FORM 10−K/A

UNOCAL CORP − ucl

Filed: April 21, 2004 (period: December 31, 2003)

Amendment to a previously filed 10−K

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

FORM 10-K/A
AMENDMENT NO. 1

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2003 or

[_] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from__________to__________

Commission file number 1-8483

UNOCAL CORPORATION

(Exact name of registrant as specified in its charter)

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

2141 Rosecrans Avenue, Suite 4000, El Segundo, California	90245
(Address of principal executive offices)	(Zip Code)

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

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

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

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant as of June 30, 2003 (based upon the average of the high and low prices of these shares reported in the New York Stock Exchange Composite Transactions listing for that date) was approximately $7.4 billion.

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

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders (filed with the Securities and Exchange Commission on April 12, 2004) are incorporated by reference into Part III of the Form 10-K filed on March 11, 2004.

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EXPLANATORY NOTE

Unocal Corporation is filing this Amendment No. 1 (this "amendment") on Form 10-K/A to amend its Annual Report on Form 10-K for the year ended December 31, 2003, to correct a typographical error in "Items 1 and 2 - Business and Properties." On page 3 of the original filing, the table under the heading "Net Daily Production" inadvertently included references to "million" and "millions", rather than to "thousand" and "thousands", in reference to barrels of liquids and barrels of oil equivalent, and to "billion", rather than to "million", in reference to cubic feet of natural gas. Otherwise, the numbers disclosed in the table are not being changed by this amendment. In accordance with the rules of the Securities and Exchange Commission, this amendment sets forth the complete text of Items 1 and 2 as amended to correct this table. The corrected table is also included below for reference:

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

This amendment also includes a correction to a typographical error on the cover page and includes a signature page and certifications of the chief executive officer and chief financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. This amendment does not update information contained in the original filing to reflect facts or events that may have occurred subsequent to the date of the original filing or subsequent to any periods for which disclosure was otherwise provided in the original filing.

PART I

ITEMS 1 AND 2 − BUSINESS AND PROPERTIES.

Unocal Corporation was incorporated in Delaware in 1983, to operate as the parent of Union Oil Company of California ("Union Oil"), which was incorporated in California in 1890. Virtually all operations are conducted by Union Oil and its subsidiaries. The terms "Unocal" and "the Company" as used in this report mean Unocal Corporation and its subsidiaries, except where the text indicates otherwise.

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

Information required under Items 1 and 2 are presented together in the following discussion of the Company's business and properties and should be read in conjunction with Management's Discussion and Analysis of Financial Condition ("MD&A") and Results of Operations in Item 7 of this report, including the discussion of risk factors and the Cautionary Statement.

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

STRATEGIC FOCUS

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

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

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

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

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

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

SEGMENT AND GEOGRAPHIC INFORMATION

Financial information relating to the Company's business segments, geographic areas of operations, and sales revenues by classes of products is presented in note 31 to the consolidated financial statements and the selected financial data section in Item 8 of this report.

EXPLORATION AND PRODUCTION

Unocal's primary activities are oil and gas exploration, development and production, and they are carried out by business units in North America and Internationally in Asia and other locations around the world. In 2003, the Company's worldwide average production was approximately 160 MBbl/d of liquids and 1,728 MMcf/d of natural gas, primarily from U.S. onshore and offshore in the U.S. Gulf of Mexico, in the Gulf of Thailand, and offshore East Kalimantan, Indonesia. Approximately 39 percent of the Company's worldwide production in 2003 and 27 percent of the Company's worldwide proved oil and gas reserves at year-end 2003 were in the U.S. Exploration and production net properties accounted for approximately 89 percent of Unocal's total net properties at December 31, 2003. Exploration and production properties in the U.S., as a percentage of total exploration and production properties were 39 percent in 2003.

The Company reports all reserve and production data pursuant to production sharing contracts utilizing the economic interest method, which excludes host country shares. The Company also reports natural gas reserves and production on a dry basis, with natural gas liquids included with crude oil and condensate volumes. Information regarding oil and gas financial data, oil and gas reserve data and the related present value of future net cash flows from oil and gas operations is presented on pages 133 through 142 of this report. During 2003, certain estimates of the Company's U.S. underground oil and gas reserves as of December 31, 2002, were filed with the U.S. Department of Energy and State agencies under the name of Union Oil. Such estimates were essentially identical to the corresponding estimates of such reserves at December 31, 2002, included in this report.

