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

Form 10-K

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2005**

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission File Number 1-368-2

Chevron Corporation

(Exact name of registrant as specified in its charter)

Delaware	94-0890210	6001 Bollinger Canyon Road, San Ramon, California 94583-2324
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)	(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code (925) 842-1000

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $.75 per share	New York Stock Exchange, Inc. Pacific Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☑

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Act. (Check one):

Large accelerated filer ☑ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter — $115,713,269,274 (As of June 30, 2005)

Number of Shares of Common Stock outstanding as of February 23, 2006 — 2,226,159,801

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2006 Annual Meeting and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company's 2006 Annual Meeting of Stockholders (in Part III)

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CAUTIONARY STATEMENT RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report on Form 10-K of Chevron Corporation contains forward-looking statements relating to Chevron's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "schedules," "estimates" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are unknown or unexpected problems in the resumption of operations affected by Hurricanes Katrina and Rita and other severe weather in the Gulf of Mexico; crude oil and natural gas prices; refining margins and marketing margins; chemicals prices and competitive conditions affecting supply and demand for aromatics, olefins and additives products; actions of competitors; the competitiveness of alternate energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; the ability to successfully integrate the operations of Chevron and Unocal Corporation; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's net production or manufacturing facilities due to war, accidents, political events, civil unrest or severe weather; the potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations and litigation (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); the potential liability resulting from pending or future litigation; the company's acquisition or disposition of assets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; and the factors set forth under the heading "Risk Factors" in this report. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

PART I

Item 1. Business

(a) General Development of Business

Summary Description of Chevron

Chevron Corporation,[1] a Delaware corporation, manages its investments in subsidiaries and affiliates and provides administrative, financial and management support to U.S. and foreign subsidiaries that engage in fully integrated petroleum operations, chemicals operations, mining operations of coal and other minerals, power generation and energy services. The company conducts business activities in the United States and approximately 180 other countries. Petroleum operations consist of exploring for, developing and producing crude oil and natural gas; refining crude oil into finished petroleum products; marketing crude oil, natural gas and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemicals operations include the manufacture and marketing, by affiliates, of commodity petrochemicals for industrial uses, and the manufacture and marketing, by a consolidated subsidiary, of fuel and lubricating oil additives.

In this report, exploration and production of crude oil, natural gas liquids and natural gas may be referred to as “E&P” or “upstream” activities. Refining, marketing and transportation may be referred to as “RM&T” or “downstream” activities. A list of the company’s major subsidiaries is presented on pages E-4 and E-5 of this Annual Report on Form 10-K. As of December 31, 2005, Chevron had more than 59,000 employees (including about 6,000 service station employees). Approximately 27,000, or 46 percent, of the company’s employees were employed in U.S. operations.

Acquisition of Unocal Corporation

On August 10, 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. This acquisition was accounted for under the rules of Financial Accounting Standards Board (FASB) Statement No. 141, *“Business Combinations.”* Unocal’s principal upstream operations are in North America and Asia, including the Caspian region. Other activities include ownership interests in proprietary and common carrier pipelines, natural gas storage facilities and mining operations. Further discussion of the Unocal acquisition is contained in Note 2 on page FS-36 of this Annual Report on Form 10-K.

Overview of Petroleum Industry

Petroleum industry operations and profitability are influenced by many factors, and individual petroleum companies have little control over some of them. Governmental policies, particularly in the areas of taxation, energy and the environment have a significant impact on petroleum activities, regulating where and how companies conduct their operations and formulate their products and, in some cases, limiting their profits directly. Prices for crude oil and natural gas, petroleum products and petrochemicals are determined by supply and demand for these commodities. The members of the Organization of Petroleum Exporting Countries (OPEC) are typically the world’s swing producers of crude oil, and their production levels are a major factor in determining worldwide supply. Demand for crude oil and its products and for natural gas is largely driven by the conditions of local, national and worldwide economies, although weather patterns and taxation relative to other energy sources also play a significant part. Variations in the components of refined products sales due to seasonality are not primary drivers of changes in the company’s overall annual earnings.

Strong competition exists in all sectors of the petroleum and petrochemical industries in supplying the energy, fuel and chemical needs of industry and individual consumers. Chevron competes with fully integrated major petroleum companies as well as independent and national petroleum companies for the acquisition of crude oil and natural gas

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[1] Incorporated in Delaware in 1926 as Standard Oil Company of California, the company adopted the name Chevron Corporation in 1984 and ChevronTexaco Corporation in 2001. On May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. As used in this report, the term “Chevron” and such terms as “the company,” “the corporation,” “our,” “we” and “us” may refer to Chevron Corporation, one or more of its consolidated subsidiaries, or to all of them taken as a whole, but unless stated otherwise, it does not include “affiliates” of Chevron — i.e., those companies accounted for by the equity method (generally owned 50 percent or less) or investments accounted for by the cost method. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

leases and other properties and for the equipment and labor required to develop and operate those properties. In its downstream business, Chevron also competes with fully integrated major petroleum companies and other independent refining, marketing and transportation entities in the sale or acquisition of various goods or services in many national and international markets.

Operating Environment

Refer to pages FS-2 through FS-11 of this Annual Report on Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion on the company's current business environment and outlook.

Chevron Strategic Direction

Chevron's primary objective is to create value and achieve sustained financial returns from its operations that will enable it to outperform its competitors. As a foundation for achieving this objective, the company had established the following strategies, which continue into 2006:

Strategies for Major Businesses

- ***Upstream* —** grow profitability in core areas, build new legacy positions and commercialize the company's natural gas equity resource base by targeting North American and Asian markets
- ***Downstream* —** improve returns by focusing on areas of market and supply strength

Enabling Strategies Companywide

- ***Invest in people*** to achieve the company's strategies
- ***Leverage technology*** to deliver superior performance and growth
- ***Build organizational capability*** to deliver world-class performance in operational excellence, cost reduction, capital stewardship and profitable growth

(b) Description of Business and Properties

The upstream and downstream activities of the company are widely dispersed geographically, with operations in North America, South America, Europe, Africa, the Middle East, Central and Far East Asia, and Australia. Besides the large upstream and downstream businesses, the company's other comparatively smaller business segment is chemicals, which is conducted by the company's 50 percent-owned affiliate — Chevron Phillips Chemical Company LLC (CPChem) — and the wholly owned Chevron Oronite Company (Chevron Oronite). CPChem has operations in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. Chevron Oronite is a fuel and lubricating-oil additives business that owns and operates facilities in the United States, France, the Netherlands, Singapore, Japan and Brazil and has equity interests in facilities in India and Mexico.

Chevron also owns an approximate 24 percent equity interest in the common stock of Dynegy Inc. (Dynegy), a provider of electricity to markets and customers throughout the United States. The company holds an additional investment in Dynegy preferred stock. Refer to page FS-13 for further information relating to the company's investment in Dynegy.

Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2005, and assets as of the end of each year — for the United States and the company's major international geographic areas — may be found in Note 8 to the consolidated financial statements beginning on page FS-40 of this Annual Report on Form 10-K. In addition, similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are contained in Notes 13 and 14 on pages FS-44 to FS-46.

Capital and Exploratory Expenditures

Excluding the $17.3 billion acquisition of Unocal Corporation, total reported expenditures for 2005 were $11.1 billion, including $1.7 billion for the company's share of affiliates' expenditures, which did not require cash outlays by the company. In 2004 and 2003, expenditures were $8.3 billion and $7.4 billion, respectively, including the company's share of affiliates' expenditures of $1.6 billion and $1.1 billion in the corresponding periods.

Of the $11.1 billion in expenditures for 2005, about three-fourths, or $8.4 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2004 and 2003. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the years, reflecting the company's continuing focus on opportunities that are available outside the United States.

In 2006, the company estimates capital and exploratory expenditures will be 33 percent higher at $14.8 billion, including spending by affiliates. About three-fourths, or $11.3 billion, is again targeted for exploration and production activities, with $8 billion of that amount outside the United States.

Refer also to a discussion of the company's capital and exploratory expenditures on pages FS-14 and FS-15 of this Annual Report on Form 10-K.

Petroleum — Exploration and Production

The table on the following page summarizes the company's and affiliates' net production of liquids and natural gas for 2005 and 2004. As part of the Unocal acquisition in August 2005, Chevron acquired interests in producing operations in Azerbaijan, Bangladesh, Canada, the Democratic Republic of the Congo, Indonesia, Myanmar, the Netherlands, Thailand and the United States. In September 2005, the producing operations in Canada were sold.

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Net Production[1] of Crude Oil and Natural Gas Liquids and Natural Gas

	Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day)		Natural Gas (Millions of Cubic Feet per Day)		Memo: Oil-Equivalent (Thousands of Barrels per Day)[2]	
	2005	2004	2005	2004	2005	2004
United States:						
California	217	221	106	108	235	239
Gulf of Mexico[3]	112	154	579	815	208	290
Texas[3]	61	62	380	382	124	125
Wyoming	9	10	161	166	36	38
Other States[3]	56	58	408	402	124	125
Total United States[3]	455	505	1,634	1,873	727	817
Africa:						
Angola	139	140	36	26	145	144
Nigeria	125	119	68	59	136	129
Chad	38	37	3	—	39	37
Republic of the Congo	11	12	8	—	12	12
Democratic Republic of the Congo[3,4]	1	4	—	—	1	4
Asia-Pacific:						
Partitioned Neutral Zone (PNZ)[5]	112	117	22	20	116	120
Thailand[3]	43	20	409	93	111	35
Australia	42	43	362	305	102	93
Kazakhstan	37	31	142	125	61	52
China	26	18	—	—	26	18
Azerbaijan[3]	13	—	1	—	13	—
Philippines	8	7	163	131	35	28
Bangladesh[3]	—	—	59	—	10	—
Myanmar[3]	—	—	32	—	5	—
Indonesia[3]	202	215	211	149	237	240
Other International:						
United Kingdom	83	106	300	340	133	163
Canada[3]	54	62	19	51	57	71
Denmark	47	46	146	130	71	68
Argentina	43	45	55	64	52	56
Norway	8	11	2	2	9	11
Venezuela	4	5	35	34	10	11
Netherlands[3]	2	—	4	—	3	—
Colombia	—	—	185	210	31	35
Trinidad and Tobago	—	—	115	135	19	23
Total International[3]	1,038	1,038	2,377	1,874	1,434	1,350
Total Consolidated Operations[3]	1,493	1,543	4,011	3,747	2,161	2,167
Equity Affiliates[6]	176	167	222	211	213	202
Total Including Affiliates[3,7,8]	1,669	1,710	4,233	3,958	2,374	2,369

1 Net production excludes royalty interests owned by others.
2 Barrels of oil-equivalent is crude oil and natural gas liquids plus natural gas converted to oil-equivalent gas (OEG) barrels at 6,000 cubic feet = 1 OEG barrel.
3 Includes net production of the former Unocal properties from August 1, 2005.
4 Chevron sold its interest in the Democratic Republic of the Congo in mid-2004 but acquired another interest as a result of the Unocal merger.
5 Located between the Kingdom of Saudi Arabia and the State of Kuwait.
6 Represents Chevron's share of production by affiliates. Affiliates include Tengizchevroil (TCO) in Kazakhstan and Hamaca in Venezuela.
7 Includes natural gas consumed on lease of 380 and 343 million cubic feet per day in 2005 and 2004, respectively.
8 Does not include other produced volumes:

Athabasca Oil Sands — net	32	27	—	—	32	27
Boscan Operating Service Agreement	111	113	—	—	111	113

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In 2005, Chevron conducted its exploration and production operations in the United States and approximately 35 other countries. Worldwide oil-equivalent production of approximately 2.5 million barrels per day in 2005, including volumes produced from oil sands in Canada and production under an operating service agreement in Venezuela, was about the same as in 2004. Production in the last five months of 2005 included volumes associated with the properties acquired from Unocal. However, production during the year from the heritage-Chevron properties declined from their levels in 2004, due mainly to operations that were offline as a result of August and September hurricanes in the Gulf of Mexico, property sales between periods, the effect of higher prices on volumes required under cost-recovery and variable-royalty provisions of certain contracts, and normal field declines. Refer to the "Results of Operations" section beginning on page FS-7 for a detailed discussion of the factors explaining the 2003 — 2005 changes in production for crude oil and natural gas liquids and natural gas.

The company estimates that its average oil-equivalent production in 2006 will be in the range of 2.7 to 2.8 million barrels per day. The additional volumes over the 2.5 million barrels per day produced in 2005 are attributable mainly to the properties acquired from Unocal and new project start-ups that are expected to help offset normal field declines in existing operations. However, the company cautions that any future estimate of production is subject to many uncertainties, including quotas that may be imposed by OPEC, the price effect on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, the rate of recovery of production being restored in the Gulf of Mexico following the 2005 hurricanes, and production that may have to be shut in due to weather conditions, civil unrest, changing geopolitics or other disruptions to daily operations. Expected additions to production capacity in 2007 through 2009 may permit worldwide oil-equivalent production levels to increase from levels in 2006. Refer to the "Review of Ongoing Exploration and Production Activities in Key Areas," beginning on page 10, for a discussion of the company's major oil and gas development projects.

Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-70 of this Annual Report on Form 10-K for data about the company's average sales price per unit of crude oil and natural gas produced as well as the average production cost per unit for 2005, 2004 and 2003.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2005 for the company and its affiliates:

Productive Oil and Gas Wells[1] at December 31, 2005

	Productive[2] Oil Wells		Productive[2] Gas Wells	
	Gross	Net	Gross	Net
United States:				
California	24,899	22,804	285	80
Gulf of Mexico	2,874	2,085	1,793	1,333
Other U.S.	24,947	9,248	10,684	4,953
Total United States	52,720	34,137	12,762	6,366
Africa	2,520	723	10	4
Asia-Pacific	2,846	1,430	1,703	1,072
Indonesia	7,986	7,843	186	148
Other International	1,700	895	295	115
Total International	15,052	10,891	2,194	1,339
Total Consolidated Companies	67,772	45,028	14,956	7,705
Equity in Affiliates	522	182	—	—
Total Including Affiliates	68,294	45,210	14,956	7,705
Multiple completion wells included above:	656	404	248	172

1 Includes wells producing or capable of producing and injection wells temporarily functioning as producing wells. Wells that produce both oil and gas are classified as oil wells.

2 Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned and the sum of the company's fractional interests in gross wells.

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Reserves

Table V, beginning on page FS-70, provides a tabulation of the company's proved net oil and gas reserves, by geographic area, as of each year-end 2003 through 2005 and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period. During 2005, the company provided oil and gas reserves estimates for 2004 to the Department of Energy, Energy Information Agency. Such estimates are consistent with, and do not differ more than 5 percent from, the information furnished to the SEC on the company's Annual Report on Form 10-K. During 2006, the company will file estimates of oil and gas reserves with the Department of Energy, Energy Information Agency, consistent with the reserve data reported in Table V.

Acreage

At December 31, 2005, the company owned or had under lease or similar agreements undeveloped and developed oil and gas properties located throughout the world. The geographical distribution of the company's acreage is shown in the following table.

Acreage[1] at December 31, 2005
(Thousands of Acres)

	Undeveloped[2]		Developed[2]		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States:						
California	146	125	204	172	350	297
Gulf of Mexico	4,726	3,277	2,115	1,425	6,841	4,702
Other U.S.	5,023	3,546	5,845	2,664	10,868	6,210
Total United States	9,895	6,948	8,164	4,261	18,059	11,209
Africa	18,048	6,045	972	289	19,020	6,334
Asia-Pacific	53,585	25,092	2,854	1,294	56,439	26,386
Indonesia	12,678	7,171	388	348	13,066	7,519
Other International	32,270	18,290	3,807	2,026	36,077	20,316
Total International	116,581	56,598	8,021	3,957	124,602	60,555
Total Consolidated Companies	126,476	63,546	16,185	8,218	142,661	71,764
Equity in Affiliates	863	407	136	60	999	467
Total Including Affiliates	127,339	63,953	16,321	8,278	143,660	72,231

1 Gross acreage includes the total number of acres in all tracts in which the company has an interest. Net acreage is the sum of the company's fractional interests in gross acreage.

2 Developed acreage is spaced or assignable to productive wells. Undeveloped acreage is acreage where wells have not been drilled or completed to permit commercial production and that may contain undeveloped proved reserves. The gross undeveloped acres that will expire in 2006, 2007 and 2008 if production is not established by certain required dates are 5,130, 9,774 and 7,681, respectively.

Contract Obligations

The company sells crude oil and natural gas from its producing operations under a variety of contractual arrangements. Most contracts generally commit the company to sell quantities based on production from specified properties, but certain natural gas sales contracts specify delivery of fixed and determinable quantities.

In the United States, the company is contractually committed to deliver to third parties and affiliates approximately 195 billion cubic feet of natural gas through 2008 from United States reserves. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed U.S. reserves. These contracts include variable-pricing terms.

Outside the United States, the company is contractually committed to deliver to third parties a total of approximately 780 billion cubic feet of natural gas from 2006 through 2008 from Australia, Canada, Colombia and the Philippines. The sales contracts contain variable pricing formulas that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery and in some cases consider inflation or other factors. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed reserves in Australia, Colombia and the Philippines. The company plans to meet its Canadian contractual delivery commitments through third-party purchases.

Development Activities

Details of the company's development expenditures and costs of proved property acquisitions for 2005, 2004 and 2003 are presented in Table I on page FS-65 of this Annual Report on Form 10-K.

The table below summarizes the company's net interest in productive and dry development wells completed in each of the past three years and the status of the company's development wells drilling at December 31, 2005. A "development well" is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. "Wells drilling" includes wells for which drilling activities have been temporarily interrupted at the end of 2005.

Development Well Activity

	Wells Drilling at 12/31/05[2]		Net Wells Completed[1]					
			2005[3]		2004		2003	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States:								
California	—	—	661	—	636	1	418	—
Gulf of Mexico	5	4	29	3	43	3	47	6
Other U.S.	53	30	256	4	221	3	232	12
Total United States	58	34	946	7	900	7	697	18
Africa	4	1	38	—	36	—	24	—
Asia-Pacific	39	15	156	—	84	—	43	—
Indonesia	—	—	107	—	163	—	562	—
Other International	28	8	96	—	84	—	107	—
Total International	71	24	397	—	367	—	736	—
Total Consolidated Companies	129	58	1,343	7	1,267	7	1,433	18
Equity in Affiliates	8	3	23	—	20	—	18	—
Total Including Affiliates	137	61	1,366	7	1,287	7	1,451	18

1 Indicates the fractional number of wells completed during the year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency.

2 Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned and the sum of the company's fractional interests in gross wells.

3 Includes completion of wells from August 1, 2005, related to the former Unocal operations.

Exploration Activities

The following table summarizes the company's net interests in productive and dry exploratory wells completed in each of the last three years and the number of exploratory wells drilling at December 31, 2005. "Exploratory wells" are wells drilled to find and produce crude oil or natural gas in unproved areas and include delineation wells, which are wells drilled to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir or to extend a known reservoir beyond the proved area. "Wells drilling" includes wells for which drilling activities have been temporarily interrupted at the end of 2005.

Exploratory Well Activity

	Wells Drilling at 12/31/05[2]		Net Wells Completed[1]					
			2005[3]		2004		2003	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States:								
California	—	—	—	—	—	—	—	—
Gulf of Mexico	10	6	14	8	13	8	25	9
Other U.S.	3	2	5	6	3	1	2	1
Total United States	13	8	19	14	16	9	27	10
Africa	1	—	4	1	3	1	3	1
Asia-Pacific	16	—	10	—	16	—	6	3
Indonesia	—	—	5	—	2	—	1	—
Other International	7	1	15	4	3	7	2	4
Total International	24	1	34	5	24	8	12	8
Total Consolidated Companies	37	9	53	19	40	17	39	18
Equity in Affiliates	—	—	7	—	—	—	—	—
Total Including Affiliates	37	9	60	19	40	17	39	18

1 Indicates the fractional number of wells completed during the year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency. Some exploratory wells are not drilled with the intention of producing from the well bore. In such cases, "completion" refers to the completion of drilling. Further categorization of productive or dry is based on the determination as to whether hydrocarbons in a sufficient quantity were found to justify completion as a producing well, whether or not the well is actually going to be completed as a producer.

2 Represents wells that are in the process of drilling but have been neither abandoned nor completed as of the last day of the year. Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned and the sum of the company's fractional interests in gross wells.

3 Includes completion of wells from August 1, 2005, related to the former Unocal operations.

Details of the company's exploration expenditures and costs of unproved property acquisitions for 2005, 2004 and 2003 are presented in Table I on page FS-65 of this Annual Report on Form 10-K.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron's 2005 key upstream activities, also discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations beginning on page FS-2, are presented below. The comments below include references to "total production" and "net production," which are defined in Exhibit 99.1 on page E-11 of this Annual Report on Form 10-K. Certain annual production statistics include volumes from the former Unocal operations from August 1, 2005. In addition to the activities discussed, Chevron was active in other geographic areas, but those activities were less significant.

The discussion below also references the status of proved reserves recognition for significant long-lead-time projects not yet on production and for projects recently placed on production. Reserves are not discussed for recent discoveries that have yet to advance to a project stage and for production in mature areas.

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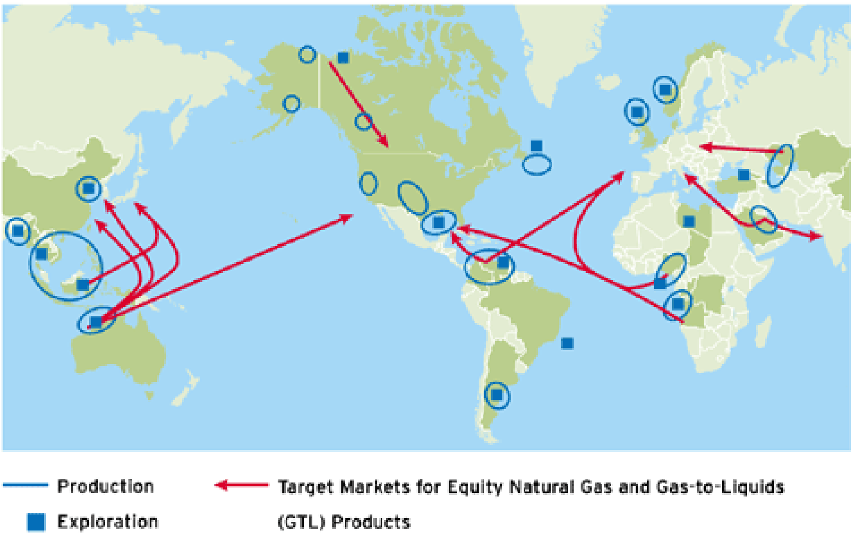
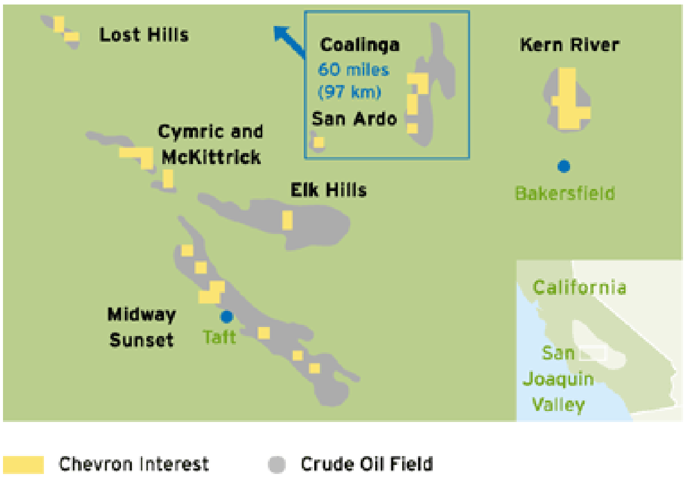
Consolidated Operations

Upstream Portfolio and Global Gas Strategy



a) United States

The United States upstream activities are concentrated in the Gulf of Mexico, Louisiana, Texas, New Mexico, the Rocky Mountains and California. Average daily net production during 2005 was 455,000 barrels of liquids and 1.6 billion cubic feet of natural gas, or 727,000 barrels per day on an oil-equivalent basis. With the acquisition of Unocal in August 2005, the company obtained properties that complemented and enhanced Chevron's already-strong positions in the Gulf of Mexico and the Permian Basin in West Texas and New Mexico. Refer to Table V beginning on page FS-70 for a discussion of the reserves and different characteristics for the company's major U.S. producing areas.



California: The company has significant production in the San Joaquin Valley. In 2005, average daily net production was 212,000 barrels of crude oil, 106 million cubic feet of natural gas and 5,000 barrels of natural gas liquids, or 235,000 barrels of daily production on an oil-equivalent basis. Approximately 83 percent of the crude oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

Gulf of Mexico: Average daily net production rates during 2005 for the company's combined interests in the Gulf of Mexico shelf and deepwater areas and the fields onshore Louisiana were 101,000 barrels of crude oil, 579 million cubic feet of natural gas and 11,000 barrels of natural gas liquids, or 208,000 oil-equivalent barrels daily. Prior to the hurricanes in August and September, oil-equivalent production in the Gulf of Mexico averaged approximately 300,000 barrels per day. Because of storm damages, fourth quarter 2005 production averaged only 160,000 barrels per day. The expected production level for the full year 2006 is about 200,000 barrels per day, with a slightly higher rate occurring in the first half of the year. Approximately 20,000 net oil-equivalent barrels of daily production are not expected to be sufficiently economic to restore.

In the deepwater areas, the company has an interest in four producing fields: Genesis, Petronius, K2 and Mad Dog. K2 and Mad Dog were added to the portfolio as a result of the Unocal acquisition.

The 57 percent-owned and operated Genesis Field averaged daily net production of approximately 9,000 barrels of crude oil and 11 million cubic feet of natural gas in 2005, or 11,000 barrels of oil-equivalent.

Petronius, which is 50 percent-owned and operated, had daily net production of 14,000 barrels of crude oil and 17 million cubic feet of natural gas in 2005, or 17,000 barrels of oil-equivalent. Petronius production was shut in for repairs following hurricane damage in September 2004 and resumed production in March 2005.

The Perseus discovery, which is part of the Petronius development, began production from its first well in the second quarter 2005. From start-up through year-end, average daily net production was 3,000 barrels of oil-equivalent. A second extended-reach well is expected to begin production in April 2006, with anticipated daily production rates between 3,000 and 7,000 barrels of net oil-equivalent. The Perseus project has an estimated production life of six to nine years, with maximum production anticipated in 2006. The company anticipates the majority of proved undeveloped reserves will be categorized as proved developed by the end of 2006.

Chevron has a 13 percent nonoperated interest in the former Unocal K2 Field, which had initial production from its first well in May 2005 and increased to approximately 2,000 barrels of net oil-equivalent production per day by November.

Chevron holds a 16 percent nonoperated interest in the Mad Dog Field, which commenced production in early 2005 and had average daily net production of 4,000 barrels of oil-equivalent for the five months following the acquisition of Unocal. Development work continues in order to increase the daily maximum total production to the design capacity of 80,000 barrels of crude oil and 40 million cubic feet of natural gas and is expected to be complete in 2008. Additional studies are under way to expand the total crude oil production capacity to more than 100,000 barrels per day. The Mad Dog Field has an estimated production life of 20 years. Additional reserve reclassification to proved developed is expected to coincide with the development program through 2008.

At Typhoon, the tension leg platform suffered catastrophic damage from Hurricane Rita in September 2005. Teams were formed to investigate the cause of the incident and evaluate options to possibly restore operations. Average daily net production prior to the storm from the 50 percent-owned and operated Typhoon Field, along with volumes processed from the nearby 25 percent-owned and nonoperated Boris Field, averaged about 6,000 barrels of oil-equivalent per day. Typhoon and Boris production remained shut-in in early 2006 pending ongoing salvage and restoration studies.

Development activity continues on the 58 percent-owned and operated Tahiti Field, where production start-up is expected in 2008. Most contracts for the engineering, procurement, fabrication and installation of the spar hull, topsides and subsea equipment were awarded in 2005. Construction of the floating production facility began in the fourth quarter. Initial booking of proved undeveloped reserves occurred in 2003, and the transfer of these reserves into the proved developed category is anticipated upon production start-up. With an expected production life of 30 years, Tahiti is anticipated to have a maximum total daily production of 125,000 barrels of crude oil and 70 million cubic feet of natural gas.

At the 63 percent-owned and operated Blind Faith discovery, a subsea development utilizing a semi-submersible production system was approved by Chevron and its partner in late 2005, at which time the company made its initial booking of proved undeveloped reserves. Reclassification of these reserves to the proved developed category is anticipated in the first half 2008, when first production is expected. Initial total daily output is estimated at 30,000 barrels of crude oil and 30 million cubic feet of natural gas.

Chevron also continues to evaluate development of the 33 percent-owned and nonoperated Great White discovery. Successful appraisal drilling was conducted in 2004, and the partners have formed a project management team to begin front-end engineering and design (FEED) in March 2006. No proved reserves had been recognized for this discovery as of early 2006.

The company participated in five wells in the Gulf of Mexico deepwater exploration program during 2005. The 2005 program resulted in two announced discoveries and one successful appraisal well. The discoveries were the 25 percent-owned and nonoperated Knotty Head discovery and the 60 percent-owned and operated Big Foot prospect. Additional appraisal activity was ongoing at both locations in early 2006. At the 30 percent-owned and nonoperated

Tubular Bells prospect that was discovered in 2003, further evaluation of commercial potential also continued, with additional follow-up drilling planned for 2006. A successful appraisal well was drilled in 2005 at the 2004 Jack discovery. An extended production test is expected to be under way in March 2006. Evaluation continues at nearby Saint Malo, where a successful follow-up appraisal well was drilled during 2004. The first appraisal well also commenced drilling at the nonoperated 2003 Puma discovery; however, the well was not completed as of early 2006 due to extensive weather and rig-related delays. Proved reserves were not yet recognized for any of these prospects as of early 2006.

Besides the activities connected with the development and exploration projects in the Gulf of Mexico area, Chevron also filed an application with the Federal Energy Regulatory Commission in the third quarter 2005 to own, construct and operate a natural gas import terminal at Casotte Landing in Jackson County, Mississippi. The proposed project, to be located adjacent to the Chevron-owned Pascagoula Refinery, would be designed to process imported liquefied natural gas (LNG) for distribution to industrial, commercial and residential customers in Mississippi and the Southeast region, including the growing Florida market. The terminal would have an initial natural-gas processing capacity of 1.3 billion cubic feet per day.

The company also exercised an option to increase its capacity at the Sabine Pass LNG terminal to 1 billion cubic feet per day. Additionally in the Sabine Pass area, the company signed an agreement in mid-2005 to secure 1 billion cubic feet per day of pipeline capacity in a new pipeline that will be connected to the Sabine Pass LNG terminal. Interconnect capacity of 600 million cubic feet per day was also secured to an existing pipeline. The new pipeline is planned to be in service in 2009, coinciding with the company's Sabine Pass terminal commitments. The new pipeline system will provide access to Chevron's Sabine and Bridgeline pipelines, which connect to the Henry Hub. The Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX) and is located on the natural gas pipeline system in Louisiana. Henry Hub interconnects to nine interstate and four intrastate pipelines.

Other U.S. Areas: Outside California and the Gulf of Mexico, the company manages operations in areas of the midcontinent United States that extend from the Rockies to southern Texas. The acquisition of Unocal in 2005 added to production operations in the Permian Basin of western Texas and southeastern New Mexico, the San Juan Basin area of New Mexico and Colorado, and in East Texas. Also as a result of the Unocal acquisition, Chevron operates 10 offshore platforms in Alaska and five producing natural gas fields in the Cook Inlet and owns nonoperated production on the North Slope. During 2005, the company's operations outside California and the Gulf of Mexico averaged daily net production of 126,000 barrels of crude oil and natural gas liquids and 949 million cubic feet of natural gas (284,000 barrels of oil-equivalent).

b) Africa

Angola: Chevron is the operator in the Block 0 and Block 14 concessions off the west coast, north of the Congo River. Block 0, in which Chevron has a 39 percent interest, is a 2,155-square-mile concession adjacent to the Cabinda coastline. Block 14, in which Chevron has a 31 percent interest, is a 1,580-square-mile deepwater concession located west of Block 0.

In Block 0, the company operates in two areas — A and B — composed of 20 fields that produced 119,000 barrels per day of net liquids in 2005. Area A, comprising 14 producing fields, averaged daily net production of approximately 73,000 barrels of crude oil and 1,000 barrels of liquefied petroleum gas (LPG) in 2005. Area B has six producing fields and averaged daily net production of 43,000 barrels of crude oil and 2,000 barrels of LPG in 2005. Included in the Area B production was the Sanha condensate natural gas utilization and Bomboco crude oil project, which started production in late 2004 and averaged daily net production of 10,000 barrels of oil-equivalent in 2005.

The Block 0 concession extends through 2030. Initial recognition of proved reserves for the Sanha Bomboco project was made at the end of 2002. Initial reclassification of reserves from proved undeveloped to proved developed occurred in 2004 and is expected to continue during the drilling program that is scheduled for completion in 2007.

In Block 14, net production from the Kuito Field, Angola's first deepwater producing area, averaged 15,000 net barrels of crude oil per day in 2005. First oil was produced from the Belize Field in January 2006. This was the initial production from Phase 1 of the $2.3 billion integrated drilling and production project for the Benguela, Belize, Lobito and Tomboco fields. Proved undeveloped reserves for both Benguela and Belize were recognized in 1998, and certain volumes for Belize were transferred to proved developed in 2005. The concession period for these fields expires in 2027.

Phase 2 of the Block 14 development involves the installation of subsea production systems, pipelines and wells for Lobito and Tomboco. Proved undeveloped reserves for these fields were recognized in 2000. Phase 2 is under construction, with first oil planned in late 2006. After both phases are completed, maximum total production in 2008 is estimated at approximately 200,000 barrels per day of crude oil. Proved developed reserves are expected to be recognized near the time of first oil once certain project milestones have been met. The concession period for these fields expires in 2027.

The Tombua and Landana fields in Block 14 were discovered in 1997 and 2001, respectively, and appraisal drilling was conducted from 1998 through 2002. Proved undeveloped reserves for Tombua and Landana were recognized in 2001 and 2002, respectively. The Tombua-Landana development is targeted as the next major capital project for Block 14, with FEED having begun in 2005. Estimated capital expenditures for the development exceed $2 billion. The concession period expires in 2028.

Chevron also has two other concessions in Angola — Block 2, 20 percent-owned and operated, and the joint venture FST area, in which the company has a 16 percent nonoperated interest. Net production from these properties in 2005 totaled 5,000 barrels of crude oil per day. Sonangol, Angola's national oil company, is scheduled to become operator of Block 2 during 2006.

In addition to the producing activities in Angola, the company also has a 36 percent interest in the planned Angola LNG project, which will be integrated with natural gas production in the area. In April 2005, the project partners awarded FEED contracts for a 5-million-metric-ton-per-year onshore LNG plant in the northern part of the country. Chevron and Sonangol are co-leaders of the project. Construction is expected to begin in 2007. Proved natural gas reserves associated with this project have not yet been recognized.

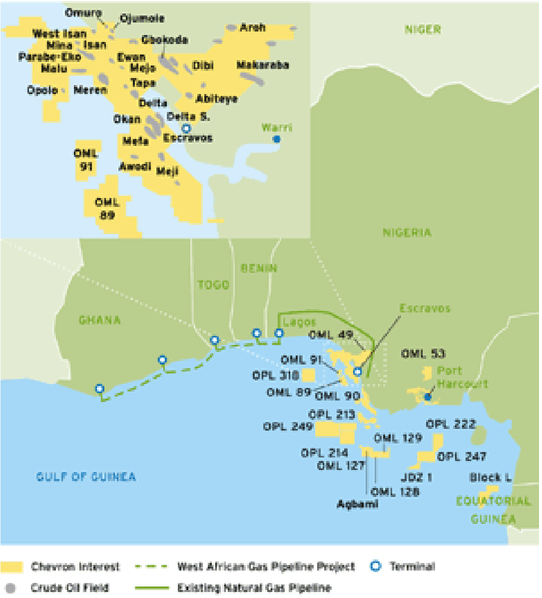
Democratic Republic of the Congo: As a result of the Unocal acquisition, Chevron acquired an 18 percent nonoperated working interest in a production-sharing contract off the coast of the Democratic Republic of the Congo. Daily net production for the five months after the Unocal acquisition from the seven acquired fields averaged 2,000 barrels of crude oil.

Republic of the Congo: Chevron has a 32 percent interest within the Haute Mer area (Nkossa, Nsoko and Moho-Bilondo exploitation permits) and a 29 percent interest within the Marine VII area (Kitina and Sounda exploitation permits), all of which are offshore Republic of the Congo and adjacent to the company's concessions in Angola. Net production from the Republic of the Congo properties averaged 11,000 barrels of crude oil per day in 2005. The Moho and Bilondo satellite field development was approved in 2005, with first production expected in 2008. Proved undeveloped reserves were initially recognized in 2001. Transfer to the proved developed category is expected near the time of first production. The Moho-Bilondo concession expires in 2030.

Southern Africa: The Lianzi-2 appraisal well was drilled in 2005 to assess the size and commerciality of the successful Lianzi-1 well drilled in the 14K/A-IMI Unit, located in a joint development area shared between the Republic of the Congo and Angola, in which the company is operator and holds a 31 percent interest. No proved reserves had been recognized as of early 2006.

Chad-Cameroon: Chevron is a nonoperating partner in a project to develop crude oil fields in southern Chad and transport crude oil by pipeline to the coast of Cameroon for export. Average daily net production from three fields in 2005 was 38,000 barrels of crude oil. Proved undeveloped reserves were recorded in 2000 and most have been reclassified to proved developed reserves. Over the next three to four years, additional reserves will be transferred to the proved developed category as additional wells are drilled, facilities are expanded and reservoir pressure-support projects are in place. Production began in 2003, and the life of the fields is estimated at 30 years. Chevron has a 25 percent interest in the upstream operations and a 21 percent interest in the pipeline.

Libya: In early 2005, the company was awarded Block 177 in Libya's first exploration license round under the Exploration and Production Sharing Agreement IV. Chevron will operate Block 177 with a 100 percent equity interest. A work program is under way, and contracting for the acquisition of seismic data is scheduled to begin in 2006.



Equatorial Guinea: Chevron is a 22 percent partner and operator of the Block L offshore Equatorial Guinea. The first exploration well completed in 2003 was non-commercial. A partner joined the venture in 2005 in return for partially funding an additional exploratory well to be drilled in 2006.

Nigeria: Chevron's principal subsidiary in Nigeria, Chevron Nigeria Limited (CNL), operates and holds a 40 percent interest in 14 concessions, predominantly in the onshore and near-offshore regions of the Niger Delta. CNL operates under a joint-venture arrangement with the Nigerian National Petroleum Corporation (NNPC), which owns the remaining 60 percent interest.

In 2005, daily net production from 32 fields averaged 122,000 barrels of crude oil, 3,000 barrels of LPG and 68 million cubic feet of natural gas.

Onshore operations in the Niger Delta with a net production capacity of approximately 45,000 barrels of crude oil per day, including the Olero Creek development, were suspended in 2003 as a result of the ongoing civil unrest. The Abiteye Field, closest to the Escravos terminal, was returned to production in 2004. Repairs to the Makaraba Flow Station were completed in mid-2005, allowing for the resumption of production of 6,000 net barrels per day from the Abiteye, Makaraba and Utonana fields and the Eastern Region. Further restoration of select Dibi wells and flowlines in late 2005 contributed to an additional 6,500 net barrels per day from the Dibi Field. As of year-end 2005, approximately 13,000 of the 45,000 barrels per day had been returned to production. Restoration activities in the remaining fields will continue at least through 2006.

During 2005, the company continued development activities for the deepwater Agbami project. The company's share of capital investment for the full project is estimated at $3.4 billion. In early 2005, the project achieved the following major milestones: conversion of Oil Prospecting License (OPL) 216 and OPL 217 to Oil Mining Lease (OML) 127 and OML 128; approval of the field development plan; award of the contract for the floating production, storage and offloading (FPSO) vessel; execution of the unit agreement; award of the subsea equipment, subsea installation and offloading system contracts; and approval of initial project funding by the partners. Five development wells were drilled in 2005, and development drilling is scheduled to continue through 2009. Proved undeveloped reserves were recognized for this project in 2002. Prior to the anticipated production start-up in 2008, certain proved undeveloped reserves are expected to be reclassified to proved developed reserves. The expected field life is approximately 20 years. Maximum total daily production of 250,000 barrels of liquids is expected to be reached within six to 12 months following start-up. Chevron's ownership interest under the unit agreement is 68 percent.

For the 2003 Aparo discovery on OPL 213, Chevron signed a joint-study agreement in 2004 with the operator of OPL 212 to conduct technical studies in pursuit of a unitized joint development of the Aparo and Bonga SW fields, which straddle OPL 212, OPL 213 and OPL 249. Unitization discussions continued through 2005, and a pre-unit agreement is expected to be signed by the end of the first quarter 2006. Development will likely involve an FPSO and subsea wells. FEED and basic engineering are expected to commence by the end of the first quarter 2006. Chevron's initial interest in the unitized field is anticipated to be 20 percent. Proved undeveloped reserves are expected to be recognized in 2006, and production start-up is targeted for late 2010.

Chevron operates and holds a 95 percent interest in the OPL 249 Nsiko discovery. The discovery well was drilled in 2003, followed by two successful appraisal wells in 2004. Subsurface evaluations and field development planning continued in 2005. FEED and basic engineering are expected to commence in late 2006.

In OPL 222 during 2005, activities continued in the greater Usan area with the successful drilling of the seventh and eighth appraisal wells. The Usan field-development plan was approved in 2005, and in early 2006, regulatory approval of the OML conversion for the Usan development was in the process of being finalized. Once approved, the end date of the concession period will be determined. Proved undeveloped reserves were recorded in 2004 for the Usan Field, and development entered its basic engineering phase in 2005. Production start-up is estimated for late 2010, before which time certain proved undeveloped reserves are expected to be reclassified to the proved developed category. The company holds a 30 percent nonoperated interest in this project.

The Nnwa Field, discovered in OPL 218 in 1999, extends into adjacent blocks OPL 219 and OPL 246. Commerciality of the field is under evaluation. During 2005, OPL 218 was converted to OML 129.

At the Escravos Gas Plant (EGP), onshore and offshore engineering, procurement and construction bids were awarded in early 2005 for the Phase 3 expansion of the natural gas processing facilities. Early site work began in late 2005, and construction commenced in February 2006. Start-up is expected in 2008 and includes adding a second natural gas plant with 395 million cubic feet of capacity, potentially increasing capacity to 680 million cubic feet of natural gas per day and LPG and condensate exports to 43,000 barrels per day. Proved undeveloped reserves associated with EGP Phase 3 were recognized in 2002. These reserves are expected to be reclassified to proved developed as various stages of EGP and related projects are completed. The anticipated life of the project is 25 years. Chevron holds a 40 percent operated interest in this project.

Refer to page 30 for a discussion on the planned Escravos gas-to-liquids facility.

The West African Gas Pipeline regional project is planned to supply Nigerian natural gas to customers in Ghana, Benin and Togo for industrial applications and power generation. Chevron holds a 38 percent interest in the project. Detailed engineering and the award of several major construction contracts occurred in early 2005. In the third quarter 2005, the company commenced installation of a 350-mile main offshore segment of the West African Gas Pipeline that will connect to an existing onshore pipeline in Nigeria. Start-up is expected in late 2006. Chevron is the managing sponsor in West African Pipeline Company Limited, which will construct, own and operate the pipeline.

The South Offshore Water Injection Project (SOWIP) is an enhanced crude-oil recovery project in the south offshore area of OML 90. Chevron holds a 40 percent interest as part of the joint venture with NNPC. The objective of the SOWIP is to increase production by providing water injection, natural gas lift and production de-bottlenecking in the South Offshore Asset Area (Okan and Delta fields). Offshore construction and commissioning activities were under way in early 2006. Incremental proved reserves were recognized for SOWIP in 2005. The project has an expected 25-year life.

In April 2005, Chevron entered into a memorandum of understanding (MOU) with partners to evaluate the viability of an LNG plant at the Olokola site located in a free trade zone between Lagos and Escravos. The plans for the proposed LNG plant, in which Chevron anticipates holding a 19 percent interest, include a phased development of four processing trains (5.5 million metric tons per year each). FEED is expected to commence by the end of the first quarter 2006. The project is expected to start up in 2010 or 2011. CNL is expected to supply approximately 1.8 billion cubic feet per day of natural gas to the project. CNL is in the process of completing the certification of the reserves required to satisfy the natural gas supply requirements for this project. No proved reserves had been recognized as of early 2006.

Nigeria - São Tomé e Príncipe Joint Development Zone (JDZ): The company was awarded JDZ Block 1 in 2004. In early 2005, the company signed a production-sharing contract with the Joint Development Authority, under which Chevron will be the operator with a 51 percent interest. The first exploration well began drilling in January 2006, with planned completion of drilling operations in March 2006.

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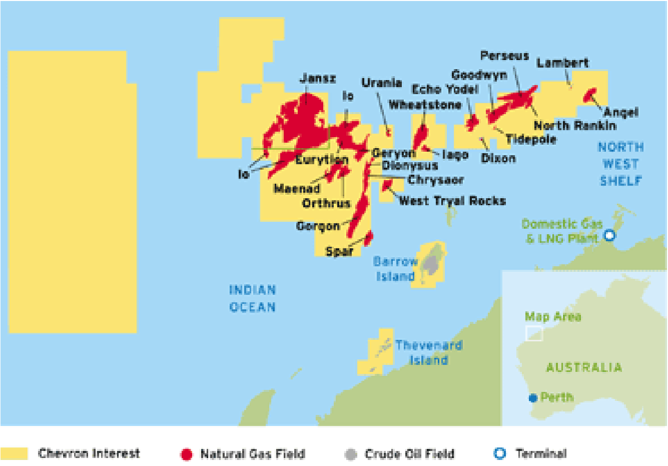
c) **Asia-Pacific**



Australia: Chevron has a 17 percent interest in the North West Shelf (NWS) venture offshore Western Australia. Daily net production from the project during 2005 averaged 17,000 barrels of condensate, 360 million cubic feet of natural gas, 14,000 barrels of crude oil and 5,000 barrels of liquefied petroleum gas. Approximately 74 percent of the natural gas was sold in the form of LNG to major utilities in Japan and South Korea, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market. Expansion of a fifth LNG train, which will increase export capacity by more than 4 million metric tons per year to approximately 16 million, was approved in 2005, with commissioning expected in 2008. In December 2005, the venture participants approved development of the Angel natural gas field, which will supply the fifth LNG train. NWS reserves are recorded according to existing sales agreements. Start-up of the fifth LNG train will accelerate reclassification of proved undeveloped reserves to proved developed. The end of the concession period for the NWS project is 2034.

