CHEVRON CORP
Form 10-K
February 25, 2010

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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, 2009**
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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes þ   No o

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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 $132,865,210,015 (As of June 30, 2009)

Number of Shares of Common Stock outstanding as of February 19, 2010 2,008,352,638

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2010 Annual Meeting and 2010 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company s 2010 Annual Meeting of Stockholders (in Part III)

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

This *Annual Report on Form 10-K* of Chevron Corporation contains forward-looking statements relating to Chevron s operations that are based on management s current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as anticipates, expects, intends, plans, targets, 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 the company s 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: changing crude-oil and natural-gas prices; changing refining, marketing and chemical margins; actions of competitors or regulators; timing of exploration expenses; timing of crude-oil liftings; 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, severe weather or crude-oil production quotas that might be imposed by the Organization of Petroleum Exporting Countries; the potential liability for remedial actions or assessments 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 other pending or future litigation; the company s future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign-currency movements compared with the U.S. dollar; 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 on pages 30 through 32 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.

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PART I

Item 1. Business

(a) General Development of Business

Summary Description of Chevron

Chevron Corporation,* a Delaware corporation, manages its investments in subsidiaries and affiliates and provides administrative, financial, management and technology support to U.S. and international subsidiaries that engage in fully integrated petroleum operations, chemicals operations, mining operations, power generation and energy services. 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 and converting natural gas 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. Chemicals 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-23 and E-24. As of December 31, 2009, Chevron had approximately 64,000 employees (including about 4,000 service station employees). Approximately 31,500 employees (including about 3,500 service station employees), or 49 percent, were employed in U.S. operations.

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, natural gas, petroleum products and petrochemicals are generally determined by supply and demand for these commodities. However, some governments impose price controls on refined products such as gasoline or diesel fuel. 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 of 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 global 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 and national petroleum companies in the sale or acquisition of various goods or services in many national and international markets.

Operating Environment

Refer to pages FS-2 through FS-9 of this Form 10-K in Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company s current business environment and outlook.

* 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.

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Chevron Strategic Direction

Chevron s primary objective is to create stockholder value and achieve sustained financial returns from its operations that will enable it to outperform its competitors. In the upstream, the company s strategies are to grow profitably in core areas, build new legacy positions and commercialize the company s equity natural-gas resource base while growing a high-impact global gas business. In the downstream, the strategies are to improve returns and selectively grow, with a focus on integrated value creation. The company also continues to invest in renewable-energy technologies, with an objective of capturing profitable positions.

(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 Australia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2009, and assets as of the end of 2009 and 2008 for the United States and the company s international geographic areas are in Note 11 to the Consolidated Financial Statements beginning on page FS-40. 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-43 through FS-45.

Capital and Exploratory Expenditures

Total expenditures for 2009 were $22.2 billion, including $1.6 billion for the company s share of equity-affiliate expenditures. In 2008 and 2007, expenditures were $22.8 billion and $20 billion, respectively, including the company s share of affiliates expenditures of $2.3 billion in both periods.

Of the $22.2 billion in expenditures for 2009, about three-fourths, or $17.1 billion, was related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2008 and 2007. International upstream accounted for about 80 percent of the worldwide upstream investment in 2009 and about 70 percent in 2008 and 2007, reflecting the company s continuing focus on opportunities available outside the United States.

In 2010, the company estimates capital and exploratory expenditures will be $21.6 billion, including $1.6 billion of spending by affiliates. About 80 percent of the total, or $17.3 billion, is budgeted for exploration and production activities, with $13.2 billion of that amount for projects outside the United States.

Refer also to a discussion of the company s capital and exploratory expenditures on page FS-12.

Upstream Exploration and Production

The table on the following page summarizes the net production of liquids and natural gas for 2009 and 2008 by the company and its affiliates.

Net Production of Crude Oil and Natural Gas Liquids and Natural Gas[1,2]

	Oil-Equivalent (Thousands of Barrels per Day)		Components of Oil-Equivalent Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day)		Natural Gas (Millions of Cubic Feet per Day)	
	2009	**2008**	**2009**	**2008**	**2009**	**2008**
United States	**717**	671	**484**	421	**1,399**	1,501
Africa:						
Nigeria	**232**	154	**225**	142	**48**	72
Angola	**150**	154	**141**	145	**49**	52
Chad	**27**	29	**26**	28	**5**	5
Republic of the Congo	**21**	13	**19**	11	**13**	12
Democratic Republic of the Congo	**3**	2	**3**	2	**1**	1
Total Africa	**433**	352	**414**	328	**116**	142
Asia:						
Indonesia	**243**	235	**199**	182	**268**	319
Thailand	**198**	217	**65**	67	**794**	894
Partitioned Zone (PZ)[3]	**105**	106	**101**	103	**21**	20
Kazakhstan	**69**	66	**42**	41	**161**	153
Bangladesh	**66**	71	**2**	2	**387**	414
Azerbaijan	**30**	29	**28**	28	**10**	7
Philippines	**27**	26	**4**	5	**137**	128
China	**19**	22	**17**	19	**16**	22
Myanmar	**13**	15			**76**	89
Total Asia	**770**	787	**458**	447	**1,870**	2,046
Other:						
United Kingdom	**110**	106	**73**	71	**222**	208
Australia	**108**	96	**35**	34	**434**	376
Denmark	**55**	61	**35**	37	**119**	142
Colombia	**41**	35			**245**	209
Argentina	**38**	44	**33**	37	**27**	45
Trinidad and Tobago	**34**	32	**1**		**199**	189
Canada	**28**	37	**27**	36	**4**	4
Netherlands	**9**	9	**2**	2	**41**	40
Norway	**5**	6	**5**	6	**1**	1
Brazil	**2**		**2**			
Total Other	**430**	426	**213**	223	**1,292**	1,214

Total Consolidated Operations	**2,350**	2,236	**1,569**	1,419	**4,677**	4,903
Equity Affiliates[4]	**328**	267	**277**	230	**312**	222
Total Including Affiliates[5]	**2,678**	2,503	**1,846**	1,649	**4,989**	5,125

[1] 2008 conformed to 2009 geographic presentation.

[2] Excludes Athabasca oil sands production, net:	**26**	27	**26**	27

[3] Located between Saudi Arabia and Kuwait.

[4] Volumes represent Chevron s share of production by affiliates, including Tengizchevroil (TCO) in Kazakhstan and Petroboscan, Petroindependiente and Petropiar in Venezuela.

[5] Volumes include natural gas consumed in operations of 521 million and 520 million cubic feet per day in 2009 and 2008, respectively.

Worldwide oil-equivalent production, including volumes from oil sands (refer to footnote 2 above), was 2.7 million barrels per day, up about 7 percent from 2008. The increase was mostly associated with the start-up of the Blind Faith and Tahiti fields in the U.S. Gulf of Mexico in late 2008 and the second quarter 2009, respectively, the commencement of operations in the third quarter 2008 at the Agbami Field in Nigeria, and the expansion at Tengiz in Kazakhstan. Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of the factors explaining the 2007-2009 changes in production for crude oil and natural gas liquids, and natural gas.

The company estimates that its average worldwide oil-equivalent production in 2010 will be approximately 2.73 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, delays in project start-ups, fluctuations in demand for natural gas in various markets, and production that may have to be shut in due to weather conditions, civil unrest,

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changing geopolitics or other disruptions to 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. 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 crude-oil and natural-gas development projects.

Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-69 for the company s average sales price per barrel of crude oil, condensate and natural gas liquids and per thousand cubic feet of natural gas produced and the average production cost per oil-equivalent barrel for 2009, 2008 and 2007.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2009 for the company and its affiliates:

Productive Oil and Gas Wells[1] at December 31, 2009

	Productive[2,3] Oil Wells		Productive[2] Gas Wells	
	Gross	**Net**	**Gross**	**Net**
United States	49,761	32,720	11,567	5,671
Africa	2,292	766	17	7
Asia	10,580	9,106	2,336	1,510
Other	1,605	963	275	74
Total Consolidated Companies	64,238	43,555	14,195	7,262
Equity in Affiliates	1,133	403	7	2
Total Including Affiliates	65,371	43,958	14,202	7,264
Multiple completion wells included above:	929	596	390	313

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 wells and the sum of the company s fractional interests in gross wells.
3 Canadian synthetic oil is not produced through wells and therefore is not presented in the table above.

Reserves

Refer to Table V beginning on page FS-69 for a tabulation of the company s proved net crude-oil and natural-gas reserves by geographic area, at the beginning of 2007 and each year-end from 2007 through 2009, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2009. During 2009, the company provided crude-oil and natural-gas reserves estimates for 2008 to the Department of Energy, Energy Information Administration (EIA) that agree with the 2008 reserve volumes in Table V. This reporting fulfilled the requirement that such estimates be consistent with, and not differ more than 5 percent from, the information furnished to the Securities and Exchange Commission (SEC) in the company s 2008 Annual Report on Form 10-K. During 2010, the company will file estimates of crude-oil and natural-gas reserves with the Department of Energy, EIA, consistent with the 2009 reserve data reported in Table V.

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The net proved-reserve balances at the end of each of the three years 2007 through 2009 are shown in the table below:

Net Proved Reserves at December 31

	2009	2008	2007
Liquids* Millions of barrels			
Consolidated Companies	**4,610**	4,735	4,665
Affiliated Companies	**2,363**	2,615	2,422
Natural Gas Billions of cubic feet			
Consolidated Companies	**22,153**	19,022	19,137
Affiliated Companies	**3,896**	4,053	3,003
Total Oil-Equivalent Millions of barrels			
Consolidated Companies	**8,303**	7,905	7,855
Affiliated Companies	**3,012**	3,291	2,922

* Crude oil, condensate and natural gas liquids. 2009 liquids amount for consolidated companies includes 460 million barrels of synthetic oil produced from oil sands mining operations in Canada in accordance with the adoption of the new SEC definition of oil and gas producing activity.

Acreage

At December 31, 2009, the company owned or had under lease or similar agreements undeveloped and developed crude-oil and natural-gas properties located throughout the world. The geographical distribution of the company s acreage is shown in the following table.

Acreage[1,2] at December 31, 2009
(Thousands of Acres)

	Undeveloped[3]		Developed[3]		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States	4,679	3,708	6,139	3,769	10,818	7,477
Africa	9,663	5,705	2,499	917	12,162	6,622
Asia	38,370	18,491	5,313	2,742	43,683	21,233
Other	53,181	26,407	3,243	792	56,424	27,199
Total Consolidated Companies	105,893	54,311	17,194	8,220	123,087	62,531
Equity in Affiliates	640	300	259	104	899	404
Total Including Affiliates	106,533	54,611	17,453	8,324	123,986	62,935

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

2

Table does not include mining acreage associated with the synthetic oil production in Canada. At year-end 2009, undeveloped gross and net acreage totaled 235 and 31, respectively. Developed gross and net acreage totaled 35 and 7, respectively. Developed acreage is acreage associated with productive mines. Undeveloped acreage is acreage on which mines have not been established and that may contain undeveloped proved reserves.

[3] Developed acreage is spaced or assignable to productive wells. Undeveloped acreage is acreage on which 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 2010, 2011 and 2012 if production is not established by certain required dates are 13,526, 9,784 and 3,662, respectively.

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Delivery Commitments

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 some natural-gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the United States, the company has no fixed and determinable delivery commitments to third-parties or affiliates.

Outside the United States, the company is contractually committed to deliver to third parties a total of 821 billion cubic feet of natural gas from 2010 through 2012 from Australia, Colombia, Denmark 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. The company believes it can satisfy these contracts from quantities available from production of the company s proved developed reserves in Australia, Colombia, Denmark and the Philippines.

Development Activities

Refer to Table I on page FS-64 for details associated with the company s development expenditures and costs of proved property acquisitions for 2009, 2008 and 2007.

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, 2009. 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 12/31/09[3]		Net Wells Completed[1,2]					
			2009		2008		2007	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**47**	**22**	**582**	**3**	846	4	875	5
Africa	**6**	**2**	**40**		33		43	
Asia	**38**	**22**	**580**		665	1	597	
Other	**11**	**4**	**43**		41		52	
Total Consolidated Companies	**102**	**50**	**1,245**	**3**	1,585	5	1,567	5
Equity in Affiliates	**1**		**6**		16		3	
Total Including Affiliates	**103**	**50**	**1,251**	**3**	1,601	5	1,570	5

1 2008 and 2007 conformed to 2009 geographic presentation.
2 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.

[3] Represents wells in the process of drilling, including wells for which drilling was not completed and which were temporarily suspended at the end of 2009. Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned wells and the sum of the company s fractional interests in gross wells.

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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, 2009. 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 12/31/09[3]		**Net Wells Completed[1,2]**					
			2009		**2008**		**2007**	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States	**3**	**1**	**4**	**5**	8	2	4	8
Africa	**6**	**2**	**2**	**1**	2	1	6	2
Asia	**1**		**9**	**1**	9	2	13	9
Other	**4**	**3**	**5**	**4**	44	2	43	6
Total Consolidated Companies	**14**	**6**	**20**	**11**	63	7	66	25
Equity in Affiliates								
Total Including Affiliates	**14**	**6**	**20**	**11**	63	7	66	25

1 2008 and 2007 conformed to 2009 geographic presentation.

