based on royalties, working interest percentages, and a number of other factors.

Liquefied Natural Gas (LNG) is a gas, mainly methane, which has been liquefied in a refrigeration and pressurization process to facilitate storage and transportation.

Liquefied Petroleum Gas (LPG) is a mixture of butane, propane and other light hydrocarbons. At normal temperature it is a gas, but when cooled or subjected to pressure it can be stored and transported as a liquid.

Multilateral institution refers to an institution with shareholders from multiple countries that lends money for specific development reasons. Examples of multilateral institutions are International Finance Corporation (IFC), European Bank for Reconstruction and Development (EBRD), and Asian Development Bank (ADB).

Natural Gas Liquids (NGLs) are primarily ethane, propane, butane and natural gasolines, which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature.

Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by our working interest percentage in the properties.

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

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

OPEC is the abbreviation for Organization of Petroleum Exporting Countries.

Producible well is a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed production expenses and taxes.

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

Prospective acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas.

Proved acreage is acreage that is allocated to producing wells or wells capable of production or to acreage that is being developed.

Reservoir is a porous and permeable underground formation containing crude oil and/or natural gas enclosed or surrounded by layers of less permeable rock and is individual and separate from other reservoirs.

Subsea tieback is a well with the wellhead equipment located on the bottom of the ocean.

Take-or-Pay is a type of contract clause where specific quantities of a product must be paid for, even if delivery is not taken. In some contracts, the purchaser has the right in following years to take product that had been paid for but not taken.

Trend or Play is an area or region of concentrated activity with a group of related fields and/or prospects.

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

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

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

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FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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

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PART I

ITEMS 1 AND 2 - BUSINESS AND PROPERTIES.

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

We make available free of charge on or through our Internet website our annual reports on Form 10-K, annual proxy statements, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Our Internet address is http://www.unocal.com. We will also make available to any stockholder, without charge, copies of our annual report on Form 10-K as filed with the SEC. For copies of this report, or any other filings, please contact: Unocal Stockholder Services, 2141 Rosecrans Avenue, Suite 4000, El Segundo, California 90245 or call (800) 252-2233.

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

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

STRATEGIC FOCUS

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

maintaining focus on high-impact exploration and growth,

maintaining capital discipline, controlling costs and improving efficiency across our businesses,

achieving world-class status in our safety processes, systems and record, leveraging advantaged positions in the Gulf of Thailand and deepwater Indonesia,

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

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

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

maintaining a profitable and sustainable North American business.

SEGMENT AND GEOGRAPHIC INFORMATION

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

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Exploration and Production

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

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

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

Estimated Net Proved Reserves

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

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

There were de minimis amounts of proved reserves attributable to minority interests at December 31, 2004 and 2003. The year-end 2002 proved reserves included reserves attributable to minority interests of approximately 2 million barrels of liquids and 29 billion cubic feet of natural gas in the U.S.

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

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

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Net Daily Production

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

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

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

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

Oil and Gas Acreage

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

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

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

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Producible Oil and Gas Wells and Drilling in Progress

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

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

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

Net Oil and Gas Wells Completed and Dry Holes

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

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

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

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Exploration and Production North America

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

United States

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

Gulf of Mexico

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

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

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

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

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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

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dedicated fields, we can sell gas from those fields to other customers so long as (1) we are meeting the delivery requirements of the new agreement and (2) the sale would not reasonably be expected to materially affect our ability to meet the delivery requirements for the remaining term of the agreement.

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

We have a contract to sell up to 450 billion cubic feet of natural gas to an affiliate of ENSTAR Natural Gas Company and we began deliveries on the contract in 2004. ENSTAR distributes natural gas to Anchorage, the Matanuska-Susitna Valley, and the Kenai Peninsula. The natural gas sold to ENSTAR is priced based on a 36-month trailing average of Henry Hub natural gas prices.

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

Canada

Our operations in Canada are primarily carried out by our wholly-owned subsidiary, Northrock Resources Ltd. (Northrock), which focuses on three core areas: West Central Alberta (O Chiese, Garrington, Caroline and Pass Creek areas), Northwest Alberta (Red Rock and Knopcik areas) and the Williston Basin (Southeastern Saskatchewan). Our Canadian production in 2004 averaged approximately 16 MBbl/d of liquids and 83 MMcf/d of natural gas. We participated in drilling 130 wells in 2004 resulting in 53 natural gas wells, 64 crude oil wells and 3 service wells.