Net Proved Reserves

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

	U.S. Lower 48	Alaska	Canada	Total N.A.	Far East	Other	Total Int'l	Total
2003								
Liquids - million barrels	141	70	57	268	217	190	407	675
Natural gas - billion cubic feet	1,395	183	315	1,893	3,994	618	4,612	6,505
Millions of barrels oil equivalent	373	101	109	583	883	293	1,176	1,759
2002								
Liquids - million barrels	165	74	56	295	200	186	386	681
Natural gas - billion cubic feet	1,896	180	306	2,382	3,787	390	4,177	6,559
Millions of barrels oil equivalent	481	104	107	692	831	251	1,082	1,774
2001								
Liquids - million barrels	161	74	51	286	208	199	407	693
Natural gas - billion cubic feet	1,965	212	289	2,466	3,873	410	4,283	6,749
Millions of barrels oil equivalent	489	109	99	697	854	267	1,121	1,818

There were no amounts of proved reserves attributable to minority interests at December 31, 2003. The year-end 2002 proved reserves included reserves attributable to minority interests of approximately 2 million barrels of liquids and 29 billion cubic feet of natural gas in the U.S. Lower 48, while 2001 proved reserves included 32 million barrels of liquids and 397 billion cubic feet of natural gas in the U.S. Lower 48. The volumes attributable to minority interests in the U.S. Lower 48 for 2001 primarily reflected the outside ownership in the Company's Pure Resources Inc. ("Pure") subsidiary at that time. For additional details, see the Oil and Gas Reserve Data in Item 8 of this report.

Net Daily Production

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

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

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

Oil and Gas Acreage

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

	(Thousands of acres)			
	Proved Acreage		Prospective Acreage	
	Gross	Net	Gross	Net
U.S. Lower 48	1,672	728	8,597	5,329
Alaska	271	57	604	349
Canada	577	286	2,274	1,139
North America Total	2,520	1,071	11,475	6,817
Far East	983	571	29,247	10,515
Other	45	24	6,410	3,960
International Total	1,028	595	35,657	14,475
Worldwide	3,548	1,666	47,132	21,292

Producible Oil and Gas Wells

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

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

<FN>
(a) The Company had 179 gross and 66 net producible wells with multiple completions.
</FN>

Drilling in Progress

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

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

<FN>
(a) Excludes service wells in progress (3 gross and 3 net).
(b) The Company had one waterflood project under development at December 31, 2003.
</FN>

Net Oil and Gas Wells Completed and Dry Holes

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

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

NORTH AMERICA:

U.S. LOWER 48

The U.S. Lower 48 business is primarily comprised of the Company's exploration and production operations in the onshore area of the Gulf of Mexico region located in Texas, Louisiana, and Alabama; operations in New Mexico and Colorado; and the shelf and deepwater areas of the Gulf of Mexico.

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

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

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

Gulf of Mexico Shelf and Onshore

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

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

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

Deepwater Gulf of Mexico

Over the past five years, the Company has acquired acreage positions in the deepwater Gulf of Mexico, with interests in 224 exploration leases. The Company's acreage is primarily in the Subsalt/Foldbelt trend, which lies beyond the Primary Basin deepwater trend. Further offshore in the Subsalt/Foldbelt trend, sometimes referred to as the "ultra-deep", the Company has a number of prospects in water depths of 5,000 feet and greater. The Company was an early entrant in the ultra-deep area and has interests in 128 blocks. In 2003, the Company relinquished 44 deepwater Gulf of Mexico blocks before their expiration dates to focus its deepwater Gulf of Mexico acreage positions on blocks that have more potential.

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

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

The Company participated in discoveries made on the Mad Dog and K-2 fields in prior years. The Company has a 15.6 percent working interest in Mad Dog on Green Canyon Block 826. In 2003, development of Mad Dog continued on track and the Company anticipates first production in the first half of 2005, with expected gross peak production of 75 MBbl/d of liquids and 30 MMcf/d of natural gas in 2007. The Company has committed approximately $225 million for its portion of the development costs for Mad Dog. The K-2 discovery is located on Green Canyon Block 562. At the end of 2003, the co-venture integrated project team of the K-2 discovery completed a development plan, and the working interest owners sanctioned the project in early 2004. The Company has committed approximately $50 million for its portion of the development costs. The Company holds a 12.5 percent working interest in the K-2 discovery.

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

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

ALASKA

The Company operates ten platforms in the Cook Inlet and five producing natural gas fields. The Company also holds working interests in two North Slope fields. The Company has a 10.52 percent working interest in the Endicott field and a 4.95 percent working interest in the Kuparuk and Kuparuk satellite fields.