On Barrow and Thevenard islands, Chevron operates crude oil producing facilities that had combined net production of 6,000 barrels per day in 2005. Chevron's equity interest in this operation is 57 percent for Barrow Island and 51 percent for Thevenard Island.

Chevron also is the operator of the Gorgon-area fields and has interests in other Greater Gorgon fields off the northwest coast of Australia. Twelve discovered natural gas fields straddle 17 lease blocks in the Greater Gorgon Area. Chevron and its two joint-venture participants signed a Framework Agreement in April 2005 that will enable the combined development of Gorgon and the nearby natural gas fields as one world-scale project. Chevron has a 50 percent ownership interest across most of the Greater Gorgon Area. The Gorgon Project awarded upstream and downstream FEED and engineering, procurement and construction contracts in June 2005 for a two-train (10 million metric tons per year) LNG facility and a possible domestic natural gas plant on Barrow Island, targeting initial production by 2010. Proved reserves have not been recognized for any of the Gorgon-area fields. Recognition is contingent on securing sufficient LNG sales agreements and other key project milestones.

In the fourth quarter 2005, the company signed separate nonbinding Heads of Agreements with three companies in Japan to supply LNG from the Gorgon project. Negotiations are under way to finalize binding sales agreements. Purchases will range from 1.2 million metric tons per year to 1.5 million metric tons per year of LNG over 25 years, commencing in 2010 and 2011.

During 2005 and early 2006, the company was awarded exploration rights to five deepwater blocks in the Carnarvon Basin offshore Western Australia. Chevron holds a 50 percent, operated interest in the blocks. Two-dimensional (2-D) seismic survey was acquired over four of the blocks.

Also in 2005, 3-D seismic survey was acquired for the wholly owned Wheatstone-1 2004 natural gas discovery offshore Western Australia. Two appraisal wells were also completed in the Browse Basin, located offshore northwest Australia.

Interests ranging from 25 percent to 50 percent in three blocks offshore southern Australia and two blocks in northwest Australia were added to Chevron's portfolio through the Unocal acquisition. The company is working with partners on a detailed technical evaluation of the blocks in southern Australia. The blocks in the northwest have well commitments that are targeted for drilling in the next three years.

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Azerbaijan: Chevron acquired Unocal's 10 percent working interest in the Azerbaijan International Operating Company (AIOC), which holds offshore crude oil reserves in the Caspian Sea from the Azeri-Chirag-Gunashli (ACG) project. Also as a result of acquiring Unocal, the company has a 9 percent equity interest in Baku-Tbilisi-Ceyhan (BTC) pipeline, which will transport AIOC production from Baku, Azerbaijan through Georgia to deepwater port facilities in Ceyhan, Turkey. The pipeline is planned to have a crude capacity of 1 million barrels per day. The first tanker-loading of crude oil at the Ceyhan marine terminal is expected to occur in the spring of 2006.

In the five months of 2005 following the company's acquisition of Unocal, AIOC's daily net crude oil production averaged 31,000 barrels. First oil production from Phase I development of the ACG crude oil project began in early 2005, and production from the first of two additional platforms in Phase II began at the end of 2005, at which time a portion of proved undeveloped reserves were reclassified to proved developed. Production from the second platform is expected in late 2006. Phase III, which is the deepwater portion of the project and the final phase of development, was approved in 2004. Production start-up for Phase III is targeted for 2008. Proved undeveloped reserves will be reclassified to proved developed reserves as new wells are drilled and completed. The AIOC operations are conducted under a 30-year production-sharing contract that expires at the end of 2024.

Kazakhstan: Chevron holds a 20 percent nonoperated interest in the Karachaganak project that is being developed in phases. Phase 2 of the field development was completed in 2004, and Phase 3 was under evaluation as of early 2006. Access for Karachaganak production to the Caspian Pipeline Consortium (CPC) pipeline allows sales of approximately 150,000 barrels per day of processed liquids (28,000 net barrels) at prices available in world markets. During 2005, Karachaganak daily net production averaged 37,000 barrels of liquids and 142 million cubic feet of natural gas. Proved developed reserves associated with Phase 2 were added in 2002 through 2005. The Karachaganak operations are conducted under a 40-year concession agreement that expires in 2038. Timing for the recognition of Phase 3 reserves and an increase in production are uncertain and depend on achieving a natural gas sales agreement. Refer also to page 23 for a discussion of Tengizchevroil, a 50 percent-owned affiliate with operations in Kazakhstan.

Russia: In 2005, OAO Gazprom included Chevron on a list of companies that could continue further commercial and technical discussions concerning the development and related commercial activities of the Shtokmanovskoye Field. Discussions were under way in early 2006, but the timing of Gazprom's selection of the company or companies that will participate in the field development was uncertain. Shtokmanovskoye is a very large natural gas field offshore Russia in the Barents Sea. OAO Gazprom is Russia's largest natural gas producer.

Turkey and Georgia: Chevron is the operator of the Silopi Block in southeast Turkey with a 25 percent interest. It also has a 25 percent interest in Turkey Black Sea deepwater Block 3534, which was part of the Unocal acquisition. Also as part of the Unocal acquisition, Chevron holds 10 percent interests in several adjacent blocks in Georgia.

Bangladesh: Through the Unocal acquisition, Chevron became operator of four blocks, with a 98 percent interest in Blocks 12, 13 and 14 and a 43 percent interest in Block 7. For the five-month period after the acquisition, the properties averaged daily net production of 141 million cubic feet of natural gas. In early 2006, Chevron was supplying about 20 percent of the natural gas market in Bangladesh. Chevron plans to build a natural gas processing plant and natural gas pipeline in connection with a 2004 agreement to produce natural gas from the Bibiyana Field in Block 12. Initial production is expected late in the fourth quarter 2006. Additional proved reserves are expected to be recorded in 2006. The Bibiyana production-sharing contract expires in 2034. First production from the Moulavi Bazar Field began in March 2005. The Moulavi Bazar production-sharing contract expires in 2028.

Cambodia: Chevron operates and holds a 55 percent interest in the 1.6 million-acre Block A, located offshore in the Gulf of Thailand. In 2004, the company processed more than 600,000 acres of 3-D seismic data and drilled five exploration wells in its second exploration campaign, resulting in four crude oil discoveries. As a result, Chevron and its partners in 2005 obtained a two-year extension of the Cambodia exploration permit. As of early 2006, the company was evaluating data from the five wells and was planning a third drilling campaign that is expected to begin later in the year and be completed in 2007.

Myanmar: As a result of the Unocal acquisition, Chevron has a 28 percent nonoperated working interest in a production-sharing contract for the production of natural gas from the Yadana Field, located offshore Myanmar in the Andaman Sea. The company also has a 28 percent ownership interest in a pipeline company that transports the natural gas from the Yadana Field to the Myanmar-Thailand border for final delivery to power plants in Thailand. Average net natural gas production following the acquisition was 76 million cubic feet per day.

Thailand: Chevron operates Blocks B8/32, 9A and G4/43 in the Gulf of Thailand. The company holds a 52 percent interest in Blocks B8/32 and 9A and a 60 percent interest in Block G4/43. Through the Unocal acquisition, the company also has operated interests ranging from 35 percent to 80 percent in Blocks 10 through 13 and 12/27 and a 16 percent nonoperated interest in Blocks 14A, 15A and 16A, known collectively as the Arthit Field. Chevron also holds both operated and nonoperated interests ranging from 33 percent to 80 percent in a number of exploration blocks that are currently inactive, pending resolution of border issues between Thailand and Cambodia.

Block B8/32 produces crude oil and natural gas from four fields: Benchamas, Maliwan, North Jamjuree and Tantawan. Block 9A was brought online in 2005. Daily net production in 2005 from these two blocks was 105 million cubic feet of natural gas and 25,000 barrels of crude oil. Also in 2005, the company completed the development study for the Block 8/32 Central Belt Area, with first production anticipated in 2007.

Two appraisal wells were drilled in Block G4/43 in early 2005 and resulted in the successful extension of the Similan and Lanta oil trends. In addition, 3-D seismic data acquisition and processing relating to other prospects were completed in August 2005. First crude oil production is anticipated in early 2007.

In the acquired Unocal operations, three platforms were installed in the Pailin and Kaphong areas and 90 wells were drilled post-merger. De-bottlenecking of several central processing platforms was nearly completed in 2005, which is expected to add more than 150 million cubic feet per day of natural gas processing capability. Thai Oil Phase 2 development of the offshore crude oil project in the Pattani Field started up in May 2005. Chevron has the right to operate in this concession until 2022. Phase 1 development of the Arthit Field began in late 2005, with first production planned for 2007. Net production from these areas for the last five months of 2005 averaged 726 million cubic feet per day of natural gas and 43,000 barrels of crude oil and condensate per day.

Vietnam: As a result of the Unocal acquisition, the company has two production-sharing contracts offshore southwest Vietnam in the northern part of the Malay Basin. Chevron has a 42 percent interest in Blocks B and 48/95 and a 43 percent interest in Block 52/97. In 2005, the company was awarded a 50 percent interest and will be the operator in Block 122, located offshore eastern Vietnam.

China: Chevron has a 33 percent nonoperated interest in Blocks 16/08 and 16/19, located in the Pearl River Delta Mouth Basin; a 25 percent interest in QHD-32-6 in Bohai Bay; and a 16 percent working interest in the unitized and producing Bozhong 25-1 Field in Bohai Bay Block 11/19. Daily net production from the company's interests in China averaged 26,000 barrels of crude oil in 2005. The company also has interests ranging from 50 percent to 64 percent in four prospective onshore natural gas blocks totaling about 1.6 million acres.

Partitioned Neutral Zone (PNZ): Saudi Arabian Texaco Inc., a Chevron subsidiary, holds a 60-year concession that expires in 2009 to produce crude oil from onshore properties in the PNZ, which is located between the Kingdom of Saudi Arabia and the State of Kuwait. As of early 2006, the company was actively seeking an extension or renewal of the agreement. The company, by virtue of its concession, has the right to Saudi Arabia's 50 percent undivided interest in the hydrocarbon resource and pays a royalty and other taxes on volumes produced. During 2005, average daily net production was 112,000 barrels of crude oil and 22 million cubic feet of natural gas. Construction of steamflood pilot facilities was completed in 2005. The facilities serve as a precursor for a second-phase pilot project that was in the front-end engineering stage in early 2006. The second phase entails drilling 16 injection wells, 25 producing wells and the installation of water-treatment and steam-generation facilities. The estimated total project cost is more than $300 million. This is the first project of its type in the Middle East.

Philippines: The company holds a 45 percent nonoperated interest in the Malampaya natural gas field located about 50 miles offshore Palawan Island. Daily net production in 2005 was 163 million cubic feet of natural gas and 8,000 barrels of condensate. As a result of the Unocal acquisition, Chevron also develops and produces steam resources under an agreement with the National Power Corporation, a Philippine government-owned company. The combined installed generating capacity is 634 megawatts.

d) Indonesia

Chevron's operated interests in Indonesia are primarily managed by two wholly owned subsidiaries, PT. Chevron Pacific Indonesia (CPI) and Chevron Geothermal Indonesia (CGI). CPI accounts for nearly half of Indonesia's total crude oil output and operates four production-sharing contracts (PSCs), with interests ranging from 50 percent to 100 percent. CGI is a power generation company that operates the Darajat geothermal contract area in West Java with a total capacity of 145 megawatts and a cogeneration facility in support of CPI's operation in North Duri. Chevron also has a 25 percent interest in a nonoperated joint venture in South Natuna Sea Block B. Through the Unocal acquisition, the company operates the Salak geothermal field located in West Java, with a total capacity of 377 megawatts, and holds interests in eight PSCs offshore East Kalimantan in the Kutei Basin and three PSCs offshore northeast Kalimantan. These interests range from 24 percent to 100 percent.

A development concept for the Sadewa project, located in the Kutei Basin, is scheduled for selection in 2006, with initial proved reserves recognition planned for 2007. First production is expected in 2008. The company also advanced development plans during 2005 for its Gendalo Hub and Gehem Hub deepwater natural gas projects, also located in the Kutei Basin. Development concepts are expected to be selected in 2006. These projects will likely be developed in parallel, with first production for both projects targeted for the 2010 to 2012 time frame. The actual timing is partially dependent on government approvals and market conditions. In addition, development is progressing on steamflood activity in North Duri.

Heritage-Chevron's share of net production in CPI-operated areas during 2005 was 193,000 barrels of oil-equivalent per day. Daily net production from South Natuna Sea Block B in 2005 averaged 21,000 barrels of oil-equivalent. Net production from the acquired Unocal operations was 56,000 barrels of oil-equivalent per day for five months ended December 31, 2005.

e) **Other International Areas**

Argentina: Chevron operates in Argentina through its subsidiary, Chevron San Jorge S.R.L. The company and its partners hold more than 2.8 million acres in the Neuquen and Austral basins in 17 operated production concessions and five exploration blocks (one operated and four nonoperated). Working interests range from approximately 19 percent to 100 percent in operated license areas. Exploration farm-out agreements were reached in three blocks during 2005, and farm-out efforts in the remaining two exploration blocks continued into 2006. Daily net production in 2005 averaged 43,000 barrels of crude oil and 55 million cubic feet of natural gas.

Brazil: Chevron holds working interests ranging from 20 percent to 52 percent in four deepwater blocks that span a total of 178 million acres. Exploration is concentrated in the Campos and Santos basins. In the nonoperated Campos Basin Block BC-20, two areas — 38 percent-owned RJS610 and 30 percent-owned RJS609 — have been retained for development following the end of the exploration phase of this block. In the RJS610 area, a three-well appraisal program on the BC-20-610 Field was completed in December 2005, and results confirmed hydrocarbons from a new Eocene reservoir. FEED for this new field is expected to commence in early 2007. In the RJS609 area, one discovery well was drilled in 2005. Two appraisal wells are planned for 2006. Also in the Campos Basin, the company holds a 30 percent nonoperated interest in the BM-C-4 Block in which one exploration well is planned during 2006. In the 20 percent-owned and nonoperated Santos Basin BS-4 Block, an additional appraisal well is planned for the second quarter 2006.

In the Frade Field (Block BC-4), located in the Campos Basin, the company is the operator and has a 43 percent interest. FEED for a floating, production, storage and offloading vessel and subsea production systems was completed in 2005. Project sanction is expected in 2006, with first oil expected in 2008. Proved undeveloped reserves were recorded for the first time in 2005. The Frade concession expires in 2025.

Colombia: The company operates three natural gas fields in Colombia — the offshore Chuchupa and the onshore Ballena and Riohacha. The fields are part of the Guajira Association contract, a joint venture production-sharing agreement, which was extended in 2003. At that time, additional proved reserves were recognized. The company continues to operate the fields and receives 43 percent of the production for the remaining life of each field as well as a variable production volume from a fixed-fee Build-Operate-Maintain-Transfer (BOMT) agreement based on prior Chuchupa capital contributions. The BOMT agreement expires in 2016. Net production averaged 185 million cubic feet of natural gas per day in 2005. New production capacity is scheduled for commissioning in 2006 and will help meet the demand from the growing Colombian natural gas market.

Trinidad and Tobago: The company has a 50 percent nonoperated interest in four blocks in offshore Trinidad, which include the producing Dolphin natural gas field and two discoveries, Dolphin Deep and Starfish. Net natural gas production from the Dolphin Field in 2005 averaged 115 million cubic feet per day. Natural gas supply to the Atlantic LNG Train 3 from the Dolphin Field began in November 2005. Initial recognition of proved undeveloped reserves associated with the natural gas sales agreement for Train 3 was made in 2003. Proved reserves associated with the Train 4 gas sales agreement were recognized in 2004. Initial production of the Train 4—related reserves is scheduled for the first half of 2006. Reserves associated with Trains 3 and 4 were transferred to the proved developed category in 2005. The contract period for Train 3 ends in 2023 and for Train 4 in 2026. Chevron also holds a 50 percent, operated interest in Block 6d. In early 2005, the company announced successful exploration drilling results at the offshore Manatee 1 exploration well in Block 6d. The company is assessing alternative development strategies. A unitization agreement is being negotiated between Trinidad and Tobago and Venezuela to develop and produce the Loran and Manatee fields as one project.

Venezuela: The company operates the onshore Boscan Field under an operating services agreement and receives operating expense reimbursement and capital recovery, plus interest and an incentive fee. Daily net production in 2005 averaged 111,000 barrels of crude oil. The company has not recorded proved reserves under this agreement. The company also has production at the 63 percent-owned LL-652 Field located in Lake Maracaibo. Net production in 2005 averaged 10,000 barrels of oil-equivalent per day. The company operates at LL-652 under a risked service agreement.

In 2005, the Venezuelan government stipulated that the existing Boscan and LL-652 operating service agreements be converted to an Empresa Mixta (EM), or a Joint Stock contractual structure, with Petróleos de Venezuela, S.A. (PDVSA) as majority shareholder. In December 2005, Chevron signed a transition agreement with PDVSA in order to negotiate the ownership and format of the final EM structure during 2006. Possible financial implications of the EM structure are uncertain but are not expected to have a material effect on the company's consolidated financial position or liquidity.

The company has ongoing exploration activity in two blocks offshore Plataforma Deltana. In Block 2, which includes Loran Field, evaluation and project development work continue after an exploration and appraisal program was completed in 2005. Proved reserves have not been recognized for this project. The company is operator and holds a 60 percent interest. In the 100 percent-owned and operated Plataforma Deltana Block 3, Chevron drilled the successful Macuira natural gas discovery well in 2005. This discovery is in close proximity to the Loran natural gas field and provides significant resources that will be included in the detailed evaluation of a project for the possible construction of Venezuela's first LNG train. Seismic work in Block 3 is planned for 2006. Chevron was awarded the exploration license in 2005 for the 100 percent-owned Cardon III exploration block, located offshore western Venezuela. The block has natural gas potential to the north of the Maracaibo producing region.

Refer also to page 24 for a discussion of the Hamaca heavy oil production and upgrading project in Venezuela.

Canada: Following the acquisition of Unocal, the company completed the sale of Northrock Resources Limited for approximately $1.7 billion. The company continues to maintain strategically significant assets in Canada, including a 27 percent nonoperated interest in the Hibernia Field; a 20 percent nonoperated interest in the Athabasca Oil Sands Project, which is discussed separately on page 29; a 28 percent operated interest in the Hebron project, where feasibility studies preceding the major development project are continuing; and exploration opportunities in the Mackenzie Delta and Orphan Basin. Excluding Athabasca and Northrock, daily net production in 2005 from the company's Canadian operations was 52,000 barrels of crude oil and natural gas liquids and 6 million cubic feet of natural gas.

Denmark: Chevron holds a 15 percent non-operating interest in the Danish Underground Consortium (DUC), which produces crude oil and natural gas from 15 fields in the Danish North Sea and has 12 percent to 27 percent interests in five exploration areas. Daily net production in 2005 from the DUC was 47,000 barrels of crude oil and 146 million cubic feet of natural gas.

Faroe Islands: In January 2005, the company was awarded five offshore exploration blocks in the second offshore licensing round. The blocks cover approximately 170,000 acres and are near the Rosebank/ Lochnagar discovery in the United Kingdom. An extensive 2-D regional seismic program was acquired in 2005 and will be interpreted in 2006. The company has a 40 percent interest in the blocks and is the operator.

Netherlands: Chevron gained interests ranging from 34 percent to 80 percent in nine blocks in the Netherlands sector of the North Sea as part of the Unocal acquisition. The company's share of daily production from four producing blocks during the five months post-acquisition was 4,000 barrels of crude oil and 10 million cubic feet of natural gas.

Norway: At the Draugen Field, where Chevron holds an 8 percent nonoperated interest, the company's share of production during 2005 was 8,000 barrels of crude oil per day. In September 2005, Chevron participated in the drilling of the Mojave exploration well (also known as Stetind) in PL 283, in which the company holds a 25 percent nonoperated interest. The results of this natural gas well were being evaluated in early 2006. In PL 324, in which the company has a 30 percent nonoperated interest, drilling is planned for late 2006. In the 40 percent-owned and operated PL 325, a seismic program will be conducted in mid-2006.

United Kingdom: Offshore United Kingdom, the company's daily net production in 2005 from several fields was 83,000 barrels of crude oil and 300 million cubic feet of natural gas. Daily net production at the 85 percent-owned and operated Captain Field was 42,000 barrels of crude oil. The company's share of daily net production in 2005 at the co-operated and 32 percent-owned Britannia Field was 8,000 barrels of crude oil and 176 million cubic feet of natural gas. At the Alba Field in the North Sea, in which Chevron holds a 21 percent interest and operatorship, daily net production averaged 12,000 barrels of crude oil.

In the fourth quarter 2005, the company was awarded equity in eight exploration blocks under the 23rd United Kingdom Offshore Licensing Round. Four blocks are located adjacent to the Rosebank/ Lochnagar offshore discovery. Chevron will be the operator with a 40 percent interest.

Chevron also holds a 19 percent interest in Clair, a nonoperated development. Initial production began in February 2005 and is expected to attain an average daily net production of 12,000 barrels of crude oil and 3 million cubic feet of natural gas in late 2006. Initial recognition of proved reserves was in 2001. Some reserves were reclassified from proved undeveloped to proved developed in late 2004. Further reclassifications are expected to occur through 2008 related to planned development drilling. Clair has an expected field life of more than 20 years.

Joint development activities continued at the Britannia satellite fields, Callanish and Brodgar, where Chevron holds 17 percent and 25 percent interests, respectively. Four development wells were completed in 2005. First production is expected in early 2007, building to planned daily net production of 10,000 barrels of crude oil and 50 million cubic feet of natural gas several months after start-up. Proved undeveloped reserves were initially recognized in 2000. In 2006, proved undeveloped reserves are expected to be reclassified to proved developed ahead of planned commencement of production in early 2007. This development has an expected production life of approximately 15 years.

Design and construction work progressed on the Captain Area C project to develop the eastern portion of the Captain Field, with first oil planned for mid-2006.

The Alder discovery, west of the Britannia Field, is being evaluated as a tie-back to existing infrastructure. Production start-up is anticipated in 2009. Initial reserves are planned to be booked in 2008.

Mexico: In early 2005, the company executed the concession title that would allow construction of the proposed Baja LNG terminal based in offshore Mexican territorial waters. If approved by the company and various government agencies, the terminal would be constructed using a gravity-based structure design with an initial processing capacity of approximately 700 million cubic feet per day.

f) Affiliate Operations

Kazakhstan: The company holds a 50 percent interest in Tengizchevroil (TCO), which is developing the Tengiz and Korolev crude oil fields located in western Kazakhstan under a 40-year concession that expires in 2033. Net production in 2005 averaged 136,000 barrels per day of crude oil and natural gas liquids and 216 million cubic feet of natural gas.

TCO is currently undertaking a significant expansion composed of two integrated projects referred to as the Second Generation Plant (SGP) and Sour Gas Injection (SGI). At a total cost of approximately $5.5 billion, these projects are designed to increase TCO's crude oil production capacity by the third quarter 2007 from the current 300,000 barrels per day to between 460,000 and 550,000 barrels. The actual production level within the estimated range is dependent partially on the effects of the SGI, which are discussed below.

SGP involves the construction of a large processing train for treating crude oil and the associated sour (i.e., high in sulfur content) gas. The SGP design is based on the same conventional technology employed in the existing processing trains. In addition to new processing capacity, SGP involves drilling and/or completing 55 production wells in the Tengiz and Korolev reservoirs to generate the volumes required for the new processing train. Proved undeveloped reserves associated with SGP were recognized in 2001. Some of these reserves were reclassified to proved developed in

2005, based upon completion of specified project milestones. Over the next decade, ongoing field development is expected to result in the reclassification of additional proved undeveloped reserves to proved developed.

SGI involves taking a portion of the rich, sour gas separated from the crude oil production at the SGP processing train and re-injecting it into the Tengiz reservoir. Chevron expects that SGI will have two key effects. First, SGI will reduce the sour gas processing capacity required at SGP, thereby increasing liquid production capacity and lowering the quantities of sulfur and gas that would otherwise be generated. Second, over time it is expected that SGI will increase production efficiency and recoverable volumes due to the maintenance of higher reservoir pressure from the gas re-injection. Between 2007 and 2008, the company anticipates recognizing additional proved reserves associated with the SGI expansion. The primary SGI risks include uncertainties about compressor performance associated with injecting high-pressure sour gas and subsurface responses to injection.

Essentially all of TCO's production is exported through the Caspian Pipeline Consortium (CPC) pipeline that runs from Tengiz in Kazakhstan to tanker loading facilities at Novorossiysk on the Russian coast of the Black Sea. CPC is working on obtaining shareholder approval for an expansion to fully accommodate increased TCO volumes by 2009. During 2005, TCO sanctioned the Crude Export project and awarded commercial contracts, which will provide additional export routes utilizing rail transportation to the Odessa Ukraine marine terminal and to marine terminals in Aktau, Kazakhstan. In conjunction with existing CPC capacity, the Crude Export project is expected to provide TCO with sufficient capacity to export all TCO production, including volumes produced by SGI/ SGP, prior to expansion of the CPC pipeline.

Venezuela: Chevron has a 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt. The crude oil upgrading began in October 2004. In the first quarter 2005, the facility reached total design capacity of processing and upgrading 190,000 barrels per day of heavy crude oil (8.5° API) into 180,000 barrels of lighter, higher-value crude oil (26° API). In 2005, net production averaged 41,000 barrels of oil-equivalent per day.

Petroleum — Sale of Natural Gas and Natural Gas Liquids

The company sells natural gas and natural gas liquids from its producing operations under a variety of contractual arrangements. Outside the United States, the majority of the company's natural gas sales occur in Thailand, the United Kingdom, Australia, and Latin America, and in the company's affiliate operations in Kazakhstan. International natural gas liquids sales take place in Africa, Australia and Europe. Refer to "Selected Operating Data," on page FS-12 in Management's Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company's natural gas and natural gas liquids sales volumes.

Petroleum — Refining Operations

At the end of 2005, the company's refining system consisted of 19 fuel refineries and an asphalt plant. The company operated nine of these facilities, and 11 were operated by affiliated companies. For these 20 facilities, crude oil distillation capacity utilization averaged 86 percent in 2005, compared with 89 percent in 2004. In general, this decrease resulted from planned and unplanned downtime as well as the impact of two hurricanes in the third quarter 2005. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 90 percent in 2005, compared with 96 percent in 2004, and cracking and coking capacity utilization averaged 76 percent and 88 percent in 2005 and 2004, respectively. Cracking and coking units, including fluid catalytic cracking units, are the primary facilities used in fuel refineries to convert heavier products to gasoline and other light products.

In 2005, the company began an expansion of the Pascagoula, Mississippi, refinery's fluid catalytic cracking unit to increase its production of gasoline and other light products. Additionally, GS Caltex, the company's 50 percent-owned affiliate, approved an upgrade project at the 650,000-barrel-per-day Yeosu refining complex in South Korea. At a total estimated cost of $1.5 billion, this project is designed to increase the yield of high-value refined products and reduce feedstock costs through the processing of heavy crude oil. Start-up of these two projects is expected in 2006 and 2007, respectively.

The company's U.S. West Coast and Gulf Coast refineries produce low-sulfur fuels that meet 2006 federal government specifications. Investments required to produce low-sulfur fuels in Europe, Canada and South Africa have been completed, and clean fuels projects in Australia are scheduled for completion in 2006.

The company processes imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 83 percent and 81 percent of Chevron's U.S. refinery inputs in 2005 and 2004, respectively.

The daily refinery inputs for 2003 through 2005 for the company and affiliate refineries are as follows:

Petroleum Refineries: Locations, Capacities and Inputs
(Inputs and Capacities in Thousands of Barrels per Day)

Locations		December 31, 2005		Refinery Inputs		
		Number	Operable Capacity	2005	2004	2003
Pascagoula	Mississippi	1	325	263	312	301
Richmond	California	1	225	233	233	235
El Segundo	California	1	260	230	234	242
Kapolei	Hawaii	1	54	50	51	52
Salt Lake City	Utah	1	45	41	42	40
El Paso[1]	Texas	—	—	—	—	36
Other[2]		1	80	28	42	45
Total Consolidated Companies — United States		**6**	**989**	**845**	**914**	**951**
Pembroke	United Kingdom	1	210	186	209	175
Cape Town	South Africa	1	110	61	62	72
Burnaby, B.C.	Canada	1	55	45	49	50
Batangas[3]	Philippines	—	—	—	—	49
Total Consolidated Companies — International		**3**	**375**	**292**	**320**	**346**
Equity in Affiliates[4]	Various Locations	11	831	746	724	694
Total Including Affiliates — International		**14**	**1,206**	**1,038**	**1,044**	**1,040**
Total Including Affiliates — Worldwide		**20**	**2,195**	**1,883**	**1,958**	**1,991**

1 Chevron sold its interest in the El Paso Refinery in August 2003.
2 Asphalt plants in Perth Amboy, New Jersey, and Portland, Oregon. The Portland plant was sold in February 2005.
3 Chevron ceased refining operations at the Batangas Refinery in November 2003 in advance of the refinery's conversion into a finished-product terminal.
4 Chevron increased its ownership interest in the Singapore Refining Company Pte. Ltd. from 33 percent to 50 percent in July 2004. This increased the company's share of operable capacity at December 31, 2004, by about 48,000 barrels per day.

Petroleum — Sale of Refined Products

Product Sales: The company markets petroleum products throughout much of the world. The principal brands for identifying these products are "Chevron," "Texaco" and "Caltex."

The following table shows the company's and affiliates' refined products sales volumes, excluding intercompany sales, for the three years ending December 31, 2005.

Refined Products Sales Volumes[1]
(Thousands of Barrels per Day)

	2005	2004	2003
United States			
Gasolines	709	701	669
Jet Fuel	291	302	314
Gas Oils and Kerosene	231	218	196
Residual Fuel Oil	122	148	123
Other Petroleum Products[2]	120	137	134
Total United States	**1,473**	**1,506**	**1,436**
International[3]			
Gasolines	669	717	643
Jet Fuel	259	250	228
Gas Oils and Kerosene	784	805	780
Residual Fuel Oil	410	463	487
Other Petroleum Products[2]	173	167	164
Total International	**2,295**	**2,402**	**2,302**
Total Worldwide[3]	**3,768**	**3,908**	**3,738**

1 Includes buy/sell arrangements:	217	180	194
2 Principally naphtha, lubricants, asphalt and coke.			
3 Includes share of equity affiliates' sales:	540	536	525

In the United States, the company markets under the Chevron and Texaco brands. The company supplies directly or through retailers and marketers almost 9,300 branded motor vehicle retail outlets, concentrated in the southeastern, southwestern and western states. Approximately 600 of the outlets are company-owned or -leased stations. By the end of 2005, the company was supplying more than 1,600 Texaco retail sites, primarily in the Southeast and West. Further expansion is planned when all rights to the Texaco brand in the United States revert to Chevron in July 2006.

Outside the United States, Chevron supplies directly or through retailers and marketers approximately 17,200 branded service stations, including affiliates, in nearly 90 countries. In British Columbia, Canada, the company markets under the Chevron brand. In Europe, the company has marketing operations under the Texaco brand primarily in the United Kingdom, Ireland, the Netherlands, Belgium and Luxembourg. In West Africa, the company operates or leases to retailers in Cameroon, Côte d'Ivoire, Nigeria, Republic of the Congo, Togo and Benin. In these regions, the company uses the Texaco brand. The company also operates across the Caribbean, Central America and South America, with a significant presence in Brazil, using the Texaco brand. In the Asia-Pacific region, Southern, Central and East Africa, Egypt, and Pakistan, the company uses the Caltex brand.

The company also operates through affiliates under various brand names. In Denmark and Norway, the company operates through its 50 percent-owned affiliate, HydroTexaco, using the Y-X and Uno-X brands. In South Korea, the company operates through its 50 percent-owned affiliate, GS Caltex, using the GS Caltex brand. The company's 50 percent-owned affiliate in Australia operates using the Caltex, Caltex Woolworths and Ampol brands. In the United Arab Emirates, the company sold its 40 percent interest in the Emirates Petroleum Products Co. joint venture in 2005.

The company continued the marketing and sale of service station sites, focusing on selected areas outside the United States in 2005. More than 700 service stations were sold, primarily in the United Kingdom and Latin America. Since the beginning of 2003, the company has sold its interests in more than 2,300 service station sites. The vast majority of these sites will continue to market company-branded gasoline through new supply agreements.

The company also manages other marketing businesses globally. Chevron markets aviation fuel in approximately 70 countries, representing a worldwide market share of about 12 percent, and is the leading marketer of jet fuels in the United States. The company also markets an extensive line of lubricant products in about 175 countries.

Petroleum — Transportation

Pipelines: Chevron owns and operates an extensive system of crude oil, refined products, chemicals, natural gas liquids and natural gas pipelines in the United States. The company also has direct or indirect interests in other U.S. and international pipelines. The company's ownership interests in pipelines are summarized in the following table.

Pipeline Mileage at December 31, 2005

	Net Mileage[1]
United States:	
Crude Oil[2]	2,882
Natural Gas	2,275
Petroleum Products[3]	7,181
Total United States	**12,338**
International:	
Crude Oil[2]	451
Natural Gas	426
Petroleum Products[3]	433
Total International	**1,310**
Worldwide	**13,648**

1 Partially owned pipelines are included in the company's equity percentage.
2 Includes gathering lines related to the transportation function. Excludes gathering lines related to the U.S. and international production activities.
3 Includes refined products, chemicals and natural gas liquids.

In the United States, the company increased its equity ownership in Bridgeline Holdings, L.P. (BLH) to 100 percent in 2005. Located in southern Louisiana along the Mississippi River corridor, BLH manages and operates an integrated intrastate natural gas pipeline and storage system, consisting of more than 1,000 miles of pipeline and 12 billion cubic feet of natural gas storage capacity, and manages marketing, supply and transportation functions. Through the Unocal acquisition, the company obtained operated and nonoperated interests in natural gas storage assets in Canada, Texas and Alaska, with total storage capacity of 74 billion cubic feet. In addition, the company acquired ownership of the Beaumont Terminal, a nonregulated terminal in Texas that handles a range of commodities. The acquisition also provided the company with ownership interests in about 2,000 net pipeline miles, including a 23 percent interest in the Colonial Pipeline Company and a 64 percent interest in the Southcap Pipeline Company.

Chevron also has a 15 percent ownership interest in the Caspian Pipeline Consortium (CPC). CPC operates a crude oil export pipeline from the Tengiz Field in Kazakhstan to the Russian Black Sea port of Novorossiysk. At the end of 2005, CPC had 11 transportation agreements in place and was transporting an average of 520,000 barrels of crude oil per day from the Caspian region. Russian crude oil entered the pipeline in late 2004 and averaged 130,000 barrels per day during 2005, bringing the total volume transported to 650,000 barrels of crude oil per day.

For information on projects under way related to the Chad-Cameroon pipeline, the West African Gas Pipeline, the Baku-Tbilisi-Ceyhan pipeline and the expansion of the CPC pipeline, refer to pages 14, 16, 18 and 24, respectively.

Tankers: At any given time during 2005, the company had approximately 70 vessels under a voyage basis or time charter of less than one year. Additionally, all tankers in Chevron's controlled seagoing fleet were utilized during 2005. The following table summarizes cargo transported on the company's controlled fleet.

Controlled Tankers at December 31, 2005

	U.S. Flag		Foreign Flag	
	Number	Cargo Capacity (Millions of Barrels)	Number	Cargo Capacity (Millions of Barrels)
Owned	3	0.8	—	—
Bareboat Chartered	—	—	18	26.7
Time Chartered*	—	—	18	9.3
Total	**3**	**0.8**	**36**	**36.0**

* One year or greater.

Federal law requires that cargo transported between U.S. ports be carried in ships built and registered in the United States, owned and operated by U.S. entities and manned by U.S. crews. At year-end 2005, the company's U.S. flag fleet was engaged primarily in transporting refined products between the Gulf Coast and the East Coast, and from California refineries to terminals on the West Coast and in Alaska and Hawaii.

The international flag vessels were engaged primarily in transporting crude oil from the Middle East, Indonesia, Mexico and West Africa to ports in the United States, Europe and Asia. Refined products were also transported by tanker worldwide.

In addition to the vessels described above, the company owns a one-sixth interest in each of seven liquefied natural gas (LNG) tankers transporting cargoes for the North West Shelf (NWS) project in Australia. Additionally, the NWS project has two LNG tankers under long-term time charter. In 2005, the company placed orders for two additional LNG tankers to support planned growth in the company's LNG business. These carriers are planned to be delivered in 2009.

The Federal Oil Pollution Act of 1990 requires the scheduled phase-out, by year-end 2010, of all single-hull tankers trading to U.S. ports or transferring cargo in waters within the U.S. Exclusive Economic Zone. This has raised the demand for double-hull tankers. By the end of 2005, Chevron had a total of 20 company-operated double-hull tankers in operation. The company is a member of many oil-spill-response cooperatives in areas around the world in which it operates.

Chemicals

Chevron Phillips Chemical Company LLC (CPChem) is equally owned with ConocoPhillips Corporation. CPChem owns or has joint venture interests in 31 manufacturing facilities and six research and technical centers in the United States, Puerto Rico, Belgium, China, Mexico, Saudi Arabia, Singapore, South Korea and Qatar.

In 2005, construction progressed on CPChem's integrated, world-scale styrene facility in Al Jubail, Saudi Arabia. Jointly owned with the Saudi Industrial Investment Group (SIIG), the project's operational start-up is anticipated in late 2007. CPChem and SIIG currently operate an aromatics complex in Al Jubail.

In the fourth quarter 2005, CPChem approved the continued development of plans for a third petrochemical project in Saudi Arabia. Preliminary studies are focused on the construction of a world-scale olefins unit, as well as downstream units, to produce polyethylene, polypropylene, 1-hexene and polystyrene. This project would capitalize on CPChem's proven technologies and be located in Al Jubail, next to CPChem and SIIG's existing aromatics complex and the styrene facility currently under construction. Final approval of the project is expected in 2007.

Also during 2005, approvals were obtained and financial closing completed for the Q-Chem II project, which will include a 350,000-metric-ton-per-year polyethylene plant and a 345,000-metric-ton-per-year normal alpha olefins plant — each utilizing CPChem proprietary technology — located adjacent to the existing Q-Chem I complex in

Mesaieed, Qatar. The Q-Chem II project also includes a separate joint venture to develop a 1,300,000-metric-ton-per-year ethylene cracker at Qatar's Ras Laffan Industrial City, in which Q-Chem II owns 54 percent of the capacity rights. CPChem and its partners expect to start up the cracker and derivatives plants in late 2008. CPChem owns a 49 percent interest of Q-Chem II.

Chevron's Oronite brand fuel and lubricant additives business is a leading developer, manufacturer and marketer of performance additives for fuels and lubricating oils. The company owns and operates facilities in the United States, Brazil, France, the Netherlands, Singapore and Japan and has equity interests in facilities in India and Mexico. The previously announced decision to close the manufacturing plant in Brazil was reversed in 2005 due to increased worldwide demand for additives.

Oronite provides additives for lubricating oil in most engine applications, such as passenger car, heavy-duty diesel, marine, two-cycle and railroad engines, and additives for fuels to improve engine performance and extend engine life.

Coal and Other Minerals

The company's coal mining and marketing subsidiary, The Pittsburg & Midway Coal Mining Co. (P&M), owned and operated two surface mines, McKinley, in New Mexico, and Kemmerer, in Wyoming, and one underground mine, North River, in Alabama, at year-end 2005. Final reclamation activities were completed at the York Canyon surface mine located in New Mexico, and reclamation activities continued in 2006 at the Farco surface mine in Texas. Chevron sold its 30 percent interest in Inter-American Coal Holding N.V. in late 2005. Sales of coal from P&M's wholly owned mines and from its affiliates were 14.1 million tons, relatively unchanged from 2004.

At year-end 2005, P&M controlled approximately 235 million tons of developed and undeveloped coal reserves in the United States, including reserves of environmentally desirable low-sulfur coal. The company is contractually committed to deliver approximately 14 million tons of coal per year through the end of 2006 and believes it will satisfy these contracts from existing coal reserves.

The company acquired Molycorp Inc., which mines and markets molybdenum and rare earth minerals, as part of the Unocal acquisition. At year-end 2005, Molycorp owned and operated the Questa molybdenum mine in New Mexico and the Mountain Pass lanthanides mine in California. In addition, Molycorp owns a 35 percent interest in Companhia Brasileira de Metalurgia e Mineracao, a producer of niobium in Brazil, and a 33 percent interest in Sumikin Molycorp, a manufacturer of neodymium compounds, located in Japan. During 2005, Molycorp performed environmental remediation activities at Questa, New Mexico and Mountain Pass, California, and closed certain operations in Colorado and Pennsylvania.

At year-end 2005, Molycorp controlled approximately 53 million pounds of developed and undeveloped molybdenum reserves at Questa and 241 million pounds of lanthanide reserves at Mountain Pass. Molycorp's share of niobium reserves totaled 1.9 million tons.

Also as part of the Unocal acquisition, the company acquired the Chicago Carbon Company that operates a 250,000-ton-per-year petroleum coke calciner facility in Illinois.

Synthetic Crude Oil

In Canada, Chevron holds a 20 percent nonoperated interest in the Athabasca Oil Sands Project (AOSP). Bitumen is extracted from oil sands and upgraded into synthetic crude oil using hydroprocessing technology. The integrated operation at AOSP commenced in 2003 with ramp-up of production substantially completed in 2005. Total 2005 bitumen production averaged 158,000 barrels per day (about 32,000 net barrels). Net proved oil sands reserves at the end of 2005 were 146 million barrels.

In early 2006, the company was evaluating feasibility of a proposed AOSP expansion. The expansion would be designed to produce approximately 100,000 barrels of bitumen per day (20,000 net barrels) and upgrade it into synthetic crude oil. If the AOSP expansion project proceeds, first production is expected in late 2009. No proved oil sands reserves have been recorded in association with this expansion.

Global Power Generation

Chevron's Global Power Generation (GPG) business has more than 20 years experience in developing and operating commercial power projects and owns 16 power assets located in the United States and Asia. GPG manages the production of more than 3,500 megawatts of electricity at 13 facilities it owns through joint ventures. The company operates gas-fired cogeneration facilities that use waste heat recovery to produce additional electricity or to support industrial thermal hosts. A number of the facilities produce steam for use in upstream operations to facilitate production of heavy oil.

In 2005, the company acquired an additional 13 percent in the Tri Energy Company, a 700-megawatt independent power producer located in Ratchaburi Province, Thailand, increasing Chevron's total ownership to 50 percent.

Gas-to-Liquids

The Sasol Chevron Global 50-50 Joint Venture was established in October 2000 to develop a worldwide gas-to-liquids (GTL) business. Through this venture, the company is engaged in discussions with Qatar Petroleum (QP) on a number of projects, which include the design, construction and operation of a base oils production facility downstream of the Sasol and QP Oryx GTL plant in Qatar, and evaluation of an expansion of the Oryx GTL foundation plant from 34,000 to 100,000 barrels per day.

In Nigeria, the Chevron Nigeria Limited and the Nigerian National Petroleum Corporation are developing a 34,000-barrel-per-day GTL facility at Escravos that will process natural gas supplied from the output of the Phase 3 expansion of the Escravos Gas Plant (EGP). The $1.7 billion engineering, procurement and construction contract was awarded in April 2005. Plant construction began in 2005, including major equipment fabrication and site preparation. Refer also to page 16 for a discussion on the EGP Phase 3 expansion.

Chevron Energy Solutions

Chevron Energy Solutions (CES) is a wholly owned subsidiary that provides public institutions and businesses with projects that are designed to increase energy efficiency, reduce energy costs and ensure reliable, high-quality power for critical operations. CES has offices in the United States and has energy-saving projects installed in more than a thousand buildings nationwide.

Research and Technology

The company's Energy Technology Company delivers integrated technologies and services to the upstream, downstream and gas-based businesses. These activities include exploration and production systems, reservoir management and optimization, heavy oil recovery and upgrading, gas-to-liquids processing, improved refining processes, safe, incident-free plant operations, and technical computing. The Information Technology Company provides a standardized digital infrastructure as well as information management and security for the company's global operations.

Chevron's Technology Ventures Company (CTV) identifies, grows and commercializes emerging technologies that have the potential to transform how energy is produced or consumed. CTV's activities range from early-stage investing of venture capital in emerging technologies to developing joint venture companies in new energy systems, such as hydrogen infrastructure, advanced batteries, nano-materials and renewable energy applications.

Chevron's research and development expenses were $316 million, $242 million and $228 million for the years 2005, 2004 and 2003, respectively.

Because some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, ultimate success is not certain. Although not all initiatives may prove to be economically viable, the company's overall investment in this area is not significant to the company's consolidated financial position.

Environmental Protection

Virtually all aspects of the company's businesses are subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to change and increase in both number and complexity and to govern not only the manner in which the company conducts its operations, but also the products it sells. Chevron expects more environmental-related regulations in the countries where it has operations. Most of the costs of complying with the many laws and regulations pertaining to its operations are embedded in the normal costs of conducting business.

In 2005, the company's U.S. capitalized environmental expenditures were $227 million, which includes $2 million for Unocal activities for the last five months of 2005 and which represents approximately 6 percent of the company's total consolidated U.S. capital and exploratory expenditures. These environmental expenditures include capital outlays to retrofit existing facilities, as well as those associated with new facilities. The expenditures are predominantly in the upstream and downstream segments and relate mostly to air- and water-quality projects and activities at the company's refineries, oil and gas producing facilities, and marketing facilities. For 2006, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $452 million. The future annual capital costs of fulfilling this commitment are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Further information on environmental matters and their impact on Chevron and on the company's 2005 environmental expenditures, remediation provisions and year-end environmental reserves are contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages FS-18 to FS-19, and on page FS-21 to FS-22 of this Annual Report on Form 10-K.

Web Site Access to SEC Reports

The company's Internet Web site can be found at http://www.chevron.com/. Information contained on the company's Internet Web site is not part of this Annual Report on Form 10-K.

The company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on the company's Web site, free of charge, soon after such reports are filed with or furnished to the SEC. Alternatively, you may access these reports at the SEC's Internet Web site: http://www.sec.gov/.

Item 1A. Risk Factors

Chevron is a major fully integrated petroleum company with a diversified business portfolio, strong balance sheet, and a history of generating sufficient cash to fund capital and exploratory expenditures and to pay dividends. Nevertheless, some inherent risks could materially impact the company's financial results of operations or financial condition.

Chevron is exposed to the effects of changing commodity prices.

Chevron is primarily in a commodities business with a history of price volatility. The single largest variable that affects the company's results of operations is crude oil prices. Except in the ordinary course of running an integrated petroleum business, Chevron does not seek to hedge its exposure to price changes. A significant, persistent decline in crude oil prices may have a material adverse effect on its results of operations and its capital and exploratory expenditure plans.

The scope of Chevron's business will decline if the company does not successfully develop resources.