2 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.

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 which were temporarily suspended at the end of 2009. Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned wells and the sum of the company s fractional interests in gross wells.

Refer to Table I on page FS-64 for detail of the company s exploration expenditures and costs of unproved property acquisitions for 2009, 2008 and 2007.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron s 2009 key upstream activities, some of which are 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 include references to total production and net production, which are defined under Production in Exhibit 99.1 on page E-42.

The discussion that follows 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 or for mature areas of production that do not have individual projects requiring significant levels of capital or exploratory investment. Amounts indicated for project costs represent total project costs, not the company s share of costs for projects that are less than wholly owned.

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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 equity natural-gas resource base while growing a high-impact global gas business. The map at left indicates Chevron s primary areas of production and exploration.

a) United States

Upstream activities in the United States are concentrated in California, the Gulf of Mexico, Louisiana, Texas, New Mexico, the Rocky Mountains and Alaska. Average net oil-equivalent production in the United States during 2009 was 717,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2009, average net oil-equivalent production was 211,000 barrels per day, composed of 191,000 barrels of crude oil, 91 million cubic feet of natural gas and 5,000 barrels of natural gas liquids. Approximately 84 percent of the crude-oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

Average net oil-equivalent production during 2009 for the company s combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region was 243,000 barrels per day. The daily oil-equivalent production comprised 149,000 barrels of crude oil, 484 million cubic feet of natural gas and 14,000 barrels of natural gas liquids.

During 2009, Chevron was engaged in various development and exploration activities in the deepwater Gulf of Mexico. The 75 percent-owned and operated Blind Faith development, which achieved first oil in the fourth quarter 2008, reached maximum total production of 70,000 barrels per day of oil-equivalent in 2009. Blind Faith has an estimated production life of 20 years.

At the 58 percent-owned and operated Tahiti Field, first oil was achieved in the second quarter 2009. Maximum total production of 135,000 barrels per day of oil-equivalent was achieved in the third quarter 2009. A second development phase is under evaluation, including additional development drilling and a probable waterflood, with a final investment decision planned formid-2010. The waterflood includes water injection topsides equipment, subsea equipment and water injection wells. Tahiti has an estimated production life of 30 years. As of the end of 2009, proved reserves had been recognized for the first development phase of the Tahiti Field.

The company is participating in the ultra-deepwater Perdido Regional Development. The project encompasses the installation of a producing host facility to service multiple fields, including Chevron s 33.3 percent-owned Great White, 60 percent-owned Silvertip and 57.5 percent-owned Tobago. Chevron has a 37.5 percent interest in the Perdido Regional Host. All of these fields and the production facility are partner-operated. Activities during 2009 included installation of the topsides on the spar, installation of umbilicals, hook-up and commissioning of the facility systems, and ongoing development drilling. First oil is expected in the first half of 2010, with the facility designed to handle 130,000 barrels of oil-equivalent per day. The project has an expected life of approximately 25 years. Proved reserves have been recognized for the project.

The company has a 60 percent-owned and operated interest in Big Foot. Two successful appraisal wells have been drilled, the most recent in the first quarter 2009. The company also acquired the rights to an adjacent block during 2009. The project entered front-end engineering and design (FEED) in October 2009 and a final investment decision is expected in late 2010. Total maximum production from the project is expected to be 63,000 barrels of oil-equivalent per day. At the end of 2009, proved reserves had not been recognized.

The Caesar and Tonga partnerships for properties located in a number of blocks in the Green Canyon area have formed a unit agreement for the area, with Chevron having a 20.3 percent nonoperated working interest. A final investment decision on the joint Caesar-Tonga project was made in the first quarter 2009. Development plans include four wells and a subsea tie-back to a nearby third-party production facility. Two development sidetracks were completed during the year. Proved reserves have been recognized for the project and first oil is expected in 2011.

The Jack and St. Malo fields are located within 25 miles of each other and are being considered for joint development. Chevron has a 50 percent-owned interest in Jack and a 51 percent-owned interest in St. Malo, following the anticipated acquisition of an additional 9.8 percent equity interest in St. Malo in March 2010. Both fields are company operated. The project entered FEED in May 2009 and a final investment decision is expected in late 2010. The facility is planned to have an initial design capacity of 150,000 barrels of oil-equivalent per day and start-up is expected in 2014. At the end of 2009, proved reserves had not been recognized.

Deepwater exploration activities in 2009 and early 2010 included participation in 10 exploratory wells five wildcat, three appraisal and two delineation. Exploratory work included the following:

Buckskin 55 percent-owned and operated. A successful wildcat discovery was announced in February 2009. The first appraisal well is scheduled to begin drilling in the second quarter 2010.

Knotty Head 25 percent nonoperated working interest. The first appraisal well began drilling in October 2009 at this 2005 discovery.

Puma 21.8 percent nonoperated working interest. An appraisal well completed drilling in early 2009. Leases were relinquished in mid-2009.

Tubular Bells 30 percent nonoperated working interest. Studies to screen and evaluate future development alternatives were continuing at the end of 2009.

At the end of 2009, the company had not 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, the company also has contracted capacity of 1 billion cubic feet per day at the third-party Sabine Pass liquefied natural gas (LNG) regasification terminal in Louisiana. The 20-year capacity reservation agreement became effective in July 2009 and enables import of natural gas for the North America market. In September 2009, Chevron began to utilize a portion of the reserved capacity under this agreement.

Chevron has also contracted 1.6 billion cubic feet per day of capacity in a third-party pipeline system connecting the Sabine Pass LNG terminal to the natural-gas pipeline grid. The new pipeline, which was placed in service in July 2009, provides access to two major salt dome storage fields and 10 major interstate pipeline systems, including an interconnect with Chevron s Sabine Pipeline, which connects to the Henry Hub. An interconnect to Chevron s Bridgeline Pipeline is scheduled to be completed in the third quarter 2010. The Henry Hub interconnects to nine interstate and four intrastate pipelines and is the pricing point for natural gas futures contracts traded on the New York

Mercantile Exchange.

Outside California and the Gulf of Mexico, the company manages operations across the mid-continental United States and Alaska. During 2009, the company s U.S. production outside California and the Gulf of Mexico averaged 263,000 net oil-equivalent barrels per day, composed of 94,000 barrels of crude oil, 824 million cubic feet of natural gas and 31,000 barrels of natural gas liquids.

In the Piceance Basin in northwestern Colorado, additional production came on line in September 2009 from the company s 100 percent-owned and operated natural-gas development. Development drilling, which began in 2007, surpassed 190 wells in 2009, with 81 completed wells available to supply natural gas to the central processing facility. Construction of compression and dehydration facilities to produce 65 million cubic feet per day of natural gas was completed in the third quarter 2009. Future work is expected to be completed in multiple stages. The full development plan includes drilling more than 2,000 wells from multi-well pads over the next 30 to 40 years. Proved reserves for subsequent stages of the project had not been recognized at year-end 2009.

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b) Africa

In Africa, the company is engaged in exploration and production activities in Angola, Chad, Democratic Republic of the Congo, Nigeria and Republic of the Congo. Net oil-equivalent production in Africa averaged 433,000 barrels per day during 2009.

Angola: Chevron holds company-operated working interests in offshore Blocks 0 and 14 and nonoperated working interests in offshore Block 2 and the onshore Fina Sonangol Texaco (FST) area. Net production from these operations in 2009 averaged 150,000 barrels of oil-equivalent per day.

The company operates the 39.2 percent-owned Block 0, which averaged 105,000 barrels per day of net liquids production in 2009. The Block 0 concession extends through 2030.

Initial production from the northern portion of the Mafumeira Field in Block 0 occurred in July 2009, and total maximum crude-oil production of 42,000 barrels per day was achieved in first quarter 2010. Front-end engineering and design (FEED) started in January 2010 on Mafumeira Sul, a project to develop the southern portion of the Mafumeira Field. A final investment decision is expected in 2011. Maximum production from Mafumeira Sul is expected to be 95,000 barrels of crude oil per day. At year-end 2009, no proved reserves had been recognized for this project.

In the Greater Vanza/Longui Area of Block 0, development concept selection was under way and continued into 2010. FEED is planned for 2011. FEED activities continued on the south extension of the N Dola Field development. At year-end 2009, no proved reserves had been recognized for these projects.

Four gas management projects in Block 0 are expected to eliminate routine flaring of natural gas by injecting excess natural gas into various reservoirs. The Takula Flare and Relief Modification Project and the Cabinda Gas Plant Project entered service in June 2009 and December 2009, respectively. These projects are expected to reduce flaring by up to 60 million cubic feet per day. Work continued on the Nemba Enhanced Secondary Recovery and Flare Reduction Project and the Malongo Flare and Relief Modification Project, which are scheduled for start-up in the fourth quarter 2010 and in 2011, respectively.

Also in Block 0, a successful two-well exploration and appraisal program was completed. The exploration well was completed in March 2009, and the appraisal well was completed in May 2009. Drilling began on another exploration well in November 2009 and was completed in the first quarter 2010. The results are under evaluation.

In the 31 percent-owned Block 14, net production in 2009 averaged 33,000 barrels of liquids per day from the Benguela Belize Lobito Tomboco development and the Kuito, Tombua and Landana fields. Development and production rights for the various fields in Block 14 expire between 2027 and 2029.

Development of the Tombua and Landana fields continued in 2009. First production occurred in August 2009 from new production facilities that were installed in late 2008. Proved developed reserves were recognized at start of production. Development drilling is expected to continue, with maximum total daily production of 100,000 barrels of crude oil anticipated in 2011.

During 2009, studies to evaluate development alternatives for the Lucapa Field continued. The project is expected to enter FEED in the fourth quarter 2010. A successful appraisal well was completed in the fourth quarter 2009 in the Malange area. As of the end of 2009, development of the Negage Field was suspended until cooperative arrangements between Angola and Democratic Republic of the Congo could be finalized. At the end of 2009, proved reserves had not been recognized for these projects.

The 39.2 percent-owned and operated Malongo Terminal Oil Export project was completed in November 2009. The new export system more than doubled export capacity from the area, which includes Blocks 0 and 14. In the 20 percent-owned Block 2 and the 16.3 percent-owned FST areas, combined production during 2009 averaged 3,000 barrels of net liquids per day.

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Equity Affiliate Operations: In addition to the exploration and producing activities in Angola, Chevron has a 36.4 percent ownership interest in the Angola LNG affiliate that began construction in early 2008 of an onshore natural gas liquefaction plant located in Soyo, Angola. The plant is designed to process more than 1 billion cubic feet of natural gas per day. Construction continued on schedule during 2009 with plant start-up scheduled for 2012. The life of the LNG plant is estimated to be in excess of 20 years. Proved reserves have been recognized for the producing operations associated with this project.

Angola Republic of the Congo Joint Development Area: Chevron operates and holds a 31.3 percent interest in the Lianzi Development Area located between Angola and Republic of the Congo. In late 2008, the development project entered FEED, which continued through 2009. No proved reserves have been recognized for Lianzi.

Republic of the Congo: Chevron has a 31.5 percent nonoperated working interest in the Nkossa, Nsoko and Moho-Bilondo exploitation permits and a 29.3 percent nonoperated working interest in the Kitina exploitation permit, all of which are offshore. The development and production rights for Nkossa, Nsoko and Kitina expire in 2027, 2018 and 2019, respectively. Net production from the Republic of the Congo fields averaged 21,000 barrels of oil-equivalent per day in 2009.

In May 2009, a successful exploration well was drilled in the Moho-Bilondo exploitation permit area. Development alternatives were being evaluated during 2009. The Moho-Bilondo subsea development project, which started production in 2008, is expected to achieve maximum total production of 90,000 barrels of crude oil per day in the third quarter 2010. Chevron s development and production rights for Moho-Bilondo expire in 2030.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2009 averaged 3,000 barrels of oil-equivalent.

Chad/Cameroon: Chevron participates in a project to develop crude-oil fields in southern Chad and transport the produced volumes by pipeline to the coast of Cameroon for export. Chevron has a 25 percent nonoperated working interest in the producing operations and an approximate 21 percent interest in two affiliates that own the pipeline. Average daily net production from the Chad fields in 2009 was 27,000 barrels of oil-equivalent. In September 2009, first production was achieved at the Timbre Field in the Doba area. The Chad producing operations are conducted under a concession that expires in 2030.

Libya: After an unsuccessful exploration well was completed, the company elected to relinquish its 100 percent interest in the onshore Block 177 exploration license in the fourth quarter 2009.

Nigeria: Chevron holds a 40 percent interest in 13 concessions in the onshore and near-offshore region of the Niger Delta. The company operates under a joint-venture arrangement in this region with the Nigerian National Petroleum Corporation, which owns a 60 percent interest. The company also owns varying interests in deepwater offshore blocks. In 2009, the company s net oil-equivalent production in Nigeria averaged 232,000 barrels per day, composed of 225,000 barrels of liquids and 48 million cubic feet of natural gas.

