BLACKROCK CALIFORNIA MUNICIPAL INCOME TRUST
Form N-Q
September 29, 2004

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

FORM N-Q

QUARTERLY SCHEDULE OF PORTFOLIO HOLDINGS OF REGISTERED MANAGEMENT INVESTMENT COMPANY

Investment Company Act file number: 811-10331

BlackRock California Municipal Income Trust

(Exact name of registrant as specified in charter)

100 Bellevue Parkway, Wilmington, DE	19809
(Address of principal executive offices)	(Zip code)

Robert S. Kapito, President
BlackRock California Municipal Income Trust
40 East 52nd Street, New York, NY 10022

(Name and address of agent for service)

Registrant's telephone number, including area code: 888-825-2257

Date of fiscal year end: October 31, 2004

Date of reporting period: July 31, 2004

Item 1. Schedule of Investments

The Trust's schedule of investments pursuant to Rule 30b1-5 under the Investment Company Act of 1940 is as follows:

PORTFOLIO OF INVESTMENTS (unaudited)
JULY 31, 2004

BlackRock California Municipal Income Trust (BFZ)

Rating[1]	Principal Amount (000)	Description	Option Call Provisions[2]	Value
		LONG-TERM INVESTMENTS 160.5%		
		California 136.9%		
		Anaheim Pub. Fin. Auth., Pub. Impvt. Proj., Ser. C, FSA,		
AAA	$24,500	Zero Coupon, 9/01/31	No Opt. Call	$ 5,125,155
AAA	6,070	Zero Coupon, 9/01/32	No Opt. Call	1,195,062
		California, GO,		
A3	10,000	5.50%, 11/01/33	11/13 @ 100	10,285,900
AAA	5,500	Ser. BZ, 5.35%, 12/01/21, MBIA	06/07 @ 101	5,565,835
AAA	5,000	Ser. BZ, 5.375%, 12/01/24, MBIA	06/07 @ 101	5,031,350
		California Cnty. Tobacco Sec. Agcy.,		
BBB	6,000	Fresno Cnty. Fdg. Corp., 6.00%, 6/01/35	06/12 @ 100	4,921,860
BBB	6,000	Kern Cnty. Corp., Ser. B, 6.25%, 6/01/37	06/12 @ 100	5,055,600
Baa3	5,000	Stanislaus Fdg., Ser. A, 5.875%, 6/01/43	06/12 @ 100	3,931,050
		California Dept. of Wtr. Res., Pwr. Sply. Rev., Ser. A,		
A2	4,000 [3]	5.375%, 5/01/21	05/12 @ 101	4,168,920
A2	6,000	5.375%, 5/01/22	05/12 @ 101	6,244,680
AAA	10,000	California Edl. Facs. Auth., Stanford Univ., Ser. Q, 5.25%, 12/01/32	06/11 @ 101	10,166,500
		California Hlth. Facs. Fin. Auth., Ser. A,		
BBB	3,000	Insured Hlth. Facs. Valleycare, 5.375%, 5/01/27	05/12 @ 100	3,006,330
AAA	4,890	Kaiser Proj., 5.40%, 5/01/28	ETM	5,038,852
		California Hsg. Fin. Agcy.,		
AAA	14,065	Ser. B, Zero Coupon, 8/01/31, FSA	08/04 @ 5.001	3,145,216
AAA	15,945	Home Mtg. Rev., Ser. Q, Zero Coupon, 2/01/33, AMBAC	08/04 @ 3.951	3,169,228
AAA	19,185	Home Mtg. Rev., Ser. T, Zero Coupon, 8/01/21, MBIA	08/04 @ 15.292	7,502,294
		California Infrastructure & Econ. Dev.,		
AAA	15,000	Bay Area Toll Brdgs., Ser. A, 5.00%, 7/01/36, AMBAC	07/13 @ 100	14,933,100
A-	15,250	J. David Gladstone Inst. Proj., 5.25%, 10/01/34	10/11 @ 101	14,846,790
A	13,500	Kaiser Hosp. Asst. LLC, Ser. A, 5.55%, 8/01/31	08/11 @ 102	13,712,355
AA-	10,000	California Statewide Cmnty. Dev. Auth., Sutter Hlth. Oblig. Grp., Ser. B, 5.625%, 8/15/42	08/12 @ 100	10,164,900
A-	5,000	Daly City Hsg. Dev. Fin. Agcy., Sr. Franciscan Acquisition Proj., Ser. A, 5.85%, 12/15/32	12/13 @ 102	5,103,650
AAA	6,000	El Monte Sr. Dept. of Pub. Svcs., Fac. Phase II, COP, 5.25%, 1/01/34, AMBAC	01/11 @ 100	6,099,900
		Elk Grove Unified Sch. Dist., Cmnty. Facs. Dist. 1, Spec. Tax, AMBAC,		
AAA	7,485	Zero Coupon, 12/01/29	12/11 @ 37.373	1,690,412
AAA	7,485	Zero Coupon, 12/01/30	12/11 @ 35.365	1,593,781
AAA	7,485	Zero Coupon, 12/01/31		1,498,647

			12/11 @ 33.465	
		Foothill/Eastn. Transp. Corridor Agcy., Toll Road Rev.,		
BBB-	5,000	Zero Coupon, 1/15/33	01/10 @ 25.78	862,000
BBB-	5,000	Zero Coupon, 1/15/34	01/10 @ 24.228	810,150
BBB-	13,445	Zero Coupon, 1/15/35	01/10 @ 22.819	2,041,355
BBB-	1,000	Zero Coupon, 1/15/38	01/10 @ 19.014	125,170
BBB-	10,030	5.75%, 1/15/40	01/10 @ 101	9,969,920
		Golden St. Tobacco Sec. Corp.,		
BBB	2,000	Ser. A-1, 6.625%, 6/01/40	06/13 @ 100	1,762,780
BBB	1,000	Ser. A-1, 6.75%, 6/01/39	06/13 @ 100	899,550
Baa1	10,200	Ser. B, 5.50%, 6/01/43	06/13 @ 100	10,214,688
Baa1	5,800	Ser. B, 5.625%, 6/01/38	06/13 @ 100	5,858,580
NR	5,000	Irvine Mobile Home Park, Meadows Mobile Home Park, Ser. A, 5.70%, 3/01/28	03/08 @ 102	4,843,600
A3	7,700	Kaweah Delta Hlth. Care Dist. Rev., 6.00%, 8/01/34	08/12 @ 102	8,031,408
		Lathrop Fin. Auth., Wtr. Sply. Proj.,		
NR	2,855[4]	5.90%, 6/01/27	06/13 @ 100	2,812,518
NR	5,140[4]	6.00%, 6/01/35	06/13 @ 100	5,142,004
Caa2	4,110	Los Angeles Regl. Arpt. Impvt., Corp. Lease Rev., Amer. Airlines Inc., Ser. C,		
		7.50%, 12/01/24	12/12 @ 102	3,493,705
BBB	1,000	Palm Springs Mobile Home Park., Sahara Mobile Home Park, 5.625%, 5/15/26	05/12 @ 102	986,910
NR	4,000	Rancho Cucamonga Cmnty. Facs. Dist., Ser. A, 6.50%, 9/01/33	09/13 @ 100	4,156,880
AAA	15,500	Rancho Cucamonga Redev. Agcy., Tax Alloc. Rev., Rancho Redev. Proj.,		
		5.125%, 9/01/30, MBIA	09/11 @ 100	15,585,095
AAA	1,905	Richmond Wst. & Wtr., Zero Coupon, 8/01/31, FGIC	No Opt. Call	411,156

BlackRock California Municipal Income Trust (BFZ) (continued)

Rating[1]	Principal Amount (000)	Description	Option Call Provisions[2]	Value
		California (continued)		
AAA	$ 6,500	San Francisco City & Cnty. Arpt. Comm., Intl. Arpt. Rev., Ser. 27-A,		
		5.25%, 5/01/31, MBIA	05/11 @ 100	$ 6,520,605
		San Francisco City & Cnty. Redev. Agcy., Cmnty. Facs. Dist., Mission Bay South,		
NR	1,775	6.125%, 8/01/31	08/09 @ 102	1,793,549
NR	7,500	6.25%, 8/01/33	08/11 @ 101	7,579,725
		San Jose Multi-Fam. Hsg.,		
AAA	2,880	Lenzen Hsg., Ser. B, 5.45%, 2/20/43	08/11 @ 102	2,923,056
AAA	4,225	Vlgs. Pkwy. Sr. Apts., Ser. D, 5.50%, 4/01/34	04/11 @ 100	4,288,121
		Santa Clara Cnty. Hsg. Auth., Multi-Fam. Hsg., Ser. A,		
NR	6,250	Blossom River Apts., 6.50%, 9/01/39	03/08 @ 102	5,992,250
A3	1,715	John Burns Gardens Apts. Proj., 5.85%, 8/01/31	02/12 @ 101	1,725,238
A3	1,235	River Town Apts. Proj., 6.00%, 8/01/41	02/12 @ 101	1,247,165
NR	3,075	Santa Clarita Facs. Dist., Valencia Town Ctr., 5.85%, 11/15/32	11/10 @ 102	3,084,686
BBB	5,345	Tobacco Sec. Auth. No. California, Tobacco Settlement Rev., Ser. A, 5.375%, 6/01/41	06/11 @ 100	3,883,303
		Tobacco Sec. Auth. So. California, Tobacco Settlement Rev., Ser. A,		
BBB	7,000	5.50%, 6/01/36	06/12 @ 100	5,426,610

BBB	11,500	5.625%, 6/01/43	06/12 @ 100	8,683,305
AAA	2,000	Upland Unified Sch. Dist., GO, Ser. B, 5.125%, 8/01/25, FSA	08/13 @ 100	2,039,680
NR	2,245	Val Verde Unified Sch. Dist. Fin. Auth., Spec. Tax Rev., 6.25%, 10/01/28	10/13 @ 102	2,299,127
A2	2,000	Vernon Elec. Sys., Malburg Generating Station Proj., 5.50%, 4/01/33	04/08 @ 100	2,014,300
				290,705,556
		Delaware 5.6%		
		Charter Mac Equity Issuer Trust,		
A3	7,000[5]	Ser. A-2, 6.30%, 6/30/49	06/09 @ 100	7,574,350
Baa1	4,000[5]	Ser. B-1, 6.80%, 11/30/50	11/10 @ 100	4,401,720
				11,976,070
		Maryland 5.0%		
		MuniMae TE Bond Subsidiary, LLC,		
NR	7,000[4,5]	Ser. A, 6.30%, 6/30/49	06/09 @ 100	7,491,540
NR	3,000[4,5]	Ser. B, 6.80%, 6/30/50	11/10 @ 100	3,219,720
				10,711,260
		Puerto Rico 13.0%		
A-	10,000	Puerto Rico Elec. Pwr. Auth., Ser. 2, 5.25%, 7/01/31	07/12 @ 101	10,064,800
		Puerto Rico Pub. Fin. Corp., Ser. E,		
BBB+	10,000[6]	5.70%, 2/01/10	N/A	11,249,900
BBB+	5,750[6]	5.75%, 2/01/07	N/A	6,235,013
				27,549,713
				340,942,599
		Total Long-Term Investments (cost $340,715,386)		

BlackRock California Municipal Income Trust (BFZ) (continued)

Shares (000)	Description	Value
	MONEY MARKET FUND 3.8%	
7,950	AIM Tax Free Investment Co. Cash Reserve Portfolio, (cost $7,950,000)	$ 7,950,000
	Total Investments 164.3% (cost $348,665,386)	348,892,599
	Liabilities in excess of other assets (2.2)%	(4,553,394)
	Preferred shares at redemption value, including dividends payable (62.1)%	(131,959,546)
	Net Assets Applicable to Common Shareholders 100%	$ 212,379,659

[1]Using the higher of Standard & Poor's, Moody's Investors Service or Fitch Ratings ratings.

[2]Date (month/year) and price of the earliest call or redemption. There may be other call provisions at varying prices at later dates.

[3]Entire or partial principal amount pledged as collateral for financial futures contracts.

[4]Security is deemed to be of investment grade quality by the investment advisor.

[5]Security is not registered under the Securities Act of 1933. These securities may be resold in transactions in accordance with Rule 144A under that Act, to qualified institutional buyers. As of July 31, 2004, the Trust held 10.7% of its net assets, with a current market value of $22,687,330, in securities restricted as to resale.

[6]This bond is prerefunded. Securities held in escrow are used to pay interest on this security, as well as to retire the bond in full at the date indicated, typically at premium to par.

KEY TO ABBREVIATIONS

AMBAC	—	American Municipal Bond Assurance Corporation	FSA	—	Financial Security Assurance
COP	—	Certificate of Participation	GO	—	General Obligation
ETM	—	Escrowed to Maturity	MBIA	—	Municipal Bond Insurance Association
FGIC	—	Financial Guaranty Insurance Company			

Item 2. Controls and Procedures

(a) The registrant's principal executive officer and principal financial officer have evaluated the registrant's disclosure controls and procedures within 90 days of this filing and have concluded that the registrant's disclosure controls and procedures are effective, as of that date, in ensuring that information required to be disclosed by the registrant in this Form N-Q was recorded, processed, summarized, and reported timely.

(b) The registrant's principal executive officer and principal financial officer are aware of no changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

Item 3. Exhibits.