The company is in an extractive business; therefore, if Chevron is not successful in replacing the crude oil and natural gas it produces with good prospects for future production, the company's business will decline. Creating and maintaining an inventory of projects depends on many factors, including obtaining rights to explore, develop and produce hydrocarbons in promising areas, drilling success, ability to bring long lead-time, capital intensive projects to completion on budget and schedule, and efficient and profitable operation of mature properties.

The company's operations could be disrupted by natural or human factors.

Chevron operates in both urban areas and remote and sometimes inhospitable regions. The company's operations and facilities are therefore subject to disruption from either natural or human causes, including hurricanes, earthquakes, floods and other forms of severe weather, war, civil unrest and other political events, fires and explosions, any of which could result in suspension of operations, or harm to people or the natural environment.

Chevron's business subjects the company to liability risks.

The company produces, transports, refines and markets materials with potential toxicity, and it purchases, handles and disposes of other potentially toxic materials in the course of the company's business. Chevron operations also produce byproducts, which may be considered pollutants. Any of these activities could result in liability, either as a result of an accidental, unlawful discharge or as a result of new conclusions on the effects of the company's operations on human health or the environment.

Political instability could harm Chevron's business.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially- or wholly owned businesses, and/or to impose additional taxes or royalties.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest, acts of violence or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries. At December 31, 2005, approximately 23 percent of the company's proved reserves were located in Kazakhstan. The company also has significant interests in Organization of Petroleum Exporting Countries (OPEC)-member countries including Indonesia, Nigeria and Venezuela. Approximately 22 percent of the company's net proved reserves, including affiliates, were located in OPEC countries at December 31, 2005.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and character of the company's crude oil, natural gas and coal properties and its refining, marketing, transportation and chemicals facilities are described above under Item 1. Business. Information required by the Securities Exchange Act Industry Guide No. 2 ("Disclosure of Oil and Gas Operations") is also contained in Item 1 and in Tables I through VII on pages FS-65 to FS-78 of this Annual Report on Form 10-K. Note 14, "Properties, Plant and Equipment," to the company's financial statements is on page FS-46 of this Annual Report on Form 10-K.

Item 3. Legal Proceedings

The South Coast Air Quality Management District (AQMD) has issued several notices of violation to the Chevron Products Company, a division of Chevron U.S.A., Inc, alleging more than 160 violations of the AQMD's Rule 463, which regulates emissions from floating roof tanks, at the company's El Segundo, California, refinery, as previously reported in the company's quarterly report on Form 10-Q for the period ended September 30, 2005. It was also noted that in August 2005, the AQMD contacted the company to ask that these violations be consolidated with a newly discovered matter involving alleged violations of the AQMD's Rule 1173 concerning Leak Detection and Repair of components that emit volatile organic compounds. The company has settled these matters by agreeing to pay a civil penalty of $5 million and $1.5 million in emission fees.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Executive Officers of the Registrant at March 1, 2006

Name and Age		Executive Office Held	Major Area of Responsibility
D.J. O'Reilly	59	Chairman of the Board since 2000 Director since 1998 Vice Chairman from 1998 to 2000 President of Chevron Products Company from 1994 to 1998 Executive Committee Member since 1994	Chief Executive Officer
P.J. Robertson	59	Office of the Chairman since 2005 Vice Chairman of the Board since 2002 Vice President from 1994 to 2001 President of Chevron Overseas Petroleum Inc. from 2000 to 2002 Executive Committee Member since 1997	Office of the Chairman; Strategic Planning; Policy, Government and Public Affairs; Human Resources
J.E. Bethancourt	54	Executive Vice President since 2003 Executive Committee Member since 2003	Technology; Chemicals; Coal; Health, Environment and Safety
G.L. Kirkland	55	Executive Vice President since 2005 President of Chevron Overseas Petroleum Inc. from 2002 to 2004 Vice President from 2000 to 2004 President of Chevron U.S.A. Production Company from 2000 to 2002 Executive Committee Member from 2000 to 2001 and since 2005	Worldwide Exploration and Production Activities and Global Gas Activities, including Natural Gas Trading
S. Laidlaw	50	Executive Vice President since 2003 Executive Committee Member since 2003	Business Development
M.K. Wirth	45	Executive Vice President, effective March 1, 2006 President Global Supply and Trading from 2004 to 2006 Executive Committee Member since 2006	Global Refining, Marketing, Lubricants, and Supply and Trading, excluding Natural Gas Trading
S.J. Crowe	58	Vice President and Chief Financial Officer since 2005 Vice President and Comptroller from 2000 through 2004 Comptroller from 1996 to 2000 Executive Committee Member since 2005	Finance
C.A. James	51	Vice President and General Counsel since 2002 Executive Committee Member since 2002	Law
J.S. Watson	49	President of Chevron International Exploration & Production since 2005 Vice President and Chief Financial Officer from 2000 through 2004 Executive Committee Member from 2000 to 2004	International Exploration and Production
R.I. Wilcox*	60	President, Chevron North America Exploration & Production Company since 2002 Vice President since 2002	North American Exploration and Production

* Effective March 31, 2006, R.I. Wilcox will retire from the company. Wilcox will be succeeded by G.P. Luquette, managing director of the European strategic business unit of Chevron International Exploration & Production Company.

The Executive Officers of the Corporation consist of the Chairman of the Board, the Vice Chairman of the Board, and such other officers of the Corporation who are either Directors or members of the Executive Committee or who are chief executive officers of principal business units. Except as noted below, all of the Corporation's Executive Officers have held one or more of such positions for more than five years.

J.E. Bethancourt	-	Vice President, Texaco Inc., President of Production Operations, Worldwide Exploration and Production, Texaco Inc. — 2000
	-	Vice President, Human Resources, Chevron Corporation — 2001
	-	Executive Vice President, Chevron Corporation — 2003
C.A. James	-	Partner, Jones Day (a major U.S. law firm) — 1992
	-	Assistant Attorney General, Antitrust Division, U.S. Department of Justice — 2001
	-	Vice President and General Counsel — 2002
S. Laidlaw	-	President and Chief Operating Officer, Amerada Hess — 2001
	-	Chief Executive Officer, Enterprise Oil plc — 2002
	-	Executive Vice President, Chevron Corporation — 2003
R.I. Wilcox	-	Vice President and General Manager, Marine Transportation, Chevron Shipping Company — 1996
	-	General Manager, Asset Management, Chevron Nigeria Limited — 1999
	-	Chairman and Managing Director, Chevron Nigeria Limited — 2000
	-	Corporate Vice President and President, Chevron North America Exploration & Production Company — 2002
M.K. Wirth	-	General Manager, U.S. Retail Marketing, Chevron Products Company — 1999
	-	President, Marketing, Caltex Corporation — 2000
	-	President, Marketing, Asia, Middle East and Africa Marketing Business Unit, Chevron Corporation — 2001
	-	President, Global Supply and Trading — 2004
	-	Executive Vice President, Chevron Corporation — 2006

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The information on Chevron's common stock market prices, dividends, principal exchanges on which the stock is traded and number of stockholders of record is contained in the Quarterly Results and Stock Market Data tabulations, on page FS-26 of this Annual Report on Form 10-K.

CHEVRON CORPORATION
ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased(1),(2)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program
Oct. 1 – Oct. 31, 2005	**3,612,153**	**61.12**	3,515,000	—
Nov. 1 – Nov. 30, 2005	**7,879,941**	**57.73**	7,622,200	—
Dec. 1 – Dec. 31, 2005	**2,013,065**	**57.77**	1,737,000	—
Total Oct. 1 – Dec 31, 2005	**13,505,159**	**58.64**	12,874,200	(2)

(1) Includes 43,905 common shares repurchased during the three-month period ended December 31, 2005 from company employees for required personal income tax withholdings on the exercise of the stock options issued to management and employees under the company's broad-based employee stock options, long-term incentive plans and former Texaco Inc. stock option plans. Also includes 587,054 shares delivered or attested to in satisfaction of the exercise price by holders of certain former Texaco Inc. employee stock options exercised during the three-month period ended December 31, 2005.

(2) On March 31, 2004, the company announced a $5 billion common stock repurchase program. The program was completed on November 23, 2005, at which time 92,096,099 shares had been repurchased for a total of $5 billion.

In December 2005, the company authorized stock repurchases of up to $5 billion that may be made from time to time at prevailing prices as permitted by securities laws and other requirements and subject to market conditions and other factors. The program will occur over a period of up to three years and may be discontinued at any time. As of December 31, 2005, a total of 1,737,000 shares had been acquired under this program for $100 million.

Item 6. Selected Financial Data

The selected financial data for years 2001 through 2005 are presented on page FS-64 of this Annual Report on Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1 of this Annual Report on Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The company's discussion of interest rate, foreign currency and commodity price market risk is contained in Management's Discussion and Analysis of Financial Condition and Results of Operations — "Financial and Derivative Instruments," beginning on page FS-17 and in Note 7 to the Consolidated Financial Statements, "Financial and Derivative Instruments," beginning on page FS-39.

Item 8. Financial Statements and Supplementary Data

The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1 of this Annual Report on Form 10-K.

Item 9. Changes in and Disagreements with Auditors on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) **Evaluation of Disclosure Controls and Procedures**

Chevron Corporation's Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of the company's "disclosure controls and procedures" (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")), as of December 31, 2005, have concluded that as of December 31, 2005, the company's disclosure controls and procedures were effective and designed to provide reasonable assurance that material information relating to the company and its consolidated subsidiaries required to be included in the company's periodic filings under the Exchange Act would be made known to them by others within those entities.

(b) **Management's Report on Internal Control Over Financial Reporting**

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that its internal control over financial reporting was effective as of December 31, 2005.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report that is included on page FS-28 of this Annual Report on Form 10-K.

(c) **Changes in Internal Control Over Financial Reporting**

During the quarter ended December 31, 2005, there were no changes in the company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information on Directors appearing under the heading “Election of Directors — Nominees For Directors” in the Notice of the 2006 Annual Meeting of Stockholders and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), in connection with the company’s 2006 Annual Meeting of Stockholders, is incorporated by reference in this Annual Report on Form 10-K. See Executive Officers of the Registrant on pages 33 and 34 of this Annual Report on Form 10-K for information about Executive Officers of the company.

The company has a separately designated standing Audit Committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the Audit Committee are Sam Ginn (Chairperson), Linnet F. Deily, Robert E. Denham, Franklyn G. Jenifer and Charles R. Shoemate, all of whom are independent under the New York Stock Exchange Corporate Governance Rules. Of these Audit Committee members, Linnet F. Deily, Robert E. Denham, Sam Ginn and Charles R. Shoemate are audit committee financial experts as determined by the Board within the applicable definition of the Securities and Exchange Commission.

The information contained under the heading “Stock Ownership Information — Section 16(a) Beneficial Ownership Reporting Compliance” in the Notice of the 2006 Annual Meeting of Stockholders and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Exchange Act, in connection with the company’s 2006 Annual Meeting of Stockholders, is incorporated by reference in this Annual Report on Form 10-K.

The company has adopted a code of business conduct and ethics for directors, officers (including the company’s Chief Executive Officer, Chief Financial Officer and Comptroller) and employees, known as the Business Conduct and Ethics Code. The code is available on the company’s Internet Web site at http://www.chevron.com/. Any amendments to the Business Conduct and Ethics Code will be posted on the company’s Web site.

Other Information

Disclosure Regarding Nominating Committee Functions and Communications Between Security Holders and Boards of Directors

No change.

Rule 10b5-1 Plan Elections

No Rule 10b5-1 plans were adopted for the period that ended on December 31, 2005.

Item 11. Executive Compensation

The information appearing under the headings “Executive Compensation” and “Directors Compensation” in the Notice of the 2006 Annual Meeting of Stockholders and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Exchange Act, in connection with the company’s 2006 Annual Meeting of Stockholders, is incorporated herein by reference in this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information appearing under the headings “Stock Ownership Information — Directors’ and Executive Officers’ Stock Ownership” and “Stock Ownership Information — Other Security Holders” in the Notice of the 2006 Annual Meeting of Stockholders and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Exchange Act, in connection with the company’s 2006 Annual Meeting of Stockholders, is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading “Equity Compensation Plan Information” in the Notice of the 2006 Annual Meeting of Stockholders and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Exchange Act, in connection with the company’s 2006 Annual Meeting of Stockholders, is incorporated by reference in this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions

None.

Item 14. Principal Accounting Fees and Services

The information appearing under the headings “Ratification of Independent Registered Public Accounting Firm — Principal Accountant Fees and Services” and “Ratification of Independent Registered Public Accounting Firm — Audit Committee Pre-Approval Policies and Procedures” in the Notice of the 2006 Annual Meeting of Stockholders and 2006 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Exchange Act, in connection with the company’s 2006 Annual Meeting of Stockholders, is incorporated by reference in this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements:

(2) Financial Statement Schedules:

We have included on page 40 of this Annual Report on Form 10-K, Schedule II — Valuation and Qualifying Accounts.

(3) Exhibits:

The Exhibit Index on pages E-1 and E-2 of this Annual Report on Form 10-K lists the exhibits that are filed as part of this report.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
Millions of Dollars

	Year Ended December 31		
	2005	2004	2003
Employee Termination Benefits:			
Balance at January 1	$ 137	$ 341	$ 336
(Deductions) additions (credited) charged to expense	(21)	29	295
Additions related to Unocal acquisition	106	—	—
Payments	(131)	(233)	(290)
Balance at December 31	**$ 91**	**$ 137**	**$ 341**
Allowance for Doubtful Accounts:			
Balance at January 1	$ 219	$ 229	$ 225
Additions charged to expense	3	36	52
Additions related to Unocal acquisition	6	—	—
Bad debt write-offs	(30)	(46)	(48)
Balance at December 31	**$ 198**	**$ 219**	**$ 229**
Deferred Income Tax Valuation Allowance:*			
Balance at January 1	$ 1,661	$ 1,553	$ 1,740
Additions charged to deferred income tax expense	1,593	714	375
Additions related to Unocal acquisition	400	—	—
Deductions credited to goodwill	(60)	—	—
Deductions credited to deferred income tax expense	(345)	(606)	(562)
Balance at December 31	**$ 3,249**	**$ 1,661**	**$ 1,553**

* See also Note 16 to the Consolidated Financial Statements beginning on page FS-47.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, on the 1st day of March, 2006.

Chevron Corporation

By /s/ DAVID J. O'REILLY

David J. O'Reilly, Chairman of the Board
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 1st day of March, 2006.

Principal Executive Officers (and Directors)	Directors
/s/DAVID J. O'REILLY David J. O'Reilly, Chairman of the Board and Chief Executive Officer	SAMUEL H. ARMACOST* Samuel H. Armacost
/s/PETER J. ROBERTSON Peter J. Robertson, Vice Chairman of the Board	LINNET F. DEILY* Linnet F. Deily
	ROBERT E. DENHAM* Robert E. Denham
	ROBERT J. EATON* Robert J. Eaton
	SAM GINN* Sam Ginn
Principal Financial Officer	
/s/STEPHEN J. CROWE Stephen J. Crowe, Vice President and Chief Financial Officer	CARLA A. HILLS* Carla A. Hills
	FRANKLYN G. JENIFER* Franklyn G. Jenifer
Principal Accounting Officer	
/s/MARK A. HUMPHREY Mark A. Humphrey, Vice President and Comptroller	SAM NUNN* Sam Nunn
	DONALD B. RICE* Donald B. Rice
*By: /s/LYDIA I. BEEBE Lydia I. Beebe, Attorney-in-Fact	CHARLES R. SHOEMATE* Charles R. Shoemate
	RONALD D. SUGAR* Ronald D. Sugar
	CARL WARE* Carl Ware

INDEX TO MANAGEMENT'S DISCUSSION AND ANALYSIS, CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

KEY FINANCIAL RESULTS

Millions of dollars, except per-share amounts	**2005**	2004	2003
Net Income	**$ 14,099**	$ 13,328	$ 7,230
Per Share Amounts:			
Net Income – Basic	**$ 6.58**	$ 6.30	$ 3.48
– Diluted	**$ 6.54**	$ 6.28	$ 3.48
Dividends	**$ 1.75**	$ 1.53	$ 1.43
Sales and Other Operating Revenues	**$ 193,641**	$ 150,865	$ 119,575
Return on:			
Average Capital Employed	**21.9%**	25.8%	15.7%
Average Stockholders' Equity	**26.1%**	32.7%	21.3%

INCOME FROM CONTINUING OPERATIONS BY MAJOR OPERATING AREA

Millions of dollars	**2005**	2004	2003
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	**$ 4,168**	$ 3,868	$ 3,160
International	**7,556**	5,622	3,199
Total Upstream	**11,724**	9,490	6,359
Downstream – Refining, Marketing and Transportation			
United States	**980**	1,261	482
International	**1,786**	1,989	685
Total Downstream	**2,766**	3,250	1,167
Chemicals	**298**	314	69
All Other	**(689)**	(20)	(213)
Income From Continuing Operations	**$ 14,099**	$ 13,034	$ 7,382
Income From Discontinued Operations – Upstream	**–**	294	44
Income Before Cumulative Effect of Changes in Accounting Principles	**$ 14,099**	$ 13,328	$ 7,426
Cumulative Effect of Changes in Accounting Principles	**–**	–	(196)
Net Income *	**$ 14,099**	$ 13,328	$ 7,230
* Includes Foreign Currency Effects:	**$ (61)**	$ (81)	$ (404)

Net income in 2003 included a $196 million charge for the cumulative effect of changes in accounting principle. The primary change related to the company's adoption of Financial Accounting Standards Board Statement No. 143, "Accounting for Asset Retirement Obligations," which is discussed in Note 24 to the Consolidated Financial Statements. Net income in 2004 included gains of approximately $1.2 billion relating to the sale of nonstrategic upstream properties. Refer also to the "Results of Operations" section beginning on page FS-7 for a detailed discussion of financial results by major operating area for the three years ending December 31, 2005.

BUSINESS ENVIRONMENT AND OUTLOOK

The company's current and future earnings depend largely on the profitability of the upstream (exploration and production) and downstream (refining, marketing and transportation) business segments. The single biggest factor that affects the results of operations for both segments is movement in the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. Overall earnings trends are typically less affected by results from the company's chemical business and other activities and investments. Earnings for the company in any period may also be affected by events or transactions that are infrequent and/or unusual in nature.

The company's long-term competitive position, particularly given the capital-intensive and commodity-based nature of the industry, is closely associated with the company's ability to invest in projects that provide adequate financial returns and to manage operating expenses effectively. Creating and maintaining an inventory of projects depends on many factors, including obtaining rights to explore for crude oil and natural gas, developing and producing hydrocarbons in promising areas, drilling successfully, bringing long-lead time capital-intensive projects to completion on budget and on schedule, and operating mature upstream properties efficiently and profitably.

The company also continuously evaluates opportunities to dispose of assets that are not key to providing long-term value, or to acquire assets or operations complementary to its asset base to help augment the company's growth. Asset-disposition and restructuring may occur in future periods and could result in significant gains or losses.

In August 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. The aggregate purchase price was $17.3 billion, which included $7.5 billion cash, approximately 169 million shares of Chevron common stock valued at $9.6 billion, and $0.2 billion for stock options on approximately 5 million shares and merger-related fees. Refer to Note 2, beginning on page FS-36, for a discussion of the Unocal acquisition.

Comments related to earnings trends for the company's major business areas are as follows:

Upstream Earnings for the upstream segment are closely aligned with industry price levels for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry inventory levels, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and regional supply interruptions that may be caused by military conflicts, civil unrest or political uncertainty.

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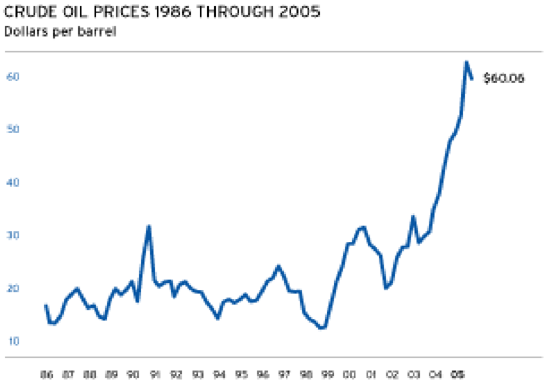
Moreover, any of these factors could also inhibit the company's production capacity in an affected region. The company monitors developments closely in the countries in which it operates and holds investments, and attempts to manage risks in operating its facilities and business.

Price levels for capitalized costs and operating expenses associated with the efficient production of crude oil and natural gas can also be subject to external factors beyond the company's control. External factors include not only the general level of inflation but also prices charged by the industry's product- and service-providers, which can be affected by the volatility of the industry's own supply and demand conditions for such products and services. The oil and gas industry



The average spot price of West Texas Intermediate, a benchmark crude oil, rose 24 percent from the fourth quarter of 2004 to the fourth quarter of 2005.

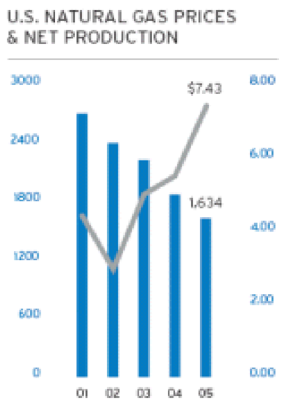
worldwide experienced significant price increases for these items during 2005 that are expected to continue into 2006. Capitalized costs and operating expenses can also be affected by uninsured damages to production facilities caused by severe weather or civil unrest.

Industry price levels for crude oil continued an upward trend in 2005. The spot price for West Texas Intermediate (WTI) crude oil, one of the benchmark crudes, averaged $57 per barrel in 2005, an increase of approximately $16 per barrel from the 2004 average price. The WTI spot price for the first two months of 2006 averaged about $64 per barrel. The rise in crude oil prices reflects, among other things, increasing demand in growing economies, the heightened level of geopolitical uncertainty in some areas of the world and supply concerns in other key producing regions, including production in the Gulf of Mexico that partially was shut in following the hurricanes.

As was the case in 2004, the differential in prices between high-quality, light-sweet crude oils, such as the U.S. benchmark WTI, and heavier crudes was unusually wide in 2005. Chevron produces heavy crude oil in California, Chad, Indonesia, the Partitioned Neutral Zone (between Saudi Arabia and Kuwait), Venezuela (including volumes produced under an operating service agreement) and certain fields in Angola, China and the United Kingdom North Sea. The price for the heavier crudes has been dampened because of ample supply, together with lower relative demand from the number of refineries that are able to process this lower-quality feedstock into light-product fuels (i.e., motor gasoline, jet fuel, aviation gasoline and diesel fuel). The demand for heavy crude was further reduced in late 2005 as refining capacity along the U.S. Gulf Coast was interrupted by hurricanes. The price for higher-quality light oil, on the other hand, has remained high, as the demand for light products, which can be manufactured by any refinery from light oil, has been robust worldwide.

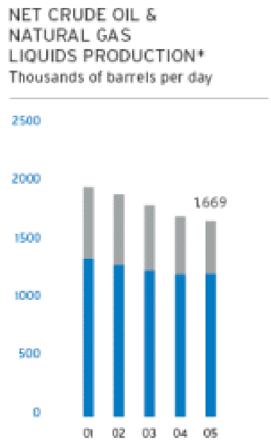
Natural gas prices, particularly in the United States, also trended upward in 2005. For the full year, U.S. benchmark prices at Henry Hub averaged about $8 per thousand cubic feet (MCF), compared with about $6 in 2004. Henry Hub spot prices peaked in December 2005 above $14, as supplies early in the winter heating season were reduced by production shut in following Hurricanes Katrina and Rita. By mid-February 2006, prices had moved downward to about $8 per MCF. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage to meet customer demand.

In contrast to the United States, certain other regions of the world in which the company operates have different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices for the company's production of natural gas. (Refer to page FS-12 for the company's average natural gas prices for the U.S. and international regions.) Additionally, excess supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-price conditions in the United States and other markets because of lack of infrastructure and the difficulties in transporting natural gas. To help address this



■ Prices in Dollars per Thousand Cubic Feet (right scale)
■ Production in Millions of Cubic Feet per Day (left scale)

Average prices increased 35 percent during 2005. Production was down 13 percent mainly due to the effects of storms in the U.S. Gulf of Mexico, asset sales and natural field declines partially offset by the addition of Unocal production.



■ United States
■ International

Net liquids production declined about 2 percent in 2005, mainly due to the effects of storms, asset sales and natural field declines partially offset by the addition of Unocal production.

*Includes equity in affiliates

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regional imbalance between supply and demand for natural gas, Chevron is planning increased investments in long-term projects in areas of excess supply to install infrastructure to produce and liquefy natural gas for transport by tanker, along with investments and commitments to regasify the product in markets where demand is strong and supplies are not as plentiful. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices in the areas of excess supply (before the natural gas is transferred to a company-owned or third-party processing facility) are expected to remain well below sales prices for natural gas that is produced much nearer to areas of high demand and that can be transported in existing natural gas pipeline networks (as in the United States).

Longer-term trends in earnings for the upstream segment are also a function of other factors besides price fluctuations, including changes in the company's crude oil and natural gas production levels and the company's ability to find or acquire and efficiently produce crude oil and natural gas reserves. Most of the company's overall capital investment is in its upstream businesses, particularly outside the United States. Investments in upstream projects generally are made well in advance of the start of the associated crude oil and natural gas production.

Chevron's worldwide net oil-equivalent production of approximately 2.5 million barrels per day in 2005, including volumes produced from oil sands and production under an operating service agreement, remained essentially unchanged from 2004. However, production in the fourth quarter 2005 was nearly 2.7 million barrels per day, reflecting the benefit of volumes associated with the properties acquired from Unocal, the effect of which was partially offset by production shut in as a result of the hurricanes in the Gulf of Mexico. Prior to the hurricanes in August and September 2005, oil-equivalent production in the Gulf of Mexico was approximately 300,000 barrels per day. In 2006, production is projected to average approximately 200,000 barrels per day, as normal field declines are expected to exceed the production being restored from wells that were shut in or damaged from the hurricanes and the production that will result from the drilling of new wells in the area. Approximately 20,000 net oil-equivalent barrels of daily production are not expected to be sufficiently economic to restore. Refer also to pages 11 through 24 for additional discussion and detail of production volumes worldwide.

The company estimates that oil-equivalent production in 2006 will average between 2.7 million and 2.8 million barrels per day. However, future estimates are subject to many uncertainties, including quotas that may be imposed by OPEC, the price effect on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, severe weather, and the potential for local civil unrest and changing geopolitics that could cause production disruptions. Approximately 26 percent of the company's net oil-equivalent production in 2005, including net barrels from oil sands and production under an operating service agreement, occurred in the OPEC-member countries of Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. Although the company's production level during 2005 was not constrained in these areas by OPEC quotas, future production could be affected by OPEC-imposed limitations. Future production levels also are affected by the size and number of economic investment opportunities and, for new large-scale projects, the time lag between initial exploration and the beginning of production. Refer to pages FS-5 through FS-7 for discussion of the company's major upstream projects.

In certain onshore areas of Nigeria, approximately 45,000 barrels per day of the company's net production capacity was shut in during 2003 because of civil unrest and damage to production facilities. The company has adopted a phased plan to restore these operations, and about one-third of the volumes had been returned to production as of early 2006.

Refer to pages FS-7 through FS-9 for additional discussion of the company's upstream operations.

Downstream Refining, marketing and transportation earnings are closely tied to global and regional supply and demand for refined products and the associated effects on industry refining and marketing margins. The company's core marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia and sub-Saharan Africa. In 2005, industry refining margins improved over the prior year, reflecting strong demand for refined products; however, marketing margins, which are highly influenced by regional market conditions, were mixed. Many regions experienced stronger marketing margins, but these margins were generally lower in the United States and Europe, as retail prices did not keep pace with rising crude oil and spot product prices. Industry margins in the future may be volatile, due primarily to changes in the price of crude oil used for refinery feedstock, disruptions at refineries resulting from maintenance programs and mishaps and levels of inventory and demand for refined products.

Other influences on the company's profitability in this segment include the operating efficiencies and expenses of the refinery network, including the effects of any downtime due to planned and unplanned maintenance, refinery upgrade projects and operating incidents. The level of operating expenses for the downstream segment can also be affected by the volatility of charter expenses for the company's shipping operations, which are driven by the industry's demand for crude oil and product tankers. Other factors affecting the company's downstream profitability that are beyond the company's control include the general level of inflation and energy costs to operate the refinery network.

Refer to pages FS-9 through FS-10 for additional discussion of the company's downstream operations.

Chemicals Earnings in the petrochemicals business are closely tied to global chemical demand, industry inventory levels and plant capacity utilization. Additionally, feedstock and fuel costs, which tend to follow crude oil and natural gas price movements, influence earnings in this segment.

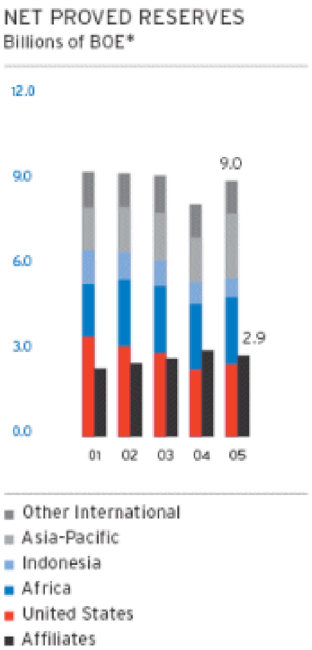
Refer to page FS-10 for additional discussion of chemical earnings for both the company's Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC.

OPERATING DEVELOPMENTS

Key operating developments and other events during 2005 and early 2006 included:

Upstream

Worldwide Proved Reserves As a result of the acquisition of Unocal in August 2005, the company increased its net oil-equivalent proved reserves by approximately 1.5 billion barrels. Significant unproved volumes of oil and gas were also added to the company's resource base. (Refer to pages FS-70 through FS-75 for a detailed discussion of proved reserve changes for 2005 and Note 2 beginning on page FS-36 for a discussion of the Unocal acquisition.)



Net proved reserves for consolidated companies climbed 10 percent in 2005, primarily due to the Unocal acquisition.

*Barrels of oil-equivalent

North America In September 2005, the company sold Northrock Resources Limited, a wholly owned Canadian subsidiary of Unocal, for $1.7 billion. The disposition was consistent with Chevron's divestiture in 2004 of its conventional crude oil and natural gas business in Western Canada, enabling the company's continued focus on the profitable growth of production of crude oil and natural gas in strategically important core areas of operation.

In late 2005, the company began construction of the floating production facility to be installed in the Tahiti Field, in the deepwater Gulf of Mexico. Tahiti is anticipated to have a maximum total daily production of 125,000 barrels per day of crude oil and 70 million cubic feet of natural gas. Chevron is the operator and holds a 58 percent working interest in the project that is being developed in phases and expected to come onto production in 2008.

In the same period, the decision was made to proceed with the development of the Blind Faith Field, also in the deepwater Gulf of Mexico. First production is expected in 2008, with initial total daily output estimated at 30,000 barrels of crude oil and 30 million cubic feet of natural gas. Chevron is the operator and holds a 62.5 percent working interest in the project.

In late 2005, the company drilled deepwater crude oil discoveries in the Gulf of Mexico at the 60 percent-owned and operated Big Foot prospect in the Walker Ridge Block 29 and the 25 percent-owned, nonoperated Knotty Head prospect located in Green Canyon Block 512. Additional appraisal activity continued into 2006 at both locations.

Angola In early 2006, first oil was produced from the 31 percent-interest deepwater Belize Field in Block 14, offshore Angola. The Benguela, Belize, Lobito and Tomboco fields form a project that is being developed in two phases. The maximum total production from both phases of the project is anticipated to reach 200,000 barrels of crude oil per day in 2008.

Australia In mid-2005, the company won exploration rights to four deepwater blocks in the northern Carnarvon Basin offshore Western Australia. In early 2006, the company was awarded rights to another block in the Carnarvon Basin. The blocks are located in an area of significant natural gas potential and near the Chevron-led Gorgon Project. Chevron holds a 50 percent operated interest in the blocks.

Kazakhstan In late 2005, the company's 50 percent-owned Tengizchevroil (TCO) affiliate awarded commercial contracts to enable increased crude-oil exports through a southern route across the Caspian Sea. The southern route will provide additional export capacity for TCO's increased production until the Caspian Pipeline Consortium pipeline is expanded. The additional crude oil production at TCO will result from major facilities-expansion projects being constructed at a total cost of approximately $5.5 billion. By the third quarter 2007, TCO's crude production capacity is projected to increase from the current capacity of 300,000 barrels per day to between 460,000 and 550,000.

Nigeria In early 2005, a construction contract was awarded for the $1.1 billion floating production, storage and offloading (FPSO) vessel to be used at the Agbami Field. The construction contract was a key milestone in the development of the 68 percent-owned Agbami Field, which is scheduled to come online in 2008 with an estimated maximum total daily production of 250,000 barrels of crude oil.

Nigeria — São Tomé e Príncipe Joint Development Zone (JDZ) In early 2005, the company signed a production-sharing contract for Block 1 in the Nigeria - São Tomé e Príncipe JDZ. Chevron will be the operator and has a 51 percent interest in the block. Drilling of the first exploration well was under way in late-February 2006.

Venezuela In June 2005, the company discovered natural gas in Block 3 of Plataforma Deltana, offshore Venezuela. The site is in the proximity of the Loran natural gas field in Block 2 and provides sufficient resources for a detailed evaluation of Venezuela's first liquefied natural gas (LNG) train.

In the third quarter 2005, the company was awarded an exploration license for the Cardon III Block, offshore western Venezuela. The block is in a region with natural gas potential to the north of the Maracaibo producing area.

In December 2005, Chevron signed a transition agreement with Petróleos de Venezuela, S.A. (PDVSA), the Venezuelan state-owned petroleum company, to convert contracts for the Boscan and LL-652 operating service agreements into an Empresa Mixta (EM). The EM is a joint-stock contractual structure with PDVSA as the majority shareholder. Negotiation of the ownership and format of the final EM structure will be conducted during 2006. Possible financial implications of the EM structure are uncertain, but are not expected to have a material effect on the company's consolidated financial position or liquidity.

Global Natural Gas Projects In Angola, the company awarded contracts in April 2005 for front-end engineering and design studies for a multi-billion-dollar onshore LNG project located in northern Angola. This project will be designed to help reduce flaring of natural gas and represents a major step toward the commercialization of some of Angola's vast natural gas resources. The company has a 36 percent ownership interest in the Angola LNG project and will co-lead development with the Angolan government's national oil company. Construction is expected to begin in 2007.

In April 2005, the company reached an agreement with joint-venture participants in the Greater Gorgon Area, offshore western Australia that will enable the combined development of natural gas at Gorgon and nearby gas fields as one project. The company is a significant holder of gas resources in the area and will have an approximate 50 percent ownership interest across most of the Greater Gorgon Area.

In June 2005, the company announced the decision to move the Australian Greater Gorgon gas development project into the front-end engineering and design phase for a two-train (10 million metric tons per year) LNG facility and a potential domestic gas plant on Barrow Island, targeting initial production by 2010. Chevron is the operator and has a 50 percent ownership interest in the licenses for the Greater Gorgon Area.

In the fourth quarter 2005, the company signed a Heads of Agreement (HOA) for first sale of LNG from the Gorgon Project into Japan, the world's largest LNG market. The preliminary agreement was signed by Chevron Australia Pty Ltd with Tokyo Gas Co. Ltd, a major Japanese utility company, for the purchase of 1.2 million metric tons per year of Gorgon LNG over 25 years. Two additional HOAs were later signed by Chevron Australia Pty Ltd with Chubu Electric Co. Inc and Osaka Gas Co. Ltd, both companies from Japan. Each preliminary agreement was for the purchase of 1.5 million metric tons per year of Gorgon LNG over 25 years commencing in 2010 and 2011, respectively.

The company and its partners in the North West Shelf (NWS) venture agreed in mid-2005 to expand the project's onshore LNG facilities in Western Australia. Chevron holds a one-sixth interest in the NWS venture. The $1.5 billion project includes adding a fifth train that will increase LNG export capacity by more than 4 million metric tons per year to approximately 16 million metric tons per year, with startup expected in 2008. In December 2005, the NWS joint venture participants approved development of the Angel natural gas field, which will provide the natural gas supply for the Train 5 expansion.

In Nigeria, the company awarded a $1.7 billion contract in April 2005 for the engineering, procurement and construction of the Escravos gas-to-liquids project. Plant construction began in 2005 including major equipment fabrication and site preparation.

In the third quarter 2005, installation began on a 350-mile main offshore segment of the West African Gas Pipeline that will provide natural gas to markets in Ghana, Togo and Benin by connecting to an existing onshore pipeline in Nigeria. The pipeline will have a capacity of approximately 475 million cubic feet per day and will help in the reduction of the flaring of natural gas in the company's areas of operation.

In Russia, OAO Gazprom has included Chevron on a list of companies that could continue further commercial and technical discussions concerning the development and related commercial activities of the Shtokmanovskoye Field. Discussions were under way in early 2006, but the timing of Gazprom's selection of the company or companies that will participate in the field development was uncertain. Shtokmanovskoye is a very large natural gas field offshore Russia in the Barents Sea. OAO Gazprom is Russia's largest natural gas producer.

In the United States, Chevron completed the acquisition of the remaining 40 percent interest of Bridgeline Holdings, L.P. in August 2005. Bridgeline manages and operates more than 1,000 miles of pipeline and 12 billion cubic feet of natural gas storage capacity in southern Louisiana.

In the third quarter 2005, the company filed an application with the Federal Energy Regulatory Commission to own, construct and operate a natural gas import terminal at the Casotte Landing site adjacent to Chevron's refinery in Pascagoula, Mississippi. The terminal will be designed to initially process 1.3 billion cubic feet of natural gas per day from imported LNG.

In the fourth quarter 2005, the company committed to pipeline and additional LNG terminal capacity in the Sabine Pass area of Louisiana. The first commitment was for 1 billion cubic feet per day of pipeline capacity in a new pipeline and additional interconnect capacity to an existing pipeline. The company also exercised its option to increase capacity at a Sabine Pass LNG terminal from 700 million to 1 billion cubic feet per day.

Downstream

United States The company initiated a project to increase the capacity of the Pascagoula, Mississippi, refinery's fluid catalytic cracking unit by approximately 25 percent, from a current capacity of 63,000 barrels per day. This project is designed to enable the refinery to increase its production of gasoline and other light products and is expected to be completed by late 2006.

South Korea The company's 50 percent-owned GS Caltex affiliate announced a major upgrade project at its 650,000-barrel-per-day Yeosu refining complex. At an estimated total cost of $1.5 billion, the facilities will increase the yield of high-value refined products and reduce feedstock costs through the processing of heavy crude oil. Start-up is expected by the end of 2007.

Chemicals

Qatar The company's 50 percent-owned affiliate, Chevron Phillips Chemical Company LLC (CPChem), has obtained approvals and completed the financial closing for the Q-Chem II complex to be located next to the existing Q-Chem I complex in Mesaieed, Qatar. The Q-Chem II complex will include a 350,000-metric-ton-per-year polyethylene plant and a 345,000-metric-ton-per-year normal alpha olefins plant. The project also includes a separate joint venture to develop a 1,300,000-metric-ton-per-year ethylene cracker at Qatar's Ras Laffan Industrial City. CPChem and its partners expect to start-up the cracker and derivatives plants in late 2008. CPChem owns a 49 percent interest of Q-Chem II.

Other

Common Stock Dividends and Stock Repurchase Program In April 2005, the company increased its quarterly common stock dividend by 12.5 percent to $0.45 per share. The company completed an authorized $5 billion of stock buybacks in November 2005 under a repurchase program initiated in April 2004. Upon completion of this program, the company then authorized the acquisition of up to $5 billion of additional shares over a period of up to three years. Purchases under this authorization totaled $481 million through mid-February 2006.

RESULTS OF OPERATIONS

Major Operating Areas The following section presents the results of operations for the company's business segments – upstream, downstream and chemicals – as well as for "all other," which includes mining operations of coal and other minerals, power generation businesses, and the various companies and departments that are managed at the corporate level. Income is also presented for the U.S. and international geographic areas of the upstream and downstream business segments. (Refer to Note 8, beginning on page FS-40, for a discussion of the company's "reportable segments," as defined in FAS 131, *"Disclosures About Segments of an Enterprise and Related Information."*)

To aid in the understanding of changes in income between periods, the discussion, when applicable, is in two parts – first on underlying trends, and second on special-item gains and charges. The special items are identified separately because of their nature and amount and also to help discern the underlying trends for the company's businesses. This section should also be read in conjunction with the discussion in "Business Environment and Outlook" on pages FS-2 through FS-5.

U.S. Upstream – Exploration and Production

Millions of dollars	**2005**	2004	2003
Income From Continuing Operations	**$ 4,168**	$ 3,868	$ 3,160
Income From Discontinued Operations	**–**	70	23
Cumulative Effect of Accounting Change	**–**	–	(350)
Total Income*	**$ 4,168**	$ 3,938	$ 2,833
*Includes Special-Item Gains (Charges):			
Asset Dispositions			
Continuing Operations	**$ –**	$ 316	$ 77
Discontinued Operations	**–**	50	–
Litigation Provisions	**–**	(55)	–
Asset Impairments/Write-offs	**–**	–	(103)
Restructuring and Reorganizations	**–**	–	(38)
Total	**$ –**	$ 311	$ (64)

U.S. upstream income of nearly $4.2 billion in 2005 increased $230 million. The amount in 2004 included net special-item benefits (discussed below) of more than $300 million. Higher prices for crude oil and natural gas in 2005 and earnings from the former Unocal operations contributed approximately $2 billion to the increase between periods. Approximately 90 percent of this amount related to the effects of higher prices on heritage-Chevron production. These benefits were partially offset by the adverse effects of lower production (discussed below), higher operating expenses and higher depreciation expense associated with heritage-Chevron properties.

Income of $3.9 billion in 2004 was $1.1 billion higher than the $2.8 billion recorded in 2003. Of this increase, $725 million resulted from the difference in the effect on earnings in the respective periods from special items and the cumulative-effect charges recorded in 2003 for the implementation of a new accounting standard. (Refer to Note 24, beginning on page FS-59, for a discussion of FAS 143, *"Accounting for Asset Retirement Obligations."*) The balance of the increase from 2003 to 2004 was composed of about a $1 billion benefit from higher prices for crude oil and natural gas that was partially offset by the effect of lower production.

The company's average realization for crude oil and natural gas liquids in 2005 was $46.97 per barrel, compared with $34.12 in 2004 and $26.66 in 2003. The average natural gas realization was $7.43 per thousand cubic feet in 2005, compared with $5.51 and $5.01 in 2004 and 2003, respectively.

Net oil-equivalent production in 2005 averaged 727,000 barrels per day, down 11 percent from 2004 and 22 percent from 2003. The decline between 2004 and 2005 was the result of the effects of hurricanes, property sales and normal field declines, which were partially offset by the benefit of

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five months of production in 2005 from properties acquired from Unocal. The lower production between 2003 and 2004 was associated with property sales, the effects of storms and normal field declines.

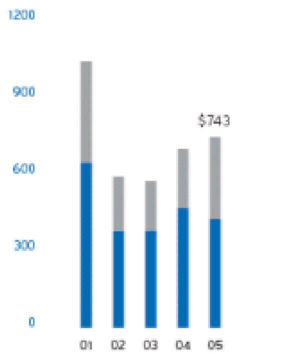
The net liquids component of oil-equivalent production for 2005 averaged 455,000 barrels per day, a decline of 10 percent from 2004 and 19 percent from 2003. Absent the effects of the Unocal volumes in 2005, property sales and storms, net liquids production in 2005 declined 6 percent and 11 percent from 2004 and 2003, respectively.

Net natural gas production averaged 1.6 billion cubic feet per day in 2005, down 13 percent and 27 percent from 2004 and 2003, respectively. Excluding the Unocal volumes in 2005, the effects of property sales and shut-in production related to storms, net natural gas production in 2005 declined 10 percent from 2004 and 20 percent from 2003.

Refer to the "Selected Operating Data" table, on page FS-12, for the three-year comparative production volumes in the United States.

No special items were recorded in 2005. Special items in 2004 included gains of $366 million from property sales, partially offset by charges of $55 million due to an adverse litigation matter. Net special charges of $64 million in 2003 were composed of charges of $103 million for asset impairments, associated mainly with the write-down of assets in anticipation of sale; charges of $38 million for restructuring and reorganization, mainly for employee severance costs; and gains of $77 million from property sales.

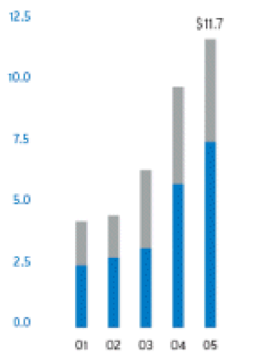
EXPLORATION EXPENSES
Millions of dollars



United States
International

Exploration expenses declined after the October 2001 merger with Texaco, reflecting, in part, the high-grading of the combined exploration portfolio.

WORLDWIDE EXPLORATION & PRODUCTION EARNINGS*
Billions of dollars



United States
International

Earnings increased in 2005 on higher prices for crude oil and natural gas.

*Before the cumulative effect of changes in accounting principles but including discontinued operations

International Upstream – Exploration and Production

Millions of dollars	**2005**	2004	2003
Income From Continuing Operations[1]	**$ 7,556**	$ 5,622	$ 3,199
Income From Discontinued Operations	**–**	224	21
Cumulative Effect of Accounting Change	**–**	–	145
Total Income[2]	**$ 7,556**	$ 5,846	$ 3,365
[1] Includes Foreign Currency Effects:	**$14**	$(129)	$(319)
[2] Includes Special-Item Gains (Charges):			
Asset Dispositions			
Continuing Operations	**$ –**	$ 644	$ 32
Discontinued Operations	**–**	207	–
Asset Impairments/Write-offs	**–**	–	(30)
Restructuring and Reorganizations	**–**	–	(22)
Tax Adjustments	**–**	–	118
Total	**$ –**	$ 851	$ 98

International upstream income of more than $7.5 billion in 2005 increased $1.7 billion from $5.8 billion in 2004. Higher prices for crude oil and natural gas in 2005 and earnings from the former Unocal operations increased earnings approximately $2.9 billion between periods. About 80 percent of this benefit arose from the effect of higher prices on heritage-Chevron production. Partially offsetting these benefits were higher expenses between periods for heritage-Chevron operations for certain income-tax items, including the absence of a $200 million benefit in 2004 relating to changes in income tax laws. The change between years also reflected the impact of $851 million of special-item gains in 2004, while no special items were recorded in 2005. Foreign currency losses in 2004 were $129 million. Gains of $14 million were recorded in 2005.