In deepwater Oil Mining Lease (OML) 127 and

OML 128, the 68.2 percent-owned and operated Agbami Field reached maximum total liquids production of 250,000 barrels per day in August 2009, following completion of development drilling. In December 2009, a subsequent 10-well development program was initiated and is expected to offset field decline. The leases that contain the Agbami Field expire in 2023 and 2024.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the Bonga SW Field in offshore OML 118 share a common geologic structure and are planned to be jointly developed under a proposed unitization agreement. Work continued in 2009 on a final unitization agreement between Chevron and partners in OML 118. At the end of 2009, no proved reserves were recognized for this project.

Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery on OML 140. Development activities continued in 2009, with FEED expected to start after commercial terms are resolved. At the end of 2009, the company had not recognized proved reserves for this project.

The company also holds a 30 percent nonoperated working interest in the deepwater Usan project in OML 138. The development plans involve subsea wells producing to a floating production, storage and offloading vessel. Development drilling started in June 2009. Production start-up is scheduled for 2012, and maximum total production of 180,000 barrels of crude oil per day is expected to be achieved within one year of start-up. Total costs for the project are estimated at $8.4 billion. Usan has an estimated production life of 20 years. Proved reserves have been recognized for this project.

Chevron participated in one successful deepwater exploration well during 2009 in Oil Prospecting License (OPL) 223. The company has a 30 percent nonoperated working interest in the license. At the end of 2009, proved reserves had not been recognized for the exploration project.

In the Niger Delta, construction on the Phase 3A expansion of the Escravos Gas Plant (EGP) was completed in late 2009 and start of production is expected in March 2010. EGP Phase 3A scope includes offshore natural-gas gathering and compression infrastructure and the addition of a second natural-gas processing facility. The modifications are designed to increase processing capacity from 285 million to 680 million cubic feet of natural gas per day and increase LPG and condensate export capacity from 15,000 to 58,000 barrels per day. EGP Phase 3A is designed to process natural gas from the Meji, Delta South, Okan and Mefa fields. The anticipated life of EGP Phase 3A is 25 years. Phase 3B of the EGP project is designed to gather natural gas from eight offshore fields and to compress and transport natural gas to onshore facilities beginning in 2012. The engineering, procurement, construction, and installation contract for the pipelines was awarded and work commenced in late 2009. Proved reserves have been recognized for these projects.

The 40 percent-owned and operated Onshore Asset Gas Management project is designed to restore approximately 125 million cubic feet per day of natural-gas production from certain onshore fields that have been shut in since 2003 due to civil unrest. Natural gas from these fields is sold in the Nigerian domestic gas market. The main on-site construction contracts are expected to be awarded in the second quarter 2010.

Refer to page 25 for a discussion of the planned gas-to-liquids facility at Escravos.

Equity Affiliate Operations: Chevron holds a 19.5 percent interest in the OKLNG Free Zone Enterprise (OKLNG) affiliate, which will operate the Olokola LNG project. OKLNG plans to build a multi-train natural-gas liquefaction facility and marine terminal located northwest of Escravos. At the end of 2009, timing of the final investment decision remains uncertain. The company has not recognized proved reserves associated with this project.

Refer to Pipelines under Transportation Operations beginning on page 26 for a discussion of the West African Gas Pipeline operations.

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c) Asia

Major producing countries in Asia include Azerbaijan, Bangladesh, Indonesia, Kazakhstan, the Partitioned Zone located between Saudi Arabia and Kuwait, and Thailand. During 2009, net oil-equivalent production averaged 1,044,000 barrels per day in Asia.

Azerbaijan: Chevron holds a 10.3 percent nonoperated working interest in the Azerbaijan International Operating Company (AIOC), which produces crude oil in the Caspian Sea from the Azeri-Chirag-Gunashli (ACG) project. Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate, which transports AIOC production by pipeline from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities in Ceyhan, Turkey. (Refer to Pipelines under Transportation Operations beginning on page 26 for a discussion of BTC operations.)

In 2009, the company s daily net production from AIOC averaged 30,000 barrels of oil-equivalent. The final investment decision on the next development phase is expected in the first half 2010. AIOC operations are conducted under a 30-year production-sharing contract (PSC) that expires in 2024.

Kazakhstan: Chevron holds a 20 percent nonoperated working interest in the Karachaganak project, which is being developed in phases. During 2009, Karachaganak net oil-equivalent production averaged 69,000 barrels per day, composed of 42,000 barrels of liquids and 161 million cubic feet of natural gas. In 2009, access to the Caspian Pipeline Consortium (CPC) and Atyrau-Samara (Russia) pipelines enabled approximately 184,000 barrels per day (33,000 net barrels) of Karachaganak liquids to be sold at world-market prices. The remaining liquids were sold into Russian markets. During 2009, work continued on a fourth train that is designed to increase total export of processed liquids by 56,000 barrels per day. The fourth train is expected to start-up in 2011.

During 2009, Chevron and its partners continued to evaluate alternatives for a Phase III development of Karachaganak. Timing for the recognition of Phase III proved reserves is uncertain and depends on finalizing a project design and achieving project milestones. Karachaganak operations are conducted under a 40-year PSC that expires in 2038.

Equity Affiliate Operations: The company holds a 50 percent interest in Tengizchevroil (TCO), which is operating and developing the Tengiz and Korolev crude-oil fields, located in western Kazakhstan, under a 40-year concession that expires in 2033. Chevron s net oil-equivalent production in 2009 from these fields averaged 274,000 barrels per day, composed of 226,000 barrels of crude oil and natural gas liquids and 289 million cubic feet of natural gas.

In 2009, TCO continued ramp-up of the Sour Gas Injection (SGI) and Second Generation Plant (SGP) facilities. The SGI facility injects approximately one-third of the sour gas separated from the crude oil back into the reservoir. The injected gas maintains higher reservoir pressure and displaces oil towards producing wells. TCO is evaluating options for another expansion project based on SGI/SGP technologies.

During 2009, the majority of TCO s crude-oil production was 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. The balance was shipped via other export routes, which included shipment via tanker to Baku for transport by the BTC pipeline to Ceyhan or by rail to Black Sea ports. (Refer to Pipelines under Transportation Operations beginning on page 26 for a discussion of CPC operations.)

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Turkey: Chevron holds a 25 percent nonoperated working interest in the Silopi licenses in southeast Turkey, which is on trend with production in Iraq s northern Zagros Fold Belt. An exploration well in the Lale prospect completed drilling in the first quarter 2010, and is under evaluation.

Bangladesh: Chevron holds interests in three operated PSCs covering onshore Blocks 12, 13 and 14 and offshore Block 7. The company has a 98 percent interest in Blocks 12, 13 and 14. Government approval of a 2009 farm-out in Block 7 was received in February 2010, reducing the company s interest from 88 percent to 43 percent. The farm-out was to GS Caltex, a 50 percent-owned affiliate of the company. Net oil-equivalent production from these operations in 2009 averaged 66,000 barrels per day, composed of 387 million cubic feet of natural gas and 2,000 barrels of liquids. In 2009, a final investment decision was achieved after the government approved the development of a compression project that is expected to support additional production starting in 2012 from the Bibiyana, Jalalabad and Moulavi Bazar natural-gas fields. Proved reserves have been recognized for this project. The government also approved an amendment to the PSC for Blocks 13 and 14 that allows the company to acquire additional 3-D seismic over the Jalalabad Field. Also in 2009, the company acquired seismic data on Block 7. Evaluation and data processing is under way, and an exploration well is planned to be completed by 2011.

Cambodia: Chevron operates the 1.2 million-acre (4,709 sq-km) Block A, located offshore in the Gulf of Thailand, and expects to reduce its ownership to 30 percent pending government approval of the farm-out that is anticipated in the second quarter 2010. In 2009, commercial evaluation of the prospects continued. The company was granted an extension for the Block A exploration period to the third quarter 2010 in exchange for the obligation to drill three exploration wells. Information gained from the drilling program is expected to provide improved definition of the resource in the block. Proved reserves had not been recognized as of the end of 2009.

Myanmar: Chevron has a 28.3 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana and Sein fields offshore in the Andaman Sea. The company also has a 28.3 percent interest in a pipeline company that transports the natural gas from Yadana to the Myanmar-Thailand border for delivery to power plants in Thailand. Most of the natural gas is purchased by Thailand s PTT Public Company Limited (PTT). The company s average net natural gas production in 2009 was 76 million cubic feet per day. During 2009, the platform for a compression project was completed. Project start-up is expected in 2011.

Thailand: Chevron has operated and nonoperated working interests in several different offshore blocks. The company s net oil-equivalent production in 2009 averaged 198,000 barrels per day, composed of 65,000 barrels of crude oil and condensate and 794 million cubic feet of natural gas. All of the company s natural-gas production is sold to PTT under long-term sales contracts.

Operated interests are in Pattani and other fields with ownership interests ranging from 35 percent to 80 percent in Blocks 10 through 13, B12/27, B8/32, 9A, G4/43 and G4/48. Blocks B8/32 and 9A produce crude oil and natural gas from eight operating areas, and Blocks 10 through 13 and B12/27 produce crude oil, condensate and natural gas from 16 operating areas.

Chevron has a 16 percent nonoperated working interest in Blocks 14A, 15A, 16A, G9/48 and G8/50, known collectively as the Arthit Field.

During 2009, construction at the 69.8 percent-owned and operated Platong Gas II project continued. The project is designed to add 420 million cubic feet per day of processing capacity in 2012. Proved reserves have been recognized for this project. Concessions for Blocks 10 through 13 expire in 2022.

During 2009, 14 exploration wells were drilled in the Gulf of Thailand, 13 were successful and one nonoperated well in the Arthit Field was unsuccessful. Two 3-D seismic surveys and geological studies for Block G4/50 were also completed in 2009. At the end of 2009, proved reserves had not been recognized for these activities. Three exploratory wells in Block G4/50 are planned for the second quarter 2010. For Blocks G6/50 and G7/50, one exploration well is scheduled in each block for completion by the third quarter 2010. In addition, Chevron holds exploration interests in a number of blocks that are currently inactive, pending resolution of border issues between Thailand and Cambodia.

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Vietnam: The company operates off the southwest coast and has a 42.4 percent interest in a PSC that includes Blocks B and 48/95, and a 43.4 percent interest in another PSC for Block 52/97. In August 2009, Chevron reduced its ownership interest in a third operated PSC to 20 percent in Block B122 offshore eastern Vietnam. No production occurred in these areas during 2009.

In the blocks off the southwest coast, the Vietnam Gas Project is aimed at developing an area in the Malay Basin to supply natural gas to state-owned Petrovietnam. The project includes installation of wellhead and hub platforms, a floating storage and offloading vessel, field pipelines and a central processing platform. The project is expected to enter front-end engineering and design (FEED) in the first quarter 2010, and a final investment decision is expected in 2011. Maximum total production is planned to be about 500 million cubic feet of natural gas per day. At the end of 2009, proved reserves had not been recognized for this project.

In conjunction with the Vietnam Gas Project, a Petrovietnam-operated pipeline will be required to support the offshore development. Chevron will have a 28.7 percent interest in the pipeline, which is planned to transport natural gas from the offshore development to customers in southern Vietnam.

During the year, the company continued to analyze well results and seismic processing from Block B and Block 52/97. In Block 122, 2-D seismic data processing and geologic studies were completed. An exploration well is planned for 2011. Proved reserves had not been recognized as of the end of 2009. Future activity in Block 122 may be affected by an ongoing territorial dispute between Vietnam and China.

China: Chevron has one operated and three nonoperated working interests in several areas. Net oil-equivalent production from the nonoperated areas in 2009 averaged 19,000 barrels per day, composed of 17,000 barrels of crude oil and condensate and 16 million cubic feet of natural gas.

The company holds a 49 percent-owned and operated interest in the Chuandongbei area in the onshore Sichuan Basin, where the company entered into a 30-year PSC effective February 2008 to develop natural-gas resources. Project plans included two sour-gas purification plants with an aggregate design capacity of 740 million cubic feet per day. During 2009, general infrastructure for the plant site and well pads progressed. Development drilling and the construction and installation of additional processing facilities and gathering systems are expected to start in 2010. Proved reserves have been recognized for this project. The PSC for Chuandongbei expires in 2038.

In the South China Sea, the company has nonoperated working interests of 32.7 percent in Blocks 16/08 and 16/19 located in the Pearl

River Delta Mouth Basin, 24.5 percent in the QHD-32-6 Field in Bohai Bay, and 16.2 percent in the unitized and producing BZ 25-1 and BZ 19-4 crude-oil fields in Bohai Bay Block 11/19. In November 2009, a storm damaged the floating production, storage and offloading (FPSO) vessel utilized by the company s nonoperated assets in Block 11/19. Temporary and permanent recovery options are under development and production is expected to fully resume in 2012.

The joint development of the HZ25-3 and HZ25-1 crude-oil fields in Block 16/19 continued through the end of 2009. First production was delayed from the third quarter 2009 and is expected to be fully restored in the fourth quarter 2010 following damage to the FPSO vessel caused by a typhoon that struck the area in September 2009.