(a) Separate certifications of Principal Executive and Financial Officers pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934 and the Investment Company Act of 1940, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

(Registrant) BlackRock California Municipal Income Trust

By: /s/ Henry Gabbay

Name: Henry Gabbay
Title: Treasurer
Date: September 28, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934 and the Investment Company Act of 1940, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By: /s/ Robert S. Kapito

Name: Robert S. Kapito
Title: Principal Executive Officer
Date: September 28, 2004

By: /s/ Henry Gabbay

Name: Henry Gabbay
Title: Principal Financial Officer
Date: September 28, 2004

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eir treatment plant costs, as well as certain other costs. The Company, Tosco Corporation (now a unit of Phillips Petroleum Company) and other defendants, but not the Shell defendants, have been invited to participate in this settlement. The Company is evaluating its position with regard to participation, which would involve its paying the City $7.5 million and contributing to the costs of the treatment plant. However, based on a rigorous technical analysis of the data, the Company believes it has strong defenses to the allegations in the complaint, including the lack of evidence that its former service stations or activities are responsible for any contamination that has reached or threatens the wellfield. The Company also believes it has certain available defenses that the settling defendants and others may not have due to tolling agreements they entered into with the City; and, unlike the Shell defendants and the settling defendants, the Company is neither the object of punitive damages claims nor a cause of the wellfield's being originally shut down. The Company is also subject to potential partial responsibility for liabilities arising from its former gasoline marketing business that was sold to Tosco in 1997. The Company's current analysis does not indicate any such liabilities are likely to be significant. For several years prior to the City's suit, the EPA and the California Regional Water Quality Control Board have asserted jurisdiction over contamination of groundwater potentially affecting the wellfield, and these agencies have issued a number of orders under RCRA and state law to the Shell defendants and the other defendant oil companies, including the Company, with respect to both investigation of individual facilities and regional contamination, and requiring replacement of water lost to the City, which Shell is currently providing. The impact of the proposed settlement in the City's lawsuit on future government agency actions is uncertain. The Company has submitted to these agencies several technical analyses, which it believes demonstrate that its sites are not a part of any regional contamination problem, but, rather, present, at the most, localized issues which the Company, under agency oversight, has been successfully resolving. Agrium Litigation: In June 2002, a lawsuit was filed against the Company by Agrium Inc., a Canadian corporation, and a U. S. subsidiary in the California Superior Court, Los Angeles County (Agrium U.S. Inc. and Agrium Inc. v. Union Oil Company of California, Case No. BC275407). The Company subsequently removed the case to the U.S. District Court for the Central District of California (Case No. 02-04769 Nm). The Agrium entities ("Agrium") allege numerous causes of action relating to their purchase from the Company of a nitrogen-based fertilizer plant on the Kenai Peninsula, Alaska, in September 2000. The primary allegations involve the Company's obligation to supply natural gas to the plant pursuant to a Gas Purchase and Sale Agreement (the "GPSA") between the parties. Agrium alleges that the Company misrepresented the amount of gas reserves available for sale to the plant as of the closing of the transaction and that the Company has failed to develop additional reserves for sale to the plant. Agrium also alleges that -13- the Company misrepresented the condition of the general effluent sewer at the plant and made misrepresentations regarding other environmental matters. Agrium seeks damages in an unspecified amount for breach of such representations and warranties, as well as for alleged misconduct by the Company in operating and managing certain oil and gas leases and other facilities. Agrium also seeks declaratory relief concerning the base price of gas under the GPSA, as well as for the calculation of payments under a "Retained Earnout" covenant that entitles the Company to certain contingent payments based on the price of ammonia subsequent to the September 2000 closing. The complaint includes demands for punitive damages and attorneys' fees. Also in June 2002, the Company filed a lawsuit against Agrium in the U.S.

District Court for the Central District of California (Union Oil Company of California v. Agrium Inc. and Agrium U.S. Inc., Case No. 02-04518 Nm(Ctx)). The Company seeks declaratory relief in its favor against the allegations of Agrium set forth above and for judgment on the Retained Earnout in the amount of $16.6 million, together with interest accrued subsequent to May 31, 2002. The Company believes that certain portions of its disputes with Agrium are subject to binding arbitration under the terms of the GPSA, and has initiated arbitration respecting the gas supply available under that agreement. Agrium claims the dispute resolution provisions of the agreement for the sale of the plant (the "PSA") supersede the arbitration provisions of the GPSA. Agrium has filed motions to stay the Company's lawsuit, to enjoin implementation of the arbitration and for Agrium's lawsuit to be remanded to the state court. A hearing on these motions is set for September 2002. The federal court recently denied a motion by Agrium to temporarily restrain implementation of the arbitration. The GPSA contains a contractual limit on liquidated damages of $25 million per year, not to exceed a total of $50 million over the life of the agreement. In addition, the PSA contains a limit on damages of $50 million. The Company believes it has a meritorious defense to each of the Agrium claims, but that in any event its exposure to damages for all disputes is limited by the agreements. Agrium alleges that it is entitled to recover damages in excess of those amounts. Petrobangla Claim: In July 2002, the Company's subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. (which was acquired in 1999 from Occidental Petroleum Corporation and, prior to the recent completion of Bangladesh name-change formalities, was still known in Bangladesh as Occidental of Bangladesh Ltd.) ("OBL"), received from the Bangladesh Oil, Gas & Mineral Corporation ("Petrobangla") a letter claiming, on behalf of the Bangladesh government and Petrobangla, compensation allegedly due in the amount of $685 million for 246 BCF of recoverable natural gas allegedly "lost and damaged" in a 1997 blowout and ensuing fire during the drilling by OBL, as operator, of the Moulavi Bazar #1 ("MB #1") exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout. Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractors' operations. Even if some form of compensation were due, the Company and OBL believe that settlement compensation for the blowout was fully addressed in a 1998 Supplemental Agreement to the PSC, which, among other matters, waived OBL's then 50-percent contractor's share (as well as the then 50-percent contractor's share held by the Company's Unocal Bangladesh, Ltd., subsidiary) of entitlement to the recovery of costs incurred in the blowout, waived their right to invoke force majeure in connection with the blowout, and reduced by five percentage points their contractors' profit share (with a concomitant increase in Petrobangla's profit share) of future production from the sands encountered by the MB #1 well to a drill depth of 840 meters or, if the blowout sand reservoir were not deemed commercial, from other commercial fields in the Moulavi Bazar "ring-fenced" area of Block 14. Consequently, the Company and OBL consider the matter closed and OBL has advised Petrobangla that no additional compensation is warranted. -14- Tax matters The company believes it has adequately provided in its accounts for tax items and issues not yet resolved. Several prior material tax issues are unresolved. Resolution of these tax issues impact not only the year in which the items arose, but also the company's tax situation in other tax years. With respect to 1979-1984 taxable years, all issues raised for these years have now been settled, with the exception of the effect of the carryback of a 1993 net operating loss ("NOL") to tax year 1984 and resultant credit adjustments. The 1985-1990 taxable years are before the Appeals division of the Internal Revenue Service. All issues raised with respect to those years have now been settled, with the exception of the effect of the 1993 NOL carryback and resultant adjustments. The Joint Committee on Taxation of the U.S. Congress has reviewed the settled issues with respect to 1979-1990 taxable years and no additional issues have been raised. While all tax issues for the 1979-1990 taxable years have been agreed and reviewed by the Joint Committee, these taxable years will remain open due to the 1993 NOL carryback. The 1993 NOL results from certain specified liability losses, which occurred during 1993, and which resulted in a tax refund of $73 million. Consequently, these tax years will remain open until the specified liability loss, which gave rise to the 1993 NOL, is finally determined by the Internal Revenue Service and is either agreed to with the IRS or otherwise concluded in the Tax Court proceeding. In 1999, the United States Tax Court granted Unocal's motion to amend the pleadings in its Tax Court cases to place the 1993 NOL carryback in issue. The 1991-1994 taxable years are now before the Appeals division of the Internal Revenue Service. The 1995-1997 taxable years are under examination by the Internal Revenue Service. Pure Resources, Inc. Employment and Severance Agreements Under circumstances specified in the employment and/or severance agreements entered into between the Company's Pure subsidiary and its officers, each covered officer will have the right to require Pure to purchase its common shares currently held or subsequently obtained by the exercise of any option held by the officer at a calculated "net asset value" per share. The circumstances under which certain officers may exercise this right include the termination of the officer without cause prior to May 25, 2003, termination for any reason after May 24, 2003, a change in control of either Pure or Unocal and other events specified in the agreements. The net asset value per share is calculated by reference to each common share's pro rata amount of the present value of Pure's proved reserves discounted at 10 percent, as defined, times 110 percent, less funded debt, as defined. At June 30, 2002, Pure estimated that the amount it may have to repurchase under these agreements was approximately $92 million, which is reflected as subsidiary stock subject to repurchase on the consolidated balance sheet. The repurchase amount will fluctuate with changes in the net asset value per share. At December 31, 2001, the repurchase amount under these agreements was approximately $70 million. -15- Other matters The Company has a lease agreement relating to its Discoverer Spirit deepwater drillship, with a remaining term of approximately three years and three months at June 30, 2002. In 2001, the Company signed a sublease agreement with a third party for a minimum period of 200 days. The completion of the sublease period is currently estimated to be in September 2002. Under the provisions of the agreement, the third party assumed all of the lease payments to the lessor during the sublease period, which began in December 2001. The drillship has a minimum daily rate of approximately $219,000. The future remaining minimum lease payment obligation, excluding the remaining sublease period, was approximately $240 million at June 30, 2002. In the normal course of business, the Company has performance obligations which are secured by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions but are funded by the Company if exercised. At June 30, 2002, the Company, including its Pure subsidiary, had obtained various surety bonds for approximately $350 million. These surety bonds primarily consisted of bonds for the Company's mining operation discussed in the following paragraph and a bond for $99 million securing the Company's performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten year period that began in January of 1999 and will end in December of 2008. The Company also had obtained approximately $64 million in standby letters of credit at June 30, 2002. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit. In addition, the Company has various other guarantees for approximately $410 million. Approximately $200 million of the $410 million in guarantees would require the Company to obtain a surety bond or a letter of credit, or establish a trust fund if its credit rating drops below investment grade, that is BBB- or Baa3 from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively. Approximately $180 million of the surety bonds, letters of credit and other guarantees that the Company is required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note. As mentioned in the previous paragraph, the Company's Molycorp subsidiary has permits covering discharges from its Questa, New Mexico, molybdenum mine. Obtaining these permits involved the posting by Molycorp of two bonds totaling $152 million that provide financial assurance of completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. These costs are based on estimations provided by agencies of the state of New Mexico. Unocal has indemnified the insurance company that issued the bonds with respect to all amounts that may be drawn against them. The Company has certain investments in entities that it accounts for under the equity method, such as Colonial Pipeline Company. These entities have approximately $1.8 billion of their own debt obligations that are either fully non-recourse or of limited recourse to the Company. Of the total $1.8 billion in equity investee debt, $1.1 billion belongs to the Colonial Pipeline Company, in which the Company holds a 23.44 percent equity interest. The Company guarantees only $27 million of the total $1.8 billion debt obligations. The Company also has other contingent liabilities with respect to litigation, claims and contractual agreements arising in the ordinary course of business. On the basis of management's assessment of the ultimate amount and timing of possible adverse outcomes and associated costs, none of such matters is presently expected to have a material adverse effect on the Company's consolidated financial condition, liquidity or results of operations. -16- 13. Financial Instruments and Commodity Hedging Fair values of debt and other long-term instruments - The estimated fair value of the Company's long-term debt at June 30, 2002, including the current portion, was approximately $3.31 billion. The fair value was based on the discounted amounts of future cash outflows using the rates offered to the Company for debt with similar remaining maturities. The estimated fair value of the

mandatorily redeemable convertible preferred securities of the Company's subsidiary trust was approximately $527 million at June 30, 2002. The fair value was based on the trading prices of the preferred securities on June 28, 2002, as reported to the Company. Commodity hedging activities - During the second quarter of 2002, the Company recognized $1 million in after-tax losses for the ineffectiveness of both cash flow and fair value hedges. For the six months ended June 30, 2002, the earnings impact of ineffectiveness was immaterial. At June 30, 2002, the Company had approximately $9 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future commodity sales for the period beginning July 2002 through October 2004. Of this amount, approximately $3 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months. Foreign currency contracts - At June 30, 2002, the Company had approximately $1 million of after-tax deferred gains in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future foreign currency denominated payment obligations through December 2003. Of this amount, the losses expected to be reclassified to the consolidated earnings statement during the next twelve months are immaterial. Interest rate contracts - At June 30, 2002, the Company had approximately $3 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges of interest rate exposure through September 2012. Of this amount, the losses expected to be reclassified to the consolidated earnings statement during the next twelve months are immaterial. -17- 14. Supplemental Condensed Consolidating Financial Information Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiaries Unocal Capital Trust and Union Oil. Such guarantees are full and unconditional and no subsidiaries of Unocal or Union Oil guarantee these securities. The following tables present condensed consolidating financial information for (a) Unocal (Parent), (b) the Trust, (c) Union Oil (Parent) and (d) on a combined basis, the subsidiaries of Union Oil (non-guarantor subsidiaries). Virtually all of the Company's operations are conducted by Union Oil and its subsidiaries. CONDENSED CONSOLIDATING EARNINGS STATEMENT For the three months ended June 30, 2002 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated
--- Revenues Sales and operating revenues $ - $ - $ 286 $ 1,298 $ (235) $ 1,349 Interest, dividends and miscellaneous income - 9 - 10 (11) 8 Gain (loss) on sales of assets - - 1 (2) - (1)
--- Total revenues - 9 287 1,306 (246) 1,356 Costs and other deductions Purchases, operating and other expenses 1 - 259 836 (240) 856 Depreciation, depletion and amortization - - 93 162 - 255 Impairments - - 21 - - 21 Dry hole costs - - 2 11 - 13 Interest expense 9 1 35 9 (11) 43 Distributions on convertible preferred securities - 8 - - - 8
--- Total costs and other deductions 10 9 410 1,018 (251) 1,196 Equity in earnings of subsidiaries 118 - 198 - (316) - Earnings from equity investments - - 2 49 - 51
--- Earnings from continuing operations before income taxes and minority interests 108 - 77 337 (311) 211
--- Income taxes (3) - (41) 139 - 95 Minority interests - - - 1 2 3
--- Earnings from continuing operations 111 - 118 197 (313) 113 Earnings from discontinued operations - - - 1 - 1
--- Net earnings $ 111 $ - $ 118 $ 198 $ (313) $ 114
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-18- CONDENSED CONSOLIDATING EARNINGS STATEMENT For the three months ended June 30, 2001 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated
--- Revenues Sales and operating revenues $ - $ - $ 487 $ 1,604 $ (407) $ 1,684 Interest, dividends and miscellaneous income - 9 4 8 (10) 11 Gain on sales of assets - - 1 - - 1
--- Total revenues - 9 492 1,612 (417) 1,696 Costs and other deductions Purchases, operating and other expenses 1 - 272 1,112 (417) 968

