CHEVRON CORP
Form 10-K
February 28, 2007

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended **December 31, 2006**

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.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ 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 þ

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 þ No o

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

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 þ 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 þ

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 $136,407,118,275 (As of June 30, 2006)

Number of Shares of Common Stock outstanding as of February 23, 2007 2,157,780,998

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2007 Annual Meeting and 2007 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company s 2007 Annual Meeting of Stockholders (in Part III)

TABLE OF CONTENTS

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, proje believes, seeks, schedules, estimates, budgets and similar expressions are intended to identify such forward-look 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 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 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 or delivery/transportation networks 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 statutes, regulations and litigation; the potential liability resulting from pending or future litigation; the company s acquisition or disposition of assets; government-mandated sales, divestitures, recapitalizations, changes in fiscal terms or restrictions on scope of company operations; 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, management and technology 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. 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 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.

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, 2006, Chevron had nearly 62,500 employees (including about 6,600 service station employees). Approximately 28,800, 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 Statement No. 141, *Business Combinations.* Unocal s principal upstream operations were in North America and Asia, including the Caspian region. Other activities included 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 beginning on page FS-34 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 how companies are structured and 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 global economies, although weather patterns and taxation relative to other energy sources also play a significant part. Seasonality is not a primary driver to changes in the company s quarterly earnings during the year.

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 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.

[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. In 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 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.

3

Table of Contents

Operating Environment

Refer to pages FS-2 through FS-9 of this 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 2007:

Strategies for Major Businesses

Upstream grow profitably in core areas, build new legacy positions and commercialize the company s natural gas equity resource base while growing a high-impact global gas business

Downstream improve base-business returns and selectively grow, with a focus on integrated value creation

The company will also continue to invest in renewable-energy technologies, with an objective of capturing profitable positions in important renewable sources of energy.

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, downstream and chemicals activities of the company and its equity affiliates are widely dispersed geographically, with operations in North America, South America, Europe, Africa, the Middle East, Asia, and Australasia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2006, and assets as of the end of 2006 and 2005 for the United States and the company s international geographic areas are in Note 8 to the consolidated financial statements beginning on page FS-38 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 in Notes 12 and 13 on pages FS-41 to FS-43.

Capital and Exploratory Expenditures

Total reported expenditures for 2006 were $16.6 billion, including $1.9 billion for Chevron s share of expenditures by affiliated companies, which did not require cash outlays by the company. In 2005 and 2004, expenditures were $11.1 billion and $8.3 billion, respectively, including the company s share of affiliates expenditures of $1.7 billion and $1.6 billion in the corresponding periods. The 2005 amount excludes the $17.3 billion acquisition of Unocal.

Of the $16.6 billion in expenditures for 2006, 77 percent, or $12.8 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2005 and 2004. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the three years, reflecting the company s continuing focus on opportunities that are available outside the United States.

In 2007, the company estimates capital and exploratory expenditures will be 18 percent higher at $19.6 billion, including $2.4 billion of spending by affiliates. About three-fourths, or $14.6 billion, is budgeted for exploration and production activities, with $10.6 billion of that amount outside the United States.

Refer also to a discussion of the company s capital and exploratory expenditures on page FS-13 of this Annual Report on Form 10-K.

Upstream Exploration and Production

The table on the following page summarizes the net production of liquids and natural gas for 2006 and 2005 by the company and its affiliates.

Table of Contents

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]	
	2006	2005	2006	2005	2006	2005
United States:						
California	207	217	101	106	224	235
Gulf of Mexico[3]	114	112	661	579	224	208
Texas[3]	79	61	425	380	150	124
Wyoming	8	9	153	161	33	36
Other States[3]	54	56	470	408	132	124
Total United States[3]	462	455	1,810	1,634	763	727
Africa:						
Angola	156	139	47	36	164	145
Nigeria	139	125	29	68	144	136
Chad	34	38	4	3	35	39
Republic of the Congo	11	11	8	8	12	12
Democratic Republic of the Congo[3]	3	1	2		3	1
Asia-Pacific:						
Partitioned Neutral Zone (PNZ)[4]	111	112	19	22	114	116
Thailand[3]	73	43	856	409	216	111
Azerbaijan[3]	46	13	4	1	47	13
Australia	39	42	360	362	99	102
Kazakhstan	38	37	143	142	62	61
China	23	26	18		26	26
Philippines	6	8	108	163	24	35
Bangladesh[3]			126	59	21	10
Myanmar[3]			89	32	15	5
Indonesia[3]	198	202	302	211	248	237
Other International:						
United Kingdom	75	83	242	300	115	133
Canada[3]	46	54	6	19	47	57
Denmark	44	47	146	146	68	71
Argentina	38	43	54	55	47	52
Norway	6	8	1	2	6	9
Venezuela[5]	3	4	21	35	7	10
Netherlands[3]	3	2	7	4	4	3
Colombia			174	185	29	31
Trinidad and Tobago			174	115	29	19

Total International[3]	1,092	1,038	2,940	2,377	1,582	1,434
Total Consolidated Operations[3]	1,554	1,493	4,750	4,011	2,345	2,161
Equity Affiliates[6]	178	176	206	222	213	213
Total Including Affiliates[3,7,8]	1,732	1,669	4,956	4,233	2,558	2,374

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 beginning August 2005 for properties associated with acquisition of Unocal.
4 Located between the Kingdom of Saudi Arabia and the State of Kuwait.
5 Through September 30, 2006, LL-652 was reported as part of Venezuela consolidated operations. As of October 1, 2006, LL-652 is reported under Equity Affiliates. See footnote 6 below.
6 Represents Chevron s share of production by affiliates, including Tengizchevroil (TCO) in Kazakhstan, Hamaca in Venezuela and for the last three months of 2006 Chevron s share of LL-652 and Boscan in Venezuela. Effective October 1, 2006, the company converted its interests in Boscan and LL-652 operating service agreements in Venezuela to Empresas Mixtas (i.e., joint stock contractual structures), and these interests are accounted for as equity affiliates. LL-652 was previously reported as part of Venezuela consolidated operations, and Boscan was included only as part of footnote 8 below, Other produced volumes.
7 Includes natural gas consumed in operations of 475 and 404 million cubic feet per day in 2006 and 2005, respectively.
8 Does not include other produced volumes:

Athabasca Oil Sands net	27	32			27	32
Boscan Operating Service Agreement (through September 30, 2006 see footnote 6 above)	82	111			82	111

5

Table of Contents

In 2006, Chevron conducted exploration and production operations in the United States and approximately 35 other countries. Worldwide oil-equivalent production of 2.67 million barrels per day in 2006, including volumes produced from oil sands in Canada and production under the Boscan operating service agreement in Venezuela, increased approximately 6 percent from 2005. The increase between periods was mostly attributable to the Unocal acquisition. Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of the factors explaining the 2004 2006 changes in production for crude oil and natural gas liquids and natural gas.

The company estimates that its average worldwide oil-equivalent production in 2007 will be approximately 2.6 million barrels per day. This estimate 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, changes in fiscal terms or restrictions on scope of company operations, and production that may have to be shut in due to weather conditions, civil unrest, changing geopolitics or other disruptions to daily operations. 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. Expected additions to production capacity in 2008 through 2010 may permit worldwide oil-equivalent production levels to increase from 2007 levels. Refer to the Review of Ongoing Exploration and Production Activities in Key Areas, beginning on page 9, 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-68 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 2006, 2005 and 2004.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2006 for the company and its affiliates:

Productive Oil and Gas Wells[1] at December 31, 2006

	Productive[2] Oil Wells		**Productive[2] Gas Wells**	
	Gross	**Net**	**Gross**	**Net**
United States:				
California	24,484	22,754	185	58
Gulf of Mexico	2,429	1,788	1,454	1,080
Other U.S.	23,602	8,525	10,793	5,074
Total United States	50,515	33,067	12,432	6,212
Africa	2,083	702	7	3
Asia-Pacific	2,394	1,146	1,989	1,251
Indonesia	7,580	7,434	203	162
Other International	989	621	239	97
Total International	13,046	9,903	2,438	1,513
Total Consolidated Companies	63,561	42,970	14,870	7,725

Equity in Affiliates	1,067	375		
Total Including Affiliates	64,628	43,345	14,870	7,725
Multiple completion wells included above:	890	542	390	281

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.

Reserves

Table V, beginning on page FS-68, provides a tabulation of the company s proved net oil and gas reserves, by geographic area, as of each year-end 2004 through 2006 and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period. During 2006, the company provided oil and gas reserves estimates for 2005 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 Securities and Exchange Commission on the company s Annual Report on Form 10-K. During 2007, 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, 2006, 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, 2006
(Thousands of Acres)

	Undeveloped[2]		Developed[2]		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States:						
California	139	121	206	178	345	299
Gulf of Mexico	3,713	2,690	1,759	1,300	5,472	3,990
Other U.S.	4,651	3,353	5,444	2,626	10,095	5,979
Total United States	8,503	6,164	7,409	4,104	15,912	10,268
Africa	18,448	8,024	2,522	925	20,970	8,949
Asia-Pacific	50,216	22,680	5,773	2,605	55,989	25,285
Indonesia	10,310	6,545	380	340	10,690	6,885
Other International	33,529	19,368	2,267	622	35,796	19,990
Total International	112,503	56,617	10,942	4,492	123,445	61,109
Total Consolidated Companies	121,006	62,781	18,351	8,596	139,357	71,377
Equity in Affiliates	924	431	252	102	1,176	533
Total Including Affiliates	121,930	63,212	18,603	8,698	140,533	71,910

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 2007, 2008 and 2009 if production is not established by certain required dates are 12,459, 7,731 and 10,207, respectively.

Contract Obligations

The company sells crude oil and natural gas from its producing operations under a variety of contractual obligations. 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 281 billion cubic feet of natural gas through 2009 from U.S. 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 560 billion cubic feet of natural gas from 2007 through 2009 from Argentina, 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

Table of Contents

production of the company s proved developed reserves in Argentina, Australia, Colombia and the Philippines. The company plans to meet its Canadian contractual delivery commitments of 27 billion cubic feet through third-party purchases.

Development Activities

Details of the company s development expenditures and costs of proved property acquisitions for 2006, 2005 and 2004 are presented in Table I on page FS-63 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, 2006. 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.

Development Well Activity

	Wells Drilling at 12/31/06[3]		**Net Wells Completed[1,2]**					
			2006		**2005**		**2004**	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States:								
California	12	3	600		661		636	1
Gulf of Mexico	14	8	34	5	29	3	43	3
Other U.S.	8	8	317	6	256	4	221	3
Total United States	34	19	951	11	946	7	900	7
Africa	10	3	45	2	38		36	
Asia-Pacific[4]	88	48	235	1	150		84	
Indonesia	6	6	258		107		163	
Other International[4]	7	2	43		79		84	
Total International	111	59	581	3	374		367	
Total Consolidated Companies	145	78	1,532	14	1,320	7	1,267	7
Equity in Affiliates			13		23		20	
Total Including Affiliates	145	78	1,545	14	1,343	7	1,287	7

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 Includes completion of wells beginning August 2005 related to the former Unocal operations.
3 Represents wells in process of drilling, including wells for which drilling was not completed and were temporarily suspended at the end of 2006. 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.

4 2005 conformed to 2006 presentation.

Table of Contents

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, 2006. 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.

Exploratory Well Activity

	Wells Drilling at 12/31/06[3]		**Net Wells Completed[1,2]**					
			2006		**2005**		**2004**	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States:								
California								
Gulf of Mexico	6	3	9	8	14	8	13	8
Other U.S.	1	1	7		5	6	3	1
Total United States	7	4	16	8	19	14	16	9
Africa	4	1	1		4	1	3	1
Asia-Pacific	15	9	18	7	10		16	
Indonesia			2		5		2	
Other International[4]	5	1	6	3	7	4	3	7
Total International	24	11	27	10	26	5	24	8
Total Consolidated Companies	31	15	43	18	45	19	40	17
Equity in Affiliates[4]			1		8			
Total Including Affiliates	31	15	44	18	53	19	40	17

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 Includes completion of wells beginning August 2005 related to the former Unocal operations.

3 Represents wells that are in the process of drilling but have been neither abandoned nor completed as of the last day of the year, including wells for which drilling was not completed and were temporarily suspended at the end of 2006. Does not include wells for which drilling was completed at year-end 2006 and were reported as

suspended wells in Note 20 on page FS-47. 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.

4 2005 conformed to 2006 presentation.

Details of the company s exploration expenditures and costs of unproved property acquisitions for 2006, 2005 and 2004 are presented in Table I on page FS-63 of this Annual Report on Form 10-K.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron s 2006 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 under Production in Exhibit 99.1 on page E-11 of this Annual Report on Form 10-K. In addition to the activities discussed, Chevron was active in other geographic areas, but those activities are considered 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.

Table of Contents

Consolidated Operations

Chevron has production and exploration activities in most of the world s major hydrocarbon basins. The company s upstream strategy is to grow profitably in core areas, build new legacy positions and commercialize the company s natural gas equity resource base while growing a high-impact global gas business. The map at left indicates Chevron s primary areas of production and exploration as well as the target markets for the company s natural gas resources.

a) United States

Upstream activities in the United States are concentrated in the Gulf of Mexico, Louisiana, Texas, New Mexico, the Rocky Mountains and California. Average daily net production during 2006 was 462,000 barrels of crude oil and natural gas liquids and 1.8 billion cubic feet of natural gas, or 763,000 barrels per day on an oil-equivalent basis. Refer to Table V beginning on page FS-68 for a discussion of the net proved reserves and different hydrocarbon characteristics for the company s major U.S. producing areas.

California: The company has significant production in the San Joaquin Valley. In 2006, average daily net production was 202,000 barrels of crude oil, 101 million cubic feet of natural gas and 5,000 barrels of natural gas liquids, or 224,000 barrels of oil-equivalent. Approximately 80 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 2006 for the company s combined interests in the Gulf of Mexico shelf and deepwater areas and the fields onshore Louisiana were 102,000 barrels of crude oil, 661 million cubic feet of natural gas and 12,000 barrels of natural gas liquids, or 224,000 barrels of oil-equivalent. Net production at the end of 2006 was approximately the same rate, which reflects restoration of most of the volumes that were economic to restore following the production outages caused by hurricanes in 2005.

In the Gulf of Mexico deepwater areas, the company s producing fields during 2006 included:

Genesis 57 percent-owned and operated. Daily net production in 2006 averaged 7,000 barrels of crude oil and 10 million cubic feet of natural gas, or 9,000 barrels of oil-equivalent.

Petronius 50 percent-owned and operated and includes the Perseus discovery, which started production from the Petronius platform in 2005. Daily net production in 2006 was 20,000 barrels of crude oil and 22 million cubic feet of natural gas, or 25,000 barrels of oil-equivalent.

Mad Dog 16 percent-owned and nonoperated and started production in 2005. Net production in 2006 averaged 5,000 barrels of oil-equivalent per day. Ongoing development work is expected to increase the maximum total daily production in 2008 to the design capacity of 80,000 barrels of crude oil and 40 million cubic feet of natural gas.

The company s interests in the deepwater Typhoon and Boris fields were sold during 2006. The production platform at Typhoon capsized during Hurricane Rita in 2005 and was safely converted into an artificial reef prior to the sale.

During 2006, Chevron was engaged in other development and exploration activities in the deepwater Gulf of Mexico. Development work continued at the 58 percent-owned and operated Tahiti Field, where production start-up is expected in 2008. Development drilling commenced in February 2006, and well completion work is expected to be finalized during 2007. Initial booking of proved undeveloped reserves occurred in 2003, and the transfer of these reserves into the proved developed category is anticipated near the time of production start-up. With an estimated production life of 30 years, Tahiti is designed 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 plan 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. Development drilling at Blind Faith commenced in early 2007. Reclassification of the reserves to the proved developed category is anticipated near the time of production start-up in 2008. Initial total daily production rates for the field are estimated at 30,000 barrels of crude oil and 30 million cubic feet of natural gas, thereafter rising to maximum rates of 40,000 barrels of crude oil and 35 million cubic feet of natural gas. The expected production life of the field is approximately 20 years.

In the fourth quarter 2006, the company announced its decision to participate in the ultra-deep Perdido Regional Development in the U.S. Gulf of Mexico. The development encompasses the installation of a producing host facility designed to service multiple fields, including Chevron s 33 percent-owned Great White, 60 percent-owned Silvertip and 58 percent-owned Tobago. Chevron has a 38 percent interest in the Perdido Regional Host. All of these fields and the production facility are partner-operated. First oil is expected to occur by 2010, with the facility capable of handling 130,000 barrels of oil-equivalent per day. The company s initial booking of proved undeveloped reserves occurred in 2006, and the phased reclassification of these reserves to the proved developed category is anticipated near the time of production start-up. The project has an expected life of approximately 25 years.

Exploration activities in 2006 included the announcement of a discovery early in the year at the 60 percent-owned and operated Big Foot prospect located in Walker Ridge Block 29. A sidetrack well at Big Foot was completed mid-year and encountered the same pay intervals as the discovery well. Additional appraisal drilling is planned for the first half of 2007.

At the 50 percent-owned and operated Jack discovery in Walker Ridge Block 758, a successful extended production flow test on the Jack #2 well was completed in mid-2006. Additional appraisal drilling is scheduled for the 2007 2008 time frame. Data evaluation continued in early 2007 at the nearby 41 percent-owned and operated Saint Malo prospect. Saint Malo was discovered in 2003, and an appraisal well was completed in 2004. Future appraisal drilling is being planned based on ongoing technical studies that are incorporating additional regional data. At the 25 percent-owned and nonoperated 2005 Knotty Head discovery, a successful sidetrack well was drilled during 2006. Additional appraisal drilling and possible development alternatives were being evaluated in early 2007. At the 30 percent-owned and nonoperated Tubular Bells prospect, an appraisal well in 2006 successfully tested the eastern portion of the reservoir structure. Additional appraisal work is being planned to further delineate the reservoir and to evaluate potential deeper targets. Plans were in progress in early 2007 at the 22 percent-owned and nonoperated Puma discovery to complete an in-progress appraisal well and to schedule additional appraisal drilling for 2007.

At the end of 2006, the company had not yet recognized proved reserves for any of the exploration projects discussed above.

Besides the activities connected with the development and exploration projects in the Gulf of Mexico area, Chevron also moved forward with the federal, state and local permitting process for construction of a natural gas import terminal at Casotte Landing in Jackson County, Mississippi. In February 2007, the company received approval from the Federal Energy Regulatory Commission to construct the facility. The terminal would be located adjacent to the company s Pascagoula Refinery and be designed to process imported liquefied natural gas (LNG) for distribution to industrial, commercial and residential customers in Mississippi, Florida and the Northeast. The terminal would have an initial natural-gas processing capacity of 1.3 billion cubic feet per day. A decision to construct the facility will be timed to align with the company s LNG supply projects.

The company also has contractual rights to 1 billion cubic feet per day of regasification capacity at the third party-owned Sabine Pass LNG terminal beginning in 2009. Also in the Sabine Pass area, the company has up to 1 billion cubic feet per day of pipeline capacity in a new pipeline that will be connected to the Sabine Pass LNG terminal. The new pipeline system will provide access to Chevron s Sabine and Bridgeline pipelines, which connect to the Henry Hub. Interconnect capacity of 600 million cubic feet per day has also been secured to an existing pipeline. 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. In the Piceance Basin of northwestern Colorado, the company drilled 14 tight-gas delineation wells during 2006 on the Skinner Ridge properties. Development drilling is scheduled to begin in the second quarter 2007 with the delivery of two custom-built drilling rigs. Chevron also operates 10 offshore platforms and five producing natural gas fields in Alaska s Cook Inlet and owns nonoperated production on the North Slope. During 2006, the company s operations outside California and the Gulf of Mexico averaged daily net production of 141,000 barrels of crude oil and natural gas liquids and about 1 billion cubic feet of natural gas (315,000 barrels of oil-equivalent).

b) Africa

Angola: Chevron has working interests in four concessions in Angola Blocks 0 and 14, which are company-operated, and Block 2 and the FST area, which are nonoperated.

The 39 percent-owned Block 0 and 31 percent-owned Block 14 are off the coast, north of the Congo River. In Block 0, the company operates in two areas A and B composed of 20 fields that produced 127,000 barrels per day of net liquids in 2006. The Block 0 concession extends through 2030.

Area A of Block 0 comprises 14 producing fields and averaged daily net production of approximately 67,000 barrels of crude oil and 1,000 barrels of liquefied petroleum gas (LPG) in 2006. The first phase of development of the Mafumeira Field in Area A was approved in 2006 and will target the northern portion of the field. Initial booking of proved undeveloped reserves for this development occurred in 2003, and reclassification of proved undeveloped reserves into the proved developed category is anticipated near the time of first production, which is expected in 2008. Maximum total daily production is expected to be approximately 30,000 barrels of crude oil in 2011.

In Area B of Block 0, average daily net production from six producing fields was 52,000 barrels of crude oil and condensate and 7,000 barrels of LPG in 2006. Included in this production were 28,000 barrels of liquids per day from the Sanha condensate natural gas utilization and Bomboco crude oil project. Initial reclassification of reserves from proved undeveloped to proved developed for this project occurred in 2004 and is expected to continue during the drilling program that is scheduled for completion in 2007. Maximum total daily production from the Sanha and Bomboco fields reached 100,000 barrels of liquids in 2006.

In Block 14, net production from the Kuito, Belize, Lobito and Landana fields averaged 25,000 barrels of crude oil per day in 2006. Belize and Lobito are part of the Benguela Belize-Lobito Tomboco (BBLT) development project. Phase 1 of the BBLT project involved the installation of an integrated drilling and production platform and the

Table of Contents

development of the Benguela and Belize fields. First oil was produced at the Belize Field in January 2006. Phase 2 of the project involved the installation of subsea production systems, pipelines and wells for the development of Lobito and Tomboco fields. First oil was produced from the Lobito Field in June 2006. Maximum total production for both phases of BBLT is estimated at 200,000 barrels of crude oil per day and is scheduled to occur in 2008. Proved undeveloped reserves for Benguela and Belize were initially recognized in 1998 and for Lobito and Tomboco in 2000. Certain proved developed reserves for Belize and Lobito were recognized in 2006, and additional BBLT reserves are expected to be reclassified to proved developed as project milestones are met. The concession period for these fields expires in 2027.

Another major project in Block 14 is the development of the Tombua and Landana fields. Construction on the project started in 2006. The maximum total daily production of 100,000 barrels of crude oil is expected to occur by 2010. First oil was produced from the Landana North reservoir in June 2006, using the BBLT infrastructure. Proved undeveloped reserves were recognized for Tombua and Landana in 2001 and 2002, respectively. Initial reclassification from proved undeveloped to proved developed for Landana occurred in 2006. Further reclassification is expected from 2009, when the Tombua-Landana facilities are completed, through 2012, when the drilling program is scheduled for completion. The concession for these fields expires in 2028. The total cost of the Tombua-Landana project is estimated at $3.8 billion.

Four exploration wells were drilled in Block 14 in 2006. One well resulted in a crude oil discovery at the deepwater Lucapa prospect. A second well appraised a prior-year discovery at Gabela, where development options are being studied. The remaining two wells are expected to be completed in the first-half 2007.

In Chevron s other two concessions, the nonoperated working interests are 20 percent in Block 2, which is adjacent to the northwestern part of Angola s coast, south of the Congo River, and 16 percent in the onshore FST area. Combined net production from these properties in 2006 was 4,000 barrels of crude oil per day.

In addition to the producing activities in Angola, Chevron has a 36 percent interest in the planned Angola LNG project, which will be integrated with natural gas production in the area. As of early 2007, participants in the Angola LNG project were finalizing the engineering, procurement, construction and commissioning contract for the 5-million-metric-ton-per-year onshore LNG plant to be located in the northern part of the country. Chevron and Sonangol, Angola s national oil company, are co-leaders of the project. Construction is expected to begin in late 2007. At the end of 2006, the company had not yet recognized proved reserves for the natural gas associated with this project.

Democratic Republic of the Congo: Chevron has an 18 percent nonoperated working interest in a production-sharing contract (PSC) off the coast of Democratic Republic of the Congo. Daily net production from seven fields averaged 3,000 barrels of crude oil in 2006.

Republic of the Congo: Chevron has a 32 percent nonoperated working interest in the Nkossa, Nsoko and Moho-Bilondo exploitation permits and a 29 percent nonoperated working interest in the Kitina and Sounda exploitation permits, all of which are offshore Republic of the Congo. Net production from the Republic of the Congo fields averaged 11,000 barrels of crude oil per day in 2006. The Moho-Bilondo development continued in 2006, with first production expected in 2008. The development plan calls for crude oil produced by subsea well clusters to flow into a floating processing unit. Maximum total daily production of 80,000 barrels of crude oil is expected by 2010. 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.

Angola-Republic of the Congo Joint Development Area: Chevron is operator and holds a 31 percent interest in the 14K/A-IMI Unit, located in a joint development area shared equally between Angola and Republic of the Congo. In

2006, Chevron submitted a conceptual field development plan to a committee of representatives from the two countries.

Chad/Cameroon: Chevron is a nonoperating partner in a project to develop crude oil fields in southern Chad and transport the crude oil by pipeline to the coast of Cameroon for export. Chevron has a 25 percent working interest in the producing operations and a 21 percent interest in the pipeline. Average daily net production from five fields in 2006 was 34,000 barrels of crude oil. The first of the satellite-field development projects was completed in the first quarter of 2006, and first oil was achieved in 2005 from the Nya Field and in March 2006 from the Moundouli Field. The second satellite-field development project, Maikeri, was approved for funding in the second half of 2006, with first oil anticipated for fourth quarter 2007. The Chad producing operations are conducted under a concession agreement that expires in 2030.

Libya: In 2005, the company was awarded Block 177 in Libya s first exploration license round under the Exploration and Production Sharing Agreement IV. Chevron is the operator and holds a 100 percent interest in the block.

Table of Contents

Acquisition and evaluation of seismic data is scheduled for completion in late 2007. A drilling program is scheduled for 2008.

Equatorial Guinea: Until October 2006, Chevron was a 22 percent partner and operator of Block L, offshore Equatorial Guinea. Following the drilling of two noncommercial wells and expiration of the exploration period, the company relinquished its equity in the block.

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 a 60 percent interest. In 2006, daily net production from 30 fields averaged 137,000 barrels of crude oil, 29 million cubic feet of natural gas and 2,000 barrels of LPG.

During 2006, the company continued development activities for the deepwater Agbami project, in which Chevron has a 68 percent operated interest. The total capital investment for this project is estimated at $5.2 billion. The Agbami Field is located approximately 70 miles off the coast in the central Niger Delta. Discovered in 1998, Agbami is at a water depth of approximately 4,800 feet. The geologic structure spans 45,000 acres across Oil Mining License (OML) 127 and OML 128. Agbami is designed as an all-subsea development, with the wells tied back to a floating production, storage and offloading (FPSO) vessel. The subsea wells will be connected to the FPSO by a system of flexible flowlines, manifolds and control umbilicals. All wells are to be drilled by a mobile drilling unit. Development drilling and completion operations were conducted throughout 2006.

During 2006, the Agbami development achieved the following major milestones: the FPSO hull was floated out of drydock in South Korea; topside modules fabricated in South Korea were installed on the FPSO and modules fabricated in Nigeria were received at the shipyard in South Korea. All other major equipment items were shipped to South Korea for installation, and manufacturing began on the equipment for the subsea wells. Completion of the FPSO and subsequent transport to Nigeria are expected in the fourth quarter 2007.

Agbami s maximum total daily production of 250,000 barrels of crude oil and natural gas liquids is expected to be reached within the first year after start-up in the second half 2008. The company initially recognized proved undeveloped reserves for Agbami in 2002. A portion of the proved undeveloped reserves will be reclassified to proved developed in advance of production start-up. The expected field life is approximately 20 years.

For Chevron s Aparo discovery in 2003 on OML 132 (formerly Oil Prospecting License [OPL] 213), the company entered into a joint-study agreement in 2004 with the partner group of the Bonga SW Field in OML 118 (formerly OPL 212) for the unitization and joint development of Aparo, which straddles OML 132 and OPL 249. Negotiation of final terms for a unitization agreement for this development was ongoing as of early 2007. Front-end engineering and design (FEED) continued through 2006, and discussions were under way in early 2007 with potential contractors. Development will likely involve an FPSO and subsea wells. Partners are expected to make the investment decision during 2007, with production start-up estimated to occur in 2011. Maximum total production of 150,000 barrels of crude oil per day is expected to be reached within one year of production start-up. The company recognized initial proved undeveloped reserves in 2006 for its approximate 20 percent nonoperated working interest in the unitized project.

The company holds a 30 percent nonoperated working interest in the Usan project, located offshore in OPL 222. FEED for the Usan Field continued through 2006 on a selected FPSO concept. Technical tendering for the major contracts were under way as of early 2007. Project partners expect to make the investment decision during 2007. The company recognized proved undeveloped reserves for the project in 2004. Production start-up is estimated for late 2011, before which time certain proved undeveloped reserves are expected to be reclassified to the proved developed category. Maximum total production of 180,000 barrels of crude oil per day is expected to be achieved within one year of start-up. The end date of the concession period will be determined after final regulatory approvals are obtained.

Chevron operates and holds a 95 percent interest in the 2003 Nsiko discovery, also on OPL 249. Two successful appraisal wells were drilled in 2004, with subsurface evaluations and field development planning ongoing in early 2007. The company expects FEED to begin in late 2007. Maximum total production of 100,000 barrels of oil per day is anticipated within one year of initial start-up, targeted for 2012. At the end of 2006, no proved reserves had been recognized for this project.

The Nnwa Field in OML 129 (formerly OPL 218) was discovered in 1999 and extends into two adjacent non-Chevron leased blocks. Chevron s nonoperated working interest in OML 129 is 46 percent. A later discovery in OML 129 was made in the Bilah Field. Commerciality of these fields is dependent upon resolution of the Nigerian Deepwater Gas fiscal regime and collaboration agreements with adjacent blocks. The Bilah Field discovery was under evaluation in early 2007 for further appraisal and the viability of a stand-alone condensate liquid recovery scheme.

Chevron is a participant in the South Offshore Water Injection Project, an enhanced crude-oil recovery project in the south offshore area of OML 90. The company operates and holds a 40 percent interest as part of the joint venture with NNPC. The objective of the project is to increase production by providing water injection, natural-gas lift and production debottlenecking in the South Offshore Asset Area (Okan and Delta fields). The 25-year-life project is in its development phase and by the end of 2006 was contributing incremental production of approximately 7,000 net barrels of crude oil per day. Maximum total production from this project is expected to be 35,000 barrels of crude oil per day in 2010. The major project milestones expected in 2007 include commencement of water injection from the new Delta South Water Inject Platform facility, drilling of 10 additional wells and the installation of pipelines. Initial recognition of proved developed and proved undeveloped reserves was made in 2005. Reclassification of proved reserves to the proved developed category is expected to occur after the evaluation of the water injection performance.

In May 2006, the company announced the discovery of crude oil at the Uge-1 well in the 20 percent-owned and nonoperated offshore OPL 214. Future drilling is contingent primarily on completing technical studies.