In 2009, Chevron relinquished its nonoperated working interest in four exploration blocks in the Ordos Basin. Government approval is expected in mid-2010.

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Indonesia: Chevron s operated interests in Indonesia are managed by several wholly owned subsidiaries, including PT Chevron Pacific Indonesia (CPI). CPI holds operated interests of 100 percent in the Rokan and Siak PSCs and 90 percent in the MFK (Mountain Front Kuantan) PSC. Other subsidiaries operate four PSCs in the Kutei Basin, located offshore East Kalimantan, and one PSC in the East Ambalat Block, located offshore northeast Kalimantan. These interests range from 80 percent to 100 percent. Chevron also has nonoperated working interests in a joint venture in Block B in the South Natuna Sea and in the NE Madura III Block inthe East Java Sea Basin. Chevron s interests in these PSCs range from 25 percent to 40 percent.

The company s net oil-equivalent production in 2009 from all of its interests in Indonesia averaged 243,000 barrels per day. The daily oil-equivalent rate comprised 199,000 barrels of liquids and 268 million cubic feet of natural gas. The largest producing field is Duri, located in the Rokan PSC. Duri has been under steamflood operation since 1985 and is one of the world s largest steamflood developments. The North Duri Development is divided into multiple expansion areas. The first expansion in Area 12 started steam injection in June 2009. Maximum total daily production from Area 12 is estimated at 34,000 barrels of crude oil in 2012. A final investment decision regarding North Duri Area 13 is expected by year-end 2010. The Rokan PSC expires in 2021.

Chevron advanced its development plans for the Gendalo and Gehem deepwater natural-gas fields located in the Kutei Basin. FEED started in December 2009, with completion dependent upon achieving project milestones and receipt of government approvals. The Bangka deepwater natural-gas project was progressed during the year under a revised, lower-cost development plan. The project is expected to enter FEED in the second quarter 2010. Under the terms of the PSCs for both projects, the company s 80 percent-owned and operated interest is expected to be reduced to 72 percent in 2010 with the farm-in of an Indonesian company. At the end of 2009, the company had not recognized proved reserves for either of these projects.

Also in the Kutei Basin, first production at the Seturian Field occurred in September 2009, which is providing natural gas to a state-owned refinery. During 2009, evaluation of the 50 percent-owned and operated Sadewa project in the Kutei Basin was suspended.

A drilling campaign continued through 2009 in South Natuna Sea Block B to provide additional supply for long-term natural-gas sales contracts with additional development drilling planned for 2010. The North Belut development project achieved first production in November 2009. The South Belut development project was under review during the year.

A two-well exploration program was conducted in the Central Sumatra Basin in 2009. One commercial discovery was made in the Rokan Block, and a second well in the Siak Block resulted in a dry hole. Chevron s working interests in two exploration blocks in western Papua, West Papua I and West Papua III, are expected to be reduced to 51 percent interests in 2010. Completion of geological studies for those blocks was ongoing at year-end 2009, and 2-D seismic acquisition is planned for the second half 2010.

In West Java, Chevron operates the wholly owned Salak geothermal field with a total power-generation capacity of 377 megawatts. Also in West Java, Chevron holds a 95 percent interest in a power generation company that operates the Darajat geothermal contract area with a total capacity of 259 megawatts. Chevron also operates a 95 percent-owned 300-megawatt cogeneration facility in support of CPI s operation in North Duri, Sumatra.

Partitioned Zone (PZ): Chevron holds a 30-year agreement with the Kingdom of Saudi Arabia to operate on behalf of the Saudi government its 50 percent interest in the petroleum resources of the onshore area of the PZ between Saudi Arabia and Kuwait. Under the agreement, the company has rights to this 50 percent interest in the hydrocarbon resource and pays royalty and taxes on the associated volumes produced until 2039.

During 2009, the company s average net oil-equivalent production was 105,000 barrels per day, composed of 101,000 barrels of crude oil and 21 million cubic feet of natural gas. In June 2009, steam injection was initiated in the second phase of a steamflood pilot project. The pilot is an application of steam injection into a carbonate reservoir and, if successful, could significantly increase heavy oil recovery. The Central Gas Utilization Project was initiated in 2009 to assess alternatives to increase natural-gas utilization and eliminate routine flaring. A final investment decision is expected in 2011. No reserves have been recognized for these projects.

Philippines: The company holds a 45 percent nonoperated working interest in the Malampaya natural-gas field located 50 miles (80 km) offshore Palawan Island. Net oil-equivalent production in 2009 averaged 27,000 barrels per day, composed of 137 million cubic feet of natural gas and 4,000 barrels of condensate. Chevron also develops and produces geothermal resources under an agreement with the Philippine government. Chevron expects to sign a new 25-year contract with the government by the end of 2010 to operate the steam fields, which supply geothermal resources to the 637 megawatt geothermal facilities.

d) Other

Other is composed of Australia, Argentina, Brazil, Colombia, Trinidad and Tobago, Venezuela, Canada, Greenland, Denmark, Faroe Islands, the Netherlands, Norway, Poland and the United Kingdom. Net oil-equivalent production from countries included in this section averaged 484,000 barrels per day during 2009. In addition, the company s share of production from oil sands (for upgrading into synthetic oil) from the Athabasca Oil Sands Project in Canada was 26,000 barrels per day.

Australia: During 2009, the average net oil-equivalent production from Chevron s interests in Australia was 108,000 barrels per day, composed of 35,000 barrels of liquids and 434 million cubic feet of natural gas.

Chevron has a 16.7 percent nonoperated working interest in the North West Shelf (NWS) Venture offshore Western Australia. Daily net production from the project during 2009 averaged 26,000 barrels of crude oil and condensate, 433 million cubic feet of natural gas, and 5,000 barrels of LPG. Approximately 70 percent of the natural gas was sold in the form of LNG to major utilities in Japan, South Korea and China, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market.

The NWS Venture continues to progress two major capital projects that achieved final investment decision in 2008. Fabrication of platform topsides for the North Rankin 2 project commenced in June 2009. The project is designed to recover remaining low-pressure natural gas from the North Rankin and Perseus natural-gas fields to meet gas supply needs and includes necessary tie-ins to, and refurbishment of, the North Rankin A platform. Upon completion, both platforms are

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designed to be operated as a single integrated facility. The project is scheduled to start production in 2013. Proved reserves have been recognized for the project.

The NWS Venture is also advancing plans to extend the period of crude-oil production. The NWS Oil Redevelopment Project is designed to replace the present floating production, storage and offloading vessel and a portion of existing subsea infrastructure that services production from the Cossack, Hermes, Lambert and Wanaea offshore fields. In 2009, work commenced on conversion of the replacement vessel. The project is expected to start-up in early 2011 and extend production past 2020. The concession for the NWS Venture expires in 2034.

On Barrow and Thevenard islands off the northwest coast of Australia, Chevron operates crude-oil producing facilities that had combined net production of 4,000 barrels per day in 2009. Chevron s interests in these operations are 57.1 percent for Barrow and 51.4 percent for Thevenard.

Also off the northwest coast of Australia, Chevron holds significant equity interests in the large natural-gas resource of the Greater Gorgon Area. The company initially held a 50 percent ownership interest across most of the area and is the operator of the Gorgon Project. Chevron and its joint-venture partners are proceeding with the combined development of Gorgon and nearby natural-gas fields as one large-scale project. Environmental approval from the Australian Commonwealth Government was issued in August 2009. In September 2009, the company announced the final investment decision and total estimated project costs for the first phase of development of $37 billion (AU$ 43 billion). The project s scope includes a three-train, 15 million-metric-ton-per-year LNG facility; a carbon sequestration project; and a domestic natural-gas plant. Natural gas for the project is expected to be supplied from the Gorgon and Io/Jansz fields.

In 2009, long-term, binding agreements were finalized with four Asian customers for the delivery of about 4.4 million metric tons per year of LNG from the Gorgon Project. Equity sales agreements with three of the customers reduced Chevron s interest in the project to 47.3 percent at the end of 2009. Nonbinding Heads of Agreements (HOA) for delivery of an additional 2.1 million metric tons per year of LNG were also signed with three additional Asian customers in 2009 and early 2010. Negotiations continue to finalize binding sales agreements, which would bring LNG delivery commitments to a combined total of about 90 percent of Chevron s share of LNG from the project. During 2009, the company recognized proved reserves for the Greater Gorgon Area fields included in the project. First production of natural gas from these fields is expected in 2014. The project s estimated economic life exceeds 40 years from the time of start-up.

Development of the company s majority-owned and operated Wheatstone and Iago fields, located offshore Western Australia, continued with the project entering front-end engineering and design (FEED) in July 2009. Chevron operates the project and plans to supply natural gas to its 75 percent-owned and operated LNG facilities from two 100 percent-owned licenses comprising the majority of the Wheatstone Field and part of the nearby Iago Field. In October 2009, agreements were signed with two companies to join the Wheatstone Project as combined 25 percent LNG facility owners and suppliers of natural gas for the project s first two LNG trains. In December 2009 and January 2010, nonbinding HOAs were signed with two Asian customers to take delivery of 4.9 million tons of LNG per year from the project, representing about 60 percent of the total LNG available from the foundation project. In addition, under these same HOAs the parties would acquire a combined 16.8 percent nonoperated working interest in the Wheatstone Field licenses and a 12.6 percent interest in the foundation natural-gas processing facilities at the final investment decision. At the end of 2009, the company had not recognized proved reserves for this project.

In the Browse Basin, the company continued engineering and survey work on two potential development concepts for the Brecknock, Calliance and Torosa fields. At the end of 2009, proved reserves had not been recognized.

In May 2009, the company announced the successful completion of a well at the Clio prospect to further explore and appraise the 66.7 percent-owned Block WA-205-P. In 2009 and early 2010, the company also announced natural-gas discoveries at the Kentish Knock prospect in the 50 percent-owned Block WA-365-P, the Achilles and Satyr prospects in the 50 percent-owned Block WA-374-P and the Yellowglen prospect in the 50 percent-owned WA-268-P Block. All prospects are Chevron-operated. At the end of 2009, proved reserves had not been recognized.

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Argentina: Chevron holds operated interests in eight concessions in the Neuquen Basin. Working interests range from 18.8 percent to 100 percent. Net oil-equivalent production in 2009 averaged 38,000 barrels per day, composed of 33,000 barrels of crude oil and natural gas liquids and 27 million cubic feet of natural gas. The company also holds a 14 percent interest in the Oleoductos del Valle S.A. pipeline. In 2009, Chevron sold its oil and gas concession in the Austral Basin and its interest in the Confluencia Field in the Neuquen Basin.

Brazil: Chevron holds working interests in three deepwater blocks in the Campos Basin. Chevron also holds a nonoperated working interest in one block in the Santos Basin. Net oil-equivalent production in 2009 averaged 2,000 barrels per day.

The Frade Field, located in the Campos Basin, achieved first oil in June 2009. Chevron is the operator and has a 51.7 percent interest in the field. Additional development drilling is under way, with an estimated maximum total production of 72,000 oil-equivalent barrels per day. The concession that includes the Frade project expires in 2025.

In the partner-operated Campos Basin Block BC-20, two areas 37.5 percent-owned Papa-Terra and 30 percent-owned Maromba were retained for developmentfollowing the end of the exploration phase of this block. The Papa-Terra project progressed through FEED, and a final investment decision was made in January 2010. The project operator estimates total costs of $5.2 billion and expects first production in 2013. The facility is expected to be capable of producing up to 140,000 barrels of crude oil per day. Evaluation of design options for Maromba continued into 2010. At the end of 2009, proved reserves had not been recognized for these projects.

In the Santos Basin, evaluation of investment options continued into 2010 for the 20 percent-owned and partner-operated Atlanta and Oliva fields. At the end of 2009, proved reserves had not been recognized for these fields.

Colombia: The company operates the offshore Chuchupa and the onshore Ballena and Riohacha natural-gas fields as part of the Guajira Association contract. In exchange, Chevron receives 43 percent of the production for the remaining life of each field and a variable production volume from a fixed-fee Build-Operate-Maintain-Transfer agreement based on prior Chuchupa capital contributions. Daily net production averaged 245 million cubic feet of natural gas in 2009.

Trinidad and Tobago: Company interests include 50 percent ownership in three partner-operated blocks in the East Coast Marine Area offshore Trinidad, which includes the Dolphin and Dolphin Deep producing natural-gas fields and the Starfish discovery. Chevron also holds a 50 percent operated interest in the Manatee area of Block 6(d). Net production in 2009 averaged 199 million cubic feet of natural gas per day. Incremental production associated with a new domestic sales agreement commenced at Dolphin in the third quarter 2009.

Venezuela: The company operates in two exploratory blocks offshore Plataforma Deltana, with working interests of 60 percent in Block 2 and 100 percent in Block 3. Chevron also holds a 100 percent operated interest in the Cardon III exploratory block, located north of Lake Maracaibo in the Gulf of Venezuela. Petróleos de Venezuela, S.A. (PDVSA), Venezuela s national crude-oil and natural-gas company, has the option to increase its ownership in each of the three company-operated blocks up to 35 percent upon declaration of commerciality. In February 2010, a Chevron-led consortium was selected to participate in a heavy-oil project composed of three blocks in the Orinoco Oil Belt of eastern Venezuela. The consortium is expected to acquire a 40 percent interest in the project, with PDVSA holding the remaining interest.