Depreciation, depletion and amortization - - 91 154 - 245 Dry hole costs - - 24 23 - 47 Interest expense 9 1 40 8 (10) 48 Distributions on convertible preferred securities - 8 - - - 8 -- Total costs and other deductions 10 9 427 1,297 (427) 1,316 Equity in earnings of subsidiaries 252 - 202 - (454) - Earnings from equity investments - - 10 39 - 49 -- Earnings from continuing operations before income taxes and minority interests 242 - 277 354 (444) 429 -- Income taxes (4) - 37 147 - 180 Minority interests - - - 5 9 14 -- Earnings from continuing operations 246 - 240 202 (453) 235 Earnings from discontinued operations - - 12 - - 12 Cumulative effect of accounting change - - - - - - -- Net earnings $ 246 $ - $ 252 $ 202 $ (453) $ 247 ==

-19- CONDENSED CONSOLIDATING EARNINGS STATEMENT For the six months ended June 30, 2002 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated -- Revenues Sales and operating revenues $ - $ - $ 495 $ 2,279 $ (401) $ 2,373 Interest, dividends and miscellaneous income - 17 7 15 (19) 20 Gain (loss) on sales of assets - - 14 (13) - 1 -- Total revenues - 17 516 2,281 (420) 2,394 Costs and other deductions Purchases, operating and other expenses 3 - 486 1,470 (402) 1,557 Depreciation, depletion and amortization - - 180 299 - 479 Impairments - - 21 - - 21 Dry hole costs - - 17 24 - 41 Interest expense 17 1 78 18 (20) 94 Distributions on convertible preferred securities - 16 - - - 16 -- Total costs and other deductions 20 17 782 1,811 (422) 2,208 Equity in earnings of subsidiaries 148 - 326 - (474) - Earnings from equity investments - - 2 86 - 88 -- Earnings from continuing operations before income taxes and minority interests 128 - 62 556 (472) 274 -- Income taxes (7) - (86) 228 - 135 Minority interests - - - 3 1 4 -- Earnings from continuing operations 135 - 148 325 (473) 135 Earnings from discontinued operations - - - 1 - 1 Cumulative effect of accounting change - - - - - - -- Net earnings $ 135 $ - $ 148 $ 326 $ (473) $ 136 ==

-20- CONDENSED CONSOLIDATING EARNINGS STATEMENT For the six months ended June 30, 2001 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated -- Revenues Sales and operating revenues $ - $ - $ 1,180 $ 3,686 $ (976) $ 3,890 Interest, dividends and miscellaneous income 5 17 3 13 (19) 19 Gain on sales of assets - - 1 - - 1 -- Total revenues 5 17 1,184 3,699 (995) 3,910 Costs and other deductions Purchases, operating and other expenses 2 - 667 2,734 (997) 2,406 Depreciation, depletion and amortization - - 177 291 - 468 Impairments - - - - - - Dry hole costs - - 34 53 - 87 Interest expense 17 1 85 13 (19) 97 Distributions on convertible preferred securities - 16 - - - 16 -- Total costs and other deductions 19 17 963 3,091 (1,016) 3,074 Equity in earnings of subsidiaries 551 - 413 - (964) - Earnings from equity investments - - 8 83 - 91 -- Earnings from continuing operations before income taxes and minority interests 537 - 642 691 (943) 927

-- Income taxes (5) - 106 269 - 370 Minority interests - - - 9 21 30
-- Earnings from continuing operations 542 - 536 413 (964) 527 Earnings from discontinued operations - - 16 - - 16 Cumulative effect of accounting change - - (1) - - (1)
-- Net earnings $ 542 $ - $ 551 $ 413 $ (964) $ 542
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-21- CONDENSED CONSOLIDATING BALANCE SHEET At June 30, 2002 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated
-- Assets Current assets Cash and cash equivalents $ 1 $ - $ 61 $ 99 $ - $ 161 Accounts and notes receivable - net 51 - 56 792 (62) 837 Inventories - - 9 102 - 111 Other current assets - - 130 31 - 161
-- Total current assets 52 - 256 1,024 (62) 1,270 Investments and long-term receivables - net 4,123 - 4,455 1,078 (8,170) 1,486 Properties - net - - 2,141 5,600 - 7,741 Other assets 3 541 456 2,130 (2,834) 296
-- Total assets $4,178 $ 541 $ 7,308 $ 9,832 $ (11,066) $ 10,793
==
Liabilities and Stockholders' Equity Current liabilities Accounts payable $ - $ - $ 242 $ 637 $ (51) $ 828 Current portion of long-term debt and capital leases - - - 8 - 8 Other current liabilities 46 3 144 372 40 605
-- Total current liabilities 46 3 386 1,017 (11) 1,441 Long-term debt and capital leases - - 2,489 622 - 3,111 Deferred income taxes - - (20) 698 - 678 Accrued abandonment, restoration and environmental liabilities - - 305 282 - 587 Other deferred credits and liabilities 541 - 376 2,695 (2,890) 722 Subsidiary stock subject to repurchase - - - 92 - 92 Minority interests - - - 313 117 430 Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures - 522 - - - 522 Stockholders' equity 3,591 16 3,772 4,113 (8,282) 3,210
-- Total liabilities and stockholders' equity $4,178 $ 541 $ 7,308 $ 9,832 $ (11,066) $ 10,793
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-22- CONDENSED CONSOLIDATING BALANCE SHEET At December 31, 2001 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated
-- Assets Current assets Cash and cash equivalents $ - $ - $ 62 $ 128 $ - $ 190 Accounts and notes receivable - net 51 - 154 693 (51) 847 Inventories - - 3 99 - 102 Other current assets - - 122 34 - 156
-- Total current assets 51 - 341 954 (51) 1,295 Investments and long-term receivables - net 4,032 - 4,143 968 (7,738) 1,405 Properties - net - - 2,149 5,365 - 7,514 Other assets 3 541 214 2,403 (2,950) 211
-- Total assets $4,086 $ 541 $ 6,847 $ 9,690 $ (10,739) $ 10,425
==
Liabilities and Stockholders' Equity Current liabilities Accounts payable $ - $ - $ 278 $ 596 $ (51) $ 823 Current portion of long-term debt and capital leases - - - 9 - 9 Other current liabilities 42 3 145 400 - 590
-- Total current liabilities 42 3 423 1,005 (51) 1,422 Long-term debt and capital leases - - 2,181 716 - 2,897 Deferred income taxes - - (71) 698 - 627 Accrued abandonment, restoration and environmental liabilities - - 293 297 - 590 Other deferred credits and liabilities 541 - 312 2,821 (2,950) 724 Subsidiary stock subject to repurchase - - - 70 - 70 Minority interests - - - 309 140 449 Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures - 522 - - - 522 Stockholders' equity 3,503 16 3,709 3,774 (7,878) 3,124
-- Total liabilities and stockholders' equity $4,086 $ 541 $ 6,847 $ 9,690 $ (10,739) $ 10,425

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-23- CONDENSED CONSOLIDATING CASH FLOWS For the six months ended June 30, 2002 Unocal Non-Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated --- Cash Flows from Operating Activities $ 80 $ - $ (110) $ 656 $ - $ 626 Cash Flows from Investing Activities Capital expenditures and acquisitions (includes dry hole costs) - - (213) (617) - (830) Proceeds from sales of assets and discontinued operations - - 15 32 - 47 --- Net cash used in investing activities - - (198) (585) - (783) --- Cash Flows from Financing Activities Change in long-term debt and capital leases - - 307 (96) - 211 Dividends paid on common stock (98) - - - - (98) Other 19 - - (4) - 15 --- Net cash provided by (used in) financing activities (79) - 307 (100) - 128 --- Net increase in cash and cash equivalents 1 - (1) (29) - (29) --- Cash and cash equivalents at beginning of period - - 62 128 - 190 --- Cash and cash equivalents at end of period $ 1 $ - $ 61 $ 99 $ - $ 161

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CONDENSED CONSOLIDATING CASH FLOWS For the six months ended June 30, 2001 Unocal Non- Unocal Capital Union Oil Guarantor Millions of dollars (Parent) Trust (Parent) Subsidiaries Eliminations Consolidated --- Cash Flows from Operating Activities $ 83 $ - $ 572 $ 589 $ - $ 1,244 Cash Flows from Investing Activities Capital expenditures and acquisitions (includes dry hole costs) - - (373) (868) - (1,241) Proceeds from sales of assets and discontinued operations - - 28 2 - 30 --- Net cash used in investing activities - - (345) (866) - (1,211) --- Cash Flows from Financing Activities Change in long-term debt and capital leases - - (5) 371 - 366 Dividends paid on common stock (97) - - - - (97) Other 13 - - (10) - 3 --- Net cash provided by (used in) financing activities (84) - (5) 361 - 272 --- Net increase (decrease) in cash and cash equivalents (1) - 222 84 - 305 --- Cash and cash equivalents at beginning of period 1 - 84 150 - 235 --- Cash and cash equivalents at end of period $ - $ - $ 306 $ 234 $ - $ 540

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-24- 15. Segment Data The Company's reportable segments are: Exploration and Production, Trade, Midstream, and Geothermal and Power Operations. General corporate overhead, unallocated costs and other miscellaneous operations, including real estate, carbon and minerals and those businesses that were sold, are included under the Corporate and Other heading. -- Segment Information Exploration & Production Trade For the Three Months North America International ended June 30, 2002 Millions of dollars Lower 48 Alaska Canada Far East Other -- Sales & operating revenues $ 124 $ 73 $ 61 $ 275 $ 37 $ 644 Other income (loss) (a) 1 - - - - - Inter-segment revenues 234 - - 62 21 1 -- Total 359 73 61 337 58 645 Earnings (loss) from equity investments 1 - - 9 2 1 Earnings (loss) from continuing operations 20 (5) 6 113 12 1 Earnings from discontinued operations - - - - - - -- Net earnings (loss)

20 (5) 6 113 12 1 Assets (at June 30, 2002) 3,255 352 1,125 2,718 804 178 --

--- Midstream Geothermal Corporate & Other Total & Power Operations Administrative Net Interest Environmental & General Expense & Litigation Other (b) --- Sales & operating revenues $ 76 $ 33 $ - $ - $ - $ 26 $ 1,349 Other income (loss) (a) 1 2 - 5 - (2) 7 Inter-segment revenues 4 - - - - (322) - --- Total 81 35 - 5 - (298) 1,356 Earnings (loss) from equity investments 18 5 - - - 15 51 - Earnings (loss) from continuing operations 23 14 (19) (28) (13) (11) 113 Earnings from discontinued operations - - - - - 1 1 --- Net earnings (loss) 23 14 (19) (28) (13) (10) 114 Assets (at June 30, 2002) 506 595 - - - 1,260 10,793 --- (a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Includes eliminations and consolidation adjustments. -25- -- Segment Information Exploration & Production Trade For the Three Months North America International ended June 30, 2001 Millions of dollars Lower 48 Alaska Canada Far East Other -- Sales & operating revenues $ 167 $ 63 $ 97 $ 269 $ 39 $ 925 Other income (loss) (a) - - 2 (3) - 6 Inter-segment revenues 406 - - 55 26 1 -- Total 573 63 99 321 65 932 Earnings from equity investments 8 - - 8 - - Earnings (loss) from continuing operations 142 13 14 113 5 4 Earnings from discontinued operations - - - - - - Cumulative effect of accounting change - - - - - - -- Net earnings (loss) 142 13 14 113 5 4 Assets (at December 31, 2001) 3,345 344 1,015 2,463 741 156 --