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

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

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

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

CANADA

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

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

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

INTERNATIONAL:

The Company's International operations encompass oil and gas exploration and production activities outside of North America. The Company, through its International subsidiaries, operates or participates in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. In 2003, International operations accounted for 56 percent and 49 percent of the Company's natural gas and liquids production, respectively. International operations also include exploration activities and the development of energy projects primarily in Asia, Australia, Brazil and West Africa. Listed below are certain of the more material oil and gas concessions and PSCs within the International operations:

Certain Oil and Gas Concessions and Production Sharing Contracts

Country	Agreement Type	Area	W.I. Share % (a)	Expiration Date	Renewal Option (b)
Thailand	Concession	Blocks 10, 11, 12 &13	70 - 80	2012	Y (c)
	Concession	Block 12/27	35	2028	Y
	Concession	Blocks 14A, 15A &16A	16	2036	Y
Myanmar	Production Sharing Contract	Blocks M5 &M6	28	2028	N (d)
Indonesia	Production Sharing Contract	East Kalimantan	93	2018	Y
	Production Sharing Contract	Makassar Strait	90	2020	Y
	Production Sharing Contract	Rapak	80	2027	Y
	Production Sharing Contract	Ganal	80	2028	Y
Azerbaijan	Production Sharing Contract	Azeri, Chirag &Deepwater Portion of Gunash1i	10	2024	Y
Bangladesh	Production Sharing Contract	Blocks 13 &14	98	2024	Y
	Production Sharing Contract	Block 12	98	(e)	Y
Vietnam	Production Sharing Contract	Blocks B &48/95	42	2021	Y
	Production Sharing Contract	Block 52/97	43	2029	Y
China	Production Sharing Contracts	Xihu Trough	20	2033	N

<FN>
(a) Share percentages rounded to the nearest whole number
(b) Terms of agreement renewal are subject to negotiation
(c) Ten-year extension option is available to the Company
(d) No renewal option specified in the PSC
(e) Production period is 25 years for gas fields from the date of approval of the development plan
</FN>

Thailand

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

Very strong sales resulting from continued strengthening in the Thai economy and the related increase in power and gas demand capped off a record year for Unocal Thailand. New daily, monthly, and annual records were set for natural gas and liquids production. Gross natural gas production from Unocal's - Gulf of Thailand operations in 2003 averaged 1,151 MMcf/d (627 MMcf/d net to the Company). The natural gas produced is used mainly in power generation, but it is also consumed by the industrial and transportation sectors and in the petrochemical industry. Gross crude oil and condensate production in 2003 averaged 58 MBbl/d, or 33 MBbl/d net to the Company. The produced crude oil is sold to both domestic and export markets, and the condensate is sold primarily as a petrochemical feedstock. The Company's natural gas production fulfills approximately 30 percent of Thailand's total electricity demand.

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

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

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

Myanmar

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

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

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

Indonesia

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

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

Shelf − The Company currently operates 11 producing oil and gas fields offshore East Kalimantan. The Company has a 92.5 percent working interest in 10 of the fields, and a 46.25 percent working interest in the Attaka field.

Oil and associated gas production from its northern fields are processed at the Company−operated Santan terminal and liquids extraction plant, and the dry gas is transported by pipelines to an LNG plant, located nearby at Bontang, East Kalimantan. Dry gas is also transported by pipelines to a fertilizer, ammonia and methanol complex, located north of Bontang. LNG is currently sold to Japan, Korea and Taiwan and the extracted LPG is exported to Japan. Oil and gas from the Company's southern fields are sent to the Company−operated Lawe−Lawe terminal, located onshore south of Balikpapan. The stored oil is either exported by tanker or transported by pipeline to a refinery in Balikpapan owned by Pertamina, the Indonesian national petroleum company. The gas is transported by pipeline and sold as fuel gas to the Pertamina refinery.

Under the terms of the Indonesia PSCs, the Company is required to sell a portion of its net entitlement crude oil production to the Indonesia government at reduced prices. For 2003, approximately 13 percent of the Company's share of this production was sold to the government for an average price that was substantially lower than market.