Chevron is involved in projects in Nigeria that support the company s strategic initiative to commercialize its significant natural gas resource base outside the United States. Construction began in early 2006 on the Phase 3A expansion of the Escravos Gas Plant (EGP). Engineering, procurement and construction are expected to continue through 2007, with start-up targeted for early 2009. The scope of EGP Phase 3A includes offshore natural gas gathering and compression infrastructure and a second plant, which potentially would increase processing capacity from 285 million to 680 million cubic feet of natural gas per day and increase LPG and condensate export capacity from 4,000 to 43,000 barrels per day. Proved undeveloped reserves associated with EGP Phase 3A were recognized in 2002. These reserves are expected to be reclassified to proved developed as various project milestones are reached 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 also to page 25 for a discussion on the planned gas-to-liquids facility at Escravos.

Chevron holds a 38 percent interest in the West African Gas Pipeline, which is expected to start up in the first-half 2007 and supply Nigerian natural gas to customers in Ghana, Benin and Togo for industrial applications and power generation. A 350-mile offshore segment of the West African Gas Pipeline connects to an existing onshore pipeline in Nigeria. Chevron is the managing sponsor in West African Pipeline Company Limited, which constructed, owns and will operate the pipeline.

In February 2006, Chevron signed a Project Development Agreement for a 19 percent nonoperated working interest in the Olokola LNG Project, which involves construction of a four-train, 22-million-metric-ton-per-year natural gas liquefaction facility and marine terminal located in a free trade zone between Lagos and Escravos. Chevron is expected to supply approximately 1.8 billion cubic feet per day of natural gas to the LNG plant. The project entered FEED in the first quarter 2006. The partners investment decision is scheduled for 2007, and initial production is targeted for 2012. The company had not recognized proved reserves for this project at the end of 2006.

Nigeria-São Tomé e Príncipe Joint Development Zone (JDZ): Chevron is the operator of JDZ Block 1 and holds a 46 percent interest following the sale of a 5 percent interest in 2006. In March 2006, the first exploration well was completed and encountered hydrocarbons. In early 2007, commercial options were being examined to determine the possible need for additional drilling.

c) Asia-Pacific

Australia: During 2006, the net daily production from Chevron s interests in Australia was 34,000 barrels of crude oil and condensate, 5,000 barrels of LPG, and 360 million cubic feet of natural gas.

Chevron has a 17 percent nonoperated working interest in the North West Shelf (NWS) Venture offshore Western Australia. Daily net production from the project during 2006 averaged 29,000 barrels of crude oil and condensate, 358 million cubic feet of natural gas, and 5,000 barrels of LPG. Approximately 75 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. A fifth LNG train, which is intended to increase export capacity by more than 4 million metric tons per year to more than 16 million, is expected to be commissioned in 2008. The Angel natural gas field, being developed at an estimated total cost of $1.2 billion, will supply the fifth LNG train. NWS reserves are recorded according to existing sales agreements. Start-up of the fifth train is projected to accelerate production of proved reserves and additional reclassification of proved undeveloped reserves to proved developed. The end of the concession period for the NWS Venture is 2034.

On Barrow and Thevenard islands off the northwest coast of Australia, Chevron operates crude oil producing facilities that had combined net production of 5,000 barrels per day in 2006. Chevron s interest in this operation is 57 percent for Barrow Island and 51 percent for Thevenard Island.

Also off the northwest coast of Australia, Chevron is the operator of the Gorgon-area fields and has a 50 percent ownership interest across most of the Greater Gorgon Area. Chevron and its two joint-venture participants signed a Framework Agreement in 2005 that will enable the combined development of Gorgon and the nearby natural gas fields as one world-scale project. In early 2007, progress continued toward securing environmental regulatory approvals necessary for the development of the Greater Gorgon LNG project on Barrow Island. A two-train, 10-million-metric-ton-per-year LNG development is planned for the island, with natural gas supplied from the Gorgon and Jansz natural gas fields.

Elsewhere in the Greater Gorgon Area during 2006, concept studies were undertaken on the Wheatstone-1 natural gas discovery located northeast of the Gorgon Field. Appraisal drilling is scheduled for 2007. The company also announced in 2006 two significant natural gas discoveries at the 67 percent-owned Clio-1 and 50 percent-owned Chandon-1 exploration wells located offshore northwestern coast in the Greater Gorgon development area. Additional work on these two company-operated prospects includes a 3-D seismic survey program that started in late 2006 to better determine the potential of the natural gas find and subsequent development options.

Chevron was also awarded exploration rights to Blocks WA-374-P (Greater Gorgon Area) and WA-383-P (Exmouth West) in the Carnarvon Basin offshore Western Australia. Chevron holds a 50 percent operated interest in the blocks. Operations commenced in WA-374-P with the acquisition of 3-D seismic data. On WA-383-P, a three-year work program includes geotechnical studies and 2-D seismic work. In early 2007, the company was also named operator and awarded a 50 percent interest in exploration acreage in Block W06-12 in the Greater Gorgon Area. A three-year work program includes geotechnical studies, seismic surveys and drilling of an exploration well.

At the end of 2006, the company had not recognized proved reserves for any of the Greater Gorgon Area fields. Recognition is contingent on securing sufficient LNG sales agreements and achieving other key project milestones. The company has signed separate nonbinding Heads of Agreements totaling 4.2 million metric tons per year with three companies in Japan to supply LNG from the Gorgon project. As of early 2007, negotiations were continuing to finalize binding sales agreements. Purchases by each of these customers are expected to range from 1.2 million metric tons per year to 1.5 million metric tons per year of LNG over 25 years beginning after 2010.

Azerbaijan: Chevron holds a 10 percent nonoperated 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. Chevron also has a 9 percent equity interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline, which transports AIOC production from Baku, Azerbaijan, through Georgia to deepwater port facilities in Ceyhan, Turkey. (Refer to Pipelines under Transportation Operations on page 27 for a discussion of the BTC operations.)

In 2006, the company s daily net crude oil production from AIOC averaged 46,000 barrels. Phase II of the ACG development project began producing from the West Azeri Field in late 2005 and was completed with the production of first oil from the East Azeri Field in October 2006. Phase III was in the final phase of development in early 2007, with production start-up targeted for 2008. Total crude oil production from the project is expected to increase to about 700,000 barrels per day in 2007 and to more than 1 million barrels per day by 2009. Proved undeveloped reserves for ACG are expected to be reclassified to proved developed reserves as new wells are drilled and completed. The AIOC operations are conducted under a 30-year PSC that expires at the end of 2024.

Kazakhstan: Chevron holds a 20 percent nonoperated working interest in the Karachaganak project that is being developed in phases. During 2006, Karachaganak daily net production averaged 38,000 barrels of liquids and 143 million cubic feet of natural gas.

The Karachaganak operations are conducted under a 40-year concession agreement that expires in 2038. In 2006, access to the Caspian Pipeline Consortium (CPC) and Atyrau-Samara pipelines allowed Karachaganak sales of approximately 143,000 barrels per day (27,000 net barrels) of processed liquids at prices available in world markets. A fourth train was approved in December 2006 that is designed to increase this export of processed liquids by 56,000 barrels per day (11,000 net barrels). The fourth train is expected to start up in 2009.

Phase III of Karachagnak field development is contingent upon the Republic of Kazakhstan s identifying and enabling a commercially attractive outlet for the increased natural gas volumes. Timing for the recognition of Phase III proved reserves and an increase in production are uncertain, and both depend on achieving a natural gas sales agreement and finalizing a viable Phase III project design.

Refer also to page 23 for a discussion of Tengizchevroil, a 50 percent-owned affiliate with operations in Kazakhstan.

Russia: In 2005, OAO Gazprom, Russia s largest natural gas producer, included Chevron on a list of companies that could continue discussions concerning the development and related commercial activities of the Shtokmanovskoye Field, a very large natural gas field offshore Russia in the Barents Sea. In October 2006, OAO Gazprom issued a public statement indicating its plan to develop Shtokmanovskoye without foreign partners. Refer also to page 24 for a discussion of the company s interest in a Russian joint venture.

Bangladesh: Chevron is the operator of four onshore blocks, with a 98 percent interest in Blocks 12, 13 and 14 and a 43 percent interest in Block 7. In 2006, the properties averaged daily net production of 126 million cubic feet of natural gas. Following a two-year development program, production from the Bibiyana Field in Block 12 is scheduled to start in the first-half 2007, reaching maximum total production of 500 million cubic feet per day by late 2010. The development program includes a gas processing plant with capacity of 600 million cubic feet per day and a natural gas pipeline. Initial proved reserves were recognized in 2005. In 2006, additional proved reserves were recognized based on additional development wells drilled during the year, and certain proved undeveloped reserves were reclassified to the proved developed category in recognition of imminent completion of the gas plant and pipeline infrastructure required for production start-up. The Bibiyana PSC expires in 2034.

Table of Contents

Cambodia: Chevron operates and holds a 55 percent interest in the 1.6 million-acre Block A, located offshore in the Gulf of Thailand. A third drilling campaign commenced in third quarter 2006 and is expected to be completed by first quarter 2007.

Myanmar: Chevron has a 28 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana and Sein fields, located offshore Myanmar in the Andaman Sea. The company also has a 28 percent 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. The company s average net natural gas production in Myanmar was 89 million cubic feet per day in 2006.

Thailand: Chevron has both operated and nonoperated working interests in several different offshore blocks in Thailand. The company s daily net production averaged 73,000 barrels of crude oil and condensate and 856 million cubic feet of natural gas in 2006.

Operated interests include concessions with ownership interests ranging from 35 percent to 80 percent in Blocks 10 through 13 and B12/27, 52 percent-owned Blocks B8/32 and 9A, 60 percent-owned G4/43 and 71 percent-owned G4/48.

In the concession containing Blocks 10 through 13 and B12/27, debottlenecking of all central processing platforms was completed, which is expected to add more than 160 million cubic feet per day of natural gas processing capability. The company anticipates this additional capacity will be used when PTT Public Company Limited completes the third natural gas pipeline to shore in 2007. In late 2007, the company expects to complete the evaluation of a possible second natural gas central processing facility in Platong to support a Heads of Agreement signed in 2003 for additional natural gas sales to meet future natural gas demands in Thailand. This Platong Gas II Project, in which the company has a 70 percent interest, would add 330 million cubic feet per day of processing capacity in the Platong area, which spans Blocks 10, 10A, 11 and 11A in the Gulf of Thailand. The new facilities would include a central processing platform, pipelines and five initial wellhead platforms. First gas sales would occur in 2010. Proved reserves would be recognized throughout the 12-year project life as the required wellhead platforms are developed.

In Blocks B8/32 and 9A, crude oil is produced from six operating areas within the Pattani Field. First production from Lanta area in Block G4/43 is anticipated in the first-half 2007.

Chevron has a 16 percent nonoperated working interest in Blocks 14A, 15A, 16A and G9/48, known collectively as the Arthit Field. Development of Arthit is progressing with six wellhead platforms installed and 41 wells drilled in 2006. First production is planned for 2008.

In 2006, the company signed two exploration concessions, Blocks G4/48 and G9/48. Two delineation wells are scheduled to be drilled in Block G4/48 in 2007. One exploration well in Block G9/48 is required to be drilled by the first quarter 2009. As of early 2007, processing and interpretation of seismic data were under way in Block G9/48. Chevron also holds exploration interests in a number of blocks that are currently inactive, pending resolution of border issues between Thailand and Cambodia.

Vietnam: The company is operator in two PSCs 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 April 2006, the company signed a 30-year PSC for Block 122 located offshore eastern Vietnam. The company has a 50 percent operated interest in this block and has undertaken a three-year work program for seismic acquisition and drilling of an exploratory well.

In July 2006, the company submitted a revised summary development plan to state-owned PetroVietnam for Blocks B, 48/95 and 52/97 for the Vietnam Gas Project. The final detailed development plan is expected to be submitted in the third quarter 2007, with FEED projected to begin by the end of 2007. First natural gas production is targeted for 2011 but is dependent on the progress of commercial negotiations. Maximum total production of approximately 500 million cubic feet of natural gas per day is projected within four years of the production start-up. Recognition of initial proved reserves is expected to follow execution of the gas sales agreements and anticipated project sanction in 2008. Total development cost for the project is approximately $3.5 billion.

Table of Contents

China: Chevron has a 33 percent nonoperated working interest in Blocks 16/08 and 16/19 located in the Pearl River Delta Mouth Basin, a 25 percent nonoperated working interest in QHD-32-6 in Bohai Bay, and a 16 percent nonoperated 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 23,000 barrels of crude oil and condensate and 18 million cubic feet of natural gas in 2006. Production during 2006 included first natural gas in January from the HZ21-1 natural gas development project, located in Block 16/08. Chevron also has interests ranging from 36 percent to 50 percent in four prospective onshore natural gas blocks in the Ordos Basin totaling about 1.5 million acres.

Partitioned Neutral Zone (PNZ): Saudi Arabian Chevron 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. In September 2006, Chevron submitted to the Kingdom of Saudi Arabia a proposal to extend the concession agreement. Under the current concession, Chevron 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 2006, average daily net production was 111,000 barrels of crude oil and 19 million cubic feet of natural gas. Facilities for the first phase of a steamflood project were completed in December 2005, and steam injection began in February 2006. The success of the first phase has led to the approval of funding for a second phase steamflood pilot project that is expected to be completed by late 2008. This pilot is a unique application of steam injection into a carbonate reservoir.

Philippines: The company holds a 45 percent nonoperated working interest in the Malampaya natural gas field located about 50 miles offshore Palawan Island. Daily net production in 2006 was 108 million cubic feet of natural gas and 6,000 barrels of condensate. Chevron also develops and produces steam resources under an agreement with the National Power Corporation, a Philippine government-owned company. The combined generating capacity is 634 megawatts.

d) Indonesia

Chevron s operated interests in Indonesia are managed by several wholly owned subsidiaries, including PT. Chevron Pacific Indonesia (CPI), Chevron Indonesia Company, Chevron Makassar Ltd, Chevron Geothermal Indonesia (CGI) and Chevron Geothermal Salak Ltd (CGS), and a subsidiary P.T. Mandau CiptaTenaga Nusantara (MCTN). CPI operates four PSCs, with interests ranging from 50 percent to 100 percent. In addition Chevron operates five PSCs in the Kutei Basin, East Kalimantan and one PSC in the Tarakan Basin, Northeast Kalimantan. These interests range from 35 percent to 100 percent. Chevron also has a 25 percent working interest in a nonoperated joint venture in South Natuna Sea Block B and a 40 percent working interest in the nonoperated NE Madura III Block in the East Java Sea Basin. CGI is a power generation company that operates the Darajat geothermal contract area in West Java, with a total capacity of 145 megawatts. MCTN operates a cogeneration facility in support of CPI s operation in North Duri. CGS operates the Salak geothermal field, located in West Java, with a total capacity of 377 megawatts.

In North Duri, located in the Rokan PSC, development is progressing on steamflood activity for the sequential development of three possible expansion areas. The first expansion involves the development of Area 12, in which the company has a 100 percent interest, and is planned to come onstream in 2008, with maximum total daily production estimated at 34,000 barrels of crude oil in 2012. Proved undeveloped reserves for North Duri were recognized in previous years, and reclassification from proved undeveloped to proved developed will occur during various stages of sequential project completion.

A drilling campaign is scheduled to continue through 2007 in South Natuna Sea Block B, with first oil from Kerisi Field expected in late 2007. In 2006, the company executed a farm-out agreement relinquishing five Indonesian PSCs in exchange for a 40 percent nonoperated working interest in the NE Madura III Block.

In early 2007, the company submitted preliminary plans of development to the government of Indonesia for the Bangka, Gendalo Hub and Gehem Hub deepwater natural gas projects, located in the Kutei Basin. These projects will

Table of Contents

likely be developed in parallel, with first production for all projects targeted for 2013. The actual timing is partially dependent on government approvals, market conditions and the achievement of key project milestones.

The development concept for the 50 percent-owned and operated Sadewa project, located in the Kutei Basin is under evaluation and is expected to be completed in late 2007. Assuming the evaluation is positive, initial proved reserves recognition would be expected to occur in 2008, with first production expected in 2010.

Daily net production from all producing areas in Indonesia averaged 198,000 barrels of crude oil and 302 million cubic feet of natural gas in 2006.

e) Other International Areas

Argentina: Chevron operates in Argentina through its subsidiary, Chevron Argentina S.R.L. The company and its partners hold 17 operated production concessions and four exploration blocks (two operated and two nonoperated) in the Neuquen and Austral basins. Working interests range from approximately 19 percent to 100 percent in operated license areas. Daily net production in 2006 averaged 38,000 barrels of crude oil and 54 million cubic feet of natural gas. Chevron also holds a 14 percent interest in Oleoductos del Valle S.A. pipeline and a 28 percent interest in the Oleoducto Transandino pipeline.

Brazil: Chevron holds working interests ranging from 20 percent to 52 percent in four deepwater blocks. In Block BC-4, located in the Campos Basin, the company is the operator and has a 52 percent interest in the Frade Field.

In 2006, the Frade project completed FEED and started construction with all major contracts in place. The total project cost is estimated at $2.8 billion. Proved undeveloped reserves were recorded for the first time in 2005. Reclassification of proved undeveloped reserves to the proved developed category is anticipated upon production start-up in early 2009 and is expected to continue until 2011. Estimated maximum total production of 90,000 oil-equivalent barrels per day is anticipated in 2011. The Frade concession expires in 2025.

The company concentrates its exploration efforts in the Campos and Santos basins. In the nonoperated Campos Basin Block BC-20, two areas 38 percent-owned Papa-Terra (formerly RJS610) and 30 percent-owned RJS609 have been retained for development following the end of the exploration phase of this block. In the Papa-Terra area, the appraisal phase has been completed confirming hydrocarbons in three separate reservoirs. In June 2006, a field development plan was submitted to the government. FEED for the Papa-Terra Field is expected to commence in late 2007 after completing an appraisal program planned for mid-2007. In the RJS609 area, all appraisal drilling was completed to fulfill requirements for a Declaration of Commerciality that was filed in December 2006 for a new field, designated Maromba. Elsewhere in Campos, the company holds a 30 percent nonoperated working interest in the BM-C-4 Block, in which drilling of the final obligatory exploration well began in October 2006. As of early 2007, drilling of the

Guarana prospect was ongoing, with completion and evaluation expected to occur later in 2007. In the 20 percent-owned and nonoperated Santos Basin BS-4 Block, the evaluation of an exploration campaign was completed in 2006, with the Declaration of Commerciality filed in December 2006 designating two new fields, Atlanta and Oliva.

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 agreement that 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 174 million cubic feet of natural gas per day in 2006. New production capacity was commissioned in 2006 and will help meet the demand of the growing Colombian natural gas market.

Trinidad and Tobago: The company has a 50 percent nonoperated working interest in four blocks in offshore Trinidad, which include the Dolphin and Dolphin Deep producing natural gas fields and the Starfish discovery. Net natural gas production from Dolphin and Dolphin Deep in 2006 averaged 174 million cubic feet per day.

Natural gas supply to the Atlantic LNG Train 3 from the Dolphin Field began in 2005. In July 2006, Chevron delivered the first natural gas from the Dolphin Deep development to the Atlantic LNG Train 3 and Train 4. The initial phase of the development became fully operational during 2006 and supplied an average of 38 million net cubic feet of natural gas per day to Train 3 and 31 million net cubic feet of natural gas per day to Train 4. Proved reserves associated with the Train 4 gas sales agreement were recognized in 2004. 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 the Manatee area of Block 6d. After successful exploration drilling results in 2005, the company assessed alternative development strategies for the Loran Field in Venezuela and Manatee area in 2006. As of early 2007, negotiations were in progress between Trinidad and Tobago and Venezuela to unitize the Loran and Manatee discoveries.

Venezuela: As of October 2006, the company s operations at the Boscan and LL-652 fields were converted to two joint stock companies. From that date, these activities were treated as affiliate operations and accounted for under the equity method. Refer to page 23 for a further discussion of these operations.

The company also has ongoing exploration activity in two blocks offshore Plataforma Deltana, in which the company is operator and holds a 60 percent interest. In Block 2, which includes the Loran Field, evaluation and project development work continued during 2006. In the 100 percent-owned and operated Block 3, Chevron discovered natural gas in 2005. The discovery is in close proximity to the Loran natural gas field and provides significant resources that will be included in the detailed evaluation as a potential gas supply source for Venezuela s first LNG train. Seismic work elsewhere in Block 3 started in 2006. Chevron also has 100 percent interest in the Cardon III exploration block, located offshore western Venezuela north of the Maracaibo producing region. Seismic work in this block, which has natural gas potential, is planned for 2007.

Refer also to page 23 for a discussion of the Hamaca heavy oil production and upgrading project in Venezuela.

Canada: The company s assets in Canada include a 27 percent nonoperated working interest in the Hibernia Field offshore eastern Canada, a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP) and exploration acreage in the Mackenzie Delta and Orphan Basin. Excluding volumes mined at the AOSP, daily net production in 2006 from the company s Canadian operations was 46,000 barrels of crude oil and natural gas liquids and 6 million cubic feet of natural gas. The company also owns a 28 percent operated interest in the Hebron project offshore eastern Canada. Negotiations with the government of Newfoundland and Labrador on commercial terms for the development of the field were suspended in April 2006, and the project team was demobilized. The timing for a possible resumption of negotiations was uncertain as of early 2007.

At the AOSP, which began operations in 2003, bitumen is mined from oil sands and upgraded into synthetic crude oil using hydroprocessing technology. Chevron s share of bitumen production in 2006 averaged 27,000 barrels per day.

In 2006, the company elected to participate in the first phase of expansion of the AOSP. The expansion is being designed to produce approximately 100,000 barrels of bitumen per day (20,000 net barrels) and upgrade it into synthetic crude oil at an estimated total cost of $10 billion. The expansion will increase total AOSP design capacity to approximately 255,000 barrels of bitumen per day by 2010. This phase of expansion includes the construction of mining and extraction facilities at the Jackpine Mine, for which net proved undeveloped oil sands reserves were recorded in 2006.

Net proved oil sands reserves at the end of 2006 were 443 million barrels, increasing from 2005 primarily due to the addition of reserves for the Jackpine Mine and proved developed oil sands reserves for the Muskeg River Mine. Securities and Exchange Commission regulations define these reserves as mining-related and not a part of conventional oil and gas reserves.

Chevron also holds a 60 percent operated interest in the Ells River In Situ Oil Sands Project in the Athabasca region. This project consists of heavy oil leases of more than 75,000 acres that were acquired in 2005 and 2006. The area contains significant volumes with the potential for recovery using Steam Assisted Gravity Drainage, a proven technology that employs steam and horizontal drilling to extract the bitumen through wells rather than through mining operations. Initial drilling began in January 2007.

Table of Contents

Denmark: Chevron holds a 15 percent nonoperated working interest in the Danish Underground Consortium (DUC), which produces crude oil and natural gas from 15 fields in the Danish North Sea and involves 12 percent to 27 percent interests in five exploration licenses. Daily net production in 2006 from the DUC was 44,000 barrels of crude oil and 146 million cubic feet of natural gas.

Faroe Islands: During 2006, the company focused on the interpretation of the seismic program over License 008, located near the Rosebank/Lochnagar discovery in the United Kingdom. The company has a 40 percent interest in five offshore blocks and is the operator.

Netherlands: Chevron is the operator and holds interests ranging from 34 percent to 80 percent in nine blocks in the Netherlands sector of the North Sea. The company s daily net production from seven producing fields averaged 3,000 barrels of crude oil and 7 million cubic feet of natural gas in 2006. Production start-up at the first stage of the A/B Gas Project is scheduled for early 2008.

Norway: At the 8 percent-owned and nonoperated Draugen Field, the company s share of production during 2006 was 6,000 barrels of crude oil per day. In the 30 percent-owned and nonoperated PL 324 Field, the first exploration well is planned for the first-half 2007. In the 40 percent-owned and operated PL 325, seismic data was acquired in 2006. Pending the results of the ongoing seismic processing, a first exploration well is planned for 2008. At PL 283, in which Chevron holds a 25 percent nonoperated working interest, an exploration well that tested natural gas in the Stetind prospect in 2006 will be followed by another exploration well in mid-2007.

Through an Area of Mutual Interest with a partner in the Barents Sea, Chevron was awarded a 40 percent nonoperated working interest in PL 397 in April 2006, encompassing six blocks located in the Nordkapp East Basin. A 3-D seismic survey was acquired and is planned to be processed in 2007.

United Kingdom: Offshore United Kingdom, the company s daily net production in 2006 from nine fields was 75,000 barrels of crude oil and 242 million cubic feet of natural gas. Of this volume, daily net production from the 85 percent-owned and operated Captain Field was 37,000 barrels of crude oil and from the co-operated and 32 percent-owned Britannia Field was 5,000 barrels of crude oil and 138 million cubic feet of natural gas. In December 2006, Chevron exchanged interests in the nonproducing North Sea Blocks 16/22 and 16/23 for an additional 2 percent interest in the Chevron-operated Alba Field, raising the company s total interest to 23 percent. Daily net production from this field averaged 11,000 barrels of crude oil in 2006.

As of early 2007, development activities were continuing at the Britannia satellite fields Callanish and Brodgar, in which Chevron holds 17 percent and 25 percent nonoperated working interests, respectively. A new platform and all subsea equipment and pipelines were installed in 2006. Production start-up from these two satellite fields is expected to occur in 2008. Together, these fields are expected to achieve maximum total daily production of 25,000 barrels of crude oil and 133 million cubic feet of natural gas several months after both fields start up. Proved undeveloped reserves were initially recognized in 2000. In 2006, proved undeveloped reserves were reclassified to the proved developed category. This project has an expected production life of approximately 15 years.

Production start-up occurred in June 2006 at the Area C project in the eastern portion of the Captain Field. The project included the installation of subsea infrastructure and the drilling of two new subsea wells. Maximum total production of 14,000 barrels of crude oil per day was achieved in September 2006. Initial proved undeveloped reserves were booked in 2004 and were reclassified as proved developed in 2006 following completion of development drilling. Further additions to proved reserves are expected to occur as the field matures.

The Alder discovery, west of the Britannia Field, is being evaluated and likely to be developed as a tieback to existing infrastructure. The company has a 70 percent operated interest in the project, which is expected to start up and reach maximum total daily production rates of 9,000 barrels of crude oil and 80 million cubic feet of natural gas in 2011. No proved reserves had been recognized as of year-end 2006.

In late 2006, the first well in a three-well program began drilling to evaluate the commercial potential of the Rosebank/Lochnagar discovery and adjacent acreage.

In early 2007, Chevron was awarded eight operated exploration blocks and two nonoperated blocks west of Shetland Islands in the 24th United Kingdom Offshore Licensing Round.

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. Chevron s share of daily net production in 2006 averaged 135,000 barrels of crude oil and natural gas liquids and 193 million cubic feet of natural gas.

TCO is undergoing a significant expansion composed of two integrated projects referred to as the Second Generation Plant (SGP) and Sour Gas Injection (SGI). At a total combined cost of approximately $6 billion, these projects are designed to increase TCO s crude oil production capacity from 300,000 barrels per day to between 460,000 and 550,000 barrels per day in 2008. The actual production level within the estimated range is dependent partially on the effects of the SGI, which are discussed below. The start-up of the SGP/SGI project is expected in 2007.

SGP involves the construction of a large processing train for treating crude oil and the associated sour gas (i.e., high in sulfur content). The SGP design is based on the same conventional technology employed in the existing processing trains. Proved undeveloped reserves associated with SGP were recognized in 2001. During 2006, 55 wells were drilled, deepened and/or completed in the Tengiz and Korolev reservoirs to generate volumes required for the new SGP train, and reserves associated with the project were reclassified to the proved developed category. 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 sour gas separated from the crude oil production at the SGP processing train and reinjecting 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, it is expected that over time SGI will increase production efficiency and recoverable volumes as the injected gas maintains higher reservoir pressure and displaces oil toward producing wells. 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 seeking stockholder approval for an expansion to accommodate increased TCO volumes beginning in 2009. During 2006, TCO continued the construction of expanded rail car loading and rail export facilities, which is expected to be completed by third quarter 2007. As of early 2007, other alternatives were also being explored to increase export capacity 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 late 2004. In 2005, the facility reached total design capacity of processing and upgrading 190,000 barrels per day of heavy crude oil (8.5 degrees API gravity) into 180,000 barrels of lighter, higher-value crude oil (26 degrees API gravity). In 2006, daily net production averaged 36,000 barrels of liquids and 8 million cubic feet of natural gas. In late February 2007, the President of Venezuela issued a decree announcing the government s intention for the state-owned oil company, Petróleos de Venezuela S.A., to increase its ownership later this year in all Orinoco Heavy Oil Associations, including Chevron s 30 percent-owned Hamaca project, to a minimum of 60 percent. The impact on Chevron from such an action is uncertain but is not expected to have a material effect on the company s results of operations, consolidated financial position or liquidity.

The company operated the onshore Boscan Field for 10 years under an operating service agreement with Petróleos de Venezuela S.A. In October 2006, the contract was converted into a joint stock company, Petroboscan, in which Chevron is a 39 percent owner. At the same time, operatorship was transferred from Chevron to Petroboscan. No proved reserves had been recognized under the operating service agreement, but proved reserves associated with this new 20-year production contract were recorded in 2006. Under the operating service agreement, Boscan had average net production of 109,000 oil-equivalent barrels per day for the first nine months of 2006. Net production for the final three months of 2006 under the joint stock company was 30,000 oil-equivalent barrels per day.

Table of Contents

The company operated the LL-652 Field for eight years under a risked-service agreement with a 63 percent interest until the contract was converted in October 2006 to a 25 percent-owned joint stock company, Petroindependiente. Under the new contract, Petroindependiente is the operator during the 20-year contract period. Located in Lake Maracaibo, LL-652 s net production averaged 3,000 barrels of liquids per day and 25 million cubic feet of natural gas per day during 2006. Chevron had previously booked reserves for LL-652 under the risked-service agreement.

Russia: In October 2006, Chevron signed a framework agreement with OAO Gazpromneft, establishing a Russian joint venture for exploration and development activities focused in the Yamal-Nenets region of Western Siberia. Chevron will maintain a 49 percent joint-operated interest in the venture. Refer to page 17 for a discussion of the company s other activities in Russia.

Sales 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 Australia, Indonesia, Latin America, Thailand and the United Kingdom 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-11 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. Refer also to Contract Obligations on page 7 for information related to the company s contractual commitments for the sale of crude oil and natural gas.

Downstream Refining, Marketing and Transportation

Refining Operations

At the end of 2006, the company s refining system consisted of 20 fuel refineries and an asphalt plant. The company operated nine of these facilities, and 12 were operated by affiliated companies.

The daily refinery inputs for 2004 through 2006 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, 2006 Number	Operable Capacity	Refinery Inputs 2006	2005	2004
Pascagoula	Mississippi	1	330	337	263	312
El Segundo	California	1	260	258	230	234
Richmond	California	1	243	224	233	233
Kapolei	Hawaii	1	54	50	50	51
Salt Lake City	Utah	1	45	39	41	42
Other[1]		1	80	31	28	42
Total Consolidated Companies	**United States**	**6**	**1,012**	**939**	**845**	**914**
Pembroke	United Kingdom	1	210	165	186	209

Cape Town[2]	South Africa	1	110	71	61	62
Burnaby, B.C.	Canada	1	55	49	45	49
Total Consolidated Companies	**International**	**3**	**375**	**285**	**292**	**320**
Affiliates[3]	Various Locations	12	834	765	746	724
Total Including Affiliates	**International**	**15**	**1,209**	**1,050**	**1,038**	**1,044**
Total Including Affiliates	**Worldwide**	**21**	**2,221**	**1,989**	**1,883**	**1,958**

1 Asphalt plants in Perth Amboy, New Jersey, and Portland, Oregon. The Portland plant was sold in February 2005.

2 Chevron holds 100 percent of the common stock issued by Chevron South Africa (Pty) Limited, which owns the Cape Town Refinery. A consortium of South African partners owns preferred shares ultimately convertible to a 25 percent equity interest in Chevron South Africa (Pty) Limited. None of the preferred shares had been converted as of February 2007.