--- Midstream Geothermal Corporate & Other Total & Power Operations Administrative Net Interest Environmental & General Expense & Litigation Other (b) --- Sales & operating revenues $ 39 $ 45 $ - $ - $ - $ 40 $ 1,684 Other income (loss) (a) 1 4 - 7 - (5) 12 Inter-segment revenues 2 - - - - (490) - --- Total 42 49 - 7 - (455) 1,696 Earnings from equity investments 19 - - - - 14 49 Earnings (loss) from continuing operations 18 2 (21) (32) (16) (7) 235 Earnings from discontinued operations - - - - - 12 12 Cumulative effect of accounting change - - - - - - - --- Net earnings (loss) 18 2 (21) (32) (16) 5 247 Assets (at December 31, 2001) 479 594 - - - 1,288 10,425 --- (a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Includes eliminations and consolidation adjustments. -26- -- Segment Information Exploration & Production Trade For the Six Months North America International ended June 30 2002 Millions of dollars Lower 48 Alaska Canada Far East Other -- Sales & operating revenues $ 237 $ 124 $ 100 $ 494 $ 60 $ 1,100 Other income (loss) (a) 4 - - - - - Inter-segment revenues 400 - - 114 41 1 -- Total 641 124 100 608 101 1,101 Earnings (loss) from equity investments - - - 17 4 - Earnings (loss) from continuing operations 24 (11) (3) 203 24 2 Earnings from discontinued operations - - - - - - -- Net earnings (loss) 24 (11) (3) 203 24 2 Assets (at June 30, 2002) 3,255 352 1,125 2,718 804 178 --

--- Midstream Geothermal Corporate & Other Total & Power Operations Administrative Net Interest Environmental & General Expense & Litigation Other (b) --- Sales & operating revenues $ 139 $ 61 $ - $ - $ - $ 58 $ 2,373 Other income (loss) (a) 2 4 - 8 - 3 21 Inter-segment revenues 6 - - - - (562) - --- Total 147 65 - 8 - (501) 2,394 Earnings (loss) from equity investments 37 2 - - - 28 88 Earnings (loss) from continuing operations 42 20 (43) (65) (36) (22) 135 Earnings from discontinued operations - - - - - 1 1 --- Net earnings (loss) 42 20 (43) (65) (36) (21) 136 Assets (at June 30, 2002) 506 595 - - - 1,260 10,793

--- (a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Includes eliminations and consolidation adjustments. -27- -- Segment Information Exploration & Production Trade For the Six Months North America International ended June 30, 2001 Millions of dollars Lower 48 Alaska Canada Far East Other -- Sales & operating revenues $ 328 $ 135 $ 129 $ 501 $ 74 $ 2,428 Other income (loss) (a) 1 - 1 (6) (1) (1) Inter-segment revenues 972 - - 110 61 1 -- Total 1,301 135 130 605 134 2,428 Earnings from equity investments 14 - - 19 - - Earnings (loss) from continuing operations 383 32 11 219 27 7 Earnings from discontinued operations - - - - - - Cumulative effect of accounting change - - - - - - -- Net earnings (loss) 383 32 11 219 27 7 Assets (at December 31, 2001) 3,345 344 1,015 2,463 741 156 -- -- Midstream Geothermal Corporate & Other Total & Power Operations Administrative Net Interest Environmental & General Expens & Litigation Other (b) -- Sales & operating revenues $ 139 $ 89 $ - $ - $ - $ 67 $ 3,890 Other income (loss) (a) 2 7 - 13 - 4 20 Inter-segment revenues 4 - - - - (1,148) - -- Total 145 96 - 13 - (1,077) 3,910 Earnings from equity investments 28 - - - - 30 91 Earnings (loss) from continuing operations 27 3 (44) (65) (50) (23) 527 Earnings from discontinued operations - - - - - 16 16 Cumulative effect of accounting change - - - - - (1) (1) -- Net earnings (loss) 27 3 (44) (65) (50) (8) 542 Assets (at December 31, 2001) 479 594 - - - 1,288 10,425 -- (a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Includes eliminations and consolidation adjustments. 16. Subsequent Event In July 2002, the Company's Unocal Geothermal of Indonesia, Ltd. ("UGI") subsidiary and Dayabumi Salak Pratama, Ltd. ("DSPL"), a 50-percent equity investee of UGI, reached agreement over pricing and production issues at its Gunung Salak geothermal project in Indonesia with PT. PLN (Persero) ("PLN"), the Indonesian state-owned electricity company, and Pertamina, the Indonesian state-owned oil and natural gas company. The new agreement extends the primary terms of the Joint Operation Contract and Energy Sales Contract ("ESC") to 2040 and also contains provisions to extend the deadline for transferring to PLN generating plants currently operated by DSPL plus any additional plants subsequently developed and operated by DSPL or the Company to the expiration date of the ESC. The new agreement lowers the selling price of electricity delivered by DSPL from 8.49 cents per kilowatt-hour (kWh) to 4.45 cents per kWh and steam supplied to PLN by UGI from 4.25 cents per kWh to 3.75 cents per kWh. Under the terms of the amended ESC both the selling price for electricity and the selling price for geothermal steam are indexed for changes in foreign exchange rates and inflation. The new agreement also provides for payment by PLN of a portion of the past due receivable balances to the Company while the Company foregoes a portion of the receivables. -28- ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS. The following discussion and analysis of the consolidated financial condition and results of operations of the Company should be read in conjunction with Management's Discussion and Analysis in Item 7 of the Unocal's 2001 Annual Report on Form 10-K. CONSOLIDATED RESULTS For the Three Months For the Six Months Ended June 30, Ended June 30, --- Millions of dollars 2002 2001 2002 2001 -- Earnings from continuing operations $ 113 $ 235 $ 135 $ 527 Earnings from discontinued operations 1 12 1 16 Cumulative effect of accounting change - - - (1) -- Net earnings $ 114 $ 247 $ 136 $ 542 ==

Continuing Operations Second Quarter Results: Earnings from continuing operations were $113 million in the second quarter of 2002 compared to $235 million for the same period a year ago. The decrease was primarily due to lower natural gas production and lower prices for natural gas and liquids. The second quarter of 2002 was impacted by lower production compared with the same period a year ago, principally in the Lower 48 operations, which reflected lower Gulf of Mexico natural gas production stemming from a decline in Ship Shoal Block 295 ("Muni field") production(10 MMcf/d, net of royalty, in the second quarter of 2002 versus 126 MMcf/d, net of royalty, in the second quarter of 2001) and reduced second-half 2001 drilling activity, compared to the first half of 2001, in response to lower commodity prices. Worldwide net daily production in the second quarter of 2002 averaged 486,000 BOE per day compared with 516,000 BOE per day a year ago. The lower worldwide production reduced net earnings by approximately $70 million. Lower natural gas prices reduced net earnings by approximately $25 million, while lower liquids prices reduced net earnings by approximately $15 million. The Company's worldwide average natural gas price, which was not impacted by hedging activities, was $2.80 per Mcf in the second quarter of 2002, which was a decrease of 61 cents per Mcf, or 18 percent, from the same period a year ago. The Company's second quarter of 2001 included a loss of one cent per Mcf from hedging activities. In the second quarter of 2002, the Company's worldwide average liquids price was $22.63 per Bbl, which was a decrease of $1.70 per Bbl, or 7 percent, from the same period a year ago. The Company's hedging program had no impact on the average liquids price in the second quarter of 2002 while the second quarter of 2001 included a loss of 5 cents per Bbl from hedging activities. The second quarter of 2002 was also negatively impacted by a $12 million after-tax impairment in Alaska and a $12 million after-tax restructuring provision for the Gulf Region business unit, which is part of the U.S. Lower 48 operations of the Exploration and Production segment. After-tax provisions for environmental and litigation matters were $13 million in the second quarter of 2002, compared with $14 million in the same period a year ago. The second quarter of 2002 also included an after-tax gain of $4 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives recorded by the Company's Northrock Resources Ltd. ("Northrock") subsidiary, compared to an after-tax gain of $21 million in the same period a year ago. -29- Six Months Results: Earnings from continuing operations were $135 million in the first six months of 2002 compared to $527 million for the same period a year ago. The decrease was primarily due to lower commodity prices and lower worldwide production. Lower natural gas prices reduced net earnings by approximately $155 million, while lower liquids prices reduced net earnings by approximately $50 million. The Company's worldwide average natural gas price, including a benefit of 6 cents per Mcf from hedging activities, was $2.61 per Mcf for the first six months of 2002, which was a decrease of $1.28 per Mcf or 33 percent from the $3.89 per Mcf, including a loss of 3 cents per Mcf from hedging activities, from the same period a year ago. In the first six months of 2002, the Company's worldwide average liquids price was $20.53 per Bbl, including a benefit of 2 cents per Bbl from hedging activities, which was a decrease of $3.92 per Bbl or 16 percent from the $24.45 per Bbl, including a loss of 5 cents per Bbl from hedging activities, from the same period a year ago. The results in the first six months of 2002 were also impacted by lower production compared with the same period a year ago, which reduced net earnings by approximately $190 million. The impact was principally in the Lower 48 operations, which reflected lower Gulf of Mexico natural gas production stemming from the decline in Muni field production(13 MMcf/d net of royalty in the first six months of 2002 versus 91 MMcf/d net of royalty for the first six months of 2001) and the reduction in the second-half 2001 drilling activity. The first six months of 2002 included $6 million after-tax in pension related expenses, compared to a benefit of $5 million after-tax in the first six months of 2001. The results in the first six months of 2002 included the $12 million after-tax impairment in Alaska and the $12 million after-tax restructuring provision for the Gulf Region business unit. After-tax provisions for environmental and litigation matters were $34 million in the first six months of 2002, compared with $45 million in the same period a year ago. The first six months of 2002 also included a $2 million after-tax gain from an insurance settlement reached with insurers for the recovery of amounts previously paid out for environmental pollution claims and related costs and a $2 million after-tax gain adjustment related to a Lower 48 prior year asset sale. The first six months of 2001 included an after-tax gain of $4 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives by the Company's Northrock subsidiary, while the first six months of 2002 did not have any gains or losses. Revenues: Total revenues from continuing operations in the second quarter of 2002 were $1.36 billion compared with $1.70 billion for the same period a year ago. In the first six months of 2002, total revenues from continuing operations were $2.39 billion compared with $3.91 billion for the same period a year ago. The decreases, in both the quarter and six months amounts, primarily reflected lower hydrocarbon commodity prices, lower domestic natural gas production and reduced activity in the purchase and resale of third party crude oil barrels intended to take advantage of market price differentials. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets. Discontinued Operations The second quarter of 2002 included a $1 million after-tax gain from discontinued operations, related to a participation payment received from the purchaser of the Company's former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. The second quarter of 2001 included a similar after-tax gain for $12 million. The total after-tax gain in the first six months of 2001 from discontinued operations was $16 million. Cumulative Effect of Accounting Change In the first quarter of 2001, the Company recorded a one-time non-cash $1 million after-tax charge consisting of the cumulative effect of a change in accounting principle related to the initial adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities". -30- Exploration and Production The Company engages in oil and gas exploration, development and production worldwide. The results of this segment are discussed under two geographical breakdowns of North America and International: North America - Included in this category are the U.S. Lower 48, Alaska and Canada oil and gas operations. The emphasis of the U.S. Lower 48 operations is on the onshore, the shelf and deepwater areas of the Gulf of Mexico region. The U.S. Lower 48 also includes the consolidated results of Pure Resources, Inc. ("Pure"), which operates primarily in the Permian and San Juan Basins in west Texas and New Mexico, the Gulf of Mexico region and offshore in the Gulf of Mexico. A substantial portion of the crude oil and natural gas produced in the U.S. Lower 48 operations, excluding that of Pure, is sold to the Company's Trade business segment. The remainder of North America production, including the production of Pure and Northrock in Canada, is sold to third parties. In Alaska, natural gas production, pursuant to agreements with the purchaser of the Company's former agricultural products business, is sold to a fertilizer plant in Nikiski, Alaska. In addition, the Company, including Pure, uses hydrocarbon derivative financial instruments such as futures, swaps and options to hedge portions of the Company's exposure to commodity price fluctuations. Second Quarter Results: After-tax earnings were $21 million in the second quarter of 2002 compared to $169 million for the same period a year ago, which was a decrease of $148 million. The decrease was primarily due to lower natural gas production and lower natural gas and liquids prices. Lower natural gas production during the second quarter of 2002 compared to the same period a year ago reduced after-tax earnings by approximately $55 million. North America average net daily natural gas production was 935 MMcf/d in the second quarter of 2002 compared to 1,132 MMcf/d in the same period a year ago, which was a decrease of 17 percent. Natural gas production in the Lower 48 was 766 MMcf/d in the second quarter of 2002 compared to 954 MMcf/d in the same period a year ago. This decline reflected lower natural gas production from the Gulf of Mexico shelf area including production from the Muni field, which averaged 10 MMcf/d, net of royalty, in the second quarter of 2002 compared to 126 MMcf/d, net of royalty, during the second quarter of 2001. Lower natural gas prices reduced after-tax earnings by approximately $45 million, while lower liquids prices reduced after-tax earnings by approximately $5 million. The average natural gas price for North America, including a gain of one cent per Mcf from hedging activities, was $2.97 per Mcf in the second quarter of 2002 compared to $4.16 per Mcf in the same period a year ago, which included a loss of 3 cents per Mcf from hedging activities. In the second quarter of 2002, the Company's North America average liquids price, with no impact from hedging activities, was $22.47 per Bbl compared to $23.45 per Bbl in the same period a year ago, which included a loss of 9 cents per Bbl from hedging activities. The results in the second quarter of 2002 were also negatively impacted by a $12 million after-tax impairment in Alaska and a $12 million after-tax restructuring provision for the Gulf Region business unit. In addition, the Company's Northrock subsidiary recorded $4 million in after-tax gains related to accruals and realized gains and losses for non-hedging commodity derivative positions during the second quarter of 2002 compared to an after-tax gain of $21 million in the same period a year ago. Restructuring: In June 2002, the Company adopted a restructuring plan that resulted in a $12 million after-tax restructuring charge. The restructuring charge covers the costs of terminating approximately 200 employees in the Company's Sugar Land, Texas office and field locations. All of the affected employees have been terminated or had received termination notices as of June 30, 2002. The restructuring plan involves organizational changes to eliminate unnecessary work processes in the Company's Gulf Region business unit, which is part of the U.S. Lower 48 operations. The restructuring charge was included in the results of the U.S. Lower 48 section of the Exploration & Production segment. Cash expenditures related to the restructuring plan are expected to be approximately $9 million in the second half of 2002 and $7 million in 2003. The Company expects the plan to reduce future salaries and benefits by an estimated $20 million pre-tax annually. -31- Six Months Results: After-tax earnings were $10 million in the first six months of 2002 compared to $426 million for the same period a year ago, which was a decrease of $416 million. The decrease was primarily due to lower natural gas and liquids prices and lower natural gas production. The average natural gas price for North America, including a gain of 11 cents per Mcf from hedging activities, was $2.66 per Mcf in the first six months of 2002 compared to $5.01 per Mcf in the same period a year ago, which included a loss of 6 cents per Mcf from hedging activities. In the first six months of 2002, the Company's North America average liquids price, including a benefit of 3 cents per Bbl from hedging activities, was $19.88 per Bbl compared to $23.96 per Bbl in the same period a year ago, which included a loss of 9 cents per Bbl from hedging activities. The lower natural gas prices reduced after-tax earnings by approximately $200 million, while the lower liquids prices reduced after-tax earnings by approximately $40 million. Natural gas production in North America was 934 MMcf/d in the first six months of 2002 compared to 1,138 MMcf/d in the same period a year ago. This decline reflected primarily lower natural gas production from the Gulf of Mexico shelf area including production from the Muni field, which averaged 13 MMcf/d net of royalty in the first six months of 2002 compared to 91 MMcf/d net of royalty during the first six months of 2001. Lower natural gas production during the first six months of 2002 compared to the same period a year ago reduced after-tax earnings by approximately $130 million. The results in the first six months of 2002 also included the $12 million after-tax impairment in Alaska and the $12 million after-tax restructuring provision for the Gulf Region business unit. The first six months of 2001 included an after-tax gain of $4 million in mark-to-market accruals and realized gains and losses for non-hedge commodity derivatives by the Company's Northrock subsidiary, while the first six months of 2002 did not have any gains or losses. Dry hole costs in the first six months of 2002 were lower by $18 million after-tax than the same period a year ago, primarily due to lower drilling activity in the Gulf of Mexico. International - Unocal's International operations include oil and gas exploration and production activities outside of North America. The Company operates or participates in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. International operations also include the Company's exploration and development activities primarily in Asia, Latin America and West Africa. Second Quarter Results: After-tax earnings totaled $125 million in the second quarter of 2002 compared to $118 million in the same period a year ago, which was an increase of $7 million. The increase was primarily due to $8 million in higher liquids sales volumes, $7 million in higher natural gas prices and $8 million in lower dry hole costs. These positive factors were partially offset by $9 million in lower liquids prices and $8 million in higher tax expense due to higher effective tax rates, primarily due to changes in the Thai baht/U.S. dollar exchange rate. Liquids sales volumes increased primarily due to the startup of oil production in Thailand. The average natural gas price for International operations was $2.64 per Mcf in the second quarter of 2002, which was an increase of 3 percent from the same period a year ago. Dry hole costs in the second quarter of 2002 were lower primarily due to exploratory dry holes recorded during the second quarter of 2001 in Brazil and Gabon. The average liquids price for International operations was $22.84 per Bbl in the second quarter of 2002, which was a decrease of $2.77 per Bbl, or 11 percent, from the same period a year ago. Six Months Results: After-tax earnings totaled $227 million in the first six months of 2002 compared to $246 million in the same period a year ago, which was a decrease of $19 million. The decrease was primarily due to $20 million in lower liquids prices and $15 million in higher tax expense due to higher effective tax rates, primarily due to changes in the Thai baht/U.S. dollar exchange rate. The average liquids price for International operations was $21.43 per Bbl in the first six months of 2002, which was a decrease of $3.67 per Bbl, or 15 percent, from the same period a year ago. These negative factors were partially offset by $7 million in higher natural gas prices and $11 million in lower dry hole costs. The average natural gas price for International operations was $2.56 per Mcf in the first six months of 2002 compared with $2.54 per Mcf in the same period a year ago. Dry hole costs for the six months of 2002 were lower primarily due to the 2001 exploratory dry holes in Brazil and Gabon. -32- OPERATING HIGHLIGHTS For the Three Months For the Six Months Ended June 30, Ended June 30, ------------------ ------------------ 2002 2001 2002 2001 -- North America Net Daily Production Liquids (thousand barrels) Lower 48 (a) (b) 54 59 55 57 Alaska 25 24 25 24 Canada 17 15 18 15 -- ------------------ Total liquids 96 98 98 96 Natural gas - dry basis (million cubic feet) Lower 48 (a) (b) 766 954 754 911 Alaska 77 93 89 115 Canada 92 85 91 112 -- ------------------ Total natural gas 935 1,132 934 1,138 North America Average Prices (excluding hedging activities) (c) (d) Liquids (per barrel) Lower 48 $ 23.48 $ 24.72 $ 20.92 $ 25.62 Alaska $ 20.86 $ 22.27 $ 18.03 $ 22.55 Canada $ 21.92 $ 20.84 $ 19.15 $ 20.65 Average $ 22.47 $ 23.54 $ 19.85 $ 24.05 Natural gas (per mcf) Lower 48 $ 3.12 $ 4.62 $ 2.68 $ 5.73 Alaska $ 1.57 $ 1.20 $ 1.57 $ 1.20 Canada $ 2.90 $ 2.85 $ 2.53 $ 3.94 Average $ 2.96 $ 4.19 $ 2.55 $ 5.07 -- North America Average Prices (including hedging activities) (c) (d) Liquids (per barrel) Lower 48 $ 23.47 $ 24.57 $ 20.97 $ 25.47 Alaska $