The Loran Field in Block 2 is projected to provide the initial supply of natural gas for Delta Caribe LNG (DCLNG) Train 1, Venezuela s first LNG train. A DCLNG framework agreement was signed in 2008, which provides Chevron with

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a 10 percent nonoperated interest in the first train and the associated offshore pipeline. An interim operating agreement governing activities prior to a final investment decision was signed by Chevron and its Train 1 partners in March 2009. In May 2009, the company relinquished part of Block 3 and retained the portion containing the 2005 Macuira natural-gas discovery. An unsuccessful exploration well was drilled in the Cardon III block in 2009. The company plans to continue to evaluate exploration potential in the Cardon III block in 2010. At the end of 2009, proved reserves had not been recognized in these exploratory blocks.

Equity Affiliate Operations: Chevron also holds interests in two affiliates located in western Venezuela and in one affiliate in the Orinoco Belt. Chevron has a 30 percent interest in the Petropiar affiliate that operates the Hamaca heavy-oil production and upgrading project located in Venezuela s Orinoco Belt, a 39.2 percent interest in the Petroboscan affiliate that operates the Boscan Field in the western part of the country, and a 25.2 percent interest in the Petroindependiente affiliate that operates the LL-652 Field in Lake Maracaibo. The company s share of average net oil-equivalent production during 2009 from these operations was 54,000 barrels per day, composed of 51,000 barrels of crude oil and natural gas liquids and 23 million cubic feet of natural gas.

Canada: Company activities in Canada include nonoperated working interests of 26.9 percent in the Hibernia Field and 26.6 percent in the Hebron Field, both offshore eastern Canada, and 20 percent in the Athabasca Oil Sands Project (AOSP) and operated interests of 60 percent in the Ells River Oil Sands Project. Excluding volumes mined at AOSP, average net oil-equivalent production during 2009 was 28,000 barrels per day, composed of 27,000 barrels of crude oil and natural gas liquids and 4 million cubic feet of natural gas.

Substantially all of this production was from the Hibernia Field, where the working interest owners are also pursuing development of the Hibernia Southern Extension (HSE). Development of the HSE nonunitized area was approved by the provincial regulator in 2009, and the first producing well for the project was completed at year-end.

In February 2010, binding agreements were signed with the Government of Newfoundland and Labrador on the development of the HSE unitized area, providing Chevron with a 23.6 percent nonoperated working interest in the unitized area.

For Hebron, agreements were reached during 2008 with the Government of Newfoundland and Labrador that allow development activities to begin. At the end of 2009, proved reserves had not been recognized for this project.

At AOSP, the company s production from oil sands (for upgrading into synthetic oil) averaged 26,000 barrels per day during 2009. The first phase of an expansion project is under way and is expected to increase total production from oil sands by 100,000 barrels per day. The expansion would increase total AOSP design capacity to more than 255,000 barrels per day in late 2010. The projected cost of this expansion is $14.3 billion.

The Ells River project consists of heavy-oil leases of more than 85,000 acres (344 sq km). The area contains significant volumes with potential for recovery by using Steam Assisted Gravity Drainage, an industry-proven technology that employs steam and horizontal drilling to extract the production from oil sands through wells rather than through mining operations. Additional field appraisal activity is not planned in the near-term. At the end of 2009, proved reserves had not been recognized.

The company also holds exploration leases in the Mackenzie Delta and Beaufort Sea region, including a 34 percent nonoperated working interest in the offshore Amauligak discovery. Three exploration wells were drilled on company leases in the Mackenzie Delta region in 2009, and assessment of development concept alternatives for Amauligak continues. The company holds additional exploration acreage in eastern Labrador and the Orphan Basin. In 2009, the company was also successful in acquiring a western Canada lease position to explore for shale gas. At the end of 2009, proved reserves had not been recognized for any of these areas.

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Greenland: Processing of the 2-D seismic survey acquired over License 2007/26 in Block 4 offshore West Greenland in 2008 continued in 2009, and evaluation will commence in the first-half 2010. Chevron has a 29.2 percent nonoperated working interest in this exploration license.

Denmark: Chevron has a 15 percent working interest in the partner-operated Danish Underground Consortium (DUC), which produces crude oil and natural gas from 15 fields in the Danish North Sea. Net oil-equivalent production in 2009 from DUC averaged 55,000 barrels per day, composed of 35,000 barrels of crude oil and 119 million cubic feet of natural gas. DUC development activity in the region includes the ongoing Halfdan Phase IV project, which achieved first production in July 2009.

Faroe Islands: Chevron withdrew from License 008 in 2009, but continues to assess exploration opportunities in the area.

Netherlands: Chevron operates and holds interests ranging from 34.1 percent to 80 percent in eight blocks in the Dutch sector of the North Sea. In 2009, the company s net oil-equivalent production from the five producing blocks was 9,000 barrels per day, composed of 2,000 barrels of crude oil and 41 million cubic feet of natural gas. In 2009 Chevron divested its 48 percent interest in the L11/b license.

Norway: The company holds a 7.6 percent interest in the partner-operated Draugen Field. The company s net production averaged 5,000 barrels of oil-equivalent per day during 2009. In 2009, Chevron was awarded a 40 percent working interest as operator of the exploration license PL 527 in the deepwater portion of the Norwegian Sea. Data acquisition was completed on a 2-D seismic survey, and evaluation is under way.

Poland: In December 2009, Chevron was awarded three five-year exploration licenses in the Zwierzyniec, Kransnik and Frampol concessions, and in February 2010, Chevron acquired the exploration rights to the Grabowiec concession. Chevron has a 100 percent-owned and operated interest in these four concessions to explore for shale gas.

United Kingdom: The company s average net oil-equivalent production in 2009 from 10 offshore fields was 110,000 barrels per day, composed of 73,000 barrels of crude oil and natural gas liquids and 222 million cubic feet of natural gas. Most of the production was from the 85 percent-owned and operated Captain Field, the 23.4 percent-owned and operated Alba Field and the 32.4 percent-owned and jointly operated Britannia Field.

Evaluation of development alternatives continued during 2009 for the 19.4 percent-owned and partner-operated Clair Phase 2 project west of the Shetland Islands. In the 40 percent-owned and operated Rosebank/Lochnagar area northwest of the Shetland Islands, an exploration well in Rosebank North was completed in the second quarter 2009 and an appraisal well in Rosebank/Lochnagar was completed in the third quarter 2009. Also northwest of the Shetland Islands, a three-well exploration and appraisal drilling program was completed in 2009 at the Cambo prospect. Technical studies have commenced to select a preferred development alternative. Additional exploration drilling in the region is expected to occur in the second-half 2010. As of the end of 2009, proved reserves had not been recognized for any of these prospects.

In February 2010, the company sold its 10 percent nonoperated interest in the Laggan/Tormore discovery.

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. In addition, the company also makes third-party purchases and sales of natural gas and natural gas liquids in connection with its trading activities.

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During 2009, U.S. and international sales of natural gas were 5.9 billion and 4.1 billion cubic feet per day, respectively, which includes the company s share of equity affiliates sales. Outside the United States, substantially all of the natural-gas sales from the company s producing interests are from operations in Australia, Bangladesh, Kazakhstan, Indonesia, Latin America, the Philippines, Thailand and the United Kingdom.

U.S. and international sales of natural gas liquids were 161 thousand and 111 thousand barrels per day, respectively, in 2009. Substantially all of the international sales of natural gas liquids are from company operations in Africa, Australia and Indonesia.

Refer to Selected Operating Data, on page FS-10 in Management s Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company s sales volumes of natural gas and natural gas liquids. Refer also to Delivery Commitments on page 8 for information related to the company s delivery commitments for the sale of crude oil and natural gas.

Downstream Refining, Marketing and Transportation

Refining Operations

At the end of 2009, the company had a refining network capable of processing more than 2 million barrels of crude oil per day. Operable capacity at December 31, 2009, and daily refinery inputs for 2007 through 2009 for the company and affiliate refineries were as follows:

Petroleum Refineries: Locations, Capacities and Inputs
(Crude-unit capacities and crude-oil inputs in thousands of barrels per day; includes equity share in affiliates)

		December 31, 2009		Refinery Inputs		
Locations		Number	Operable Capacity	2009	2008	2007
Pascagoula	Mississippi	**1**	**330**	**345**	299	285
El Segundo	California	**1**	**269**	**247**	263	222
Richmond	California	**1**	**243**	**218**	237	192
Kapolei	Hawaii	**1**	**54**	**49**	46	51
Salt Lake City	Utah	**1**	**45**	**40**	38	42
Perth Amboy[1]	New Jersey	**1**	**80**		8	20
Total Consolidated Companies	**United States**	**6**	**1,021**	**899**	891	812
Pembroke	United Kingdom	**1**	**210**	**205**	203	212
Cape Town[2]	South Africa	**1**	**110**	**72**	75	72
Burnaby, B.C.	Canada	**1**	**55**	**49**	36	49
Total Consolidated Companies	**International**	**3**	**375**	**326**	314	333
Affiliates[3]	Various Locations	**8**	**762**	**653**	653	688
Total Including Affiliates	**International**	**11**	**1,137**	**979**	967	1,021
Total Including Affiliates	**Worldwide**	**17**	**2,158**	**1,878**	1,858	1,833

[1] Perth Amboy has been idled since early 2008 and is operated as a terminal.
[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 2010.
[3] Includes 3,000, 6,000 and 35,000 barrels per day of refinery inputs in 2009, 2008 and 2007, respectively, for interests in refineries that were sold during those periods.

Average crude oil distillation capacity utilization during 2009 was 91 percent, compared with 87 percent in 2008, largely a result of improved utilization at the refineries in Mississippi, Canada and Thailand. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 96 percent in 2009, compared with 95 percent in 2008, and cracking and coking capacity utilization averaged 85 percent and 86 percent in 2009 and 2008, respectively. Cracking and coking units are the primary facilities used in fuel refineries to convert heavier feedstocks into gasoline and other light products.

The company s refineries in the United States, the United Kingdom, Canada, South Africa and Australia produce low-sulfur fuels. During 2009, GS Caltex, the company s 50 percent-owned affiliate, continued construction on a new heavy-oil hydrocracker designed to increase high-value product yield and lower feedstock costs at the Yeosu, South Korea complex. Project completion is expected in 2010. Modifications were completed in 2009 that enable the company s 50 percent-owned Singapore Refining Company s refinery to meet regional specifications for clean diesel fuels.

At the Pascagoula Refinery, construction progressed on a continuous catalytic reformer that is expected to improve refinery reliability. Planning continued for a premium base-oil facility at the company s Pascagoula Refinery. The facility is being designed to produce approximately 25,000 barrels per day of premium base oil for use in manufacturing high-performance lubricants, such as motor oils for consumer and commercial applications. At the refinery in El Segundo, California, design, engineering and construction work advanced during 2009 on projects that will reduce feedstock costs and improve yields.

At the beginning of 2009, Chevron held a 5 percent interest in Reliance Petroleum Limited, a company formed by Reliance Industries Limited to construct a new refinery in Jamnagar, India. During the year, the company sold its 5 percent interest to Reliance Industries Limited.

Chevron processes imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 85 percent and 88 percent of Chevron s U.S. refinery inputs in 2009 and 2008, respectively.

Gas-to-Liquids

In Nigeria, Chevron and the Nigerian National Petroleum Corporation are developing a 33,000 barrel-per-day gas-to-liquids facility at Escravos designed to process 325 million cubic feet per day of natural gas supplied from the Phase 3A expansion of the Escravos Gas Plant (EGP). At the end of 2009, construction was under way with two gas-to-liquids reactors and the process modules delivered to the site. Chevron has a 75 percent interest in the plant, which is expected to be operational by 2012. The estimated cost of the plant is $5.9 billion. Refer also to page 14 for a discussion on the EGP Phase 3A expansion.

Marketing Operations

The company markets petroleum products under the principal brands of Chevron, Texaco and Caltex throughout much of the world. The table below identifies the company s and affiliates refined products sales volumes, excluding intercompany sales, for the three years ended December 31, 2009.