3 Chevron acquired an 8 percent ownership interest in the SONARA refinery located in Limbe, Cameroon, in July 2006. This increased the company s share of operable capacity by about 3,000 barrels per day.

Average crude oil distillation capacity utilization during 2006 was 90 percent, compared with 86 percent in 2005. In general, this increase resulted from less planned and unplanned downtime in 2006, due partly to downtime in 2005 that was attributable to hurricanes in the U.S. Gulf of Mexico. No downtime was caused by hurricanes in 2006. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 99 percent in 2006, compared with 90 percent in 2005, and cracking and coking capacity utilization averaged 86 percent and 76 percent in 2006 and 2005, respectively. Cracking and coking units, including fluid catalytic cracking units, are the primary facilities used in fuel refineries to convert heavier products into gasoline and other light products.

The company s U.S. West Coast, Gulf Coast and Salt Lake refineries produce low-sulfur fuels that meet 2006 federal government specifications. Investments required to produce low-sulfur fuels in Europe, Canada, South Africa and Australia were completed in 2006. The company is evaluating alternatives for clean-fuel projects in its Southeast Asia refineries.

In 2006, the company completed an expansion of the Pascagoula, Mississippi, refinery s Fluid Catalytic Cracking Unit to increase the production of gasoline and other light products. In addition, construction projects began at the El Segundo, California, refinery to increase heavy, sour crude oil processing capability and at the Pembroke, United Kingdom, refinery to increase the capability to process Caspian-blend crude oils. Completion of these projects is expected in 2007. Additional projects to upgrade the company s refineries in Mississippi and California were being evaluated in early 2007.

Also in 2006, GS Caltex, the company s 50 percent-owned affiliate, began construction of 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. Completion of the Yeosu project is expected in late 2007.

In April 2006, Chevron purchased a 5 percent interest in Reliance Petroleum Limited, a company formed by Reliance Industries Limited to own and operate a new export refinery being constructed in Jamnagar, India. The 580,000-barrel-per-day-crude-oil-capacity refinery is expected to begin operation in December 2008. Chevron has future rights to increase its equity ownership to 29 percent. The new refinery would be the world s sixth largest on a single site.

Refer to page FS-2 for a discussion of the pending disposition of the company s 31 percent interest in the Nerefco Refinery in the Netherlands.

Chevron processes imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 87 percent and 83 percent of Chevron s U.S. refinery inputs in 2006 and 2005, respectively.

Gas-to-Liquids

The Sasol Chevron Global 50-50 Joint Venture was established in 2000 to develop a worldwide gas-to-liquids (GTL) business. Through this venture, the company is pursuing GTL opportunities in Qatar and other countries.

In Nigeria, 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 Phase 3A expansion of the Escravos Gas Plant (EGP). Plant construction began in 2005, and the first process modules are expected to be delivered to the site by the second half of 2007. The GTL plant is expected to be operational by the end of the decade. Refer also to page 15 for a discussion on the EGP Phase 3A expansion.

Marketing Operations

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

The table on the following page shows the company s and affiliates refined products sales volumes, excluding intercompany sales, for the three years ending December 31, 2006.

Table of Contents

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

	2006	2005	2004
United States			
Gasolines	712	709	701
Jet Fuel	280	291	302
Gas Oils and Kerosene	252	231	218
Residual Fuel Oil	128	122	148
Other Petroleum Products[2]	122	120	137
Total United States	**1,494**	**1,473**	**1,506**
International[4]			
Gasolines	595	662	715
Jet Fuel	266	258	250
Gas Oils and Kerosene	776	781	804
Residual Fuel Oil	324	404	458
Other Petroleum Products[2]	166	147	141
Total International[3]	**2,127**	**2,252**	**2,368**
Total Worldwide[4]	**3,621**	**3,725**	**3,874**

1 Includes buy/sell arrangements. Refer to Note 14 on page FS-43.	50	217	180
2 Principally naphtha, lubricants, asphalt and coke.			
3 2005 and 2004 conformed to 2006 presentation.			
4 Includes share of equity affiliates sales:	492	498	502

In the United States, the company markets under the Chevron and Texaco brands. The company supplies directly or through retailers and marketers almost 9,600 branded motor vehicle retail outlets, concentrated in the mid-Atlantic, southern and western states. Approximately 600 of the outlets are company-owned or -leased stations. By the end of 2006, the company was supplying more than 2,100 Texaco retail sites, primarily in the Southeast and West. All rights to the Texaco brand in the United States reverted to Chevron in July 2006.

Outside the United States, Chevron supplies directly or through retailers and marketers approximately 16,200 branded service stations, including affiliates, in about 75 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 Benin, Cameroon, Côte d Ivoire, Nigeria, Republic of the Congo and Togo. In these countries, 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 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 Scandinavia, the company sold its 50 percent interest in the HydroTexaco joint venture in 2006.

The company continued the marketing and sale of service station sites, focusing on selected areas outside the United States. In 2006, the company sold its interest in more than 450 service stations, primarily in the United Kingdom and Latin America. Since the beginning of 2003, the company has sold its interests in nearly 2,800 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 75 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 and coolant products in about 175 countries under brand names that include Havoline, Delo, Ursa and Revtex.

Refer to page FS-2 for a discussion of the possible disposition of the company s fuels marketing operations in the Netherlands, Belgium and Luxembourg regions.

Table of Contents

Transportation Operations

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, 2006

	Net Mileage[1]
United States:	
Crude Oil[2]	2,884
Natural Gas	2,275
Petroleum Products[3]	6,932
Total United States	**12,091**
International:	
Crude Oil[2]	714
Natural Gas	475
Petroleum Products[3]	421
Total International	**1,610**
Worldwide	**13,701**

1 Partially owned pipelines are included at 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 during 2006, the company completed the sale of three refined-product pipeline systems in Texas and New Mexico as well as its interest in the Windy Hill natural gas storage project in northeastern Colorado. By year-end 2006, work to restore the company s Empire Terminal in Louisiana, which was damaged in the 2005 hurricanes, was substantially complete. During 2006, the company began a project to expand capacity at its Keystone natural gas storage facility by about 3 billion cubic feet to meet increased demand in the Permian Basin production region near the Waha Hub. The Waha Hub is a pricing point for natural-gas-basis swap-futures contracts traded on the New York Mercantile Exchange (NYMEX) and is located in West Texas south of the natural gas deposits in the San Juan and Permian Basins.

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 2006, CPC had transported an average of 664,000 barrels of crude oil per day, including 519,000 barrels per day from the Caspian region and 145,000 barrels per day from Russia.

In addition, the company has a 9 percent equity interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline, which transports Azerbaijan International Operating Company (AIOC) production from Baku, Azerbaijan, through Georgia to deepwater port facilities in Ceyhan, Turkey. Chevron holds a 10 percent nonoperated working interest in AIOC. The first tanker loading at the Ceyhan marine terminal on the Mediterranean Sea occurred in June 2006. The pipeline has a crude oil capacity of 1 million barrels per day and is expected to accommodate the majority of the AIOC production. Another crude oil production export route is the 515-mile Baku-Supsa pipeline, wholly owned by AIOC, with crude oil capacity to transport 145,000 barrels per day from Baku, Azerbaijan, to the terminal at Supsa, Georgia.

For information on projects under way related to the Chad/Cameroon pipeline, the West African Gas Pipeline and the expansion of the CPC pipeline, refer to pages 13, 15 and 23, respectively.

Tankers: At any given time during 2006, the company had approximately 70 vessels chartered on a voyage basis or for a period of less than one year. Additionally, all tankers in Chevron s controlled seagoing fleet were utilized during 2006. The following table summarizes cargo transported on the company s controlled fleet.

Controlled Tankers at December 31, 2006

	U.S. Flag		Foreign Flag	
	Number	**Cargo Capacity (Millions of Barrels)**	**Number**	**Cargo Capacity (Millions of Barrels)**
Owned	3	0.8	1	1.1
Bareboat Chartered			18	27.4
Time Chartered*			22	11.5
Total	**3**	**0.8**	**41**	**40.0**

* One year or more.

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 2006, 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. During the year, the company contracted for the building of four U.S. flagged product tankers, each capable of carrying 300,000 barrels of cargo. These tankers are scheduled for delivery from 2007 through 2010 and are intended to replace the existing three U.S. flag ships.

The international flag vessels were engaged primarily in transporting crude oil from the Middle East, Asia, Black Sea, Mexico and West Africa to ports in the United States, Europe, Australia and Asia. Refined products were also transported by tanker worldwide. During 2006, the company took delivery of two new double-hulled tankers with a total capacity of 2.5 million barrels and terminated the lease on its last single-hulled vessel.

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, Chevron placed orders for two additional LNG tankers to support expected 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. At the end of 2006, 100 percent of the company s owned and bareboat-chartered fleet was double-hulled. 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. At the end of 2006, CPChem owned or had joint venture interests in 30 manufacturing facilities and six research and technical centers in the United States, Puerto Rico, Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar.

In 2006, 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. The styrene facility is located adjacent to CPChem and SIIG s existing aromatics complex in Al Jubail. Also during the year, CPChem continued development of plans for a third petrochemical project in Al Jubail. Preliminary studies are focused on the construction of a world-scale olefins unit, as well as related downstream units, to produce polyethylene, polypropylene, 1-hexene and polystyrene.

In addition, construction continued on the Q-Chem II project in 2006. The Q-Chem II project includes 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 and is 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 1.3-million-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 plants in early 2009. CPChem owns a 49 percent interest in 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, Japan, the Netherlands and Singapore and has equity interests in facilities in India and Mexico.

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

Other Businesses

Mining

Chevron s mining companies in the United States produce and market coal, molybdenum, rare earth minerals and calcined petroleum coke. Sales occur in both U.S. and international markets.

The company s coal mining and marketing subsidiary, The Pittsburg & Midway Coal Mining Co. (P&M), owns and operates two surface mines, McKinley, in New Mexico, and Kemmerer, in Wyoming, and one underground mine, North River, in Alabama. Sales of coal from P&M s wholly owned mines were 12.6 million tons, down 1.0 million tons from 2005. Final reclamation activities continued in 2006 at the Farco surface mine in Texas.

At year-end 2006, P&M controlled approximately 225 million tons of proven and probable coal reserves in the United States, including reserves of environmentally desirable low-sulfur coal. The company is contractually committed to deliver between 11 million and 12 million tons of coal per year through the end of 2009 and believes it will satisfy these contracts from existing coal reserves.

Molycorp Inc. is the company s mining and marketing subsidiary for molybdenum and rare earth minerals. Molycorp owns and operates the Questa molybdenum mine in New Mexico and the Mountain Pass lanthanides mine in California. In addition, the company owns a 33 percent interest in Sumikin Molycorp, a manufacturer of neodymium compounds, located in Japan. During 2006, Molycorp performed environmental remediation activities at Questa and Mountain Pass, and at its closed rare-earth processing facility in Pennsylvania. The company s 35 percent interest in Companhia Brasileira de Metalurgia e Mineracao, a producer of niobium in Brazil, was sold in 2006.

At year-end 2006, Molycorp controlled approximately 60 million pounds of proven molybdenum reserves at Questa and 240 million pounds of proven and probable lanthanide reserves at Mountain Pass.

The company also owns the Chicago Carbon Company, a producer and marketer of calcined petroleum coke, which operates a 250,000-ton-per-year petroleum coke calciner facility in Lemont, Illinois.

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 15 power assets located in the United States and Asia. GPG manages the production of more than 2,334 megawatts of electricity at 11 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.

The company has major geothermal operations in Indonesia and the Philippines and is investigating several advanced solar technologies for use in oil field operations as part of its renewable energy strategy. For additional information on the company s geothermal operations and renewable energy projects, refer to pages 19 and 30, respectively.

In September 2006, the company sold its interest in the 8-megawatt Amada Rayong power generation facility in Thailand.

Chevron Energy Solutions

Chevron Energy Solutions (CES) is a wholly owned subsidiary that provides public institutions and businesses with projects designed to increase energy efficiency and reliability, reduce energy costs and utilize renewable and alternative power technologies. CES has energy-saving projects installed in more than a thousand buildings nationwide. Major projects completed by CES in 2006 include energy efficiency and renewable power installations for U.S. Postal Service facilities, the first megawatt-class hydrogen fuel cell cogeneration plant in California, and cogeneration and biomass facilities for a municipal water pollution control plant.

Research and Technology

The company s Energy Technology Company supports Chevron s upstream and downstream businesses with technologies that span the hydrocarbon value chain from exploration to refining and marketing.

The Technology Ventures Company identifies, grows and commercializes emerging technologies with the potential to transform energy production and use. The business development portfolio includes biofuels, hydrogen infrastructure, advanced batteries, nano-materials and renewable energy applications.

In the second quarter 2006, the company completed the acquisition of a 22 percent interest in Galveston Bay Biodiesel L.P., which is building one of the first large-scale biofuel plants in the United States. During 2006, the company also entered into research alliances with the University of California, Davis and the Georgia Institute of Technology. Both are focused on converting cellulosic biomass into viable transportation fuels.

Chevron s research and development expenses were $468 million, $316 million and $242 million for the years 2006, 2005 and 2004, respectively.

Some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, and ultimate successes are 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 U.S. federal, state and local environmental, health and safety laws and regulations, and similar laws and regulations in other countries. 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 2006, the company s U.S. capitalized environmental expenditures were $385 million, representing approximately 7 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 2007, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $350 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 2006 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-17 through FS-19 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 soon after such reports are filed with or furnished to the Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC s Internet Web site: http://www.sec.gov/.

Table of Contents

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, floods and other forms of severe weather, war, civil unrest and other political events, fires, earthquakes, 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 by-products, 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 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, 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 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, 2006, 24 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 25 percent of the company s net proved reserves, including affiliates, were located in OPEC countries at December 31, 2006. In December 2006, OPEC admitted Angola as a new member effective January 1, 2007. Oil-equivalent reserves at the end of 2006 in Angola represented 5 percent of the company s total.

Regulation of greenhouse gas emissions could increase Chevron s operational costs and reduce demand for Chevron s products.

Management believes it is reasonably likely that the scientific and political attention to issues concerning the existence and extent of climate change, and the role of human activity in it, will continue, with the potential for further regulation that affects the company s operations. Although uncertain, these developments could increase costs or reduce the demand for the products the company sells. The company s production and processing operations (e.g., the production of crude oil at offshore platforms and the processing of natural gas at liquefied natural gas facilities) typically result in emissions of greenhouse gases. Likewise, emissions arise from midstream and downstream operations, including crude oil transportation and refining. Finally, although beyond the control of the company, the use of passenger vehicle fuels and related products by consumers also results in these emissions.

International agreements, domestic legislation and regulatory measures to limit greenhouse gas emissions are currently in various phases of discussion or implementation. These include the Kyoto Protocol, proposed federal legislation and current state-level actions. Some of the countries in which Chevron operates have ratified the Kyoto Protocol, and the company is currently complying with greenhouse gas emissions limits within the European Union. Although resolutions supporting cap and trade systems have been introduced in the U.S. Congress, no bill restricting greenhouse gas emissions has been passed to date.

In California, the Global Warming Solutions Act became effective on January 1, 2007. This law caps California s greenhouse gas emissions at 1990 levels by 2020; directs the Air Resources Board, the responsible state agency, to determine greenhouse gas emissions in and outside California to adopt mandatory reporting rules for significant sources of greenhouse gases; delegates to the agency the authority to adopt compliance mechanisms (including market-based approaches); and permits a one-year extension of the targets under extraordinary circumstances. Related regulatory activity is under way within the California Public Utilities Commission. The company extracts crude oil and natural gas, operates refineries, and markets and sells gasoline in California. It is not known at this time whether or to what extent the state agencies regulations will affect the company s California operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and character of the company s crude oil, natural gas and mining 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-63 to FS-76 of this Annual Report on Form 10-K. Note 13, Properties, Plant and Equipment, to the company s financial statements is on page FS-43 of this Annual Report on Form 10-K.

Item 3. Legal Proceedings

Chevron s U.S. refineries are implementing a consent decree with the federal Environmental Protection Agency (EPA) and four state air agencies to resolve claims about Chevron s past application of New Source Review permitting programs under the Clean Air Act. The consent decree provides that Chevron will pay stipulated penalties for certain violations of the consent decree, if demand is made by the EPA. In July 2006, Chevron s refinery in Pascagoula, Mississippi exceeded its emission limit under the consent decree for particulate matter. The exceedance was reported at the time and the possibility of a penalty was discussed. In January 2007, the Mississippi Department of Environmental Quality (MDEQ) and the EPA issued a notice of violation and a request for payment of $210,000 in stipulated penalties for the July 2006 particulate matter exceedance. The company, the EPA and the MDEQ are in negotiation with regard to the nature and amount of the penalty demand.

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

None.

32

Table of Contents

Executive Officers of the Registrant at February 28, 2007

Name and Age		Executive Office Held	Major Area of Responsibility
D.J. O Reilly	60	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	60	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	Strategic Planning; Policy, Government and Public Affairs; Human Resources
J.E. Bethancourt	55	Executive Vice President since 2003 Executive Committee Member since 2003	Technology; Chemicals; Coal; Health, Environment and Safety
G.L. Kirkland	56	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
M.K. Wirth	46	Executive Vice President, effective March 1, 2006 President of 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	59	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	52	Vice President and General Counsel since 2002 Executive Committee Member since 2002	Law
J.S. Watson	50	Vice President and President of Chevron International Exploration and Production Company since 2005 Vice President and Chief Financial Officer from 2000 through 2004 Executive Committee Member from 2000 to 2004	International Exploration and Production

G.P. Luquette	51	Vice President and President, Chevron North America Exploration and Production Company since 2006	North American Exploration and Production

Table of Contents

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
G.P. Luquette	-	Vice President, San Joaquin Valley Business Unit, Chevron North America Exploration and Production 2001
	-	President and Managing Director, Chevron Upstream Europe 2003
	-	Vice President and President, Chevron North America Exploration and Production 2006
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-24 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, 2006	**6,888,498**	**64.33**	6,647,000	
Nov. 1 Nov. 30, 2006	**11,568,904**	**69.53**	11,115,500	
Dec. 1 Dec. 31, 2006	**1,512,735**	**74.68**	1,336,000	
Total Oct. 1 Dec. 31, 2006	**19,970,137**	**68.13**	19,098,500	(2)

(1) Includes 116,630 common shares repurchased during the three-month period ended December 31, 2006, 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 755,007 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, 2006.

(2) In December 2005, the company announced a $5 billion common stock repurchase program. The program was completed on November 30, 2006, at which time 80,260,800 shares had been repurchased for a total of $5 billion.

In December 2006, 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, 2006, 1,336,000 shares had been acquired under this program for $100 million.

Item 6. Selected Financial Data

The selected financial data for years 2002 through 2006 are presented on page FS-62 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-15 and in Note 7 to the Consolidated Financial Statements, Financial and Derivative Instruments, beginning on page FS-37.

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, 2006, have concluded that as of December 31, 2006, 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, 2006.

The company management s assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report that is included on page FS-26 of this Annual Report on Form 10-K.

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

During the quarter ended December 31, 2006, 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.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information on Directors appearing under the heading Election of Directors Nominees For Directors in the Notice of the 2007 Annual Meeting of Stockholders and 2007 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 2007 Annual Meeting of Stockholders (the 2007 Proxy Statement), 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 information contained under the heading Stock Ownership Information Section 16(a) Beneficial Ownership Reporting Compliance in the 2007 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading Board Operations Business Conduct and Ethics Code in the 2007 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

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 Charles R. Shoemate (Chairperson), Linnet F. Deily, Robert E. Denham and Franklyn G. Jenifer, all of whom are independent under the New York Stock Exchange Corporate Governance Rules. Of these Audit Committee members, Charles R. Shoemate, Linnet F. Deily and Robert E. Denham are audit committee financial experts as determined by the Board within the applicable definition of the SEC.

There were no changes to the process by which stockholders may recommend nominees to the Board of Directors during the last fiscal year.

Item 11. Executive Compensation

The information appearing under the headings Executive Compensation and Directors Compensation in the 2007 Proxy Statement is incorporated herein by reference in this Annual Report on Form 10-K.

The members of the Compensation Committee of the Board of Directors during the last fiscal year were Carla A. Hills (until her retirement on April 26, 2006), Robert J. Eaton, Samuel H. Armacost, Ronald D. Sugar and Carl Ware, none of whom is a present or former officer or employee of the company. In addition, during 2006, no officers had an interlock relationship, as that term is defined by the SEC, to report.

The information appearing under the heading Management Compensation Committee Report in the 2007 Proxy Statement is incorporated herein by reference in this Annual Report on Form 10-K. Pursuant to the rules and regulations of the SEC under the Exchange Act, the information under such caption incorporated by reference from the 2007 Proxy Statement shall not be deemed filed for purposes of Section 18 of the Exchange Act nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information appearing under the heading Stock Ownership Information Security Ownership of Certain Beneficial Owners and Management in the 2007 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading Equity Compensation Plan Information in the 2007 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information appearing under the heading Board Operations in the 2007 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

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 2007 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

Table of Contents

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 39 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.

Table of Contents

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS
Millions of Dollars

	Year Ended December 31		
	2006	2005	2004
Employee Termination Benefits:			
Balance at January 1	$ 91	$ 137	$ 341
(Deductions) additions (credited) charged to expense	(21)	(21)	29
Additions related to Unocal acquisition		106	
Payments	(42)	(131)	(233)
Balance at December 31	**$ 28**	**$ 91**	**$ 137**
Allowance for Doubtful Accounts:			
Balance at January 1	$ 198	$ 219	$ 229
Additions charged to expense	61	3	36
Additions related to Unocal acquisition		6	
Bad debt write-offs	(42)	(30)	(46)
Balance at December 31	**$ 217**	**$ 198**	**$ 219**
Deferred Income Tax Valuation Allowance:*			
Balance at January 1	$ 3,249	$ 1,661	$ 1,553
Additions charged to deferred income tax expense	1,700	1,593	714
Additions related to Unocal acquisition		400	
Deductions credited to goodwill	(77)	(60)	
Deductions credited to deferred income tax expense	(481)	(345)	(606)
Balance at December 31	**$ 4,391**	**$ 3,249**	**$ 1,661**

* See also Note 16 to the Consolidated Financial Statements beginning on page FS-44.

Table of Contents

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 28th day of February, 2007.

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 28th day of February, 2007.

Principal Executive Officers (and Directors)

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

/s/Peter J. Robertson
Peter J. Robertson, Vice Chairman of the Board

Principal Financial Officer

/s/Stephen J. Crowe
Stephen J. Crowe, Vice President and Chief Financial Officer

Principal Accounting Officer

/s/Mark A. Humphrey
Mark A. Humphrey, Vice President and Comptroller

Directors

Samuel H. Armacost*
Samuel H. Armacost

Linnet F. Deily*
Linnet F. Deily

Robert E. Denham*
Robert E. Denham

Robert J. Eaton*
Robert J. Eaton

Sam Ginn*
Sam Ginn

Franklyn G. Jenifer*
Franklyn G. Jenifer

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

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

KEY FINANCIAL RESULTS

Millions of dollars, except per-share amounts	**2006**	2005	2004
Net Income	**$ 17,138**	$ 14,099	$ 13,328
Per Share Amounts:			
Net Income Basic	**$ 7.84**	$ 6.58	$ 6.30
Diluted	**$ 7.80**	$ 6.54	$ 6.28
Dividends	**$ 2.01**	$ 1.75	$ 1.53
Sales and Other Operating Revenues	**$ 204,892**	$ 193,641	$ 150,865
Return on:			
Average Capital Employed	**22.6%**	21.9%	25.8%
Average Stockholders Equity	**26.0%**	26.1%	32.7%

INCOME FROM CONTINUING OPERATIONS BY MAJOR OPERATING AREA

Millions of dollars	**2006**	2005	2004
Income From Continuing Operations			
Upstream Exploration and Production			
United States	**$ 4,270**	$ 4,168	$ 3,868
International	**8,872**	7,556	5,622
Total Upstream	**13,142**	11,724	9,490
Downstream Refining, Marketing and Transportation			
United States	**1,938**	980	1,261
International	**2,035**	1,786	1,989
Total Downstream	**3,973**	2,766	3,250
Chemicals	**539**	298	314
All Other	**(516)**	(689)	(20)
Income From Continuing Operations	**$ 17,138**	$ 14,099	$ 13,034
Income From Discontinued Operations Upstream			294
Net Income*	**$ 17,138**	$ 14,099	$ 13,328

* Includes Foreign Currency Effects:	**$(219)**	$(61)	$(81)

Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of financial results by major operating area for the three years ending December 31, 2006.

BUSINESS ENVIRONMENT AND OUTLOOK

Chevron s current and future earnings depend largely on the profitability of its 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. The overall trend in earnings is typically less affected by results from the company s chemicals business and other activities and investments. Earnings for the company in any period may also be influenced by events or transactions that are infrequent and/ or unusual in nature. Chevron and the oil and gas industry at large are currently experiencing an increase in certain costs that exceeds the general trend of inflation in many areas of the world. This increase in costs is affecting the company s

operating expenses for all business segments and capital expenditures, particularly for the upstream business.

To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer adequate financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments. Changes in economic, legal or political circumstances can have significant effects on the profitability of a project over its expected life. In the current environment of higher commodity prices, certain governments have sought to renegotiate contracts or impose additional costs on the company. Other governments may attempt to do so in the future. The company will continue to monitor these developments, take them into account in evaluating future investment opportunities, and otherwise seek to mitigate any risks to the company s current operations or future prospects. In late February 2007, the President of Venezuela issued a decree announcing the government s intention for the state-owned oil company, Petróleos de Venezuela S.A., to increase its ownership later this year in all Orinoco Heavy Oil Associations, including Chevron s 30 percent-owned Hamaca project, to a minimum of 60 percent. The impact on Chevron from such an action is uncertain but is not expected to have a material effect on the company s results of operations, consolidated financial position or liquidity.

The company also continually evaluates opportunities to dispose of assets that are not key to providing sufficient long-term value, or to acquire assets or operations complementary to its asset base to help augment the company s growth. During the first quarter 2007, the company authorized the sale of its 31 percent ownership interest in the Nerefco Refinery and the associated TEAM Terminal in the Netherlands. The transaction is subject to signing of the sales agreement and obtaining necessary regulatory approvals. The company expects to record a gain upon close of the sale. In early 2007, the company was also in discussions regarding the possible sale of its fuels marketing operations in the Netherlands, Belgium and Luxembourg. Neither the refining nor marketing assets were classified as held-for-sale as of December 31, 2006, in accordance with the held-for-sale criteria of Financial Accounting Standards Board (FASB) Statement No. 144, *Impairment or Disposal of Long-Lived Assets*. Other asset dispositions and restructurings may occur in future periods and could result in significant gains or losses.

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.

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 capital and exploratory 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 worldwide experienced significant price increases for these items during 2005 and 2006, and an upward trend in prices may continue into 2007. Capital and exploratory expenditures and operating expenses also can be affected by uninsured damages to production facilities caused by severe weather or civil unrest.

Industry price levels for crude oil generally increased in the first half of 2006 and declined in the second half. Prices at the end of 2006 were slightly lower than at the beginning of the year. The spot price for West Texas Intermediate (WTI) crude oil, a benchmark crude oil, averaged $66 per barrel in 2006, an increase of approximately $9 per barrel from the 2005 average price. The rise in crude oil prices between years reflected, 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. For early 2007 into late February, the WTI spot price averaged about $56 per barrel.

As was the case in 2005, a wide differential in prices existed in 2006 between high-quality, light-sweet crude oils (such as the U.S. benchmark WTI) and heavier types of crude. The price for the heavier crudes has been dampened because of ample supply and lower relative demand due to the limited number of refineries that are able to process this lower-quality feedstock into light products (i.e., motor gasoline, jet fuel, aviation gasoline and diesel fuel). The price

for higher-quality, light-sweet crude oil has remained high, as the demand for light products, which can be more easily manufactured by refineries from light-sweet crude oil, has been strong worldwide. Chevron produces heavy crude oil in California, Chad, Indonesia, the Partitioned Neutral Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom North Sea. (Refer to page FS-11 for the company s average U.S. and international crude oil prices.)

In contrast to price movements in the global market for crude oil, price changes for natural gas are more closely aligned with regional supply and demand conditions. In the United States during 2006, benchmark prices at Henry Hub averaged about $6.50 per thousand cubic feet (MCF), compared with about $8 in 2005. For early 2007 into late February, prices averaged about $7 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 relative to customer demand. Natural gas prices in the United States are also typically higher during the winter period when demand for heating is greatest.

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-11 for the company s average natural gas prices for the United States 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 the lack of infrastructure to transport and receive liquefied natural gas.

To help address this regional imbalance between supply and demand for natural gas, Chevron is planning increased

FS-3

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 can be transported in existing natural gas pipeline networks (as in the United States).

Besides the impact of the fluctuation in price for crude oil and natural gas, the longer-term trend in earnings for the upstream segment is also a function of other factors, including the company s ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms, and the cost of goods and services.

Chevron s worldwide net oil-equivalent production in 2006, including volumes produced from oil sands and production under an operating service agreement, averaged 2.67 million barrels per day, or 6 percent higher than production in 2005. The increase between periods was largely due to volumes associated with the acquisition of Unocal in August 2005. The company estimates that oil-equivalent production in 2007 will average approximately 2.6 million barrels per day. This estimate 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, changes in fiscal terms or restrictions on the scope of company operations, and production disruptions that could be caused by severe weather, local civil unrest and changing geopolitics. 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. Most of Chevron s upstream investment is currently being made 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.

Approximately 24 percent of the company s net oil-equivalent production in 2006 occurred in the OPEC-member countries of Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. In December 2006, OPEC admitted Angola as a new member effective January 1, 2007. Oil-equivalent production for 2006 in Angola represented 6 percent of the company s total. In October 2006, OPEC announced its decision to reduce OPEC-member production quotas by 1.2 million barrels of crude oil per day, or 4.4 percent, from a production level of 27.5 million barrels, effective November 1, 2006. In December 2006, OPEC announced an additional quota reduction of 500,000 barrels of crude oil per day, effective February 1, 2007. OPEC quotas did not significantly affect Chevron s production level in 2006. The impact of quotas on the company s production in 2007 is uncertain.

In October 2006, Chevron s Boscan and LL-652 operating service agreements in Venezuela were converted to Empresas Mixtas (i.e. joint stock contractual structures), with Petróleos de Venezuela S.A., as majority shareholder. Beginning in October, Chevron reported its equity share of the Boscan and LL-652 production, which was approximately 90,000 barrels per day less than what the company previously reported under the operating service agreements. The change to the Empresa Mixta structure did not have a material effect on the company s results of operations, consolidated financial position or liquidity.