20.86 $ 22.27 $ 18.03 $ 22.55 Canada $ 21.92 $ 20.84 $ 19.15 $ 20.65 Average $ 22.47 $ 23.45 $ 19.88 $ 23.96 Natural gas (per mcf) Lower 48 $ 3.12 $ 4.62 $ 2.80 $ 5.69 Alaska $ 1.57 $ 1.20 $ 1.57 $ 1.20 Canada $ 2.97 $ 2.48 $ 2.62 $ 3.65 Average $ 2.97 $ 4.16 $ 2.66 $ 5.01 -- (a) Includes proportional shares of production of equity investees. (b) Includes minority interest shares of : Liquids 9 9 9 8 Natural gas 98 106 98 95 Barrels oil equivalent 25 26 25 24 (c) Excludes Trade segment margins. (d) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portion of hedges. -33- OPERATING HIGHLIGHTS (CONTINUED) For the Three Months For the Six Months Ended June 30, Ended June 30, ------------------ ------------------ 2002 2001 2002 2001 -- International Net Daily Production (e) Liquids (thousand barrels) Far East 54 48 53 49 Other (a) 20 19 20 19 -- ------------------ Total liquids 74 67 73 68 Natural gas - dry basis (million cubic feet) Far East 883 908 852 851 Other (a) 79 69 78 63 -- ------------------ Total natural gas 962 977 930 914 International Average Prices (f) Liquids (per barrel) Far East $ 22.50 $ 24.91 $ 20.95 $ 24.57 Other $ 23.91 $ 27.51 $ 23.03 $ 26.36 Average $ 22.84 $ 25.61 $ 21.43 $ 25.10 Natural gas (per mcf) Far East $ 2.63 $ 2.54 $ 2.55 $ 2.51 Other $ 2.79 $ 2.92 $ 2.64 $ 2.90 Average $ 2.64 $ 2.56 $ 2.56 $ 2.54 -- Worldwide Net Daily Production (a) (b) (e) Liquids (thousand barrels) 170 165 171 164 Natural gas - dry basis (million cubic feet) 1,897 2,109 1,864 2,052 Barrels oil equivalent (thousands) 486 516 482 506 Worldwide Average Prices (excluding hedging activities) (c) (d) Liquids (per barrel) $ 22.63 $24.38 $ 20.51 $ 24.50 Natural gas (per mcf) $ 2.80 $ 3.42 $ 2.55 $ 3.92 Worldwide Average Prices (including hedging activities) (c) (d) Liquids (per barrel) $ 22.63 $24.33 $ 20.53 $ 24.45 Natural gas (per mcf) $ 2.80 $ 3.41 $ 2.61 $ 3.89 -- (a) Includes proportional shares of production of equity investees. (b) Includes minority interest shares of : Liquids 9 9 9 8 Natural gas 98 106 98 95 Barrels oil equivalent 25 26 25 24 (c) Excludes Trade segment margins. (d) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portion of hedges. (e) International production is presented utilizing the economic interest method. (f) International did not have any hedging activities. -34- TRADE The Trade segment externally markets the majority of the Company's worldwide liquids production, excluding that of Pure, and North American natural gas production, excluding that of Pure and the Alaska business unit. It is also responsible for executing various derivative contracts on behalf of the Company's Exploration and Production segment, excluding Pure, in order to manage the Company's exposure to commodity price changes. The Trade segment also purchases liquids and natural gas from certain of the Company's royalty owners, joint venture partners and other unaffiliated oil and gas producing and trading companies for resale. In addition, the segment trades hydrocarbon derivative instruments to manage exposures to commodity price fluctuations for which hedge accounting is not used and to exploit anticipated opportunities arising from commodity price fluctuations. These general risk-management and 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. The segment also purchases limited amounts of physical commodity inventories for energy trading purposes when arbitrage opportunities arise. Second Quarter Results: After-tax earnings totaled $1 million in the second quarter of 2002 compared to $4 million in the same period a year ago. The decrease was primarily due to lower results related to domestic natural gas and crude oil marketing activities. Sales and operating revenues from the Trade business segment were $645 million in the second quarter of 2002 compared to $925 million in the same period a year ago, which was a decrease of $280 million. These revenues represented approximately 48 percent and 55 percent of the Company's total sales and operating revenues for the second quarters of 2002 and 2001, respectively. In the second quarter of 2002, natural gas revenues declined by $160 million primarily due to lower commodity prices and lower domestic production volumes. Crude oil revenues declined by $115 million, primarily due to reduced activity in the purchase and resale of third party barrels intended to take advantage of marketing opportunities. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets. Six Months Results: After-tax earnings totaled $2 million in the first six months of 2002 compared to $7 million in the same period a year ago. The decrease was primarily due to lower results related to domestic natural gas marketing activities. Sales and operating revenues were