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Exploration and Production   International

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

Oil and Gas Concessions and Production Sharing Contracts

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

Country	Agreement Type	Area	Working Interest Share% (a)	Expiration Date	Renewal Option (b)
Thailand	Concession	Blocks 10, 11, 12 & 13	70 - 80	2012	Y(c)
	Concession	Block 12/27	35	2028	Y
	Concession	Blocks 14A, 15A & 16A	16	2036	Y
Myanmar	Production Sharing Contract	Blocks M5 & M6	28.26	2028	N(d)
Indonesia	Production Sharing Contract	East Kalimantan	92.5	2018	Y
	Production Sharing Contract	Makassar Strait	90	2020	Y
	Production Sharing Contract	Rapak	80	2027	Y
	Production Sharing Contract	Ganal	80	2028	Y
Azerbaijan	Production Sharing Contract	Azeri, Chirag & Deepwater Portion of Gunashli	10.28	2024	Y
Bangladesh	Production Sharing Contract	Blocks 13 & 14	98	2028	Y
	Production Sharing Contract	Block 12	98	2034	Y
Vietnam	Production Sharing Contract	Blocks B & 48/95	42.38	2026	Y
	Production Sharing Contract	Block 52/97	43.3	2029	Y

(a) Share percentages rounded to the nearest whole number. Working interest and net working interest are defined in our glossary.

(b) Terms of agreement renewal are subject to negotiation. We cannot predict whether the concession or PSC will in fact be renewed.

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

Asia

Thailand

Through our Unocal Thailand, Ltd. (Unocal Thailand) subsidiary, we currently conduct oil and gas operations in five contract areas in the Pattani field located in the Gulf of Thailand. This field is subdivided into 15 operating areas. Unocal s average net working interest in contract areas 1, 2, 3 and 5 is 62 percent and 31 percent in contract area 4, the Pailin operational area. We had 1,165 employees in our Thailand operations at year-end 2004 with Thai nationals making up approximately 92 percent of the total.

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

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We sell all of our Thailand natural gas production to PTT Public Co., Ltd. (PTT), under long-term natural gas sales agreements (GSA) with expiration dates ranging from 2010 to 2029. The GSA prices are based on formulas that allow prices to fluctuate with market prices for crude oil and refined products and are indexed to the U.S. dollar. See note 29 to the consolidated financial statements for sales figures to PTT. We have typically supplied more natural gas to PTT than the minimum daily contract quantity provision of our GSAs. The minimum gross quantity of natural gas that PTT is contractually obligated to purchase from us and our co-venturers under the existing GSAs is 1,093 MMcf/d. Included in this total is the Pailin operational area where gross contracted natural gas sales volumes are currently 353 MMcf/d.

To meet growing demand for domestic natural gas in Thailand, we continued discussions, during 2004, to finalize the commercial arrangements required to extend our existing GSAs and expand contract quantities for two of our GSAs after PTT completes its expected installation in 2006 of a third pipeline to shore. In 2003, we signed a heads of agreement with PTT with a goal of amending and extending the two GSAs, while increasing gross contracted sales volumes from 740 MMcf/d to 850 MMcf/d in 2006, with additional increases up to 1,240 MMcf/d in subsequent years.

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

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

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

Myanmar

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

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

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

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Indonesia

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

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

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

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

Crude oil and natural gas production from our northern fields are processed at our company-operated Santan terminal and liquids extraction plant, and the dry natural gas is transported by pipelines to an LNG plant, located nearby at Bontang, East Kalimantan. Dry natural gas is also transported by pipelines to a fertilizer, ammonia and methanol complex, located north of Bontang. LNG is currently sold to Japan, Korea and Taiwan and the extracted LPG is exported to Japan.

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

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

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

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

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

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

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

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

Bangladesh

Through our subsidiaries, we hold interests in three PSCs in Bangladesh, encompassing over 3.5 million acres. Two PSCs cover Blocks 12, 13 and 14 and the third PSC covers Block 7. We have a 98 percent working interest in Blocks 12, 13 and 14 and are the operator. Our working interest in Block 7 is 90 percent and we are the operator.

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

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

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

Vietnam

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

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

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

Other

Azerbaijan

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

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

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The Netherlands

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

Democratic Republic of Congo

Through a subsidiary, we have a 17.7 percent non-operating working interest in a PSC with rights to explore and produce hydrocarbons in the entire offshore area of the country. Gross production averaged about 18 MBbl/d of crude oil (2 MBbl/d net) from seven fields in 2004.