Refined Products Sales Volumes
(Thousands of Barrels per Day)

	2009	**2008**	**2007**
United States			
Gasolines	**720**	692	728
Jet Fuel	**254**	274	271
Gas Oils and Kerosene	**226**	229	221
Residual Fuel Oil	**110**	127	138
Other Petroleum Products[1]	**93**	91	99
Total United States	**1,403**	1,413	1,457
International[2]			
Gasolines	**555**	589	581

Jet Fuel	**264**	278	274
Gas Oils and Kerosene	**647**	710	730
Residual Fuel Oil	**209**	257	271
Other Petroleum Products[1]	**176**	182	171
Total International	**1,851**	2,016	2,027
Total Worldwide[2]	**3,254**	3,429	3,484

[1] Principally naphtha, lubricants, asphalt and coke.			
[2] Includes share of equity affiliates sales:	516	512	492

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In the United States, the company markets under the Chevron and Texaco brands. At year-end 2009, the company supplied directly or through retailers and marketers approximately 9,600 Chevron- and Texaco-branded motor vehicle service stations, primarily in the mid-Atlantic, southern and western states. Approximately 500 of these outlets are company-owned or -leased stations. The company plans to discontinue, by mid-2010, sales of Chevron- and Texaco-branded motor fuels in the mid-Atlantic and other eastern states, where the company sold to retail customers through approximately 1,100 stations and to commercial and industrial customers through supply arrangements. Sales in these markets represent approximately 8 percent of the company s total U.S. retail fuels sales volumes. Additionally, in January 2010, the company sold the rights to the Gulf trademark in the United States and its territories that it had previously licensed for use in the U.S. Northeast and Puerto Rico.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 12,400 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. The company markets in the United Kingdom, Ireland, Latin America and the Caribbean using the Texaco brand. In the Asia-Pacific region, southern 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, and in Australia through its 50 percent-owned affiliate, Caltex Australia Limited.

In 2009, the company completed the sale of businesses in Brazil, Haiti, Nigeria, Benin, Cameroon, Republic of the Congo, Côte d Ivoire, Togo, Kenya, Uganda, India, Italy, Peru and Chile. The company retained its lubricants business in Brazil. In addition, the company sold its interest in about 465 individual service-station sites in various other countries, including the United States. The majority of these sites continue to market company-branded gasoline through new supply agreements.

The company also manages other marketing businesses globally. Chevron markets aviation fuel at more than 875 airports. The company also markets an extensive line of lubricant and coolant products under brand names that include Havoline, Delo, Ursa, Meropa and Taro.

Transportation Operations

Pipelines: Chevron owns and operates an extensive network of crude-oil, refined-product, chemicals, natural-gas-liquids (NGL) and natural-gas pipelines and other infrastructure assets 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, 2009

	Net Mileage[1,2]
United States:	
Crude Oil	2,803
Natural Gas	2,255
Petroleum Products[3]	5,768
Total United States	10,826
International:	
Crude Oil	700
Natural Gas	613

Petroleum Products[3]	438
Total International	1,751
Worldwide	12,577

[1] Partially owned pipelines are included at the company s equity percentage of total pipeline mileage.
[2] Excludes gathering lines related to the U.S. and international crude-oil and natural-gas production function.
[3] Includes the company s share of chemical pipelines managed by the 50 percent-owned Chevron Phillips Chemical Company LLC.

During 2009, work progressed on a project that is designed to expand capacity by about 2 billion cubic feet at the Keystone natural-gas storage facility near Midland, Texas, which would bring the total capacity of the facility to nearly 7 billion cubic feet. The project completion is anticipated in the second quarter 2010.

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Work commenced in late 2009 to bring the Cal-Ky Pipeline, which was decommissioned in 2002, back into crude-oil service as a supply line for the Pascagoula Refinery. This crude-oil pipeline is also expected to provide additional outlets for the company s equity production. The pipeline is expected to return to service in 2011. The company is also leading the evaluation and negotiations associated with a 136 mile, 24-inch pipeline from the proposed Jack and St. Malo production facility to Green Canyon 19 in the U.S. Gulf of Mexico. In December 2009, the company sold its interest in the western portion of the Texaco Expanded NGL Distribution System and its 64 percent ownership interest in Southcap Pipeline Company, which included Chevron s 13.4 percent ownership interest in the Capline Pipeline.

Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC) affiliate. CPC operates a crude-oil export pipeline from the Tengiz Field in Kazakhstan to the Russian Black Sea port of Novorossiysk. During 2009, CPC transported an average of approximately 743,000 barrels of crude oil per day, including 597,000 barrels per day from Kazakhstan and 146,000 barrels per day from Russia. In December 2009, partners approved the Expansion Project Implementation Plan, which is expected to increase the pipeline capacity to 1.4 million barrels per day. A final investment decision is expected in late 2010.

The company has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate that owns and operates a pipeline that primarily transports crude oil produced by Azerbaijan International Operating Company (AIOC) (owned 10.3 percent by Chevron) from Baku, Azerbaijan, through Georgia to deepwater port facilities in Ceyhan, Turkey. The BTC pipeline has a crude-oil capacity of 1.2 million barrels per day and transports the majority of the AIOC production. Another production export route for crude oil is the Western Route Export Pipeline, wholly owned by AIOC, with capacity to transport 145,000 barrels per day from Baku, Azerbaijan, to the marine terminal at Supsa, Georgia.

Chevron is the largest shareholder, with a 37 percent interest, in the West African Gas Pipeline Company Limited affiliate, which constructed, owns and operates the 421-mile (678-km) West African Gas Pipeline. The pipeline is designed to supply Nigerian natural gas to customers in Benin, Ghana and Togo for industrial applications and power generation. Compression facilities are expected to be installed in the second quarter 2010 that are designed to increase capacity to 170 million cubic feet per day.

Tankers: All tankers in Chevron s controlled seagoing fleet were utilized during 2009. At any given time during 2009, the company had 42 deep-sea vessels chartered on a voyage basis, or for a period of less than one year. Additionally, the following table summarizes the capacity of the company s controlled fleet.

Controlled Tankers at December 31, 2009[1]

	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	2	0.7	18	27.1
Time-Chartered[2]			17	12.4
Total	5	1.5	36	40.6

1 Consolidated companies only. Excludes tankers chartered on a voyage basis, those with dead-weight tonnage less than 25,000 and those used exclusively for storage.

[2] Tankers chartered for more than one year.

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. The company s U.S.-flagged fleet is 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. As part of its fleet modernization program, the company has two U.S.-flagged tankers scheduled for delivery in 2010 and plans to retire three U.S.-flagged product tankers between 2010 and 2011. The new tankers are expected to bring improved efficiencies to Chevron s U.S.-flagged fleet.

The foreign-flagged vessels are engaged primarily in transporting crude oil from the Middle East, Asia, the Black Sea, Mexico and West Africa to ports in the United States, Europe, Australia and Asia. The company s foreign-flagged vessels also transport refined products to and from various locations worldwide.

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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) Venture in Australia. The NWS project also has two LNG tankers under long-term time charter.

The Federal Oil Pollution Act of 1990 requires the 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. As of the end of 2009, the company s owned and chartered fleet was completely double-hulled. The company is a member of many oil-spill-response cooperatives in areas in which it operates around the world.

Chemicals

Chevron Phillips Chemical Company LLC (CPChem) is equally owned with ConocoPhillips Corporation. At the end of 2009, CPChem owned or had joint-venture interests in 34 manufacturing facilities and five research and technical centers in Belgium, Brazil, China, Colombia, Qatar, Saudi Arabia, Singapore, South Korea and the United States.

During 2009, CPChem completed construction of the 22 million-pounds-per-year Ryton® polyphenylene-sulfide (PPS) manufacturing facility at Borger, Texas. Ryton® PPS is an engineering thermoplastic used in a variety of applications, including automotives and electronics.

Outside the United States, CPChem s 35 percent-owned Saudi Polymers Company continued construction during 2009 on a petrochemical project in Al Jubail, Saudi Arabia. The joint-venture project includes an olefins unit and downstream polyethylene, polypropylene, 1-hexene and polystyrene units. Project completion is expected in 2011.

CPChem continued construction during 2009 on the 49 percent-owned Q-Chem II project, located in both Mesaieed and Ras Laffan, Qatar. The project includes a 350,000-metric-ton-per-year high-density polyethylene plant and a 345,000-metric-ton-per-year normal alpha olefins plant, each utilizing CPChem proprietary technology. These plants are located adjacent to the existing Q-Chem I complex. The Q-Chem II project also includes a separate joint venture to develop a 1.3 million-metric-ton-per-year ethylene cracker in Ras Laffan, in which Q-Chem II owns 54 percent of the capacity rights. Start-up for the ethylene cracker is expected in March 2010, and start-up for the polyethylene and alpha olefins plants is anticipated in the third quarter 2010.

Chevron s Oronite brand lubricant and fuel additives business is a leading developer, manufacturer and marketer of performance additives for lubricating oils and fuels. The company owns and operates facilities in Brazil, France, Japan, the Netherlands, Singapore and the United States and has equity interests in facilities in India and Mexico. Oronite lubricant additives are blended into refined base oil to produce finished lubricant packages used 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. During 2009, production began at the detergent expansion facility in Palau Sakra, Singapore. This additional capacity enhances the company s ability to produce detergent components for applications in marine and automotive engines.

Other Businesses

Mining

Chevron s U.S.-based mining company produces and markets coal and molybdenum. Sales occur in both U.S. and international markets.

The company owns and is the operator of a surface coal mine in Kemmerer, Wyoming, an underground coal mine, North River, in Alabama, and a surface coal mine in McKinley, New Mexico. The company continues to actively market for sale its coal reserves at the North River Mine and elsewhere in Alabama. The decision was made in late 2009 to suspend production at the McKinley Mine, and conduct reclamation activities in 2010. The company also owns a 50 percent interest in Youngs Creek Mining Company LLC, which was formed to develop a coal mine in northern Wyoming. Coal sales from wholly owned mines in 2009 were 10 million tons, down about 1 million tons from 2008.

At year-end 2009, Chevron controlled approximately 193 million tons of proven and probable coal reserves in the United States, including reserves of low-sulfur coal. The company is contractually committed to deliver between 7 million and 9 million tons of coal per year through the end of 2012 and believes it will satisfy these contracts from existing coal reserves.

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In addition to the coal operations, Chevron owns and operates the Questa molybdenum mine in New Mexico. At year-end 2009, Chevron controlled approximately 53 million pounds of proven molybdenum reserves at Questa. Underground development and production plans at Questa were scaled back in 2009 in response to weakening prices for molybdenum.

Power Generation

Chevron s power generation business has interests in 13 power assets with a total operating capacity of more than 3,100 megawatts, primarily through joint ventures in the United States and Asia. Twelve of these are efficient combined-cycle and gas-fired cogeneration facilities that utilize waste heat recovery to produce electricity and support industrial thermal hosts. The thirteenth facility is a wind farm, located in Casper, Wyoming, that began operating in late 2009. The 100 percent-owned and operated Casper Wind Farm is a small-scale wind power facility designed to optimize the efficient use of a decommissioned refinery site for delivery of clean, renewable energy to the local utility provider.

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 page 18 and Research and Technology below.

Chevron Energy Solutions

Chevron Energy Solutions (CES) is a wholly owned subsidiary that designs and implements sustainable solutions for public institutions and businesses to increase energy efficiency and reliability, reduce energy costs, and utilize renewable and alternative-power technologies. Since 2000, CES has developed hundreds of projects that help governments, educational institutions and other customers reduce their energy costs and environmental impact. Major projects completed by CES in 2009 included solar and energy-efficiency installations for the Los Angeles County Metropolitan Transportation Authority and the San Jose Unified School District, which were the largest projects of their kind for a U.S. transit authority and school district.

Research and Technology

The company s energy technology organization supports Chevron s upstream and downstream businesses by providing technology, services and competency development in earth sciences; reservoir and production engineering; drilling and completions; facilities engineering; manufacturing; process technology; catalysis; technical computing; and health, environment and safety. The information technology organization integrates computing, telecommunications, data management, security and network technology to provide a standardized digital infrastructure and enable Chevron s global operations and business processes.

Chevron Technology Ventures (CTV) manages investments and projects in emerging energy technologies and their integration into Chevron s core businesses. As of the end of 2009, CTV continued to explore technologies such as next-generation biofuels and advanced solar.

Chevron s research and development expenses were $603 million, $702 million and $510 million for the years 2009, 2008 and 2007, respectively.

Some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, and ultimate technical or commercial successes are not certain. 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 to 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. Most of the costs of complying with the many laws and regulations pertaining to its operations are, or are expected to become, embedded in the normal costs of conducting business.

In 2009, the company s U.S. capitalized environmental expenditures were approximately $887 million, representing approximately 15 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 relate mostly to air- and water-quality projects and activities at the company s refineries, oil and gas producing facilities, and marketing facilities. For 2010, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $831 million. The future annual capital costs are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Chevron expects an increase in environment-related regulations, including those that are intended to address concerns about greenhouse gas emissions and global climate change, in the countries where it has operations. For instance, under California s Global Warming Solutions Act enacted in 2006, the California Air Resources Board (CARB), charged with implementing the law, has adopted a new low-carbon fuel standard intended to reduce the carbon intensity of transportation fuels, which is expected to apply beginning in 2011. Additionally, CARB is expected to propose regulations to implement the cap and trade emissions regulation provisions of the law, for adoption in the second half 2010. The effect of any such regulation on the company s business is uncertain.

Refer to Management s Discussion and Analysis of Financial Condition and Results of Operations on pages FS-16 through FS-17 for additional information on environmental matters and their impact on Chevron and on the company s 2009 environmental expenditures, remediation provisions and year-end environmental reserves. Refer also to Item 1A. Risk Factors on pages 30 through 32 for a discussion of greenhouse gas regulation and climate change.