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

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

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

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

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

Azerbaijan

The Company, through a subsidiary, has a 10.28 percent working interest in the AIOC project that is producing and developing offshore oil reserves in the Caspian Sea from the Azeri and Chirag fields. In 2003, AIOC's gross oil production averaged 131 MBbl/d (12 MBbl/d net to the Company). AIOC currently has access to two pipelines to export its oil production: a northern pipeline route, which connects in Russia to an existing pipeline system, and a western pipeline route from Baku, Azerbaijan through Georgia. Both pipelines connect with ports on the Black Sea. In 2003, approximately 90 percent of production from the consortium was exported through the western pipeline and the remaining 10 percent through the northern pipeline.

AIOC is in the process of constructing Phases I and II of the offshore Azeri field in the Azeri-Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea. Phase I, which will develop an estimated 1.5 billion gross barrels of proved crude oil reserves, is under construction and on schedule with first oil expected in early 2005. Phase II of the project is expected to be similar in size to Phase I and is expected to begin production from two additional platforms in 2006 and 2007. The Company has approved $710 million in expenditures for its share of the costs for Phases I and II. The Company anticipates financing portions of these costs. The Company closed its financing of Phase 1 development in February of 2004 and anticipates funding early in 2004. The Company, through its AIOC participation, has an equity interest in the development of a pipeline from Baku to Ceyhan, Turkey (see the discussion under the Midstream segment for further details).

Bangladesh

The Company, through its subsidiaries, holds interests in three PSCs in Bangladesh, encompassing over 3.5 million acres. Two PSCs cover Blocks 12, 13 and 14 and the third PSC covers Block 7. The Company has a 98 percent working interest in Blocks 12, 13 and 14 and is the operator. The Company's working interest in Block 7 is 90 percent. Gross production from the Jalalabad field on Block 13 averaged 120 MMcf/d (64 MMcf/d net to the Company) of natural gas and 1,300 Bbl/d (506 b/d net to the Company) of liquids in 2003. The natural gas production supplies approximately 10 percent of the country's gas demand. The Company also discovered the Moulavi Bazar gas field on Block 14 in 1999 and the Bibiyana field, a major gas field located on Block 12, in 1998. .

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

The Netherlands

The Company, through a subsidiary, has interests ranging from 34 percent to 80 percent in four blocks in the Netherlands sector of the North Sea. Average gross production in 2003 was approximately 5 MBbl/d of crude oil (4 MBbl/d net to the Company) and 13 MMcf/d (7 MMcf/d net to the Company) of natural gas. The Company is the operator and has an average 70 percent working interest.

Democratic Republic of Congo

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

Brazil

The Company, through an affiliate, holds a 50 percent interest in a company that has a 35 percent participation agreement with Petroleo Brasileiro SA ("Petrobras") in the Pescada-Arabaiana oil and gas project in the Potiguar basin, offshore Brazil. The agreement covered the acquisition of an initial 79 percent participation interest from Petrobras in five concession areas. The project currently consists of six production platforms and a 45-mile long, 26-inch diameter multi-phase pipeline. In 2003, gross production from the project averaged 3 MBbl/d of oil and 47 MMcf/d of natural gas. Net production from the project averaged 1 MBbl/d of oil and 17 MMcf/d of natural gas.

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

Vietnam

The Company, through its subsidiaries, is the operator of two PSCs offshore southwest Vietnam in the northern part of the Malay Basin, which encompass approximately 1.1 million acres. The Company has a 42.38 percent working interest in one PSC, which includes Block B and Block 48/95. The Company made the initial gas discovery on the Kim Long prospect on Block B in 1997. The Company also holds a 43.4 percent working interest in a PSC for Block 52/97, which covers 500,000 acres.

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

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

China

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

Australia

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

The Company, through the same subsidiary, also holds two other exploration blocks offshore southeast Australia. The Company holds a 50 percent non-operating working interest in Block T/32P, which is located in the Sorell Basin, off the northwestern shore of Tasmania. In addition, the Company holds a 33.33 percent non-operating working interest in Block VIC/P52, which is located in the Otway Basin, offshore Victoria.

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

TRADE

The primary function of the Trade segment is to externally market the Company's hydrocarbon production. Marketing activities include transporting and selling the Company's production. To that end, the Trade segment conducts the majority of the Company's: (a) worldwide crude oil and condensate marketing activities, and (b) North American natural gas marketing activities, excluding those of the Alaska business unit. Commodities are sold to third parties at market prices, terms and conditions. Most of the Company's U.S. production is sold on an intracompany basis from the Exploration and Production segment to the Trade segment at market prices and then resold by the Trade segment to third-party customers. These intracompany sales and purchase transactions, including any intracompany profits and losses, are eliminated upon consolidation. To market the Company's crude oil production, the segment enters into various sale and purchase transactions with unaffiliated oil and gas producing, refining, marketing and trading companies. These transactions effectively transfer the commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity. These transactions allow the Company to better manage its commodity-related risks and seek additional revenues beyond the market values available at production locations. Currently, these sale and purchase transactions represent a significant portion of the segment's U.S. crude oil sales and purchases.