Income of $5.8 billion in 2004 was nearly $2.5 billion higher than earnings recorded in 2003. Approximately $900 million of the increase was the difference between the effects in each period from special items (discussed below) and foreign currency losses. Approximately $1.1 billion of the increase was associated with higher prices for crude oil and natural gas. Another $400 million resulted from lower income-tax expense between periods, including a benefit of about $200 million in 2004 as a result of changes in income tax laws. Partially offsetting these effects were higher transportation costs in 2006 of about $200 million. The balance of the change between periods was associated with a gain in 2003 from the implementation of a new accounting standard. (Refer to Note 24, beginning on page FS-59, for a discussion of FAS 143, *"Accounting for Asset Retirement Obligations."*)

Net oil-equivalent production of 1.8 million barrels per day in 2005, including 143,000 net barrels per day from oil sands in Canada and production under an operating service agreement in Venezuela, increased about 6 percent from 2004 and 5 percent from 2003. Absent the net effect of increased volumes in 2005 from five months of production from the former Unocal operations, the effect of property sales and the effect of higher prices on cost-recovery and variable-royalty provisions of certain contracts, oil-equivalent production in 2005 was essentially the same as 2004 and 2003.

The net liquids component of oil-equivalent production was 1.4 million barrels per day in 2005, unchanged from 2004 and 2003. Excluding the effects of Unocal production, property sales and the effect of higher prices on cost-recovery and variable-royalty volumes, 2005 net liquids production was essentially the same as 2004 and decreased 1 percent from 2003.

Net natural gas production of 2.6 billion cubic feet per day in 2005 was up 25 percent and 26 percent from 2004 and 2003, respectively. Excluding the effect of production from the Unocal properties, production increased 2 percent and 3 percent from 2004 and 2003, respectively.

Refer to the "Selected Operating Data" table, on page FS-12, for the three-year comparative of international production volumes.

No special items were recorded in 2005. Special-item gains in 2004 included $585 million from the sale of producing properties in Western Canada and $266 million from the sale of other nonstrategic assets, including the company's operations in the Democratic Republic of the Congo and a Canadian natural-gas processing business. In 2003, net special-item gains of $98 million included benefits of $150 million related to income taxes and property sales, partially offset by asset impairments and charges for employee termination costs.

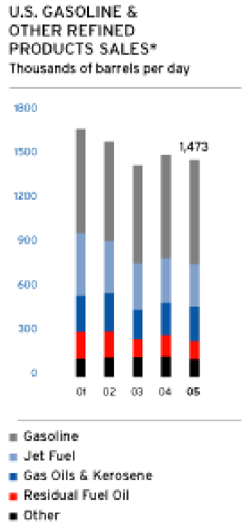
U.S. Downstream – Refining, Marketing and Transportation

Millions of dollars	**2005**	2004	2003
Income*	**$ 980**	$ 1,261	$ 482
*Includes Special-Item Gains (Charges):			
Asset Dispositions	**$ –**	$ –	$ 37
Environmental Remediation Provisions	**–**	–	(132)
Restructuring and Reorganizations	**–**	–	(28)
Total	**$ –**	$ –	$ (123)

U.S. downstream earnings of nearly $1 billion in 2005 decreased about $300 million from 2004 and were up $500 million from 2003. Results in 2003 included net special-item charges (discussed below) of $123 million. Average refined-product margins in 2005 were higher than in 2004, and margins in 2004 were significantly higher than in 2003. However, the effects of increased downtime at refineries and other facilities and higher fuel costs dampened earnings in 2005. A portion of the downtime in 2005 was associated with hurricanes in the Gulf of Mexico. As a result of the storms, the company's refinery in Pascagoula, Mississippi, was shut down for more than a month, and the company's marketing and pipeline operations along the Gulf Coast were also disrupted for an extended period.

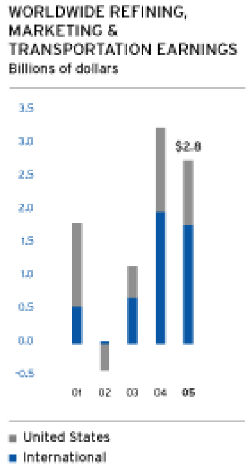
Sales volumes of refined products in 2005 were approximately 1.5 million barrels per day, or about 2 percent lower than in 2004. Branded gasoline sales volumes of approximately 600,000 barrels per day increased about 4 percent from the 2004 period. In 2004, refined-product sales volumes increased about 5 percent from 2003, primarily due to higher sales of gasoline, diesel fuel and fuel oil. Refer to the "Selected Operating Data" table, on page FS-12, for the three-year comparative refined-product sales volumes in the United States.

In 2003, net special-item charges of $123 million included $132 million for environmental remediation and $28 million for employee severance costs associated with the global downstream restructuring and reorganization. These charges were partially offset by net gains of $37 million from asset sales.



Refined products sales volumes declined about 2 percent from 2004, with lower sales of fuel oils and other products.

*Includes equity in affiliates



Downstream earnings declined due to lower international margins for refined products and U.S. refinery downtime.

International Downstream – Refining, Marketing and Transportation

Millions of dollars	**2005**	2004	2003
Income[1,2]	**$ 1,786**	$ 1,989	$ 685
[1] Includes Foreign Currency Effects:	**$(24)**	$7	$(141)
[2] Includes Special-Item Charges:			
Asset Dispositions	**$ –**	$ –	$ (24)
Asset Impairments/Write-offs	**–**	–	(123)
Restructuring and Reorganizations	**–**	–	(42)
Total	**$ –**	$ –	$ (189)

The international downstream includes the company's consolidated refining and marketing businesses, non-U.S. shipping operations, non-U.S. supply and trading activities, and equity earnings of affiliates, primarily in the Asia-Pacific region.

Income of nearly $1.8 billion in 2005 decreased 10 percent from $2 billion in 2004 but was up about $1.1 billion from 2003. The decrease from the 2004 period was due mainly to lower sales volumes, higher costs for fuel and transportation, expenses associated with an explosion and fire at a 40 percent-owned, nonoperated terminal in the United Kingdom, and tax adjustments in various countries. These items more than offset an improvement in average refined-product

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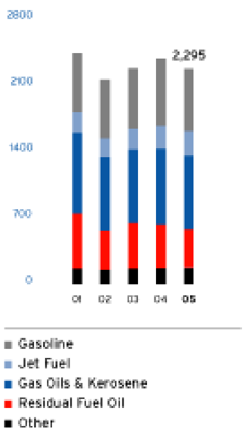
INTERNATIONAL GASOLINE & OTHER REFINED PRODUCTS SALES*
Thousands of barrels per day



Refined products sales volumes decreased about 4 percent from 2004.

*Includes equity in affiliates

margins between periods. The $1.3 billion increase in income from 2003 to 2004 reflected significantly higher average refined-product margins in most of the company's operating areas and higher earnings from international shipping operations. Earnings in 2003 also included special-item charges (discussed below) and foreign currency losses that totaled more than $300 million.

Total international refined products sales volumes were 2.3 million barrels per day in 2005, about 4 percent lower than 2004. The sales decline was primarily the result of lower gasoline trading activity and lower fuel-oil sales. Refined product sales volume of 2.4 million barrels per day in 2004 was about 4 percent higher than 2.3 million in 2003. Refer to the "Selected Operating Data" table, on page FS-12, for the three-year comparative refined-product sales volumes in the international areas.

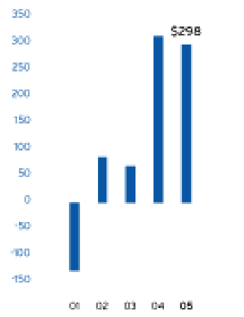
The special-item charges of $189 million in 2003 included the write-down of the Batangas Refinery in the Philippines in advance of its conversion to a product terminal facility, employee severance costs associated with the global downstream restructuring and reorganization, the recognition of the impairment of certain assets in anticipation of their sale and the company's share of losses from an asset sale and asset impairment by an equity affiliate.

Chemicals

Millions of dollars	**2005**	2004	2003
Segment Income*	**$ 298**	$ 314	$ 69
*Includes Foreign Currency Effects:	$ –	$ (3)	$ 13

The chemicals segment includes the company's Oronite subsidiary and the company's 50 percent share of its equity investment in Chevron Phillips Chemical Company LLC (CPChem). In 2005, results for the company's Oronite subsidiary were down due to significantly higher costs for feedstocks and adverse effects from the shut-down of operations in the U.S. Gulf Coast due to hurricanes. Earnings in 2005 for CPChem were higher than 2004 on improved margins for commodity chemicals. Results for both businesses in 2005 were dampened by the effects of the U.S. hurricanes. Significantly lower earnings in 2003 reflected weak demand for commodity chemicals and industry oversupply conditions in the period.

WORLDWIDE CHEMICALS EARNINGS*
Millions of dollars



Chemicals earnings declined about 5 percent from 2004 mainly due to the effects of storms.

*Includes equity in affiliates

All Other

Millions of dollars	**2005**	2004	2003
Charges Before Cumulative Effect of Changes in Accounting Principles	**$ (689)**	$ (20)	$ (213)
Cumulative Effect of Accounting Changes	**–**	–	9
Net Charges[1,2]	**$ (689)**	$ (20)	$ (204)
[1] Includes Foreign Currency Effects:	**$(51)**	$44	$43
[2] Includes Special-Item Gains (Charges):			
Dynegy-Related	**$ –**	$ –	$ 325
Asset Impairments/Write-offs	**–**	–	(84)
Restructuring and Reorganizations	**–**	–	(16)
Total	**$ –**	$ –	$ 225

All Other consists of the company's interest in Dynegy, mining operations of coal and other minerals, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities and technology companies.

The net charges of $689 million in 2005 increased significantly from $20 million in 2004. Approximately $400 million of the change related to larger benefits in 2004 from corporate-level tax adjustments. Higher charges in 2005 were associated with environmental remediation of properties that had been sold or idled and ongoing Unocal corporate-level activities. Interest expense also was higher in 2005 due to an increase in interest rates and the debt assumed with the Unocal acquisition.

The improvement between 2003 and 2004 was primarily associated with the company's investment in Dynegy, including gains from the redemption of certain Dynegy securities, higher interest income, lower interest expense and the favorable corporate-level tax adjustments.

Net special-item gains in 2003 included a Dynegy-related net benefit of $325 million, which was composed of a gain of $365 million from the exchange of the company's investment in Dynegy securities that was partially offset by a $40 million charge for Chevron's share of an asset impairment by Dynegy. Other special-item charges were for asset write-downs of $84 million, primarily in Chevron's gasification business, and employee severance costs of $16 million.

CONSOLIDATED STATEMENT OF INCOME

Comparative amounts for certain income statement categories are shown below. Amounts associated with special items in the comparative periods are also indicated to assist in the explanation of the period-to-period changes. Besides the information in this section, separately disclosed on the face of the Consolidated Statement of Income are a gain from the exchange of Dynegy securities and the cumulative effect of changes in accounting principles. These matters are discussed elsewhere in Management's Discussion and Analysis and in Note 27 to the Consolidated Financial Statements, on page FS-62. Refer to the Results of Operations section, beginning of page FS-7, for additional information relating to special-item gains and charges.

Millions of dollars	**2005**	2004	2003
Sales and other operating revenues	**$ 193,641**	$ 150,865	$ 119,575

Sales and other operating revenues in 2005 increased over 2004 and 2003 due primarily to higher prices for crude oil, natural gas and refined products worldwide. The amount in 2005 also included revenues for five months from former Unocal operations.

Millions of dollars	**2005**	2004	2003
Income from equity affiliates	**$ 3,731**	$ 2,582	$ 1,029
Memo: Special-item gains, before tax	$ –	$ –	$ 179

Improved results for Tengizchevroil and Hamaca (Venezuela) accounted for nearly three-fourths of the increased income from equity affiliates in 2005. Profits in 2005 also increased at the company's CPChem and Dynegy affiliates. The improvement in 2004 from 2003 was the result of higher earnings from the company's downstream affiliates in the Asia-Pacific area, Tengizchevroil, CPChem, Dynegy and the Caspian Pipeline Consortium. Refer to Note 13, beginning on page FS-44, for a discussion of Chevron's investment in affiliated companies.

Millions of dollars	**2005**	2004	2003
Other income	**$ 828**	$ 1,853	$ 308
Memo: Special-item gains, before tax	$ –	$ 1,281	$ 217

Other income in 2005 included no special-item gains or losses; however, net special-item gains relating to upstream property sales were nearly $1.3 billion in 2004 and more than $200 million in 2003. The increase from 2003 through 2005 was otherwise partly due to higher interest income in each period – $400 million in 2005, $200 million in 2004 and $120 million in 2003 – on higher average interest rates and balances of cash and marketable securities. Foreign currency losses were $60 million in both 2005 and 2004 and about $200 million in 2003.

Millions of dollars	**2005**	2004	2003
Purchased crude oil and products	**$ 127,968**	$ 94,419	$ 71,310

Crude oil and product purchases in 2005 increased approximately 35 percent from 2004, due mainly to higher prices for crude oil, natural gas and refined products as well as to the inclusion in 2005 of Unocal-related amounts for five months. Crude oil and product purchase costs increased 32 percent in 2004 from the prior year as a result of higher prices and increased purchased volumes of crude oil and products.

Millions of dollars	**2005**	2004	2003
Operating, selling, general and administrative expenses	**$ 17,019**	$ 14,389	$ 12,940
Memo: Special-item charges, before tax	$ –	$ 85	$ 475

Operating, selling, general and administrative expenses in 2005 increased 18 percent from a year earlier. Higher amounts in 2005 included former-Unocal expenses for five months, and for heritage-Chevron operations, higher costs for labor and transportation, uninsured costs associated with storms in the Gulf of Mexico, asset write-offs, repair and maintenance services, fuel costs for plant operations and a number of corporate items that individually were not significant. Total expenses increased from 2003 to 2004 due mainly to costs for chartering crude oil tankers and other transportation expenses.

Millions of dollars	**2005**	2004	2003
Exploration expense	**$ 743**	$ 697	$ 570

Exploration expenses in 2005 increased mainly due to the inclusion of Unocal amounts for five months. In 2004, amounts were higher than in 2003 for international operations, primarily for seismic costs and expenses associated with evaluating the feasibility of different project alternatives.

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Millions of dollars	2005	2004	2003
Depreciation, depletion and amortization	**$ 5,913**	$ 4,935	$ 5,326
Memo: Special-item charges, before tax	$ –	$ –	$ 286

Depreciation, depletion and amortization expenses in 2005 increased mainly as a result of five months of depreciation and depletion expense for the former Unocal assets and higher depreciation rates for certain heritage-Chevron crude oil and natural gas producing fields worldwide. Between 2003 and 2004, expenses did not change materially, after consideration of the effects of special-item charges for asset impairments in 2003.

Millions of dollars	2005	2004	2003
Interest and debt expense	**$ 482**	$ 406	$ 474

Interest and debt expense in 2005 increased mainly due to the inclusion of debt assumed with the Unocal acquisition and higher average interest rates for commercial paper borrowings. The decline between 2003 and 2004 reflected lower average debt balances.

Millions of dollars	2005	2004	2003
Taxes other than on income	**$ 20,782**	$ 19,818	$ 17,901

Taxes other than on income in 2005 increased as a result of higher international taxes assessed on product values, higher duty rates in the areas of the company's European downstream operations and higher U.S. federal excise taxes on jet fuel resulting from a change in tax law that became effective in 2005. The increase in 2004 from 2003 primarily reflected the weakening U.S. dollar on foreign currency–denominated duties in the company's European downstream operations.

Millions of dollars	2005	2004	2003
Income tax expense	**$ 11,098**	$ 7,517	$ 5,294
Memo: Special-item charges (benefits)	$	$ 291	$ (312)

Effective income tax rates were 44 percent in 2005, 37 percent in 2004 and 43 percent in 2003, after excluding the effect of net special items. Rates were higher in 2005 compared with the prior year due to the absence of benefits in 2004 from changes in the income tax laws for certain international operations and an increase in earnings in countries with higher tax rates. As compared with the effective tax rate in 2003, the effective tax rate in 2004 benefited from changes in the income tax laws for certain international operations, a change in the mix of international upstream earnings occurring in countries with different tax rates and favorable corporate consolidated tax effects. Refer also to the discussion of income taxes in Note 16 to the Consolidated Financial Statements, beginning on page FS-47.

SELECTED OPERATING DATA[1,2]

	2005	2004	2003
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)[3]	**455**	505	562
Net Natural Gas Production (MMCFPD)[3,4]	**1,634**	1,873	2,228
Net Oil-Equivalent Production (MBOEPD)[3]	**727**	817	933
Sales of Natural Gas (MMCFPD)	**5,449**	4,518	4,304
Sales of Natural Gas Liquids (MBPD)	**151**	177	194
Revenues From Net Production Liquids ($/Bbl)	**$ 46.97**	$ 34.12	$ 26.66
Natural Gas ($/MCF)	**$ 7.43**	$ 5.51	$ 5.01
International Upstream			
Net Crude and Natural Gas Liquids Production (MBPD)[3]	**1,214**	1,205	1,246
Net Natural Gas Production (MMCFPD)[3,4]	**2,599**	2,085	2,064
Net Oil-Equivalent Production (MBOEPD)[3,5]	**1,790**	1,692	1,704
Sales Natural Gas (MMCFPD)	**2,289**	1,885	1,951
Sales Natural Gas Liquids (MBPD)	**108**	105	107
Revenues From Liftings Liquids ($/Bbl)	**$ 47.59**	$ 34.17	$ 26.79
Natural Gas ($/MCF)	**$ 3.19**	$ 2.68	$ 2.64
U.S. and International Upstream			
Net Oil-Equivalent Production Including Other Produced Volumes (MBOEPD)[4,5]			
United States	**727**	817	933
International	**1,790**	1,692	1,704
Total	**2,517**	2,509	2,637
U.S. Downstream – Refining, Marketing and Transportation			
Gasoline Sales (MBPD)[6]	**709**	701	669
Other Refined Products Sales (MBPD)	**764**	805	767
Total (MBPD)[7]	**1,473**	1,506	1,436
Refinery Input (MBPD)[8]	**845**	914	951
International Downstream – Refining Marketing and Transportation			
Gasoline Sales (MBPD)[6]	**669**	717	643
Other Refined Products Sales (MBPD)	**1,626**	1,685	1,659
Total (MBPD)[7,9]	**2,295**	2,402	2,302
Refinery Input (MBPD)	**1,038**	1,044	1,040

[1] Includes equity in affiliates.

[2] MBPD = Thousands of barrels per day; MMCFPD = Millions of cubic feet per day; MBOEPD = Thousands of barrels of oil equivalents per day; Bbl = Barrel; MCF = Thousands of cubic feet. Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of gas = 1 barrel of oil.

[3] Includes net production from August 1, 2005, related to former Unocal properties.

[4] Includes natural gas consumed on lease (MMCFPD):

	2005	2004	2003
United States	**48**	50	65
International	**332**	293	268

[5] Includes other produced volumes (MBPD):

	2005	2004	2003
Athabasca Oil Sands – Net	**32**	27	15
Boscan Operating Service Agreement	**111**	113	99
	143	140	114

[6] Includes branded and unbranded gasoline

[7] Includes volumes for buy/sell contracts (MBPD):

	2005	2004	2003
United States	**82**	84	90
International	**129**	96	104

[8] The company sold its interest in the El Paso Refinery in August 2003.

[9] Includes sales of affiliates (MBPD): **540** 536 525

INFORMATION RELATED TO INVESTMENT IN DYNEGY INC.

At year-end 2005, Chevron owned an approximate 24 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States. The company also held an investment in Dynegy preferred stock.

Investment in Dynegy Common Stock At December 31, 2005, the carrying value of the company's investment in Dynegy common stock was approximately $300 million. This amount was about $200 million below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. The difference had been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors associated with the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate to recognize a portion of the difference between these allocated values and Dynegy's historical book values. The market value of the company's investment in Dynegy's common stock at the end of 2005 was approximately $470 million.

Investments in Dynegy Preferred Stock At the end of 2005, the company held $400 million face value of Dynegy Series C Convertible Preferred Stock with a stated maturity of 2033. The stock is accounted for at its fair value, which was estimated to be $360 million at year-end 2005. Temporary changes in the estimated fair value of the preferred stock are reported in "Other Comprehensive Income." However, if in any future period a decline in fair value is deemed to be other than temporary, a charge against income in the period would be recorded. Dividends received from the preferred stock are recorded to income in the period received.

LIQUIDITY AND CAPITAL RESOURCES

Cash, cash equivalents and marketable securities Total balances were $11.1 billion and $10.7 billion at December 31, 2005 and 2004, respectively. Cash provided by operating activities in 2005 was $20.1 billion, compared with $14.7 billion in 2004 and $12.3 billion in 2003.

The 2005 increase in cash provided by operating activities mainly reflected higher earnings in the upstream segment, including earnings from the former Unocal operations. Cash provided by operating activities was net of contributions to employee pension plans of $1.0 billion, $1.6 billion and $1.4 billion in 2005, 2004 and 2003, respectively. Cash provided by investing activities included proceeds from asset sales of $2.7 billion in 2005, $3.7 billion in 2004 and $1.1 billion in 2003.

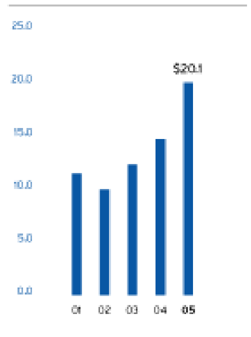
Cash provided by operating activities and asset sales during 2005 was sufficient to fund the company's $8.7 billion capital and exploratory program, pay $3.8 billion of dividends to stockholders, repay approximately $970 million in long-term debt and repurchase $3 billion of common stock. Partial consideration for the acquisition of Unocal in August 2005 also included $7.5 billion in cash. Unocal balances of cash, cash equivalents and marketable securities at the acquisition date totaled $1.6 billion.

Dividends The company paid dividends of approximately $3.8 billion in 2005, $3.2 billion in 2004 and $3 billion in 2003. In April 2005, the company increased its quarterly common stock dividend by 12.5 percent to 45 cents per share.

Debt, capital lease and minority interest obligations Total debt and capital lease balances were $12.9 billion at December 31, 2005, up from $11.3 billion at year-end 2004. The 2005 year-end balance included approximately $2.2 billion of debt and capital lease obligations assumed with the acquisition of Unocal. The company also had minority interest obligations of $200 million, up from $172 million at December 31, 2004.

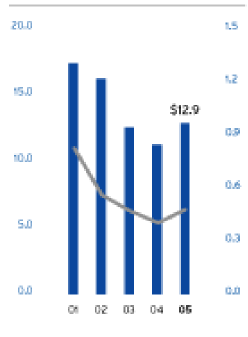
The company's debt and capital lease obligations due within one year, consisting primarily of commercial paper and the current portion of long-term debt, totaled $5.6 billion at December 31, 2005, unchanged from December 31, 2004. Of these amounts, $4.9 billion and $4.7 billion were reclassified to long-term at the end of each period, respectively. At year-end 2005, settlement of these obligations was not expected to require the use of working capital in 2006, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis. The company's practice has been to continually refinance its commercial paper, maintaining levels it believes appropriate and economic.

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars



Operating cash flow increased 37 percent mainly due to higher earnings in the upstream segment.

TOTAL INTEREST EXPENSE & TOTAL DEBT AT YEAR-END
Billions of dollars



■ Total Interest Expense (right scale)
■ Total Debt (left scale)

Interest expense rose mainly due to debt assumptions from the Unocal acquisition.

At year-end 2005, the company had $4.9 billion in committed credit facilities with various major banks, which permitted the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowings and also can be used for general corporate purposes. The company's practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management

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believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company's strong credit rating. No borrowings were outstanding under these facilities at December 31, 2005. In addition, the company has three existing effective "shelf" registration statements on file with the Securities and Exchange Commission that together would permit additional registered debt offerings up to an aggregate $3.8 billion of debt securities. Following the acquisition of Unocal, the company withdrew Unocal's "shelf" registration statements.

In October 2005, the company fully redeemed the Unocal subsidiary Pure Resources' 7.125 percent Senior Notes due 2011 for $395 million. The company's $150 million of Texaco Brasil zero coupon notes were paid at maturity in November 2005. In December 2005, the company exercised a par-call redemption of $200 million in Texaco Capital Inc. 5.7 percent Notes due 2008.

In February 2006, the company retired Union Oil bonds at maturity for approximately $185 million.

Texaco Capital LLC, a wholly owned finance subsidiary, issued Deferred Preferred Shares Series C (Series C) in December 1995. In February 2005, the company redeemed the Series C shares and paid accumulated dividends of approximately $140 million.

In January 2005, the company contributed $98 million to its Employee Stock Ownership Plan (ESOP) to permit the ESOP to make a $144 million debt service payment, which included a principal payment of $113 million.

In the second quarter 2004, Chevron entered into $1 billion of interest rate fixed-to-floating swap transactions, in which the company receives a fixed interest rate and pays a floating rate, based on the notional principal amounts. Under the terms of the swap agreements, of which $250 million and $750 million will terminate in September 2007 and February 2008, respectively, the net cash settlement will be based on the difference between fixed-rate and floating rate interest amounts.

Chevron's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investors Service. The company's senior debt of Texaco Capital Inc. is rated Aa3, and Union Oil Company of California bonds are rated A1 by Moody's. These companies are wholly owned subsidiaries of Chevron. The company's U.S. commercial paper is rated A-1+ by Standard and Poor's and P-1 by Moody's, and the company's Canadian commercial paper is rated R-1 (middle) by Dominion Bond Rating Service. All of these ratings denote high-quality investment-grade securities.

The company's future debt level is dependent primarily on results of operations, the capital-spending program and cash that may be generated from asset dispositions. Further reductions from debt balances at December 31, 2005, are dependent upon many factors, including management's continuous assessment of debt as an appropriate component of the company's overall capital structure. The company believes it has substantial borrowing capacity to meet unanticipated cash requirements, and during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, the company believes that it has the flexibility to increase borrowings and/or modify capital-spending plans to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

Common Stock Repurchase Program In connection with a $5 billion stock-repurchase program initiated in April 2004, the company acquired 92.1 million of its common shares for $5 billion through November 2005. During 2005, about 49.8 million of common shares were repurchased under this program for a total cost of $2.9 billion.

In December 2005, the company authorized the acquisition of up to an additional $5 billion of its common shares from time to time at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. The program is for a period of up to three years and may be discontinued at any time. Under this program, the company acquired approximately 1.7 million shares in the open market for $100 million during December 2005. Purchases through mid-February 2006 increased the total shares acquired to 8.3 million at a cost of $481 million.

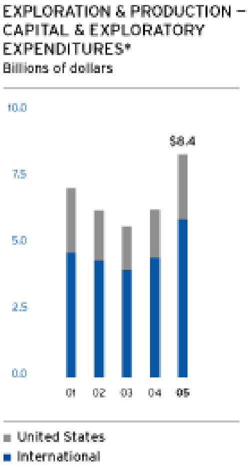
Capital and exploratory expenditures Excluding the $17.3 billion acquisition of Unocal Corporation, total reported expenditures for 2005 were $11.1 billion, including $1.7 billion for the company's share of affiliates' expenditures, which did not require cash outlays by the company. In 2004

Capital and Exploratory Expenditures

			2005			2004			2003
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream – Exploration and Production	**$ 2,450**	**$ 5,939**	**$ 8,389**	$ 1,820	$ 4,501	$ 6,321	$ 1,641	$ 4,034	$ 5,675
Downstream – Refining, Marketing and Transportation	**818**	**1,332**	**2,150**	497	832	1,329	403	697	1,100
Chemicals	**108**	**43**	**151**	123	27	150	173	24	197
All Other	**329**	**44**	**373**	512	3	515	371	20	391
Total	**$ 3,705**	**$ 7,358**	**$ 11,063**	$ 2,952	$ 5,363	$ 8,315	$ 2,588	$ 4,775	$ 7,363
Total, Excluding Equity in Affiliates	**$ 3,522**	**$ 5,860**	**$ 9,382**	$ 2,729	$ 4,024	$ 6,753	$ 2,306	$ 3,920	$ 6,226

and 2003, expenditures were $8.3 billion and $7.4 billion, respectively, including the company's share of affiliates' expenditures of $1.6 billion and $1.1 billion in the corresponding periods.

Of the $11.1 billion in expenditures for 2005, about three-fourths, or $8.4 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2004 and 2003. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the years, reflecting the company's continuing focus on opportunities that are available outside the United States.



Exploration and production projects accounted for 76 percent of total capital and exploratory expenditures in 2005.

*Includes equity in affiliates

In 2006, the company estimates capital and exploratory expenditures will be 33 percent higher at $14.8 billion, including spending by affiliates. About three-fourths, or $11.3 billion, is again for exploration and production activities, with $8 billion of that amount outside the United States. Spending is primarily targeted for exploratory prospects in the deepwater Gulf of Mexico and western Africa and major development projects in Angola, Nigeria, Kazakhstan and the deepwater Gulf of Mexico. Included in the upstream expenditures is about $1 billion to develop the company's international natural gas resource base.

Worldwide downstream spending in 2006 is estimated at $2.8 billion, with about $1.9 billion for refining and marketing and $900 million for supply and transportation projects, including pipelines to support expanded upstream production. Approximately two-thirds of the total projected spending is outside the United States.

Investments in chemicals businesses in 2006 are budgeted at $250 million. Estimates for energy technology, information technology and facilities, real estate activities, power-related businesses and other businesses total approximately $460 million.

Pension Obligations In 2005, the company's pension plan contributions totaled approximately $1 billion, including nearly $200 million to the Unocal plans. Approximately $800 million of the total was contributed to U.S. plans. In 2006, the company estimates contributions will be $500 million. Actual amounts are dependent upon plan-investment results, changes in pension obligations, regulatory environments and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in "Critical Accounting Estimates and Assumptions," beginning on page FS-22.

FINANCIAL RATIOS

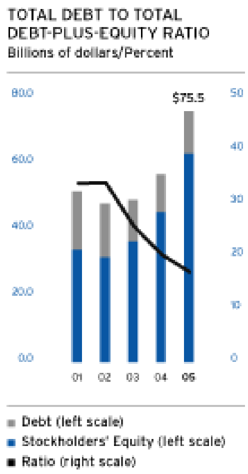
Financial Ratios

	At December 31		
	2005	2004	2003
Current Ratio	**1.4**	1.5	1.2
Interest Coverage Ratio	**47.5**	47.6	24.3
Total Debt/Total Debt-Plus-Equity	**17.0%**	19.9%	25.8%

Current Ratio – current assets divided by current liabilities. The current ratio in all periods was adversely affected by the fact that Chevron's inventories are valued on a LIFO basis. At year-end 2005, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $4.8 billion.

Interest Coverage Ratio – income before income tax expense, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs. The company's interest coverage ratio was essentially unchanged between 2004 and 2005. The interest coverage ratio was higher in 2004 compared with 2003, primarily due to higher before-tax income and lower average debt balances.

Debt Ratio – total debt as a percentage of total debt plus equity. Although total debt was higher at the end of 2005 than a year earlier, the debt ratio declined as a result of higher stockholders' equity balances for retained earnings and the capital stock that was issued in connection with the Unocal acquisition. The decline in the debt ratio between 2003 and 2004 was primarily due to lower debt levels and higher retained earnings.



Chevron's ratio of total debt to total debt-plus-equity fell to 17 percent at year-end as the company's stockholders' equity climbed.

GUARANTEES, OFF-BALANCE-SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS, AND OTHER CONTINGENCIES

*Direct or Indirect Guarantees**

Millions of dollars		Commitment Expiration by Period			
	Total	2006	2007-2009	2010	After 2010
Guarantees of non-consolidated affiliates or joint venture obligations	$ 985	$ 454	$ 426	$ 35	$ 70
Guarantees of obligations of third parties	294	113	136	8	37
Guarantees of Equilon debt and leases	193	24	55	19	95

* The amounts exclude indemnifications of contingencies associated with the sale of the company's interest in Equilon and Motiva in 2002, as discussed in the "Indemnifications" section on page FS-16 through FS-17.

At December 31, 2005, the company and its subsidiaries provided guarantees, either directly or indirectly, of $985 million in guarantees for notes and other contractual obligations of affiliated companies and $294 million for third parties as described by major category below. There are no material amounts being carried as liabilities for the company's obligations under these guarantees.

Of the $985 million in guarantees provided to affiliates, $806 million relate to borrowings for capital projects or general corporate purposes. These guarantees were undertaken to achieve lower interest rates and generally cover the construction period of the capital projects. Included in these amounts are Unocal-related guarantees of $230 million associated with a construction completion guarantee for the debt financing of Unocal's equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Approximately 95 percent of the amounts guaranteed will expire between 2006 and 2010 with the remaining guarantees expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed. There are no recourse provisions, and no assets are held as collateral for these guarantees. The remaining balance of $179 million represents obligations in connection with pricing of power-purchase agreements for certain of the company's cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliates do not perform under the agreements. There are no recourse provisions to third parties, and no assets are held as collateral for these pricing guarantees.

Guarantees of $294 million have been provided to third parties, including guarantees of approximately $150 million related to construction loans to host governments in the company's international upstream operations. The remaining guarantees of $144 million were provided principally as conditions of sale of the company's interest in certain operations, to provide a source of liquidity to the guaranteed parties and in connection with company marketing programs. No amounts of the company's obligations under these guarantees are recorded as liabilities. About 85 percent of the total amounts guaranteed will expire in 2010, with the remainder expiring after 2010. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed. Approximately $85 million of the guarantees have recourse provisions, which enable the company to recover any payments made under the terms of the guarantees from securities held over the guaranteed parties' assets.

At December 31, 2005, Chevron also had outstanding guarantees for about $190 million of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell Oil Company (Shell) for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2006 through 2010 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc. in connection with the February 2002 sale of the company's interests in those investments. The indemnities cover certain contingent liabilities. The company would be required to perform should the indemnified liabilities become actual losses. Should that occur, the company could be required to make future payments up to $300 million. Through the end of 2005, the company paid approximately $38 million under these indemnities. The company expects to receive additional requests for indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the periods of Texaco's ownership interests in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims relating to Equilon indemnities must be asserted as early as February 2007, or no later than February 2009, and claims relating to Motiva must be asserted no later than February 2012. Under the terms of the indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described above are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any applicable incident.

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets of Unocal's 76 Products Company business that existed prior to its sale in 1997. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments by the company; however, the purchaser shares certain costs under this indemnity up to an aggregate cap of $200 million. Claims relating to these indemnities must be asserted by April 2022. Through the end of 2005, approximately $113 million had been applied to the cap, which includes payments made by either Unocal or Chevron totaling $80 million.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying special purpose entities (SPEs). At December 31, 2005, approximately $1.2 billion, representing about 7 percent of Chevron's total current accounts receivable balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2005, was approximately $60 million. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event of the SPEs experiencing major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Throughput Agreements and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements, and take-or-pay agreements, some of which relate to supplier's financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are 2006 – $2.2 billion; 2007– $1.9 billion; 2008 – $1.8 billion; 2009 – $1.8 billion; 2010 – $0.5 billion; 2011 and after – $3.8 billion. Total payments under the agreements were approximately $2.1 billion in 2005, $1.6 billion in 2004, and $1.4 billion in 2003. The most significant take-or-pay agreement calls for the company to purchase approximately 55,000 barrels per day of refined products from an equity affiliate refiner in Thailand. This purchase agreement is in conjunction with the financing of a refinery owned by the affiliate and expires in 2009. The future estimated commitments under this contract are: 2006 – $1.3 billion; 2007 – $1.3 billion; 2008 – $1.3 billion; and 2009 – $1.3 billion. In 2005, under the terms of an agreement entered in 2004, the company exercised its option to acquire additional regasification capacity at the Sabine Pass Liquefied Natural Gas Terminal. Payments of $2.5 billion over the 20-year period are expected to commence in 2009.

Minority Interests The company has commitments of approximately $200 million related to minority interests in subsidiary companies.

The following table summarizes the company's significant contractual obligations:

Contractual Obligations

Millions of dollars	Payments Due by Period				
	Total	2006	2007-2009	2010	After 2010
On Balance Sheet:					
Short-Term Debt [1]	$ 739	$ 739	$ –	$ –	$ –
Long-Term Debt [1,2]	11,807	–	8,775	176	2,856
Noncancelable Capital Lease Obligations	324	–	154	36	134
Interest Expense	5,600	500	1,100	300	3,700
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	2,917	507	1,194	284	932
Unconditional Purchase Obligations	1,200	500	600	100	–
Throughput and Take-or-Pay Agreements	10,800	1,700	4,900	400	3,800

1 $4.9 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2007–2009 period.

2 Includes guarantees of $247 of LESOP (leveraged employee stock ownership plan) debt, $14 due in 2006 and $233 due after 2006.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to the price volatility of crude oil, refined products, natural gas, natural gas liquids and refinery feed-stock. The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase or sale of crude oil; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids.

Chevron also uses derivative commodity instruments for trading purposes. The results of this activity were not material to the company's financial position, net income or cash flows in 2005.

The company's positions are monitored and managed on a daily basis by an internal risk control group to ensure compliance with the company's risk management policy that has been approved by the Audit Committee of the company's Board of Directors.

The derivative instruments used in the company's risk management and trading activities consist mainly of futures, options, and swap contracts traded on the New York Mercantile Exchange and the International Petroleum Exchange. In addition, crude oil, natural gas and refined product swap contracts and option contracts are entered into principally with major financial institutions and other oil and gas companies in the "over-the-counter" markets.

Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from market quotes and other independent third-party quotes.

Each hypothetical 10 percent increase in the price of natural gas and crude oil would increase the fair value of the natural gas purchase derivative contracts by approximately $33 million and reduce the fair value of the crude oil sale

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derivative contracts by about $11 million. The same hypothetical decrease in the prices of these commodities would result in the same opposite effects on the fair values of the contracts.

The hypothetical effect on these contracts was estimated by calculating the cash value of the contracts as the difference between the hypothetical and contract delivery prices multiplied by the contract amounts.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The aggregate effect of a hypothetical 10 percent increase in the value of the U.S. dollar at year-end 2005 would be a reduction in the fair value of the foreign exchange contracts of approximately $70 million. The effect would be the opposite for a hypothetical 10 percent decrease in the year-end value of the U.S. dollar.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company's fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

At year-end 2005, the weighted average maturity of "receive fixed" interest rate swaps was approximately 2 years. There were no "receive floating" swaps outstanding at year end. A hypothetical increase of 10 basis points in fixed interest rates would reduce the fair value of the "receive fixed" swaps by approximately $3 million.

For the financial and derivative instruments discussed above, there was not a material change in market risk between 2005 and 2004.

The hypothetical variances used in this section were selected for illustrative purposes only and do not represent the company's estimation of market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A of the company's 2005 Annual Report on Form 10-K.

TRANSACTIONS WITH RELATED PARTIES

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements. Long-term purchase agreements are in place with the company's refining affiliate in Thailand. Refer to page FS-17 for further discussion. Management believes the foregoing agreements and others have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

LITIGATION AND OTHER CONTINGENCIES

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive.

Chevron is a party to more than 70 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepage of MTBE into groundwater. Resolution of these actions may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future.

The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. The company does not use MTBE in the manufacture of gasoline in the United States.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites including, but not limited to federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, and land development areas, whether operating, closed or divested.

The following table displays the annual changes to the company's before-tax environmental remediation reserves, including those for federal Superfund sites and analogous sites under state laws.

Millions of dollars	**2005**	2004	2003
Balance at January 1	**$1,047**	$1,149	$1,090
Net Additions	**731**	155	296
Expenditures	**(309)**	(257)	(237)
Balance at December 31	**$1,469**	$1,047	$1,149

Included in the additions for 2005 were liabilities assumed in connection with the acquisition of Unocal. These liabilities relate primarily to sites that had been divested or closed by Unocal prior to its acquisition by Chevron, includ-

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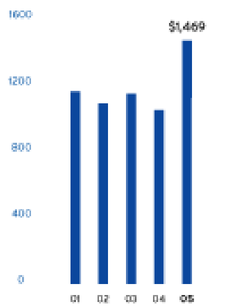
ing but were not limited to, former refineries, transportation and distribution facilities and service stations; former crude oil and natural gas fields and mining operations, as well as active mining operations. Other liability additions during 2005 for heritage-Chevron related primarily to refined-product marketing sites and various operating, closed or divested facilities in the United States.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2005 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

As of December 31, 2005, Chevron was involved with the remediation activities of 221 sites for which it had been identified as a potentially responsible party or otherwise by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation reserve for these sites at year-end 2005 was $139 million. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's consolidated financial position or liquidity.

YEAR-END ENVIRONMENTAL REMEDIATION RESERVES
Millions of dollars



Reserves for environmental remediation increased 40 percent from 2004, mainly due to the assumption of Unocal environmental liabilities.

Of the remaining year-end 2005 environmental reserves balance of $1,330 million, $855 million related to approximately 2,250 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining $475 million was associated with various sites in the international downstream ($101 million), upstream ($257 million), chemicals ($50 million) and other ($67 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil and/or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. Although the amount of future costs may be material to the company's results of operations in the period in which they are recognized, the company does not expect these costs will have a material adverse effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemical companies.

Effective January 1, 2003, the company implemented Financial Accounting Standards Board Statement No. 143, *"Accounting for Asset Retirement Obligations"* (FAS 143). Under FAS 143, the fair value of a liability for an asset retirement obligation is recorded when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. The liability balance of $4.3 billion for asset retirement obligations at year-end 2005 related primarily to upstream and coal properties.

For the company's other ongoing operating assets, such as refineries and chemicals facilities, no provisions are made for exit or cleanup costs that may be required when such assets reach the end of their useful lives unless a decision to sell or otherwise abandon the facility has been made, as the indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the asset retirement obligation.

Refer also to Note 24, beginning on page FS-59, related to FAS 143 and the company's adoption in 2005 of FIN 47, FASB Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143"* (FIN 47), and the discussion of "Environmental Matters" on page FS-21.

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. The U.S. federal income tax liabilities have been settled through 1996 for Chevron Corporation (formerly ChevronTexaco Corporation) and 1997 for Chevron Global Energy Inc. (formerly Caltex Corporation), Unocal Corporation (Unocal), and Texaco Inc. (Texaco). The company's California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal and through 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Areas in which the company and its affiliates have significant operations or ownership interests include the United States, Canada, Australia, the United Kingdom, Norway, Denmark, France, the Netherlands, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of the Congo, Angola, Nigeria, Chad, South Africa, the Democratic Republic of the Congo, Indonesia, Bangladesh, the Philippines, Myanmar, Singapore, China, Thailand, Vietnam, Cambodia, Azerbaijan, Kazakhstan, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago and South Korea. The company's Caspian Pipeline Consortium (CPC) affiliate operates in Russia and Kazakhstan. The company's Tengizchevroil affiliate operates in Kazakhstan. Through an affiliate, the company participates in the development of the Baku-Tbilisi-Ceyhan (BTC) pipeline through Azerbaijan, Georgia and Turkey. Also through an affiliate, the company has an interest in the Chad/Cameroon pipeline. The company's Petrolera Ameriven affiliate operates the Hamaca project in Venezuela. The company's Chevron Phillips Chemical Company LLC (CPChem) affiliate manufactures and markets a wide range of petrochemicals on a worldwide basis, with manufacturing facilities in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially or wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest, acts of violence or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries. Refer to page FS-6 for a discussion of the company's transition agreement with Petróleos de Venezuela, S.A. (PDVSA), the Venezuelan state-owned petroleum company, to convert contracts for the Boscan and LL-652 operating service agreements into an Empresa Mixta.

Suspended Wells The company suspends the costs of exploratory wells pending a final determination of the commercial potential of the related crude oil and natural gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity, or development decisions or both. If the company decides not to continue development, the costs of these wells are expensed. At December 31, 2005, the company had approximately $1.1 billion of suspended exploratory wells included in properties, plant and equipment, an increase of more than $400 million from 2004 and an increase of less than $600 million from 2003. Of the increase in 2005, about $300 million was the year-end suspended well balance for the former-Unocal operations. The year-end 2005 balance primarily reflects drilling activities in the United States, Nigeria and Indonesia.

The future trend of the company's exploration expenses can be affected by amounts associated with well write-offs, including wells that had been previously suspended pending determination as to whether the well had found reserves that could be classified as proved. The effect on exploration expenses in future periods of the $1.1 billion of suspended wells at year-end 2005 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 20, beginning on page FS-49, for additional discussion of suspended wells.

Equity Redetermination For crude oil and natural gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. Chevron currently estimates its maximum possible net before-tax liability at approximately $200 million. At the same time, a possible maximum net amount that could be owed to Chevron was estimated at about $50 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Accounting for Buy/Sell Contracts In the first quarter 2005, the Securities and Exchange Commission (SEC) issued comment letters to Chevron and other companies in the oil and gas industry requesting disclosure of information related to the accounting for buy/sell contracts. Under a buy/sell contract, a company agrees to buy a specific quantity and quality of a commodity to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of a commodity at a different location to the same counterparty. Physical delivery occurs for each side of the transaction, and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and risk of nonperformance by the counterparty. Both parties settle each side of the buy/sell through separate invoicing.

The company routinely enters into buy/sell contracts, primarily in the United States downstream business, associated with crude oil and refined products. For crude oil, these contracts are used to facilitate the company's crude oil marketing activity, which includes the purchase and sale of crude oil production, fulfillment of the company's supply arrangements as to physical delivery location and crude oil specifications, and purchase of crude oil to supply the company's refining system. For refined products, buy/sell arrangements are used to help fulfill the company's supply agreements to customer locations and specifications.

The company has historically accounted for buy/sell transactions in the Consolidated Statement of Income the same as for a monetary transaction – purchases are reported as "Purchased crude oil and products;" sales are reported as "Sales and other operating revenues." The SEC raised the issue as to whether the accounting for buy/sell contracts should be shown net on the income statement and accounted for under the provisions of Accounting Principles Board (APB) Opinion No. 29, *"Accounting for Nonmonetary Transactions"* (APB 29). The company understands that others in the oil and gas industry may report buy/sell transactions on a net basis in the income statement rather than gross.

The Emerging Issues Task Force (EITF) of the FASB deliberated this topic as Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty"* (EITF 04-13). At its September 2005 meeting, the EITF reached consensus that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, should be combined and considered as a single arrangement for purposes of applying APB 29 when the transactions were entered into "in contemplation" of one another. EITF 04-13 was ratified by the FASB in September 2005 and is effective for new arrangements, or modifications or renewals of existing arrangements, entered into beginning on or after April 1, 2006, which will be the effective date for the company's adoption of this standard. Upon adoption, the company will report the net effect of buy/sell transactions on its Consolidated Statement of Income as "Purchased crude oil and products" instead of reporting the revenues associated with these arrangements as "Sales and other operating revenues" and the costs as "Purchased crude oil and products."