Web Site Access to SEC Reports

The company s Internet Web site is at 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 free of charge on the company s Web site soon after such reports are filed with or furnished to the Securities and Exchange Commission (SEC). The reports are also available at the SEC s Web site at www.sec.gov.

Item 1A. Risk Factors

Chevron is a major fully integrated petroleum company with a diversified business portfolio, a 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 the price of crude oil, which can be influenced by general economic conditions and geopolitical risk.

During extended periods of historically low prices for crude oil, the company s upstream earnings and capital and exploratory expenditure programs will be negatively affected. Upstream assets may also become impaired. The impact on downstream earnings is dependent upon the supply and demand for refined products and the associated margins on refined-product sales.

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 or through acquisitions, the company s business will decline.

Creating and maintaining an inventory of projects depends on many factors, including obtaining and renewing rights to explore, develop and produce hydrocarbons; 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, explosions and system failures, any of which could result in suspension of operations or harm to people or the natural environment.

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Chevron s business subjects the company to liability risks from litigation or government action.

The company produces, transports, refines and markets materials with potential toxicity, and it purchases, handles and disposes of other potentially toxic materials in the course of the company s business. Chevron operations also produce byproducts, which may be considered pollutants. Often these operations are conducted through joint ventures over which the company may have limited influence and control. Any of these activities could result in liability arising from private litigation or government action, 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. In addition, to the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to the company s causation of or contribution to the asserted damage or to other mitigating factors.

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 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, 2009, 26 percent of the company s net proved reserves were located in Kazakhstan. The company also has significant interests in Organization of Petroleum Exporting Countries (OPEC)-member countries including Angola, Nigeria and Venezuela and in the Partitioned Zone between Saudi Arabia and Kuwait. Twenty-two percent of the company s net proved reserves, including affiliates, were located in OPEC countries at December 31, 2009.

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

Continued political attention to issues concerning climate change, the role of human activity in it and potential mitigation through regulation could have a material impact on the company s operations and financial results.

International agreements and national or regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. For instance, the Kyoto Protocol, Australia s proposed legislation and California s Global Warming Solutions Act, along with other actual or pending federal, state and provincial regulations, envision a reduction of greenhouse gas emissions through market-based regulatory programs, technology-based or performance-based standards or a combination of them. The company is subject to existing greenhouse gas emissions limits in jurisdictions where such regulation is currently effective, including the European Union and New Zealand.

In December 2009, the U.S. Environmental Protection Agency (EPA) issued a final endangerment finding for greenhouse gases, which specifically found that emissions of six greenhouse gases threaten the public health and welfare and that greenhouse gases from new motor vehicles and engines also contribute to such pollution. These findings do not themselves impose regulatory requirements. However, the agency is currently in the process of promulgating greenhouse gas emission standards for light-duty vehicles and regulations that would require certain stationary source facilities that exceed an as-yet undetermined threshold to obtain permits in advance, which permits could require implementation of so-called best available control technologies. In June 2009, the U.S. House of Representatives approved the American Clean Energy and Security Act. This is known as the Waxman-Markey bill, which includes provisions for a cap-and-trade program, aimed at controlling and reducing emissions of greenhouse gases in the United States. At this time it is not possible to predict whether or when the U.S. Senate may act on climate change legislation, how any bill approved by the Senate will be reconciled with the Waxman-Markey legislation or whether any federal legislation will supersede the EPA s regulatory actions.

These and other greenhouse gas emissions-related laws, policies and regulations, may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary by jurisdiction depending on the laws enacted in each jurisdiction, the company s activities in it and market conditions. The company s exploration and production of crude oil, natural gas and

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various minerals such as coal; the upgrading of production from oil sands into synthetic oil; power generation; the conversion of crude oil and natural gas into refined products; the processing, liquefaction and regasification of natural gas; the transportation of crude oil, natural gas and related products and consumers or customers use of the company s products result in greenhouse gas emissions that could well be regulated. Some of these activities, such as consumers and customers use of the company s products, as well as actions taken by the company s competitors in response to such laws and regulations, are beyond the company s control.

The effect of regulation on the company s financial performance will depend on a number of factors, including, among others, the sectors covered, the greenhouse gas emissions reductions required by law, the extent to which Chevron would be entitled to receive emission allowance allocations or need to purchase compliance instruments on the open market or through auctions, the price and availability of emission allowances and credits, and the impact of legislation or other regulation on the company s ability to recover the costs incurred through the pricing of the company s products. Material price increases or incentives to conserve or use alternative energy sources could reduce demand for products the company currently sells and adversely affect the company s sales volumes, revenues and margins.

Changes in management s estimates and assumptions may have a material impact on the company s consolidated financial statements and financial or operations performance in any given period.

In preparing the company s periodic reports under the Securities Exchange Act of 1934, including its financial statements, Chevron s management is required under applicable rules and regulations to make estimates and assumptions as of a specified date. These estimates and assumptions are based on management s best estimates and experience as of that date and are subject to substantial risk and uncertainty. Materially different results may occur as circumstances change and additional information becomes known. Areas requiring significant estimates and assumptions by management include measurement of benefit obligations for pension and other postretirement benefit plans; estimates of crude oil and natural gas recoverable reserves; accruals for estimated liabilities, including litigation reserves; and impairments to property, plant and equipment. Changes in estimates or assumptions or the information underlying the assumptions, such as changes in the company s business plans, general market conditions or changes in commodity prices, could affect reported amounts of assets, liabilities or expenses.

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 on page 3 under Item 1. Business. Information required by Subpart 1200 of Regulation S-K (Disclosure by Registrants Engaged in Oil and Gas Producing Activities) is also contained in Item 1 and in Tables I through VII on pages FS-64 through FS-77. Note 13, Properties, Plant and Equipment, to the company s financial statements is on page FS-45.

Item 3. Legal Proceedings

Ecuador Chevron is a defendant in a civil lawsuit before the Superior Court of Nueva Loja in Lago Agrio, Ecuador, brought in May 2003 by plaintiffs who claim to be representatives of certain residents of an area where an oil production consortium formerly had operations. The lawsuit alleges damage to the environment from the oil exploration and production operations, and seeks unspecified damages to fund environmental remediation and restoration of the alleged environmental harm, plus a health monitoring program. Until 1992, Texaco Petroleum Company (Texpet), a subsidiary of Texaco Inc., was a minority member of this consortium with Petroecuador, the

Ecuadorian state-owned oil company, as the majority partner; since 1990, the operations have been conducted solely by Petroecuador. At the conclusion of the consortium and following an independent third-party environmental audit of the concession area, Texpet entered into a formal agreement with the Republic of Ecuador and Petroecuador for Texpet to remediate specific sites assigned by the government in proportion to Texpet s ownership share of the consortium. Pursuant to that agreement, Texpet conducted a three-year remediation program at a cost of $40 million. After certifying that the sites were properly remediated, the government granted Texpet and all related corporate entities a full release from any and all environmental liability arising from the consortium operations.

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously given to Texpet by the Republic of Ecuador and Petroecuador. With regard to the facts, the company believes that the evidence confirms that Texpet s remediation was properly conducted and that the remaining environmental damage reflects Petroecuador s failure to timely fulfill its legal obligations and Petroecuador s further conduct since assuming full control over the operations.

In April 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $8 billion, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems, and additional infrastructure for Petroecuador. The engineer s report also asserted that an additional $8.3 billion could be assessed against Chevron for unjust enrichment. The engineer s report is not binding on the court. Chevron also believes that the engineer s work was performed and his report prepared in a manner contrary to law and in violation of the court s orders. Chevron submitted a rebuttal to the report in which it asked the court to strike the report in its entirety. In November 2008, the engineer revised the report and, without additional evidence, recommended an increase in the financial compensation for purported damages to a total of $18.9 billion and an increase in the assessment for purported unjust enrichment to a total of $8.4 billion. Chevron submitted a rebuttal to the revised report, which the court dismissed. In September 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case petitioned to be recused. In late September 2009, the judge was recused, and in October 2009, the full chamber of the provincial court affirmed the recusal, resulting in the appointment of a new judge. Chevron filed motions to annul all of the rulings made by the prior judge, but the new judge denied these motions. The court has completed most of the procedural aspects of the case and could render a judgment at any time. Chevron will continue a vigorous defense of any attempted imposition of liability.

In the event of an adverse judgment, Chevron would expect to pursue its appeals and vigorously defend against enforcement of any such judgment; therefore, the ultimate outcome and any financial effect on Chevron remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this case. Due to the defects associated with the engineer s report, management does not believe the report has any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

Government Proceedings

In November 2008, the California Air Resources Board (CARB) proposed a civil penalty against the company s Sacramento, California, terminal for alleged violations between August and December 2007 of CARB s regulations governing the minimum concentration of additives in gasoline. Due to a computer programming error, the Sacramento terminal s automatic dispensers had failed to inject additive detergent into a gasoline line.

In November 2008, CARB proposed a civil penalty against the company s Richmond, California, refinery for a notice of violation relating to gasoline that was not properly certified as to composition. The company corrected the composition certificates for the gasoline without requiring any change to the composition of the gasoline. In July 2009, CARB issued the refinery a notice of violation relating to an error in gasoline blending that caused the product composition certifications to be in error. The composition certifications were corrected without requiring any change to the gasoline. Discussions with CARB officials relating to all of these matters took place in the fourth quarter 2009 and continue in 2010.

In July 2009, the Hawaii Department of Health (DOH) alleged that Chevron is obligated to pay stipulated civil penalties exceeding $100,000 in conjunction with commitments the company undertook to install and operate certain air pollution abatement equipment at its Hawaii Refinery pursuant to Clean Air Act settlement with the United States Environmental Protection Agency and DOH. The company has disputed many of the allegations.

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

None.

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.

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(2)
Oct. 1 Oct. 31, 2009	516	75.79		
Nov. 1 Nov. 30, 2009	2,380	78.59		
Dec. 1 Dec. 31, 2009				
Total Oct. 1 Dec. 31, 2009	**2,896**	**78.09**		

(1) Pertains to common shares repurchased during the three-month period ended December 31, 2009, 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 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, 2009.

(2) In September 2007, the company authorized stock repurchases of up to $15 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 is authorized for a period of up to three years, expiring in September 2010, and may be discontinued at any time. As of December 31, 2009, 118,996,749 shares had been acquired under this program for $10.1 billion. No share repurchases occurred in 2009.

Item 6. Selected Financial Data

The selected financial data for years 2005 through 2009 are presented on page FS-63.

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

The index to Management s Discussion and Analysis of Financial Condition and Results of Operations, Consolidated Financial Statements and Supplementary Data is presented on page FS-1.

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-14 and in Note 10 to the Consolidated Financial Statements, Financial and Derivative Instruments, beginning on page FS-39.

Item 8. Financial Statements and Supplementary Data

The index to Management s Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a)
Evaluation of Disclosure Controls and Procedures

The company s management has evaluated, with the participation of the Chief Executive Officer and Chief Financial Officer, the effectiveness of the company s disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the company s disclosure controls and procedures were effective as of December 31, 2009.

(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 Rule 13a-15(f). The company s management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company s 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 internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the company s internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page FS-26.

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

During the quarter ended December 31, 2009, there were no changes in the company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company s internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 25, 2010

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 members of the Executive Committee.

Name and Age		Current and Prior Positions (up to five years)	Current Areas of Responsibility
J.S. Watson	53	Chairman of the Board and Chief Executive Officer (since 2010) Vice Chairman of the Board (2009) Executive Vice President (2008 to 2009) Vice President and President of Chevron International Exploration and Production Company (2005 through 2007)	Chief Executive Officer
G.L. Kirkland	59	Vice Chairman of the Board and Executive Vice President (since 2010) Executive Vice President (2005 through 2009)	Worldwide Exploration and Production Activities and Global Gas Activities, including Natural Gas Trading
J.E. Bethancourt	58	Executive Vice President (since 2003)	Technology; Mining; Health, Environment and Safety; Project Resources Company; Procurement
C.A. James	55	Executive Vice President (since 2009) Vice President and General Counsel (2002 to 2009)	Law; Human Resources
M.K. Wirth	49	Executive Vice President (since 2006) President of Global Supply and Trading (2004 to 2006)	Global Refining, Marketing, Lubricants, and Supply and Trading, excluding Natural Gas Trading; Chemicals
P.E. Yarrington	53	Vice President and Chief Financial Officer (since 2009) Vice President and Treasurer (2007 through 2008) Vice President, Policy, Government and Public Affairs (2002 to 2007)	Finance
R.H. Pate	47	Vice President and General Counsel (since 2009) Partner and Head of Global Competition Practice of Hunton & Williams LLP (2005 to 2009)	Law

The information about directors required by Item 401(a) and (e) of Regulation S-K and contained under the heading Election of Directors in the Notice of the 2010 Annual Meeting and 2010 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 2010 Annual Meeting of Stockholders (the 2010 Proxy Statement), is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 405 of Regulation S-K and contained under the heading Stock Ownership Information Section 16(a) Beneficial Ownership Reporting Compliance in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 406 of Regulation S-K and contained under the heading Board Operations Business Conduct and Ethics Code in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(d)(4) and (5) of Regulation S-K and contained under the heading Board Operations Board Committee Membership and Functions in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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