At the end of 2005 in certain onshore areas of Nigeria, approximately 30,000 barrels per day of the company s net production capacity remained shut-in following civil unrest and damage to production facilities that occurred in 2003. By the end of 2006, the company had resumed operations in portions of all the affected fields, and more than 20,000 barrels per day of production had been restored. In early 2007, additional production restoration activities continued in the area; however, intermittent civil unrest could adversely impact company operations in the future.

Refer to pages FS-6 through FS-7 for additional discussion of the company s upstream operations.

Downstream Earnings for the downstream segment are closely tied to global and regional supply and demand for refined products and the associated effects on industry refining and marketing margins. Other factors include the reliability and efficiency of the company s refining and marketing network, the effectiveness of the crude-oil and product-supply functions, and the economic returns on invested capital. Profitability 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 that are beyond the company s control include the general level of inflation and energy costs to operate the company s refinery and distribution network.

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. The company operates or has ownership interests in refineries in each of these areas, except Latin America. In 2006, earnings for the segment improved substantially, mainly as the result of higher average margins for refined products and improved operations at the company s refineries.

Table of Contents

Industry margins in the future may be volatile and are influenced by changes in the price of crude oil used for refinery feedstock and by changes in the supply and demand for crude oil and refined products. The industry supply and demand balance can be affected by disruptions at refineries resulting from maintenance programs and unplanned outages, including weather-related disruptions; refined-product inventory levels; and geopolitical events.

Refer to pages FS-8 through FS-9 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. Feedstock and fuel costs, which tend to follow crude oil and natural gas price movements, also influence earnings in this segment.

Refer to page FS-9 for additional discussion of chemicals earnings.

OPERATING DEVELOPMENTS

Key operating developments and other events during 2006 and early 2007 included:

Upstream

United States In the Gulf of Mexico, the company announced in September 2006 the completion of a successful production test on the 50 percent-owned and operated Jack #2 well. The test was a follow-up to the 2004 Jack discovery and was the deepest well-test ever accomplished in the Gulf of Mexico.

Also in the Gulf of Mexico, the company announced in October its decision to develop the Great White, Tobago and Silvertip fields via a common producing hub, the Perdido Regional Host,

which will have a processing capacity of 130,000 barrels of oil-equivalent per day. First production from the 38 percent-owned Perdido Regional Host is anticipated by 2010. The company s ownership interests in the fields are Great White 33 percent, Tobago 58 percent and Silvertip 60 percent.

Angola In June 2006, the company produced the first crude oil from the offshore Lobito field, located in Block 14. Lobito is part of the 31 percent-owned and operated Benguela Belize Lobito Tomboco (BBLT) development project. As fields and wells are added over the next two years, BBLT s maximum production is expected to reach approximately 200,000 barrels of oil per day. Also in Block 14, the company produced first crude oil in June 2006

from the Landana North reservoir in the 31 percent-owned and operated Tombua-Landana development area. This initial production is tied back to the nearby BBLT production facilities. Tombua-Landana is the company s third deepwater development offshore Angola. Maximum production from the completed Tombua-Landana development is estimated at 100,000 barrels per day by 2010.

In early 2007, the company announced a discovery of crude oil at the 31 percent-owned and operated Lucapa-1 well in deepwater Block 14. The company plans to conduct appraisal drilling and additional geologic and engineering studies to assess the potential resource.

Australia In July 2006, the company discovered natural gas at the Chandon-1 exploration well offshore the northwestern coast in the Greater Gorgon development area. The company s interest in the property is 50 percent.

Also offshore the northwestern coast, the company announced in November 2006 a significant natural gas discovery at its Clio-1 exploration well. The company holds a 67 percent interest in the block where Clio-1 is located. Chevron will be undertaking further work, including a 3-D seismic survey program that started in late 2006, to better determine the potential of the gas find and subsequent development options.

In early 2007, the company was also named operator and awarded a 50 percent interest in exploration acreage in the Greater Gorgon Area. A three-year work program includes geotechnical studies, seismic surveys and drilling of an exploration well.

Azerbaijan The first tanker lifting of crude oil transported through the 9 percent-owned Baku-Tbilisi-Ceyhan (BTC) pipeline occurred in June 2006. The crude is being supplied by the Azerbaijan International Oil Company, in which the company has a 10 percent nonoperated working interest.

Brazil In June 2006, the company announced the decision to develop the 52 percent-owned and operated offshore Frade Field. Initial production is targeted by early 2009, with a maximum annual rate estimated at 90,000 oil-equivalent barrels per day in 2011.

Canada The company acquired heavy oil leases in the Athabasca region of northern Alberta, Canada in 2005 and 2006. The leases comprise more than 75,000 acres and contain significant volumes that have potential for recovery using Steam Assisted Gravity Drainage technology.

Also in Alberta, the company announced its decision in October 2006 to participate in the expansion of the Athabasca Oil Sands Project (AOSP). The expansion is expected to add 100,000 barrels per day of mining and upgrading capacity at an estimated total project cost of $10 billion. Completion of the expansion is planned for 2010, increasing total capacity of the project to approximately 255,000 barrels per day. The company holds a 20 percent nonoperated working interest in AOSP.

Nigeria In May 2006, the company announced the discovery of crude oil at the nonoperated Uge-1 exploration well in the 20 percent-owned offshore Oil Prospecting License 214. Future drilling is contingent primarily on the outcome of ongoing technical studies.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Norway In April 2006, the company was awarded the rights to six blocks in the 19th Norwegian Licensing Round. The 40 percent-owned blocks are located in the Nordkapp East Basin in the Norwegian Barents Sea. A 3-D seismic survey was acquired and is planned to be processed in 2007.

Thailand In early 2006, the company signed two petroleum exploration concessions in the Gulf of Thailand. Chevron has a 71 percent operated interest in one concession, which is in the proximity of the company s Tantawan and Plamuk fields. Initial drilling in the concession is scheduled during 2007. Drilling is projected by 2009 for the other concession, in which Chevron has a 16 percent nonoperated working interest.

United Kingdom In June 2006, the company produced the first crude oil from the 85 percent-owned and operated Area C in the Captain Field. The project reached maximum production of 14,000 barrels of crude oil per day in September 2006.

In early 2007, the company was awarded eight operated exploration blocks and two nonoperated blocks west of Shetland Islands in the 24th United Kingdom Offshore Licensing Round.

Vietnam In April 2006, the company signed a 30-year production-sharing contract with Vietnam Oil and Gas Corporation for Block 122 offshore eastern Vietnam. The company has a 50 percent interest in this block and has undertaken a three-year work program for seismic acquisition and drilling of an exploratory well.

Downstream

United States In December 2006, the company completed the expansion of the Fluid Catalytic Cracking Unit at the company s refinery in Pascagoula, Mississippi, increasing the refinery s gasoline manufacturing capacity by about 10 percent. The company also submitted an environmental permit application for construction of facilities to increase gasoline output by another 15 percent.

India In April 2006, the company acquired a 5 percent interest in Reliance Petroleum Limited, a company formed by Reliance Industries Limited to construct, own and operate a refinery in Jamnagar, India. The new refinery would be the world s sixth largest, designed for a crude oil processing capacity of 580,000 barrels per day. Chevron and Reliance Industries also signed two memoranda of understanding to jointly pursue other downstream and upstream business opportunities. If discussions pursuant to the memoranda of understanding lead to definitive agreements, Chevron may increase its equity stake in Reliance Petroleum to 29 percent.

Other

Biofuels In May 2006, the company announced that it had completed the acquisition of a 22 percent interest in Galveston Bay Biodiesel L.P., which is building one of the first large-scale biodiesel plants in the United States. The following month, the company entered into a research alliance with the Georgia Institute of Technology to pursue advanced technology aimed at making cellulosic biofuels and hydrogen into transportation fuels. In September, the company announced a research collaboration with the University of California, Davis aimed at converting cellulosic biomass into transportation fuels.

Common Stock Dividends and Stock Repurchase Program In April 2006, the company increased its quarterly common stock dividend by 15.5 percent to $0.52 per share. In November, the company completed its second $5 billion common stock buyback program since 2004 and in December authorized the acquisition of up to $5 billion of additional shares over a period of up to three years.

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, 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-38, for a discussion of the company s reportable segments, as defined in FASB No. 131, *Disclosures About Segments of an Enterprise and Related Information*.) 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	**2006**	2005	2004
Income From Continuing Operations	**$ 4,270**	$ 4,168	$ 3,868
Income From Discontinued Operations			70
Total Income	**$ 4,270**	$ 4,168	$ 3,938

U.S. upstream income of $4.3 billion in 2006 increased approximately $100 million from 2005. Earnings in 2006 benefited about $850 million from higher average prices on oil-equivalent production and the effect of seven additional months of production from the Unocal properties that were acquired in August 2005. Substantially offsetting these benefits were increases in operating expense and expenses for depreciation and exploration. Included in the operating expense increases were costs associated with the carryover effects of hurricanes in the Gulf of Mexico in 2005.

Income of $4.2 billion in 2005 was $230 million higher than 2004. The 2004 amount included gains of approximately $400 million from asset sales. Higher prices for crude oil and natural gas in 2005 and five months of 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 substantially offset by the adverse effects of lower production, higher operating expenses and higher depreciation expense associated with the heritage Chevron properties.

The company s average realization for crude oil and natural gas liquids in 2006 was $56.66 per barrel, compared with $46.97 in 2005 and $34.12 in 2004. The average natural gas realization was $6.29 per thousand cubic feet in 2006, compared with $7.43 and $5.51 in 2005 and 2004, respectively.

Net oil-equivalent production in 2006 averaged 763,000 barrels per day, up 5 percent from 2005 and down 7 percent from 2004. The increase between 2005 and 2006 was due to the full-year benefit of production from the former Unocal

properties. The decrease from 2004 was associated mainly with the effects of hurricanes, property sales and normal field declines, partially offset by additional volumes from the former Unocal properties.

The net liquids component of oil-equivalent production for 2006 averaged 462,000 barrels per day, an increase of approximately 2 percent from 2005 and a decrease of 9 percent from 2004. Net natural gas production averaged 1.8 billion cubic feet per day in 2006, up 11 percent from 2005 and down 3 percent from 2004.

Refer to the Selected Operating Data table, on page FS-11, for the three-year comparative production volumes in the United States.

International Upstream Exploration and Production

Millions of dollars	**2006**	2005	2004
Income From Continuing Operations*	**$ 8,872**	$ 7,556	$ 5,622
Income From Discontinued Operations			224
Total Income*	**$ 8,872**	$ 7,556	$ 5,846
*Includes Foreign Currency Effects:	**$ (371)**	$ 14	$ (129)

International upstream income of approximately $8.9 billion in 2006 increased $1.3 billion from 2005. Earnings in 2006 benefited approximately $3.0 billion from higher prices for crude oil and natural gas and an additional seven months of production from the former Unocal properties. About 70 percent of this benefit was associated with the impact of higher prices. Substantially offsetting these benefits were increases in depreciation expense, operating expense and exploration expense. Also adversely affecting 2006 income were higher taxes related to an increase in tax rates in the U.K. and Venezuela and settlement of tax claims and other tax items in Venezuela, Angola and Chad. Foreign currency effects reduced earnings by $371 million in 2006, but increased income $14 million in 2005.

Income in 2005 was approximately $7.5 billion, compared with $5.8 billion in 2004, which included gains of approximately $850 million from property sales. Higher prices for crude oil and natural gas in 2005 and five months of earnings from the former Unocal operations increased income approximately $2.9 billion between periods. About 80 percent of this benefit arose from the effects of higher prices on heritage-Chevron production. Partially offsetting these benefits were higher expenses between periods for certain income tax items, including the absence of a $200 million benefit in 2004 relating to changes in income tax laws. Foreign currency effects increased income $14 million in 2005 but reduced income $129 million in 2004.

The company s average realization for crude oil and natural gas liquids in 2006 was $57.65 per barrel, compared with $47.59 in 2005 and $34.17 in 2004. The average natural gas realization was $3.73 per thousand cubic feet in 2006, compared with $3.19 and $2.68 in 2005 and 2004, respectively.

Net oil-equivalent production of 1.9 million barrels per day in 2006, including about 100,000 net barrels per day from oil sands in Canada and production under an operating service agreement in Venezuela prior to its conversion to a joint stock company, increased about 6 percent from 2005 and 13 percent from 2004. This trend was largely the result of the effects of the Unocal acquisition in August 2005, partially offset by the effect of normal field declines and property sales in 2004.

The net liquids component of oil-equivalent production was 1.4 million barrels per day in 2006, an increase of approximately 2 percent from 2005 and 2004. Net natural gas production of 3.1 billion cubic feet per day in 2006 was up 21 percent and 51 percent from 2005 and 2004, respectively.

Refer to the Selected Operating Data table, on page FS-11, for the three-year comparative of international production volumes.

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS

U.S. Downstream Refining, Marketing and Transportation

Millions of dollars	**2006**	2005	2004
Income	**$ 1,938**	$ 980	$ 1,261

U.S. downstream earnings of $1.9 billion in 2006 increased about $1 billion from 2005 and approximately $700 million from 2004. Average refined-product margins in 2006 were higher than in 2005, which in turn were also higher than in 2004. Refinery crude inputs were higher in 2006 than in the other comparative periods and also benefited earnings. However, earnings declined in 2005 from

a year earlier due mainly to increased downtime at the company s refineries, including the shutdown of operations at Pascagoula, Mississippi, for more than a month due to hurricanes in the Gulf of Mexico. The company s marketing and pipeline operations along the Gulf Coast were also disrupted for an extended period due to the hurricanes. Fuel costs were also higher in 2005 than in 2004.

Sales volumes of refined products in 2006 were approximately 1.5 million barrels per day, an increase of 1 percent from 2005 and relatively unchanged from 2004. The reported sales volume for 2006 was on a different basis than in 2005 and 2004 due to a change in accounting rules that became effective April 1, 2006, for certain purchase and sale

(buy/sell) contracts with the same counterparty. Excluding the impact of the accounting change, refined product sales in 2006 increased by approximately 6 percent and 3 percent from 2005 and 2004, respectively. Branded gasoline sales volumes of approximately 614,000 barrels per day in 2006 increased about 4 percent from 2005, largely due to the growth of the Texaco brand. In 2005, refined-product sales volumes decreased about 2 percent from 2004, primarily due to disruption related to the hurricanes.

Refer to the Selected Operating Data table, on page FS-11, for the three-year comparative refined-product sales volumes in the United States. Refer also to Note 14, *Accounting for Buy/Sell Contracts*, on page FS-43 for a discussion of the accounting for purchase and sale contracts with the same counterparty.

International Downstream Refining, Marketing and Transportation

Millions of dollars	**2006**	2005	2004
Income*	**$ 2,035**	$ 1,786	$ 1,989
*Includes Foreign Currency Effects:	**$ 98**	$ (24)	$ 7

International downstream income of $2 billion in 2006 increased about $250 million from 2005 and about $50 million from 2004. The increase in 2006 from 2005 was associated mainly with the benefit of higher-refined product margins in Asia-Pacific and Canada and improved results from crude-oil and refined-product trading activities. The decrease in earnings in 2005 from 2004 was due mainly to lower sales volumes; higher costs for fuel and transportation; expenses associated with a 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 margins between periods. Foreign currency effects improved income by $98 million and $7 million in 2006 and 2004, respectively, but reduced income by $24 million in 2005.

Table of Contents

Refined-product sales volumes were 2.1 million barrels per day in 2006, about 6 percent lower than 2005. Excluding the accounting change for buy/sell contracts, sales were down 1 percent between 2005 and 2006. Refined-product sales volume of 2.3 million barrels per day in 2005 were about 4 percent lower than in 2004, primarily the result of lower gasoline trading activity and lower fuel oil sales. Refer to the Selected Operating Data table, on page FS-11, for the three-year comparative refined-product sales volumes in the international areas.

Chemicals

Millions of dollars	**2006**	2005	2004
Income*	**$ 539**	$ 298	$ 314
*Includes Foreign Currency Effects:	**$(8)**	$	$(3)

The chemicals segment includes the company s Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem). In 2006, earnings of $539 million increased about $200 million from both 2005 and 2004. Margins in 2006 for commodity chemicals at CPChem and for fuel and lubricant additives at Oronite were higher than in 2005 and 2004. The earnings decline from 2004 to 2005 was mainly attributable to plant outages and expenses in the Gulf of Mexico region due to hurricanes, which affected both Oronite and CPChem.

All Other

Millions of dollars	**2006**	2005	2004
Net Charges*	**$ (516)**	$ (689)	$ (20)
*Includes Foreign Currency Effects:	**$62**	$(51)	$44

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

Net charges of $516 million in 2006 decreased $173 million from $689 million in 2005. Excluding the effects of foreign currency, net charges declined $60 million between periods. Interest income was higher in 2006, and interest expense was lower.

Between 2004 and 2005, net charges increased $669 million. Excluding the effects of foreign exchange, net charges increased $574 million. Approximately $400 million of the increase was related to larger benefits in 2004 from

corporate-level tax adjustments. Higher charges in 2005 also were associated with environmental remediation of properties that had been sold or idled and Unocal corporate-level activities. Interest expense was higher in 2005 due to an increase in interest rates and the debt assumed with the Unocal acquisition.

CONSOLIDATED STATEMENT OF INCOME

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2006**	2005	2004

Sales and other operating revenues	**$ 204,892**	$ 193,641	$ 150,865

Sales and other operating revenues in 2006 increased over 2005 due primarily to higher prices for refined products. The increase in 2005 from 2004 was a result of the same factor plus the effect of higher average prices for crude oil and natural gas. The higher revenues in 2006 were net of an impact from the change in the accounting for buy/sell contracts, as described in Note 14 on page FS-43.

Millions of dollars	**2006**	2005	2004
Income from equity affiliates	**$ 4,255**	$ 3,731	$ 2,582

Increased income from equity affiliates in 2006 was mainly due to improved results for Tengizchevroil (TCO) and CPChem. The improvement in 2005 from 2004 was primarily due to improved results for TCO and Hamaca (Venezuela). Refer to Note 12, beginning on page FS-41, for a discussion of Chevron s investment in affiliated companies.

Millions of dollars	**2006**	2005	2004
Other income	**$ 971**	$ 828	$ 1,853

Other income of nearly $1.9 billion in 2004 included approximately $1.3 billion of gains from upstream property sales. Interest income contributed $600 million, $400 million and $200 million in 2006, 2005 and 2004, respectively. Average interest rates and balances of cash and marketable securities increased each year. Foreign currency losses were $260 million in 2006 and $60 million in both 2005 and 2004.

Millions of dollars	**2006**	2005	2004
Purchased crude oil and products	**$ 128,151**	$ 127,968	$ 94,419

Crude oil and product purchases in 2006 increased from 2005 on higher prices for crude oil and refined products and the inclusion of Unocal-related amounts for a full year in 2006. The increase was mitigated by the effect of the accounting change in April 2006 for buy/sell contracts. Purchase costs increased 35 percent in 2005 from the prior year as a result of higher prices for crude oil, natural gas and refined products, as well as to the inclusion of Unocal-related amounts for five months.

Millions of dollars	**2006**	2005	2004
Operating, selling, general and administrative expenses	**$ 19,717**	$ 17,019	$ 14,389

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Operating, selling, general and administrative expenses in 2006 increased 16 percent from a year earlier. Expenses associated with the former Unocal operations are included for the full year in 2006, vs. five months in 2005. Besides this effect, expenses were higher in 2006 for labor, transportation, uninsured costs associated with the hurricanes in 2005 and a number of corporate items that individually were not significant. Total expenses increased in 2005 from 2004 due mainly to the inclusion of former-Unocal expenses for five months, higher costs for labor and transportation, uninsured costs associated with storms in the Gulf of Mexico, and asset write-offs.

Millions of dollars	**2006**	2005	2004
Exploration expense	**$ 1,364**	$ 743	$ 697

Exploration expenses in 2006 increased from 2005 mainly due to higher amounts for well write-offs and geological and geophysical costs for operations outside the United States, as well as the inclusion of expenses for the former Unocal operations for a full year in 2006. Expenses increased in 2005 from 2004 due mainly to the inclusion of Unocal-related amounts for five months.

Millions of dollars	**2006**	2005	2004
Depreciation, depletion and amortization	**$ 7,506**	$ 5,913	$ 4,935

Depreciation, depletion and amortization expenses increased from 2004 through 2006 mainly as a result 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.

Millions of dollars	**2006**	2005	2004
Interest and debt expense	**$ 451**	$ 482	$ 406

Interest and debt expense in 2006 decreased from 2005 primarily due to lower average debt balances and an increase in the amount of interest capitalized, partially offset by higher average interest rates on commercial paper and other variable-rate debt. The increase in 2005 over 2004 was mainly due to the inclusion of debt assumed with the Unocal acquisition and higher average interest rates for commercial paper borrowings.

Millions of dollars	**2006**	2005	2004
Taxes other than on income	**$ 20,883**	$ 20,782	$ 19,818

Taxes other than on income were essentially unchanged in 2006 from 2005, with the effect of higher U.S. refined product sales being offset by lower sales volumes subject to duties in the company s European downstream operations. The increase in 2005 from 2004 was the 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.

Millions of dollars	**2006**	2005	2004
Income tax expense	**$ 14,838**	$ 11,098	$ 7,517

Effective income tax rates were 46 percent in 2006, 44 percent in 2005 and 37 percent in 2004. The higher tax rate in 2006 included the effect of one-time charges totaling $400 million, including an increase in tax rates on upstream operations in the U.K. North Sea and settlement of a tax claim in Venezuela. Rates were higher in 2005 compared with the prior year due to an increase in earnings in countries with higher tax rates and the absence of benefits in 2004 from changes in the income tax laws for certain international operations. Refer also to the discussion of income taxes in Note 16 beginning on page FS-44.

SELECTED OPERATING DATA[1,2]

	2006	2005	2004
U.S. Upstream[3]			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	**462**	455	505
Net Natural Gas Production (MMCFPD)[4]	**1,810**	1,634	1,873
Net Oil-Equivalent Production (MBOEPD)	**763**	727	817
Sales of Natural Gas (MMCFPD)	**7,051**	5,449	4,518
Sales of Natural Gas Liquids (MBPD)	**124**	151	177
Revenues From Net Production			
Liquids ($/Bbl)	**$ 56.66**	$ 46.97	$ 34.12
Natural Gas ($/MCF)	**$ 6.29**	$ 7.43	$ 5.51
International Upstream[3]			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**1,270**	1,214	1,205
Net Natural Gas Production (MMCFPD)[4]	**3,146**	2,599	2,085
Net Oil-Equivalent Production (MBOEPD)[5]	**1,904**	1,790	1,692
Sales Natural Gas (MMCFPD)	**3,478**	2,450	2,039
Sales Natural Gas Liquids (MBPD)	**102**	120	118
Revenues From Liftings			
Liquids ($/Bbl)	**$ 57.65**	$ 47.59	$ 34.17
Natural Gas ($/MCF)	**$ 3.73**	$ 3.19	$ 2.68
U.S. and International Upstream[3]			
Net Oil-Equivalent Production Including Other Produced Volumes (MBOEPD)[4,5]			
United States	**763**	727	817
International	**1,904**	1,790	1,692
Total	**2,667**	2,517	2,509
U.S. Downstream			
Gasoline Sales (MBPD)[6]	**712**	709	701
Other Refined Products Sales (MBPD)	**782**	764	805
Total (MBPD)[7]	**1,494**	1,473	1,506
Refinery Input (MBPD)	**939**	845	914
International Downstream			
Gasoline Sales (MBPD)[6]	**595**	662	715
Other Refined Products Sales (MBPD)	**1,532**	1,590	1,653
Total (MBPD)[7,8]	**2,127**	2,252	2,368
Refinery Input (MBPD)	**1,050**	1,038	1,044

[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 beginning August 2005, for properties associated with acquisition of Unocal.

[4] Includes natural gas consumed in operations (MMCFPD):			
United States	**56**	48	50
International	**419**	356	293
[5] Includes other produced volumes (MBPD):			
Athabasca Oil Sands Net	**27**	32	27
Boscan Operating Service Agreement	**82**	111	113
	109	143	140
[6] Includes branded and unbranded gasoline.			
[7] Includes volumes for buy/sell contracts (MBPD):			
United States	**26**	88	84
International	**24**	129	96
[8] Includes sales of affiliates (MBPD):	**492**	498	502

INFORMATION RELATED TO INVESTMENT IN DYNEGY INC.

At year-end 2006, Chevron owned a 19 percent equity interest in the common stock of Dynegy Inc., a provider of electricity to markets and customers throughout the United States.

Investment in Dynegy Common Stock At December 31, 2006, the carrying value of the company s investment in Dynegy common stock was approximately $250 million. This amount was about $180 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 December 31, 2006, was approximately $700 million.

Investments in Dynegy Preferred Stock In May 2006, the company s investment in Dynegy Series C preferred stock was redeemed at its face value of $400 million. Upon redemption of the preferred stock, the company recorded a before-tax gain of $130 million ($87 million after tax).

Dynegy Proposed Business Combination with LS Power Group Dynegy and LS Power Group, a privately held power plant investor, developer and manager, announced in September 2006 that the companies had executed a definitive agreement to combine Dynegy s assets and operations with LS Power Group s power-generation portfolio and for Dynegy to acquire a 50 percent ownership interest in a development joint venture with LS Power. Upon close of the transaction, Chevron will receive the same number of shares of the new company s Class A common stock that it currently holds in Dynegy. Chevron s ownership interest in the combined company will be approximately 11 percent. The transaction is subject to specified conditions, including the affirmative vote of two-thirds of Dynegy s common shareholders and the receipt of regulatory approvals.

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

LIQUIDITY AND CAPITAL RESOURCES

Cash, cash equivalents and marketable securities Total balances were $11.4 billion and $11.1 billion at December 31, 2006 and 2005, respectively. Cash provided by operating activities in 2006 was $24.3 billion, compared with $20.1 billion in 2005 and $14.7 billion in 2004.

The 2006 increase in cash provided by operating activities mainly reflected higher earnings in the upstream and downstream segments, including a full year of earnings from the former Unocal operations that were acquired in August 2005. Cash provided by operating activities was net of contributions to employee pension plans of $0.4 billion, $1.0 billion and $1.6 billion in 2006, 2005 and 2004, respectively. Cash provided by investing activities included proceeds from asset sales of $1.0 billion in 2006, $2.7 billion in 2005 and $3.7 billion in 2004.

Cash provided by operating activities and asset sales during 2006 was sufficient to fund the company s $13.8 billion capital and exploratory program, pay $4.4 billion of dividends to stockholders, repay approximately $2.9 billion in debt and repurchase $5 billion of common stock.

Dividends The company paid dividends of approximately $4.4 billion in 2006, $3.8 billion in 2005 and $3.2 billion in 2004. In April 2006, the company increased its quarterly common stock dividend by 15.5 percent to 52 cents per share.

Debt, capital lease and minority interest obligations Total debt and capital lease balances were $9.8 billion at December 31, 2006, down from $12.9 billion at year-end 2005. The company also had minority interest obligations of $209 million, up from $200 million at December 31, 2005.

The $3.1 billion reduction in total debt and capital lease obligations during 2006 included the early redemption and maturity of several individual debt issues. In the first quarter, $185 million of Union Oil Company bonds matured. In the second quarter, the company redeemed approximately $1.7 billion of Unocal debt prior to maturity. In the fourth quarter, a $129 million Texaco Capital Inc. bond matured, and Union Oil Company bonds of $196 million were redeemed prior to maturity. Commercial paper balances at the end of 2006 were reduced $626 million from year-end 2005. In February 2007, a $144 million Texaco Capital Inc. bond matured.

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 $6.6 billion at December 31, 2006, up from $5.6 billion at year-end 2005. Of these amounts, $4.5 billion and $4.9 billion were reclassified to long-term at the end of each period, respectively. At year-end 2006, settlement of the reclassified amount was not expected to require the use of working capital in 2007, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance the amounts on a long-term basis. The company s practice has been to maintain commercial paper levels it believes appropriate and economic.

At year-end 2006, the company had $5 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 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 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,

2006. 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.

In 2004, Chevron entered into $1 billion of interest rate 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 interest rates and floating interest rates.

Table of Contents

The company has outstanding public bonds issued by Chevron Corporation Profit Sharing/Savings Plan Trust Fund, Chevron Canada Funding Company (formerly Chevron Texaco Capital Company), Texaco Capital Inc. and Union Oil Company of California. All of these securities are guaranteed by Chevron Corporation and are rated AA by Standard and Poor s Corporation and Aa2 by Moody s Investors Service. 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. The company believes that it has substantial borrowing capacity to meet unanticipated cash requirements and that during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, 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 A $5 billion stock repurchase program initiated in December 2005 was completed in November 2006. During 2006, about 78.5 million common shares were repurchased under this program at a total cost of $4.9 billion.

In December 2006, 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 1.3 million shares in the open market for $100 million during December 2006 and through mid-February 2007 increased the total shares acquired to 8.2 million at a cost of $592 million.

Capital and exploratory expenditures Total reported expenditures for 2006 were $16.6 billion, including $1.9 billion for the company s share of affiliates expenditures, which did not require cash outlays by the company. In 2005 and 2004, expenditures were $11.1 billion and $8.3 billion, respectively, including the company s share of affiliates expenditures of $1.7 billion and $1.6 billion in the cor-
responding periods. The 2005 amount excludes the $17.3 billion acquisition of Unocal Corporation.

Of the $16.6 billion in expenditures for 2006, about three-fourths, or $12.8 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2005 and 2004. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the three years, reflecting the company s continuing focus on opportunities that are available outside the United States.

In 2007, the company estimates capital and exploratory expenditures will be 18 percent higher at $19.6 billion, including $2.4 billion of spending by affiliates. About three-fourths of the total, or $14.6 billion, is budgeted for

exploration and production activities, with $10.6 billion of this amount outside the United States. Spending in 2007 is primarily targeted for exploratory prospects in the deepwater Gulf of Mexico and western Africa and major development projects in Angola, Australia, Brazil, Kazakhstan, Nigeria, the deepwater Gulf of Mexico and an oil sands project in Canada.

Worldwide downstream spending in 2007 is estimated at $3.8 billion, with about $1.6 billion for projects in the United States. Capital projects include upgrades to refineries in the United States and South Korea and construction of liquefied natural gas tankers and gas-to-liquids facilities in support of associated upstream projects.

Investments in chemicals, technology and other corporate businesses in 2007 are budgeted at $1.2 billion. Technology investments include projects related to molecular transformation, unconventional hydrocarbons, oil and gas reservoir management and development of second-generation biofuel production.

Capital and Exploratory Expenditures

Millions of dollars	U.S.	Int'l.	**2006** Total	U.S.	Int'l.	2005 Total	U.S.	Int'l.	2004 Total
Upstream									
Exploration and Production	**$ 4,123**	**$ 8,696**	**$ 12,819**	$ 2,450	$ 5,939	$ 8,389	$ 1,820	$ 4,501	$ 6,321
Downstream									
Refining, Marketing and Transportation	**1,176**	**1,999**	**3,175**	818	1,332	2,150	497	832	1,329
Chemicals	**146**	**54**	**200**	108	43	151	123	27	150
All Other	**403**	**14**	**417**	329	44	373	512	3	515
Total	**$ 5,848**	**$ 10,763**	**$ 16,611**	$ 3,705	$ 7,358	$ 11,063	$ 2,952	$ 5,363	$ 8,315
Total, Excluding Equity in Affiliates	**$ 5,642**	**$ 9,050**	**$ 14,692**	$ 3,522	$ 5,860	$ 9,382	$ 2,729	$ 4,024	$ 6,753

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pension Obligations In 2006, the company s pension plan contributions totaled approximately $450 million. Approximately $225 million of the total was contributed to U.S. plans. In 2007, the company estimates total contributions will be $500 million. Actual amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements 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-20.