The Company's non-U.S. crude oil and condensate production is generally marketed by the Trade segment on a commission or fee basis on behalf of the Exploration and Production segment. Intracompany profits and losses related to these marketing arrangements are eliminated upon consolidation.

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

The segment also purchases crude oil, condensate and natural gas for resale from certain of the Company's royalty owners, joint venture partners and unaffiliated oil and gas producing, refining, and trading companies.

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

As mentioned above, a large portion of the Exploration and Production segment's production is sold to the Trade segment. However, since this production is sold to the Trade segment at market prices, the Trade segment's business is, as a consequence, a low-margin business. Intracompany profits and losses related to the Trade segment's intracompany purchases, commissions, or fee arrangements are eliminated upon consolidation.

For additional details on the Trade segment activities, see note 31 to the consolidated financial statements in Item 8 of this report.

MIDSTREAM

The Midstream segment is comprised of the Company's pipelines business and North America gas storage businesses.

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

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

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

The Company and Marathon Oil formed the Kenai Kachemak Pipeline LLC, which operates a natural gas pipeline between Kenai and Ninilchik in Alaska, which began operations in 2003. The Kachemak pipeline is approximately 33 miles in length.

The Company owns varying interests in natural gas storage facilities in west-central Canada and Texas. The Company, through Canadian subsidiaries, holds a 94 percent interest in the Aitken Creek Gas Storage Project in British Columbia, which was expanded to 48 billion cubic feet of capacity and 500 MMcf/d of deliverability. The Company also holds an interest in the Cal Ven Pipeline and the Alberta Hub natural gas storage facility in Alberta. The Company also operates the Keystone Gas Storage Project in West Texas with a storage capacity of 3 BCF and holds a 100 percent interest in the project.

GEOTHERMAL AND POWER OPERATIONS

The Company is a producer of geothermal energy, with more than 35 years experience in geothermal resource exploration, reservoir delineation and management. The Company also has proven experience in planning, designing, building and operating private power projects and related project finance and economics. The Company, through its subsidiaries, operates major geothermal fields producing steam for power generation projects at Gunung Salak and Wayang Windu in Indonesia and at Tiwi and Mak-Ban in the Philippines. Together, these projects have a combined installed electrical generating capacity of 1,120 megawatts.

Indonesia - The Company develops and produces geothermal steam pursuant to the terms of exclusive Joint Operation contracts with Pertamina and sells geothermal steam to PT PLN (Persero) ("PLN"), the state electricity company, to fuel three power generation plants at Gunung Salak, West Java, with a total installed capacity of 165 megawatts, pursuant to the terms of energy sales contracts. The Company also has a 50 percent interest in Dayabumi Salak Pratama, Ltd. ("DSPL"), which operates three power generation plants with a total installed capacity of 197 megawatts associated with the Gunung Salak steam field. DSPL operates these power plants and sells electrical energy to PLN pursuant to the build-operate-transfer provisions of current Energy Sales contracts. The Company also operates the Wayang Windu geothermal power project near Bandung, West Java on behalf of an equity investee, which owns a 50 percent non-controlling interest in the project. The project, which includes a 110 megawatt power plant and geothermal steam field, is currently operating at full capacity. Title to geothermal resources rests with the Indonesian central government. The Company's Unocal North Sumatra Geothermal, Ltd. subsidiary sold its rights and interest in the Sarulla geothermal project on the island of Sumatra, Indonesia to PLN. The sales price was $60 million, and the transaction closed in February 2004.

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

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

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

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

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

<FN>
(a) Includes reserves underlying a service fee arrangement in the Philippines.
</FN>

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

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

PATENTS

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

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

In 2002, the Company filed a lawsuit against Valero Energy Corporation in the same U.S. District Court for infringement of both the `393 patent and a subsequent `126 patent by Valero and Ultramar Diamond Shamrock (acquired by Valero in 2001). The Company is seeking 5.75 cents per gallon for motor gasolines infringing one or more claims under the patents and a trebling of the amount for willful infringement. The Company is also seeking a mandatory licensing of its patents by Valero with respect to future activities.

Proceedings in both of the Company's lawsuits have been temporarily suspended pending the outcome of the reexamination of the patents discussed below.