While this issue was under deliberation by the EITF, the SEC staff directed Chevron and other companies to disclose on the face of the income statement the amounts associated with buy/sell contracts and to discuss in a footnote to the financial statements the basis for the underlying accounting. The amounts for buy/sell contracts shown on the company's Consolidated Statement of Income "Sales and other operating revenues" for the three years ending December 31, 2005, were $23,822, $18,650 and $14,246, respectively. These revenue amounts associated with buy/sell contracts represented 12 percent of total "Sales and other operating revenues" in 2005, 2004 and 2003. Nearly all of these revenue amounts in each period associated with buy/sell contracts pertain to the company's downstream segment. The costs associated with these buy/sell revenue amounts are included in "Purchased crude oil and products" on the Consolidated Statement of Income in each period.

Other Contingencies Chevron receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and may take lengthy periods to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

ENVIRONMENTAL MATTERS

Virtually all aspects of the businesses in which the company engages are subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to increase in both number and complexity over time and govern not only the manner in which the company conducts its operations, but also the products it sells. Most of the costs of complying with laws and regulations pertaining to company operations and products are embedded in the normal costs of doing business.

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. In addition to the costs for environmental protection associated with its ongoing operations and products, the company may incur expenses for corrective actions at various owned and previously owned facilities and at third-party-owned waste-disposal sites used by the company. An obligation may arise when operations are closed or sold or at non-Chevron sites where company products have been handled or disposed of. Most of the expenditures to fulfill these obligations relate to facilities and sites where past operations followed practices and procedures that were considered acceptable at the time but now require investigative or remedial work or both to meet current standards.

Using definitions and guidelines established by the American Petroleum Institute, Chevron estimated its worldwide environmental spending in 2005 at approximately $1.3 billion for its consolidated companies. Included in these expenditures were $341 million of environmental capital expenditures and $979 million of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites, which includes $14 million and $66 million, respectively, for Unocal activities for the last five months of 2005.

For 2006, total worldwide environmental capital expenditures are estimated at $1.1 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

It is not possible to predict with certainty the amount of additional investments in new or existing facilities or amounts of incremental operating costs to be incurred in the future to: prevent, control, reduce or eliminate releases of hazardous materials into the environment; comply with existing and new environmental laws or regulations; or remediate and restore areas damaged by prior releases of hazardous materials. Although these costs may be significant to the results of operations in any single period, the company does not expect them to have a material effect on the company's liquidity or financial position.

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

Management makes many estimates and assumptions in the application of generally accepted accounting principles (GAAP) that may have a material impact on the company's consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. All such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on management's experience and other information available prior to the issuance of the financial statements. Materially different results can occur as circumstances change and additional information becomes known.

The discussion in this section of "critical" accounting estimates or assumptions is according to the disclosure guidelines of the Securities and Exchange Commission (SEC), wherein:

1. the nature of the estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters, or the susceptibility of such matters to change;
2. the impact of the estimates and assumptions on the company's financial condition or operating performance is material.

Besides those meeting these "critical" criteria, the company makes many other accounting estimates and assumptions in preparing its financial statements and related disclosures. Although not associated with "highly uncertain matters," these estimates and assumptions are also subject to revision as circumstances warrant, and materially different results may sometimes occur.

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be "more likely than not." Another example is the estimation of oil and gas reserves under SEC rules that require "...geological and engineering data (that) demonstrate with reasonable certainty (reserves) to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made." Refer to Table V, "Reserve Quantity Information," beginning on page FS-70, for the changes in these estimates for the three years ending December 31, 2005, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page FS-78 for estimates of proved-reserve values for each of the three years ending December 31, 2003 through 2005, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements, beginning on page FS-34, includes a description of the "successful efforts" method of accounting for oil and gas exploration and production activities. The estimates of crude oil and natural gas reserves are important to the timing of expense recognition for costs incurred.

The discussion of the critical accounting policy for "Impairment of Property, Plant and Equipment and Investments in Affiliates," on page FS-23, includes reference to conditions under which downward revisions of proved reserve quantities could result in impairments of oil and gas properties. This commentary should be read in conjunction with disclosures elsewhere in this discussion and in the Notes to the Consolidated Financial Statements related to estimates, uncertainties, contingencies and new accounting standards. Significant accounting policies are discussed in Note 1 to the Consolidated Financial Statements, beginning on page FS-34. The development and selection of accounting estimates and assumptions, including those deemed "critical," and the associated disclosures in this discussion have been discussed by management with the audit committee of the Board of Directors.

The areas of accounting and the associated "critical" estimates and assumptions made by the company are as follows:

Pension and Other Postretirement Benefit Plans The determination of pension plan expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. For other postretirement employee benefit (OPEB) plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining OPEB expense are the discount rate applied to benefit obligations and the assumed health care cost-trend rates used in the calculation of benefit obligations.

Note 21, beginning on page FS-50, includes information for the three years ending December 31, 2005, on the components of pension and OPEB expense and on the underlying assumptions as well as on the funded status for the company's pension plans at the end of 2005 and 2004.

To estimate the long-term rate of return on pension assets, the company employs a rigorous process that incorporates actual historical asset-class returns and an assessment of expected future performance and takes into consideration external actuarial advice and asset-class factors. Asset allocations are periodically updated using pension plan asset/ liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies. The expected long-term rate of return on United States pension plan assets, which account for 72 percent of the company's pension plan assets, has remained at 7.8 percent since 2002.

The year-end market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market value in the preceding three months as opposed to the maximum allowable period of five years under U.S. accounting rules. Management considers the three-month period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of the measurement date is used in calculating the pension expense.

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2005, the company selected a 5.5 percent discount rate based on Moody's Aa Corporate Bond Index and a cash flow analysis using the Citigroup Pension Discount Curve for the major U.S. pension and postretirement benefit plans. The discount rates at the end of 2004 and 2003 were 5.8 percent and 6 percent, respectively.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2005 was approximately $600 million. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the company's primary U.S. pension plan, which accounted for about 53 percent of the companywide pension obligation, would have reduced total pension plan expense for 2005 by approximately $50 million. A 1 percent increase in the discount rate for this same plan would have reduced total benefit plan expense for 2005 by approximately $130 million. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

In 2005, the company's pension plan contributions were approximately $1 billion (nearly $800 million to the U.S. plans). In 2006, the company expects contributions to be approximately $500 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory environments and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

Pension expense is recorded on the Consolidated Statement of Income in "Operating expenses" or "Selling, general and administrative expenses" and applies to all business segments. Depending upon the funding status of the different plans, either a long-term prepaid asset or a long-term liability is recorded. Any unfunded accumulated benefit obligation in excess of recorded liabilities is recorded in "Other comprehensive income." See Note 21 to the Consolidated Financial Statements, beginning on page FS-50, for the pension-related balance sheet effects at the end of 2005 and 2004.

For the company's OPEB plans, expense for 2005 was about $200 million and was also recorded as "Operating expenses" or "Selling, general and administrative expenses" in all business segments.

Effective January 1, 2005, the company amended its main U.S. postretirement medical plan to limit future increases in the company contribution. For current retirees, the increase in company contribution is capped at 4 percent each year. For future retirees, the 4 percent cap will be effective at retirement. For active employees and retirees below age 65 whose claims experiences are combined for rating purposes, the assumed health care cost trend rates start with 10 percent in 2006 and gradually drop to 5 percent for 2011 and beyond.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2005, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 80 percent of the companywide OPEB obligation, would have decreased OPEB expense by approximately $20 million.

Impairment of Property, Plant and Equipment and Investments in Affiliates The company assesses its property, plant and equipment (PP&E) for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in the company's business plans, changes in commodity prices and, for crude oil and natural gas properties, significant downward revisions of estimated proved reserve quantities. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply and demand conditions for crude oil, natural gas, commodity chemicals and refined products. However, the impairment reviews and calculations are based on assumptions that are consistent with the company's business plans and long-term investment decisions.

The amount and income statement classification of major impairments of PP&E for the three years ending December 31, 2005, are included in the commentary on the business segments elsewhere in this discussion. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in the impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for impairment when the fair value of the investment falls below the company's carrying value. When such a decline is deemed to be other than temporary, an impairment charge is recorded to the income statement for the difference between the investment's carrying value and its estimated fair value at the time. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. Differing assumptions could affect whether an investment is impaired in any period or the amount of the impairment and are not subject to sensitivity analysis.

From time to time, the company performs impairment reviews and determines that no write-down in the carrying value of an asset or asset group is required. For example, when significant downward revisions to crude oil and natural gas reserves are made for any single field or concession, an impairment review is performed to determine if the carrying value of the asset remains recoverable. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed of. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision was made to sell such assets, that is, the asset is held for sale, and the estimated proceeds less costs to sell were less than the associated carrying values.

Business Combinations – Purchase-Price Allocation Accounting for business combinations requires the allocation of the company's purchase price to the various assets and liabilities of the acquired business at their respective fair values. The company uses all available information to make these fair value determinations, and for major acquisitions, may hire an independent appraisal firm to assist in making fair-value estimates. In some instances, assumptions with respect to the timing and amount of future revenues and expenses associated with an asset might have to be used in determining its fair value. Actual timing and amount of net cash flows from revenues and expenses related to that asset over time may differ materially from those initial estimates, and if the timing is delayed significantly or if the net cash flows decline significantly, the asset could become impaired.

Goodwill When acquired as part of a business combination, goodwill is not subject to amortization. As required by Financial Accounting Standards Board (FASB) Statement No. 142, *"Goodwill and Other Intangible Assets,"* the company will test such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page FS-36.

Contingent Losses Management also makes judgments and estimates in recording liabilities for claims, litigation, tax matters and environmental remediation. Actual costs can frequently vary from estimates for a variety of reasons. For example, the costs from settlement of claims and litigation can vary from estimates based on differing interpretations of laws, opinions on culpability and assessments on the amount of damages. Similarly, liabilities for environmental remediation are subject to change because of changes in laws, regulations and their interpretation; the determination of additional information on the extent and nature of site contamination; and improvements in technology.

Under the accounting rules, a liability is recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally records these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. Refer to the business segment discussions elsewhere in this discussion for the effect on earnings from losses associated with certain litigation and environmental remediation and tax matters for the three years ended December 31, 2005.

An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in recording these liabilities is not practicable because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, both in terms of the probability of loss and the estimates of such loss.

NEW ACCOUNTING STANDARDS

FASB Statement No. 151, "Inventory Costs, an Amendment of ARB No. 43, Chapter 4 (FAS 151) In November 2004, the FASB issued FAS 151, which became effective for the company on January 1, 2006. The standard amends the guidance in Accounting Research Bulletin (ARB) No. 43, Chapter 4, "Inventory Pricing" to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. In addition, the standard requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. The adoption of this standard will not have an impact on the company's results of operations, financial position or liquidity.

EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry" (Issue 04-6) In March 2005, the FASB ratified the earlier EITF consensus on Issue 04-6, which is effective for the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to ARB No. 43, "Restatement and Revision of Accounting Research Bulletins." Adoption of this accounting for its coal, oil sands and other mining operations will not have a significant effect on the company's results of operations, financial position or liquidity.

QUARTERLY RESULTS AND STOCK MARKET DATA
Unaudited

Millions of dollars, except per-share amount	2005 4TH Q	2005 3RD Q	2005 2ND Q	2005 1ST Q	2004 4TH Q	2004 3RD Q	2004 2ND Q	2004 1ST Q
REVENUES AND OTHER INCOME								
Sales and other operating revenues [1,2]	$ 52,457	$ 53,429	$ 47,265	$ 40,490	$ 41,612	$ 39,611	$ 36,579	$ 33,063
Income (loss) from equity affiliates	1,110	871	861	889	785	613	740	444
Other income	227	156	217	228	295	496	924	138
TOTAL REVENUES AND OTHER INCOME	53,794	54,456	48,343	41,607	42,692	40,720	38,243	33,645
COSTS AND OTHER DEDUCTIONS								
Purchased crude oil and products	34,246	36,101	31,130	26,491	26,290	25,650	22,452	20,027
Operating expenses	3,819	3,190	2,713	2,469	2,874	2,557	2,234	2,167
Selling, general and administrative expenses	1,340	1,337	1,152	999	1,319	1,231	986	1,021
Exploration expenses	274	177	139	153	274	173	165	85
Depreciation, depletion and amortization	1,725	1,534	1,320	1,334	1,283	1,219	1,243	1,190
Taxes other than on income [1]	5,063	5,282	5,311	5,126	5,216	4,948	4,889	4,765
Interest and debt expense	135	136	104	107	112	107	94	93
Minority interests	33	24	18	21	22	23	18	22
TOTAL COSTS AND OTHER DEDUCTIONS	46,635	47,781	41,887	36,700	37,390	35,908	32,081	29,370
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	7,159	6,675	6,456	4,907	5,302	4,812	6,162	4,275
INCOME TAX EXPENSE	3,015	3,081	2,772	2,230	1,862	1,875	2,056	1,724
INCOME FROM CONTINUING OPERATIONS	4,144	3,594	3,684	2,677	3,440	2,937	4,106	2,551
INCOME FROM DISCONTINUED OPERATIONS	–	–	–	–	–	264	19	11
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	$ 4,144	$ 3,594	$ 3,684	$ 2,677	$ 3,440	$ 3,201	$ 4,125	$ 2,562
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, NET OF TAX	–	–	–	–	–	–	–	–
NET INCOME [3]	$ 4,144	$ 3,594	$ 3,684	$ 2,677	$ 3,440	$ 3,201	$ 4,125	$ 2,562
PER-SHARE OF COMMON STOCK [4]								
INCOME FROM CONTINUING OPERATIONS								
– BASIC	$ 1.88	$ 1.65	$ 1.77	$ 1.28	$ 1.64	$ 1.38	$ 1.93	$ 1.21
– DILUTED	$ 1.86	$ 1.64	$ 1.76	$ 1.28	$ 1.63	$ 1.38	$ 1.93	$ 1.20
INCOME FROM DISCONTINUED OPERATIONS								
– BASIC	$ –	$ –	$ –	$ –	$ –	$ 0.13	$ 0.01	$ –
– DILUTED	$ –	$ –	$ –	$ –	$ –	$ 0.13	$ 0.01	$ –
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES								
– BASIC	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
– DILUTED	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
NET INCOME								
– BASIC	$ 1.88	$ 1.65	$ 1.77	$ 1.28	$ 1.64	$ 1.51	$ 1.94	$ 1.21
– DILUTED	$ 1.86	$ 1.64	$ 1.76	$ 1.28	$ 1.63	$ 1.51	$ 1.94	$ 1.20
DIVIDENDS	$ 0.45	$ 0.45	$ 0.45	$ 0.40	$ 0.40	$ 0.40	$ 0.37	$ 0.36
COMMON STOCK PRICE RANGE								
– HIGH	$ 64.45	$ 65.77	$ 59.34	$ 62.08	$ 56.07	$ 54.49	$ 47.50	$ 45.71
– LOW	$ 55.75	$ 56.36	$ 50.51	$ 50.55	$ 50.99	$ 46.21	$ 43.95	$ 41.99
[1] Includes consumer excise taxes:	$ 2,173	$ 2,268	$ 2,162	$ 2,116	$ 2,150	$ 2,040	$ 1,921	$ 1,857
[2] Includes amounts for buy/sell contracts:	$ 5,897	$ 6,588	$ 5,962	$ 5,375	$ 5,117	$ 4,640	$ 4,637	$ 4,256
[3] Net benefits (charges) for special items included in "Net Income":	$ –	$ –	$ –	$ –	$ 146	$ 486	$ 585	$ (55)

[4] The amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX) and on the Pacific Exchange. As of February 23, 2006, stockholders of record numbered approximately 230,000. There are no restrictions on the company's ability to pay dividends.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

To the Stockholders of Chevron Corporation

Management of Chevron is responsible for preparing the accompanying Consolidated Financial Statements and the related information appearing in this report. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and fairly represent the transactions and financial position of the company. The financial statements include amounts that are based on management's best estimates and judgment.

As stated in its report included herein, the independent registered public accounting firm of PricewaterhouseCoopers LLP has audited the company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Board of Directors of Chevron has an Audit Committee composed of directors who are not officers or employees of the company. The Audit Committee meets regularly with members of management, the internal auditors and the independent registered public accounting firm to review accounting, internal control, auditing and financial reporting matters. Both the internal auditors and the independent registered public accounting firm have free and direct access to the Audit Committee without the presence of management.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a–15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that its internal control over financial reporting was effective as of December 31, 2005.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

/S/ DAVID J. O'REILLY

DAVID J. O'REILLY

Chairman of the Board
and Chief Executive Officer

/S/ STEPHEN J. CROWE

STEPHEN J. CROWE

Vice President
and Chief Financial Officer

February 27, 2006

/S/ MARK A. HUMPHREY

MARK A. HUMPHREY

Vice President
and Comptroller

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Chevron Corporation:

We have completed integrated audits of Chevron Corporation's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULE

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) of the Annual Report on Form 10-K present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 24 beginning on page FS-59 to the Consolidated Financial Statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ PricewaterhouseCoopers LLP

San Francisco, California
February 27, 2006

CONSOLIDATED STATEMENT OF INCOME

Millions of dollars, except per-share amounts

	Year ended December 31 2005	2004	2003
REVENUES AND OTHER INCOME			
Sales and other operating revenues[1,2]	**$ 193,641**	$ 150,865	$ 119,575
Income from equity affiliates	**3,731**	2,582	1,029
Other income	**828**	1,853	308
Gain from exchange of Dynegy preferred stock	**–**	–	365
TOTAL REVENUES AND OTHER INCOME	**198,200**	155,300	121,277
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products[2]	**127,968**	94,419	71,310
Operating expenses	**12,191**	9,832	8,500
Selling, general and administrative expenses	**4,828**	4,557	4,440
Exploration expenses	**743**	697	570
Depreciation, depletion and amortization	**5,913**	4,935	5,326
Taxes other than on income[1]	**20,782**	19,818	17,901
Interest and debt expense	**482**	406	474
Minority interests	**96**	85	80
TOTAL COSTS AND OTHER DEDUCTIONS	**173,003**	134,749	108,601
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	**25,197**	20,551	12,676
INCOME TAX EXPENSE	**11,098**	7,517	5,294
INCOME FROM CONTINUING OPERATIONS	**14,099**	13,034	7,382
INCOME FROM DISCONTINUED OPERATIONS	**–**	294	44
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**$ 14,099**	$ 13,328	$ 7,426
Cumulative effect of changes in accounting principles	**–**	–	(196)
NET INCOME	**$ 14,099**	$ 13,328	$ 7,230
PER-SHARE OF COMMON STOCK[3]			
INCOME FROM CONTINUING OPERATIONS			
– BASIC	**$ 6.58**	$ 6.16	$ 3.55
– DILUTED	**$ 6.54**	$ 6.14	$ 3.55
INCOME FROM DISCONTINUED OPERATIONS			
– BASIC	**$ –**	$ 0.14	$ 0.02
– DILUTED	**$ –**	$ 0.14	$ 0.02
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES			
– BASIC	**$ –**	$ –	$ (0.09)
– DILUTED	**$ –**	$ –	$ (0.09)
NET INCOME			
– BASIC	**$ 6.58**	$ 6.30	$ 3.48
– DILUTED	**$ 6.54**	$ 6.28	$ 3.48

[1] Includes consumer excise taxes:	**$ 8,719**	$ 7,968	$ 7,095
[2] Includes amounts in revenues for buy/sell contracts associated costs are in "Purchased crude oil and products." See Note 15, on page FS-46:	**$ 23,822**	$ 18,650	$ 14,246

[3] All periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Millions of dollars

	Year ended December 31		
	2005	2004	2003
NET INCOME	**$ 14,099**	$ 13,328	$ 7,230
Currency translation adjustment			
Unrealized net change arising during period	**(5)**	36	32
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(32)**	35	445
Reclassification to net income of net realized (gain)	**–**	(44)	(365)
Total	**(32)**	(9)	80
Net derivatives (loss) gain on hedge transactions			
Net (loss) gain arising during period			
Before income taxes	**(242)**	(8)	115
Income taxes	**89**	(1)	(40)
Reclassification to net income of net realized loss			
Before income taxes	**34**	–	–
Income taxes	**(12)**	–	–
Total	**(131)**	(9)	75
Minimum pension liability adjustment			
Before income taxes	**89**	719	12
Income taxes	**(31)**	(247)	(10)
Total	**58**	472	2
OTHER COMPREHENSIVE (LOSS) GAIN, NET OF TAX	**(110)**	490	189
COMPREHENSIVE INCOME	**$ 13,989**	$ 13,818	$ 7,419

See accompanying Notes to the Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEET

Millions of dollars, except per-share amounts

	At December 31	
	2005	2004
ASSETS		
Cash and cash equivalents	**$ 10,043**	$ 9,291
Marketable securities	**1,101**	1,451
Accounts and notes receivable (less allowance: 2005 – $156; 2004 – $174)	**17,184**	12,429
Inventories:		
Crude oil and petroleum products	**3,182**	2,324
Chemicals	**245**	173
Materials, supplies and other	**694**	486
Total inventories	**4,121**	2,983
Prepaid expenses and other current assets	**1,887**	2,349
TOTAL CURRENT ASSETS	**34,336**	28,503
Long-term receivables, net	**1,686**	1,419
Investments and advances	**17,057**	14,389
Properties, plant and equipment, at cost	**127,446**	103,954
Less: Accumulated depreciation, depletion and amortization	**63,756**	59,496
Properties, plant and equipment, net	**63,690**	44,458
Deferred charges and other assets	**4,428**	4,277
Goodwill	**4,636**	–
Assets held for sale	**–**	162
TOTAL ASSETS	**$ 125,833**	$ 93,208
LIABILITIES AND STOCKHOLDERS' EQUITY		
Short-term debt	**$ 739**	$ 816
Accounts payable	**16,074**	10,747
Accrued liabilities	**3,690**	3,410
Federal and other taxes on income	**3,127**	2,502
Other taxes payable	**1,381**	1,320
TOTAL CURRENT LIABILITIES	**25,011**	18,795
Long-term debt	**11,807**	10,217
Capital lease obligations	**324**	239
Deferred credits and other noncurrent obligations	**10,507**	7,942
Noncurrent deferred income taxes	**11,262**	7,268
Reserves for employee benefit plans	**4,046**	3,345
Minority interests	**200**	172
TOTAL LIABILITIES	**63,157**	47,978
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	**–**	–
Common stock (authorized 4,000,000,000 shares, $0.75 par value; 2,442,676,580 and 2,274,032,014 shares issued at December 31, 2005 and 2004, respectively)	**1,832**	1,706
Capital in excess of par value	**13,894**	4,160
Retained earnings	**55,738**	45,414
Notes receivable – key employees	**(3)**	–
Accumulated other comprehensive loss	**(429)**	(319)
Deferred compensation and benefit plan trust	**(486)**	(607)
Treasury stock, at cost (2005 – 209,989,910 shares; 2004 – 166,911,890 shares)	**(7,870)**	(5,124)
TOTAL STOCKHOLDERS' EQUITY	**62,676**	45,230
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 125,833**	$ 93,208

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

Millions of dollars

	Year ended December 31		
	2005	2004	2003
OPERATING ACTIVITIES			
Net income	**$ 14,099**	$ 13,328	$ 7,230
Adjustments			
Depreciation, depletion and amortization	**5,913**	4,935	5,326
Dry hole expense	**226**	286	256
Distributions less than income from equity affiliates	**(1,304)**	(1,422)	(383)
Net before-tax gains on asset retirements and sales	**(134)**	(1,882)	(194)
Net foreign currency effects	**62**	60	199
Deferred income tax provision	**1,393**	(224)	164
Net (increase) decrease in operating working capital	**(54)**	430	162
Minority interest in net income	**96**	85	80
(Increase) decrease in long-term receivables	**(191)**	(60)	12
Decrease (increase) in other deferred charges	**668**	(69)	1,646
Cumulative effect of changes in accounting principles	**–**	–	196
Gain from exchange of Dynegy preferred stock	**–**	–	(365)
Cash contributions to employee pension plans	**(1,022)**	(1,643)	(1,417)
Other	**353**	866	(597)
NET CASH PROVIDED BY OPERATING ACTIVITIES	**20,105**	14,690	12,315
INVESTING ACTIVITIES			
Cash portion of Unocal acquisition, net of Unocal cash received	**(5,934)**	–	–
Capital expenditures	**(8,701)**	(6,310)	(5,625)
Advances to equity affiliate	**–**	(2,200)	–
Repayment of loans by equity affiliates	**57**	1,790	293
Proceeds from asset sales	**2,681**	3,671	1,107
Net sales (purchases) of marketable securities	**336**	(450)	153
NET CASH USED FOR INVESTING ACTIVITIES	**(11,561)**	(3,499)	(4,072)
FINANCING ACTIVITIES			
Net (payments) borrowings of short-term obligations	**(109)**	114	(3,628)
Proceeds from issuances of long-term debt	**20**	–	1,034
Repayments of long-term debt and other financing obligations	**(966)**	(1,398)	(1,347)
Cash dividends – common stock	**(3,778)**	(3,236)	(3,033)
Dividends paid to minority interests	**(98)**	(41)	(37)
Net (purchases) sales of treasury shares	**(2,597)**	(1,645)	57
Redemption of preferred stock of subsidiaries	**(140)**	(18)	(75)
NET CASH USED FOR FINANCING ACTIVITIES	**(7,668)**	(6,224)	(7,029)
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	**(124)**	58	95
NET CHANGE IN CASH AND CASH EQUIVALENTS	**752**	5,025	1,309
CASH AND CASH EQUIVALENTS AT JANUARY 1	**9,291**	4,266	2,957
CASH AND CASH EQUIVALENTS AT DECEMBER 31	**$ 10,043**	$ 9,291	$ 4,266

See accompanying Notes to the Consolidated Financial Statements.

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CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

Shares in thousands; amounts in millions of dollars

	2005		2004		2003	
	Shares	Amount	Shares	Amount	Shares	Amount
PREFERRED STOCK	**–**	**$ –**	–	$ –	–	$ –
COMMON STOCK [1]						
Balance at January 1	**2,274,032**	**$ 1,706**	2,274,042	$ 1,706	2,274,042	$ 1,706
Shares issued for Unocal acquisition	**168,645**	**126**		–		–
Conversion of Texaco Inc. acquisition	**–**	**–**	(10)	–	–	–
BALANCE AT DECEMBER 31	**2,442,677**	**$ 1,832**	2,274,032	$ 1,706	2,274,042	$ 1,706
CAPITAL IN EXCESS OF PAR [1]						
Balance at January 1		**$ 4,160**		$ 4,002		$ 3,980
Shares issued for Unocal acquisition		**9,585**		–		–
Stock options and restricted stock units		**67**		–		–
Treasury stock transactions		**82**		158		22
BALANCE AT DECEMBER 31		**$ 13,894**		$ 4,160		$ 4,002
RETAINED EARNINGS						
Balance at January 1		**$ 45,414**		$ 35,315		$ 30,942
Net income		**14,099**		13,328		7,230
Cash dividends on common stock		**(3,778)**		(3,236)		(3,033)
Tax benefit from dividends paid on unallocated ESOP shares and other		**3**		7		6
Exchange of Dynegy securities		**–**		–		170
BALANCE AT DECEMBER 31		**$ 55,738**		$ 45,414		$ 35,315
NOTES RECEIVABLE – KEY EMPLOYEES		**$ (3)**		$ –		$ –
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		**$ (140)**		$ (176)		$ (208)
Change during year [2]		**(5)**		36		32
Balance at December 31		**$ (145)**		$ (140)		$ (176)
Minimum pension liability adjustment						
Balance at January 1		**$ (402)**		$ (874)		$ (876)
Change during year		**58**		472		2
Balance at December 31		**$ (344)**		$ (402)		$ (874)
Unrealized net holding gain on securities						
Balance at January 1		**$ 120**		$ 129		$ 49
Change during year		**(32)**		(9)		80
Balance at December 31		**$ 88**		$ 120		$ 129
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 103**		$ 112		$ 37
Change during year [2]		**(131)**		(9)		75
Balance at December 31		**$ (28)**		$ 103		$ 112
BALANCE AT DECEMBER 31		**$ (429)**		$ (319)		$ (809)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST						
DEFERRED COMPENSATION						
Balance at January 1		**$ (367)**		$ (362)		$ (412)
Net reduction of ESOP debt and other		**121**		(5)		50
BALANCE AT DECEMBER 31		**(246)**		(367)		(362)
BENEFIT PLAN TRUST (COMMON STOCK) [1]	**14,168**	**(240)**	14,168	(240)	14,168	(240)
BALANCE AT DECEMBER 31	**14,168**	**$ (486)**	14,168	$ (607)	14,168	$ (602)
TREASURY STOCK AT COST [1]						
Balance at January 1	**166,912**	**$ (5,124)**	135,747	$ (3,317)	137,769	$ (3,374)
Purchases	**52,013**	**(3,029)**	42,607	(2,122)	81	(3)
Issuances – mainly employee benefit plans	**(8,935)**	**283**	(11,442)	315	(2,103)	60
BALANCE AT DECEMBER 31	**209,990**	**$ (7,870)**	166,912	$ (5,124)	135,747	$ (3,317)
TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31		**$ 62,676**		$ 45,230		$ 36,295

1 2003 restated to reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

2 Includes Unocal balances at December 31, 2005.

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Chevron manages its investments in and provides administrative, financial and management support to U.S. and foreign subsidiaries and affiliates that engage in fully integrated petroleum and chemicals operations. In addition, Chevron holds investments in businesses involving power generation, geothermal production, and the mining of coal and other minerals. Collectively, these companies conduct business activities in approximately 180 countries. Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and also marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil, natural gas and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemical operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant oil additives.

The company's Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. These require the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Although the company uses its best estimates and judgments, actual results could differ from these estimates as future confirming events occur.

The nature of the company's operations and the many countries in which it operates subject the company to changing economic, regulatory and political conditions. The company does not believe it is vulnerable to the risk of near-term severe impact as a result of any concentration of its activities.

Subsidiary and Affiliated Companies The Consolidated Financial Statements include the accounts of controlled subsidiary companies more than 50 percent owned and variable interest entities in which the company is the primary beneficiary. Undivided interests in oil and gas joint ventures and certain other assets are consolidated on a proportionate basis. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent or for which the company exercises significant influence but not control over policy decisions are accounted for by the equity method. As part of that accounting, the company recognizes gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity currently in income. Deferred income taxes are provided for these gains and losses.

Investments are assessed for possible impairment when events indicate that the fair value of the investment may be below the company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in net income. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. The new cost basis of investments in these equity investees is not changed for subsequent recoveries in fair value. Subsequent recoveries in the carrying value of other investments are reported in "Other comprehensive income."

Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the various factors giving rise to the difference. The company's share of the affiliate's reported earnings is adjusted quarterly when appropriate to reflect the difference between these allocated values and the affiliate's historical book values.

Derivatives The majority of the company's activity in commodity derivative instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's trading activity, gains and losses from the derivative instruments are reported in current income. For derivative instruments relating to foreign currency exposures, gains and losses are reported in current income. Interest rate swaps – hedging a portion of the company's fixed-rate debt – are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the Consolidated Balance Sheet, with resulting gains and losses reflected in income.

Short-Term Investments All short-term investments are classified as available for sale and are in highly liquid debt securities. Those investments that are part of the company's cash management portfolio and have original maturities of three months or less are reported as "Cash equivalents." The balance of the short-term investments is reported as "Marketable securities" and are marked-to-market, with any unrealized gains or losses included in "Other comprehensive income."

Inventories Crude oil, petroleum products and chemicals are generally stated at cost, using a Last-In, First-Out (LIFO) method. In the aggregate, these costs are below market. "Materials, supplies and other" inventories generally are stated at average cost.

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs are also capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 20, beginning on page FS-49, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted future net before-tax cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset, significant change in the extent or manner of use of or a physical change in an asset, and a more-likely-than-not expectation that a long-lived asset or asset group will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted future net before-tax cash flows. For proved crude oil and natural gas properties in the United States, the company generally performs the impairment review on an individual field basis. Outside the United States, reviews are performed on a country, concession or field basis, as appropriate. In the refining, marketing, transportation and chemical areas, impairment reviews are generally done on the basis of a refinery, a plant, a marketing area or marketing assets by country. Impairment amounts are recorded as incremental "Depreciation, depletion and amortization" expense.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value.

Effective January 1, 2003, the company implemented Financial Accounting Standards Board Statement No. 143, *"Accounting for Asset Retirement Obligations (FAS 143),"* in which the fair value of a liability for an asset retirement obligation is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 24, beginning on page FS-59, relating to asset retirement obligations, which includes additional information on the company's adoption of FAS 143.

Depreciation and depletion of all capitalized costs of proved crude oil and natural gas producing properties, except mineral interests, are expensed using the unit-of-production method by individual field as the proved developed reserves are produced. Depletion expenses for capitalized costs of proved mineral interests are recognized using the unit-of-production method by individual field as the related proved reserves are produced. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed.

Depreciation and depletion expenses for coal assets are determined using the unit-of-production method as the proved reserves are produced. The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method generally is used to depreciate international plant and equipment and to amortize all capitalized leased assets.

Gains or losses are not recognized for normal retirements of properties, plant and equipment subject to composite group amortization or depreciation. Gains or losses from abnormal retirements are recorded as expenses and from sales as "Other income."

Expenditures for maintenance, repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill acquired in a business combination is not subject to amortization. As required by Financial Accounting Standards Board (FASB) Statement No. 142, *"Goodwill and Other Intangible Assets,"* the company will test such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page FS-36.

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

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – Continued

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company's U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and coal producing properties, a liability for an asset retirement obligation is made, following FAS 143. Refer to Note 24, beginning on page FS-59, for a discussion of FAS 143.

For federal Superfund sites and analogous sites under state laws, the company records a liability for its designated share of the probable and estimable costs and probable amounts for other potentially responsible parties when mandated by the regulatory agencies because the other parties are not able to pay their respective shares.

The gross amount of environmental liabilities is based on the company's best estimate of future costs using currently available technology and applying current regulations and the company's own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

Currency Translation The U.S. dollar is the functional currency for substantially all of the company's consolidated operations and those of its equity affiliates. For those operations, all gains and losses from currency translations are currently included in income. The cumulative translation effects for those few entities, both consolidated and affiliated, using functional currencies other than the U.S. dollar are included in the currency translation adjustment in "Stockholders' equity."

Revenue Recognition Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized on the basis of the company's net working interest (entitlement method). Refer to Note 15, beginning on page FS-46, for a discussion of the accounting for buy/sell arrangements.

Stock Options and Other Share-Based Compensation Effective July 1, 2005, the company adopted the provisions of Financial Accounting Standards Board (FASB) Statement No. 123R, *"Share-Based Payment,"* (FAS 123R) for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "*Accounting for Stock Issued to Employees,*" (APB 25) and related interpretations and disclosure requirements established by FAS 123, *"Accounting for Stock-Based Compensation."*

Refer to Note 22, beginning on page FS-54, for a description of the company's share-based compensation plans, information related to awards granted under those plans and additional information on the company's adoption of FAS 123R.

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 to stock options, stock appreciation rights, performance units and restricted stock units for periods prior to adoption of FAS 123R, and the actual effect on net income and earnings per share for periods after adoption of FAS 123R.

	Year ended December 31		
	2005	2004	2003
Net income, as reported	**$14,099**	$13,328	$7,230
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects[1]	$ **81**	$ 42	$ 16
Deduct: Total stock-based employee compensation expense determined under fair-valued-based method for awards, net of related tax effects[1,2]	$ **(108)**	$ (84)	$ (41)
Pro forma net income	**$14,072**	$13,286	$7,205
Net income per share:[3,4]			
Basic – as reported	**$ 6.58**	$ 6.30	$ 3.48
Basic – pro forma	**$ 6.56**	$ 6.28	$ 3.47
Diluted – as reported	**$ 6.54**	$ 6.28	$ 3.48
Diluted – pro forma	**$ 6.53**	$ 6.26	$ 3.47

1 Periods prior to 2005 conformed to the 2005 presentation.

2 Fair value determined using the Black-Scholes option-pricing model.

3 Per-share amounts in all periods refl ect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

4 The amounts in 2003 include a benefit of $0.08 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which under the applicable accounting rules was recorded directly to the company's retained earnings and not included in net income for the period.

NOTE 2.
ACQUISITION OF UNOCAL CORPORATION

On August 10, 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. Unocal's principal upstream operations are in North America and Asia, including the Caspian region. Also located in Asia are Unocal's geothermal energy and electrical power businesses. Other activities include ownership interests in proprietary and common carrier pipelines, natural gas storage facilities and mining operations.

The aggregate purchase price of Unocal was approximately $17,300, which included approximately $7,500 cash, 169 million shares of Chevron common stock valued at or about $9,600, and $200 for stock options on approximately 5 million shares and merger-related fees. The value of the common shares was based on the average market price for a 5-day period beginning two days before the terms of the acquisition were finalized and announced on July 19, 2005. The issued shares represented approximately 7.5 percent of the number of shares outstanding immediately after the August 10 close. The value of the stock options at the acquisition date was determined using the Black-Scholes option-pricing model.

A third-party appraisal firm has been engaged to assist the company in the process of determining the fair values of Unocal's tangible and intangible assets. Initial fair-value estimates were made in the third quarter 2005, and adjustments to those initial estimates were made in the fourth quarter. The company expects the valuation process will be finalized in the first half of 2006. Once completed, the associated deferred tax liabilities will also be adjusted. No significant intangible assets other than goodwill are included in the preliminary allocation of the purchase price in the table below. No in-process research and development assets were acquired.

The acquisition was accounted for under the rules of Financial Accounting Standards Board (FASB) Statement No. 141, *"Business Combinations."* The following table summarizes the preliminary allocation of the purchase price to Unocal's assets and liabilities:

	At August 1, 2005
Current assets	$ 3,531
Investments and long-term receivables	1,647
Properties	17,288
Goodwill	4,700
Other assets	2,055
Total assets acquired	29,221
Current liabilities	(2,365)
Long-term debt and capital leases	(2,392)
Deferred income taxes	(3,743)
Other liabilities	(3,435)
Total liabilities assumed	(11,935)
Net assets acquired	$ 17,286

The $4,700 of goodwill is assigned to the upstream segment. None of the goodwill is deductible for tax purposes. The goodwill represents benefits of the acquisition that are additional to the fair values of the other net assets acquired. The primary reasons for the acquisition and the principal factors that contributed to a Unocal purchase price that resulted in the recognition of goodwill were as follows:

- The "going concern" element of the Unocal businesses, which presents the opportunity to earn a higher rate of return on the assembled collection of net assets than would be expected if those assets were acquired separately. These benefits include upstream growth opportunities in the Asia-Pacific, Gulf of Mexico and Caspian regions. Some of these areas contain operations that are complementary to Chevron's, and the acquisition is consistent with Chevron's long-term strategies to grow profitability in its core upstream areas, build new legacy positions and commercialize the company's large undeveloped natural gas resource base.
- Cost savings that can be obtained through the capture of operational synergies. The opportunities for cost savings include the elimination of duplicate facilities and services, high-grading of investment opportunities in the combined portfolio and the sharing of best practices of the two companies.

Goodwill recorded in the acquisition is not subject to amortization, but will be tested periodically for impairment as required by FASB Statement No. 142, *"Goodwill and Other Intangible Assets."*

The following unaudited pro forma summary presents the results of operations as if the acquisition of Unocal had occurred at the beginning of each period:

	Year ended December 31	
	2005	2004
Sales and other operating revenues	**$198,762**	$158,471
Net income	**14,967**	14,164
Net income per share of common stock		
Basic	**$ 6.68**	$ 6.22
Diluted	**$ 6.64**	$ 6.19

The pro forma summary uses estimates and assumptions based on information available at the time. Management believes the estimates and assumptions to be reasonable; however, actual results may differ significantly from this pro forma financial information. The pro forma information does not reflect any synergistic savings that might be achieved from combining the operations and is not intended to reflect the actual results that would have occurred had the companies actually been combined during the periods presented.

NOTE 3.
INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

	Year ended December 31		
	2005	2004	2003
Net (increase) decrease in operating working capital was composed of the following:			
Increase in accounts and notes receivable	**$ (3,164)**	$ (2,515)	$ (265)
(Increase) decrease in inventories	**(968)**	(298)	115
(Increase) decrease in prepaid expenses and other current assets	**(54)**	(76)	261
Increase in accounts payable and accrued liabilities	**3,851**	2,175	242
Increase (decrease) in income and other taxes payable	**281**	1,144	(191)
Net (increase) decrease in operating working capital	**$ (54)**	$ 430	$ 162
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$ 455**	$ 422	$ 467
Income taxes	**$ 8,875**	$ 6,679	$ 5,316
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (918)**	$ (1,951)	$ (3,563)
Marketable securities sold	**1,254**	1,501	3,716
Net sales (purchases) of marketable securities	**$ 336**	$ (450)	$ 153

The 2005 "Net increase in operating working capital" included a reduction of $20 for excess income tax benefits associated with stock options exercised since July 1, 2005, in accordance with the cash-flows classifi cation requirements of

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NOTE 3. INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS— Continued

FAS 123R, *"Share-Based Payment."* This amount was offset by an equal amount in "Net purchases of treasury shares." Refer to Note 22, beginning on page FS-54, for additional information related to the company's adoption of FAS 123R.

The "Net (purchases) sales of treasury shares" in 2005 and 2004 included purchases of $3,029 and $2,122, respectively, related to the company's common stock repurchase programs and share-based compensation plans, which were partially offset by the issuance of shares for the exercise of stock options.

The 2003 "Net cash provided by operating activities" included an $890 "Decrease in other deferred charges" and a decrease of the same amount in "Other" related to balance sheet netting of certain pension-related asset and liability accounts, in accordance with the requirements of Financial Accounting Standards Board (FASB) Statement No. 87, *"Employers' Accounting for Pensions."*

The "cash portion of Unocal acquisition, net of Unocal cash received" represents the purchase price, net of $1,600 of cash received. The aggregate purchase price of Unocal was $17,300. Refer to Note 2 starting on page FS-36 for additional discussion of the Unocal acquisition.

The major components of "Capital expenditures" and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, presented in Management's Discussion and Analysis, beginning on page FS-13, are presented in the following table:

	Year ended December 31		
	2005	2004	2003
Additions to properties, plant and equipment[1]	**$ 8,154**	$ 5,798	$ 4,953
Additions to investments	**459**	303	687
Current-year dry hole expenditures	**198**	228	132
Payments for other liabilities and assets, net	**(110)**	(19)	(147)
Capital expenditures	**8,701**	6,310	5,625
Expensed exploration expenditures	**517**	412	315
Assets acquired through capital lease obligations and other financing obligations	**164**	31	286[2]
Capital and exploratory expenditures, excluding equity affiliates	**9,382**	6,753	6,226
Equity in affiliates' expenditures	**1,681**	1,562	1,137
Capital and exploratory expenditures, including equity affiliates	**$ 11,063**	$ 8,315	$ 7,363

1 Net of noncash additions of $435 in 2005, $212 in 2004 and $1,183 in 2003.
2 Includes deferred payment of $210 related to the 1993 acquisition of the company's interest in the Tengizchevroil joint venture.

NOTE 4.
SUMMARIZED FINANCIAL DATA – CHEVRON U.S.A. INC.

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of Chevron Corporation. CUSA and its subsidiaries manage and operate most of Chevron's U.S. businesses. Assets include those related to the exploration and production of crude oil, natural gas and natural gas liquids and those associated with the refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids, excluding most of the regulated pipeline operations of Chevron. CUSA also holds Chevron's investments in the Chevron Phillips Chemical Company LLC (CPChem) joint venture and Dynegy Inc. (Dynegy), which are accounted for using the equity method.

During 2003, Chevron implemented legal reorganizations in which certain Chevron subsidiaries transferred assets to or under CUSA and other Chevron companies were merged with and into CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the following table gives retroactive effect to the reorganizations, with all periods presented as if the companies had always been combined and the reorganizations had occurred on January 1, 2003. However, the financial information included in this table may not reflect the financial position and operating results in the future or the historical results in the periods presented had the reorganizations actually occurred on January 1, 2003.

	Year ended December 31		
	2005	2004	2003
Sales and other operating revenues	**$ 138,296**	$ 108,351	$ 82,760
Total costs and other deductions	**132,180**	102,180	78,399
Net income*	**4,693**	4,773	3,083

* 2003 net income includes a charge of $323 for the cumulative effect of changes in accounting principles.

	At December 31	
	2005	2004
Current assets	**$ 27,878**	$ 23,147
Other assets	**20,611**	19,961
Current liabilities	**20,286**	17,044
Other liabilities	**12,897**	12,533
Net equity	**15,306**	13,531
Memo: Total debt	**$ 8,353**	$ 8,349

NOTE 5.
SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of Chevron Corporation. CTC is the principal operator of Chevron's international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC's shipping revenue is derived from providing transportation services to other Chevron companies. Chevron Corporation has guaranteed this subsidiary's obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is presented in the following table:

NOTE 5. SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD. – Continued

	Year ended December 31		
	2005	2004	2003
Sales and other operating revenues	**$ 640**	$ 660	$ 601
Total costs and other deductions	**509**	495	535
Net income	**113**	160	50

	At December 31	
	2005	2004
Current assets	**$ 358**	$ 292
Other assets	**283**	219
Current liabilities	**119**	67
Other liabilities	**243**	278
Net equity	**279**	166

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2005.

NOTE 6.

STOCKHOLDERS' EQUITY

Retained earnings at December 31, 2005 and 2004, included approximately $5,000 and $3,950, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2005, about 142 million shares of Chevron's common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP), as amended and restated, which was approved by the stockholders in 2004. In addition, approximately 561 thousand shares remain available for issuance from the 800 thousand shares of the company's common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan (Non-Employee Directors' Plan), which was approved by stockholders in 2003. Refer to Note 26, on page FS-62, for a discussion of the company's common stock split in 2004.

NOTE 7.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to price volatility of crude oil, refined products, natural gas, natural gas liquids and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including: firm commitments and anticipated transactions for the purchase or sale of crude oil; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids. The company also uses derivative commodity instruments for limited trading purposes.

The company uses International Swaps Dealers Association agreements to govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transactions, bilateral collateral arrangements may also be required. When the company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable netting agreement with that counterparty, the net marked-to-market exposure represents the netting of the positive and negative exposures with that counterparty and is a reasonable measure of the company's credit risk exposure. The company also uses other netting agreements with certain counterparties with which it conducts significant transactions to mitigate credit risk.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as "Accounts and notes receivable," "Accounts payable," "Long-term receivables – net" and "Deferred credits and other noncurrent obligations." Gains and losses on the company's risk management activities are reported as either "Sales and other operating revenues" or "Purchased crude oil and products," whereas trading gains and losses are reported as "Other income." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as "Accounts and notes receivable" or "Accounts payable," with gains and losses reported as "Other income." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company's fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps related to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as "Accounts and notes receivable" or "Accounts payable," with gains and losses reported directly in income as part of "Interest and debt expense." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

Fair Value Fair values are derived either from quoted market prices or, if not available, the present value of the expected cash flows. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end.