FINANCIAL RATIOS

Financial Ratios

	At December 31		
	2006	2005	2004
Current Ratio	**1.3**	1.4	1.5
Interest Coverage Ratio	**53.5**	47.5	47.6
Total Debt/Total Debt-Plus-Equity	**12.5%**	17.0%	19.9%

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 Last-In-First-Out basis. At year-end 2006, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $6 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 interest coverage ratio was higher in 2006 compared with 2005, primarily due to higher before-tax income and lower average debt balances. The company s interest coverage ratio was essentially unchanged between 2005 and 2004.

Debt Ratio total debt as a percentage of total debt plus equity. The decrease between 2005 and 2006 was due to lower average debt levels and an increase in stockholders equity. Although total debt was slightly higher at the end of 2005 than a year earlier due to the assumption of debt associated with the Unocal acquisition, 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.

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

*Direct or Indirect Guarantees**

Millions of dollars		Commitment Expiration by Period			
	Total	2007	2008-2010	2011	After 2011
Guarantees of non-consolidated affiliates or joint-venture obligations	$ 296	$ 21	$ 253	$ 9	$ 13
Guarantees of obligations of third parties	131	4	113	3	11
Guarantees of Equilon debt and leases	119	14	38	11	56

* 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-15.

At December 31, 2006, the company and its subsidiaries provided guarantees, either directly or indirectly, of $296 million for notes and other contractual obligations of affiliated companies and $131 million for third parties, as described by major category below. There are no amounts being carried as liabilities for the company s obligations under these guarantees.

The $296 million in guarantees provided to affiliates related to borrowings for capital projects. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are the company s guarantees of $214 million associated with a construction completion guarantee for the debt financing of the company s equity interest in the BTC crude oil pipeline project. Substantially all of the $296 million guaranteed will expire between 2007 and 2011, with the remaining 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.

The $131 million in guarantees provided on behalf of third parties relate to construction loans to governments of certain of the company s international upstream operations. Substantially all of the $131 million in guarantees expire by 2011, with the remainder expiring by 2015. 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.

At December 31, 2006, Chevron also had outstanding guarantees for about $120 million of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from 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 2007 through 2011 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 million. Through the end of 2006, the company paid approximately $48 million under these indemnities and continues to be obligated for possible additional 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 period 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 indemnities must be asserted either as early as February 2007 or no later than February 2012. Under the terms of these 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 that were sold in 1997. Under the indemnification agreement, the company s liability is unlimited until April 2022, when the liability expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of $200 million, which had not been reached as of December 31, 2006.

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, 2006, approximately $1.2 billion, representing about 7 percent of Chevron s total current accounts and notes receivable balance, were securitized. Chevron s total estimated financial exposure under these securitizations at December 31, 2006, was approximately $80 million. 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, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput 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, drilling rigs, 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: 2007 $3.2 billion; 2008 $1.7 billion; 2009 $2.1 billion; 2010 $1.9 billion; 2011 $0.9 billion; 2012 and after $4.1 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3.0 billion in 2006, $2.1 billion in 2005 and $1.6 billion in 2004.

Minority Interests The company has commitments of $209 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	2007	2008 2010	2011	After 2011
On Balance Sheet:					
Short-Term Debt[1]	$2,159	$2,159	$	$	$
Long-Term Debt[1,2]	7,405		5,868	50	1,487
Noncancelable Capital Lease Obligations	274		138	40	96
Interest	5,269	491	1,173	366	3,239
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	3,058	509	1,374	311	864
Throughput and Take-or-Pay Agreements	9,796	2,765	3,027	475	3,529
Other Unconditional Purchase Obligations	4,072	383	2,696	427	566

1 $4.5 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 2008 2010 period.

2 Includes guarantees of $213 of ESOP (employee stock ownership plan) debt due after 2007. The 2007 amount of $20, which was scheduled for payment on the first business day of January 2007, was paid in late December 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, liquefied natural gas 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, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of this activity were not material to the company s financial position, net income or cash flows in 2006.

The company s market exposure positions are monitored and managed on a daily basis by an internal Risk

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Control group to ensure compliance with the company s risk management policies that have 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 NYMEX (New York Mercantile Exchange) and on electronic platforms of ICE (Inter-Continental Exchange) and GLOBEX (Chicago Mercantile 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 published market quotes and other independent third-party quotes.

Each hypothetical 10 percent increase in the price of natural gas, crude oil and refined products would increase the fair value of the natural gas purchase derivative contracts by approximately $10 million, increase the fair value of the crude oil purchase derivative contracts by about $4 million and reduce the fair value of the refined product sale derivative contracts by about $30 million, respectively. The same hypothetical decrease in the prices of these commodities would result in approximately the same opposite effects on the fair values of the contracts.

The hypothetical effect on these contracts was estimated by calculating the fair value of the contracts as the difference between the hypothetical and current market 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 2006 would be a reduction in the fair value of the foreign exchange contracts of approximately $40 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 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.

At year-end 2006, the weighted average maturity of receive fixed interest rate swaps was approximately one year. 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 $2 million.

For the financial and derivative instruments discussed above, there was not a material change in market risk between 2006 and 2005.

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 2006 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-15 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 approximately 75 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 currently does not use MTBE in the manufacture of gasoline in the United States.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal s undisclosed and pending patents. Eleven lawsuits are now consolidated in U.S. District Court for the Central District of California and three are consolidated in California State Court. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys fees, and interest on behalf of an alleged class of consumers who purchased summertime RFG in California from January 1995 through August 2005. Unocal believes it has valid defenses and intends to vigorously defend against these lawsuits. The company s potential exposure related to these lawsuits cannot currently be estimated.

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,

land development areas, and mining operations, 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.

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	**2006**	2005	2004
Balance at January 1	**$ 1,469**	$ 1,047	$ 1,149
Net Additions	**366**	731	155
Expenditures	**(394)**	(309)	(257)
Balance at December 31	**$ 1,441**	$ 1,469	$ 1,047

Chevron s environmental reserve as of December 31, 2006, was $1,441 million. Included in this balance were remediation activities of 242 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation 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 2006 was $122 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.

Of the remaining year-end 2006 environmental reserves balance of $1,319 million, $834 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 $485 million was associated with various sites in the international downstream ($117 million), upstream ($252 million), chemicals ($61 million) and other ($55 million). 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.

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 2006 had a recorded liability that was material to the company s financial position, results of operations or liquidity.

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.

Effective January 1, 2003, the company implemented FASB 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

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

long-lived assets and the liability can be reasonably estimated. The liability balance of approximately $5.8 billion for asset retirement obligations at year-end 2006 related primarily to upstream and mining properties. Refer to Note 24 on page FS-58 for a discussion of the company s asset retirement obligations.

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, on page FS-58, related to FAS 143 and the company s adoption in 2005 of FASB Interpretation No. (FIN) 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-19.

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, 1997 for Unocal Corporation (Unocal) and 2001 for Texaco Corporation (Texaco). California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal and 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. Besides the United States, the company and its affiliates have significant operations in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, France, India, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, Venezuela, and Vietnam.

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 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, 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 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.

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. At December 31, 2006, the company had approximately $1.2 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $130 million from 2005 and an increase of $568 million from 2004. More than $300 million of suspended wells were added at the time of the Unocal acquisition in August 2005.

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 $1.2 billion of suspended wells at year-end 2006 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 20, beginning on page FS-47, for additional discussion of suspended wells.

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. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately $200 million, and the possible maximum net amount that could be owed to Chevron is

Table of Contents

estimated at about $150 million. 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, 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.

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 2006 at approximately $2.2 billion for its consolidated companies. Included in these expenditures were approximately $870 million of environmental capital expenditures and $1.3 billion 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.

For 2007, total worldwide environmental capital expenditures are estimated at $1.2 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; and
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 crude oil and natural 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-68, for the changes in these estimates for the three years ending December 31, 2006, and to Table VII, Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves on page FS-76 for estimates of proved-reserve values for each of the three years ending December 31, 2004 through 2006, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements, beginning on page FS-32, includes a description of the successful efforts method of accounting for oil and gas exploration and production activities. The estimates of crude oil and

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

natural gas reserves are important to the timing of expense recognition for costs incurred.

The discussion of the critical accounting policy for Impairment of Properties, Plant and Equipment and Investments in Affiliates, on page FS-21, 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-32. 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 obligations and 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 obligations and expense are the discount rate and the assumed health care cost-trend rates.

Note 21, beginning on page FS-48, includes information on the funded status of the company s pension and OPEB plans at the end of 2006 and 2005, the components of pension and OPEB expense for the three years ending December 31, 2006, and the underlying assumptions for those periods. The note also presents the incremental impact of recording the funded status of each of the company s pension and OPEB plans at year-end 2006 under the provisions of FASB Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R* (FAS 158).

Pension and OPEB expense is recorded on the Consolidated Statement of Income in Operating expenses or Selling, general and administrative expenses and applies to all business segments. With the adoption of FAS 158, the year-end 2006 funded status, measured as the difference between plan assets and obligations, of each of the company s pension and OPEB plans is recognized on the Consolidated Balance Sheet. The funded status of overfunded pension plans is recorded as a long-term asset in Deferred charges and other assets. The funded status of underfunded or unfunded

pension and OPEB plans is recorded in Accrued liabilities or Reserves for employee benefit plans. Amounts yet to be recognized as components of pension or OPEB expense are recorded in Accumulated other comprehensive income.

To estimate the long-term rate of return on pension assets, the company uses a 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 U.S. pension plan assets, which account for 70 percent of the company s pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2006, actual asset returns averaged 9.7 percent for this plan.

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, 2006, the company selected a 5.8 percent discount rate for the major U.S. pension and postretirement plans. This rate was selected based on Moody s Aa Corporate Bond Index and a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2006. The discount rates at the end of 2005 and 2004 were 5.5 percent and 5.8 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 2006 was approximately $585 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 would have reduced total pension plan expense for 2006 by approximately $60 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 60 percent of the companywide pension obligation, would have reduced total pension plan expense for 2006 by approximately $160 million.

An increase in the discount rate would decrease pension obligation, thus changing the funded status of a plan recorded on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2006, for underfunded plans was approximately $1.7 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company s primary U.S. pension plan would have reduced the plan obligation by approximately $275 million, which would have changed the plan s funded status from underfunded to overfunded, resulting in a pension asset of about $250 million. Other plans would be less underfunded as discount rates increase. 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 2006, the company s pension plan contributions were approximately $450 million (approximately $225 million to the U.S. plans). In 2007, the company estimates contributions will be approximately $500 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

For the company s OPEB plans, expense for 2006 was about $230 million and the total liability, which reflected the underfunded status of the plans at the end of 2006, was $3.3 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2006, a 1 percent increase in the discount rate for the company s primary U.S. OPEB plan, which accounted for about 75 percent of the company-wide OPEB expense, would have decreased OPEB expense by approximately $25 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 90 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2006 by approximately $70 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. The cap becomes effective in the year of retirement for pre Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre Medicare-eligible employees retiring before that date and all Medicare-eligible retirees. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 9 percent in 2007 and gradually drop to 5 percent for 2011 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2006, a 1 percent increase in the rates for the main U.S. postretirement medical plan, which accounted for about 90 percent of the companywide OPEB obligations, would have increased OPEB expense $8 million.

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are not included in benefit plan costs in
the year the difference occurs. Instead, the differences are included in actuarial gain/loss and unamortized amounts have been reflected in Accumulated other comprehensive loss on the Consolidated Balance Sheet. Refer to Note 21, beginning on page FS-48, for information on the $2.6 billion of actuarial losses recorded by the company as of December 31, 2006; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2007.

Impairment of Properties, Plant and Equipment and Investments in Affiliates The company assesses its properties, 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.

No major impairments of PP&E were recorded for the three years ending December 31, 2006. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in 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

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets 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 Goodwill acquired in a business combination is not subject to amortization. As required by FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests 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-34.

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 section for the effect on earnings from losses associated with certain litigation and environmental remediation and tax matters for the three years ended December 31, 2006.

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

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 Emerging Issues Task Force (EITF) consensus on Issue 04-6, which was adopted by 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 Accounting Research Bulletin (ARB) No. 43, *Restatement and Revision of Accounting Research Bulletins*. Adoption of this accounting for the company s coal, oil sands and other mining operations resulted in a $19 million reduction of retained earnings as of January 1, 2006.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109 (FIN 48) In July 2006, the FASB issued FIN 48, which became effective for the company on January 1, 2007. This interpretation clarifies the accounting for income tax benefits that are uncertain in nature. Under FIN 48, a company will recognize a tax benefit in the financial statements for an uncertain tax position only if management s assessment is that its position is more likely than not (i.e., a greater than 50 percent likelihood) to be upheld on audit based only on the technical merits of the tax position. This accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, interest and penalties recognition, and accounting for the cumulative-effect adjustment. The new interpretation is intended to provide better financial statement comparability among companies.

Required annual disclosures include a tabular reconciliation of unrecognized tax benefits at the beginning and end of the period; the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; the amounts of interest and penalties recognized in the financial statements; any expected significant impacts from unrecognized tax benefits on the financial statements over the subsequent 12-month reporting period; and a description of the tax years remaining to be examined in major tax jurisdictions.

As a result of the implementation of FIN 48, the company expects to recognize an increase in the liability for unrecognized tax benefits and associated interest and penalties as of January 1, 2007. In connection with this increase in liability, the company estimates retained earnings at the beginning of 2007 will be reduced by $250 million or less. The amount of the liability and impact on retained earnings will depend in part on clarification expected to be issued by the FASB related to the criteria for determining the date of ultimate settlement with a tax authority.

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which will become effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 does not require any new fair value measurements but would apply to assets and liabilities that are required to be recorded at fair value under other accounting standards. The impact, if any, to the company from the adoption of FAS 157 in 2008 will depend on the company s assets and liabilities at that time that are required to be measured at fair value.

FASB Statement No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R) (FAS 158) In September 2006, the FASB issued FAS 158, which was adopted by the company on December 31, 2006. Refer to Note 21, beginning on page FS-48, for additional information.

Table of Contents

QUARTERLY RESULTS AND STOCK MARKET DATA

Unaudited

				2006				200
illions of dollars, except per-share amounts	**4TH Q**	**3RD Q**	**2ND Q**	**1ST Q**	4TH Q	3RD Q	2ND Q	1ST
EVENUES AND OTHER INCOME								
les and other operating revenues[1,2]	**$ 46,238**	**$ 52,977**	**$ 52,153**	**$ 53,524**	$ 52,457	$ 53,429	$ 47,265	$ 40,49
come from equity affiliates	**1,079**	**1,080**	**1,113**	**983**	1,110	871	861	88
her income	**429**	**155**	**270**	**117**	227	156	217	22
OTAL REVENUES AND OTHER NCOME	**47,746**	**54,212**	**53,536**	**54,624**	53,794	54,456	48,343	41,60
OSTS AND OTHER DEDUCTIONS								
rchased crude oil and products[2]	**27,658**	**32,076**	**32,747**	**35,670**	34,246	36,101	31,130	26,49
perating expenses	**4,092**	**3,650**	**3,835**	**3,047**	3,819	3,190	2,713	2,46
lling, general and administrative expenses	**1,203**	**1,428**	**1,207**	**1,255**	1,340	1,337	1,152	99
ploration expenses	**547**	**284**	**265**	**268**	274	177	139	15
epreciation, depletion and amortization	**1,988**	**1,923**	**1,807**	**1,788**	1,725	1,534	1,320	1,33
xes other than on income[1]	**5,533**	**5,403**	**5,153**	**4,794**	5,063	5,282	5,311	5,12
terest and debt expense	**92**	**104**	**121**	**134**	135	136	104	10
inority interests	**2**	**20**	**22**	**26**	33	24	18	2
OTAL COSTS AND OTHER EDUCTIONS	**41,115**	**44,888**	**45,157**	**46,982**	46,635	47,781	41,887	36,70
NCOME BEFORE INCOME TAX XPENSE	**6,631**	**9,324**	**8,379**	**7,642**	7,159	6,675	6,456	4,90
NCOME TAX EXPENSE	**2,859**	**4,307**	**4,026**	**3,646**	3,015	3,081	2,772	2,23
ET INCOME	**$ 3,772**	**$ 5,017**	**$ 4,353**	**$ 3,996**	$ 4,144	$ 3,594	$ 3,684	$ 2,67
ER-SHARE OF COMMON STOCK NCOME FROM CONTINUING PERATIONS								
BASIC	**$ 1.75**	**$ 2.30**	**$ 1.98**	**$ 1.81**	$ 1.88	$ 1.65	$ 1.77	$ 1.2
DILUTED	**$ 1.74**	**$ 2.29**	**$ 1.97**	**$ 1.80**	$ 1.86	$ 1.64	$ 1.76	$ 1.2
ET INCOME								
BASIC	**$ 1.75**	**$ 2.30**	**$ 1.98**	**$ 1.81**	$ 1.88	$ 1.65	$ 1.77	$ 1.2
DILUTED	**$ 1.74**	**$ 2.29**	**$ 1.97**	**$ 1.80**	$ 1.86	$ 1.64	$ 1.76	$ 1.2
IVIDENDS	**$ 0.52**	**$ 0.52**	**$ 0.52**	**$ 0.45**	$ 0.45	$ 0.45	$ 0.45	$ 0.4
OMMON STOCK PRICE RANGE								
IGH	**$ 75.97**	**$ 67.85**	**$ 62.88**	**$ 62.21**	$ 64.45	$ 65.77	$ 59.34	$ 62.0

LOW	**$ 62.94**	**$ 60.88**	**$ 56.78**	**$ 54.08**	$ 55.75	$ 56.36	$ 50.51	$ 50.5
ncludes excise, value-added and other milar taxes:	**$ 2,498**	**$ 2,522**	**$ 2,416**	**$ 2,115**	$ 2,173	$ 2,268	$ 2,162	$ 2,11
ncludes amounts for buy/sell contracts:	**$**	**$**	**$**	**$ 6,725**	$ 5,897	$ 6,588	$ 5,962	$ 5,37

The company s common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 23, 2007,
stockholders of record numbered approximately 223,000. There are no restrictions on the company s ability to pay dividends.

Table of Contents

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, 2006.

The company management s assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

DAVID J. O REILLY	STEPHEN J. CROWE	MARK A. HUMPHREY
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 28, 2007

FS-25

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 consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 14 to the Consolidated Financial Statements, the Company changed its method of accounting for buy/sell contracts on April 1, 2006.

As discussed in Note 21 to the Consolidated Financial Statements, the Company changed its method of accounting for defined benefit pension and other postretirement plans on December 31, 2006.

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, 2006, 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, 2006, 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 28, 2007

CONSOLIDATED STATEMENT OF INCOME

Millions of dollars, except per-share amounts

	Year ended December 31		
	2006	2005	2004
REVENUES AND OTHER INCOME			
Sales and other operating revenues[1,2]	**$ 204,892**	$ 193,641	$ 150,865
Income from equity affiliates	**4,255**	3,731	2,582
Other income	**971**	828	1,853
TOTAL REVENUES AND OTHER INCOME	**210,118**	198,200	155,300
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products[2]	**128,151**	127,968	94,419
Operating expenses	**14,624**	12,191	9,832
Selling, general and administrative expenses	**5,093**	4,828	4,557
Exploration expenses	**1,364**	743	697
Depreciation, depletion and amortization	**7,506**	5,913	4,935
Taxes other than on income[1]	**20,883**	20,782	19,818
Interest and debt expense	**451**	482	406
Minority interests	**70**	96	85
TOTAL COSTS AND OTHER DEDUCTIONS	**178,142**	173,003	134,749
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	**31,976**	25,197	20,551
INCOME TAX EXPENSE	**14,838**	11,098	7,517
INCOME FROM CONTINUING OPERATIONS	**17,138**	14,099	13,034
INCOME FROM DISCONTINUED OPERATIONS			294
NET INCOME	**$ 17,138**	$ 14,099	$ $13,328
PER-SHARE OF COMMON STOCK[3]			
INCOME FROM CONTINUING OPERATIONS			
BASIC	**$ 7.84**	$ 6.58	$ 6.16
DILUTED	**$ 7.80**	$ 6.54	$ 6.14
INCOME FROM DISCONTINUED OPERATIONS			
BASIC	**$**	$	$ 0.14
DILUTED	**$**	$	$ 0.14
NET INCOME			
BASIC	**$ 7.84**	$ 6.58	$ 6.30
DILUTED	**$ 7.80**	$ 6.54	$ 6.28

[1] Includes excise, value-added and other similar taxes:	**$ 9,551**	$ 8,719	$ 7,968

[2] Includes amounts in revenues for buy/sell contracts; associated costs are in Purchased crude oil and products. Refer also to Note 14, on page FS-43.	**$ 6,725**	$ 23,822	$ 18,650

[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.

Table of Contents

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Millions of dollars

	Year ended December 31		
	2006	2005	2004
NET INCOME	**$ 17,138**	$ 14,099	$ 13,328
Currency translation adjustment			
Unrealized net change arising during period	**55**	(5)	36
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(88)**	(32)	35
Reclassification to net income of net realized (gain)			(44)
Total	**(88)**	(32)	(9)
Net derivatives gain (loss) on hedge transactions			
Net gain (loss) arising during period			
Before income taxes	**2**	(242)	(8)
Income taxes	**6**	89	(1)
Reclassification to net income of net realized gain (loss)			
Before income taxes	**95**	34	
Income taxes	**(36)**	(12)	
Total	**67**	(131)	(9)
Minimum pension liability adjustment			
Before income taxes	**(88)**	89	719
Income taxes	**50**	(31)	(247)
Total	**(38)**	58	472
OTHER COMPREHENSIVE (LOSS) GAIN, NET OF TAX	**(4)**	(110)	490
COMPREHENSIVE INCOME	**$ 17,134**	$ 13,989	$ 13,818

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

Millions of dollars, except per-share amounts

	At December 31	
	2006	2005
ASSETS		
Cash and cash equivalents	**$ 10,493**	$ 10,043
Marketable securities	**953**	1,101
Accounts and notes receivable (less allowance: 2006 $175; 2005 $156)	**17,628**	17,184
Inventories:		
Crude oil and petroleum products	**3,586**	3,182
Chemicals	**258**	245
Materials, supplies and other	**812**	694
Total inventories	**4,656**	4,121
Prepaid expenses and other current assets	**2,574**	1,887
TOTAL CURRENT ASSETS	**36,304**	34,336
Long-term receivables, net	**2,203**	1,686
Investments and advances	**18,552**	17,057
Properties, plant and equipment, at cost	**137,747**	127,446
Less: Accumulated depreciation, depletion and amortization	**68,889**	63,756
Properties, plant and equipment, net	**68,858**	63,690
Deferred charges and other assets	**2,088**	4,428
Goodwill	**4,623**	4,636
TOTAL ASSETS	**$ 132,628**	$ 125,833
LIABILITIES AND STOCKHOLDERS EQUITY		
Short-term debt	**$ 2,159**	$ 739
Accounts payable	**16,675**	16,074
Accrued liabilities	**4,546**	3,690
Federal and other taxes on income	**3,626**	3,127
Other taxes payable	**1,403**	1,381
TOTAL CURRENT LIABILITIES	**28,409**	25,011
Long-term debt	**7,405**	11,807
Capital lease obligations	**274**	324
Deferred credits and other noncurrent obligations	**11,000**	10,507
Noncurrent deferred income taxes	**11,647**	11,262
Reserves for employee benefit plans	**4,749**	4,046
Minority interests	**209**	200
TOTAL LIABILITIES	**63,693**	63,157

Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)		
Common stock (authorized 4,000,000,000 shares, $0.75 par value; 2,442,676,580 shares issued at December 31, 2006 and 2005)	**1,832**	1,832
Capital in excess of par value	**14,126**	13,894
Retained earnings	**68,464**	55,738
Notes receivable key employees	**(2)**	(3)
Accumulated other comprehensive loss	**(2,636)**	(429)
Deferred compensation and benefit plan trust	**(454)**	(486)
Treasury stock, at cost (2006 278,118,341 shares; 2005 209,989,910 shares)	**(12,395)**	(7,870)
TOTAL STOCKHOLDERS EQUITY	**68,935**	62,676
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 132,628**	$ 125,833

See accompanying Notes to the Consolidated Financial Statements.

Table of Contents

CONSOLIDATED STATEMENT OF CASH FLOWS

Millions of dollars

	Year ended December 31		
	2006	2005	2004
OPERATING ACTIVITIES			
Net income	**$ 17,138**	$ 14,099	$ 13,328
Adjustments			
Depreciation, depletion and amortization	**7,506**	5,913	4,935
Dry hole expense	**520**	226	286
Distributions less than income from equity affiliates	**(979)**	(1,304)	(1,422)
Net before-tax gains on asset retirements and sales	**(229)**	(134)	(1,882)
Net foreign currency effects	**259**	62	60
Deferred income tax provision	**614**	1,393	(224)
Net decrease (increase) in operating working capital	**1,044**	(54)	430
Minority interest in net income	**70**	96	85
Increase in long-term receivables	**(900)**	(191)	(60)
Decrease (increase) in other deferred charges	**232**	668	(69)
Cash contributions to employee pension plans	**(449)**	(1,022)	(1,643)
Other	**(503)**	353	866
NET CASH PROVIDED BY OPERATING ACTIVITIES	**24,323**	20,105	14,690
INVESTING ACTIVITIES			
Cash portion of Unocal acquisition, net of Unocal cash received		(5,934)	
Capital expenditures	**(13,813)**	(8,701)	(6,310)
Repayment of loans by equity affiliates	**463**	57	1,790
Proceeds from asset sales	**989**	2,681	3,671
Net sales (purchases) of marketable securities	**142**	336	(450)
Advances to equity affiliate			(2,200)
NET CASH USED FOR INVESTING ACTIVITIES	**(12,219)**	(11,561)	(3,499)
FINANCING ACTIVITIES			
Net (payments) borrowings of short-term obligations	**(677)**	(109)	114
Repayments of long-term debt and other financing obligations	**(2,224)**	(966)	(1,398)
Cash dividends common stock	**(4,396)**	(3,778)	(3,236)
Dividends paid to minority interests	**(60)**	(98)	(41)
Net purchases of treasury shares	**(4,491)**	(2,597)	(1,645)
Redemption of preferred stock of subsidiaries		(140)	(18)
Proceeds from issuances of long-term debt		20	
NET CASH USED FOR FINANCING ACTIVITIES	**(11,848)**	(7,668)	(6,224)
	194	(124)	58

EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS			
NET CHANGE IN CASH AND CASH EQUIVALENTS	**450**	752	5,025
CASH AND CASH EQUIVALENTS AT JANUARY 1	**10,043**	9,291	4,266
CASH AND CASH EQUIVALENTS AT DECEMBER 31	**$ 10,493**	$ 10,043	$ 9,291

See accompanying Notes to the Consolidated Financial Statements.

Table of Contents

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

Shares in thousands; amounts in millions of dollars

	2006 Shares	**2006** Amount	2005 Shares	2005 Amount	2004 Shares	2004 Amount
PREFERRED STOCK		**$**		$		$
COMMON STOCK						
Balance at January 1	**2,442,677**	**$ 1,832**	2,274,032	$ 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**	2,442,677	$ 1,832	2,274,032	$ 1,706
CAPITAL IN EXCESS OF PAR						
Balance at January 1		**$ 13,894**		$ 4,160		$ 4,002
Shares issued for Unocal acquisition				9,585		
Treasury stock transactions		**232**		149		158
BALANCE AT DECEMBER 31		**$ 14,126**		$ 13,894		$ 4,160
RETAINED EARNINGS						
Balance at January 1		**$ 55,738**		$ 45,414		$ 35,315
Net income		**17,138**		14,099		13,328
Cash dividends on common stock		**(4,396)**		(3,778)		(3,236)
Adoption of EITF 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry		**(19)**				
Tax benefit from dividends paid on unallocated ESOP shares and other		**3**		3		7
BALANCE AT DECEMBER 31		**$ 68,464**		$ 55,738		$ 45,414
		$ (2)		$ (3)		$

NOTES RECEIVABLE KEY EMPLOYEES						
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		**$ (145)**		$ (140)		$ (176)
Change during year		**55**		(5)		36
Balance at December 31		**$ (90)**		$ (145)		$ (140)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (344)**		$ (402)		$ (874)
Change to minimum pension liability during year		**(38)**		58		472
Adoption of FAS 158, Employers Accounting for Defined Pension and Other Postretirement Plans		**(2,203)**				
Balance at December 31		**$ (2,585)**		$ (344)		$ (402)
Unrealized net holding gain on securities						
Balance at January 1		**$ 88**		$ 120		$ 129
Change during year		**(88)**		(32)		(9)
Balance at December 31		**$**		$ 88		$ 120
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ (28)**		$ 103		$ 112
Change during year		**67**		(131)		(9)
Balance at December 31		**$ 39**		$ (28)		$ 103
BALANCE AT DECEMBER 31		**$ (2,636)**		$ (429)		$ (319)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST DEFERRED COMPENSATION						
Balance at January 1		**$ (246)**		$ (367)		$ (362)
Net reduction of ESOP debt and other		**32**		121		(5)
BALANCE AT DECEMBER 31		**(214)**		(246)		(367)
	14,168	**(240)**	14,168	(240)	14,168	(240)

BENEFIT PLAN TRUST (COMMON STOCK)						
BALANCE AT DECEMBER 31	**14,168**	**$ (454)**	14,168	$ (486)	14,168	$ (607)
TREASURY STOCK AT COST						
Balance at January 1	**209,990**	**$ (7,870)**	166,912	$ (5,124)	135,747	$ (3,317)
Purchases	**80,369**	**(5,033)**	52,013	(3,029)	42,607	(2,122)
Issuances mainly employee benefit plans	**(12,241)**	**508**	(8,935)	283	(11,442)	315
BALANCE AT DECEMBER 31	**278,118**	**$ (12,395)**	209,990	$ (7,870)	166,912	$ (5,124)
TOTAL STOCKHOLDERS EQUITY AT DECEMBER 31		**$ 68,935**		$ 62,676		$ 45,230

See accompanying Notes to the Consolidated Financial Statements.

Table of Contents

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
Millions of dollars, except per-share amounts

NOTE 1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General 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 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.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES Continued

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-47, 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, development area, 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.

As required under Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143), the fair value of a liability for an ARO 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, on page FS-58, relating to AROs.

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 mining assets are determined using the unit-of-production method as the proven 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 (including those for planned major maintenance projects), 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 FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests 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-34.

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.

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 mineral producing properties, a liability for an asset retire-

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES Continued

ment obligation is made, following FAS 143. Refer to Note 24, on page FS-58, 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). Excise, value-added and other similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income on page FS-27. Refer to Note 14, on page FS-43, 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 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 FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

Refer to Note 22, beginning on page FS-53, 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 2005 net income and earnings per share for periods after adoption of FAS 123R.

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

[1] Fair value determined using the Black-Scholes option-pricing model.

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

NOTE 2.