$1,100 million in the first six months of 2002 compared to $2,428 million in the same period a year ago, which was a decrease of $1,328 million. These revenues represented approximately 46 percent and 62 percent of the Company's total sales and operating revenues for the first six months of 2002 and 2001, respectively. In the first six months of 2002, natural gas revenues declined by $625 million primarily due to lower commodity prices and lower domestic production volumes. Crude oil revenues declined by $640 million, primarily due to reduced activity in the purchase and resale of third party barrels intended to take advantage of market price differentials. During 2001, management decided to decrease its outside crude oil purchases for resale due to increased volatility in the oil markets. MIDSTREAM The Midstream segment is comprised of the Company's equity interests in petroleum pipeline companies, wholly-owned pipeline systems throughout the U.S., and the Company's North America gas storage business. Second Quarter Results: After-tax earnings totaled $23 million in the second quarter of 2002 compared to $18 million in the same period a year ago. The increase was due primarily to improved results in the gas storage business. Six Months Results: After-tax earnings totaled $42 million in the first six months of 2002 compared to $27 million in the same period a year ago. The increase was due primarily to $4 million in improved throughput volumes from the pipeline business and a $6 million asset write-down related to a Colonial Pipeline Company investment that was recorded in the first six months of 2001. In addition, after-tax earnings in the gas storage business in the first six months of 2002 have improved by $5 million compared with the same period a year ago. -35- GEOTHERMAL AND POWER OPERATIONS The Geothermal and Power Operations business segment produces geothermal steam for power generation, with operations in the Philippines and Indonesia. The segment's activities also include the operation of power plants in Indonesia and equity interests in gas-fired power plants in Thailand. The Company's non-exploration and production business development activities, primarily power-related, are also included in this segment. Second Quarter Results: After-tax earnings totaled $14 million in the second quarter of 2002 compared to $2 million in the same period a year ago. The improved results were primarily due to approximately $7 million after-tax in lower receivable provisions related to geothermal operations in Indonesia and $4 million after-tax in improved equity earnings from the Company's investments in non-geothermal power plants in Thailand. Six Months Results: After-tax earnings totaled $20 million in the first six months of 2002 compared to $3 million in the same period a year ago. The improved results were primarily due to approximately $15 million after-tax in lower receivable provisions related to geothermal operations in Indonesia. Agreements Reached on Indonesia Geothermal Contracts: In July 2002, the Company's Unocal Geothermal of Indonesia, Ltd. ("UGI"), subsidiary and Dayabumi Salak Pratama, Ltd. ("DSPL"), a 50-percent equity investee of UGI, reached agreement over pricing and production issues at its Gunung Salak geothermal project in Indonesia with PT. PLN (Persero) ("PLN"), the Indonesian state-owned electricity company, and Pertamina, the Indonesian state-owned oil and natural gas company. Gunung Salak is a 330-megawatt (nominal installed nameplate rating) geothermal production and electricity generation project on the western side of the island of Java. UGI operates the steam fields as a contractor to Pertamina and delivers geothermal steam to PLN, which operates three electricity-generating plants at Salak. UGI also delivers steam to DSPL for three generating plants that supply electricity to PLN on behalf of Pertamina. The new agreement extends the primary terms of the Joint Operation Contract and Energy Sales Contract ("ESC") to 2040. The new agreement increases the Unit Rated Capacities for the generating plants operated by DSPL by 32 megawatts thereby increasing minimum take-or-pay amounts payable under the ESC and also includes a commitment by PLN to accept as much steam and electricity as possible over the take-or-pay quantities in order to meet increased demand. In addition, the agreement reaffirms the Government of Indonesia guarantee of PLN's obligations to UGI, DSPL, Pertamina and the project's lenders. The new agreement lowers the selling price of electricity delivered by DSPL from 8.49 cents per kilowatt-hour (kWh) to 4.45 cents per kWh and steam supplied to PLN by UGI from 4.25 cents per kWh to 3.75 cents per kWh. Under the terms of the amended ESC both the selling price for electricity and the selling price for geothermal steam are indexed for changes in foreign exchange rates and inflation. The new agreement also provides for payment by PLN of a portion of the past due receivable balances to the Company while the Company foregoes a portion of the receivables. As of June 30, 2002, the Company's Indonesian Geothermal business unit had a gross receivable balance of approximately $455 million. In July 2002, the Company received $51 million from PLN in payment of a portion of the past due receivable balances. The Company will retain a receivable balance of $93 million plus interest and expects to collect in full this amount over a period of approximately four years. The remaining part of the outstanding receivables will be written-off against a previously established allowance for bad debts. -36- CORPORATE AND OTHER Corporate and Other includes general corporate overhead, miscellaneous operations (e.g., real estate activities, carbon and minerals) and other corporate unallocated costs. Net interest expense represents interest expense, net of interest income and capitalized interest. Second Quarter Results: The after-tax earnings effect for the second quarter of 2002 was a loss of $71 million compared to a loss of $76 million in the same period a year ago. Lower after-tax expenses for environmental and litigation matters benefited the second quarter of 2002, with expenses of $13 million after-tax compared to $16 million after-tax for the same period a year ago. The second quarter of 2002 results included tax related benefit adjustments and lower employee related compensation, which was offset by higher pension related expenses. Six Months Results: The after-tax earnings effect for the first six months of 2002 was a loss of $166 million compared to a loss of $182 million in the same period a year ago. Lower after-tax provisions for environmental and litigation matters benefited the first six months of 2002, with expenses of $36 million after-tax compared to $50 million after-tax for the same period a year ago. The first six months of 2002 also benefited from a $2 million after-tax gain from an insurance settlement related reached with insurers for the recovery of amounts previously paid out for environmental pollution claims and related costs. The first six months results of 2001 included a $10 million pre-tax, or $7 million after-tax, contribution to a charitable foundation, while the first six months of 2002 included a similar contribution of $3 million pre-tax, or $2 million after-tax. The 2002 earnings benefit from the lower contribution and the tax related benefit adjustments were partially offset by higher pension related expenses. The first six months of 2002 included $6 million after-tax in pension related expenses, compared to a benefit of $5 million after-tax in the first six months of 2001. Net interest expense remained unchanged in the first six months of 2002, as higher interest expense from a premium on an early repayment of long-term debt was offset by higher capitalized interest on development projects. FINANCIAL CONDITION At At At June 30, December 31, June 30, -- Millions of dollars 2002 2001 2001 -- Current ratio 0.9:1 0.9:1 1.1:1 Total debt and capital leases $ 3,119 $ 2,906 $ 2,959 Trust convertible preferred securities 522 522 522 Stockholders' equity 3,210 3,124 3,155 -- Total capitalization $ 6,851 $ 6,552 $ 6,636 == Total debt/total capitalization 46% 44% 45% Floating-rate debt/total debt 21% 8% 6% -- Cash flows from operating activities, including discontinued operations and working capital and other changes, were $626 million in the first six months of 2002 compared to $1,244 million in the same period a year ago. This decrease principally reflected the effects of lower worldwide average natural gas and liquids prices. The decrease was partially offset by $155 million in lower income tax payments, net of refunds, compared to the first six months of 2001 and $30 million from the sale of certain domestic trade receivables during the first six months of 2002. -37- Pre-tax proceeds from asset sales, including those classified as discontinued operations, were $47 million for the first six months of 2002. Proceeds of approximately $27 million were from an asset sale by the Company's Pure subsidiary of oil and gas producing properties in the U.S. The remaining $20 million of proceeds were from various other oil and gas asset sales and other miscellaneous properties. Pre-tax proceeds from asset sales, including those classified as discontinued operations, were $30 million for the first six months of 2001. The proceeds included $12 million from the sale of certain oil and gas properties, $11 million from the sale of miscellaneous assets and $7 million related to a participation payment received from the purchaser of the Company's former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. Capital expenditures in the first six months of 2002 were $830 million, compared with $824 million in the same period a year ago. The higher capital expenditures in 2002 were primarily due to higher development expenditures in Indonesia and an acquisition in Canada, the aggregate of which was substantially offset by lower Gulf of Mexico exploratory expenditures. The Canadian acquisition involved the Company's Northrock subsidiary, which completed, in June 2002, a cash acquisition of all the outstanding shares of common stock of Corsair Exploration Inc. ("Corsair") for $1.98 per share, or approximately $29 million. This acquisition was funded with cash on hand. Corsair is a Canadian exploration and production company primarily engaged in activity in West Central Alberta, Canada. The transaction was valued at approximately $36 million, which included $7 million in assumed debt and working capital deficiency. The capital expenditures amount for the first six months of 2001 excludes Pure's acquisition of properties from International Paper Company for $267 million and Pure's cash outlay of $150 million, as of June 30, 2001, for the acquisition Hallwood Energy Corporation, which are included as part of the major acquisitions line on the consolidated cash flows statement. The Company has taken appropriate action to mitigate credit exposure to counterparties whose creditworthiness has deteriorated since the beginning of the year. Counterparty credit lines have been reduced substantially or rescinded entirely where it has been determined that there is unwarranted credit exposure. In other instances, credit assurances in the form of prepayments, letters of credit or guarantees have been obtained to support the credit extension. The Company's long-term debt, including the current portion, was $3.12 billion at June 30, 2002, compared with $2.91 billion at year-end 2001. This increase primarily reflected the commercial paper borrowings made by the Company to fund scheduled maturing fixed-rate debt and for other general corporate purposes (see note 10 for further detail on the Company's long-term debt). The Company has two credit facilities in place: a $400 million 364-day credit agreement and a $600 million 5-year credit agreement. The agreements provide for the termination of their loan commitments and require the prepayment of all outstanding borrowings in the event that (1) any person or group becomes the beneficial owner of more than 30 percent of the then outstanding voting stock of Unocal other than in a transaction having the approval of Unocal's board of directors, at least a majority of which are continuing directors, or (2) if continuing directors shall cease to constitute at least a majority of the board. The agreements do not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade. Based on current commodity prices and current development projects, the Company does not expect cash generated from operating activities, asset sales and cash on hand in 2002 to be sufficient to cover its operating and capital spending requirements and to meet dividend payments. The Company has substantial borrowing capacity to enable it to meet anticipated and unanticipated cash requirements. The Company relies on the commercial paper market on an interim basis, its accounts receivable securitization program and its revolving credit facilities to cover short-term borrowing requirements. The Company decreased the fund availability of its accounts receivable securitization program availability to $125 million from $204 million in the second quarter of 2002. At June 30, 2002, the Company had sold $100 million of its domestic trade receivables under this program. The Company also has in place a universal shelf registration statement with an unutilized balance of approximately $739 million, which can be issued as debt and/or equity securities, depending on the Company's needs and market conditions. From time to time, the Company may also look to fund some of its long-term projects using other financing sources, including multilateral and bilateral agencies. -38- Maintaining investment-grade credit ratings, that is "BBB- / Baa3" and above from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively, is a significant factor in the Company's ability to raise short-term and long-term financing. As a result of the Company's current investment grade ratings, the Company has access to both the commercial paper and bank loan markets. The Company currently has a BBB+ / Baa1 credit rating by Standard & Poor's and Moody's, respectively. In May 2002, Moody's changed its rating outlook for the Company's long-term debt to negative from stable and retained an outlook of stable for the Company's Prime-2 commercial paper rating. As outlined in the tables on pages 40 and 41 of Management's Discussion and Analysis in Item 7 of the Company's 2001 Annual Report on Form 10-K, the Company continues to believe that it does not have a liquidity exposure in the event of a credit rating downgrade. In the event that the Company's credit ratings fall to a level that prohibits it from accessing the commercial paper markets, the Company would still be able to access funds under its revolving credit facilities. ENVIRONMENTAL MATTERS At June 30, 2002, the Company's reserves for environmental remediation obligations totaled $231 million, of which $116 million was included in current liabilities. During the six months ended June 30, 2002, cash payments of $55 million were applied against the reserve and $49 million in provisions were added to the reserve balance. In the first quarter of 2002, provisions of $31 million were recorded primarily for service stations and distribution facilities; the former Guadalupe oil field; and the McColl Superfund site. A provision was recorded for revised cost estimates related to the anticipated cleanup of the Company's former service stations and distribution facilities throughout the United States. The reserves for these sites are included in the "Former Company-operated Sites" environmental reserve category shown in the table below. The first quarter provisions also included an additional accrual for revised cost estimates for various remediation projects at the Company's former Guadalupe oil field on the central California coast. The reserve for the Guadalupe oil field is included in the "Inactive or Closed Company Facilities" category. The Company also recorded a provision for its estimated remaining share of oversight and monitoring costs related to the McColl Superfund site in Fullerton, California. The provision was recorded as the result of a federal appeals court overturning a 1998 court decision that held the federal government responsible for cleanup of the site because of its role in encouraging oil companies to produce gasoline during World War II. In the second quarter of 2002, provisions of $18 million were recorded primarily for a former oil field in Michigan and for a site in York, Pennsylvania. A provision for the estimated cost to cleanup contaminated areas that have been identified at a former oil field in Michigan was added to the reserve in the second quarter. This reserve is included in the "Former Company-operated Sites" category. In the second quarter, a provision was also recorded for revised remediation cost estimates related to a shutdown facility in York, Pennsylvania. The facility had been operated by the Company's Molycorp subsidiary. The reserve for this site is included in the "Inactive or Closed Company Facilities" category. The Company also estimated as of June 30, 2002, that it possibly could incur additional remediation costs aggregating approximately $245 million. The Company's total environmental reserve and possible additional liability amounts are grouped into the following four categories. At June 30, 2002 --------------------------- Possible Millions of dollars Reserves Additional -- Superfund and similar sites $ 18 $ 11 Active company facilities 37 66 Company facilities sold with retained liabilities and former company-operated sites 97 71 Inactive or closed company facilities 79 107 -- Total reserves $ 231 $ 255 == Also see notes 11 and 12 to the consolidated financial statement in Item 1 of this report for additional information on environmental related matters. -39- OUTLOOK Certain of the statements in this discussion, as well as other forward-looking statements within this document, contain estimates and projections of amounts of or increases / decreases in future revenues, earnings, cash flows, capital expenditures, assets, liabilities and other financial items and of future levels of or increases / decreases in reserves, production, sales including related costs and prices, drilling activities and other statistical items; plans and objectives of management regarding the Company's future operations, products and services; and certain assumptions underlying such estimates, projection plans and objectives. While these forward-looking statements are made in good faith, future operating, market, competitive, legal, economic, political, environmental, and other conditions and events could cause actual results to differ materially from those in the foward-looking statements. See pages 51 through 53 of Management's Discussion and Analysis in Item 7 of the Company's 2001 Annual Report on Form 10-K for a discussion of certain of such conditions and events. Volatile energy prices are expected to continue to impact financial results in the year 2002. The Company expects energy prices to remain volatile due to changes in climate conditions, worldwide demand, crude oil and natural gas inventory levels, production quotas set by OPEC, current and future worldwide political instability and security and other factors. The economic situation in Asia, where most of the Company's international activity is centered, is still recovering with positive signs showing in the region. The Company looks at the natural gas market in Asia as one of its major strategic investments and believes that the governments in the region are committed to undertaking the reforms and restructuring necessary to enable their nations to continue their recoveries from the downturn. The Company estimates that its net worldwide daily production for 2002 will average in the lower end of the range between 490,000 and 500,000 BOE. The anticipated production increase through the remainder of 2002 reflects new projects in the Far East and Gulf of Mexico. The Company forecasts its net earnings per share to be between $1.60 and $1.80 in 2002. This forecast assumes average NYMEX benchmark prices of $25.10 per Bbl of crude oil and $3.05 per MMBtus for North America natural gas. These price assumptions are based on year-to-date actual prices and the NYMEX strip for the remainder of the year. Earnings are expected to change 16 cents per share for every $1 change in the Company's average worldwide realized price for crude oil and 8 cents per share for every 10-cent change in the Company's average realized North America natural gas price. The full-year forecast also includes pre-tax dry hole costs of $110 to $125 million. Exploration and Production - North America U.S. Lower 48: In the Gulf of Mexico deep water, the Company is continuing its appraisal of the Trident discovery and is planning to drill a second appraisal well in late 2002. After completing the Trident second appraisal well, the Company plans to commence drilling another deepwater prospect by the end of 2002 or early 2003. In addition, the Company is continuing its participation in the development of the Mad Dog discovery. The Company is continuing to focus its exploration effort on deeper prospects with higher resource potential in the Gulf of Mexico shelf. The Company anticipates selling some of its low margin properties in the Gulf Region towards the end of 2002 or in early 2003. Alaska: The Company continues its participation in the Ninilchik Exploration Unit on Alaska's Kenai Peninsula, where it holds a 40 percent working interest in the 25,000-acre Ninilchik Exploration Unit. Marathon Oil Corporation ("Marathon") is operator and holds the remaining interest. The Ninilchik Exploration Unit is located about 35 miles south of Kenai, Alaska. Canada: The Company's Northrock subsidiary will work on integrating the recently acquired operations of Corsair, a Canadian exploration and production company primarily engaged in activity in West Central Alberta, Canada. -40- Exploration and Production - International Far East Thailand: The Company's Unocal Thailand, Ltd. ("Unocal Thailand"), subsidiary started natural gas production from the Phase II development in the northern part of Pailin field in the B12/27 concession area in the Gulf of Thailand. The minimum daily contract quantity of natural gas sales from the Phase II ("North Pailin") facilities is 165 gross MMcf/d, raising the gross contracted natural gas sales from the Pailin field to 330 MMcf/d under an agreement with PTT Public Co., Ltd. ("PTT"), the partially privatized state petroleum company. The North Pailin facilities have produced an average of 180 gross MMcf/d throughout the month of July. In addition, the North Pailin facilities have produced an average of 5,300 gross b/d of condensate throughout the month of July, raising total condensate production from Pailin to more than 14,600 gross b/d. Unocal Thailand is operator of the field and holds a 35 percent working interest (31 percent net of royalty). The Company began crude oil production in May 2002 from its Yala field in the Gulf of Thailand. The Company began initial production of crude oil from the neighboring Plamuk field in 2001. The Company expects production from the Plamuk, Yala and Surat fields to reach 15 MBbl/d gross in 2002. The Company has a 71 percent working interest in these fields (62 percent net of royalty). Vietnam: In May 2002, the Company's Vietnam subsidiaries filed a declaration of commercial discovery with PetroVietnam, the national oil company, for three natural gas fields offshore southwest Vietnam. The declaration followed the drilling of 10 successful exploration wells on Blocks B and 52/97, including four wells that were drilled in 2001. The declaration is the first step toward signing a gas sales agreement, which is required before any field development can begin. As a result of the declaration, PetroVietnam may exercise its option to convert its carried participating interests into paying working interests. Should PetroVietnam opt to convert to normal working interests, the Company would hold a 42 percent working interest in Block B and Block 48/95 and a 43 percent working interest in Block 52/97. Indonesia: The Company's Unocal Rapak, Ltd. ("Unocal Rapak"), subsidiary is continuing its evaluation of engineering and development studies for the deepwater Ranggas oil prospect offshore East Kalimantan, Indonesia. The Company plans to drill the Ranggas #6 delineation well in the third quarter of 2002. Unocal Rapak is operator of the Rapak PSC area and holds an 80 percent working interest. The Company is also evaluating early development options for the condensate discovered at its deepwater Gendalo-Gandang discovery in the Ganal PSC, offshore Indonesia. The Company is the operator of the Ganal PSC and holds an 80 percent working interest. The Company is continuing its development of the West Seno project. Gross development costs for the first phase are expected to be approximately $460 million, with an additional $225 million for the second phase (Unocal's net share is expected to be approximately $415 million and $200 million for phase 1 and 2, respectively). The Company and its co-venturer are currently working to secure financing for a portion of the total costs through the Overseas Private Investment Corporation ("OPIC"). The Company and its co-venturer expect to complete financing arrangements with OPIC in 2002 for two loans. One loan is $300 million for the first phase, and the other loan is $50 million for the second phase. Other International Azerbaijan: The Azerbaijan International Operating Company ("AIOC") consortium is working on the development of the "Phase 1" portion of the offshore oil reserves in the Caspian Sea from the Azeri and Chirag fields. This phase of the project will develop an estimated 1.5 billion barrels of proved crude oil reserves. Phase 1 gross production is scheduled to commence in early 2005 and is expected to peak at approximately 360 MBbl/d. The Company has committed up to $310 million for its share of the costs to develop Phase 1. The Company has approved the expenditure of $400 million representing its share of the estimated Azeri-Chirag-Gunashli Production Sharing Agreement Phase 2 project expenditures over a five to six year period. Such expenditure is subject to partner and government approval of the project which the Company anticipates occurring in the third quarter of 2002. -41- Bangladesh: The Company continues to work with the government of Bangladesh and Petrobangla, the state oil and gas company, to develop additional reserves and export natural gas to markets in neighboring India. At June 30, 2002, the Company's business unit in Bangladesh had a gross receivable balance of approximately $31 million relating to invoices billed for natural gas and condensate sales to Petrobangla. Approximately $27 million of the outstanding balance represented past due amounts and accrued interest for invoices covering December 2001 through May 2002. In July 2002, payments were received for natural gas sales and condensate covering billings for December 2001 and January 2002. Generally, invoices, when paid, have been paid in full. The Company is working with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables. See also Note 12 to the consolidated financial statement in Item 1 of this report for information regarding a claim made by Petrobangla in July 2002 against one of the Company's subsidiaries for compensation with respect to a 1997 well blowout. Brazil: The drilling of an exploratory well on the BM-ES-1 Block in the Espirito Santo Basin began in July of 2002. The Company acquired a 25 percent non-operating working interest in the Block earlier in 2002. Drilling in the adjacent BM-ES-2 Block will wait on results from the BM-ES-1 Block and is projected to commence in the first quarter of 2003 at the earliest. The Company, as operator, holds a 40.5 percent working interest in the BM-ES-2 Block. Midstream Construction of the Keystone Gas Storage Project in West Texas continues and is expected to be on-line by the end of third quarter of 2002. The project will initially have storage capacity of 3 billion cubic feet. The Company holds a 100 percent interest in the project. In early August, the Company, through its participation in the AIOC consortium, signed the agreement approving engineering plans for the Baku-Tblisi-Ceyhan ("BTC") pipeline in Turkey. The pipeline project is planned to have a crude oil capacity of 1 million b/d. Completion of the pipeline is excepted in late 2004 at an overall estimated cost of approximately $3 billion, and the pipeline is expected to be in operation in early 2005. The Company has an 8.9 percent interest and is one of eight shareholders in the BTC pipeline project. The pipeline company anticipates financing up to 70 percent of the pipeline's cost. In Alaska, the Company along with Marathon, through their interests in the Kenai Kachemak Pipeline LLC, are developing a 33-mile natural gas pipeline that would connect a future producing area in Ninilchik with the existing south central Alaska pipeline system in Kenai. The cost of the pipeline is currently estimated to be $25 million. The Company holds a 40 percent interest in the pipeline company. The Company anticipates the sale of certain interests in nonstrategic pipelines in the U.S. by the end of 2002. Corporate and Other For the full-year 2002, pension costs related to the Company's U.S. based employees are expected to increase by approximately $25 million after-tax compared to the full-year 2001. Lower returns on plan assets and the use of a lower discount rate to measure benefit-related liabilities are the principal factors behind the increase in current year expense. The Company's consulting actuaries have completed the January 1, 2002 actuarial valuation calculations for the Unocal Qualified Retirement Plan ("Plan") covering eligible employees on the U.S. payroll and have reviewed pension trust investment results for the first six months of 2002. The fair value of the pension trust investments at June 30, 2002 is still in excess of the Plan's accumulated benefit obligation ("ABO"). The Company is closely monitoring the performance of the Plan's investment advisors and the returns on plan assets. If actual returns on plan assets were to continue to be negative for the balance of the current year resulting in the fair value of the Plan's assets falling below the ABO, the resulting shortfall would require a charge to accumulated other comprehensive income on the Company's consolidated balance sheet with no impact on earnings for 2002. Furthermore, continued negative returns on Plan assets would result in increased pension expense in future years and could result in the termination of the "contribution holiday" currently in effect for the Plan. -42- Reformulated Gasoline Patents The Company's efforts to enforce its patents for reformulated gasolines continue. In its lawsuit to collect additional infringement damages from five California refiners, the court has requested additional information and arguments with respect to the royalty rate to be applied for infringing volumes produced subsequent to July 1996. In June 2002, the U.S. Patent and Trademark Office ("PTO") initially rejected all of the claims of the Company's '126 patent, as it had done earlier with respect to the '393 patent, as part of the reexamination process. In July, the PTO granted a second request for reexamination of the '393 patent based on additional alleged "prior art". The Company continues to expect the claims of these patents to be sustained following the conclusion of their reexamination. FUTURE ACCOUNTING CHANGES In August 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No 143, "Accounting for Asset Retirement Obligations". It is effective for fiscal years beginning after June 15, 2002, and it requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, as a capitalized cost of the long-lived asset and to depreciate it over the useful life of the asset. The Company is currently in the process of evaluating the impact that SFAS No. 143 will have on its financial position and results of operations. In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". This statement provides guidance on the recognition and measurement of liabilities associated with disposal activities and is effective for the Company on January 1, 2003. The Company is currently reviewing the provisions of SFAS No. 146 to determine the impact that the statement will have on its financial position and results of operations. Other proposed accounting changes considered from time to time by the FASB, the U.S. SEC, the American Institute of Certified Public Accountants and the United States Congress could materially impact the Company's reported financial position and results of operations. -43- ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Market risk generally represents the risk that losses may occur in the values of financial instruments as a result of changes in interest rates, foreign currency exchange rates, counterparty liquidity and commodity prices. As part of its overall risk management strategies, the Company uses derivative financial instruments to manage and reduce risks associated with these factors. The Company also trades hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations.