In 2001, petitions were filed with the U.S. Patent and Trademark Office ("PTO") by Washington, D.C., law firms, acting on behalf of unnamed parties, requesting reexaminations of the `393 and `126 patents based on the existence of alleged "prior art". In 2002, the PTO initially rejected all of the claims of the two patents as part of the reexamination process. The PTO subsequently granted a second request for reexamination of the `393 patent based on additional alleged prior art and later rejected all of the claims of the `393 patent in a non-final "Office Action." In March 2003, the Company filed a response to this rejection, including an appeal within the PTO, which was followed by yet a third reexamination request. The Company is now awaiting an action from the USPTO in this reexamination. Likewise the Company is awaiting a response from the PTO to its submission arguing against the initial rejection of the `126 patent.

A second reexamination request of the `126 patent has been made, and it was merged with the first. The completion of the reexamination processes, including appeals within the PTO, is expected to take several months, but the Company believes the claims of both patents are novel and non-obvious and expects them ultimately to be sustained. Licensing fees and judgments collected during the pendency of the reexaminations are not refundable.

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

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

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

The Company will continue to vigorously contest this action and believes that it did not engage in misleading or deceptive practices before the CARB.

COMPETITION

The energy resource industry is highly competitive around the world. As an independent oil and gas exploration and production company, Unocal competes against integrated oil and gas companies, independent oil and gas companies, government-owned oil and gas companies, individual producers, marketing companies and operators for finding, developing, producing, transporting and marketing oil and gas resources. The Company believes that it is in a position to compete effectively. Competition occurs in bidding for U.S. prospective leases or international exploration rights, acquisition of geological, geophysical and engineering knowledge, and the cost-efficient exploration, development, production, transportation, and marketing of oil and gas. The future availability of prospective leases/concessions is subject to competing land uses and federal, state, foreign and local statutes and policies. The principal factors affecting competition for the energy resource industry are oil and gas sales prices, demand, worldwide production levels, alternative fuels and government and environmental regulations. The Company's geothermal and power operations are in competition with producers of other energy resources.

EMPLOYEES

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

GOVERNMENT REGULATION

As a lessee from the U.S. government, Unocal is subject to Department of the Interior Minerals Management Service regulations covering activities onshore and on the Outer Continental Shelf ("OCS"). In addition, state regulations impose strict controls on both state-owned and privately-owned lands.

Some federal and state bills would, if enacted, significantly and adversely affect Unocal and the petroleum industry. These include the imposition of additional taxes, land use controls, prohibitions against operating in certain foreign countries and restrictions on exploration and development.

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

Regulations promulgated by the Environmental Protection Agency ("EPA"), the Department of the Interior, the Department of Energy, the State Department, the Department of Commerce and other government agencies are complex and subject to change. New regulations may be adopted. The Company cannot predict how existing regulations may be interpreted by enforcement agencies or court rulings, whether amendments or additional regulations will be adopted, or what effect such changes may have on its current or future business or financial condition.

ENVIRONMENTAL REGULATION

Federal, state and local laws and provisions regulating the discharge of materials into the environment or otherwise relating to environmental protection have continued to impact the Company's operations. Significant federal legislation applicable to the Company's operations includes the following: the Clean Water Act, as amended in 1977; the Clean Air Act, as amended in 1977 and 1990; the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"); the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended in 1986; the Oil Pollution Act of 1990; and laws governing low level radioactive materials. Various foreign, state and local governments have adopted or are considering the adoption of similar laws and regulations. The Company believes that it can continue to meet the requirements of existing environmental laws and regulations. The following discussion describes the nature and impact of the laws and regulations that may have a material affect on the Company.

The Clean Water Act, as amended in 1977, requires all oil and gas exploration and production facilities, as well as mining and other operations, of the Company and its subsidiaries to eliminate or meet stringent permit standards for the discharge of pollutants into the waters of the United States from both point sources and from storm water runoff. The act requires the Company to construct and operate waste water treatment systems and injection wells; to transport and dispose of onshore spent drilling muds and other associated wastes; to monitor compliance with permit requirements; and to implement other control and preventive measures. Requirements under the act have become more stringent in recent years and now include increased control of toxic discharges.