ACQUISITION OF UNOCAL CORPORATION

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

The aggregate purchase price of Unocal was approximately $17,288. A third-party appraisal firm was engaged to assist the company in the process of determining the fair values of Unocal s tangible and intangible assets. The final purchase-price allocation to the assets and liabilities acquired was completed as of June 30, 2006.

NOTE 2. ACQUISITION OF UNOCAL CORPORATION
Continued

The acquisition was accounted for under the rules of FASB Statement No. 141, *Business Combinations*. The following table summarizes the final purchase-price allocation:

Current assets	$ 3,573
Investments and long-term receivables	1,695
Properties	17,285
Goodwill	4,820
Other assets	2,174
Total assets acquired	29,547
Current liabilities	(2,364)
Long-term debt and capital leases	(2,392)
Deferred income taxes	(4,009)
Other liabilities	(3,494)
Total liabilities assumed	(12,259)
Net assets acquired	$ 17,288

The $4,820 of goodwill, which represents benefits of the acquisition that are additional to the fair values of the other net assets acquired, was assigned to the upstream segment. The goodwill is not deductible for tax purposes. The goodwill balance was reviewed for possible impairment as of June 30, 2006, according to the requirements of FASB Statement No. 142, *Goodwill and Other Intangible Assets*, to test goodwill for impairment on an annual basis. Goodwill was determined not to be impaired at that time, and no events have occurred subsequently that would necessitate an additional impairment review.

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		
	2006	2005	2004
Net decrease (increase) in operating working capital was composed of the following:			
Decrease (increase) in accounts and notes receivable	**$ 17**	$ (3,164)	$ (2,515)
Increase in inventories	**(536)**	(968)	(298)
Increase in prepaid expenses and other current assets	**(31)**	(54)	(76)
Increase in accounts payable and accrued liabilities	**1,246**	3,851	2,175
Increase in income and other taxes payable	**348**	281	1,144
Net decrease (increase) in operating working capital	**$ 1,044**	$ (54)	$ 430
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$ 470**	$ 455	$ 422
Income taxes	**$ 13,806**	$ 8,875	$ 6,679
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (1,271)**	$ (918)	$ (1,951)
Marketable securities sold	**1,413**	1,254	1,501
Net sales (purchases) of marketable securities	**$ 142**	$ 336	$ (450)

The Consolidated Statement of Cash Flows excludes the effects of noncash transactions. In October 2006, operating service agreements in Venezuela were converted to joint stock companies. Upon conversion, the company reclassified $441 of long-term receivables, $132 of accounts receivable and $45 of properties, plant and equipment to investments in equity affiliates. Refer also to Note 21 on page FS-48 for the non-cash effects associated with the implementation of FASB Statement No. 158, *Employers Accounting for Defined Pension and Other Postretirement Plans*.

In accordance with the cash-flow classification requirements of FAS 123R, *Share-Based Payment*, the Net decrease (increase) in operating working capital includes reductions of $94 and $20 for excess income tax benefits associated with stock options exercised during 2006 and 2005, respectively. These amounts are offset by Net purchases of treasury shares.

The Net purchases of treasury shares represents the cost of common shares acquired in the open market less the cost of shares issued for share-based compensation plans. Open-market purchases totaled $5,033, $3,029 and $2,122 in 2006, 2005 and 2004, respectively.

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

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

In May 2006, the company s investment in Dynegy Series C preferred stock was redeemed at its face value of $400. Upon redemption of the preferred stock, the company recorded a before-tax gain of $130 ($87 after tax). The $130 gain is included in the Consolidated Statement of Income as Income from equity affiliates.

The 2005 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 approximately $17,288. Refer to Note 2, starting on page FS-34, 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-2, are presented in the following table:

	Year ended December 31		
	2006	2005	2004
Additions to properties, plant and equipment*	**$ 12,800**	$ 8,154	$ 5,798
Additions to investments	**880**	459	303
Current-year dry hole expenditures	**400**	198	228
Payments for other liabilities and assets, net	**(267)**	(110)	(19)
Capital expenditures	**13,813**	8,701	6,310
Expensed exploration expenditures	**844**	517	412
Assets acquired through capital lease obligations and other financing obligations	**35**	164	31
Capital and exploratory expenditures, excluding equity affiliates	**14,692**	9,382	6,753
Equity in affiliates expenditures	**1,919**	1,681	1,562
Capital and exploratory expenditures, including equity affiliates	**$ 16,611**	$ 11,063	$ 8,315

*Net of noncash additions of $440 in 2006, $435 in 2005 and $212 in 2004.

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.

	Year ended December 31		
	2006	2005	2004
Sales and other operating revenues	**$ 146,447**	$ 138,296	$ 108,351
Total costs and other deductions	**138,494**	132,180	102,180
Net income	**5,399**	4,693	4,773

	At December 31	
	2006	2005
Current assets	**$ 26,356**	$ 27,878
Other assets	**23,200**	20,611
Current liabilities	**17,250**	20,286
Other liabilities	**11,501**	12,897
Net equity	**20,805**	15,306
Memo: Total debt	**$ 6,020**	$ 8,353

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 fully and unconditionally 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:

	Year ended December 31		
	2006	2005	2004
Sales and other operating revenues	**$ 692**	$ 640	$ 660
Total costs and other deductions	**602**	509	495
Net income	**119**	113	160

	At December 31	
	2006	2005
Current assets	**$ 413**	$ 358
Other assets	**345**	283
Current liabilities	**92**	119
Other liabilities	**250**	243
Net equity	**416**	279

There were no restrictions on CTC s ability to pay dividends or make loans or advances at December 31, 2006.

NOTE 6.

STOCKHOLDERS EQUITY

Retained earnings at December 31, 2006 and 2005, included approximately $5,580 and $5,000, respectively, for the company s share of undistributed earnings of equity affiliates.

At December 31, 2006, about 134 million shares of Chevron s common stock remained available for issuance from

NOTE 6. STOCKHOLDER S EQUITY Continued

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 503,000 shares remain available for issuance from the 800,000 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 25, on page FS-58, 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, liquefied natural gas 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, sale and storage of crude oil, refined products, natural gas, natural gas liquids, and feedstock for company refineries. 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. Ga 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.

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.

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.

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.

Long-term debt of $5,131 and $7,424 had estimated fair values of $5,621 and $7,945 at December 31, 2006 and 2005, respectively.

The company holds cash equivalents and marketable securities in U.S. and non-U.S. 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 $9,200 and $8,995 at December 31, 2006 and 2005, respectively. Of these balances, $8,247 and $7,894 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 1.4 years.

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

Fair values of other financial and derivative instruments at the end of 2006 and 2005 were not material.

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 finan-

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 7. FINANCIAL AND DERIVATIVE INSTRUMENTS Continued

cial 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, the company believes 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.

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 Financial Accounting Standards Board (FASB) Statement No. 131, *Disclosures About Segments of an Enterprise and Related Information* (FAS 131).

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 accountable directly 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, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels, 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 from continuing operations is presented in the following table:

	Year ended December 31		
	2006	2005	2004
Income From Continuing Operations			
Upstream			
United States	**$ 4,270**	$ 4,168	$ 3,868
International	**8,872**	7,556	5,622
Total Upstream	**13,142**	11,724	9,490
Downstream			
United States	**1,938**	980	1,261
International	**2,035**	1,786	1,989
Total Downstream	**3,973**	2,766	3,250
Chemicals			
United States	**430**	240	251
International	**109**	58	63
Total Chemicals	**539**	298	314
Total Segment Income	**17,654**	14,788	13,054
All Other			
Interest expense	**(312)**	(337)	(257)
Interest income	**380**	266	129
Other	**(584)**	(618)	108
Income From Continuing Operations	**17,138**	14,099	13,034
Income From Discontinued Operations			294
Net Income	**$ 17,138**	$ 14,099	$ 13,328

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA   Continued

Segment Assets   Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2006 and 2005 are as follows:

	At December 31	
	2006	2005
Upstream		
United States	**$ 20,727**	$ 19,006
International	**51,844**	46,501
Goodwill	**4,623**	4,636
Total Upstream	**77,194**	70,143
Downstream		
United States	**13,482**	12,273
International	**22,892**	22,294
Total Downstream	**36,374**	34,567
Chemicals		
United States	**2,568**	2,452
International	**832**	727
Total Chemicals	**3,400**	3,179
Total Segment Assets	**116,968**	107,889
All Other*		
United States	**8,481**	9,234
International	**7,179**	8,710
Total All Other	**15,660**	17,944
Total Assets United States	**45,258**	42,965
Total Assets International	**82,747**	78,232
Goodwill	**4,623**	4,636
Total Assets	**$ 132,628**	$ 125,833

* 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, 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 2006, 2005 and 2004 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, no single country accounted for 10 percent or more of the company s total sales and other operating revenues in 2006.

	Year ended December 31		
	2006	2005	2004
Upstream			
United States	**$ 18,061**	$ 16,044	$ 8,242
Intersegment	**10,069**	8,651	8,121
Total United States	**28,130**	24,695	16,363
International	**14,560**	10,190	7,246
Intersegment	**17,139**	13,652	10,184
Total International	**31,699**	23,842	17,430
Total Upstream	**59,829**	48,537	33,793
Downstream			
United States	**69,367**	73,721	57,723
Excise and other similar taxes	**4,829**	4,521	4,147
Intersegment	**533**	535	179
Total United States	**74,729**	78,777	62,049
International	**91,325**	83,223	67,944
Excise and other similar taxes	**4,657**	4,184	3,810
Intersegment	**37**	14	87
Total International	**96,019**	87,421	71,841
Total Downstream	**170,748**	166,198	133,890
Chemicals			
United States	**372**	343	347
Excise and other similar taxes	**2**		
Intersegment	**243**	241	188

Total United States	**617**	584	535
International	**959**	760	747
Excise and other similar taxes	**63**	14	11
Intersegment	**160**	131	107
Total International	**1,182**	905	865
Total Chemicals	**1,799**	1,489	1,400
All Other			
United States	**653**	597	551
Intersegment	**584**	514	431
Total United States	**1,237**	1,111	982
International	**44**	44	97
Intersegment	**23**	26	16
Total International	**67**	70	113
Total All Other	**1,304**	1,181	1,095
Segment Sales and Other Operating Revenues			
United States	**104,713**	105,167	79,929
International	**128,967**	112,238	90,249
Total Segment Sales and Other Operating Revenues	**233,680**	217,405	170,178
Elimination of intersegment sales	**(28,788)**	(23,764)	(19,313)
Total Sales and Other Operating Revenues*	**$ 204,892**	$ 193,641	$ 150,865

*Includes buy/sell contracts of $6,725 in 2006, $23,822 in 2005 and $18,650 in 2004. Substantially all of the amounts in each period relates to the downstream segment. Refer to Note 14, on page FS-43 for a discussion of the company s accounting for buy/sell contracts.

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA Continued

Segment Income Taxes Segment income tax expenses for the years 2006, 2005 and 2004 are as follows:

	Year ended December 31		
	2006	2005	2004
Upstream			
United States	**$ 2,668**	$ 2,330	$ 2,308
International	**10,987**	8,440	5,041
Total Upstream	**13,655**	10,770	7,349
Downstream			
United States	**1,162**	575	739
International	**586**	576	442
Total Downstream	**1,748**	1,151	1,181
Chemicals			
United States	**213**	99	47
International	**30**	25	17
Total Chemicals	**243**	124	64
All Other	**(808)**	(947)	(1,077)
Income Tax Expense From Continuing Operations*	**$ 14,838**	$ 11,098	$ 7,517

*Income tax expense of $100 related to discontinued operations for 2004 is not included.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page FS-41. Information related to properties, plant and equipment by segment is contained in Note 13, on page FS-43.

NOTE 9.

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	
	2006	2005
Upstream	**$ 461**	$ 442
Downstream	**896**	837
Total	**1,357**	1,279
Less: Accumulated amortization	**813**	745
Net capitalized leased assets	**$ 544**	$ 534

Rental expenses incurred for operating leases during 2006, 2005 and 2004 were as follows:

	Year ended December 31		
	2006	2005	2004
Minimum rentals	**$ 2,326**	$ 2,102	$ 2,093
Contingent rentals	**6**	6	7
Total	**2,332**	2,108	2,100
Less: Sublease rental income	**33**	43	40
Net rental expense	**$ 2,299**	$ 2,065	$ 2,060

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, 2006, 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: 2007	$ 509	$ 91
2008	507	80
2009	477	81
2010	390	59
2011	311	57
Thereafter	864	520
Total	$ 3,058	$ 888
Less: Amounts representing interest and executory costs		(262)
Net present values		626
Less: Capital lease obligations included in short-term debt		(352)

Long-term capital lease obligations	$ 274

NOTE 10.
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 by eliminating redundant operations, consolidating offices and facilities, and sharing common services and functions.

As part of the restructuring and reorganization, approximately 600 employees were eligible for severance payments. Most of the associated positions are in the United States and relate primarily to corporate and upstream executive and administrative functions. By year-end 2006, the program was substantially complete.

NOTE 10. RESTRUCTURING AND REORGANIZATION COSTS Continued

An accrual of $106 was established as part of the purchase-price allocation for Unocal. The $11 balance at year-end 2006 was classified as a current liability on the Consolidated Balance Sheet. Activity for this accrual is shown in the table below.

Amounts before tax	**2006**	2005
Balance at January 1	**$ 44**	$
Additions/Adjustments	**(14)**	106
Payments	**(19)**	(62)
Balance at December 31	**$ 11**	$ 44

Shown in the table below is the activity for the company s liability related to various other reorganizations and restructurings across several businesses and corporate departments. The $17 balance at year-end 2006 was also classified as a current liability on the Consolidated Balance Sheet. The associated charges or credits during the periods were categorized as Operating expenses or Selling, general and administrative expenses on the Consolidated Statement of Income.

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

Amounts before tax	**2006**	2005
Balance at January 1	**$ 47**	$ 119
Additions/adjustments	**(7)**	(10)
Payments	**(23)**	(62)
Balance at December 31	**$ 17**	$ 47

NOTE 11.
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		
	2006	2005	2004
Revenues and other income	**$**	$	$ 635
Income from discontinued operations before income tax expense			394

Income from discontinued operations, net of tax	294

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.

Subsequent to December 31, 2006, approximately $300 of the company s refining assets in the Netherlands met the criteria for classifying the assets as held for sale. The company expects to record a gain upon close of sale, which is subject to

signing of the sales agreement and obtaining necessary regulatory approvals.

NOTE 12.

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 shown in the table below. For certain equity affiliates, Chevron pays its share of some income taxes directly. For such affiliates, the equity in earnings do not include these taxes, which are reported on the Consolidated Statement of Income as Income tax expense.

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2006	2005	**2006**	2005	2004
Upstream					
Tengizchevroil	**$ 5,507**	$ 5,007	**$ 1,817**	$ 1,514	$ 950
Hamaca	**928**	1,189	**319**	390	98
Petroboscan	**712**		**31**		
Other	**682**	679	**123**	139	148
Total Upstream	**7,829**	6,875	**2,290**	2,043	1,196
Downstream					
GS Caltex Corporation	**2,176**	1,984	**316**	320	296
Caspian Pipeline Consortium	**990**	1,014	**117**	101	140
Star Petroleum Refining Company Ltd.	**787**	709	**116**	81	207
Caltex Australia Ltd.	**559**	435	**186**	214	173
Colonial Pipeline Company	**555**	565	**34**	13	
Other	**1,839**	1,562	**358**	273	143
Total Downstream	**6,906**	6,269	**1,127**	1,002	959
Chemicals					
Chevron Phillips Chemical Company LLC	**2,044**	1,908	**697**	449	334
Other	**22**	20	**5**	3	2
Total Chemicals	**2,066**	1,928	**702**	452	336

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.

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 12. INVESTMENTS AND ADVANCES
Continued

Petroboscan Chevron has a 39 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela. Chevron previously operated the field under an operating service agreement. At December 31, 2006, the company s carrying value of its investment in Petroboscan was approximately $300 higher than the amount of underlying equity in Petroboscan s net assets.
GS Caltex Corporation Chevron owns 50 percent of GS Caltex, 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 predominantly in South Korea.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC), which provides the critical export route for crude oil from both TCO and Karachaganak. At December 31, 2006, the company s carrying value of its investment in CPC was about $50 higher than the amount of underlying equity in CPC s net assets.

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 in 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, 2006, the fair value of Chevron s share of CAL common stock was approximately $2,400. The aggregate carrying value of the company s investment in CAL was approximately $60 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest in the Colonial Pipeline Company. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market. At December 31, 2006, the company s carrying value of its investment in Colonial Pipeline was approximately $590 higher than the amount of underlying equity in Colonial Pipeline s net assets.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC (CPChem), with the other half owned by ConocoPhillips Corporation. At December 31, 2006, the company s carrying value of its investment in CPChem was approximately $80 lower than the amount of underlying equity in CPChem s net assets.

Dynegy Inc. Chevron owns a 19 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States.
Investment in Dynegy Common Stock At December 31, 2006, the carrying value of the company s investment in Dynegy common stock was approximately $250. This amount was about $180 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, 2006, was approximately $700.

Investment in Dynegy Preferred Stock In May 2006, the company s investment in Dynegy Series C preferred stock was redeemed at its face value of $400. Upon redemption of the preferred stock, the company recorded a before-tax gain of $130 ($87 after tax).

Dynegy Proposed Business Combination With LS Power Group Dynegy and LS Power Group, a privately held power plant investor, developer and manager, announced in September 2006 that the companies had executed a definitive agreement to combine Dynegy s assets and operations with LS Power Group s power generation portfolio and for Dynegy to acquire a 50 percent ownership interest in a development joint venture with LS Power. Upon close of the transaction, Chevron will receive the same number of shares of the new company s Class A common stock that it currently holds in Dynegy. Chevron s ownership interest in the combined company will be approximately 11 percent. The transaction is subject to specified conditions, including the affirmative vote of two-thirds of Dynegy s common shareholders and the receipt of regulatory approvals.

Other Information Sales and other operating revenues on the Consolidated Statement of Income includes $9,582, $8,824 and $7,933 with affiliated companies for 2006, 2005 and 2004, respectively. Purchased crude oil and products includes $4,222, $3,219 and $2,548 with affiliated companies for 2006, 2005 and 2004, respectively.

Accounts and notes receivable on the Consolidated Balance Sheet includes $1,297 and $1,729 due from affiliated companies at December 31, 2006 and 2005, respectively. Accounts payable includes $262 and $249 due to affiliated companies at December 31, 2006 and 2005, respectively.

Table of Contents

NOTE 12. INVESTMENTS AND ADVANCES Continued

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron s total share, which includes Chevron loans to affiliates of $3,915 at December 31, 2006.

			Affiliates			Chevron Share
Year ended December 31	**2006**	2005	2004	**2006**	2005	2004
Total revenues	**$ 73,746**	$ 64,642	$ 55,152	**$ 35,695**	$ 31,252	$ 25,916
Income before income tax expense	**10,973**	7,883	5,309	**5,295**	4,165	3,015
Net income	**7,905**	6,645	4,441	**4,072**	3,534	2,582
At December 31						
Current assets	**$ 19,769**	$ 19,903	$ 16,506	**$ 8,944**	$ 8,537	$ 7,540
Noncurrent assets	**49,896**	46,925	38,104	**18,575**	17,747	15,567
Current liabilities	**15,254**	13,427	10,949	**6,818**	6,034	4,962
Noncurrent liabilities	**24,059**	26,579	22,261	**3,902**	4,906	4,520
Net equity	**$ 30,352**	$ 26,822	$ 21,400	**$ 16,799**	$ 15,344	$ 13,625

NOTE 13.

PROPERTIES, PLANT AND EQUIPMENT[1]

					At December 31							Year ended December 31
		Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expense[3,4]	
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Upstream												
United States	**$ 46,191**	$ 43,390	$ 37,329	**$ 16,706**	$ 15,327	$ 10,047	**$ 3,739**	$ 2,160	$ 1,584	**$ 2,374**	$ 1,869	$ 1,508
International	**61,281**	54,497	38,721	**37,730**	34,311	21,192	**7,290**	4,897	3,090	**3,888**	2,804	2,180
Total Upstream	**107,472**	97,887	76,050	**54,436**	49,638	31,239	**11,029**	7,057	4,674	**6,262**	4,673	3,688
Downstream												
United States	**14,553**	13,832	12,826	**6,741**	6,169	5,611	**1,109**	793	482	**474**	461	490
International	**11,036**	11,235	10,843	**5,233**	5,529	5,443	**532**	453	441	**551**	550	572
	25,589	25,067	23,669	**11,974**	11,698	11,054	**1,641**	1,246	923	**1,025**	1,011	1,062

otal Downstream												
hemicals												
Jnited States	**645**	624	615	**289**	282	292	**25**	12	12	**19**	19	20
nternational	**771**	721	725	**431**	402	392	**54**	43	27	**24**	23	26
otal Chemicals	**1,416**	1,345	1,340	**720**	684	684	**79**	55	39	**43**	42	46
ll Other[5]												
Jnited States	**3,243**	3,127	2,877	**1,709**	1,655	1,466	**270**	199	314	**171**	186	158
nternational	**27**	20	18	**19**	15	15	**8**	4	2	**5**	1	3
otal All Other	**3,270**	3,147	2,895	**1,728**	1,670	1,481	**278**	203	316	**176**	187	161
otal United tates	**64,632**	60,973	53,647	**25,445**	23,433	17,416	**5,143**	3,164	2,392	**3,038**	2,535	2,176
otal nternational	**73,115**	66,473	50,307	**43,413**	40,257	27,042	**7,884**	5,397	3,560	**4,468**	3,378	2,781
otal	**$ 137,747**	$ 127,446	$ 103,954	**$ 68,858**	$ 63,690	$ 44,458	**$ 13,027**	$ 8,561	$ 5,952	**$ 7,506**	$ 5,913	$ 4,957

[1] Includes assets acquired in connection with the acquisition of Unocal Corporation in August 2005. Refer to Note 2, beginning on page FS-34, for additional information.

[2] Net of dry hole expense related to prior years expenditures of $120, $28 and $58 in 2006, 2005 and 2004, respectively.

[3] Depreciation expense includes accretion expense of $275, $187 and $93 in 2006, 2005 and 2004, respectively.

[4] Depreciation expense includes discontinued operations of $22 in 2004.

[5] Primarily mining operations, power generation businesses, real estate assets and management information systems.

NOTE 14.

ACCOUNTING FOR BUY/SELL CONTRACTS

The company adopted the accounting prescribed by EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (Issue 04-13) on a prospective basis from April 1, 2006. Issue 04-13 requires that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, be combined and considered as a single arrangement for purposes of applying the provisions of Accounting Principles Board Opinion No. 29, *Accounting for Nonmonetary Transactions,* when the transactions are entered into in contemplation of one

another. In prior periods, the company accounted for buy/sell transactions in the Consolidated Statement of Income as a monetary transaction purchases were reported as Purchased crude oil and products ; sales were reported as Sales and other operating revenues.

With the company s adoption of Issue 04-13, buy/sell transactions beginning in the second quarter 2006 are netted against each other on the Consolidated Statement of Income, with no effect on net income. Amounts associated with buy/ sell transactions in periods prior to the second quarter 2006 are shown as a footnote to the Consolidated

Statement of Income on page FS-27.

Table of Contents

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 15.
LITIGATION

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 approximately 75 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 currently does not use MTBE in the manufacture of gasoline in the United States.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal s undisclosed and pending patents. Eleven lawsuits are now consolidated in U.S. District Court for the Central District of California and three are consolidated in California State Court. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys fees, and interest on behalf of an alleged class of consumers who purchased summertime RFG in California from January 1995 through August 2005. Unocal believes it has valid defenses and intends to vigorously defend against these lawsuits. The company s potential exposure related to these lawsuits cannot currently be estimated.

NOTE 16.

TAXES

	Year ended December 31		
	2006	2005	2004
Taxes on income*			
U.S. federal			
Current	**$ 2,828**	$ 1,459	$ 2,246
Deferred	**200**	567	(290)
State and local	**581**	409	345
Total United States	**3,609**	2,435	2,301
International			
Current	**11,030**	7,837	5,150
Deferred	**199**	826	66

Total International	**11,229**	8,663	5,216
Total taxes on income	**$ 14,838**	$ 11,098	$ 7,517

* Excludes income tax expense of $100 related to discontinued operations for 2004.

In 2006, the before-tax income for U.S. operations, including related corporate and other charges, was $9,131, compared with a before-tax income of $6,733 and $7,776 in 2005 and 2004, respectively. For international operations, before-tax income was $22,845, $18,464 and $12,775 in 2006, 2005 and 2004, respectively. U.S. federal income tax expense was reduced by $116, $289 and $176 in 2006, 2005 and 2004, 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		
	2006	2005	2004
U.S. statutory federal income tax rate	**35.0%**	35.0%	35.0%
Effect of income taxes from international operations at rates different from the U.S. statutory rate	**10.3**	9.2	5.3
State and local taxes on income, net of U.S. federal income tax benefit	**1.0**	1.0	0.9
Prior-year tax adjustments	**0.9**	0.1	(1.0)
Tax credits	**(0.4)**	(1.1)	(0.9)
Effects of enacted changes in tax laws	**0.3**		(0.6)
Capital loss tax benefit		(0.1)	(2.1)
Other	**(0.7)**		
Effective tax rate	**46.4%**	44.1%	36.6%

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	
	2006	2005
Deferred tax liabilities		
Properties, plant and equipment	**$ 16,054**	$ 14,220
Investments and other	**2,137**	1,469
Total deferred tax liabilities	**18,191**	15,689
Deferred tax assets		
Abandonment/environmental reserves	**(2,925)**	(2,083)
Employee benefits	**(2,707)**	(1,250)
Tax loss carryforwards	**(1,509)**	(1,113)
Capital losses	**(246)**	(246)
Deferred credits	**(1,670)**	(1,618)
Foreign tax credits	**(1,916)**	(1,145)

Inventory	**(378)**	(182)
Other accrued liabilities	**(375)**	(240)
Miscellaneous	**(1,144)**	(1,237)
Total deferred tax assets	**(12,870)**	(9,114)
Deferred tax assets valuation allowance	**4,391**	3,249
Total deferred taxes, net	**$ 9,712**	$ 9,824

In 2006, deferred tax liabilities increased by approximately $2,500 from the amount reported in 2005. The

NOTE 16. TAXES   Continued

increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets increased by approximately $3,800 in 2006. The increase related primarily to higher pension and other benefit obligations resulting from the implementation of FAS 158, increased foreign tax credits resulting from higher crude oil prices in tax jurisdictions with high income tax rates, and increased asset retirement obligations.

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 international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2007 through 2029. Foreign tax credit carryforwards of $1,916 will expire between 2009 and 2016.

At December 31, 2006 and 2005, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2006	2005
Prepaid expenses and other current assets	**$ (1,167)**	$ (892)
Deferred charges and other assets	**(844)**	(547)
Federal and other taxes on income	**76**	1
Noncurrent deferred income taxes	**11,647**	11,262
Total deferred income taxes, net	**$ 9,712**	$ 9,824

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 $21,035 at December 31, 2006. 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 is to be phased in from 2005 through 2010. The company expects the net effect of this provision of the Act to result in a decrease in the federal effective tax rate for 2007 to approximately 33 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		
	2006	2005	2004
United States			

Excise and other similar taxes on products and merchandise	**$ 4,831**	$ 4,521	$ 4,147
Import duties and other levies	**32**	8	5
Property and other miscellaneous taxes	**475**	392	359
Payroll taxes	**155**	149	137
Taxes on production	**360**	323	257
Total United States	**5,853**	5,393	4,905
International			
Excise and other similar taxes on products and merchandise	**4,720**	4,198	3,821
Import duties and other levies	**9,618**	10,466	10,542
Property and other miscellaneous taxes	**491**	535	415
Payroll taxes	**75**	52	52
Taxes on production	**126**	138	86
Total International	**15,030**	15,389	14,916
Total taxes other than on income*	**$ 20,883**	$ 20,782	$ 19,821

* Includes taxes on discontinued operations of $3 in 2004.

NOTE 17.
SHORT-TERM DEBT

	At December 31	
	2006	2005
Commercial paper*	**$ 3,472**	$ 4,098
Notes payable to banks and others with originating terms of one year or less	**122**	170
Current maturities of long-term debt	**2,176**	467
Current maturities of long-term capital leases	**57**	70
Redeemable long-term obligations Long-term debt	**487**	487
Capital leases	**295**	297
Subtotal	**6,609**	5,589
Reclassified to long-term debt	**(4,450)**	(4,850)
Total short-term debt	**$ 2,159**	$ 739

* Weighted-average interest rates at December 31, 2006 and 2005, were 5.25 percent and 4.18 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-37, for information concerning the company s debt-related derivative activities.

At December 31, 2006, the company had $4,950 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

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 17. SHORT-TERM DEBT   Continued

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 2006 or at year-end.

At December 31, 2006 and 2005, the company classified $4,450 and $4,850, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2007, 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, 2006, was $7,405. The company s long-term debt outstanding at year-end 2006 and 2005 was as follows:

	At December 31	
	2006	2005
3.5% notes due 2007	**$ 1,996**	$ 1,992
3.375% notes due 2008	**738**	736
5.5% notes due 2009	**401**	406
9.75% debentures due 2020	**250**	250
7.327% amortizing notes due 2014[1]	**213**	247
8.625% debentures due 2031	**199**	199
8.625% debentures due 2032	**199**	199
7.5% debentures due 2043	**198**	198
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
7.5% debentures due 2029		475
5.05% debentures due 2012		412
7.35% debentures due 2009		347
7% debentures due 2028		259
Fixed and floating interest rate loans due 2007 to 2009		194
9.125% debentures due 2006		167
8.25% debentures due 2006		129
Medium-term notes, maturing from 2017 to 2043 (7.7%)[2]	**210**	210
Fixed interest rate notes, maturing from 2007 to 2011 (7.4%)[2]	**46**	241
Other foreign currency obligations (2.2%)[2]	**23**	30
Other long-term debt (7.6%)[2]	**66**	141
Total including debt due within one year	**5,131**	7,424

Debt due within one year	**(2,176)**	(467)
Reclassified from short-term debt	**4,450**	4,850
Total long-term debt	**$ 7,405**	$ 11,807

[1] Guarantee of ESOP debt.

[2] Less than $100 individually; weighted-average interest rate at December 31, 2006.

Long-term debt of $5,131 matures as follows: 2007 $2,176; 2008 $805; 2009 $428; 2010 $185; 2011 $50; and after 2011 $1,487.

In the first quarter of 2006, $185 of Union Oil Company bonds were retired at maturity. In the second quarter, the company redeemed approximately $1,700 of Unocal debt and recognized a $92 before-tax gain. In October 2006, a $129 Texaco Capital Inc. bond matured. In November 2006, the company retired Union Oil Company bonds of $196.

NOTE 19.

NEW ACCOUNTING STANDARDS

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 Emerging Issues Task Force (EITF) consensus on Issue 04-6, which was adopted by 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 the company s coal, oil sands and other mining operations resulted in a $19 reduction of retained earnings as of January 1, 2006.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109(FIN 48) In July 2006, the FASB issued FIN 48, which became effective for the company on January 1, 2007. This interpretation clarifies the accounting for income tax benefits that are uncertain in nature. Under FIN 48, a company will recognize a tax benefit in the financial statements for an uncertain tax position only if management s assessment is that its position is more likely than not (i.e., a greater than 50 percent likelihood) to be upheld on audit based only on the technical merits of the tax position. This accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, interest and penalties recognition, and accounting for the cumulative-effect adjustment. The new interpretation is intended to provide better financial statement comparability among companies.