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NOTE 7. FINANCIAL AND DERIVATIVE INSTRUMENTS – Continued

Long-term debt of $7,424 and $5,815 had estimated fair values of $7,945 and $6,444 at December 31, 2005 and 2004, respectively.

For interest rate swaps, the notional principal amounts of $1,400 and $1,665 had estimated fair values of $(10) and $36 at December 31, 2005 and 2004, respectively.

The company holds cash equivalents and U.S. dollar marketable securities in domestic and offshore portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had fair values of $8,995 and $8,789 at December 31, 2005 and 2004, respectively. Of these balances, $7,894 and $7,338 at the respective year-ends were classified as cash equivalents that had average maturities under 90 days. The remainder, classified as marketable securities, had average maturities of approximately 2 years.

For the financial and derivative instruments discussed above, there was not a material change in market risk from that presented in 2004.

Concentrations of Credit Risk The company's financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, marketable securities, derivative financial instruments and trade receivables. The company's short-term investments are placed with a wide array of financial institutions with high credit ratings. This diversified investment policy limits the company's exposure both to credit risk and to concentrations of credit risk. Similar standards of diversity and creditworthiness are applied to the company's counterparties in derivative instruments.

The trade receivable balances, reflecting the company's diversified sources of revenue, are dispersed among the company's broad customer base worldwide. As a consequence, concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, requiring Letters of Credit is a principal method used to support sales to customers.

Investment in Dynegy Preferred Stock At December 31, 2005, the company held an investment in $400 face value of Dynegy Series C Convertible Preferred Stock, with a stated maturity date of 2033. The stock was recorded at its fair value, which was estimated to be $360 at the end of 2005.

Temporary changes in the estimated fair value of the preferred stock are reported in "Other comprehensive income." However, if any future decline in fair value is deemed to be other than temporary, a charge against income in the period would be recorded. Dividends payable on the preferred stock are recognized in income each period.

NOTE 8.
OPERATING SEGMENTS AND GEOGRAPHIC DATA

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. For this purpose, the investments are grouped as follows: upstream – exploration and production; downstream – refining, marketing and transportation; chemicals; and all other. The first three of these groupings represent the company's "reportable segments" and "operating segments" as defined in FAS 131, *"Disclosures About Segments of an Enterprise and Related Information."*

The segments are separately managed for investment purposes under a structure that includes "segment managers" who report to the company's "chief operating decision maker" (CODM) (terms as defined in FAS 131). The CODM is the company's Executive Committee, a committee of senior officers that includes the Chief Executive Officer and that in turn reports to the Board of Directors of Chevron Corporation.

The operating segments represent components of the company as described in FAS 131 terms that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and to assess their performance; and (c) for which discrete financial information is available.

Segment managers for the reportable segments are directly accountable to and maintain regular contact with the company's CODM to discuss the segment's operating activities and financial performance. The CODM approves annual capital and exploratory budgets at the reportable segment level, as well as reviews capital and exploratory funding for major projects and approves major changes to the annual capital and exploratory budgets. However, business-unit managers within the operating segments are directly responsible for decisions relating to project implementation and all other matters connected with daily operations. Company officers who are members of the Executive Committee also have individual management responsibilities and participate in other committees for purposes other than acting as the CODM.

"All Other" activities include the company's interest in Dynegy, mining operations of coal and other minerals, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities and technology companies.

The company's primary country of operation is the United States of America, its country of domicile. Other components of the company's operations are reported as "International" (outside the United States).

Segment Earnings The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments. However, operating segments are billed for the direct use of corporate services. Nonbillable costs remain at the corporate level in

"All Other." After-tax segment income (loss) from continuing operations is presented in the following table:

	Year ended December 31		
	2005	2004	2003
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	**$ 4,168**	$ 3,868	$3,160
International	**7,556**	5,622	3,199
Total Upstream	**11,724**	9,490	6,359
Downstream – Refining, Marketing and Transportation			
United States	**980**	1,261	482
International	**1,786**	1,989	685
Total Downstream	**2,766**	3,250	1,167
Chemicals			
United States	**240**	251	5
International	**58**	63	64
Total Chemicals	**298**	314	69
Total Segment Income	**14,788**	13,054	7,595
All Other			
Interest expense	**(337)**	(257)	(352)
Interest income	**266**	129	75
Other	**(618)**	108	64
Income From Continuing Operations	**14,099**	13,034	7,382
Income From Discontinued Operations	**–**	294	44
Cumulative effect of changes in accounting principles	**–**	–	(196)
Net Income	**$ 14,099**	$ 13,328	$7,230

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2005 and 2004 follow:

	At December 31	
	2005	2004
Upstream – Exploration and Production		
United States	**$ 19,006**	$ 11,869
International	**46,501**	31,239
Goodwill	**4,636**	–
Total Upstream	**70,143**	43,108
Downstream – Refining, Marketing and Transportation		
United States	**12,273**	10,091
International	**22,294**	19,415
Total Downstream	**34,567**	29,506
Chemicals		
United States	**2,452**	2,316
International	**727**	667
Total Chemicals	**3,179**	2,983
Total Segment Assets	**107,889**	75,597
All Other*		
United States	**9,234**	11,746
International	**8,710**	5,865
Total All Other	**17,944**	17,611
Total Assets – United States	**42,965**	36,022
Total Assets – International	**78,232**	57,186
Goodwill	**4,636**	–
Total Assets	**$125,833**	$ 93,208

* All Other assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company's investment in Dynegy, mining operations of coal and other minerals, power generation businesses, technology companies, and assets of the corporate administrative functions.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2005, 2004 and 2003 are presented in the following table. Products are transferred between operating segments at internal product values that approximate market prices.

Revenues for the upstream segment are derived primarily from the production and sale of crude oil and natural gas, as well as the sale of third-party production of natural gas. Revenues for the downstream segment are derived from the refining and marketing of petroleum products, such as gasoline, jet fuel, gas oils, kerosene, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Revenues for the chemicals segment are derived primarily from the manufacture and sale of additives for lubricants and fuel. "All Other" activities include revenues from mining operations of coal and other minerals, power generation businesses, insurance operations, real estate activities and technology companies.

Other than the United States, the only country in which Chevron recorded significant revenues was the United Kingdom, with revenues of $15,296, $13,985 and $12,121 in 2005, 2004 and 2003, respectively.

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA — Continued

	Year ended December 31		
	2005	2004	2003
Upstream — Exploration and Production			
United States	**$ 16,044**	$ 8,242	$ 6,842
Intersegment	**8,651**	8,121	6,295
Total United States	**24,695**	16,363	13,137
International	**10,190**	7,246	7,013
Intersegment	**13,652**	10,184	8,142
Total International	**23,842**	17,430	15,155
Total Upstream	**48,537**	33,793	28,292
Downstream — Refining, Marketing and Transportation			
United States	**73,721**	57,723	44,701
Excise taxes	**4,521**	4,147	3,744
Intersegment	**535**	179	225
Total United States	**78,777**	62,049	48,670
International	**83,223**	67,944	52,486
Excise taxes	**4,184**	3,810	3,342
Intersegment	**14**	87	46
Total International	**87,421**	71,841	55,874
Total Downstream	**166,198**	133,890	104,544
Chemicals			
United States	**343**	347	323
Intersegment	**241**	188	129
Total United States	**584**	535	452
International	**760**	747	677
Excise taxes	**14**	11	9
Intersegment	**131**	107	83
Total International	**905**	865	769
Total Chemicals	**1,489**	1,400	1,221
All Other			
United States	**597**	551	338
Intersegment	**514**	431	121
Total United States	**1,111**	982	459
International	**44**	97	100
Intersegment	**26**	16	4
Total International	**70**	113	104
Total All Other	**1,181**	1,095	563
Segment Sales and Other Operating Revenues			
United States	**105,167**	79,929	62,718
International	**112,238**	90,249	71,902
Total Segment Sales and Other Operating Revenues	**217,405**	170,178	134,620
Elimination of intersegment sales	**(23,764)**	(19,313)	(15,045)
Total Sales and Other Operating Revenues*	**$ 193,641**	$ 150,865	$ 119,575

* Includes buy/sell contracts of $23,822 in 2005, $18,650 in 2004 and $14,246 in 2003. Substantially all of the amounts in each period relates to the downstream segment. Refer to Note 15, beginning on page FS-46, for a discussion of the company's accounting for buy/sell contracts.

Segment Income Taxes Segment income tax expenses for the years 2005, 2004 and 2003 are as follows:

	Year ended December 31		
	2005	2004	2003[1]
Upstream — Exploration and Production			
United States	**$ 2,330**	$ 2,308	$ 1,853
International	**8,440**	5,041	3,831
Total Upstream	**10,770**	7,349	5,684
Downstream — Refining, Marketing and Transportation			
United States	**575**	739	300
International	**576**	442	275
Total Downstream	**1,151**	1,181	575
Chemicals			
United States	**99**	47	(25)
International	**25**	17	6
Total Chemicals	**124**	64	(19)
All Other	**(947)**	(1,077)	(946)
Income Tax Expense From Continuing Operations [2]	**$ 11,098**	$ 7,517	$ 5,294

1 See Note 24, beginning on page FS-59, for information concerning the cumulative effect of changes in accounting principles due to the adoption of FAS 143, *"Accounting for Asset Retirement Obligations."*

2 Income tax expense of $100 and $50 related to discontinued operations for 2004 and 2003, respectively, is not included.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 13, beginning on page FS-44. Information related to properties, plant and equipment by segment is contained in Note 14, on page FS-46.

NOTE 9.
LITIGATION

Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to more than 70 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepage of MTBE into groundwater. Resolution of these actions may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future.

The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. The company does not use MTBE in the manufacture of gasoline in the United States.

NOTE 10.
LEASE COMMITMENTS

Certain noncancelable leases are classified as capital leases, and the leased assets are included as part of "Properties, plant and equipment, at cost." Such leasing arrangements involve tanker charters, crude oil production and processing equipment, service stations, and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on such leases are recorded as expense. Details of the capitalized leased assets are as follows:

	At December 31	
	2005	2004
Exploration and Production	**$ 442**	$ 277
Refining, Marketing and Transportation	**837**	842
Total	**1,279**	1,119
Less: Accumulated amortization	**745**	690
Net capitalized leased assets	**$ 534**	$ 429

Rental expenses incurred for operating leases during 2005, 2004 and 2003 were as follows:

	Year ended December 31		
	2005	2004	2003
Minimum rentals	**$2,102**	$2,093	$1,567
Contingent rentals	**6**	7	3
Total	**2,108**	2,100	1,570
Less: Sublease rental income	**43**	40	48
Net rental expense	**$2,065**	$2,060	$1,522

Contingent rentals are based on factors other than the passage of time, principally sales volumes at leased service stations. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, renewal options ranging up to 25 years, and options to purchase the leased property during or at the end of the initial or renewal lease period for the fair market value or other specified amount at that time.

At December 31, 2005, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a non-cancelable term of more than one year, were as follows:

		At December 31	
		Operating Leases	Capital Leases
Year:	2006	$ 507	$ 106
	2007	444	87
	2008	401	76
	2009	349	77
	2010	284	58
	Thereafter	932	564
Total		$ 2,917	$ 968
Less: Amounts representing interest and executory costs			(277)
Net present values			691
Less: Capital lease obligations included in short-term debt			(367)
Long-term capital lease obligations			$ 324

NOTE 11.
RESTRUCTURING AND REORGANIZATION COSTS

In connection with the Unocal acquisition, the company implemented a restructuring and reorganization program as part of the effort to capture the synergies of the combined companies. The program is expected to be substantially completed by the end of 2006 and is aimed at eliminating redundant operations, consolidating offices and facilities, and sharing common services and functions.

As part of the restructuring and reorganization, approximately 700 positions have been preliminarily identified for elimination. Most of the positions are in the United States and relate primarily to corporate and upstream executive and administrative functions. By year-end 2005, approximately 250 of these employees had been terminated.

An accrual of $106 was established as part of the purchase-price allocation for Unocal. Payments against the accrual in 2005 were $62. The balance at year-end 2005 was classified as a current liability on the Consolidated Balance Sheet. Adjustments to the accrual may occur in future periods as the implementation plans are finalized and estimates are refined.

Amounts before tax	**2005**
Balance at August 1	**$ 106**
Payments	**(62)**
Balance at December 31	**$ 44**

As a result of various other reorganizations and restructurings across several businesses and corporate departments, the company recorded before-tax charges of $258 ($146 after tax) during 2003 for estimated termination benefits for approximately 4,500 employees. Nearly half of the liability related to the global downstream segment. Substantially all of the employee reductions had occurred by early 2006.

Activity for the company's liability related to these other reorganizations and restructurings is summarized in the following table:

Amounts before tax	**2005**	2004
Balance at January 1	**$ 119**	$ 240
Additions/adjustments	**(10)**	27
Payments	**(62)**	(148)
Balance at December 31	**$ 47**	$ 119

At December 31, 2005, the amount was classified as a current liability on the Consolidated Balance Sheet and the associated charges or credits during the period were categorized as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income.

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NOTE 12.
ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

At December 31, 2004, the company classified $162 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. Assets in this category related to a group of service stations outside the United States.

Summarized income statement information relating to discontinued operations is as follows:

	Year ended December 31		
	2005	2004	2003
Revenues and other income	**$ –**	$ 635	$ 485
Income from discontinued operations before income tax expense	**–**	394	94
Income from discontinued operations, net of tax	**–**	294	44

Not all assets sold or to be disposed of are classified as discontinued operations, mainly because the cash flows from the assets were not, or will not be, eliminated from the ongoing operations of the company.

NOTE 13.
INVESTMENTS AND ADVANCES

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, are as follows:

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2005	2004	**2005**	2004	2003
Upstream — Exploration and Production					
Tengizchevroil	**$ 5,007**	$ 4,725	**$1,514**	$ 950	$ 611
Hamaca	**1,189**	836	**390**	98	45
Other	**679**	341	**139**	148	155
Total Upstream	**6,875**	5,902	**2,043**	1,196	811
Downstream — Refining, Marketing and Transportation					
GS Caltex Corporation	**1,984**	1,820	**320**	296	107
Caspian Pipeline Consortium	**1,014**	1,039	**101**	140	52
Star Petroleum Refining Company Ltd.	**709**	663	**81**	207	8
Caltex Australia Ltd.	**435**	263	**214**	173	13
Colonial Pipeline Company	**565**	–	**13**	–	–
Other	**1,562**	1,125	**273**	143	100
Total Downstream	**6,269**	4,910	**1,002**	959	280
Chemicals					
Chevron Phillips Chemical Company LLC	**1,908**	1,896	**449**	334	24
Other	**20**	19	**3**	2	1
Total Chemicals	**1,928**	1,915	**452**	336	25
All Other					
Dynegy Inc.	**682**	525	**189**	86	(56)
Other	**740**	601	**45**	5	(31)
Total equity method	**$ 16,494**	$ 13,853	**$3,731**	$2,582	$1,029
Other at or below cost	**563**	536			
Total investments and advances	**$ 17,057**	$ 14,389			
Total United States	**$ 4,624**	$ 3,788	**$ 833**	$ 588	$ 175
Total International	**$ 12,433**	$ 10,601	**$2,898**	$1,994	$ 854

Descriptions of major affiliates are as follows:

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude oil fields in Kazakhstan over a 40-year period.

Hamaca Chevron has a 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex (formerly LG Caltex Oil Corporation), a joint venture with GS Holdings. The joint venture, originally formed in 1967 between the LG Group and Caltex, imports, refines and markets petroleum products and petrochemicals in South Korea.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, which provides the critical export route for crude oil both from TCO and Karachaganak.

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Star Petroleum Refining Company Ltd. Chevron has a 64 percent equity ownership interest in Star Petroleum Refining Company Limited (SPRC), which owns the Star Refinery at Map Ta Phut, Thailand. The Petroleum Authority of Thailand owns the remaining 36 percent of SPRC.

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2005, the fair value of Chevron's share of CAL common stock was approximately $1,900. The aggregate carrying value of the company's investment in CAL was approximately $70 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest as a result of the Unocal acquisition. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of CPChem, formed in 2000 when Chevron merged most of its petrochemicals businesses with those of Phillips Petroleum Company (now ConocoPhillips Corporation). At December 31, 2005, the company's carrying value of its investment in CPChem was approximately $100 lower than the amount of underlying equity in CPChem's net assets.

Dynegy Inc. Chevron owns an approximate 24 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States. The company also holds investments in Dynegy preferred stock.

Investment in Dynegy Common Stock At December 31, 2005, the carrying value of the company's investment in Dynegy common stock was approximately $300. This amount was about $200 below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. This difference has been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors contributing to the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate to reflect the difference between these allocated values and Dynegy's historical book values. The market value of the company's investment in Dynegy's common stock at December 31, 2005, was approximately $470.

Investment in Dynegy Preferred Stock Refer to Note 7, beginning on page FS-39, for a discussion of this investment.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $8,824, $7,933 and $6,308 with affiliated companies for 2005, 2004 and 2003, respectively. "Purchased crude oil and products" includes $3,219, $2,548 and $1,740 with affiliated companies for 2005, 2004 and 2003, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,729 and $1,188 due from affiliated companies at December 31, 2005 and 2004, respectively. "Accounts payable" includes $249 and $192 due to affiliated companies at December 31, 2005 and 2004, respectively.

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share.

	Affiliates			Chevron Share		
Year ended December 31	**2005**	2004	2003	**2005**	2004	2003
Total revenues	**$ 64,642**	$ 55,152	$ 42,323	**$ 31,252**	$ 25,916	$ 19,467
Income before income tax expense	**7,883**	5,309	1,657	**4,165**	3,015	1,211
Net income	**6,645**	4,441	1,508	**3,534**	2,582	1,029
At December 31						
Current assets	**$ 19,903**	$ 16,506	$ 12,204	**$ 8,537**	$ 7,540	$ 5,180
Noncurrent assets	**46,925**	38,104	39,422	**17,747**	15,567	15,765
Current liabilities	**13,427**	10,949	9,642	**6,034**	4,962	4,132
Noncurrent liabilities	**26,579**	22,261	22,738	**4,906**	4,520	5,002
Net equity	**$ 26,822**	$ 21,400	$ 19,246	**$ 15,344**	$ 13,625	$ 11,811

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NOTE 14.
PROPERTIES, PLANT AND EQUIPMENT[1,2]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[3]			Depreciation Expense[4,5]		
	2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Upstream												
United States	**$ 43,390**	$ 37,329	$ 34,798	**$ 15,327**	$ 10,047	$ 9,953	**$ 2,160**	$ 1,584	$ 1,776	**$ 1,869**	$ 1,508	$ 1,815
International	**54,497**	38,721	37,402	**34,311**	21,192	20,572	**4,897**	3,090	3,246	**2,804**	2,180	2,227
Total Upstream	**97,887**	76,050	72,200	**49,638**	31,239	30,525	**7,057**	4,674	5,022	**4,673**	3,688	4,042
Downstream												
United States	**13,832**	12,826	12,959	**6,169**	5,611	5,881	**793**	482	389	**461**	490	493
International	**11,235**	10,843	11,174	**5,529**	5,443	5,944	**453**	441	388	**550**	572	655
Total Downstream	**25,067**	23,669	24,133	**11,698**	11,054	11,825	**1,246**	923	777	**1,011**	1,062	1,148
Chemicals												
United States	**624**	615	613	**282**	292	303	**12**	12	12	**19**	20	21
International	**721**	725	719	**402**	392	404	**43**	27	24	**23**	26	38
Total Chemicals	**1,345**	1,340	1,332	**684**	684	707	**55**	39	36	**42**	46	59
All Other [6]												
United States	**3,127**	2,877	2,772	**1,655**	1,466	1,393	**199**	314	169	**186**	158	109
International	**20**	18	119	**15**	15	88	**4**	2	8	**1**	3	26
Total All Other	**3,147**	2,895	2,891	**1,670**	1,481	1,481	**203**	316	177	**187**	161	135
Total United States	**60,973**	53,647	51,142	**23,433**	17,416	17,530	**3,164**	2,392	2,346	**2,535**	2,176	2,438
Total International	**66,473**	50,307	49,414	**40,257**	27,042	27,008	**5,397**	3,560	3,666	**3,378**	2,781	2,946
Total	**$ 127,446**	$ 103,954	$ 100,556	**$ 63,690**	$ 44,458	$ 44,538	**$ 8,561**	$ 5,952	$ 6,012	**$ 5,913**	$ 4,957	$ 5,384

1 Refer to Note 24, beginning on page FS-59, for a discussion of the effect on 2003 PP&E balances and depreciation expenses related to the adoption of FAS 143, *"Accounting for Asset Retirement Obligations."*
2 2005 balances include assets acquired in connection with the acquisition of Unocal Corporation. Refer to Note 2, beginning on page FS-36, for additional information.
3 Net of dry hole expense related to prior years' expenditures of $28, $58 and $124 in 2005, 2004 and 2003, respectively.
4 Depreciation expense includes accretion expense of $187, $93 and $132 in 2005, 2004 and 2003, respectively.
5 Depreciation expense includes discontinued operations of $22 and $58 in 2004 and 2003, respectively.
6 Primarily mining operations of coal and other minerals, power generation businesses, real estate assets and management information systems.

NOTE 15.
ACCOUNTING FOR BUY/SELL CONTRACTS

In the first quarter 2005, the Securities and Exchange Commission (SEC) issued comment letters to Chevron and other companies in the oil and gas industry requesting disclosure of information related to the accounting for buy/sell contracts. Under a buy/sell contract, a company agrees to buy a specific quantity and quality of a commodity to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of a commodity at a different location to the same counterparty. Physical delivery occurs for each side of the transaction, and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and risk of nonperformance by the counterparty. Both parties settle each side of the buy/sell through separate invoicing.

The company routinely enters into buy/sell contracts, primarily in the United States downstream business, associated with crude oil and refined products. For crude oil, these contracts are used to facilitate the company's crude oil marketing activity, which includes the purchase and sale of crude oil production, fulfillment of the company's supply arrangements as to physical delivery location and crude oil specifications, and purchase of crude oil to supply the company's refining system. For refined products, buy/sell arrangements are used to help fulfill the company's supply agreements to customer locations and specifications.

The company has historically accounted for buy/sell transactions in the Consolidated Statement of Income the same as for a monetary transaction — purchases are reported as "Purchased crude oil and products"; sales are reported as "Sales and other operating revenues." The SEC raised the issue as to whether the accounting for buy/sell contracts should be shown net on the income statement and accounted for under the provisions of Accounting Principles Board (APB) Opinion No. 29, *"Accounting for Nonmonetary Transactions"* (APB 29). The company understands that others in the oil and gas industry may report buy/sell transactions on a net basis in the income statement rather than gross.

The Emerging Issues Task Force (EITF) of the FASB deliberated this topic as Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty."* At its September 2005 meeting, the EITF reached consensus that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, should be combined and considered as a single arrangement for purposes of applying APB 29 when the transactions were entered into "in contemplation" of one another. EITF 04-13 was ratified by the FASB in September 2005 and is effective for new arrangements, or modifications or renewals of existing arrangements, entered into beginning on or after April 1, 2006, which will be the effective date for the company's adoption of this standard. Upon adoption, the company will report the net effect of buy/sell transactions on its Consolidated Statement of Income as "Purchased crude oil and products" instead of reporting the revenues associated with these arrangements as "Sales and other operating revenues" and the costs as "Purchased crude oil and products."

While this issue was under deliberation by the EITF, the SEC staff directed Chevron and other companies to disclose on the face of the income statement the amounts associated with buy/sell contracts and to discuss in a footnote to the financial statements the basis for the underlying accounting. The amounts for buy/sell contracts shown on the company's Consolidated Statement of Income "Sales and other operating revenues" for the three years ending December 31, 2005, were $23,822, $18,650 and $14,246, respectively. These revenue amounts associated with buy/sell contracts represented 12 percent of total "Sales and other operating revenues" in 2005, 2004 and 2003. Nearly all of these revenue amounts in each period associated with buy/sell contracts pertain to the company's downstream segment. The costs associated with these buy/sell revenue amounts are included in "Purchased crude oil and products" on the Consolidated Statement of Income in each period.

NOTE 16.
TAXES

	Year ended December 31		
	2005	2004	2003
Taxes on income [1]			
U.S. federal			
Current	**$ 1,459**	$2,246	$1,133
Deferred [2]	**567**	(290)	121
State and local	**409**	345	133
Total United States	**2,435**	2,301	1,387
International			
Current	**7,837**	5,150	3,864
Deferred [2]	**826**	66	43
Total International	**8,663**	5,216	3,907
Total taxes on income	**$11,098**	$7,517	$5,294

[1] Excludes income tax expense of $100 and $50 related to discontinued operations for 2004 and 2003, respectively.
[2] Excludes a U.S. deferred tax benefit of $191 and a foreign deferred tax expense of $170 associated with the adoption of FAS 143 in 2003 and the related cumulative effect of changes in accounting method in 2003.

In 2005, the before-tax income for U.S. operations, including related corporate and other charges, was $6,733, compared with a before-tax income of $7,776 and $5,664 in 2004 and 2003, respectively. For international operations, before-tax income was $18,464, $12,775 and $7,012 in 2005, 2004 and 2003, respectively. U.S. federal income tax expense was reduced by $289, $176 and $196 in 2005, 2004 and 2003, respectively, for business tax credits.

The reconciliation between the U.S. statutory federal income tax rate and the company's effective income tax rate is explained in the table below:

	Year ended December 31		
	2005	2004	2003
U.S. statutory federal income tax rate	**35.0%**	35.0%	35.0%
Effect of income taxes from international operations in excess of taxes at the U.S. statutory rate	**9.2**	5.3	12.8
State and local taxes on income, net of U.S. federal income tax benefit	**1.0**	0.9	0.5
Prior-year tax adjustments	**0.1**	(1.0)	(1.6)
Tax credits	**(1.1)**	(0.9)	(1.5)
Effects of enacted changes in tax laws	**–**	(0.6)	0.3
Capital loss tax benefit	**(0.1)**	(2.1)	(0.8)
Other	**0.2**	–	(1.9)
Consolidated companies	**44.3**	36.6	42.8
Effect of recording income from equity affiliates on an after-tax basis	**(0.2)**	–	(1.0)
Effective tax rate	**44.1%**	36.6%	41.8%

The company records its deferred taxes on a tax-jurisdiction basis and classifies those net amounts as current or noncurrent based on the balance sheet classification of the related assets or liabilities.

The reported deferred tax balances are composed of the following:

	At December 31	
	2005	2004
Deferred tax liabilities		
Properties, plant and equipment	**$14,220**	$ 8,889
Investments and other	**1,469**	931
Total deferred tax liabilities	**15,689**	9,820
Deferred tax assets		
Abandonment/environmental reserves	**(2,083)**	(1,495)
Employee benefits	**(1,250)**	(965)
Tax loss carryforwards	**(1,113)**	(1,155)
Capital losses	**(246)**	(687)
Deferred credits	**(1,618)**	(838)
Foreign tax credits	**(1,145)**	(93)
Inventory	**(182)**	(99)
Other accrued liabilities	**(240)**	(300)
Miscellaneous	**(1,237)**	(876)
Total deferred tax assets	**(9,114)**	(6,508)
Deferred tax assets valuation allowance	**3,249**	1,661
Total deferred taxes, net	**$ 9,824**	$ 4,973

In 2005, the reported amount of net total deferred taxes increased by approximately $5,000 from the amount reported in 2004. The increase was largely attributable to net deferred taxes arising through the Unocal acquisition.

Deferred tax assets related to foreign tax credits increased approximately $1,000 between 2004 and 2005. The associated valuation allowance also increased approximately the same amount. The change in both categories reflected the addition of Unocal amounts as well as the effect of the company's tax election in 2005 for certain heritage-Chevron international upstream operations.

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NOTE 16. TAXES — Continued

The overall valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences for which no benefit is expected to be realized. Tax loss carryforwards exist in many foreign jurisdictions. Whereas some of these tax loss carry forwards do not have an expiration date, others expire at various times from 2006 through 2013. Foreign tax credit carryforwards of $1,145 will expire in 2015.

At December 31, 2005 and 2004, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2005	2004
Prepaid expenses and other current assets	**$ (892)**	$(1,532)
Deferred charges and other assets	**(547)**	(769)
Federal and other taxes on income	**1**	6
Noncurrent deferred income taxes	**11,262**	7,268
Total deferred income taxes, net	**$ 9,824**	$ 4,973

It is the company's policy for subsidiaries that are included in the U.S. consolidated tax return to record income tax expense as though they file separately, with the parent recording the adjustment to income tax expense for the effects of consolidation.

Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled $14,317 at December 31, 2005. A significant majority of this amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of such earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

American Jobs Creation Act of 2004 In October 2004, the American Jobs Creation Act of 2004 was passed into law. The Act provides a deduction for income from qualified domestic refining and upstream production activities, which will be phased in from 2005 through 2010. For that income, the company expects the net effect of this provision of the Act to result in a decrease in the federal effective tax rate for 2006 to approximately 34 percent, based on current earnings levels. In the long term, the company expects that the new deduction will result in a decrease of the annual effective tax rate to about 32 percent for that category of income, based on current earnings levels.

Taxes other than on income were as follows:

	Year ended December 31		
	2005	2004	2003
United States			
Excise taxes on products and merchandise	**$ 4,521**	$ 4,147	$ 3,744
Import duties and other levies	**8**	5	11
Property and other miscellaneous taxes	**392**	359	309
Payroll taxes	**149**	137	138
Taxes on production	**323**	257	244
Total United States	**5,393**	4,905	4,446
International			
Excise taxes on products and merchandise	**4,198**	3,821	3,351
Import duties and other levies	**10,466**	10,542	9,652
Property and other miscellaneous taxes	**535**	415	320
Payroll taxes	**52**	52	54
Taxes on production	**138**	86	83
Total International	**15,389**	14,916	13,460
Total taxes other than on income*	**$20,782**	$19,821	$17,906

* Includes taxes on discontinued operations of $3 and $5 in 2004 and 2003, respectively.

NOTE 17.
SHORT-TERM DEBT

	At December 31	
	2005	2004
Commercial paper*	**$ 4,098**	$ 4,068
Notes payable to banks and others with originating terms of one year or less	**170**	310
Current maturities of long-term debt	**467**	333
Current maturities of long-term capital leases	**70**	55
Redeemable long-term obligations		
Long-term debt	**487**	487
Capital leases	**297**	298
Subtotal	**5,589**	5,551
Reclassified to long-term debt	**(4,850)**	(4,735)
Total short-term debt	**$ 739**	$ 816

* Weighted-average interest rates at December 31, 2005 and 2004, were 4.18 percent and 1.98 percent, respectively.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date.

The company periodically enters into interest rate swaps on a portion of its short-term debt. See Note 7, beginning on page FS-39, for information concerning the company's debt-related derivative activities.

At December 31, 2005, the company had $4,850 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company's commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2005 or at year-end.

At December 31, 2005 and 2004, the company classified $4,850 and $4,735, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2006, as the company has both the intent and the ability to refinance this debt on a long-term basis.

NOTE 18.
LONG-TERM DEBT

Chevron has three "shelf" registration statements on file with the SEC that together would permit the issuance of $3,800 of debt securities pursuant to Rule 415 of the Securities Act of 1933. Total long-term debt, excluding capital leases, at December 31, 2005, was $11,807, which included $1,861 assumed in connection with the acquisition of Unocal. The company's long-term debt outstanding at year-end 2005 and 2004 was as follows:

	At December 31	
	2005	2004
3.5% notes due 2007	**$ 1,992**	$ 1,995
3.375% notes due 2008	**736**	754
7.5% debentures due 2029 [1]	**475**	–
5.05% debentures due 2012 [1]	**412**	–
5.5% notes due 2009	**406**	422
7.35% debentures due 2009 [1]	**347**	–
7% debentures due 2028 [1]	**259**	–
9.75% debentures due 2020	**250**	250
7.327% amortizing notes due 2014 [2]	**247**	360
Fixed interest rate notes, maturing from 2006 to 2015 (8.1%) [1,3]	**241**	–
8.625% debentures due 2031	**199**	199
8.625% debentures due 2032	**199**	199
7.5% debentures due 2043	**198**	198
Fixed and floating interest rate loans due 2007 to 2009 (4.4%) [1,3]	**194**	–
9.125% debentures due 2006 [1]	**167**	–
8.625% debentures due 2010	**150**	150
8.875% debentures due 2021	**150**	150
8% debentures due 2032	**148**	148
7.09% notes due 2007	**144**	144
8.25% debentures due 2006	**129**	129
Medium-term notes, maturing from 2017 to 2043 (7.5%) [3]	**210**	210
Other foreign currency obligations (3.2%) [3]	**30**	39
5.7% notes due 2008	**–**	206
Other long-term debt (6.4%) [3]	**141**	262
Total including debt due within one year	**7,424**	5,815
Debt due within one year	**(467)**	(333)
Reclassified from short-term debt	**4,850**	4,735
Total long-term debt	**$ 11,807**	$ 10,217

[1] Debt assumed with acquisition of Unocal in 2005.
[2] Guarantee of ESOP debt.
[3] Less than $100 individually; weighted-average interest rate at December 31, 2005.

Consolidated long-term debt maturing after December 31, 2005, is as follows: 2006 – $467; 2007 – $2,287; 2008 – $856; 2009 – $782; and 2010 – $176; after 2010 – $2,856.

In October 2005, the company fully redeemed Pure Resources 7.125 percent Senior Notes due 2011 for $395. The company's $150 of Texaco Brasil zero coupon notes were paid at maturity in November 2005. In December 2005, the company exercised a par call redemption of $200 for Texaco Capital Inc. 5.7 percent Notes due 2008.

In January 2005, the company contributed $98 to permit the ESOP to make a principal payment of $113.

NOTE 19.
NEW ACCOUNTING STANDARDS

FASB Statement No. 151, "Inventory Costs, an Amendment of ARB No. 43, Chapter 4" (FAS 151) In November 2004, the FASB issued FAS 151, which became effective for the company on January 1, 2006. The standard amends the guidance in Accounting Research Bulletin (ARB) No. 43, Chapter 4, *"Inventory Pricing,"* to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. In addition, the standard requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. The adoption of this standard will not have an impact on the company's results of operations, financial position or liquidity.

EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" (Issue 04-6) In March 2005, the FASB ratified the earlier EITF consensus on Issue 04-6, which is effective for the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to ARB No. 43, *"Restatement and Revision of Accounting Research Bulletins."* Adoption of this accounting for its coal, oil sands and other mining operations will not have a significant effect on the company's results of operations, financial position or liquidity.

NOTE 20.
ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS

Refer to Note 1, beginning on page FS-34, in the section "Properties, Plant and Equipment" for a discussion of the company's accounting policy for the cost of exploratory wells. The company's suspended wells are reviewed in this context on a quarterly basis.

In April 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1, *"Accounting for Suspended Well Costs,"* which amended FAS 19, *"Financial Accounting and Reporting by Oil and Gas Producing Companies."* The company elected early application of this guidance with the first quarter 2005 financial statements.

Under the provisions of FSP FAS 19-1, exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project.

NOTE 20. ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS – Continued

If either condition is not met, or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. The FSP provides a number of indicators that can assist an entity to demonstrate sufficient progress is being made in assessing the reserves and economic viability of the project.

The following table indicates the changes to the company's suspended exploratory-well costs for the three years ended December 31, 2005. No capitalized exploratory well costs were charged to expense upon the adoption of FSP FAS 19-1. Amounts may differ from those previously disclosed due to the requirements of FSP FAS 19-1 to exclude costs suspended and expensed in the same annual period.

	Year ended December 31		
	2005	2004	2003
Beginning balance at January 1	**$ 671**	$ 549	$ 478
Additions associated with the acquisition of Unocal	**317**	–	–
Additions to capitalized exploratory well costs pending the determination of proved reserves	**290**	252	344
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(140)**	(64)	(145)
Capitalized exploratory well costs charged to expense	**(6)**	(66)	(126)
Other reductions*	**(23)**	–	(2)
Ending balance at December 31	**$1,109**	$ 671	$ 549

* Represent property sales and an exchange.

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling. The aging of the former Unocal wells is based on the date the drilling was completed, rather than Chevron's August 2005 acquisition of Unocal.

	Year ended December 31		
	2005	2004	2003
Exploratory well costs capitalized for a period of one year or less	**$ 259**	$ 222	$ 181
Exploratory well costs capitalized for a period greater than one year	**850**	449	368
Balance at December 31	**$1,109**	$ 671	$ 549
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**40**	22	22

* Certain projects have multiple wells or fields or both.

Of the $850 of exploratory well costs capitalized for a period greater than one year at December 31, 2005, approximately $313 (20 projects) related to projects that had drilling activities under way or firmly planned for the near future. An additional $63 (four projects) had drilling activity during 2005. The $474 balance related to 16 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the $474 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $141 — additional seismic interpretation planned, with front-end engineering and design (FEED) expected to commence in 2007 (two projects); (b) $82 — evaluation of drilling results and pre-FEED studies on-going with FEED expected to commence in 2006 (one project); (c) $74 — finalization of pre-unit agreement with operator of adjacent field and the progression of joint subsurface and joint concept selection studies, with FEED expected to begin in 2006 (one project); (d) $63 — FEED contracts executed in 2005 and continued marketing of equity natural gas (two projects); (e) $114 — miscellaneous activities for 10 projects with smaller amounts suspended. While progress was being made on all the projects in this category, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations connected with the projects. The majority of these decisions are expected to occur in the next three years.

The $850 of suspended well costs capitalized for a period greater than one year as of December 31, 2005, represents 105 exploratory wells in 40 projects. The tables below contain the aging of these costs on a well and project basis:

Exploratory wells costs greater than one year:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1994–2000	$ 147	28
2001–2004	703	77
Total	$ 850	105

Aging based on drilling completion date of last well in project:	Amount	Number of projects
1998–2000	$ 91	4
2001–2005	759	36
Total	$ 850	40

NOTE 21.
EMPLOYEE BENEFIT PLANS

The company has defined-benefit pension plans for many employees. The company typically pre-funds defined-benefit plans as required by local regulations or in certain situations where pre-funding provides economic advantages. In the United States, all qualified tax-exempt plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund domestic nonqualified tax-exempt pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be

NOTE 21. EMPLOYEE BENEFIT PLANS — Continued

less economic and investment returns may be less attractive than the company's other investment alternatives.

The company also sponsors other postretirement plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees.

The plans are unfunded, and the company and the retirees share the costs. For retiree medical coverage in the company's main U.S. plan, the increase to the company contributions for retiree medical coverage is limited to no more than 4 percent each year, effective at retirement, beginning in 2005. Certain life insurance benefits are paid by the company and annual contributions are based on actual plan experience.

The company uses a measurement date of December 31 to value its pension and other postretirement benefit plan obligations.

The status of the company's pension and other postretirement benefit plans for 2005 and 2004 is as follows:

	Pension Benefits				Other Benefits	
	2005		2004			
	U.S.	Int'l.	U.S.	Int'l.	2005	2004
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	$ 6,587	$ 3,144	$ 5,819	$ 2,708	$ 2,820	$ 3,135
Assumption of Unocal benefit obligations	1,437	169	–	–	277	–
Service cost	208	84	170	70	30	26
Interest cost	395	199	326	180	164	164
Plan participants' contributions	1	6	1	6	–	–
Plan amendments	42	7	–	26	–	(811)
Actuarial loss	593	476	861	165	189	497
Foreign currency exchange rate changes	–	(293)	–	207	(2)	8
Benefits paid	(669)	(181)	(590)	(213)	(226)	(199)
Curtailment	–	–	–	(6)	–	–
Special termination benefits	–	–	–	1	–	–
Benefit obligation at December 31	8,594	3,611	6,587	3,144	3,252	2,820
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	5,776	2,634	4,444	2,129	–	–
Acquisition of Unocal plan assets	1,034	65	–	–	–	–
Actual return on plan assets	527	441	589	229	–	–
Foreign currency exchange rate changes	–	(303)	–	172	–	–
Employer contributions	794	228	1,332	311	226	199
Plan participants' contributions	1	6	1	6	–	–
Benefits paid	(669)	(181)	(590)	(213)	(226)	(199)
Fair value of plan assets at December 31	7,463	2,890	5,776	2,634	–	–
FUNDED STATUS	(1,131)	(721)	(811)	(510)	(3,252)	(2,820)
Unrecognized net actuarial loss	2,332	1,108	2,080	939	1,167	1,071
Unrecognized prior-service cost	305	89	308	104	(679)	(771)
Unrecognized net transitional assets	–	5	–	7	–	–
Total recognized at December 31	$ 1,506	$ 481	$ 1,577	$ 540	$ (2,764)	$ (2,520)
AMOUNTS RECOGNIZED IN THE CONSOLIDATED BALANCE SHEET AT DECEMBER 31						
Prepaid benefit cost	$ 1,961	$ 960	$ 1,759	$ 933	$ –	$ –
Accrued benefit liability[1]	(890)	(545)	(712)	(458)	(2,764)	(2,520)
Intangible asset	12	2	14	5	–	–
Accumulated other comprehensive income[2]	423	64	516	60	–	–
Net amount recognized	$ 1,506	$ 481	$ 1,577	$ 540	$ (2,764)	$ (2,520)

1 The company recorded additional minimum liabilities of $435 and $66 in 2005 for U.S. and international plans, respectively, and $530 and $64 in 2004 for U.S. and international plans, respectively, to reflect the amount of unfunded accumulated benefit obligations. The long-term portion of accrued benefits liability is recorded in "Reserves for employee benefit plans," and the short-term portion is reflected in "Accrued liabilities."

2 "Accumulated other comprehensive income" includes deferred income taxes of $148 and $22 in 2005 for U.S. and international plans, respectively, and $181 and $21 in 2004 for U.S. and international plans, respectively. This item is presented net of these taxes in the Consolidated Statement of Stockholders' Equity.

NOTE 21. EMPLOYEE BENEFIT PLANS – Continued

The accumulated benefit obligations for all U.S. and international pension plans were $7,931 and $3,080 respectively, at December 31, 2005, and $6,117 and $2,734, respectively, at December 31, 2004.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2005 and 2004 was:

	At December 31	
	2005	2004
Projected benefit obligations	**$2,950**	$1,449
Accumulated benefit obligations	**2,625**	1,360
Fair value of plan assets	**1,359**	282

The components of net periodic benefit cost for 2005, 2004 and 2003 were:

	Pension Benefits						Other Benefits		
	2005		2004		2003				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2005**	2004	2003
Service cost	**$ 208**	**$ 84**	$ 170	$ 70	$ 144	$ 54	**$ 30**	$ 26	$ 28
Interest cost	**395**	**199**	326	180	334	151	**164**	164	191
Expected return on plan assets	**(449)**	**(208)**	(358)	(169)	(224)	(132)	**–**	–	–
Amortization of transitional assets	**–**	**2**	–	1	–	(3)	**–**	–	–
Amortization of prior-service costs	**45**	**16**	42	16	45	14	**(91)**	(47)	(3)
Recognized actuarial losses	**177**	**51**	114	69	133	42	**93**	54	12
Settlement losses	**86**	**–**	96	4	132	1	**–**	–	–
Curtailment losses	**–**	**–**	–	2	–	6	**–**	–	–
Special termination benefits recognition	**–**	**–**	–	1	–	–	**–**	–	–
Net periodic benefit cost	**$ 462**	**$ 144**	$ 390	$ 174	$ 564	$ 133	**$ 196**	$ 197	$ 228

Assumptions The following weighted average assumptions were used to determine benefit obligations and net period benefit costs for years ended December 31:

	Pension Benefits						Other Benefits		
	2005		2004		2003				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2005**	2004	2003
Assumptions used to determine benefit obligations									
Discount rate	**5.5%**	**5.9%**	5.8%	6.4%	6.0%	6.8%	**5.6%**	5.8%	6.1%
Rate of compensation increase	**4.0%**	**5.1%**	4.0%	4.9%	4.0%	4.9%	**4.0%**	4.1%	4.1%
Assumptions used to determine net periodic benefit cost									
Discount rate [1,2]	**5.5%**	**6.4%**	5.9%	6.8%	6.3%	7.1%	**5.8%**	6.1%	6.8%
Expected return on plan assets [1,2]	**7.8%**	**7.9%**	7.8%	8.3%	7.8%	8.3%	**N/A**	N/A	N/A
Rate of compensation increase [2]	**4.0%**	**5.0%**	4.0%	4.9%	4.0%	5.1%	**4.0%**	4.1%	4.1%

1 Discount rate and expected rate of return on plan assets were reviewed and updated as needed on a quarterly basis for the main U.S. pension plan.
2 The 2005 discount rate, expected return on plan assets and rate of compensation increase reflect the remeasurement of the Unocal benefit plans at July 31, 2005, due to the acquisition of Unocal.

Expected Return on Plan Assets The company employs a rigorous process to determine estimates of the long-term rate of return on pension assets. These estimates are primarily driven by actual historical asset-class returns, an assessment of expected future performance, advice from external actuarial firms and the incorporation of specific asset-class risk factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies.

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 72 percent of the company's pension plan assets. At December 31, 2005, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

The market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market values in the three months preceding the year-end measurement date, as opposed to the maximum allowable period of five years under U.S. accounting rules. Management considers the three-month time period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of the measurement date is used in calculating the pension expense.

Discount Rate The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2005, the company selected a

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5.5 percent discount rate (shown in the table on page FS-52) based on Moody's Aa Corporate Bond Index and a cash flow analysis using the Citigroup Pension Discount Curve. The discount rates at the end of 2004 and 2003 were 5.8 percent and 6 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2005, for the main U.S. postretirement medical plan, the assumed health care cost trend rates start with 10 percent in 2006 and gradually decline to 5 percent for 2011 and beyond. For this measurement at December 31, 2004, the assumed health care cost trend rates started with 9.5 percent in 2005 and gradually declined to 4.8 percent for 2010 and beyond. In both measurements, increases in the company's contributions are capped at 4 percent effective at retirement.

Assumed health care cost-trend rates have a significant effect on the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects:

	1 Percent Increase	1 Percent Decrease
Effect on total service and interest cost components	$ 8	$ (9)
Effect on postretirement benefit obligation	$ 126	$ (184)

Plan Assets and Investment Strategy The company's pension plan weighted-average asset allocations at December 31 by asset category are as follows:

	U.S.		International	
Asset Category	**2005**	2004	**2005**	2004
Equities	**69%**	70%	**60%**	57%
Fixed Income	**21%**	21%	**39%**	42%
Real Estate	**9%**	9%	**1%**	1%
Other	**1%**	–	**–**	–
Total	**100%**	100%	**100%**	100%

The pension plans invest primarily in asset categories with sufficient size, liquidity and cost efficiency to permit investments of reasonable size. The pension plans invest in asset categories that provide diversification benefits and are easily measured. To assess the plans' investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income 20–60 percent, Real Estate 0–15 percent and Other 0–5 percent. The significant international pension plans also have established maximum and minimum asset allocation ranges that vary by each plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset category risk.