The Clean Air Act, as amended in 1977 and 1990, and its regulations require, among other things, enhanced monitoring of major sources of specified pollutants; stringent air emission limits on the Company's marine terminals, mining operations and other facilities; and risk management plans for storage of hazardous substances. Title V of the act requires major emission sources to obtain new permits. Title V also requires more comprehensive measurement of specified air pollutants from major emission sources. Title V has a significant impact on Company monitoring, recording and reporting requirements ("MR&R"). MR&R involves periodic reporting such as semi-annual monitoring reports, permit deviation reports and annual compliance

certifications. Failure to properly file these reports may result in a Notice of Violation and possible fine. The Risk Management Plan regulations under the Clean Air Act require that any non-exempted facility that processes or stores a threshold amount of a regulated substance prepare and implement a risk management plan to detect, prevent and minimize accidental releases.
The regulations require undertaking an offsite hazard assessment, preparing a response plan and communication with the local community. The Company has risk management plans in place for these potential hazards.

Under the Clean Air Act, the EPA is required to adopt a number of national air toxic reduction programs that address hazardous air pollutants, also known as "HAPs." One of these programs is the adoption of Maximum Achievable Control Technology ("MACT") for large HAP sources. Once the EPA has issued all of the MACT standards, it is required to conduct a health risk assessment and revise the standards if it is shown to be necessary to protect public health. The EPA must promulgate regulations establishing emission standards for about 175 categories of HAP sources. The standards require the maximum degree of emission reduction that the EPA determines to be achievable for each particular source category. Different MACT criteria are applicable for new and for existing sources. Under the act, the EPA is required to develop and implement a program for assessing the risk remaining ("residual risk") after facilities have implemented MACT standards. The EPA has finalized MACT control requirements for certain categories of oil and gas production and gas transmission and storage facilities. There are pending MACT regulations under the categories of Organic Liquids Distribution, Combustions, Turbines, Industrial Boilers and Heaters and Reciprocating Internal Combustion Engines. In order to comply with National Ambient Air Quality Standards, which were promulgated to protect public health, some states and the proposed MACT rules will require large reductions in the emission of nitrogen oxides and carbon monoxide. This will require the addition of significant new controls and associated MR&R.

The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"), regulates the storage, handling, treatment, transportation and disposal of hazardous and nonhazardous wastes. It also requires the investigation and remediation of certain locations at several former Company facilities, where such wastes have been handled, released or disposed. RCRA requirements have become increasingly stringent in recent years and the EPA has expanded the definition of hazardous wastes. Company facilities generate and handle a number of wastes regulated by RCRA and have facilities that have been used for the storage, handling or disposal of RCRA wastes that are subject to investigation and corrective action. The Company must provide financial assurance for future closure and post-closure costs of its RCRA-permitted facilities and for potential third-party liability. Management of wastes from the exploration and production of oil and gas are typically classified as non-hazardous oil field wastes regulated by the states rather than the EPA. Subchapter IX regulates underground storage tanks, including corrective action for releases and financial assurance for corrective action and third-party liability. This subchapter and similar state laws, such as the California Health and Safety Code, the Texas Administrative Code, Title 30 (Environmental Quality), and the Alaska Administrative Code, Title 18 (Environmental Conservation), impact the cleanup of the Company's former service stations and other facilities.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended in 1986, provides that waste generators, site owners, facility operators and certain other parties may be strictly and jointly and severally liable for the costs of addressing sites contaminated by spills or waste disposal regardless of fault or the amount of waste sent to a site. Additionally, each state has laws similar to CERCLA. A federal tax on oil and certain chemical products was enacted to fund a part of the CERCLA program, but this tax has been suspended for several years while CERCLA reform legislation is debated in the U.S. Congress. At year-end 2003, the Company had been identified as a Potentially Responsible Party ("PRP") under CERCLA at approximately 26 sites by the EPA and various state agencies and private parties had identified the Company as a PRP at 20 other similar sites. A PRP has strict and joint and several liability for site remediation and agency oversight costs and so the Company may be required to assume, among other costs, all or portions of the shares attributed to insolvent, unidentified or other parties. The Company does not anticipate that its ultimate exposure at these sites individually, or in the aggregate, will have a material adverse impact on the Company's financial condition or liquidity, but could have a material adverse impact on results of operations.

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

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

- The Toxic Substances Control Act of 1976, as amended in 1986, regulates the development, testing, import, export and introduction of new chemical products into commerce.

- SARA Title III, the Emergency Planning and Community Right-to-Know Act of 1986, requires the Company to prepare emergency planning and spill notification plans, as well as public disclosure of chemical usage and emissions.

- The Safe Drinking Water Act and related state programs regulate underground injection control wells, including those used for the injection of fluids brought to the surface in connection with oil and gas production or for secondary or tertiary recovery of oil and gas.