Australia

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

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

Midstream and Marketing

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

Pipelines

Our pipelines business principally includes equity interests in certain petroleum pipeline companies and wholly-owned pipeline systems throughout the U.S., including our pipeline investments in the Colonial Pipeline Company (Colonial Pipeline), in which we hold a 23.44 percent equity interest. The Colonial Pipeline system runs from Texas to New Jersey and transports a significant portion of all petroleum products consumed in its 13-state market area. Also included is the Unocal Pipeline Company, a wholly-owned subsidiary, which holds a 1.36 percent participation interest in the TransAlaska Pipeline System (TAPS). TAPS transports crude oil from the North Slope of Alaska to the port of

Valdez. We also have a 40 percent equity interest in the Kenai Kachemak Pipeline LLC, which operates a natural gas pipeline between Kenai and Ninilchik in Alaska.

Through an equity investee and our working interest in AIOC, we are participating in the construction of a 42-inch pipeline from Baku, Azerbaijan to Ceyhan, Turkey. The BTC pipeline will carry crude oil from Azerbaijan through Georgia and Turkey to the deep water port facilities on the Mediterranean Sea. The pipeline is planned to have a crude oil capacity of 1 million Bbl/d. The pipeline is estimated to cost approximately $3.5 billion and is expected to be in operation in the middle of 2005. Construction on the pipeline has progressed with the overall project now more than 93 percent complete. We have an 8.9 percent equity interest in the pipeline company and are one of eleven shareholders. Up to 70 percent of the pipeline s cost is covered under financing agreements with both bilateral and multilateral agencies and commercial lenders.

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

Natural Gas Storage

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

Marketing

Marketing activities include transporting and selling our hydrocarbon production. To that end, the marketing group conducts the majority of our: (a) worldwide crude oil and condensate marketing activities, and (b) North American natural gas marketing activities, excluding those of the Alaska business unit. Commodities are sold to third parties at market prices, terms and conditions.

Most of our U.S. production is sold on an intracompany basis from the Exploration and Production segment to the Midstream and Marketing segment at market prices and then is resold to third-party customers. However, because this production is sold at market prices, our marketing business is, consequently, a low-margin business. These intracompany sales and purchase transactions, including any intracompany profits and losses, are eliminated upon consolidation. To market our production, the marketing group enters into various sale and purchase transactions with unaffiliated oil and gas producing, refining, marketing and trading companies. These transactions effectively transfer the commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity. These transactions allow us to better manage our commodity-related risks. Currently, these sale and purchase transactions represent a significant portion of the Midstream and Marketing segment s U.S. crude oil sales and purchases.

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

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

The marketing group is also responsible for implementing commodity-specific risk management activities on behalf of the Exploration and Production segment. The objectives of these risk management activities include reducing the overall volatility of our cash flows and preserving revenues. The marketing group enters into various hydrocarbon derivative financial instrument contracts, such as futures, swaps and options (derivative contracts), to hedge or offset portions of our exposures to commodity price changes for future sales transactions. Our commodity-risk management program is authorized by our senior management and board of directors.

The marketing group also trades hydrocarbon derivative instruments, for which hedge accounting is not used, to exploit anticipated opportunities arising from commodity price fluctuations. These instruments primarily consist of exchange-traded futures and options contracts. The marketing group also purchases limited amounts of physical inventories for energy trading purposes when arbitrage opportunities arise. These trading activities are subject to internal restrictions, including value at risk limits, which measure our potential loss from likely changes in market prices.

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Geothermal Operations

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

Indonesia

We develop and produce geothermal steam pursuant to the terms of exclusive Joint Operation contracts with Pertamina and sell geothermal steam to PT PLN (Persero) (PLN), the state electricity company, to fuel three power generation plants at Gunung Salak, West Java, with a total installed capacity of 165 megawatts, pursuant to the terms of an Energy Sales Contract. In 2004, we acquired the remaining 50 percent interest in Dayabumi Salak Pratama, Ltd. (DSPL) and now own 100 percent of this subsidiary, which operates three other power generation plants with a total installed capacity of 197 megawatts also located within the Gunung Salak steam field. DSPL operates these power plants and sells electrical energy to PLN pursuant to the build-operate-transfer provisions of the current Energy Sales Contract. Title to geothermal resources rests with the Indonesian central government.