Equities include investments in the company's common stock in the amount of $13 and $8 at December 31, 2005 and 2004, respectively. The "Other" asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments In 2005, the company contributed $794 and $228 to its U.S. and international pension plans, respectively. In 2006, the company expects contributions to be approximately $300 and $200 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon plan-investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately $220 in 2006, as compared with $226 paid in 2005.

The following benefit payments, which include estimated future service, are expected to be paid by the company in the next ten years:

	Pension Benefits		Other
	U.S.	Int'l.	Benefits
2006	$ 788	$ 177	$ 220
2007	$ 639	$ 185	$ 218
2008	$ 674	$ 195	$ 224
2009	$ 714	$ 202	$ 231
2010	$ 729	$ 212	$ 237
2011–2015	$ 3,803	$ 1,240	$ 1,238

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP).

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is discussed below. Total company matching contributions to employee accounts within the ESIP were $145, $139 and $136 in 2005, 2004 and 2003, respectively. This cost was reduced by the value of shares released from the LESOP totaling $(4), $(138) and $(23) in 2005, 2004 and 2003, respectively. The remaining amounts, totaling $141, $1 and $113 in 2005, 2004 and 2003, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron Employee Savings Investment Plan (ESIP) is an employee stock ownership plan (ESOP). In 1989, Chevron established a leveraged employee stock ownership plan (LESOP) as a constituent part of the ESOP. The LESOP provides partial prefunding of the company's future commitments to the ESIP.

As permitted by American Institute of Certified Public Accountants (AICPA) Statement of Position 93-6, *"Employers' Accounting for Employee Stock Ownership Plans,"* the company has elected to continue its practices, which are based on AICPA Statement of Position 76-3, *"Accounting Practices for Certain Employee Stock Ownership Plans,"* and subsequent consensus of the EITF of the FASB. The debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" on the Consolidated Balance Sheet and the Consolidated Statement of Stockholders' Equity.

The company reports compensation expense equal to LESOP debt principal repayments less dividends received and used by the LESOP for debt service. Interest accrued on LESOP debt is recorded as interest expense. Dividends paid on LESOP shares are reflected as a reduction of retained earnings. All LESOP shares are considered outstanding for earnings-per-share computations.

Total expenses (credits) recorded for the LESOP were $94, $(29) and $24 in 2005, 2004 and 2003, respectively, including $18, $23 and $28 of interest expense related to LESOP debt and a charge (credit) to compensation expense of $76, $(52) and $(4).

Of the dividends paid on the LESOP shares, $55, $52 and $61 were used in 2005, 2004 and 2003, respectively, to service LESOP debt. Included in the 2004 amount was a repayment of debt entered into in 1999 to pay interest on the ESOP debt. Interest expense on this debt was recognized and reported as LESOP interest expense in 1999. In addition, the company made contributions in 2005 and 2003 of $98 and $26, respectively, to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2004 as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Shares held in the LESOP are released and allocated to the accounts of plan participants based on debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. LESOP shares as of December 31, 2005 and 2004, were as follows:

Thousands	**2005**	2004
Allocated shares	**23,928**	24,832
Unallocated shares	**9,163**	9,940
Total LESOP shares	**33,091**	34,772

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2005, the trust contained 14.2 million shares of Chevron treasury stock. The company intends to continue to pay its obligations under the benefit plans. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans.

At December 31, 2005, trust assets totaled $130 and were invested primarily in interest-earning accounts.

Management Incentive Plans Chevron has two incentive plans, the Management Incentive Plan (MIP) and the Long-Term Incentive Plan (LTIP), for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. The MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by the recipients by conversion to stock units or other investment fund alternatives. Aggregate charges to expense for MIP were $155, $147 and $125 in 2005, 2004 and 2003, respectively. Awards under the LTIP consist of stock options and other share-based compensation which are described more fully in Note 22 below.

Other Incentive Plans The company has a program that provides eligible employees, other than those covered by MIP and LTIP, with an annual cash bonus if the company achieves certain financial and safety goals. Additionally, in August 2005, the company assumed responsibility for the remaining pro-rated cash bonuses under the Unocal Annual Incentive Plan. Charges for the programs were $324, $339 and $151 in 2005, 2004 and 2003, respectively.

NOTE 22.
STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION

Effective July 1, 2005, the company adopted the provisions of Financial Accounting Standards Board (FASB) Statement No. 123R, *"Share-Based Payment,"* (FAS 123R) for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *"Accounting for Stock Issued to Employees,"* (APB 25) and related interpretations and disclosure requirements established by FAS 123, *"Accounting for Stock-Based Compensation."*

The company adopted FAS 123R using the modified prospective method and, accordingly, results for prior periods have not been restated. Refer to Note 1, beginning on page FS-34, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition of FAS 123 for periods prior to adoption of FAS 123R and the actual effect on net income and earnings per share for periods after adoption of FAS 123R.

For 2005, compensation expense charged against income for the first time for stock options was $65 ($42 after tax). In addition, compensation expense charged against income for stock appreciation rights, performance units and restricted stock units was $59 ($39 after tax), $65 ($42 after tax) and $25 ($16 after tax) for 2005, 2004 and 2003, respectively. There were no significant capitalized stock-based compensation costs at December 31, 2005.

Cash received from option exercises under all share-based payment arrangements for 2005, 2004 and 2003 was $297, $385 and $32, respectively. Actual tax benefits realized for the tax deductions from option exercises was $71, $49 and $6 for 2005, 2004 and 2003, respectively.

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Cash paid to settle performance units and stock appreciation rights was $110, $23 and $11 for 2005, 2004 and 2003, respectively. Cash paid in 2005 included $73 million for Unocal awards paid under change-in-control plan provisions.

At adoption of FAS 123R, the impact of measuring stock appreciation rights at fair value instead of intrinsic value resulted in an insignificant charge against income in the third quarter 2005. For restricted stock units, FAS 123R required that unrecognized compensation amounts presented in “Deferred compensation and benefit plan trust” on the Consolidated Balance Sheet be reclassified against the appropriate equity accounts. This resulted in a reclassification of $7 to “Capital in excess of par value.”

Prior to the adoption of FAS 123R, the company presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in the Consolidated Statement of Cash Flows. FAS 123R requires the cash flow resulting from the tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. Refer to Note 3, beginning on page FS-37, for information on excess tax benefits.

In November 2005, the FASB issued a Staff Position FAS 123R-3 (FSP FAS 123R-3), “*Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards,*” which provides a one-time transition election for companies to follow in calculating the beginning balance of the pool of excess tax benefits related to employee compensation and a simplified method to determine the subsequent impact on the pool of employee awards that are fully vested and outstanding upon the adoption of FAS 123R. Under the FSP, the company must decide by November 2006 whether to make this one-time transition election, which may provide some administrative relief in calculating the future tax effects of stock option issuances. Whether or not the one-time election is made, the company anticipates no significant difference in the amount of tax expense recorded in future periods.

In the discussion below, the references to share price and number of shares have been adjusted for the two-for-one stock split in September 2004.

Chevron Long-Term Incentive Plan (LTIP) Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and non-stock grants. For a 10-year period after April 2004, no more than 160 million shares may be issued under the LTIP, and no more than 64 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient.

Stock options and stock appreciation rights granted under the LTIP extend for 10 years from grant date. Effective with options granted in June 2002, one-third of each award vests on the first, second and third anniversaries of the date of grant. Prior to this change, options granted by Chevron vested one year after the date of grant. Performance units granted under the LTIP extend for 3 years from grant date and are settled in cash at the end of the period. Settlement amounts are based on achievement of performance targets relative to major competitors over the period, and payments are indexed to the company’s stock price.

Texaco Stock Incentive Plan (Texaco SIP) On the closing of the acquisition of Texaco in October 2001, outstanding options granted under the Texaco SIP were converted to Chevron options. These options retained a provision for being restored, which enables a participant who exercises a stock option to receive new options equal to the number of shares exchanged or who has shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant, and the exercise price is the market value of the common stock on the day the restored option is granted. Apart from the restored options, no further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) On the closing of the acquisition of Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options at a conversion ratio of 1.07 Chevron shares for each Unocal share. These awards retained the same provisions as the original Unocal Plans. Awards issued prior to 2004 generally may be exercised for up to 3 years after termination of employment (depending upon the terms of the individual award agreements), or the original expiration date, whichever is earlier. Awards issued since 2004 generally remain exercisable until the end of the normal option term if termination of employment occurs prior to August 10, 2007. Other awards issued under the Unocal Plans, including restricted stock, stock units, restricted stock units and performance shares, became vested at the acquisition date, and shares or cash were issued to recipients in accordance with change-in-control provisions of the plans.

NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION — Continued

The fair market values of stock options and stock appreciation rights granted in 2005, 2004 and 2003 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2005	2004	2003
Chevron LTIP:			
Expected term in years[1]	**6.4**	7.0	7.0
Volatility[2]	**24.5%**	16.5%	19.3%
Risk-free interest rate based on zero coupon U.S. treasury note	**3.8%**	4.4%	3.1%
Dividend yield	**3.4%**	3.7%	3.5%
Weighted-average fair value per option granted	**$ 11.66**	$ 7.14	$ 5.51
Texaco SIP:			
Expected term in years[1]	**2.1**	2.0	2.0
Volatility[2]	**18.6%**	17.8%	22.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**3.8%**	2.5%	1.7%
Dividend yield	**3.4%**	3.8%	3.9%
Weighted-average fair value per option granted	**$ 6.09**	$ 4.00	$ 4.03
Unocal Plans:[3]			
Expected term in years[1]	**4.2**	–	–
Volatility[2]	**21.6%**	–	–
Risk-free interest rate based on zero coupon U.S. treasury note	**3.9%**	–	–
Dividend yield	**3.4%**	–	–
Weighted-average fair value per option granted	**$21.48**	$ –	$ –

1 Expected term is based on historical exercise and post-vesting cancellation data.
2 Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.
3 Represents options converted at the acquisition date.

A summary of option activity under the LTIP as well as former Texaco and Unocal plans is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2005	54,440	$ 42.89		
Granted	8,718	$ 56.76		
Granted in Unocal acquisition	5,313	$ 35.02		
Exercised*	(13,946)	$ 44.19		
Restored	5,596	$ 58.41		
Forfeited*	(597)	$ 49.19		
Outstanding at December 31, 2005	59,524	$ 45.32	6.1 yrs.	$ 694
Exercisable at December 31, 2005	40,033	$ 42.18	5.2 yrs.	$ 586

* Includes fully-vested Chevron options exchanged for outstanding Unocal options.

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2005, 2004 and 2003 was $258, $129 and $17, respectively.

At adoption of FAS 123R, the company elected to amortize newly issued graded awards on a straight-line basis over the requisite service period. In accordance with FAS 123R implementation guidance issued by the staff of the Securities and Exchange Commission, the company accelerates the vesting period for retirement-eligible employees in accordance with vesting provisions of the company's share-based compensation programs for awards issued after adoption of FAS 123R. As of December 31, 2005, there was $89 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 2.3 years.

At January 1, 2005, the number of LTIP performance units outstanding was equivalent to 2,673,482 shares. During 2005, 709,900 units were granted, 1,012,932 units vested with cash proceeds distributed to recipients, and 24,434 units were forfeited. At December 31, 2005, units outstanding were 2,346,016, and the value of the liability recorded for these instruments was $83. In addition, outstanding stock appreciation rights that were awarded under various LTIP and former Texaco and Unocal programs totaled approximately 800,000 equivalent shares as of December 31, 2005. A liability of $16 was recorded for these awards.

Broad-Based Employee Stock Options In addition to the plans described above, Chevron granted all eligible employees stock options or equivalents in 1998. The options vested after two years, in February 2000, and expire after 10 years, in February 2008. A total of 9,641,000 options were awarded with an exercise price of $38.15625 per share.

The fair value of each option on the date of grant was estimated at $9.54 using the Black-Scholes model for the preceding 10 years. The assumptions used in the model, based on a 10-year average, were: a risk-free interest rate of 7 percent, a dividend yield of 4.2 percent, an expected life of 7 years and a volatility of 24.7 percent.

At January 1, 2005, the number of broad-based employee stock options outstanding was 2,109,504. During 2005, exercises of 397,500 shares and forfeitures of 29,100 shares reduced outstanding options to 1,682,904. As of December 31, 2005, these instruments had an aggregate intrinsic value of $31 and the remaining contractual term of these options was 2.1 years. The total intrinsic value of these options exercised during 2005 and 2004 was $9 and $16, respectively. Exercises in 2003 were insignificant.

NOTE 23.
OTHER CONTINGENCIES AND COMMITMENTS

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. The U.S. federal income tax liabilities have been settled through 1996 for Chevron (formerly ChevronTexaco Corporation) and 1997 for Chevron Global

Energy Inc. (formerly Caltex Corporation), Unocal Corporation (Unocal) and Texaco Inc. (Texaco). California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal and through 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company, and in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees At December 31, 2005, the company and its subsidiaries provided, either directly or indirectly, guarantees of $985 for notes and other contractual obligations of affiliated companies and $294 for third parties, as described by major category below. There are no material amounts being carried as liabilities for the company's obligations under these guarantees.

Of the $985 guarantees provided to affiliates, $806 related to borrowings for capital projects or general corporate purposes. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are Unocal-related guarantees of approximately $230 associated with a construction completion guarantee for the debt financing of Unocal's equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Approximately 95 percent of the $806 guaranteed will expire between 2006 and 2010, with the remaining guarantees expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed. There are no recourse provisions, and no assets are held as collateral for these guarantees. The other guarantees of $179 represent obligations in connection with pricing of power-purchase agreements for certain of the company's cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliates do not perform under the agreements. There are no provisions for recourse to third parties, and no assets are held as collateral for these pricing guarantees.

Of the $294 in guarantees provided to third parties, approximately $150 related to construction loans to host governments of certain of the company's international upstream operations. The remaining guarantees of $144 were provided principally as conditions of sale of the company's interest in certain operations, to provide a source of liquidity to the guaranteed parties and in connection with company marketing programs. No amounts of the company's obligations under these guarantees are recorded as liabilities. About 85 percent of the $294 in guarantees expire by 2010, with the remainder expiring after 2010. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed. Approximately $85 of the guarantees have recourse provisions, which enable the company to recover any payments made under the terms of the guarantees from securities held over the guaranteed parties' assets.

At December 31, 2005, Chevron also had outstanding guarantees for about $190 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell Oil Company (Shell) for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2006 through 2010 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300. Through the end of 2005, the company paid approximately $38 under these indemnities. The company expects to receive additional requests for indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the periods of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims relating to Equilon indemnities must be asserted either as early as February 2007, or no later than February 2009, and claims relating to Motiva must be asserted no later than February 2012. Under the terms of the indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described above are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any applicable incident.

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets of Unocal's 76 Products Company business that existed prior to its sale in 1997. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments by the company; however, the purchaser shares certain costs under this indemnity up to an aggregate cap of $200. Claims relating to these indemnities must be asserted by April 2022. Through the end of 2005,

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS — Continued

approximately $113 had been applied to the cap, which includes payments made by either Unocal or Chevron totaling $80.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying Special Purpose Entities (SPEs). At December 31, 2005, approximately $1,200, representing about 7 percent of Chevron's total current accounts receivables balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2005, was approximately $60. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event that the SPEs experience major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Throughput Agreements, and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements, and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are 2006 — $2,200; 2007 — $1,900; 2008 — $1,800; 2009 — $1,800; 2010 — $500; 2011 and after — $3,800. Total payments under the agreements were approximately $2,100 in 2005, $1,600 in 2004 and $1,400 in 2003.

The most significant take-or-pay agreement calls for the company to purchase approximately 55,000 barrels per day of refined products from an equity affiliate refiner in Thailand. This purchase agreement is in conjunction with the financing of a refinery owned by the affiliate and expires in 2009. The future estimated commitments under this contract are: 2006 — $1,300; 2007 — $1,300; 2008 — $1,300; and 2009 — $1,300. Under the terms of a 2004 agreement, the company exercised its option in 2005 to acquire additional regasification capacity at the Sabine Pass Liquefied Natural Gas Terminal. Payments of $2.5 billion over the 20-year period are expected to commence in 2009.

Minority Interests The company has commitments of approximately $200 related to minority interests in subsidiary companies.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, and land development areas, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had or will have any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemical companies.

Chevron's environmental reserve as of December 31, 2005, was $1,469. Included in this balance were liabilities assumed in connection with the acquisition of Unocal, which relate primarily to sites that had been previously divested or closed by Unocal. The sites included, but were not limited to, former refineries, transportation and distribution facilities and service stations, crude oil and natural gas fields and mining operations, as well as active mining operations.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state and local regulations. No single remediation site at year-end 2005 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

Included in the year-end 2005 balance was $139 related to sites for which Chevron had been identified by the U.S. Environmental Protection Agency or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws as a "potentially responsible party" or otherwise involved in the remediation.

Of the remaining year-end 2005 environmental reserves balance of $1,330, $855 related to approximately 2,250 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining $475 was associated with various sites in the international downstream ($101), upstream ($257), chemicals ($50) and other ($67). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Areas in which the company and its affiliates have significant operations include the United States, Canada, Australia, the United Kingdom, Norway, Denmark, France, the Netherlands, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of the Congo, Angola, Nigeria, Chad, South Africa, the Democratic Republic of the Congo, Indonesia, Bangladesh, the Philippines, Myanmar, Singapore, China, Thailand, Vietnam, Cambodia, Azerbaijan, Kazakhstan, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago, and South Korea. The company's Caspian Pipeline Consortium (CPC) affiliate operates in Russia and Kazakhstan. The company's Tengizchevroil (TCO) affiliate operates in Kazakhstan. Through an affiliate, the company participates in the development of the Baku-Tbilisi-Ceyhan (BTC) pipeline through Azerbaijan, Georgia and Turkey. Also through an affiliate, the company has an interest in the Chad/Cameroon pipeline. The company's Petrolera Ameriven affiliate operates the Hamaca project in Venezuela. The company's CPChem affiliate manufactures and markets a wide range of petrochemicals on a worldwide basis, with manufacturing facilities in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially or wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest, acts of violence or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have at times significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

Equity Redetermination For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. Chevron estimates its maximum possible net before-tax liability at approximately $200. At the same time, a possible maximum net amount that could be owed to Chevron is estimated at about $50. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies Chevron receives claims from and submits claims to customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers, and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

NOTE 24.
ASSET RETIREMENT OBLIGATIONS

The company adopted Financial Accounting Standards Board Statement (FASB) No. 143, *"Accounting for Asset Retirement Obligations,"* (FAS 143), effective January 1, 2003. This accounting standard applies to the fair value of a liability for an asset retirement obligation that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition in certain circumstances: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates. FAS 143 primarily affects the company's accounting for crude oil and natural gas producing assets and differs in several respects from previous accounting under FAS 19, *"Financial Accounting and Reporting by Oil and Gas Producing Companies."*

In the first quarter 2003, the company recorded a net after-tax charge of $200 for the cumulative effect of the adoption of FAS 143, including the company's share of amounts attributable to equity affiliates. The cumulative-effect adjustment also increased the following balance sheet categories: "Properties, plant and equipment," $2,568; "Accrued liabilities," $115; and "Deferred credits and other noncurrent

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NOTE 24. ASSET RETIREMENT OBLIGATIONS — Continued

obligations,” $2,674. “Noncurrent deferred income taxes” decreased by $21.

Upon adoption, no significant asset retirement obligations associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets generally were recognized, as indeterminate settlement dates for the asset retirements prevented estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream and chemical long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

Other than the cumulative-effect net charge, the effect of the new accounting standard on net income in 2003 was not materially different from what the result would have been under FAS 19 accounting. Included in “Depreciation, depletion and amortization” were $52 related to the depreciation of the ARO asset and $132 related to the accretion of the ARO liability.

In March 2005, the FASB issued *FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations — An Interpretation of FASB Statement No. 143,”* (FIN 47), which was effective for the company on December 31, 2005. FIN 47 clarifies that the phrase “conditional asset retirement obligation,” as used in FAS 143, refers to a legal obligation to perform an asset retirement activity for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the company. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. In adopting FIN 47, the company did not recognize any additional liabilities for conditional retirement obligations due to an inability to reasonably estimate the fair value of those obligations because of their indeterminate settlement dates.

The following table indicates the changes to the company’s before-tax asset retirement obligations in 2005, 2004 and 2003:

	2005	2004	2003
Balance at January 1	**$ 2,878**	$ 2,856	$ 2,797*
Liabilities assumed in the Unocal acquisition	**1,216**	–	–
Liabilities incurred	**90**	37	14
Liabilities settled	**(172)**	(426)	(128)
Accretion expense	**187**	93	132
Revisions in estimated cash flows	**105**	318	41
Balance at December 31	**$ 4,304**	$ 2,878	$ 2,856

* Includes the cumulative effect of the accounting change.

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NOTE 25.
EARNINGS PER SHARE

Basic earnings per share (EPS) is based upon net income less preferred stock dividend requirements and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company and the company's share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company's retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (see Note 22, "Stock Options and Other Share-Based Compensation" beginning on page FS-54). The following table sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2005	2004	2003
BASIC EPS CALCULATION			
Income from continuing operations	**$ 14,099**	$ 13,034	$ 7,382
Add: Dividend equivalents paid on stock units	**2**	3	2
Add: Affiliated stock transaction recorded to retained earnings[1]	**–**	–	170
Income from continuing operations available to common stockholders	**$ 14,101**	$ 13,037	$ 7,554
Income from discontinued operations	**–**	294	44
Cumulative effect of changes in accounting principle[2]	**–**	–	(196)
Net income available to common stockholders – Basic	**$ 14,101**	$ 13,331	$ 7,402
Weighted-average number of common shares outstanding[3]	**2,143**	2,114	2,123
Add: Deferred awards held as stock units	**1**	2	2
Total weighted-average number of common shares outstanding	**2,144**	2,116	2,125
Per-Share of Common Stock			
Income from continuing operations available to common stockholders	**$ 6.58**	$ 6.16	$ 3.55
Income from discontinued operations	**–**	0.14	0.02
Cumulative effect of changes in accounting principle	**–**	–	(0.09)
Net income – Basic	**$ 6.58**	$ 6.30	$ 3.48
DILUTED EPS CALCULATION			
Income from continuing operations	**$ 14,099**	$ 13,034	$ 7,382
Add: Dividend equivalents paid on stock units	**2**	3	2
Add: Affiliated stock transaction recorded to retained earnings[1]	**–**	–	170
Add: Dilutive effects of employee stock-based awards	**2**	1	2
Income from continuing operations available to common stockholders	**$ 14,103**	$ 13,038	$ 7,556
Income from discontinued operations	**–**	294	44
Cumulative effect of changes in accounting principle[2]	**–**	–	(196)
Net income available to common stockholders – Diluted	**$ 14,103**	$ 13,332	$ 7,404
Weighted-average number of common shares outstanding[3]	**2,143**	2,114	2,123
Add: Deferred awards held as stock units	**1**	2	2
Add: Dilutive effect of employee stock-based awards	**11**	6	2
Total weighted-average number of common shares outstanding	**2,155**	2,122	2,127
Per-Share of Common Stock			
Income from continuing operations available to common stockholders	**$ 6.54**	$ 6.14	$ 3.55
Income from discontinued operations	**–**	0.14	0.02
Cumulative effect of changes in accounting principle	**–**	–	(0.09)
Net income – Diluted	**$ 6.54**	$ 6.28	$ 3.48

1 2003 amount is the company's share of a capital stock transaction of its Dynegy affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings.
2 Includes a net loss of $200 for the adoption of FAS 143 and a net gain of $4 for the company's share of Dynegy's cumulative effect of adoption of EITF 02-3.
3 Share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

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NOTE 26.
COMMON STOCK SPLIT

On July 28, 2004, the company's Board of Directors approved a two-for-one stock split in the form of a stock dividend to the company's stockholders of record on August 19, 2004, with distribution of shares on September 10, 2004. The total number of authorized common stock shares and associated par value were unchanged by this action. All per-share amounts in the financial statements reflect the stock split for all periods presented. The effect of the common stock split is reflected on the Consolidated Balance Sheet in "Common stock" and "Capital in excess of par value."

NOTE 27.
OTHER FINANCIAL INFORMATION

Net income in 2004 included gains of approximately $1.2 billion relating to the sale of nonstrategic upstream properties.

Other financial information is as follows:

	Year ended December 31		
	2005	2004	2003
Total financing interest and debt costs	**$ 542**	$ 450	$ 549
Less: Capitalized interest	**60**	44	75
Interest and debt expense	**$ 482**	$ 406	$ 474
Research and development expenses	**$ 316**	$ 242	$ 228
Foreign currency effects*	**$ (61)**	$ (81)	$ (404)

* Includes $(2), $(13) and $(96) in 2005, 2004 and 2003, respectively, for the company's share of equity affiliates' foreign currency effects.

The excess of market value over the carrying value of inventories for which the LIFO method is used was $4,846, $3,036 and $2,106 at December 31, 2005, 2004 and 2003, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of $34, $36 and $82 were included in net income for the years 2005, 2004 and 2003, respectively.

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FIVE-YEAR FINANCIAL SUMMARY
Unaudited

Millions of dollars, except per-share amounts	**2005**	2004	2003	2002	2001
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	**$ 193,641**	$ 150,865	$ 119,575	$ 98,340	$ 103,951
Income from equity affiliates and other income	**4,559**	4,435	1,702	197	1,751
TOTAL REVENUES AND OTHER INCOME	**198,200**	155,300	121,277	98,537	105,702
TOTAL COSTS AND OTHER DEDUCTIONS	**173,003**	134,749	108,601	94,437	97,517
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**25,197**	20,551	12,676	4,100	8,185
INCOME TAX EXPENSE	**11,098**	7,517	5,294	2,998	4,310
INCOME FROM CONTINUING OPERATIONS	**14,099**	13,034	7,382	1,102	3,875
INCOME FROM DISCONTINUED OPERATIONS	**–**	294	44	30	56
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**14,099**	13,328	7,426	1,132	3,931
Extraordinary loss, net of tax	**–**	–	–	–	(643)
Cumulative effect of changes in accounting principles	**–**	–	(196)	–	–
NET INCOME	**$ 14,099**	$ 13,328	$ 7,230	$ 1,132	$ 3,288
PER SHARE OF COMMON STOCK[1]					
INCOME FROM CONTINUING OPERATIONS[2]					
– Basic	**$ 6.58**	$ 6.16	$ 3.55	$ 0.52	$ 1.82
– Diluted	**$ 6.54**	$ 6.14	$ 3.55	$ 0.52	$ 1.82
INCOME FROM DISCONTINUED OPERATIONS					
– Basic	**$ –**	$ 0.14	$ 0.02	$ 0.01	$ 0.03
– Diluted	**$ –**	$ 0.14	$ 0.02	$ 0.01	$ 0.03
EXTRAORDINARY ITEM					
– Basic	**$ –**	$ –	$ –	$ –	$ (0.30)
– Diluted	**$ –**	$ –	$ –	$ –	$ (0.30)
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES					
– Basic	**$ –**	$ –	$ (0.09)	$ –	$ –
– Diluted	**$ –**	$ –	$ (0.09)	$ –	$ –
NET INCOME[2]					
– Basic	**$ 6.58**	$ 6.30	$ 3.48	$ 0.53	$ 1.55
– Diluted	**$ 6.54**	$ 6.28	$ 3.48	$ 0.53	$ 1.55
CASH DIVIDENDS PER SHARE	**$ 1.75**	$ 1.53	$ 1.43	$ 1.40	$ 1.33
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	**$ 34,336**	$ 28,503	$ 19,426	$ 17,776	$ 18,327
Noncurrent assets	**91,497**	64,705	62,044	59,583	59,245
TOTAL ASSETS	**125,833**	93,208	81,470	77,359	77,572
Short-term debt	**739**	816	1,703	5,358	8,429
Other current liabilities	**24,272**	17,979	14,408	14,518	12,225
Long-term debt and capital lease obligations	**12,131**	10,456	10,894	10,911	8,989
Other noncurrent liabilities	**26,015**	18,727	18,170	14,968	13,971
TOTAL LIABILITIES	**63,157**	47,978	45,175	45,755	43,614
STOCKHOLDERS' EQUITY	**$ 62,676**	$ 45,230	$ 36,295	$ 31,604	$ 33,958

1 Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

2 The amount in 2003 includes a benefit of $0.08 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

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SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES

Unaudited

In accordance with Statement of FAS 69, *"Disclosures About Oil and Gas Producing Activities,"* this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved reserve quantities; standardized measure of estimated discounted future net cash flows related to proved reserves; and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Republic of the Congo and the Democratic Republic of the Congo. The Asia-Pacific geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the

TABLE I – COSTS INCURRED IN EXPLORATION, PROPERTY ACQUISITIONS AND DEVELOPMENT[1]

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
YEAR ENDED DEC. 31, 2005												
Exploration												
Wells	**$ –**	**$ 452**	**$ 24**	**$ 476**	**$ 105**	**$ 38**	**$ 9**	**$ 201**	**$ 353**	**$ 829**	**$ –**	**$ –**
Geological and geophysical	**–**	**67**	**–**	**67**	**96**	**28**	**10**	**68**	**202**	**269**	**–**	**–**
Rentals and other	**–**	**93**	**8**	**101**	**24**	**58**	**12**	**72**	**166**	**267**	**–**	**–**
Total exploration	**–**	**612**	**32**	**644**	**225**	**124**	**31**	**341**	**721**	**1,365**	**–**	**–**
Property acquisitions												
Proved – Unocal[2,3]	**–**	**1,608**	**2,388**	**3,996**	**30**	**6,609**	**637**	**1,790**	**9,066**	**13,062**	**–**	**–**
Proved – Other[2]	**–**	**6**	**10**	**16**	**2**	**2**	**–**	**12**	**16**	**32**	**–**	**–**
Unproved – Unocal	**–**	**819**	**295**	**1,114**	**11**	**2,209**	**821**	**38**	**3,079**	**4,193**	**–**	**–**
Unproved – Other	**–**	**17**	**6**	**23**	**67**	**–**	**–**	**28**	**95**	**118**	**–**	**–**
Total property acquisitions	**–**	**2,450**	**2,699**	**5,149**	**110**	**8,820**	**1,458**	**1,868**	**12,256**	**17,405**	**–**	**–**
Development[4]	**494**	**639**	**596**	**1,729**	**1,871**	**1,026**	**325**	**713**	**3,935**	**5,664**	**767**	**43**
ARO asset	**13**	**41**	**5**	**59**	**21**	**62**	**57**	**13**	**153**	**212**	**–**	**–**
TOTAL COSTS INCURRED	**$ 507**	**$ 3,742**	**$ 3,332**	**$ 7,581**	**$ 2,227**	**$ 10,032**	**$ 1,871**	**$ 2,935**	**$ 17,065**	**$ 24,646**	**$ 767**	**$ 43**
YEAR ENDED DEC. 31, 2004												
Exploration												
Wells	$ –	$ 388	$ –	$ 388	$ 116	$ 25	$ 2	$ 127	$ 270	$ 658	$ –	$ –
Geological and geophysical	–	47	2	49	103	10	12	46	171	220	–	–
Rentals and other	–	43	3	46	52	47	1	53	153	199	–	–
Total exploration	–	478	5	483	271	82	15	226	594	1,077	–	–
Property acquisitions												
Proved[2]	–	6	1	7	111	16	–	4	131	138	–	–
Unproved	–	29	–	29	82	–	–	5	87	116	–	–
Total property acquisitions	–	35	1	36	193	16	–	9	218	254	–	–
Development[4]	412	457	372	1,241	1,047	567	245	542	2,401	3,642	896	208
ARO asset	1	9	3	13	10	53	158	85	306	319	–	–
TOTAL COSTS INCURRED	$ 413	$ 979	$ 381	$ 1,773	$ 1,521	$ 718	$ 418	$ 862	$ 3,519	$ 5,292	$ 896	$ 208
YEAR ENDED DEC. 31, 2003												
Exploration												
Wells	$ –	$ 415	$ 9	$ 424	$ 116	$ 43	$ 2	$ 72	$ 233	$ 657	$ –	$ –
Geological and geophysical	–	16	23	39	75	9	5	30	119	158	–	–
Rentals and other	–	64	(20)	44	12	58	–	46	116	160	–	–
Total exploration	–	495	12	507	203	110	7	148	468	975	–	–
Property acquisitions												
Proved[2]	–	15	3	18	–	20	–	7	27	45	–	–
Unproved	–	30	3	33	51	6	–	14	71	104	–	–
Total property acquisitions	–	45	6	51	51	26	–	21	98	149	–	–
Development	264	434	350	1,048	974	605	363	461	2,403	3,451	551	199
TOTAL COSTS INCURRED	$ 264	$ 974	$ 368	$ 1,606	$ 1,228	$ 741	$ 370	$ 630	$ 2,969	$ 4,575	$ 551	$ 199

1 Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 24, "Asset Retirement Obligations," beginning on page FS-59.
2 Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.
3 Included in proved property acquisitions for Unocal are $845 of ARO assets, composed of: Gulf of Mexico $115; Other U.S. $271; Africa $9; Asia-Pacific $366; Indonesia $25; Other International $59.
4 Includes $160 and $63 costs incurred prior to assignment of proved reserves in 2005 and 2004, respectively.

Supplemental Information on Oil and Gas Producing Activities — Continued

Partitioned Neutral Zone between Kuwait and Saudi Arabia, Papua New Guinea (sold in 2003), the Philippines, and Thailand. The international "Other" geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, Germany, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and other countries. Amounts shown for affiliated companies are Chevron's 50 percent equity share of TCO, an exploration and production partnership operating in the Republic of Kazakhstan, and a 30 percent equity share of Hamaca, an exploration and production partnership operating in Venezuela.

Amounts in the tables exclude the cumulative effect adjustment for the adoption of FAS 143, *"Asset Retirement Obligations,"* discussed in Note 24, beginning on page FS-59.

TABLE II – CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES[1]

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
AT DEC. 31, 2005												
Unproved properties	$ 769	$ 1,077	$ 397	$ 2,243	$ 407	$ 2,287	$ 645	$ 983	$ 4,322	$ 6,565	$ 108	$ –
Proved properties and related producing assets	9,530	17,871	11,103	38,504	8,169	14,308	4,441	9,259	36,177	74,681	2,259	1,212
Support equipment	204	193	230	627	715	426	3,124	356	4,621	5,248	549	–
Deferred exploratory wells	–	284	5	289	245	154	173	248	820	1,109	–	–
Other uncompleted projects	149	782	209	1,140	2,878	790	427	946	5,041	6,181	2,332	–
ARO asset[2]	16	412	364	792	235	620	265	368	1,488	2,280	5	1
GROSS CAP. COSTS	10,668	20,619	12,308	43,595	12,649	18,585	9,075	12,160	52,469	96,064	5,253	1,213
Unproved properties valuation	736	90	22	848	162	69	–	318	549	1,397	17	–
Proved producing properties – Depreciation and depletion	6,813	13,866	5,943	26,622	4,132	3,915	2,895	5,533	16,475	43,097	455	90
Support equipment depreciation	140	119	149	408	317	88	1,824	222	2,451	2,859	213	–
ARO asset depreciation[2]	5	201	106	312	134	101	66	187	488	800	5	–
Accumulated provisions	7,694	14,276	6,220	28,190	4,745	4,173	4,785	6,260	19,963	48,153	690	90
NET CAPITALIZED COSTS	$ 2,974	$ 6,343	$ 6,088	$ 15,405	$ 7,904	$ 14,412	$ 4,290	$ 5,900	$ 32,506	$ 47,911	$ 4,563	$ 1,123
AT DEC. 31, 2004												
Unproved properties	$ 769	$ 380	$ 109	$ 1,258	$ 322	$ 211	$ –	$ 970	$ 1,503	$ 2,761	$ 108	$ –
Proved properties and related producing assets	9,170	16,610	8,660	34,440	7,188	7,485	3,643	8,961	27,277	61,717	2,163	963
Support equipment	211	175	208	594	513	127	3,030	361	4,031	4,625	496	–
Deferred exploratory wells	–	225	–	225	213	81	–	152	446	671	–	–
Other uncompleted projects	91	400	169	660	2,050	605	351	391	3,397	4,057	1,749	149
ARO asset[2]	28	204	70	302	206	113	181	292	792	1,094	20	–
GROSS CAP. COSTS	10,269	17,994	9,216	37,479	10,492	8,622	7,205	11,127	37,446	74,925	4,536	1,112
Unproved properties valuation	734	111	27	872	118	67	–	294	479	1,351	15	–
Proved producing properties – Depreciation and depletion	6,694	13,562	5,617	25,873	3,753	3,122	2,396	4,933	14,204	40,077	423	43
Support equipment depreciation	148	107	139	394	268	60	1,802	206	2,336	2,730	190	–
ARO asset depreciation[2]	24	174	64	262	128	49	36	148	361	623	5	–
Accumulated provisions	7,600	13,954	5,847	27,401	4,267	3,298	4,234	5,581	17,380	44,781	633	43
NET CAPITALIZED COSTS	$ 2,669	$ 4,040	$ 3,369	$ 10,078	$ 6,225	$ 5,324	$ 2,971	$ 5,546	$ 20,066	$ 30,144	$ 3,903	$ 1,069

1 Includes assets held for sale.
2 See Note 24, "Asset Retirement Obligations," beginning on page FS-59.

TABLE II – CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES[1] — Continued

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
AT DEC. 31, 2003[2]												
Unproved properties	$ 769	$ 416	$ 131	$ 1,316	$ 290	$ 214	$ –	$ 1,048	$ 1,552	$ 2,868	$ 108	$ –
Proved properties and related producing assets	8,785	18,069	10,749	37,603	6,474	6,288	3,097	10,469	26,328	63,931	2,091	356
Support equipment	200	200	277	677	519	100	3,016	374	4,009	4,686	425	–
Deferred exploratory wells	–	126	1	127	233	67	2	120	422	549	–	–
Other uncompleted projects	76	280	152	508	1,894	1,502	715	334	4,445	4,953	1,011	661
ARO asset[3]	25	227	83	335	207	60	23	236	526	861	20	1
GROSS CAP. COSTS	9,855	19,318	11,393	40,566	9,617	8,231	6,853	12,581	37,282	77,848	3,655	1,018
Unproved properties valuation	731	138	43	912	101	59	1	310	471	1,383	12	–
Proved producing properties – Depreciation and depletion	6,473	14,450	6,894	27,817	3,656	2,793	2,022	6,015	14,486	42,303	354	24
Future equipment depreciation	141	133	180	454	237	68	1,784	200	2,289	2,743	160	–
ARO asset depreciation[3]	23	186	79	288	133	36	19	148	336	624	4	–
Accumulated provisions	7,368	14,907	7,196	29,471	4,127	2,956	3,826	6,673	17,582	47,053	530	24
NET CAPITALIZED COSTS	$ 2,487	$ 4,411	$ 4,197	$ 11,095	$ 5,490	$ 5,275	$ 3,027	$ 5,908	$ 19,700	$ 30,795	$ 3,125	$ 994

1 Includes assets held for sale.
2 2003 reclassified to conform to 2005 presentation.
3 See Note 24, "Asset Retirement Obligations," beginning on page FS-59.

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TABLE III – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES[1]

The company's results of operations from oil and gas producing activities for the years 2005, 2004 and 2003 are shown in the following table. Net income from exploration and production activities as reported on page FS-41 reflects income taxes computed on an effective rate basis.

In accordance with FAS 69, income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page FS-41.

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
YEAR ENDED DEC. 31, 2005												
Revenues from net production												
Sales	**$ 337**	**$ 1,576**	**$ 3,174**	**$ 5,087**	**$ 2,142**	**$ 2,941**	**$ 539**	**$ 2,668**	**$ 8,290**	**$ 13,377**	**$ 2,307**	**$ 666**
Transfers	**3,497**	**2,127**	**1,395**	**7,019**	**3,615**	**3,179**	**1,986**	**2,607**	**11,387**	**18,406**	**–**	**–**
Total	**3,834**	**3,703**	**4,569**	**12,106**	**5,757**	**6,120**	**2,525**	**5,275**	**19,677**	**31,783**	**2,307**	**666**
Production expenses excluding taxes	**(916)**	**(638)**	**(777)**	**(2,331)**	**(558)**	**(570)**	**(660)**	**(596)**	**(2,384)**	**(4,715)**	**(152)**	**(82)**
Taxes other than on income	**(65)**	**(41)**	**(384)**	**(490)**	**(48)**	**(189)**	**(1)**	**(195)**	**(433)**	**(923)**	**(27)**	**–**
Proved producing properties:												
Depreciation and depletion	**(253)**	**(936)**	**(520)**	**(1,709)**	**(414)**	**(852)**	**(550)**	**(672)**	**(2,488)**	**(4,197)**	**(83)**	**(46)**
Accretion expense[2]	**(13)**	**(35)**	**(46)**	**(94)**	**(22)**	**(20)**	**(15)**	**(25)**	**(82)**	**(176)**	**(1)**	**–**
Exploration expenses	**–**	**(307)**	**(13)**	**(320)**	**(117)**	**(90)**	**(26)**	**(190)**	**(423)**	**(743)**	**–**	**–**
Unproved properties valuation	**(3)**	**(32)**	**(4)**	**(39)**	**(50)**	**(8)**	**–**	**(24)**	**(82)**	**(121)**	**–**	**–**
Other income (expense)[3]	**2**	**(354)**	**(140)**	**(492)**	**(243)**	**(182)**	**182**	**280**	**37**	**(455)**	**(9)**	**8**
Results before income taxes	**2,586**	**1,360**	**2,685**	**6,631**	**4,305**	**4,209**	**1,455**	**3,853**	**13,822**	**20,453**	**2,035**	**546**
Income tax expense	**(913)**	**(482)**	**(953)**	**(2,348)**	**(3,430)**	**(2,264)**	**(644)**	**(1,938)**	**(8,276)**	**(10,624)**	**(611)**	**(186)**
RESULTS OF PRODUCING OPERATIONS	**$ 1,673**	**$ 878**	**$ 1,732**	**$ 4,283**	**$ 875**	**$ 1,945**	**$ 811**	**$ 1,915**	**$ 5,546**	**$ 9,829**	**$ 1,424**	**$ 360**
YEAR ENDED DEC. 31, 2004												
Revenues from net production												
Sales	$ 251	$ 1,925	$ 2,163	$ 4,339	$ 1,321	$ 1,191	$ 256	$ 2,481	$ 5,249	$ 9,588	$ 1,619	$ 205
Transfers	2,651	1,768	1,224	5,643	2,645	2,265	1,613	1,903	8,426	14,069	–	–
Total	2,902	3,693	3,387	9,982	3,966	3,456	1,869	4,384	13,675	23,657	1,619	205
Production expenses excluding taxes	(710)	(547)	(697)	(1,954)	(574)	(431)	(591)	(544)	(2,140)	(4,094)	(143)	(53)
Taxes other than on income	(57)	(45)	(321)	(423)	(24)	(138)	(1)	(134)	(297)	(720)	(26)	–
Proved producing properties:												
Depreciation and depletion	(232)	(774)	(384)	(1,390)	(367)	(401)	(393)	(798)	(1,959)	(3,349)	(104)	(4)
Accretion expense[2]	(12)	(25)	(19)	(56)	(22)	(8)	(13)	11	(32)	(88)	(2)	–
Exploration expenses	–	(227)	(6)	(233)	(235)	(69)	(17)	(144)	(465)	(698)	–	–
Unproved properties valuation	(3)	(29)	(4)	(36)	(23)	(8)	–	(25)	(56)	(92)	–	–
Other income (expense)[3]	14	24	474	512	49	10	12	1,028	1,099	1,611	(7)	(58)
Results before income taxes	1,902	2,070	2,430	6,402	2,770	2,411	866	3,778	9,825	16,227	1,337	90
Income tax expense	(703)	(765)	(898)	(2,366)	(2,036)	(1,395)	(371)	(1,759)	(5,561)	(7,927)	(401)	–
RESULTS OF PRODUCING OPERATIONS	$ 1,199	$ 1,305	$ 1,532	$ 4,036	$ 734	$ 1,016	$ 495	$ 2,019	$ 4,264	$ 8,300	$ 936	$ 90

1 The value of owned production consumed on lease as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

2 Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," beginning on page FS-59.

3 Includes net sulfur income, foreign currency transaction gains and losses, certain significant impairment write-downs in 2004 and 2003, miscellaneous expenses, etc. Also includes net income from related oil and gas activities that do not have oil and gas reserves attributed to them (for example, net income from technical and operating service agreements) and items identified in the Management's Discussion and Analysis on pages FS-7 through FS-11. Does not include results for LNG-related activities.

TABLE III – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES[1] – Continued

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
YEAR ENDED DEC. 31, 2003[2]												
Revenues from net production												
Sales	$ 261	$ 2,197	$ 2,049	$ 4,507	$ 1,339	$ 1,442	$ 55	$ 2,556	$ 5,392	$ 9,899	$ 1,116	$ 104
Transfers	2,085	1,740	1,096	4,921	1,835	1,738	1,566	1,356	6,495	11,416	–	–
Total	2,346	3,937	3,145	9,428	3,174	3,180	1,621	3,912	11,887	21,315	1,116	104
Production expenses excluding taxes	(631)	(578)	(750)	(1,959)	(505)	(331)	(616)	(669)	(2,121)	(4,080)	(117)	(20)
Taxes other than on income	(28)	(48)	(280)	(356)	(22)	(126)	(1)	(100)	(249)	(605)	(29)	–
Proved producing properties: Depreciation and depletion	(224)	(878)	(430)	(1,532)	(327)	(398)	(314)	(846)	(1,885)	(3,417)	(97)	(4)
Accretion Expense[3]	(12)	(37)	(20)	(69)	(20)	(5)	(8)	(26)	(59)	(128)	(2)	–
Exploration expenses	(2)	(168)	(23)	(193)	(123)	(130)	(8)	(117)	(378)	(571)	–	–
Unproved properties valuation	–	(16)	(4)	(20)	(20)	(9)	–	(41)	(70)	(90)	–	–
Other (expense) income[4]	(18)	(104)	(51)	(173)	(173)	(342)	2	(175)	(688)	(861)	(4)	(35)
Results before income taxes	1,431	2,108	1,587	5,126	1,984	1,839	676	1,938	6,437	11,563	867	45
Income tax expense	(528)	(777)	(585)	(1,890)	(1,410)	(1,158)	(289)	(831)	(3,688)	(5,578)	(260)	–
RESULTS OF PRODUCING OPERATIONS	$ 903	$ 1,331	$ 1,002	$ 3,236	$ 574	$ 681	$ 387	$ 1,107	$ 2,749	$ 5,985	$ 607	$ 45

1 The value of owned production consumed on lease as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

2 2003 includes certain reclassifications to conform to 2005 presentation.