- The Atomic Energy Act and related federal and state laws have a significant impact on the mining operations and former processing plants of the Company's Molycorp subsidiary. These laws govern management of low level radioactive waste materials associated with mineral production and licensing and decommissioning of facilities, as well as naturally occurring radioactive materials from oil and gas operations. These laws also require the Company to provide financial assurances related the decommissioning of facilities and waste disposal.

Environmental regulatory requirements impacting the cleanup of petroleum release sites may also include state and local laws, including the California Safe Drinking Water and Toxic Enforcement Act ("Proposition 65"), the federal and state Endangered Species Acts and the Archaeological and Historic Preservation Act of 1974, which protects certain archaeological and historical areas from destruction.

The Company has been a party to a number of administrative and judicial proceedings under federal, state and local provisions relating to environmental protection. These proceedings include actions for civil penalties or fines for alleged environmental violations; orders to investigate and/or cleanup past environmental contamination under CERCLA or other laws; closure of waste management facilities under RCRA or decommissioning of facilities under radioactive materials licenses; permit proceedings; and variance requests under air, water or waste management laws and similar matters.

In 1997, the Third Conference of the Parties to the United Nations Framework Convention on Climate Change adopted the Kyoto Protocol, which sets legally binding commitments for developed, but not developing, nations to reduce their emissions of greenhouse gases (GHG) by 2008-2012. The Kyoto Protocol will come into force upon ratification by 55 parties, including developed country parties representing 55 percent of developed country emissions of GHG in 1990. At year-end 2003, the Kyoto Protocol had not achieved sufficient ratification to bring it into force. Currently, 120 developed and developing countries have ratified the Kyoto Protocol and its entry into force is now pending Russia's ratification. Among the developed countries that have ratified the Kyoto Protocol, Unocal currently conducts operations in Canada and the Netherlands. The United States has indicated that it does not intend to ratify the Kyoto Protocol, but it may take appropriate domestic action to reduce GHG emissions. Some states have either passed or proposed GHG-related legislation, including limited, but mandatory, emission reduction requirements. In addition, GHG-related legislation is being considered in Congress. Although the Kyoto Protocol's fate is uncertain, the European Union has indicated that its GHG cap-and-trade Emissions Trading System (ETS), which is set to start in 2005, will proceed. Other developed countries that have ratified have made similar commitments. Unocal also operates in many developing countries, primarily Thailand, Indonesia, Philippines, Bangladesh, China and Vietnam, where the Kyoto Protocol GHG reduction commitments or similar regulations are not expected to be adopted for some time. Although it is not possible to estimate the cost of complying with the emerging foreign and U.S. climate change programs, such costs could be substantial.

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

For information regarding the Company's environment-related capital expenditures, charges to earnings, reserves for probable environmental remediation liabilities and possible future environmental cost exposures, see

Item 3 - Legal Proceedings, the Environmental Matters section of Management's Discussion and Analysis in Item 7 of this report and notes 20 and 24 to the consolidated financial statements in Item 8 of this report.

PART IV

ITEM 15 - EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

The exhibit index below lists the exhibits that are filed as part of this amendment.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this amendment to be signed on its behalf by the undersigned, thereunto duly authorized.

UNOCAL CORPORATION
(Registrant)

Dated: April 21, 2004

By: /s/ TERRY G. DALLAS

Terry G. Dallas
Executive Vice President
and Chief Financial Officer

EXHIBIT INDEX

Exhibit 31.1 CEO certifications pursuant to Exchange Act Rule 13a-14(a).

Exhibit 31.2 CFO certifications pursuant to Exchange Act Rule 13a-14(a).

Copies of exhibits will be furnished upon request. Requests should be addressed to the Corporate Secretary.

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EXHIBIT 31.1

CERTIFICATIONS

I, Charles R. Williamson, certify that:

1. I have reviewed this Amendment No. 1 to the annual report on Form 10-K/A of Unocal Corporation for the fiscal year ended December 31, 2003;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. [not applicable]

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

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

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 21, 2004

/s/CHARLES R. WILLIAMSON

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

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EXHIBIT 31.2

CERTIFICATIONS

I, Terry G. Dallas, certify that:

1. I have reviewed this Amendment No. 1 to the annual report on Form 10-K/A of Unocal Corporation for the fiscal year ended December 31, 2003;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. [not applicable]

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

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

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 21, 2004

/s/ TERRY G. DALLAS

Terry G. Dallas
Executive Vice President
and Chief Financial Officer

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