Required annual disclosures include a tabular reconciliation of unrecognized tax benefits at the beginning and end of the period; the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; the amounts of interest and penalties recognized in the financial statements; any expected significant impacts from unrecognized tax benefits on the financial statements over the subsequent 12-month reporting period; and a description of the tax years remaining to be examined in major tax jurisdictions.

As a result of the implementation of FIN 48, the company expects to recognize an increase in the liability for unrecog-

NOTE 19. NEW ACCOUNTING STANDARDS Continued

nized tax benefits and associated interest and penalties as of January 1, 2007. In connection with this increase in liability, the company estimates retained earnings at the beginning of 2007 will be reduced by $250 or less. The amount of the liability and impact on retained earnings will depend in part on clarification expected to be issued by the FASB related to the criteria for determining the date of ultimate settlement with a tax authority.

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which will become effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The Statement does not require any new fair value measurements but would apply to assets and liabilities that are required to be recorded at fair value under other accounting standards. The impact, if any, to the company from the adoption of FAS 157 in 2008 will depend on the company s assets and liabilities at that time that are required to be measured at fair value.

FASB Statement No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an Amendment of FASB Statements No. 87, 88, 106 and 132(R) (FAS 158) In September 2006, the FASB issued FAS 158, which was adopted by the company on December 31, 2006. Refer to Note 21, beginning on page FS-48 for additional information.

NOTE 20.

ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS

The company accounts for the cost of exploratory wells in accordance with FASB Statement No. 19, *Financial and Reporting by Oil and Gas Producing Companies* (FAS 19), as amended by FASB Staff Position (FSP) FAS 19-1, *Accounting for Suspended Well Costs*, which provides that 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. 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. FAS 19 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, 2006. No capitalized exploratory well costs were charged to expense upon the 2005 adoption of FSP FAS 19-1.

	Year ended December 31		
	2006	2005	2004
Beginning balance at January 1	**$ 1,109**	$ 671	$ 549
Additions associated with the acquisition of Unocal		317	
	446	290	252

Additions to capitalized exploratory well costs pending the determination of proved reserves			
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(171)**	(140)	(64)
Capitalized exploratory well costs charged to expense	**(121)**	(6)	(66)
Other reductions*	**(24)**	(23)	
Ending balance at December 31	**$ 1,239**	$ 1,109	$ 671

* Represent property sales and exchanges.

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 acquisition of Unocal in 2005.

	Year ended December 31		
	2006	2005	2004
Exploratory well costs capitalized for a period of one year or less	**$ 332**	$ 259	$ 222
Exploratory well costs capitalized for a period greater than one year	**907**	850	449
Balance at December 31	**$ 1,239**	$ 1,109	$ 671
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**44**	40	22

* Certain projects have multiple wells or fields or both.

Of the $907 of exploratory well costs capitalized for a period greater than one year at December 31, 2006, $447 (23 projects) is related to projects that had drilling activities under way or firmly planned for the near future. An additional $63 (one project) had drilling activity during 2006. The $397 balance related to 20 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 $397 referenced above had the following activities associated with assessing the reserves and the projects economic viability: (a) $99 million (two projects) development plans submitted to a government in early 2007; (b) $80 million (one project) pre-FEED (front-end engineering and design) studies are ongoing with FEED expected to commence in 2007; (c) $75 million (three projects) continued to pursue unitization opportunities on

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 20. ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS Continued

adjacent discoveries that span international boundaries; (d) $42 million (one project) finalize analysis of new seismic study to determine the development facility concept; (e) $101 miscellaneous activities for 13 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 $907 of suspended well costs capitalized for a period greater than one year as of December 31, 2006, represents 110 exploratory wells in 44 projects. The tables below contain the aging of these costs on a well and project basis:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1994-1996	$ 27	3
1997-2001	128	33
2002-2005	752	74
Total	$ 907	110

Aging based on drilling completion date of last well in project:	Amount	Number of projects
1999 2001	$ 9	2
2002 2006	898	42
Total	$ 907	44

NOTE 21.
EMPLOYEE BENEFIT PLANS

The company has defined-benefit pension plans for many employees. The company typically prefunds defined-benefit plans as required by local regulations or in certain situations where prefunding provides economic advantages. In the United States, all qualified plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund U.S. nonqualified pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be 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. Medical coverage for Medicare-eligible retirees in the company s main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the company contribution for retiree medical coverage is limited to no more than 4 percent per year. This contribution cap becomes effective in the year of retirement for pre-Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre-Medicare-eligible retirees retiring

before that date and all Medicare-eligible retirees. Certain life insurance benefits are paid by the company, and annual contributions are based on actual plan experience.

In June 2006, the company announced changes to several of its U.S. pension and other postretirement benefit plans, primarily merging benefits under several Unocal plans into related Chevron plans. Under the plan combinations, former-Unocal employees retiring on or after July 1, 2006, received recognition for Unocal pay and service history toward benefits to be paid under the Chevron pension and postretirement benefit plans. Unocal employees who retired before July 1, 2006, and were participating in the Unocal postretirement medical plan were merged into the Chevron primary U.S. plan effective January 1, 2007. In addition, the company s contributions for Medicare-eligible retirees under the Chevron plan were increased in 2007 in conjunction with the merger of former-Unocal participants into the Chevron plan.

Effective December 31, 2006, the company implemented the recognition and measurement provisions of Financial Accounting Standards Board (FASB) Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)*(FAS 158), which requires the recognition of the overfunded or underfunded status of each of its defined benefit pension and other postretirement benefit plans as an asset or liability, with the offset to Accumulated other comprehensive loss. In addition, Chevron recognized its share of amounts recorded by affiliated companies in Accumulated other comprehensive loss to reflect their adoption of FAS 158 at December 31, 2006. The following table illustrates the incremental effect of the adoption of FAS 158 on individual lines in the company s December 2006 Consolidated Balance Sheet after applying the additional minimum liability adjustment required by FASB Statement No. 87, *Employers Accounting for Pensions*.

	Before Application of FAS 158*	FAS 158 Adjustments	After Application of FAS 158
Noncurrent assets			
Investments and advances	$ 18,542	$ 10	$ 18,552
Noncurrent assets			
Deferred charges and other assets	$ 4,794	$ (2,706)	$ 2,088
Total assets	$ 135,324	$ (2,696)	$ 132,628
Noncurrent liabilities Noncurrent deferred income taxes	$ 12,924	$ (1,277)	$ 11,647
Noncurrent liabilities Reserves for employee benefits	$ 3,965	$ 784	$ 4,749
Total liabilities	$ 64,186	$ (493)	$ 63,693
Accumulated other comprehensive (loss)	$ (433)	$ (2,203)	$ (2,636)
Total stockholders equity	$ 71,138	$ (2,203)	$ 68,935

* Accounts include minimum pension liabilities of $636 ($40 for affiliates) recognized prior to application of FAS 158 at December 31, 2006. Deferred income taxes of $234 ($13 for affiliates) were recognized on the amounts reflected in Accumulated other comprehensive loss .

Table of Contents

NOTE 21. EMPLOYEE BENEFIT PLANS Continued

The company uses a measurement date of December 31 to value its benefit plan assets and obligations. The funded status of the company s pension and other postretirement benefit plans for 2006 and 2005 is as follows:

	Pension Benefits				Other Benefits	
	2006		2005			
	U.S.	Int l.	U.S.	Int l.	**2006**	2005
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	**$ 8,594**	**$ 3,611**	$ 6,587	$ 3,144	**$ 3,252**	$ 2,820
Assumption of Unocal benefit obligations			1,437	169		277
Service cost	**234**	**98**	208	84	**35**	30
Interest cost	**468**	**214**	395	199	**181**	164
Plan participants contributions		**7**	1	6	**134**	129
Plan amendments	**14**	**37**	42	7	**107**	
Actuarial loss	**297**	**97**	593	476	**(102)**	189
Foreign currency exchange rate changes		**355**		(293)	**(5)**	(2)
Benefits paid	**(815)**	**(212)**	(669)	(181)	**(345)**	(355)
Benefit obligation at December 31	**8,792**	**4,207**	8,594	3,611	**3,257**	3,252
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	**7,463**	**2,890**	5,776	2,634		
Acquisition of Unocal plan assets			1,034	65		
Actual return on plan assets	**1,069**	**225**	527	441		
Foreign currency exchange rate changes		**321**		(303)		
Employer contributions	**224**	**225**	794	228	**211**	226
Plan participants contributions		**7**	1	6	**134**	129
Benefits paid	**(815)**	**(212)**	(669)	(181)	**(345)**	(355)
Fair value of plan assets at December 31	**7,941**	**3,456**	7,463	2,890		
FUNDED STATUS AT DECEMBER 31	**(851)**	**(751)**	(1,131)	(721)	**(3,257)**	(3,252)

Unrecognized net actuarial loss			2,332	1,108		1,167
Unrecognized prior-service cost			305	89		(679)
Unrecognized net transitional assets				5		
Total recognized at December 31	**$ (851)**	**$ (751)**	$ 1,506	$ 481	**$ (3,257)**	$ (2,764)

Amounts recognized in the Consolidated Balance Sheet for the company s pension and other postretirement benefit plans at December 31, 2005, reflected the net of cumulative employer contributions and net periodic benefit costs recognized in earnings. The 2005 amounts for noncurrent pension liabilities also included minimum pension liability adjustments, which were offset in Accumulated other comprehensive loss and Deferred charges and other assets. Amounts recognized at December 31, 2006, reflected the net funded status of each of the company s defined-benefit pension and other postretirement plans presented as either a net asset (overfunded) or a liability (underfunded).

	Pension Benefits					
	2006		2005		Other Benefits	
	U.S.	Int l.	U.S.	Int l.	**2006**	2005
Noncurrent assets Prepaid benefit cost [1]	**$ 18**	**$ 96**	$ 1,961	$ 960	**$**	$
Noncurrent assets Intangible asset [1]			12	2		
Current liabilities Accrued liabilities	**(53)**	**(47)**	(57)	(17)	**(223)**	(186)
Noncurrent liabilities Reserves for employee benefit plans [2]	**(816)**	**(800)**	(833)	(528)	**(3,034)**	(2,578)
Accumulated other comprehensive income [3]						
Minimum pension liability			423	64		
Net amount recognized	**$ (851)**	**$ (751)**	$ 1,506	$ 481	**$ (3,257)**	$ (2,764)

[1] Noncurrent assets are recorded in Deferred charges and other assets on the Consolidated Balance Sheet.

[2] The company recorded additional minimum liabilities of $435 and $66 in 2005 for U.S. and international pension plans, respectively.

[3] Accumulated other comprehensive loss in 2005 includes deferred income taxes of $148 and $22 for U.S. and international plans, respectively. This amount is presented net of those taxes in the Consolidated Statement of Stockholders Equity.

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 21. EMPLOYEE BENEFIT PLANS Continued

Amounts recognized on a before-tax basis in Accumulated other comprehensive loss for the company s pension and other postretirement plans (excludes affiliates) at the end of 2006 after adoption of FAS 158 consisted of:

	Pension Benefits		Other Benefits
		2006	**2006**
	U.S.	Int'l.	
Net actuarial loss	**$ 1,892**	**$ 1,288**	**$ 972**
Prior-service cost (credit)	**272**	**126**	**(485)**
Total recognized at December 31	**$ 2,164**	**$ 1,414**	**$ 487**

The accumulated benefit obligations for all U.S. and international pension plans were $7,987 and $3,669 respectively, at December 31, 2006, and $7,931 and $3,080, respectively, at December 31, 2005.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2006 and 2005, was:

	Pension Benefits			
		2006		2005
	U.S.	Int'l.	U.S.	Int'l.
Projected benefit obligations	**$ 848**	**$ 849**	$ 2,132	$ 818
Accumulated benefit obligations	**806**	**741**	1,993	632
Fair value of plan assets	**12**	**172**	1,206	153

The components of net periodic benefit cost for 2006, 2005 and 2004 were:

	Pension Benefits						Other Benefits		
		2006		2005		2004			
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2006**	2005	2004
Service cost	**$ 234**	**$ 98**	$ 208	$ 84	$ 170	$ 70	**$ 35**	$ 30	$ 26
Interest cost	**468**	**214**	395	199	326	180	**181**	164	164
Expected return on plan assets	**(550)**	**(227)**	(449)	(208)	(358)	(169)			
Amortization of transitional assets		**1**		2		1			
	46	**14**	45	16	42	16	**(86)**	(91)	(47)

Amortization of prior-service costs									
Recognized actuarial losses	**149**	**69**	177	51	114	69	**97**	93	54
Settlement losses	**70**		86		96	4			
Curtailment losses						2			
Special termination benefits recognition						1			
Net periodic benefit cost	**$ 417**	**$ 169**	$ 462	$ 144	$ 390	$ 174	**$ 227**	$ 196	$ 197

Net actuarial losses recorded in Accumulated other comprehensive income at December 31, 2006, related to the company s U.S. pension, international pension and other postretirement benefit plans are being amortized on a straight-line basis over approximately nine, 13 and 10 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2007, the company estimates actuarial losses of $139 and $81 will be amortized from accumulated other comprehensive income for U.S. and international pension plans, and actuarial losses of $81 will be amortized from accumulated other comprehensive income for other postretirement benefit plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded at December 31, 2006, was approximately six and 13 years for U.S. and international pension plans, respectively, and seven years for other postretirement benefit plans. During 2007, the company estimates prior service costs of $46 and $17 will be amortized from accumulated other comprehensive income for U.S. and international pension plans, and prior service credits of $81 will be amortized from accumulated other comprehensive income for other postretirement benefit plans.

Table of Contents

NOTE 21. EMPLOYEE BENEFIT PLANS Continued

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

	Pension Benefits								
	2006		2005		2004		Other Benefits		
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2006**	2005	2004
Assumptions used to determine benefit obligations									
Discount rate	**5.8%**	**6.0%**	5.5%	5.9%	5.8%	6.4%	**5.8%**	5.6%	5.8%
Rate of compensation increase	**4.5%**	**6.1%**	4.0%	5.1%	4.0%	4.9%	**4.5%**	4.0%	4.1%
Assumptions used to determine net periodic benefit cost									
Discount rate[1,2,3]	**5.8%**	**5.9%**	5.5%	6.4%	5.9%	6.8%	**5.9%**	5.8%	6.1%
Expected return on plan assets[1,2]	**7.8%**	**7.4%**	7.8%	7.9%	7.8%	8.3%	**N/A**	N/A	N/A
Rate of compensation increase[2]	**4.2%**	**5.1%**	4.0%	5.0%	4.0%	4.9%	**4.2%**	4.0%	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.

[3] The 2006 U.S. discount rate reflects remeasurement on July 1, 2006, due to plan combinations and changes, primarily merging benefits under several Unocal plans into related Chevron plans.

Expected Return on Plan Assets The company s estimates of the long-term rate of return on pension assets is driven primarily 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 70 percent of the company s pension plan assets. At December 31, 2006, 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, 2006, the company selected a 5.8 percent discount rate based on Moody s Aa Corporate Bond Index and a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve. The discount rates at the end of 2005 and 2004 were 5.5 percent and 5.8 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2006, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 9 percent in 2007 and gradually decline to 5 percent for 2011 and beyond. For this measurement at December 31, 2005, the assumed health care cost-trend rates started with 10 percent in 2006 and gradually decline to 5 percent for 2011 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company s medical contributions for the primary U.S. plan. 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	$ (8)
Effect on postretirement benefit obligation	$ 89	$ (85)

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	**2006**	2005	**2006**	2005
Equities	**68%**	69%	**62%**	60%
Fixed Income	**21%**	21%	**37%**	39%
Real Estate	**10%**	9%	**1%**	1%
Other	**1%**	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

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 21. EMPLOYEE BENEFIT PLANS   Continued

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 $17 and $13 at December 31, 2006 and 2005, respectively. The Other asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments In 2006, the company contributed $224 and $225 to its U.S. and international pension plans, respectively. In 2007, 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 $223 in 2007, as compared with $211 paid in 2006.

The following benefit payments, which include estimated future service, are expected to be paid in the next 10 years:

	Pension Benefits		Other
	U.S.	Int l.	Benefits
2007	$ 775	$ 206	$ 223
2008	$ 755	$ 228	$ 226
2009	$ 786	$ 237	$ 228
2010	$ 821	$ 253	$ 233
2011	$ 865	$ 249	$ 239
2012 2016	$ 4,522	$ 1,475	$ 1,252

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 $169, $145 and $139 in 2006, 2005 and 2004, respectively. This cost was reduced by the value of shares released from the LESOP totaling $6, $4 and $138 in 2006, 2005 and 2004, respectively. The remaining amounts, totaling $163, $141 and $1 in 2006, 2005 and 2004, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron ESIP is an employee stock ownership plan (ESOP). In 1989, Chevron established a 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 (credits) expenses recorded for the LESOP were $(1), $94 and $(29) in 2006, 2005 and 2004, respectively, including $17, $18 and $23 of interest expense related to LESOP debt and a (credit) charge to compensation expense of $(18), $76 and $(52).

Of the dividends paid on the LESOP shares, $59, $55 and $52 were used in 2006, 2005 and 2004, respectively, to service LESOP debt. The amount in 2006 included $28 of LESOP debt service that was scheduled for payment on the first business day of January 2007 and was paid in late December 2006. 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 of $98 to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2006 or 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, 2006 and 2005, were as follows:

NOTE 21. EMPLOYEE BENEFIT PLANS Continued

Thousands	**2006**	2005
Allocated shares	**21,827**	23,928
Unallocated shares	**8,316**	9,163
Total LESOP shares	**30,143**	33,091

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2006, 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, 2006 and 2005, trust assets of $98 and $130, respectively, 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 $180, $155 and $147 in 2006, 2005 and 2004, respectively. Awards under the LTIP consist of stock options and other share-based compensation that are described 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. Charges for the programs were $329, $324 and $339 in 2006, 2005 and 2004, 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 Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations and dis-

closure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

The company adopted FAS 123R using the modified prospective method and, accordingly, results for prior periods were not restated. Refer to Note 1, beginning on page FS-32, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 for periods prior to adoption of FAS 123R.

For 2006 and 2005, compensation expense charged against income for stock options was $125 ($81 after tax) and $65 ($42 after tax), respectively. In addition, compensation expense charged against income for stock appreciation rights, performance units and restricted stock units was $113 ($73 after tax), $59 ($39 after tax) and $65 ($42 after tax) for 2006, 2005 and 2004, respectively. There were no significant stock-based compensation costs at December 31, 2006 and 2005, that were capitalized.

Cash received from option exercises under all share-based payment arrangements for 2006, 2005 and 2004 was $444, $297 and $385, respectively. Actual tax benefits realized for the tax deductions from option exercises were $91, $71 and $49 for 2006, 2005 and 2004, respectively.

Cash paid to settle performance units and stock appreciation rights was $68, $110 and $23 for 2006, 2005 and 2004, respectively. Cash paid in 2005 included $73 million for Unocal awards paid under change-in-control plan provisions.

The company presents the tax benefits of deductions from the exercise of stock options as financing cash inflows in the Consolidated Statement of Cash Flows. In the second quarter 2006, the company implemented the transition method of FASB Staff Position FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, for calculating the beginning balance of the pool of excess tax benefits related to employee compensation and determining the subsequent impact on the pool of employee awards that were fully vested and outstanding upon the adoption of FAS 123R. The company s reported tax expense for the period subsequent to the implementation of FAS 123R was not affected by this election. Refer to Note 3, beginning on page FS-35, for information on excess tax benefits reported on the company s Statement of Cash Flows.

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. From April 2004 through January 2014, 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

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION Continued

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 settle in cash at the end of a three-year performance 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 and appreciation rights 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 three 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.

The fair market values of stock options and stock appreciation rights granted in 2006, 2005 and 2004 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2006	2005	2004
Chevron LTIP			
Expected term in years [1]	**6.4**	6.4	7.0
Volatility [2]	**23.7%**	24.5%	16.5%

Risk-free interest rate based on zero coupon U.S. treasury note	**4.7%**	3.8%	4.4%
Dividend yield	**3.1%**	3.4%	3.7%
Weighted-average fair value per option granted	**$ 12.74**	$ 11.66	$ 7.14
Texaco SIP			
Expected term in years [1]	**2.2**	2.1	2.0
Volatility [2]	**19.6%**	18.6%	17.8%
Risk-free interest rate based on zero coupon U.S. treasury note	**4.8%**	3.8%	2.5%
Dividend yield	**3.3%**	3.4%	3.8%
Weighted-average fair value per option granted	**$ 7.72**	$ 6.09	$ 4.00
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 during 2006 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	59,524	$ 45.32		
Granted	9,248	$ 56.64		
Exercised	(14,921)	$ 46.11		
Restored	4,002	$ 64.13		
Forfeited	(1,908)	$ 57.09		
Outstanding at December 31, 2006	55,945	$ 47.91	6.0 yrs.	$ 1,433
Exercisable at December 31, 2006	37,063	$ 43.56	5.1yrs.	$ 1,111

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2006, 2005 and 2004 was $281, $258 and $129, 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 vest-

NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION Continued

ing 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, 2006, there was $99 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 2.0 years.

At January 1, 2006, the number of LTIP performance units outstanding was equivalent to 2,346,016 shares. During 2006, 709,200 units were granted, 827,450 units vested with cash proceeds distributed to recipients, and 117,570 units were forfeited. At December 31, 2006, units outstanding were 2,110,196, and the fair value of the liability recorded for these instruments was $113. In addition, outstanding stock appreciation rights that were awarded under various LTIP and former Texaco and Unocal programs totaled approximately 700,000 equivalent shares as of December 31, 2006. 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 9,641,600 options were awarded with an exercise price of $38.16 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 seven years and a volatility of 24.7 percent.

At January 1, 2006, the number of broad-based employee stock options outstanding was 1,682,904. During 2006, exercises of 354,845 shares and forfeitures of 22,000 shares reduced outstanding options to 1,306,059. As of December 31, 2006, these instruments had an aggregate intrinsic value of $46 and the remaining contractual term of these options was 1.1 years. The total intrinsic value of these options exercised during 2006, 2005 and 2004 was $10, $9 and $16, respectively.

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 Corporation, 1997 for Unocal Corporation (Unocal) and 2001 for Texaco Corporation (Texaco). California franchise tax liabilities have been

settled through 1991 for Chevron, 1998 for Unocal and 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, 2006, the company and its subsidiaries provided guarantees, either directly or indirectly, of $296 for notes and other contractual obligations of affiliated companies and $131 for third parties, as described by major category below. There are no amounts being carried as liabilities for the company s obligations under these guarantees.

The $296 in guarantees provided to affiliates related to borrowings for capital projects. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are the company s guarantees of $214 associated with a construction completion guarantee for the debt financing of the company s equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Substantially all of the $296 guaranteed will expire between 2007 and 2011, with the remaining 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.

The $131 in guarantees provided on behalf of third parties related to construction loans to governments of certain of the company s international upstream operations. Substantially all of the $131 in guarantees expire by 2011, with the remainder expiring by 2015. 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.

At December 31, 2006, Chevron also had outstanding guarantees for about $120 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from 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 2007 through 2011 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.

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS Continued

Through the end of 2006, the company paid approximately $48 under these indemnities and continues to be obligated for possible additional 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 period 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 indemnities must be asserted either as early as February 2007, or no later than February 2012. Under the terms of these 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 that were sold in 1997. Under the indemnification agreement, the company s liability is unlimited until April 2022, when the liability expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of $200, which had not been reached as of December 31, 2006.

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, 2006, approximately $1,200, representing about 7 percent of Chevron s total current accounts and notes receivables balance, were securitized. Chevron s total estimated financial exposure under these securitizations at December 31, 2006, was approximately $80. 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, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput 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, drilling rigs, 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: 2007 $3,200; 2008 $1,700; 2009 $2,100; 2010 $1,900; 2011 $900; 2012 and after $4,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3,000 in 2006, $2,100 in 2005 and $1,600 in 2004.

Minority Interests The company has commitments of $209 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 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, land development areas, and mining operations, 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, 2006, was $1,441. Included in this balance were remediation activities of 242 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation 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

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS Continued

reserve for these sites at year-end 2006 was $122. 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.

Of the remaining year-end 2006 environmental reserves balance of $1,319, $834 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 $485 was associated with various sites in the international downstream ($117), upstream ($252), chemicals ($61) and other ($55). 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.

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 2006 had a recorded liability that was material to the company s financial position, results of operations or liquidity.

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.

Effective January 1, 2003, the company implemented FASB 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 approximately $5,800 for asset retirement obligations at year-end 2006 related primarily to upstream and mining properties. Refer to Note 24 on page FS-58 for a discussion of the company s Asset Retirement Obligations.

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.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Besides the United States, the company and its affiliates have significant operations in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, France, India, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, Venezuela and Vietnam.

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 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, 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 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. For this range of settlement,

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS Continued

Chevron estimates its maximum possible net before-tax liability at approximately $200, and the possible maximum net amount that could be owed to Chevron is estimated at about $150. 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, 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 accounts for asset retirement obligations in accordance with Financial Accounting Standards Board Statement (FASB) No. 143, *Accounting for Asset Retirement Obligations*, (FAS 143). This accounting standard applies to the fair value of a liability for an asset retirement obligation (ARO) 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. In 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 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 ARO 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 ARO. FIN 47 also clarifies when an entity would have sufficient information to reasonably

estimate the fair value of an ARO. In adopting FIN 47, the company did not recognize any additional liabilities for conditional AROs due to an inability to reasonably estimate the fair value of those obligations because of their indeterminate settlement dates.

FAS 143 and FIN 47 primarily affect the company s accounting for crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets have been 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.

The following table indicates the changes to the company s before-tax asset retirement obligations in 2006, 2005 and 2004:

	2006	2005	2004
Balance at January 1	**$ 4,304**	$ 2,878	$ 2,856
Liabilities assumed in the Unocal acquisition		1,216	
Liabilities incurred	**153**	90	37
Liabilities settled	**(387)**	(172)	(426)
Accretion expense	**275**	187	93
Revisions in estimated cash flows	**1,428***	105	318
Balance at December 31	**$ 5,773**	$ 4,304	$ 2,878

* Includes $1,128 associated with estimated costs to dismantle and abandon wells and facilities damaged by the 2005 hurricanes in the Gulf of Mexico.

NOTE 25.

COMMON STOCK SPLIT

In September 2004, the company effected a two-for-one stock split in the form of a stock dividend. 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.

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 26.

OTHER FINANCIAL INFORMATION
Net income in 2004 included gains of approximately $1,200 relating to the sale of nonstrategic upstream properties. Of this amount, $257 related to assets classified as discontinued operations.

Other financial information is as follows:

	Year ended December 31		
	2006	2005	2004
Total financing interest and debt costs	**$ 608**	$ 542	$ 450
Less: Capitalized interest	**157**	60	44
Interest and debt expense	**$ 451**	$ 482	$ 406
Research and development expenses	**$ 468**	$ 316	$ 242
Foreign currency effects*	**$ (219)**	$ (61)	$ (81)

* Includes $15, $(2) and $(13) in 2006, 2005 and 2004, 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 Last-In, First-Out (LIFO) method is used was $6,010, $4,846 and $3,036 at December 31, 2006, 2005 and 2004, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of $82, $34 and $36 were included in net income for the years 2006, 2005 and 2004, respectively.

NOTE 27.

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 (refer to Note 22, Stock Options and Other Share-Based Compensation beginning on page FS-53). The table on the following page sets forth the computation of basic and diluted EPS:

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

NOTE 27. EARNINGS PER SHARE Continued

	Year ended December 31		
	2006	2005	2004
BASIC EPS CALCULATION			
Income from continuing operations	**$ 17,138**	$ 14,099	$ 13,034
Add: Dividend equivalents paid on stock units	**1**	2	3
Income from continuing operations available to common stockholders	**$ 17,139**	$ 14,101	$ 13,037
Income from discontinued operations			294
Net income available to common stockholders Basic	**$ 17,139**	$ 14,101	$ 13,331
Weighted-average number of common shares outstanding*	**2,185**	2,143	2,114
Add: Deferred awards held as stock units	**1**	1	2
Total weighted-average number of common shares outstanding	**2,186**	2,144	2,116
Per share of common stock			
Income from continuing operations available to common stockholders	**$ 7.84**	$ 6.58	$ 6.16
Income from discontinued operations			0.14
Net income Basic	**$ 7.84**	$ 6.58	$ 6.30
DILUTED EPS CALCULATION			
Income from continuing operations	**$ 17,138**	$ 14,099	$ 13,034
Add: Dividend equivalents paid on stock units	**1**	2	3
Add: Dilutive effects of employee stock-based awards		2	1
Income from continuing operations available to common stockholders	**$ 17,139**	$ 14,103	$ 13,038
Income from discontinued operations			294
Net income available to common stockholders Diluted	**$ 17,139**	$ 14,103	$ 13,332
Weighted-average number of common shares outstanding*	**2,185**	2,143	2,114
Add: Deferred awards held as stock units	**1**	1	2
Add: Dilutive effect of employee stock-based awards	**11**	11	6
Total weighted-average number of common shares outstanding	**2,197**	2,155	2,122
Per share of common stock			

Income from continuing operations available to common stockholders	**$ 7.80**	$ 6.54	$ 6.14
Income from discontinued operations			0.14
Net income Diluted	**$ 7.80**	$ 6.54	$ 6.28

* Share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

Table of Contents

This page intentionally left blank.