3 Represents accretion of ARO liability. Refer to Note 24, "Assets Retirement Obligation," beginning on page F5-59.

4 Includes net sulfur income, foreign currency transaction gains and losses, certain significant impairment write-downs, miscellaneous expenses, etc. Also includes net income from related oil and gas activities that do not have oil and gas reserves attributed to them (for example, net income from technical and operating service agreements) and items identified in the Management's Discussion and Analysis on pages FS-7 through FS-11.

Supplemental Information on Oil and Gas Producing Activities — Continued

TABLE IV – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES – UNIT PRICES AND COSTS[1,2]

	Consolidated Companies										Affiliated Companies	
	United States				International							
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
YEAR ENDED DEC. 31, 2005												
Average sales prices												
Liquids, per barrel	**$45.24**	**$48.80**	**$48.29**	**$46.97**	**$50.54**	**$45.88**	**$44.40**	**$48.61**	**$47.83**	**$47.56**	**$45.59**	**$45.89**
Natural gas, per thousand cubic feet	**6.94**	**8.43**	**6.90**	**7.43**	**0.04**	**3.59**	**5.74**	**3.31**	**3.48**	**5.18**	**0.61**	**0.26**
Average production costs, per barrel	**10.74**	**8.55**	**7.57**	**8.88**	**4.72**	**3.38**	**11.28**	**4.32**	**4.93**	**6.32**	**2.45**	**5.53**
YEAR ENDED DEC. 31, 2004												
Average sales prices												
Liquids, per barrel	$33.43	$34.69	$34.61	$34.12	$34.85	$31.34	$31.12	$34.58	$33.33	$33.60	$30.23	$23.32
Natural gas, per thousand cubic feet	5.18	6.08	5.07	5.51	0.04	3.41	3.88	2.68	2.90	4.27	0.65	0.27
Average production costs, per barrel	8.14	5.26	6.65	6.60	4.89	3.50	9.69	3.47	4.67	5.43	2.31	6.10
YEAR ENDED DEC. 31, 2003												
Average sales prices												
Liquids, per barrel	$25.77	$27.89	$26.48	$26.66	$28.54	$24.66	$25.10	$27.56	$26.70	$26.69	$22.07	$17.06
Natural gas, per thousand cubic feet	5.04	5.56	4.51	5.01	0.04	3.64	2.26	2.58	2.87	4.08	0.68	0.33
Average production costs, per barrel[3]	7.01	4.47	6.40	5.82	4.42	2.49	9.30	3.99	4.41	4.99	2.04	3.24

1 The value of owned production consumed on lease as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
2 Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.
3 Conformed to 2005 presentation to exclude taxes.

TABLE V – RESERVE QUANTITY INFORMATION

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting – three deemed commercial and three noncommercial. Within the commercial classification are proved reserves and two categories of unproved, probable and possible. The noncommercial categories are also referred to as contingent resources. For reserves estimates to be classified as proved, they must meet all SEC and company standards.

Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

Proved reserves are classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

Due to the inherent uncertainties and the limited nature of reservoir data, estimates of underground reserves are subject to change as additional information becomes available.

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the executive vice president responsible for the company's worldwide exploration and production activities. All of the RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC coordinates its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

The RAC has the following primary responsibilities: provide independent reviews of the business units' recommended reserve changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual*, which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

During the year, the RAC is represented in meetings with each of the company's upstream business units to review and discuss reserve changes recommended by the various asset teams. Major changes are also reviewed with the company's Strategy and Planning Committee and the Executive Committee, whose members include the Chief Executive Officer and the Chief Financial Officer. The company's annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

RAC subteams also conduct in-depth reviews during the year of many of the fields that have the largest proved reserves quantities. These reviews include an examination of the proved reserve records and documentation of their alignment with the *Corporate Reserves Manual.*

Reserve Quantities At December 31, 2005, oil-equivalent reserves for the company's consolidated operations totaled 9.0 billion barrels. (Refer to page E-11 for the definition of oil-equivalent reserves.) Nearly 22 percent of the total was in the United States. Year-end reserves of approximately 1.4 billion barrels were associated with the properties obtained as part of the August 2005 acquisition of Unocal. For the company's interests in equity affiliates, oil-equivalent reserves totaled 2.9 billion barrels, 84 percent of which was associated with the company's 50 percent ownership in TCO.

Aside from the TCO operations, no single property accounted for more than 5 percent of the company's total oil-equivalent proved reserves. Fewer than 20 individual properties each contained between 1 percent and 5 percent of the total. In the aggregate, these properties accounted for 35 percent of the company's total proved oil-equivalent reserves. These other properties were geographically dispersed, located in the United States, South America, Europe, West Africa, the Middle East and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2005 were 2.6 billion barrels. Of this amount, 39 percent, 21 percent and 40 percent were located in California, the Gulf of Mexico and other U.S. areas, respectively.

In California, liquids reserves represented 95 percent of the total, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company's heavy-oil fields in California employ a continuous steamflooding process.

In the Gulf of Mexico region, liquids represented approximately 63 percent of total oil-equivalent reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Costs include investments in wells, production platforms and other facilities, such as gathering lines and storage facilities.

In other U.S. areas, the reserves were split about equally between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including water-flood and CO_2 injection.

The pattern of net reserve changes shown in the following tables for the three years ending December 31, 2005, is not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, matters that are outside the company's control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties and civil unrest.

The company's estimated net proved underground oil and natural gas reserves and changes thereto for the years 2003, 2004 and 2005 are shown in the tables on pages FS-72 and FS-74.

Supplemental Information on Oil and Gas Producing Activities — Continued

TABLE V – RESERVE QUANTITY INFORMATION – Continued

NET PROVED RESERVES OF CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS

	Consolidated Companies											
	United States				International						Affiliated Companies	
Millions of barrels	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
RESERVES AT JAN. 1, 2003	1,102	389	626	2,117	1,976	815	889	697	4,377	6,494	1,689	485
Changes attributable to:												
Revisions	(4)	(5)	–	(9)	(1)	105	(57)	19	66	57	200	–
Improved recovery	38	8	7	53	36	–	54	52	142	195	–	–
Extensions and discoveries	2	113	9	124	24	15	3	26	68	192	–	–
Purchases[1]	–	1	–	1	–	–	–	12	12	13	–	–
Sales[2]	(3)	(2)	(18)	(23)	–	(42)	–	(1)	(43)	(66)	–	–
Production	(84)	(69)	(52)	(205)	(112)	(97)	(82)	(109)	(400)	(605)	(49)	(6)
RESERVES AT DEC. 31, 2003	1,051	435	572	2,058	1,923	796	807	696	4,222	6,280	1,840	479
Changes attributable to:												
Revisions	13	(68)	(2)	(57)	(70)	(43)	(36)	(12)	(161)	(218)	206	(2)
Improved recovery	28	–	6	34	34	–	6	–	40	74	–	–
Extensions and discoveries	–	8	6	14	77	9	–	17	103	117	–	–
Purchases[1]	–	2	–	2	–	–	–	–	–	2	–	–
Sales[2]	–	(27)	(103)	(130)	(16)	–	–	(33)	(49)	(179)	–	–
Production	(81)	(56)	(47)	(184)	(115)	(86)	(79)	(101)	(381)	(565)	(52)	(9)
RESERVES AT DEC. 31, 2004	1,011	294	432	1,737	1,833	676	698	567	3,774	5,511	1,994	468
Changes attributable to:												
Revisions	**(23)**	**(6)**	**(11)**	**(40)**	**(29)**	**(56)**	**(108)**	**(6)**	**(199)**	**(239)**	**(5)**	**(19)**
Improved recovery	**57**	**–**	**4**	**61**	**67**	**4**	**42**	**29**	**142**	**203**	**–**	**–**
Extensions and discoveries	**–**	**37**	**7**	**44**	**53**	**21**	**1**	**65**	**140**	**184**	**–**	**–**
Purchases[1]	**–**	**49**	**147**	**196**	**4**	**287**	**20**	**65**	**376**	**572**	**–**	**–**
Sales[2]	**(1)**	**–**	**(1)**	**(2)**	**–**	**–**	**–**	**(58)**	**(58)**	**(60)**	**–**	**–**
Production	**(79)**	**(41)**	**(45)**	**(165)**	**(114)**	**(103)**	**(74)**	**(89)**	**(380)**	**(545)**	**(50)**	**(14)**
RESERVES AT DEC. 31, 2005[3]	**965**	**333**	**533**	**1,831**	**1,814**	**829**	**579**	**573**	**3,795**	**5,626**	**1,939**	**435**
DEVELOPED RESERVES[4]												
At Jan. 1, 2003	867	335	564	1,766	1,042	642	655	529	2,868	4,634	99	63
At Dec. 31, 2003	832	304	515	1,651	1,059	641	588	522	2,810	4,461	1,304	140
At Dec. 31, 2004	832	192	386	1,410	990	543	490	469	2,492	3,902	1,510	188
At Dec. 31, 2005	**809**	**177**	**474**	**1,460**	**945**	**534**	**439**	**416**	**2,334**	**3,794**	**1,611**	**196**

1 Includes reserves acquired through property exchanges.
2 Includes reserves disposed of through property exchanges.
3 Net reserve changes (excluding production) in 2005 consist of 490 million barrels of developed reserves and (170) million barrels of undeveloped reserves for consolidated companies and (178) million barrels of developed reserves and (154) million barrels of undeveloped reserves for affiliated companies.
4 During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 11 percent and 20 percent for consolidated companies and affiliated companies, respectively.

INFORMATION ON CANADIAN OIL SANDS NET PROVED RESERVES NOT INCLUDED ABOVE:

In addition to conventional liquids and natural gas proved reserves, Chevron has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, Chevron views these reserves and their development as an integral part of total upstream operations. However, SEC regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 146 million barrels as of December 31, 2005. The oil sands reserves are not considered in the standardized measure of discounted future net cash flows for conventional oil and gas reserves, which is found on page FS-76.

Noteworthy amounts in the categories of proved-reserve changes for 2003 through 2005 in the table above are discussed below:

Revisions In 2003, net revisions increased reserves by 57 million barrels for consolidated companies. Whereas net U.S. reserve changes were minimal, international volumes increased 66 million barrels. The largest increase was in Kazakhstan in the Asia-Pacific area based on an updated geologic model for one field. The 200-million-barrel increase for TCO was based on an updated model of reservoir and well performance.

In 2004, net revisions decreased reserves 218 million barrels for consolidated companies and increased reserves for affiliates by 204 million barrels. For consolidated companies, the decrease was composed of 161 million barrels for international areas and 57 million barrels for the United States. The largest downward revision internationally was 70 million barrels in Africa. One field in Angola accounted for the majority of the net decline as changes were made to oil-in-place estimates based on reservoir performance data. One field in the Asia-Pacific area essentially accounted for the 43-million-barrel downward revision for that region. The revision was associated with reduced well performance. Part of the 36-million-barrel net downward revision for Indonesia was associated with the effect of higher year-end prices on the calculation of reserves for cost-oil recovery under a production-sharing contract. In the United States, the 68-million-barrel net downward revision in the Gulf of Mexico area was across several fields and based mainly on reservoir analyses and assessments of well performance. For affiliated companies, the 206-million-barrel increase for TCO was based on an updated assessment of reservoir performance for the Tengiz Field. Partially offsetting this increase was a downward effect of higher year-end prices on the variable royalty-rate calculation. Downward revisions also occurred in other geographic areas because of the effect of higher year-end prices on various production-sharing terms and variable royalty calculations.

In 2005, net revisions reduced reserves by 239 million and 24 million barrels for worldwide consolidated companies and equity affiliates, respectively. For consolidated companies, the net decrease was 199 million barrels in the international areas and 40 million barrels in the United States. The largest downward net revisions internationally were 108 million barrels in Indonesia and 53 million barrels in Kazakhstan, due primarily to the effect of higher year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. In the United States, the 40-million-barrel reduction was across many fields in each of the geographic sections. Most of the downward revision for affiliated companies was a 19-million-barrel reduction in Hamaca, attributable to revised government royalty provisions. For TCO, the downward effect of higher year-end prices was partially offset by increased reservoir performance.

Improved Recovery In 2005, improved recovery increased liquids volumes worldwide by 203 million barrels for consolidated companies. International areas accounted for 142 million barrels of the increase. Indonesia added 42 million barrels due to improved performance. Reserve additions of 67 million barrels in Africa occurred primarily in Angola and resulted from infill drilling, wells workovers and secondary recovery from gas injection. Additions of 29 million barrels in the "Other" international area were mainly attributable to improved waterflood performance offshore eastern Canada. An increase of 61 million barrels occurred in the United States, primarily in California due to improved performance on a large heavy oil field under thermal recovery.

Extensions and Discoveries In 2005, extensions and discoveries increased liquids volumes worldwide by 184 million barrels for consolidated companies. The largest increase was 49 million barrels in Nigeria, reflecting new development drilling, including in the Agbami Field, among others. New field developments in Brazil contributed another 41 million barrels of discoveries. In the United States, the 44-million-barrel addition was associated mainly with the initial booking of reserves for the Blind Faith Field in the deepwater Gulf of Mexico.

Purchases In 2005, the acquisition of 572 million barrels of liquids related solely to the acquisition of Unocal in August. About three-fourths of the 376 million barrels acquired in the international areas were represented by volumes in Azerbaijan and Thailand. Most volumes acquired in the United States were in Texas and Alaska.

Sales In 2004, sales of liquids volumes reduced reserves of consolidated companies by 179 million barrels. Sales totaled 130 million barrels in the United States and 33 million barrels in the "Other" international region. Sales in the "Other" region of the United States totaled 103 millions barrels, with two fields accounting for approximately one- half of the volume. The 27 million barrels sold in the Gulf of Mexico reflect the sale of a number of Shelf properties. The "Other" international sales include the disposal of western Canada properties and several fields in the United Kingdom. All the sales were associated with the company's program to dispose of assets deemed nonstrategic to the portfolio of producing properties.

In 2005, sales of 58 million barrels in the "Other" international area related to the disposition of the former Unocal operations onshore in Canada.

Supplemental Information on Oil and Gas Producing Activities – Continued

TABLE V – RESERVE QUANTITY INFORMATION – Continued

NET PROVED RESERVES OF NATURAL GAS

	Consolidated Companies										Affiliated Companies	
	United States				International							
Billions of cubic feet	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
RESERVES AT JAN. 1, 2003	325	2,052	4,040	6,417	2,298	4,646	518	2,924	10,386	16,803	2,489	43
Changes attributable to:												
Revisions	25	(106)	(525)	(606)	342	879	36	976	2,233	1,627	109	70
Improved recovery	15	7	1	23	17	–	15	35	67	90	–	–
Extensions and discoveries	–	270	118	388	3	76	12	47	138	526	–	–
Purchases[1]	–	8	–	8	–	7	–	55	62	70	–	–
Sales[2]	(1)	(12)	(51)	(64)	–	–	–	(6)	(6)	(70)	–	–
Production	(41)	(378)	(394)	(813)	(18)	(235)	(61)	(366)	(680)	(1,493)	(72)	(1)
RESERVES AT DEC. 31, 2003	323	1,841	3,189	5,353	2,642	5,373	520	3,665	12,200	17,553	2,526	112
Changes attributable to:												
Revisions	27	(391)	(316)	(680)	346	236	21	325	928	248	963	23
Improved recovery	2	–	1	3	7	–	13	–	20	23	–	–
Extensions and discoveries	1	54	89	144	16	39	2	13	70	214	–	–
Purchases[1]	–	5	–	5	–	4	–	–	4	9	–	–
Sales[2]	–	(147)	(289)	(436)	–	–	–	(111)	(111)	(547)	–	–
Production	(39)	(298)	(348)	(685)	(32)	(247)	(54)	(354)	(687)	(1,372)	(76)	(1)
RESERVES AT DEC. 31, 2004	314	1,064	2,326	3,704	2,979	5,405	502	3,538	12,424	16,128	3,413	134
Changes attributable to:												
Revisions	**21**	**(15)**	**(15)**	**(9)**	**211**	**(428)**	**(31)**	**243**	**(5)**	**(14)**	**(547)**	**49**
Improved recovery	**8**	**–**	**–**	**8**	**13**	**–**	**–**	**31**	**44**	**52**	**–**	**–**
Extensions and discoveries	**–**	**68**	**99**	**167**	**25**	**118**	**5**	**55**	**203**	**370**	**–**	**–**
Purchases[1]	**–**	**269**	**899**	**1,168**	**5**	**3,962**	**247**	**274**	**4,488**	**5,656**	**–**	**–**
Sales[2]	**–**	**–**	**(6)**	**(6)**	**–**	**–**	**–**	**(248)**	**(248)**	**(254)**	**–**	**–**
Production	**(39)**	**(215)**	**(350)**	**(604)**	**(42)**	**(434)**	**(77)**	**(315)**	**(868)**	**(1,472)**	**(79)**	**(2)**
RESERVES AT DEC. 31, 2005[3]	**304**	**1,171**	**2,953**	**4,428**	**3,191**	**8,623**	**646**	**3,578**	**16,038**	**20,466**	**2,787**	**181**
DEVELOPED RESERVES[4]												
At Jan. 1, 2003	266	1,770	3,600	5,636	582	2,934	262	2,157	5,935	11,571	1,474	6
At Dec. 31, 2003	265	1,572	2,964	4,801	954	3,627	223	3,043	7,847	12,648	1,789	52
At Dec. 31, 2004	252	937	2,191	3,380	1,108	3,701	271	2,273	7,353	10,733	2,584	63
At Dec. 31, 2005	**251**	**977**	**2,794**	**4,022**	**1,346**	**4,819**	**449**	**2,453**	**9,067**	**13,089**	**2,314**	**85**

1 Includes reserves acquired through property exchanges.
2 Includes reserves disposed of through property exchanges.
3 Net reserve changes (excluding production) in 2005 consist of 5,141 billion cubic feet of developed reserves and 669 billion cubic feet of undeveloped reserves for consolidated companies and (672) billion cubic feet of developed reserves and 174 billion cubic feet of undeveloped reserves for affiliated companies.
4 During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 12 percent and 19 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of proved-reserve changes for 2003 through 2005 in the table above are discussed below:

Revisions In 2003, revisions accounted for a net increase of 1,627 BCF for consolidated companies, as net increases of 2,233 BCF internationally were partially offset by net downward revisions of 606 BCF in the United States. Internationally, the net 879 BCF increase in the Asia-Pacific region related primarily to Australia and Kazakhstan. In Australia, the increase was associated mainly with a change to the probabilistic method of aggregating the reserves for multiple fields produced through common offshore infrastructure into a single LNG plant. The increase in Kazakhstan related to an updated geologic model for one field and higher gas sales to a third-party processing plant. The net 976 BCF increase in the "Other" international area was mainly the result of operating contract extensions for two fields in South America. In the United States, about one-third of the net 606 BCF negative revision related to two coal bed methane fields in the Mid-Continent region, based on performance data for producing wells. Downward revisions for the balance of the write-down were associated with several fields, based on assessments of well performance and other data.

In 2004, revisions increased reserves for consolidated companies by a net 248 BCF, composed of increases of 928 BCF internationally and decreases of 680 BCF in the United States. Internationally, about half of the 346 BCF increase in Africa related to properties in Nigeria, for which changes were associated with well performance reviews, development drilling and lease fuel calculations. The 236 BCF addition in the Asia-Pacific region was related primarily to reservoir analysis for a single field. Most of the 325 BCF in the "Other" international area is related to a new gas sales contract in Trinidad and Tobago. In the United States, the net 391 BCF downward revision in the Gulf of Mexico was related to well-performance reviews and technical analyses in several fields. Most of the net 316 BCF negative revision in the "Other" U.S. area related to two coal bed methane fields in the Mid-Continent region and their associated wells' performance. The 963 BCF increase for TCO was connected with updated analyses of reservoir performance and processing plant yields.

In 2005, reserves were revised downward by 14 BCF for consolidated companies and 498 BCF for equity affiliates. For consolidated companies, negative revisions were 428 BCF in the Asia-Pacific region. Most of the decrease was attributable to one field in Kazakhstan, due mainly to the effects of higher year-end prices on variable-royalty provisions of the production-sharing contract. Reserves additions for consolidated companies totaled 211 BCF and 243 BCF in Africa and "Other," respectively. The majority of the African region changes were in Angola, due to a revised forecast of fuel gas usage, and in Nigeria from improved reservoir performance. The availability of third-party compression in Colombia accounted for most of the increase in the "Other" region. Revisions in the United States decreased reserves by 9 BCF, as nominal increases in the San Joaquin Valley were more than offset by decreases in the Gulf of Mexico and "Other" region. For the TCO affiliate in Kazakhstan, a reduction of 547 BCF reflects the updated forecast of future royalties payable and year-end price effects, partially offset by volumes added as a result of an updated assessment of reservoir performance.

Extensions and Discoveries In 2003, extensions and discoveries accounted for an increase of 526 BCF for consolidated companies, reflecting a 388 BCF increase in the United States, with 270 BCF added in the Gulf of Mexico and 118 BCF in the "Other" region. The Gulf of Mexico increase includes discoveries in several offshore Louisiana fields, with a large number of fields in Texas, Louisiana and other states accounting for the increase in "Other."

In 2004, extensions and discoveries accounted for an increase of 214 BCF, reflecting an increase in the United States of 144 BCF, with 89 BCF added in the "Other" region and 54 BCF added in the Gulf of Mexico through drilling activities in a large number of fields.

In 2005, consolidated companies increased reserves by 370 BCF, including 167 BCF in the United States and 118 BCF in the Asia-Pacific region. In the United States, 99 BCF was added in the "Other" region and 68 BCF in the Gulf of Mexico, primarily due to drilling activities. The addition in Asia-Pacific resulted primarily from increased drilling in Kazakhstan.

Purchases In 2005, all except 7 BCF of the 5,656 BCF total purchases were associated with the Unocal acquisition. International reserve acquisitions were 4,488 BCF, with Thailand accounting for about half the volumes. Other significant volumes were added in Bangladesh and Myanmar.

Sales In 2004, sales for consolidated companies totaled 547 BCF. Of this total, 436 BCF was in the United States and 111 BCF in the "Other" international region. In the United States, "Other" region sales accounted for 289 BCF, reflecting the disposal of a large number of smaller properties, including a coal bed methane field. Gulf of Mexico sales of 147 BCF reflected the sale of Shelf properties, with four fields accounting for more than one-third of the total sales. Sales in the "Other" international region reflected the disposition of the properties in western Canada and the United Kingdom.

In 2005, sales of 248 BCF in the "Other" international region related to the disposition of former-Unocal's onshore properties in Canada.

TABLE VI – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of FAS 69. Estimated future cash inflows from production are computed by applying year-end prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed under FAS 69 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves. In the following table, "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

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TABLE VI – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES – Continued

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
AT DECEMBER 31, 2005												
Future cash inflows from production	**$ 50,771**	**$ 29,422**	**$ 50,039**	**$ 130,232**	**$ 101,912**	**$ 73,612**	**$ 32,538**	**$ 44,680**	**$ 252,742**	**$ 382,974**	**$ 97,707**	**$ 20,616**
Future production costs	**(15,719)**	**(5,758)**	**(12,767)**	**(34,244)**	**(11,366)**	**(12,459)**	**(18,260)**	**(11,908)**	**(53,993)**	**(88,237)**	**(7,399)**	**(2,101)**
Future devel. costs	**(2,274)**	**(2,467)**	**(873)**	**(5,614)**	**(8,197)**	**(5,840)**	**(1,730)**	**(2,439)**	**(18,206)**	**(23,820)**	**(5,996)**	**(762)**
Future income taxes	**(11,092)**	**(7,173)**	**(12,317)**	**(30,582)**	**(50,894)**	**(21,509)**	**(5,709)**	**(13,917)**	**(92,029)**	**(122,611)**	**(23,818)**	**(6,036)**
Undiscounted future net cash flows	**21,686**	**14,024**	**24,082**	**59,792**	**31,455**	**33,804**	**6,839**	**16,416**	**88,514**	**148,306**	**60,494**	**11,717**
10 percent midyear annual discount for timing of estimated cash flows	**(10,947)**	**(4,520)**	**(10,838)**	**(26,305)**	**(14,881)**	**(14,929)**	**(2,269)**	**(5,635)**	**(37,714)**	**(64,019)**	**(37,674)**	**(7,768)**
STANDARDIZED MEASURE NET CASH FLOWS	**$ 10,739**	**$ 9,504**	**$ 13,244**	**$ 33,487**	**$ 16,574**	**$ 18,875**	**$ 4,570**	**$ 10,781**	**$ 50,800**	**$ 84,287**	**$ 22,820**	**$ 3,949**
AT DECEMBER 31, 2004												
Future cash inflows from production	$ 32,793	$ 19,043	$ 28,676	$ 80,512	$ 64,628	$ 35,960	$ 25,313	$ 30,061	$ 155,962	$ 236,474	$ 61,875	$ 12,769
Future production costs	(11,245)	(3,840)	(7,343)	(22,428)	(10,662)	(8,604)	(12,830)	(7,884)	(39,980)	(62,408)	(7,322)	(3,734)
Future devel. costs	(1,731)	(2,389)	(667)	(4,787)	(6,355)	(2,531)	(717)	(1,593)	(11,196)	(15,983)	(5,366)	(407)
Future income taxes	(6,706)	(4,336)	(6,991)	(18,033)	(29,519)	(9,731)	(5,354)	(9,914)	(54,518)	(72,551)	(13,895)	(2,934)
Undiscounted future net cash flows	13,111	8,478	13,675	35,264	18,092	15,094	6,412	10,670	50,268	85,532	35,292	5,694
10 percent midyear annual discount for timing of estimated cash flows	(6,656)	(2,715)	(6,110)	(15,481)	(9,035)	(6,966)	(2,465)	(3,451)	(21,917)	(37,398)	(22,249)	(3,817)
STANDARDIZED MEASURE NET CASH FLOWS	$ 6,455	$ 5,763	$ 7,565	$ 19,783	$ 9,057	$ 8,128	$ 3,947	$ 7,219	$ 28,351	$ 48,134	$ 13,043	$ 1,877
AT DECEMBER 31, 2003												
Future cash inflows from production	$ 30,307	$ 23,521	$ 33,251	$ 87,079	$ 55,532	$ 33,031	$ 26,288	$ 29,987	$ 144,838	$ 231,917	$ 56,485	$ 9,018
Future production costs	(10,692)	(5,003)	(9,354)	(25,049)	(8,237)	(6,389)	(11,387)	(6,334)	(32,347)	(57,396)	(6,099)	(1,878)
Future devel. costs	(1,668)	(1,550)	(990)	(4,208)	(4,524)	(2,432)	(1,729)	(1,971)	(10,656)	(14,864)	(6,066)	(463)
Future income taxes	(6,073)	(5,742)	(7,752)	(19,567)	(25,369)	(9,932)	(5,993)	(7,888)	(49,182)	(68,749)	(12,520)	(2,270)
Undiscounted future net cash flows	11,874	11,226	15,155	38,255	17,402	14,278	7,179	13,794	52,653	90,908	31,800	4,407
10 percent midyear annual discount for timing of estimated cash flows	(6,050)	(3,666)	(7,461)	(17,177)	(8,482)	(6,392)	(3,013)	(5,039)	(22,926)	(40,103)	(20,140)	(2,949)
STANDARDIZED MEASURE NET CASH FLOWS	$ 5,824	$ 7,560	$ 7,694	$ 21,078	$ 8,920	$ 7,886	$ 4,166	$ 8,755	$ 29,727	$ 50,805	$ 11,660	$ 1,458

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TABLE VII – CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED RESERVES

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production volumes and costs. Changes in the timing of production are included with "Revisions of previous quantity estimates."

	Consolidated Companies*			Affiliated Companies		
Millions of dollars	**2005**	2004	2003	**2005**	2004	2003
PRESENT VALUE AT JANUARY 1	**$ 48,134**	$ 50,805	$ 48,585	**$ 14,920**	$ 13,118	$ 12,606
Sales and transfers of oil and gas produced net of production costs	**(26,145)**	(18,843)	(16,630)	**(2,712)**	(1,602)	(1,054)
Development costs incurred	**5,504**	3,579	3,451	**810**	1,104	750
Purchases of reserves	**25,307**	58	97	**–**	–	–
Sales of reserves	**(2,006)**	(3,734)	(839)	**–**	–	–
Extensions, discoveries and improved recovery less related costs	**7,446**	2,678	5,445	**–**	–	–
Revisions of previous quantity estimates	**(13,564)**	1,611	1,200	**(2,598)**	970	653
Net changes in prices, development and production costs	**61,370**	6,173	1,857	**19,205**	266	(1,187)
Accretion of discount	**8,160**	8,139	7,903	**2,055**	1,818	1,709
Net change in income tax	**(29,919)**	(2,332)	(264)	**(4,911)**	(754)	(359)
Net change for the year	**36,153**	(2,671)	2,220	**11,849**	1,802	512
PRESENT VALUE AT DECEMBER 31	**$ 84,287**	$ 48,134	$ 50,805	**$ 26,769**	$ 14,920	$ 13,118

* 2003 conformed to 2004 and 2005 presentation.

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EXHIBIT INDEX

Exhibit No.	Description
2.1	Amendment No. 1 to Agreement and Plan of Merger dated as of July 19, 2005, by and among Unocal Corporation, Chevron Corporation and Blue Merger Sub Inc., filed as Annex A to Exhibit 20.1 to Chevron's Current Report on Form 8-K dated July 25, 2005, and incorporated herein by reference.
3.1	Restated Certificate of Incorporation of Chevron Corporation, dated May 9, 2005, filed as Exhibit 99.1 to Chevron's Current Report on Form 8-K dated July 25, 2005, and incorporated herein by reference.
3.2	By-Laws of Chevron Corporation, as amended June 29, 2005, filed as Exhibit 3.2 to Chevron Corporation's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, and incorporated herein by reference.
4	Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the corporation and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the corporation and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Commission upon request.
10.1	Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan, approved by the company's stockholders on May 22, 2003, filed as Appendix A to Chevron Corporation's Notice of Annual Meeting of Stockholders and Proxy Statement dated March 24, 2003, and incorporated herein by reference.
10.2	Management Incentive Plan of Chevron Corporation, as amended and restated on December 7, 2005, filed as Exhibit 10.3 to Chevron Corporation's Current Report on Form 8-K dated December 7, 2005, and incorporated herein by reference.
10.3	Chevron Corporation Excess Benefit Plan, amended and restated as of April 1, 2002, filed as Exhibit 10.3 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.
10.4	Chevron Corporation Long-Term Incentive Plan, as amended and restated on December 7, 2005, filed as Exhibit 10.4 to Chevron Corporation's Current Report on Form 8-K dated December 7, 2005, and incorporated herein by reference.
10.6	Chevron Corporation Deferred Compensation Plan for Management Employees, as amended and restated on December 7, 2005, filed as Exhibit 10.5 to Chevron Corporation's Current Report on Form 8-K dated December 7, 2005, and incorporated herein by reference.
10.8	Texaco Inc. Stock Incentive Plan, adopted May 9, 1989, as amended May 13, 1993, and May 13, 1997, filed as Exhibit 10.13 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.
10.9	Supplemental Pension Plan of Texaco Inc., dated June 26, 1975, filed as Exhibit 10.14 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.
10.10	Supplemental Bonus Retirement Plan of Texaco Inc., dated May 1, 1981, filed as Exhibit 10.15 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.
10.11	Texaco Inc. Director and Employee Deferral Plan approved March 28, 1997, filed as Exhibit 10.16 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.

Exhibit No.	Description
10.12	Chevron Corporation 1998 Stock Option Program for U.S. Dollar Payroll Employees, filed as Exhibit 10.12 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2002, and incorporated herein by reference.
10.13	Summary of Chevron's Management and Incentive Plan Awards and Criteria, filed as Exhibit 10.13 to Chevron Corporation's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005, and incorporated herein by reference.
10.14	Chevron Corporation Change in Control Surplus Employee Severance Program For Salary Grades 41 and Above, as amended on December 7, 2005, filed as Exhibit 10.1 to Chevron Corporation's Current Report on Form 8-K dated December 7, 2005, and incorporated herein by reference.
10.15	Chevron Corporation Benefit Protection Program, as amended and restated on December 7, 2005, filed as Exhibit 10.2 to Chevron Corporation's Current Report on Form 8-K dated December 7, 2005, and incorporated herein by reference.
10.16	Form of Notice of Grant under the Chevron Corporation Long-Term Incentive Plan, filed as Exhibit 10.1 to Chevron's Current Report on Form 8-K dated June 29, 2005, and incorporated herein by reference.
10.17	Form of Retainer Stock Option Agreement under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan, filed as Exhibit 10.2 to Chevron's Current Report on Form 8-K dated June 29, 2005, and incorporated herein by reference.
12.1*	Computation of Ratio of Earnings to Fixed Charges (page E-3).
21.1*	Subsidiaries of Chevron Corporation (page E-4 to E-5).
23.1*	Consent of PricewaterhouseCoopers LLP (page E-6).
24.1 to 24.12	Powers of Attorney for directors and certain officers of Chevron Corporation, authorizing the signing of the Annual Report on Form 10-K on their behalf.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of the company's Chief Executive Officer (page E-7).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company's Chief Financial Officer (page E-8).
32.1*	Section 1350 Certification of the company's Chief Executive Officer (page E-9).
32.2*	Section 1350 Certification of the company's Chief Financial Officer (page E-10).
99.1*	Definitions of Selected Energy and Financial Terms (page E-11).

* Filed herewith.

Copies of above exhibits not contained herein are available, to any security holder upon written request to the Corporate Governance Department, Chevron Corporation, 6001 Bollinger Canyon Road, San Ramon, California 94583-2324.

Exhibit 12.1

Chevron Corporation — Total Enterprise Basis
Computation of Ratio of Earnings to Fixed Charges

(Millions of dollars)

	Year Ended December 31,				
	2005	2004	2003	2002	2001
Income from Continuing Operations	$ 14,099	$ 13,034	$ 7,382	$ 1,102	$ 3,875
Income Tax Expense	11,098	7,517	5,294	2,998	4,310
Distributions (Less) Greater Than Equity in Earnings of Affiliates	(1,304)	(1,422)	(383)	510	(489)
Minority Interest	96	85	80	57	121
Previously Capitalized Interest Charged to Earnings During Period	93	83	76	70	67
Interest and Debt Expense	482	406	474	565	833
Interest Portion of Rentals*	688	687	507	407	357
Earnings Before Provision for Taxes And Fixed Charges	**$ 25,252**	**$ 20,390**	**$ 13,430**	**$ 5,709**	**$ 9,074**
Interest and Debt Expense	$ 482	$ 406	$ 474	$ 565	$ 833
Interest Portion of Rentals*	688	687	507	407	357
Preferred Stock Dividends of Subsidiaries	1	1	4	5	48
Capitalized Interest	60	44	75	67	122
Total Fixed Charges	**$ 1,231**	**$ 1,138**	**$ 1,060**	**$ 1,044**	**$ 1,360**
Ratio Of Earnings To Fixed Charges	**20.51**	**17.92**	**12.67**	**5.47**	**6.67**

* Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.

Exhibit 21.1

SUBSIDIARIES OF CHEVRON CORPORATION*
At December 31, 2005

Name of Subsidiary	State or County in Which Organized
Bermaco Insurance Company Limited	Bermuda
Cabinda Gulf Oil Company Limited	Bermuda
Caltex New Zealand Limited	New Zealand
Caltex Oil (Pakistan) Limited	Bahamas
Caltex Oil (Thailand) Limited	Bahamas
Caltex (Philippines) Inc.	Philippines
Chevron Asiatic Limited	Delaware
Chevron Australia Pty Ltd.	Australia
Chevron Australia Transport Pty Ltd.	Australia
Chevron Brasil Ltda.	Brazil
Chevron Canada Capital Company	Nova Scotia
Chevron Canada Finance Limited	Canada
Chevron Canada Limited	Canada
Chevron Capital Corporation	Delaware
Chevron Capital U.S.A. Inc.	Delaware
Chevron Caspian Pipeline Consortium Company	Delaware
Chevron Credit Bank, N.A.	Utah
Chevron Environmental Management Company	California
Chevron Environmental Services Company	Delaware
Chevron Equatorial Guinea Ltd.	Bermuda
Chevron Finance Company	Delaware
Chevron Geothermal Indonesia, Ltd.	Bermuda
Chevron Global Energy Inc.	Delaware
Chevron Global Power Generation	Pennsylvania
Chevron Global Technology Services Company	Delaware
Chevron International (Congo) Limited	Bermuda
Chevron International Exploration and Production Company	Pennsylvania
Chevron LNG Shipping Company Limited	Bermuda
Chevron Nigeria Deepwater A Limited	Nigeria
Chevron Nigeria Deepwater B Limited	Nigeria
Chevron Nigeria Deepwater C Limited	Nigeria
Chevron Nigeria Deepwater D Limited	Nigeria
Chevron Nigeria Limited	Nigeria
Chevron Oil Congo (D.R.C.) Limited	Bermuda
Chevron Oronite Company LLC	Delaware
Chevron Oronite Pte. Ltd.	Singapore
Chevron Oronite S.A.	France
Chevron Overseas (Congo) Limited	Bermuda
Chevron Overseas Company	Delaware
Chevron Overseas Petroleum Brasil Limitada	Brazil
Chevron Overseas Petroleum Limited	Bahamas
Chevron Overseas Pipeline (Cameroon) Limited	Bahamas
Chevron Overseas Pipeline (Chad) Limited	Bahamas
Chevron Petroleum Chad Company Limited	Bermuda
Chevron Petroleum Company	New Jersey
Chevron Petroleum Limited	Bermuda
Chevron Pipe Line Company	Delaware
Chevron San Jorge S.R.L.	Argentina
Chevron Synfuels Limited	Bermuda
Chevron Thailand Exploration and Production, Ltd.	Bermuda
Chevron Thailand Inc.	Delaware
Chevron Transport Corporation Ltd.	Bermuda
Chevron United Kingdom Limited	England
Chevron U.S.A. Holdings Inc.	Delaware
Chevron U.S.A. Inc.	Pennsylvania
ChevronTexaco Capital Company	Nova Scotia

Name of Subsidiary	State or County in Which Organized
ChevronTexaco International Petroleum Company	Delaware
ChevronTexaco UK Limited	England and Wales
Four Star Oil & Gas Company	Delaware
Fuel and Marine Marketing LLC	Delaware
Getty Mining Company	Delaware
Heddington Insurance Limited	Bermuda
HUTTS, LLC	Delaware
Insco Limited	Bermuda
PT. Chevron Pacific Indonesia	Indonesia
Saudi Arabian Texaco Inc.	Delaware
Texaco Block B South Natuna Sea Inc.	Liberia
Texaco Britain Limited	England and Wales
Texaco Capital Inc.	Delaware
Texaco Capital LLC	Turks and Caicos Islands
Texaco Captain Inc.	Delaware
Texaco Inc.	Delaware
Texaco Investments (Netherlands) Inc.	Delaware
Texaco Limited	England and Wales
Texaco Natural Gas Inc.	Delaware
Texaco Nederland B.V.	Netherlands
Texaco North Sea U.K. Limited	Delaware
Texaco Overseas Holdings Inc.	Delaware
Texaco Raffinaderij Pernis B.V.	Netherlands
Texaco Venezuela Holdings (I) Company	Delaware
The Pittsburg & Midway Coal Mining Co.	Missouri
Traders Insurance Limited	Bermuda
TRMI Holdings Inc.	Delaware
Union Oil Company of California	California
Unocal Corporation	Delaware
Unocal Energy Trading Inc.	Delaware
Unocal International Corporation	Nevada
Unocal Pipeline Company	California
West Australian Petroleum Pty Limited	Western Australia

* All of the subsidiaries in the above list are wholly owned, either directly or indirectly, by Chevron Corporation. Certain subsidiaries are not listed since, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary at December 31, 2005.

Exhibit 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 33-58463, 33-56377, 33-56373 and 333-110487) of Chevron Corporation, and to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-102269, 333-72672, 333-21805, 333-21807, 333-21809, 333-26731, 333-46261, 333-105136, 333-122121, 333-02011) of Chevron Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-110487-01) of Chevron Funding Corporation and Chevron Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-110487-02) of ChevronTexaco Capital Company and Chevron Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-110487-03) of Chevron Capital U.S.A. Inc. and Chevron Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 33-14307) of Chevron Capital U.S.A. Inc. and Chevron Corporation of our report dated February 27, 2006, relating to the financial statements, financial statement schedule, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP

San Francisco, California
March 1, 2006

Exhibit 24.1

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ SAMUEL H. ARMACOST

Exhibit 24.2

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, KARI H. ENDRIES, and PATRICIA L. TAI or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ LINNET F. DEILY

Exhibit 24.3

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

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IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ ROBERT E. DENHAM

Exhibit 24.4

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ ROBERT J. EATON

Exhibit 24.5

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ SAM GINN

Exhibit 24.6

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the “Corporation”), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ Carla A. Hills

Exhibit 24.7

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ Franklyn G. Jenifer

Exhibit 24.8

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ Sam Nunn

Exhibit 24.9

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, KARI H. ENDRIES, and PATRICIA L. TAI or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ DONALD B. RICE

Exhibit 24.10

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ CHARLES R. SHOEMATE

Exhibit 24.11

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the "Corporation"), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ Ronald D. Sugar

Exhibit 24.12

POWER OF ATTORNEY

WHEREAS, Chevron Corporation, a Delaware corporation (the “Corporation”), contemplates filing with the Securities and Exchange Commission at Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder, an Annual Report on Form 10-K for the year ended December 31, 2005;

WHEREAS, the undersigned is an officer or director, or both, of the Corporation;

N O W, T H E R E F O R E, the undersigned hereby constitutes and appoints LYDIA I. BEEBE, CHRISTOPHER A. BUTNER, PATRICIA L. TAI, WALKER C. TAYLOR, or any of them, his or her attorneys-in-fact and agents, with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign the aforementioned Annual Report on Form 10-K (and any and all amendments thereto) and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully as to all intents and purposes he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do and cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has hereunto set his or her hand this 1st day of March, 2006.

/s/ CARL WARE

Exhibit 31.1

RULE 13a-14(a)/15d-14(a) CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David J. O'Reilly, certify that:

1. I have reviewed this Annual Report on Form 10-K of Chevron Corporation;

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

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

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

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

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

/s/ DAVID J. O'REILLY

David J. O'Reilly
Chairman of the Board and
Chief Executive Officer

Dated: March 1, 2006

Exhibit 31.2

RULE 13a-14(a)/15d-14(a) CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Crowe, certify that:

1. I have reviewed this Annual Report on Form 10-K of Chevron Corporation;

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

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

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

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

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

/s/ STEPHEN J. CROWE

Stephen J. Crowe
Vice President and
Chief Financial Officer

Dated: March 1, 2006

Exhibit 32.1

CERTIFICATION PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002 (18 U.S.C. SECTION 1350)

In connection with the Annual Report of Chevron Corporation (the "Company") on Form 10-K for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David J. O'Reilly, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DAVID J. O'REILLY

David J. O'Reilly
Chairman of the Board and
Chief Executive Officer

Dated: March 1, 2006

Exhibit 32.2

**CERTIFICATION PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002 (18 U.S.C. SECTION 1350)**

In connection with the Annual Report of Chevron Corporation (the “Company”) on Form 10-K for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Stephen J. Crowe, Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ STEPHEN J. CROWE

Stephen J. Crowe
Vice President and
Chief Financial Officer

Dated: March 1, 2006

Exhibit 99.1

DEFINITIONS OF SELECTED ENERGY TERMS

Barrels of oil-equivalent (BOE)
A unit of measure to quantify crude oil and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content. See *oil-equivalent gas* and *production.*

Cost-recovery barrels
A company's production entitlement to recover its costs (i.e., production costs, exploration costs and other costs) under a *production-sharing contract.* As prices increase or decrease, the number of cost-recovery barrels decreases or increases, respectively, to recover the same level of costs.

Development
Drilling, construction and related activities following discovery that are necessary to begin production and transportation of crude oil and natural gas.

Exploration
Searching for crude oil and/or natural gas by utilizing geologic and topographical studies, geophysical and seismic surveys, and drilling of wells.

Liquefied natural gas (LNG)
Natural gas that is liquefied under extremely cold temperatures to facilitate storage or transportation in specially designed vessels.

Liquefied petroleum gas (LPG)
Light gases, such as butane and propane, that can be maintained as liquids while under pressure.

Oil-equivalent gas (OEG)
The volume of natural gas needed to generate the equivalent amount of heat as a barrel of crude oil. Approximately 6,000 cubic feet of natural gas is equivalent to one barrel of crude oil.

Oil sands
Naturally occurring mixture of bitumen — a heavy viscous form of crude oil — water, sand and clay. Using hydroprocessing technology, bitumen can be refined to yield *synthetic crude oil.*

Production
Total production refers to all the crude oil and natural gas produced from a property. *Gross production* is the company's share of total production before deducting both royalties paid to landowners and a host government's agreed-upon share of production under a *production-sharing contract. Net production* is gross production minus both royalties paid to landowners and a host government's agreed-upon share of production under a *production-sharing contract. Oil-equivalent production* is the sum of the barrels of liquids and the oil-equivalent barrels of natural gas produced. See *barrels of oil-equivalent* and *oil-equivalent gas.*

Production-sharing contract
A contractual agreement between a company and a host government whereby the company bears all exploration, development and production costs in return for an agreed-upon share of production.

Reserves
Crude oil or natural gas contained in underground rock formations called reservoirs. *Proved reserves* are the estimated quantities that geologic and engineering data demonstrate can be produced with reasonable certainty from known reservoirs under existing economic and operating conditions. Estimates change as additional information becomes available. *Oil-equivalent reserves* are the sum of the liquids reserves and the oil-equivalent gas reserves. See *barrels of oil-equivalent* and *oil-equivalent gas.*

Synthetic crude oil
A marketable and transportable hydrocarbon liquid, resembling crude oil, that is produced by upgrading highly viscous to solid hydrocarbons (such as extra-heavy crude oil or *oil sands*).

DEFINITIONS OF SELECTED FINANCIAL TERMS

Current ratio
Current ratio is current assets divided by current liabilities.

Goodwill
Goodwill is the excess of the purchase price of an acquired entity over the total fair value assigned to assets acquired and liabilities assumed.

Interest coverage ratio
Interest coverage ratio is income before income tax expense, including cumulative effect of change in accounting principles and extraordinary items, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs.

Return on average stockholders' equity
Return on average stockholders' equity is net income divided by average stockholders' equity. Average stockholders' equity is computed by averaging the sum of the beginning-of-year and end-of-year balances.

Return on capital employed (ROCE)
ROCE is calculated by dividing net income (adjusted for after-tax interest expense and minority interest) by the average of total debt, minority interest and stockholders' equity for the year.

Total debt to total-debt-plus-equity ratio
Total debt to total-debt-plus-equity ratio is total debt, including capital lease obligations, divided by total debt and stockholders' equity.