Philippines

The Republic of the Philippines retains title to geothermal resources in the ground and the National Power Corporation (NPC), a Philippine government-owned corporation, acts as the steward to develop steam resources. Unocal Philippines, Inc. (UPI), a wholly-owned subsidiary formerly known as Philippine Geothermal, Inc. (PGI), has developed and produced steam resources for NPC pursuant to a 1971 service contract. NPC is the owner of all of the equipment and surface lands used in steam field operations and owns and operates power plants with a combined installed generating capacity of 649 megawatts at Tiwi and Mak-Ban on the island of Luzon.

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

UPI had been operating the steam fields under an Interim Agreement with NPC while the parties were negotiating this settlement. The settlement provides that: the 1971 service contract (and Interim Agreement) will be terminated upon completion by NPC of the rehabilitation of the Tiwi and Mak-Ban power plants, expected in early 2006; UPI will be granted the right to operate the steam fields until at least 2021; and UPI will sell geothermal resources to NPC/PSALM at a negotiated price to ensure base-load operation of the Tiwi and Mak-Ban power plants.

Thailand

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

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Geothermal Reserves and Operating Data

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

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

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

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

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PATENTS

We hold five U.S. patents resulting from our independent research on cleaner-burning reformulated gasolines (RFG). We have entered into nine licensing agreements that grant motor gasoline refiners, blenders and importers the right to make cleaner-burning gasolines using these formulations. We have a uniform licensing schedule that specifies a range from 1.2 to 3.4 cents per gallon for volumes that fall under the patents.

The first of these patents (the 393 patent) was the subject of litigation initiated in the U.S. District Court for the Central District of California by the major California refiners. Following a jury verdict in a 1997 trial upholding the patent and awarding us damages, the refiners appealed unsuccessfully to the U.S. Circuit Court of Appeals for the Federal Circuit. In 2000, we received approximately $91 million, including interest and attorneys fees, for infringement by the refiners for the period of March through July of 1996. In 2002, the Court determined that the 5.75 cent per gallon royalty rate determined by the jury in the trial would apply to the defendants infringing gasolines in California for the period subsequent to July 1996. No determination has been made by the Court as to the royalty rate for non-California gasolines in this action.

In 2002, we filed a lawsuit against Valero Energy Corporation in the same U.S. District Court for infringement of both the 393 patent and a subsequent 126 patent by Valero and Ultramar Diamond Shamrock (acquired by Valero in 2001). We are seeking 5.75 cents per gallon for motor gasolines infringing one or more claims under the patents and a trebling of the amount for willful infringement. We are also seeking a mandatory licensing of our patents by Valero with respect to future activities. Proceedings in both of our lawsuits have been temporarily suspended pending the outcome of the reexamination of the patents discussed below.

In 2001, petitions were filed with the U.S. Patent and Trademark Office (PTO) by Washington, D.C., law firms, acting independently on behalf of unnamed parties, requesting reexaminations of the 393 and 126 patents based on the existence of alleged prior art . In 2002, the PTO initially rejected all of the claims of the two patents as part of the reexamination process.

The PTO subsequently granted a second request for reexamination of the 393 patent based on additional alleged prior art and later rejected all of the claims of the 393 patent in a non-final Office Action. In March 2003, we filed a response to this rejection, including an appeal within the PTO, which was followed by yet a third reexamination request of the 393 patent. That request was granted and the PTO merged the three 393 reexaminations. We are now awaiting a response from the PTO to our submission of March 2003.

A second reexamination request of the 126 patent was also granted and merged with the first, and yet a third request for reexamination of the 126 patent was filed in October 2004 and granted in January 2005. The completion of the reexamination processes, including appeals within the PTO, is expected to take some time, but we believe the claims of both patents are novel and non-obvious and expect them ultimately to be sustained. Licensing fees and judgments collected during the pendency of the reexaminations are not refundable.

Also in 2001, ExxonMobil Corporation requested the U.S. Federal Trade Commission (FTC) to conduct an investigation into certain alleged unfair competition practices allegedly engaged in by us in the regulatory processes that established California and federal standards for RFG, thereby allegedly gaining monopoly profits in the RFG market. ExxonMobil requested that the FTC use its authority to fashion an appropriate remedy. Subsequently, the FTC conducted a nonpublic investigation.

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

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

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issues. The complaint counsel appealed that decision to the FTC in December 2003. In July 2004, the FTC reversed the decision and remanded the matter to the Administrative Law Judge for trial. The subsequent trial commenced in October 2004 an