Table of Contents

FIVE-YEAR FINANCIAL SUMMARY

Unaudited

Millions of dollars, except per-share amounts	**2006**	2005	2004	2003	2002
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	**$ 204,892**	$ 193,641	$ 150,865	$ 119,575	$ 98,340
Income from equity affiliates and other income	**5,226**	4,559	4,435	1,702	197
TOTAL REVENUES AND OTHER INCOME	**210,118**	198,200	155,300	121,277	98,537
TOTAL COSTS AND OTHER DEDUCTIONS	**178,142**	173,003	134,749	108,601	94,437
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**31,976**	25,197	20,551	12,676	4,100
INCOME TAX EXPENSE	**14,838**	11,098	7,517	5,294	2,998
INCOME FROM CONTINUING OPERATIONS	**17,138**	14,099	13,034	7,382	1,102
INCOME FROM DISCONTINUED OPERATIONS			294	44	30
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**17,138**	14,099	13,328	7,426	1,132
Cumulative effect of changes in accounting principles				(196)	
NET INCOME	**$ 17,138**	$ 14,099	$ 13,328	$ 7,230	$ 1,132
PER SHARE OF COMMON STOCK[1]					
INCOME FROM CONTINUING OPERATIONS[2]					
Basic	**$ 7.84**	$ 6.58	$ 6.16	$ 3.55	$ 0.52
Diluted	**$ 7.80**	$ 6.54	$ 6.14	$ 3.55	$ 0.52
INCOME FROM DISCONTINUED OPERATIONS					
Basic	**$**	$	$ 0.14	$ 0.02	$ 0.01
Diluted	**$**	$	$ 0.14	$ 0.02	$ 0.01
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES					
Basic	**$**	$	$	$ (0.09)	$

Diluted	**$**	$	$	$ (0.09)	$
NET INCOME[2]					
Basic	**$ 7.84**	$ 6.58	$ 6.30	$ 3.48	$ 0.53
Diluted	**$ 7.80**	$ 6.54	$ 6.28	$ 3.48	$ 0.53
CASH DIVIDENDS PER SHARE	**$ 2.01**	$ 1.75	$ 1.53	$ 1.43	$ 1.40
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	**$ 36,304**	$ 34,336	$ 28,503	$ 19,426	$ 17,776
Noncurrent assets	**96,324**	91,497	64,705	62,044	59,583
TOTAL ASSETS	**132,628**	125,833	93,208	81,470	77,359
Short-term debt	**2,159**	739	816	1,703	5,358
Other current liabilities	**26,250**	24,272	17,979	14,408	14,518
Long-term debt and capital lease obligations	**7,679**	12,131	10,456	10,894	10,911
Other noncurrent liabilities	**27,605**	26,015	18,727	18,170	14,968
TOTAL LIABILITIES	**63,693**	63,157	47,978	45,175	45,755
STOCKHOLDERS EQUITY	**$ 68,935**	$ 62,676	$ 45,230	$ 36,295	$ 31,604

[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 affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

FS-62

Table of Contents

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 Democratic Republic of the Congo. The Asia-Pacific

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	Other
YEAR ENDED DEC. 31, 2006												
Exploration												
Wells	$	$ **493**	$ **22**	$ **515**	$ **151**	$ **121**	$ **20**	$ **246**	$ **538**	$ **1,053**	$ **25**	$
Geological and geophysical		**96**	**8**	**104**	**180**	**53**	**12**	**92**	**337**	**441**		
Rentals and other		**116**	**16**	**132**	**48**	**140**	**58**	**50**	**296**	**428**		
Total exploration		**705**	**46**	**751**	**379**	**314**	**90**	**388**	**1,171**	**1,922**	**25**	
Property acquisitions												
Proved[2]	**6**	**152**		**158**	**1**	**10**		**15**	**26**	**184**		**581**
Unproved	**1**	**47**	**10**	**58**		**1**		**135**	**136**	**194**		
Total property acquisitions	**7**	**199**	**10**	**216**	**1**	**11**		**150**	**162**	**378**		**581**
Development[3]	**686**	**1,632**	**868**	**3,186**	**2,890**	**1,788**	**460**	**1,019**	**6,157**	**9,343**	**671**	**25**

TOTAL COSTS INCURRED	**$ 693**	**$ 2,536**	**$ 924**	**$ 4,153**	**$ 3,270**	**$ 2,113**	**$ 550**	**$ 1,557**	**$ 7,490**	**$ 11,643**	**$ 696**	**$ 606**
YEAR ENDED DEC. 31, 2005[4]												
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]		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[3]	507	680	601	1,788	1,892	1,088	382	726	4,088	5,876	767	43
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[4]												
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[3]	413	466	375	1,254	1,057	620	403	627	2,707	3,961	896	208
TOTAL COSTS INCURRED	$ 413	$ 979	$ 381	$ 1,773	$ 1,521	$ 718	$ 418	$ 862	$ 3,519	$ 5,292	$ 896	$ 208

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 24, Asset Retirement Obligations, on page FS-58.

[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.

[3] Includes $160, $160 and $63 costs incurred prior to assignment of proved reserves in 2006, 2005 and 2004, respectively.

[4] 2005 and 2004 presentation conformed to 2006.

Table of Contents

Supplemental Information on Oil and Gas Producing Activities   Continued

geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The international   Other geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and other countries. Amounts for TCO represent Chevron   s 50 percent equity share of Tengizchevroil, an exploration and
production partnership in the Republic of Kazakhstan. The affiliated companies   Other   amounts are composed of a 30 percent equity share of Hamaca, an exploration and production partnership in Venezuela and, effective October 2006, Chevron   s 39 percent interest and 25 percent interest in Petroboscan and Petroindependiente, respectively. These joint stock companies are involved in the development of the Boscan and LL-652 fields in Venezuela, respectively.

TABLE II   CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES

	Consolidated Companies										Affiliate	
	United States				International						Companie	
illions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l.	Total	TCO	Othe
T DEC. 31, 06												
nproved operties	**$ 770**	**$ 1,007**	**$ 370**	**$ 2,147**	**$ 342**	**$ 2,373**	**$ 707**	**$ 1,082**	**$ 4,504**	**$ 6,651**	**$ 112**	**$**
oved properties d related oducing assets	**9,960**	**18,464**	**12,284**	**40,708**	**9,943**	**15,486**	**7,110**	**10,461**	**43,000**	**83,708**	**2,701**	**1,09**
pport equipment	**189**	**212**	**226**	**627**	**745**	**240**	**1,093**	**364**	**2,442**	**3,069**	**611**	
eferred ploratory wells		**343**	**7**	**350**	**231**	**217**	**149**	**292**	**889**	**1,239**		
her uncompleted ojects	**370**	**2,188**		**2,558**	**4,299**	**1,546**	**493**	**917**	**7,255**	**9,813**	**2,493**	**4**
ROSS CAP. OSTS	**11,289**	**22,214**	**12,887**	**46,390**	**15,560**	**19,862**	**9,552**	**13,116**	**58,090**	**104,480**	**5,917**	**1,13**
nproved operties luation	**738**	**52**	**29**	**819**	**189**	**74**	**14**	**337**	**614**	**1,433**	**22**	
	7,082	**14,468**	**6,880**	**28,430**	**4,794**	**5,273**	**4,971**	**6,087**	**21,125**	**49,555**	**541**	**10**

oved producing operties epreciation and pletion												
pport equipment preciation	**125**	**111**	**130**	**366**	**400**	**102**	**522**	**238**	**1,262**	**1,628**	**242**	
ccumulated ovisions	**7,945**	**14,631**	**7,039**	**29,615**	**5,383**	**5,449**	**5,507**	**6,662**	**23,001**	**52,616**	**805**	**10**
ET APITALIZED OSTS	**$ 3,344**	**$ 7,583**	**$ 5,848**	**$ 16,775**	**$ 10,177**	**$ 14,413**	**$ 4,045**	**$ 6,454**	**$ 35,089**	**$ 51,864**	**$ 5,112**	**$ 1,02**
T DEC. 31, 05*												
nproved operties	$ 769	$ 1,077	$ 397	$ 2,243	$ 407	$ 2,287	$ 645	$ 983	$ 4,322	$ 6,565	$ 108	$
oved properties d related oducing assets	9,546	18,283	11,467	39,296	8,404	14,928	6,613	9,627	39,572	78,868	2,264	1,21
pport equipment	204	193	230	627	715	426	1,217	356	2,714	3,341	549	
eferred ploratory wells		284	5	289	245	154	173	248	820	1,109		
her uncompleted ojects	149	782	209	1,140	2,878	790	427	946	5,041	6,181	2,332	
ROSS CAP. OSTS	10,668	20,619	12,308	43,595	12,649	18,585	9,075	12,160	52,469	96,064	5,253	1,21
nproved operties luation	736	90	22	848	162	69		318	549	1,397	17	
oved producing operties epreciation and pletion	6,818	14,067	6,049	26,934	4,266	4,016	4,105	5,720	18,107	45,041	460	9
pport equipment preciation	140	119	149	408	317	88	680	222	1,307	1,715	213	
ccumulated ovisions	7,694	14,276	6,220	28,190	4,745	4,173	4,785	6,260	19,963	48,153	690	9
ET APITALIZED OSTS	$ 2,974	$ 6,343	$ 6,088	$ 15,405	$ 7,904	$ 14,412	$ 4,290	$ 5,900	$ 32,506	$ 47,911	$ 4,563	$ 1,12

* Conformed to 2006 presentation.

TABLE II CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES 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	Other
AT DEC. 31, 2004[1,2]												
Unproved properties	$ 769	$ 380	$ 109	$ 1,258	$ 322	$ 211	$	$ 970	$ 1,503	$ 2,761	$ 108	$
Proved properties and related producing assets	9,198	16,814	8,730	34,742	7,394	7,598	5,731	9,253	29,976	64,718	2,183	963
Support equipment	211	175	208	594	513	127	1,123	361	2,124	2,718	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
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	6,718	13,736	5,681	26,135	3,881	3,171	3,576	5,081	15,709	41,844	428	43
Support equipment depreciation	148	107	139	394	268	60	658	206	1,192	1,586	190	
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] Conformed to 2006 presentation.

Table of Contents

Supplemental Information on Oil and Gas Producing Activities
Continued

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 2006, 2005 and 2004 are shown in the following table. Net income from exploration and production activities as reported on page FS-38 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-38.

	Consolidated Companies											
	United States				International						Affiliated Companie	
illions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l.	Total	TCO	Othe
EAR ENDED EC. 31, 2006												
evenues from net oduction												
les	**$ 308**	**$ 1,845**	**$ 2,976**	**$ 5,129**	**$ 2,377**	**$ 4,938**	**$1,001**	**$ 2,814**	**$ 11,130**	**$ 16,259**	**$2,861**	**$ 59**
ansfers	**4,072**	**2,317**	**2,046**	**8,435**	**5,264**	**4,084**	**2,211**	**2,848**	**14,407**	**22,842**		
otal	**4,380**	**4,162**	**5,022**	**13,564**	**7,641**	**9,022**	**3,212**	**5,662**	**25,537**	**39,101**	**2,861**	**59**
oduction penses cluding taxes	**(889)**	**(765)**	**(1,057)**	**(2,711)**	**(640)**	**(740)**	**(728)**	**(664)**	**(2,772)**	**(5,483)**	**(202)**	**(4**
axes other than n income	**(84)**	**(57)**	**(442)**	**(583)**	**(57)**	**(231)**	**(1)**	**(60)**	**(349)**	**(932)**	**(28)**	**(**
oved producing operties:												
epreciation and pletion	**(275)**	**(1,096)**	**(763)**	**(2,134)**	**(579)**	**(1,475)**	**(666)**	**(703)**	**(3,423)**	**(5,557)**	**(114)**	**(3**
ccretion pense[2]	**(11)**	**(80)**	**(39)**	**(130)**	**(26)**	**(30)**	**(23)**	**(49)**	**(128)**	**(258)**	**(1)**	
xploration penses		**(407)**	**(24)**	**(431)**	**(296)**	**(209)**	**(110)**	**(318)**	**(933)**	**(1,364)**	**(25)**	
nproved operties luation	**(3)**	**(73)**	**(8)**	**(84)**	**(28)**	**(15)**	**(14)**	**(27)**	**(84)**	**(168)**		

ther income xpense)[3]	**1**	**(732)**	**254**	**(477)**	**(435)**	**(475)**	**50**	**385**	**(475)**	**(952)**	**8**	**(5**
esults before come taxes	**3,119**	**952**	**2,943**	**7,014**	**5,580**	**5,847**	**1,720**	**4,226**	**17,373**	**24,387**	**2,499**	**46**
come tax pense	**(1,169)**	**(357)**	**(1,103)**	**(2,629)**	**(4,740)**	**(3,224)**	**(793)**	**(2,151)**	**(10,908)**	**(13,537)**	**(750)**	**(17**
ESULTS OF RODUCING PERATIONS	**$ 1,950**	**$ 595**	**$ 1,840**	**$ 4,385**	**$ 840**	**$ 2,623**	**$ 927**	**$ 2,075**	**$ 6,465**	**$ 10,850**	**$1,749**	**$ 29**
EAR ENDED EC. 31, 2005												
evenues from net oduction												
les	$ 337	$ 1,576	$ 3,174	$ 5,087	$ 2,142	$ 2,941	$ 539	$ 2,668	$ 8,290	$ 13,377	$2,307	$ 66
ansfers	3,497	2,127	1,395	7,019	3,615	3,179	1,986	2,607	11,387	18,406		
otal	3,834	3,703	4,569	12,106	5,757	6,120	2,525	5,275	19,677	31,783	2,307	66
oduction penses cluding taxes	(916)	(638)	(777)	(2,331)	(558)	(570)	(660)	(596)	(2,384)	(4,715)	(152)	(8
axes other than income	(65)	(41)	(384)	(490)	(48)	(189)	(1)	(195)	(433)	(923)	(27)	
oved producing operties:												
epreciation and epletion	(253)	(936)	(520)	(1,709)	(414)	(852)	(550)	(672)	(2,488)	(4,197)	(83)	(4
ccretion pense[2]	(13)	(35)	(46)	(94)	(22)	(20)	(15)	(25)	(82)	(176)	(1)	
xploration penses		(307)	(13)	(320)	(117)	(90)	(26)	(190)	(423)	(743)		
nproved operties luation	(3)	(32)	(4)	(39)	(50)	(8)		(24)	(82)	(121)		
ther income xpense)[3]	2	(354)	(140)	(492)	(243)	(182)	182	280	37	(455)	(9)	
esults before come taxes	2,586	1,360	2,685	6,631	4,305	4,209	1,455	3,853	13,822	20,453	2,035	54
come tax pense	(913)	(482)	(953)	(2,348)	(3,430)	(2,264)	(644)	(1,938)	(8,276)	(10,624)	(611)	(18
ESULTS OF RODUCING PERATIONS	$ 1,673	$ 878	$ 1,732	$ 4,283	$ 875	$ 1,945	$ 811	$ 1,915	$ 5,546	$ 9,829	$1,424	$ 36

[1] The value of owned production consumed in operations 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, on page FS-58.

[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

Table of Contents

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	Other
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)	
	$1,199	$1,305	$1,532	$ 4,036	$ 734	$ 1,016	$ 495	$ 2,019	$ 4,264	$ 8,300	$ 936	$ 90

RESULTS OF PRODUCING OPERATIONS

[1] The value of owned production consumed in operations 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, on page FS-58.

[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

Table of Contents

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	Other
YEAR ENDED DEC. 31, 2006												
Average sales prices												
Liquids, per barrel	**$55.20**	**$60.35**	**$55.80**	**$56.66**	**$61.53**	**$57.05**	**$52.23**	**$57.31**	**$57.92**	**$57.53**	**$56.80**	**$37.26**
Natural gas, per thousand cubic feet	**6.08**	**7.20**	**5.73**	**6.29**	**0.06**	**3.44**	**7.12**	**4.03**	**3.88**	**4.85**	**0.77**	**0.36**
Average production costs, per barrel	**10.94**	**9.59**	**9.26**	**9.85**	**5.13**	**3.36**	**11.44**	**5.23**	**5.17**	**6.76**	**3.31**	**2.51**
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

[1] The value of owned production consumed in operations 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.

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.

Table of Contents

TABLE V RESERVE QUANTITY INFORMATION
Continued

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, 2006, oil-equivalent reserves for the company s consolidated operations were 8.6 billion barrels. (Refer to page E-11 for the definition of oil-equivalent reserves.) Approximately 28 percent of the total reserves were in the United States. For the company s interests in equity affiliates, oil-equivalent reserves were 3 billion barrels, 80 percent of which were associated with the company s 50 percent ownership in TCO. During the year, the company s Boscan and LL-652 contracts in Venezuela were converted to Empresas Mixtas (i.e., joint stock contractual structures). The company had not previously recorded any reserves for its Boscan operations, but did so this year as a result of the conversion. The conversion of LL-652 reserves was treated as the sale of consolidated company reserves and the acquisition of equity affiliate reserves.

Aside from the TCO operations, no single property accounted for more than 5 percent of company s total oil-equivalent proved reserves. Fewer than 20 other individual properties in the company s portfolio of assets each contained between 1 percent and 5 percent of the company s oil-equivalent proved reserves, which in the aggregate accounted for about 36 percent of the company s proved reserves total. These properties were geographically dispersed, located in the United States, South America, West Africa, the Middle East and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2006 were 2.4 billion barrels. Of this amount, 40 percent, 21 percent and 39 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 64 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, 2006, is not necessarily indicative of future trends. Apart from acquisitions, the company s ability to add proved reserves is affected by, among other things, events and circumstances 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 2004, 2005 and 2006 are shown in the tables on pages FS-70 and FS-72.

Table of Contents

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	Other
RESERVES AT JAN. 1, 2004	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[3]	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
Changes attributable to:												
Revisions	**(14)**	**7**	**7**		**(49)**	**72**	**61**	**(45)**	**39**	**39**	**60**	**24**
Improved recovery	**49**		**3**	**52**	**13**	**1**	**6**	**11**	**31**	**83**		
		25	**8**	**33**	**30**	**6**	**2**	**36**	**74**	**107**		

Extensions and discoveries												
Purchases[1]	**2**	**2**		**4**	**15**			**2**	**17**	**21**		**119**
Sales[2]								**(15)**	**(15)**	**(15)**		
Production	**(76)**	**(42)**	**(51)**	**(169)**	**(125)**	**(123)**	**(72)**	**(78)**	**(398)**	**(567)**	**(49)**	**(16)**
RESERVES AT DEC. 31, 2006[3,4]	**926**	**325**	**500**	**1,751**	**1,698**	**785**	**576**	**484**	**3,543**	**5,294**	**1,950**	**562**
DEVELOPED RESERVES[5]												
At Jan. 1, 2004	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
At Dec. 31, 2006	**749**	**163**	**443**	**1,355**	**893**	**530**	**426**	**349**	**2,198**	**3,553**	**1,003**	**311**

1 Includes reserves acquired through property exchanges.

2 Includes reserves disposed of through property exchanges.

3 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-11 for the definition of a PSC). PSC-related reserve quantities are 30 percent, 29 percent and 28 percent for consolidated companies for 2006, 2005 and 2004, respectively, and 100 percent for TCO for each year.

4 Net reserve changes (excluding production) in 2006 consist of 326 million barrels of developed reserves and (91) million barrels of undeveloped reserves for consolidated companies and (428) million barrels of developed reserves and 631 million barrels of undeveloped reserves for affiliated companies.

5 During 2006, the percentages of undeveloped reserves at December 31, 2005, transferred to developed reserves were 11 percent and 2 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 443 million barrels as of December 31, 2006. 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-75.

Noteworthy amounts in the categories of proved-reserve changes for 2004 through 2006 in the table above are discussed below:

Revisions 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

Table of Contents

TABLE V RESERVE QUANTITY INFORMATION
Continued

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.

In 2006, net revisions increased reserves by 39 million and 84 million barrels for worldwide consolidated companies and equity affiliates, respectively. International consolidated companies accounted for the net increase of 39 million barrels. The largest upward net revisions were 61 million barrels in Indonesia and 27 million barrels in Thailand. In Indonesia, the increase was the result of infill drilling and improved steamflood performance. The upward revision in Thailand reflected additional drilling and development activity during the year. These upward revisions were partially offset by reductions in reservoir performance in Nigeria and the United Kingdom, which decreased reserves by 43 million barrels and by 32 million barrels, respectively. Most of the upward revision for affiliated companies was related to a 60 million barrel increase in TCO as a result of improved reservoir performance.

Improved Recovery In 2006, improved recovery increased liquids volumes worldwide by 83 million barrels for consolidated companies. Reserves in the United States increased 52 million barrels, with California representing 49 million barrels of the total increase due to steamflood expansion and revised modeling activities. Internationally, improved recovery increased reserves by 31 million barrels, with no single country accounting for an increase of more than 10 million barrels.

Extensions and Discoveries In 2006, extensions and discoveries increased liquids volumes worldwide by 107 million barrels for consolidated companies. Reserves in Nigeria increased by 27 million barrels due in part to the initial booking of reserves for the Aparo field. Additional drilling activities contributed 19 million barrels in the United Kingdom and 14 million barrels in Argentina. In the United States, the Gulf of Mexico added 25 million barrels, mainly the result of the initial booking of the Great White Field in the deepwater Perdido Fold Belt area.

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.

In 2006, acquisitions increased liquids volumes worldwide by 21 million barrels for consolidated companies and 119 million barrels for equity affiliates. For consolidated companies, the amount was mainly the result of new agreements in Nigeria, which added 13 million barrels of reserves. The other-equity-affiliates quantity reflects the result of the conversion of Boscan and LL-652 operations to joint stock companies in Venezuela.

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 million 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.

In 2006, sales decreased reserves by 15 million barrels due to the conversion of the LL-652 risked service agreement to a joint stock company in Venezuela.

Table of Contents

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	Other
RESERVES AT JAN. 1, 2004[3]	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[3]	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
Changes attributable to:												
Revisions	**32**	**40**	**(102)**	**(30)**	**34**	**400**	**38**	**39**	**511**	**481**	**26**	
Improved recovery	**5**			**5**	**3**			**5**	**8**	**13**		

Extensions and discoveries		**111**	**157**	**268**	**11**	**510**		**10**	**531**	**799**		
Purchases[1]	**6**	**13**		**19**		**16**			**16**	**35**		**54**
Sales[2]			**(1)**	**(1)**				**(148)**	**(148)**	**(149)**		
Production	**(37)**	**(241)**	**(383)**	**(661)**	**(33)**	**(629)**	**(110)**	**(302)**	**(1,074)**	**(1,735)**	**(70)**	**(4)**
RESERVES AT DEC. 31, 2006[3,4]	**310**	**1,094**	**2,624**	**4,028**	**3,206**	**8,920**	**574**	**3,182**	**15,882**	**19,910**	**2,743**	**231**
DEVELOPED RESERVES[5]												
At Jan. 1, 2004	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
At Dec. 31, 2006	**250**	**873**	**2,434**	**3,557**	**1,306**	**4,751**	**377**	**1,912**	**8,346**	**11,903**	**1,412**	**144**

[1] Includes reserves acquired through property exchanges.

[2] Includes reserves disposed of through property exchanges.

[3] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-11 for the definition of a PSC). PSC-related reserve quantities are 47 percent, 44 percent and 33 percent for consolidated companies for 2006, 2005 and 2004, respectively, and 100 percent for TCO for each year.

[4] Net reserve changes (excluding production) in 2006 consist of 549 billion cubic feet of developed reserves and 630 billion cubic feet of undeveloped reserves for consolidated companies and (769) billion cubic feet of developed reserves and 849 billion cubic feet of undeveloped reserves for affiliated companies.

[5] During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 5 percent and 2 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of proved-reserve changes for 2004 through 2006 in the table above are discussed below:

Revisions In 2004, revisions increased reserves for consolidated companies by a net 248 billion cubic feet (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 was 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 attribut-

Table of Contents

TABLE V RESERVE QUANTITY INFORMATION
Continued

able 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.

In 2006, revisions accounted for a net increase of 481 BCF for consolidated companies and 26 BCF for affiliates. For consolidated companies, net increases of 511 BCF internationally were partially offset by a 30 BCF downward revision in the United States. Drilling and development activities added 337 BCF of reserves in Thailand, while Kazakhstan added 200 BCF, largely due to development activity. Trinidad and Tobago increased 185 BCF, attributable to improved reservoir performance and a new contract for sales of natural gas. These additions were partially offset by downward revisions of 224 BCF in the United Kingdom and 130 BCF in Australia due to drilling results and reservoir performance. U.S. Other had a downward revision of 102 BCF due to reservoir performance, which was partially offset by upward revisions of 72 BCF in the Gulf of Mexico and California related to reservoir performance and development drilling. TCO had an upward revision of 26 BCF associated with additional development activity and updated reservoir performance.

Extensions and Discoveries 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.

In 2006, extensions and discoveries accounted for an increase of 799 BCF for consolidated companies, reflecting a 531 BCF increase outside the United States and a U.S. increase of 268 BCF. Bangladesh added 451 BCF, the result of development activity and field extensions, and Thailand added 59 BCF, the result of drilling activities. U.S. Other contributed
157 BCF, approximately half of which was related to the South Texas and the Piceance Basin, and the Gulf of Mexico added 111 BCF, partly due to the initial booking of reserves at the Great White field in the deepwater Perdido Fold Belt area.

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.

In 2006, acquisition of natural gas reserves were 35 BCF for consolidated companies, about evenly divided between the company s United States and international operations. Affiliated companies added 54 BCF of reserves, the result of conversion of an operating service agreement to a joint stock company in Venezuela.

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.

In 2006, sales for consolidated companies totaled 149 BCF, mostly associated with the conversion of a risked service agreement to a joint stock company in Venezuela.

Table of Contents

Supplemental Information on Oil and Gas Producing Activities
Continued

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.

Table of Contents

TABLE VI STANDARDIZED MEASURE OF DISCOUNTED
FUTURE NET CASH FLOWS
RELATED TO PROVED OIL AND GAS RESERVES
Continued

	Consolidated Companies										C
	United States				International						
f dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l.	Total	TCO
MBER											
n inflows ction	**$ 48,828**	**$ 23,768**	**$ 38,727**	**$ 111,323**	**$ 97,571**	**$ 70,288**	**$ 30,538**	**$ 36,272**	**$ 234,669**	**$ 345,992**	**$ 104,069**
duction	**(14,791)**	**(6,750)**	**(12,845)**	**(34,386)**	**(12,523)**	**(13,398)**	**(16,281)**	**(10,777)**	**(52,979)**	**(87,365)**	**(7,796)**
el. costs	**(3,999)**	**(2,947)**	**(1,399)**	**(8,345)**	**(9,648)**	**(6,963)**	**(2,284)**	**(3,082)**	**(21,977)**	**(30,322)**	**(7,026)**
ome	**(10,171)**	**(4,764)**	**(8,290)**	**(23,225)**	**(53,214)**	**(20,633)**	**(5,448)**	**(11,164)**	**(90,459)**	**(113,684)**	**(25,212)**
ted cash	**19,867**	**9,307**	**16,193**	**45,367**	**22,186**	**29,294**	**6,525**	**11,249**	**69,254**	**114,621**	**64,035**
midyear count for stimated	**(9,779)**	**(3,256)**	**(7,210)**	**(20,245)**	**(10,065)**	**(12,457)**	**(2,426)**	**(3,608)**	**(28,556)**	**(48,801)**	**(40,597)**
RDIZED E NET OWS	**$ 10,088**	**$ 6,051**	**$ 8,983**	**$ 25,122**	**$ 12,121**	**$ 16,837**	**$ 4,099**	**$ 7,641**	**$ 40,698**	**$ 65,820**	**$ 23,438**
MBER											
n inflows ction	$ 50,771	$ 29,422	$ 50,039	$ 130,232	$ 101,912	$ 73,612	$ 32,538	$ 44,680	$ 252,742	$ 382,974	$ 97,707
duction	(15,719)	(5,758)	(12,767)	(34,244)	(11,366)	(12,459)	(18,260)	(11,908)	(53,993)	(88,237)	(7,399)
el. costs	(2,274)	(2,467)	(873)	(5,614)	(8,197)	(5,840)	(1,730)	(2,439)	(18,206)	(23,820)	(5,996)
ome	(11,092)	(7,173)	(12,317)	(30,582)	(50,894)	(21,509)	(5,709)	(13,917)	(92,029)	(122,611)	(23,818)

ted cash	21,686	14,024	24,082	59,792	31,455	33,804	6,839	16,416	88,514	148,306	60,494
midyear count for stimated	(10,947)	(4,520)	(10,838)	(26,305)	(14,881)	(14,929)	(2,269)	(5,635)	(37,714)	(64,019)	(37,674)
RDIZED E NET OWS	$ 10,739	$ 9,504	$ 13,244	$ 33,487	$ 16,574	$ 18,875	$ 4,570	$ 10,781	$ 50,800	$ 84,287	$ 22,820
MBER											
n inflows ction	$ 32,793	$ 19,043	$ 28,676	$ 80,512	$ 64,628	$ 35,960	$ 25,313	$ 30,061	$ 155,962	$ 236,474	$ 61,875
duction	(11,245)	(3,840)	(7,343)	(22,428)	(10,662)	(8,604)	(12,830)	(7,884)	(39,980)	(62,408)	(7,322)
el. costs	(1,731)	(2,389)	(667)	(4,787)	(6,355)	(2,531)	(717)	(1,593)	(11,196)	(15,983)	(5,366)
ome	(6,706)	(4,336)	(6,991)	(18,033)	(29,519)	(9,731)	(5,354)	(9,914)	(54,518)	(72,551)	(13,895)
ted cash	13,111	8,478	13,675	35,264	18,092	15,094	6,412	10,670	50,268	85,532	35,292
midyear count for stimated	(6,656)	(2,715)	(6,110)	(15,481)	(9,035)	(6,966)	(2,465)	(3,451)	(21,917)	(37,398)	(22,249)
RDIZED E NET OWS	$ 6,455	$ 5,763	$ 7,565	$ 19,783	$ 9,057	$ 8,128	$ 3,947	$ 7,219	$ 28,351	$ 48,134	$ 13,043

Supplemental Information on Oil and Gas Producing Activities
Continued

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	**2006**	2005	2004	**2006**	2005	2004
PRESENT VALUE AT JANUARY 1	**$ 84,287**	$ 48,134	$ 50,805	**$ 26,769**	$ 14,920	$ 13,118
Sales and transfers of oil and gas produced net of production costs	**(32,690)**	(26,145)	(18,843)	**(3,180)**	(2,712)	(1,602)
Development costs incurred	**8,875**	5,504	3,579	**721**	810	1,104
Purchases of reserves	**580**	25,307	58	**1,767**		
Sales of reserves	**(306)**	(2,006)	(3,734)			
Extensions, discoveries and improved recovery less related costs	**4,067**	7,446	2,678			
Revisions of previous quantity estimates	**7,277**	(13,564)	1,611	**(967)**	(2,598)	970
Net changes in prices, development and production costs	**(24,725)**	61,370	6,173	**(837)**	19,205	266
Accretion of discount	**14,218**	8,160	8,139	**3,673**	2,055	1,818
Net change in income tax	**4,237**	(29,919)	(2,332)	**(1,412)**	(4,911)	(754)
Net change for the year	**(18,467)**	36,153	(2,671)	**(235)**	11,849	1,802
PRESENT VALUE AT DECEMBER 31	**$ 65,820**	$ 84,287	$ 48,134	**$ 26,534**	$ 26,769	$ 14,920

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description
3.1	Restated Certificate of Incorporation of Chevron Corporation, dated May 9, 2005, filed as Exhibit 99.1 to Chevron Corporation s Current Report on Form 8-K dated May 10, 2005, and incorporated herein by reference.
3.2	By-Laws of Chevron Corporation, as amended January 31, 2007, filed as Exhibit 3.1 to Chevron Corporation s Current Report on Form 8-K dated January 31, 2007, 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 filed as Exhibit 10.6 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.
10.2	Management Incentive Plan of Chevron Corporation filed as Exhibit 10.3 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.
10.4	Chevron Corporation Long-Term Incentive Plan filed as Exhibit 10.4 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, 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.
10.7	Chevron Corporation Deferred Compensation Plan for Management Employees II filed as Exhibit 10.5 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, 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.
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 through 43 filed as Exhibit 10.1 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.

Table of Contents

Exhibit No.	Description
10.15	Chevron Corporation Benefit Protection Program filed as Exhibit 10.2 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, 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.
10.18	Chevron Corporation Retirement Restoration Plan filed as Exhibit 10.18 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, and incorporated herein by reference.
10.19	Chevron Corporation ESIP Restoration Plan filed as Exhibit 10.19 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, and incorporated herein by reference.
10.20	Form of Restricted Stock Unit Grant Agreement under the Chevron Corporation Long-Term Incentive Plan filed as Exhibit 10.20 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, 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).
24.1to 24.11*	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-18).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Financial Officer (page E-19).
32.1*	Section 1350 Certification of the company s Chief Executive Officer (page E-20).
32.2*	Section 1350 Certification of the company s Chief Financial Officer (page E-21).
99.1*	Definitions of Selected Energy and Financial Terms (page E-22 to E-23).

* 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.