The Company determines the fair values of its derivative financial instruments primarily based upon market quotes of exchange traded instruments. Most futures and options contracts are valued based upon direct exchange quotes or industry published price indices. Some instruments with longer maturity periods require financial modeling to accommodate calculations beyond the horizons of available exchange quotes. These models calculate values for outer periods using current exchange quotes (i.e., forward curve) and assumptions regarding interest rates, commodity and interest rate volatility and, in some cases, foreign currency exchange rates. While the Company feels that current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors to measure the fair value of its longer termed hydrocarbon derivative instruments, other pricing assumptions or methodologies may lead to materially different results in some instances. Interest Rate Risk - From time to time the Company temporarily invests its excess cash in short-term interest-bearing securities issued by high-quality issuers. Company policies limit the amount of investment in securities of any one financial institution. Due to the short time the investments are outstanding and their general liquidity, these instruments are classified as cash equivalents in the consolidated balance sheet and do not represent a material interest rate risk to the Company. The Company's primary market risk exposure for changes in interest rates relates to the Company's long-term debt obligations. The Company manages its exposure to changing interest rates principally through the use of a combination of fixed and floating rate debt. Interest rate risk sensitive derivative financial instruments, such as swaps or options may also be used depending upon market conditions. The Company evaluated the potential effect that near term changes in interest rates would have had on the fair value of its interest rate risk sensitive financial instruments at June 30, 2002. Assuming a ten percent decrease in the Company's weighted average borrowing costs at June 30, 2002, the potential increase in the fair value of the Company's debt obligations and associated interest rate derivative instruments, including the Company's net interests in the debt obligations and associated interest rate derivative instruments of its subsidiaries, would have been approximately $111 million at June 30, 2002. Foreign Exchange Rate Risk - The Company conducts business in various parts of the world and in various foreign currencies. To limit the Company's foreign currency exchange rate risk related to operating income, foreign sales agreements generally contain price provisions designed to insulate the Company's sales revenues against adverse foreign currency exchange rates. In most countries, energy products are valued and sold in U.S. dollars and foreign currency operating cost exposures have not been significant. In other countries, the Company is paid for product deliveries in local currencies but at prices indexed to the U.S. dollar. These funds, less amounts retained for operating costs, are converted to U.S. dollars as soon as practicable. The Company's Canadian subsidiaries are paid in Canadian dollars for their crude oil and natural gas sales. From time to time the Company may purchase foreign currency options or enter into foreign currency swap or foreign currency forward contracts to limit the exposure related to its foreign currency debt or other obligations. At June 30, 2002, the Company had various foreign currency swaps and foreign currency forward contracts outstanding related to operations in Canada, Thailand and The Netherlands. The Company evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of the Company's combined foreign currency position related to its outstanding foreign currency swaps and forward contracts. -44- Assuming an adverse change of ten percent in foreign exchange rates at June 30, 2002, the potential decrease in fair value of the Company's foreign currency forward contracts, foreign-currency denominated debt, foreign currency swaps and foreign currency forward contracts of its subsidiaries, would have been approximately $10 million at June 30, 2002. Credit Risk - The Company has taken appropriate action to mitigate credit exposure to counterparties whose creditworthiness has deteriorated since the beginning of the year. Counterparty credit lines have been reduced substantially or rescinded entirely where it has been determined that there is unwarranted credit exposure. In other instances, credit assurances in the form of prepayments, letters of credit or guarantees have been obtained to support the credit extension. Commodity Price Risk - The Company is a producer, purchaser, marketer and trader of certain hydrocarbon commodities such as crude oil and condensate, natural gas and refined products and is subject to the associated price risks. The Company uses hydrocarbon price-sensitive derivative instruments ("hydrocarbon derivatives"), such as futures contracts, swaps, collars and options to mitigate its overall exposure to fluctuations in hydrocarbon commodity prices. The Company may also enter into hydrocarbon derivatives to hedge contractual delivery commitments and future crude oil and natural gas production against price exposure. The Company also actively trades hydrocarbon derivatives, primarily exchange regulated futures and options contracts, subject to internal policy limitations. The Company uses a variance-covariance value at risk model to assess the market risk of its hydrocarbon derivatives. Value at risk represents the potential loss in fair value the Company would experience on its hydrocarbon derivatives, using calculated volatilities and correlations over a specified time period with a given confidence level. The Company's risk model is based upon historical data and uses a three-day time interval with a 97.5 percent confidence level. The model includes offsetting physical positions for hydrocarbon derivatives related to the Company's fixed price pre-paid crude oil and pre-paid natural gas sales. The model also includes the Company's net interests in its subsidiaries' crude oil and natural gas hydrocarbon derivatives and forward sales contracts. Based upon the Company's risk model, the value at risk related to hydrocarbon derivatives held for purposes other than hedging was approximately $2 million at June 30, 2002. The value at risk related to hydrocarbon derivatives held for hedging purposes was approximately $5 million at June 30, 2002. In order to provide a more comprehensive view of the Company's commodity price risk, a tabular presentation of open hydrocarbon derivatives is also provided. The following table sets forth the future volumes and price ranges of hydrocarbon derivatives held by the Company at June 30, 2002, along with the fair values of those instruments. -45- Open Hydrocarbon Hedging Derivative Instruments (a) (Thousands of dollars) Fair Value 2002 2003 2004 2005 2006-2009 Asset (Liability) (b) --- Natural Gas Futures Positions Volume (MMBtu) 2,450,000 - - - - $ 787 Average price, per MMBtu $ 3.43 --- Natural Gas Swap Positions Pay fixed price Volume (MMBtu) 4,915,500 7,498,000 7,241,000 7,218,000 21,677,000 $ 41,405 Average swap price, per MMBtu $ 2.46 $ 2.33 $ 2.33 $ 2.37 $ 2.47 Receive fixed price (c) Volume (MMBtu) 13,190,875 131,508 95,438 - - $ (3,093) Average swap price, per MMBtu $ 2.77 $ 1.97 $ 1.97 --- Natural Gas Basis Swap Positions Volume (MMBtu) - - - - - $ - Average price received, per MMBtu Average price paid, per MMBtu --- Natural Gas Collar Positions Volume (MMBtu) 34,255,000 5,636,010 202,500 - - $ 1,413 Average ceiling price, per MMBtu $ 4.08 $ 4.67 $ 4.94 Average floor price, per MMBtu $ 2.92 $ 3.64 $ 2.92 --- Natural Gas Option (Listed) Call Volume (MMBtu) 180,000 180,000 - - - $ 10 Average Call price $ 5.95 $ 6.35 Put Volume (MMBtu) (1,180,000) (180,000) $ (271) Average Put Price $ 3.04 $ 3.25 --- Natural Gas Option (OTC) Put Volume (MMBtu) 94,944 - - - - $ 86 Average Put Price $ 3.96 --- --- Crude Oil Future position Volume (Bbls) 427,000 - - - - $ 1,765 Average price, per Bbl $ 22.72 --- Crude Oil Option Put Volume (Bbls) 500,000 - - - - $ 18 Average price, per Bbl $ 22.90 Call Volume (Bbls) 350,000 - - - - $ 152 Average price, per Bbl $ 32.14 --- Crude Oil Option (Calender Spread) Put Volume (Bbls) 300,000 - - - - $ 11 Average price, per Bbl $ 0.22 Call Volume (Bbls) (400,000) - - - - $ (34) Average price, per Bbl $ 0.14 --- Crude Oil Option (Calender Spread) OTC Put Volume (Bbls) 600,000 - - - - $ 66 Average price, per Bbl $ 0.10 Call Volume (Bbls) (200,000) - - - - $ 54 Average price, per Bbl $ 0.50 --- Crude Oil Swap Positions Pay fixed price Volume (Bbls) 19,500 - - - - $ 3 Average swap price, per Bbl $ 25.88 Receive fixed price Volume (Bbls) 27,500 - - - - $ (188) Average swap price, per Bbl $ 18.71 --- Crude Oil Collars Volume (Bbls) 88,421 156,802 77,778 - - $ (457) Average ceiling price, per Bbl $ 27.15 $ 25.33 $ 24.87 Average floor price, per Bbl $ 20.61 $ 19.77 $ 18.77 --- (a) Positions reflect long (short) volumes. (b) Includes $5,983 thousand net claims against counterparties with non-investment grade credit ratings. (c) Includes $9,369 thousand in assumed liabilities which were capitalized as acquisition costs. -46- Open Hydrocarbon Non-Hedging Derivative Instruments (a) (Thousands of dollars) Fair Value 2002 2003 Asset (Liability) (b)

-- Natural Gas Futures Positions Volume (MMBtu) (370,000) - $ 416 Average price, per MMBtu $ 3.73
-- Natural Gas Swap Positions Pay fixed price Volume (MMBtu) 8,823,725 828,400 $ (13,912) Average swap price, per MMBtu $ 3.35 $ 3.27 Receive fixed price Volume (MMBtu) 8,967,500 - $ (472) Average swap price, per MMBtu $ 3.36
-- Natural Gas Basis Swap Positions Volume (MMBtu) 2,725,000 - $ 426 Average price received, per MMBtu $ 2.92 Average price paid, per MMBtu $ 2.77
-- Natural Gas Option (Listed) Call Volume (MMBtu) (2,250,000) - $ 227 Average Call price $ 3.53 Put Volume (MMBtu) (250,000) - $ (92) Average Put Price $ 3.00
-- Natural Gas Option (Over the Counter) Call Volume (MMBtu) (4,833,050) (3,055,200) $ (4,637) Average Call price $ 4.40 $ 2.55 Put Volume (MMBtu) (5,500,000) - $ 120 Average Put price $ 2.14
-- Natural Gas Spread Option (Over the Counter) NYMEX / IFERC (c) Put Volume (MMBtu) (12,310,000) (2,000,000) $ 421 Average Strike price $ 0.24 $ 0.60

-- Crude Oil Future position Volume (Bbls) (441,000) - $ 750 Average price, per Bbl $ 27.11
-- Crude Oil Option Put Volume (Bbls) - - $ (320) Average price, per Bbl Call Volumes (Bbls) 300,000 - $ (113) Average price, per Bbl $ 26.92
-- Crude Oil Option (Calender Spread) Put Volume (Bbls) 200,000 - $ 0 Average price, per Bbl $ 0.15
-- Crude Oil Swap Positions Pay fixed price Volume (Bbls) 7,738,006 - $ 1,082 Average swap price, per Bbl $ 27.00 Receive fixed price Volume (Bbls) 2,925,024 - $ (5,353) Average swap price, per Bbl $ 23.36
-- (a) Positions reflect long (short) volumes. (b) Includes $706 thousand net claims against counterparties with non-investment grade credit ratings. (c) Prices quoted from the New York Mercantile Exchange (NYMEX) and Inside FERC Gas Report (IFERC). -47- PART II - OTHER INFORMATION ITEM 1. LEGAL PROCEEDINGS. See the information with respect to certain legal proceedings pending or threatened against the Company previously reported in Item 3 of Unocal's Annual Report on Form 10-K for the year ended December 31, 2001 ("2001 Form 10-K"), and in Item 1 of Part II of Unocal's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002. There is incorporated by reference: the information regarding environmental remediation reserves and possible additional remediation costs in notes 11 and 12 to the consolidated financial statements in Item 1 of Part I of this report; the discussion of such amounts in the Environmental Matters section of Management's Discussion and Analysis in Item 2 of Part I; and the information regarding certain litigation and claims, tax matters and other contingent liabilities in note 12 to the consolidated financial statements. See also the discussion under "Reformulated Gasoline Patents" in the Outlook section of Management's Discussion and Analysis of recent developments in certain proceedings in which the Company is seeking to enforce its patents for cleaner-burning gasolines. Information with respect to recent developments in certain previously reported proceedings and with respect to certain additional proceedings is set forth below: 1. In the California Superior Court cases (the Doe and Roe cases) alleging the Company's liability in connection with the construction of the natural gas pipeline from the Yadana field across Myanmar to the Thailand border, described in Paragraph 3 of Item 3 of the 2001 Form 10-K, in June 2002, the court, ruling on various pending motions, dismissed all of the plaintiffs' tort causes of action that were premised on alleged intentional or negligent actions of the Company. In August 2002, the court orally denied the Doe plantiffs' motion for class certification and set a February 2003 trial date. The remaining causes of action in both cases are all premised on whether the Company should be held vicariously liable for the alleged wrongful acts of the Myanmar military. Therefore, the Company views the award of any punitive or exemplary damages against the Company to be remote, as it is not claimed that the

Company was a direct perpetrator of any wrongful acts. With possible damages at trial limited to lost wages and property appropriation claims of the individual plaintiffs, the Company believes that the outcomes of these cases are not likely to have a material adverse effect on the Company's financial condition or liquidity or, based on management's current assessment of the cases, the Company's results of operations. Certain Environmental Matters Involving Civil Penalties 2. In June 2002, the U.S. Environmental Protection Agency ("EPA") issued to the Company an administrative complaint alleging 16 violations of the Emergency Planning and Community Right-To-Know Act of 1986. The complaint, which seeks civil penalties aggregating $385,000, alleges that the Company failed to make timely and/or complete and accurate chemical release reports to the EPA with regard to certain chemicals manufactured, processed or otherwise used at its former Los Angeles refinery during 1996 and 1997. -48- ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS. The 2002 Annual Meeting of Stockholders of Unocal was held on May 20, 2002. The following actions were taken by the stockholders at the Annual Meeting, for which proxies were solicited pursuant to Regulation 14 under the Securities Exchange Act of 1934, as amended: 1. The three nominees proposed by the board of directors were elected as directors by the following votes for three-year terms expiring at the 2005 Annual Meeting of Stockholders, or until their successors are duly elected and qualified: Name Votes For Votes Withheld James W. Crownover 213,235,772 6,327,893 Timoth H. Ling 214,066,046 5,497,619 Donald B. Rice 214,593,616 4,970,049 2. A proposal to ratify the appointment of PricewaterhouseCoopers LLP as Unocal's independent accountants for 2002 was passed by a vote of 213,626,825 for versus 4,941,605 against and 995,235 abstentions. There were no broker non-votes. 3. A proposal to approve the amendments to the 1998 Management Incentive Program was passed by a vote of 200,022,248 for versus 17,507,867 against and 2,033,549 abstentions. There were no broker non-votes. 4. A stockholder proposal to urge the Board of Directors to adopt, implement and enforce a code of conduct based on the International Labor Organization's Conventions on Workplace Human Rights failed to pass, with a vote of 61,266,708 for versus 125,497,527 against and 8,731,434 abstentions. There were 24,067,996 broker non-votes. 5. A stockholder proposal to link compensation and bonus packages of Unocal's executives to the Company's ethical and social performance failed to pass, with a vote of 16,276,788 for versus 173,508,678 against and 5,710,203 abstentions. There were 24,067,996 broker non-votes. ITEM 5. OTHER INFORMATION. Effective June 27, 2002, Charles R. Larson resigned from the Unocal Board of Directors to pursue his candidacy for Lieutenant Governor in the State of Maryland. His position is currently vacant. -49- ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K. (a) Exhibits: The Exhibit Index on page 46 of this report lists the exhibits that are filed as part of this report. (b) Reports on Form 8-K: Filed during the second quarter of 2002: (1) Current Report on Form 8-K, dated and filed April 8, 2002, for the purpose of reporting, under Item 5, the Company's drilling results in Indonesia and a first quarter 2002 provision for environmental remediation. (2) Current Report on Form 8-K, dated and filed April 25, 2002, for the purpose of reporting, under Item 5, the Company's first quarter 2002 earnings and related information and the Company's 2002 earnings forecast. (3) Current Report on Form 8-K, dated June 20, 2002, and filed June 25, 2002, for the purpose of reporting, under Item 5, the Company's restructuring of its Gulf business unit. Filed during the third quarter of 2002 to the date hereof: (1) Current Report on Form 8-K, dated June 10, 2002, and filed July 29, 2002, for the purpose of reporting, under Item 5, the Company's second quarter 2002 earnings, the commencement of production from Phase II of the Pailin field in Thailand, Agreements reached on Indonesia Geothermal Contracts, Agrium Inc. Litigation, a Bangladesh-related claim and the Company's 2002 earnings forecast. (2) Current Report on Form 8-K, dated and filed August 2, 2002, for the purpose of reporting, under Item 5, Amendment No. 2 to the Rights Agreement, dated as of August 2, 2002, between Unocal Corporation and Mellon Investor Services LLC.
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SIGNATURE Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. UNOCAL CORPORATION (Registrant) Dated: August 12, 2002 By: /s/JOE D. CECIL -------------------------------- Joe D. Cecil Vice President and Comptroller (Duly Authorized Officer Principal Accounting Officer)
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EXHIBIT INDEX 12.1 Statement regarding computation of ratio of earnings to fixed charges of Unocal Corporation for the six months ended June 30, 2002 and 2001. 12.2 Statement regarding computation of ratio of earnings to fixed charges of Union Oil Company of California for the six months ended June 30, 2002 and 2001.

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Copies of exhibits will be furnished upon request. Requests should be addressed to the Corporate Secretary. -51-