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Item 11. Executive Compensation

The information required by Item 402 of Regulation S-K and contained under the headings Executive Compensation and Director Compensation in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(4) of Regulation S-K and contained under the heading Board Operations Board Committee Membership and Functions in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(5) of Regulation S-K and contained under the heading Board Operations Management Compensation Committee Report in the 2010 Proxy Statement is incorporated herein by reference into 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 2010 Proxy Statement shall not be deemed filed for purposes of Section 18 of the Exchange Act nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

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

The information required by Item 403 of Regulation S-K and contained under the heading Stock Ownership Information Security Ownership of Certain Beneficial Owners and Management in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 201(d) of Regulation S-K and contained under the heading Equity Compensation Plan Information in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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

The information required by Item 404 of Regulation S-K and contained under the heading Board Operations Transactions with Related Persons in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(a) of Regulation S-K and contained under the heading Election of Directors Independence of Directors in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services

The information required by Item 9(e) of Schedule 14A and contained under the heading Proposal to Ratify the Independent Registered Public Accounting Firm in the 2010 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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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:

Schedule Of Valuation And Qualifying Accounts Disclosure

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS
Millions of Dollars

	Year Ended December 31		
	2009	**2008**	**2007**
Employee Termination Benefits:			
Balance at January 1	**$ 44**	$ 117	$ 28
(Deductions from) additions to expense	**(12)**	(13)	106
Payments	**(19)**	(60)	(17)
Balance at December 31	**$ 13**	$ 44	$ 117
Allowance for Doubtful Accounts:			
Balance at January 1	**$ 275**	$ 200	$ 217
Additions to expense	**92**	105	29
Bad debt write-offs	**(74)**	(30)	(46)
Balance at December 31	**$ 293**	$ 275	$ 200

Deferred Income Tax Valuation Allowance:*

Balance at January 1	**$ 7,535**	$ 5,949	$ 4,391
Additions to deferred income tax expense	**2,204**	2,599	1,894
Reduction of deferred income tax expense	**(1,818)**	(1,013)	(336)
Balance at December 31	**$ 7,921**	$ 7,535	$ 5,949

* See also Note 15 to the Consolidated Financial Statements beginning on page FS-46.

(3) Exhibits:

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

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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 25th day of February, 2010.

Chevron Corporation

By /s/ John S. Watson
John S. Watson, 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 25th day of February, 2010.

Principal Executive Officers (and Directors)

/s/John S. Watson
John S. Watson, Chairman of the Board and Chief Executive Officer

/s/George L. Kirkland
George L. Kirkland, Vice Chairman of the Board

Principal Financial Officer

/s/Patricia E. Yarrington
Patricia E. Yarrington, 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

Enrique Hernandez, Jr.*
Enrique Hernandez, Jr.

Franklyn G. Jenifer*
Franklyn G. Jenifer

Sam Nunn*
Sam Nunn

Donald B. Rice*
Donald B. Rice

	Kevin W. Sharer* Kevin W. Sharer
*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

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Management s Discussion and Analysis of
Financial Condition and Results of Operations

Key Financial Results

Millions of dollars, except per-share amounts	**2009**	2008	2007
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
Basic	**$ 5.26**	$ 11.74	$ 8.83
Diluted	**$ 5.24**	$ 11.67	$ 8.77
Dividends	**$ 2.66**	$ 2.53	$ 2.26
Sales and Other Operating Revenues	**$ 167,402**	$ 264,958	$ 214,091
Return on:			
Capital Employed	**10.6%**	26.6%	23.1%
Stockholders Equity	**11.7%**	29.2%	25.6%

Earnings by Major Operating Area

Millions of dollars	**2009**	2008	2007
Upstream Exploration and Production			
United States	**$ 2,216**	$ 7,126	$ 4,532
International	**8,215**	14,584	10,284
Total Upstream	**10,431**	21,710	14,816
Downstream Refining, Marketing and Transportation			
United States	**(273)**	1,369	966
International	**838**	2,060	2,536
Total Downstream	**565**	3,429	3,502
Chemicals	**409**	182	396
All Other	**(922)**	(1,390)	(26)
Net Income Attributable to Chevron Corporation[1],[2]	**$ 10,483**	$ 23,931	$ 18,688
[1] Includes foreign currency effects:	**$ (744)**	$ 862	$ (352)

[2] Also referred to as earnings in the discussions that follow.

Refer to the Results of Operations section beginning on page FS-6 for a discussion of financial results by major operating area for the three years ended December 31, 2009.

Business Environment and Outlook

Chevron is a global energy company with significant business activities in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Zone between Saudi Arabia and Kuwait, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, the United States, Venezuela and Vietnam.

Earnings of the company 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 or unusual in nature.

The company s operations, especially upstream, can also be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. Civil unrest, acts of violence or strained relations between a government and the company or other governments may impact the company s operations or investments. Those developments have at times significantly affected the company s operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer attractive 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. From time to time, certain governments have sought to renegotiate contracts or impose additional costs on the company. 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.

The company also continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company s financial performance and growth. Refer to the Results of Operations section beginning on FS-6 for discussions of net gains on asset sales during 2009. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

In recent years, Chevron and the oil and gas industry at large experienced an increase in certain costs that exceeded the general trend of inflation in many areas of the world. This increase in costs affected the company s operating expenses and capital programs for all business segments, but particularly for upstream. Softening of these cost pressures started in late 2008 and continued through most of 2009. Costs began to level out in the fourth quarter 2009. The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. (Refer to the Upstream section below for a discussion of the trend in crude-oil prices.)

The company continues to closely monitor developments in the financial and credit markets, the level of worldwide economic activity and the implications to the company of movements in prices for crude oil and natural gas. Management is taking these developments into account in the conduct of daily operations and for business planning. The company remains confident of its underlying financial strength to address potential challenges presented in this environment. (Refer also to the Liquidity and Capital Resources section beginning on FS-11.)

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 or fears thereof 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 businesses. Besides the impact of the fluctuation in prices 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 of contracts and changes in tax laws and regulations.

Price levels for capital and exploratory costs and operating expenses associated with the 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 commodity prices and prices charged by the industry s material and service providers, which can be affected by the volatility of the industry s own supply-and-demand conditions for such materials and services. Capital and exploratory expenditures and operating expenses also can be affected by damage to production facilities caused by severe weather or civil unrest.

The chart at left shows the trend in benchmark prices for West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. Industry price levels for crude oil continued to be volatile during 2009, with prices for WTI ranging from $34 to $81 per barrel. The WTI price averaged $62 per barrel for the full-year 2009, compared to $100 in 2008. The decline in prices from 2008 was largely associated with a weakening in global economic conditions and a reduction in the demand for crude oil and petroleum products. As of mid-February 2010, the WTI price was about $77.

A differential in crude-oil prices exists between high-quality (high-gravity, low-sulfur) crudes and those of lower-quality
(low-gravity, high-sulfur). The amount of the differential in any period is associated with the supply of heavy crude available versus the demand that is a function of the number of refineries that are able to process this lower-quality feedstock into light products
(motor gasoline, jet fuel, aviation gasoline and diesel fuel). The differential remained narrow through 2009 as production declines in the industry have been mainly for lower-quality crudes.

Chevron produces or shares in the production of heavy crude oil in California, Chad, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page FS-10 for the company s average U.S. and international crude-oil realizations.)

In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. In the United States, prices at Henry Hub averaged about $3.80 per thousand cubic feet (MCF) during 2009, compared with almost $9 during 2008. At December 31, 2009, and as of mid-February 2010, the Henry Hub spot price was about $5.70 and $5.50 per MCF, respectively. Fluctuations in the price for natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America and the level of inventory in underground storage. Weaker U.S. demand in 2009 was associated with the economic slowdown.

Certain international natural-gas markets in which the company operates have different supply, demand and regulatory circumstances, which historically have resulted in lower average sales prices for the company s production of natural gas in these locations. Chevron continues to invest in long-term projects in these locations to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets where greater demand results in higher prices. International natural-gas realizations averaged about $4.00 per MCF during 2009, compared with about $5.20 per MCF during 2008. Unlike prior years, these realizations compared favorably with those in the United States during 2009, primarily as a result of the deterioration of U.S. supply-and-demand conditions resulting from the economic slowdown. (See page FS-10 for the company s average natural gas realizations for the U.S. and international regions.)

The company s worldwide net oil-equivalent production in 2009 averaged 2.70 million barrels per day. About one-fifth of the company s net oil-equivalent production in 2009 occurred in the OPEC-member countries of Angola, Nigeria and Venezuela and in the Partitioned Zone between Saudi Arabia and Kuwait. For the year 2009, the company s net oil production was reduced by an average of 20,000 barrels per day due to quotas imposed by OPEC. All of the imposed curtailments took place during the first half of the year. At the December 2009 meeting, members of OPEC supported maintaining production quotas in effect since December 2008.

The company estimates that oil-equivalent production in 2010 will average approximately 2.73 million barrels per day. This estimate is subject to many factors and uncertainties, including additional quotas that may be imposed by OPEC, price effects 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, delays in project startups, fluctuations in demand for natural gas in various markets, weather conditions that may shut in production, civil unrest, changing geopolitics, or other disruptions to operations. The outlook for future production levels is also 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. Investments in upstream projects generally begin well in advance of the start of the associated crude-oil and natural-gas production. A significant majority of Chevron s upstream investment is made outside the United States.

Refer to the Results of Operations section on pages FS-6 through FS-7 for additional discussion of the company s upstream business.

Refer to Table V beginning on page FS-69 for a tabulation of the company s proved net oil and gas reserves by geographic area, at the beginning of 2007 and each year-end from 2007 through 2009, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2009.

Downstream Earnings for the downstream segment are closely tied to margins on the refining and marketing of products that include gasoline, diesel, jet fuel, lubricants, fuel oil and feedstocks for chemical manufacturing. Industry margins are sometimes volatile and can be affected by the global and regional supply-and-demand balance for refined products and by changes in the price of crude oil used for refinery feedstock. Industry margins can also be influenced by refined-product inventory levels, geopolitical events, cost of materials and services, refinery maintenance programs and disruptions at refineries resulting from unplanned outages due to severe weather, fires or other operational events.

Other factors affecting profitability for downstream operations include the reliability and efficiency of the company s refining and marketing network and the effectiveness of the crude-oil and product-supply functions. Profitability can also be affected by the volatility of tanker-charter rates for the company s shipping operations, which are driven by the industry s demand for crude-oil and product tankers. Other factors 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 most significant marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia, southern Africa and the United Kingdom. Chevron operates or has significant ownership interests in refineries in each of these areas except Latin America. The company completed sales of marketing businesses during 2009 in certain countries in Latin America and Africa. The company plans to discontinue, by mid-2010, sales of Chevron- and Texaco-branded motor fuels in the mid-Atlantic and other eastern states, where the company sold to retail customers through approximately 1,100 stations and to commercial and industrial customers through supply arrangements. Sales in these markets represent approximately 8 percent of the company s total U.S. retail fuel sales volumes. Additionally, in January 2010, the company sold the rights to the Gulf trademark in the United States and its territories that it had previously licensed for use in the U.S. Northeast and Puerto Rico.

The company s refining and marketing margins in 2009 were generally weak due to challenging industry conditions, including a sharp drop in global demand reflecting the economic slowdown, excess refined-product supplies and surplus refining capacity. Given these conditions, in January 2010 the company announced to its employees that high-level evaluations of Chevron s refining and marketing organizations had been completed. These evaluations concluded that the company s downstream organization should be restructured to improve operating efficiency and achieve sustained improvement in financial performance. Details of the restructuring will be further developed over the next three to six months and may include exits from additional markets, dispositions of assets, reductions in the number of employees and other actions, which may result in gains or losses in future periods.

Refer to the Results of Operations section on pages FS-7 and FS-8 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 the Results of Operations section on page FS-8 for additional discussion of chemical earnings.

Operating Developments

Key operating developments and other events during 2009 and early 2010 included the following:

Upstream

Angola Production began at the 39.2 percent-owned and operated Mafumeira Norte offshore project in Block 0 and the 31 percent-owned and operated deepwater Tombua-Landana project in Block 14. Mafumeira Norte is expected to reach maximum total daily production of 42,000 barrels of crude oil in the third quarter 2010, and the Tombua-Landana project is expected to reach its maximum total production of approximately 100,000 barrels of crude oil per day in 2011. The company also discovered crude oil offshore in the 39.2 percent-owned and operated Block 0 concession, extending a trend of earlier discoveries in the Greater Vanza/Longui Area.

Australia The company and its partners reached final investment decision to proceed with the development of the Gorgon Project, located offshore Western Australia, in which Chevron has a 47.3 percent-owned and operated interest as of December 31, 2009. In addition, the company finalized long-term sales agreements for delivery of liquefied natural gas (LNG) from the Gorgon Project with four Asian customers, three of which also acquired an ownership interest in the project. Nonbinding Heads of Agreement (HOAs) with three additional Asian customers were also signed in late 2009 and early 2010 for delivery of LNG from the project. Negotiations continue to finalize binding sales agreements, which would bring LNG delivery commitments to a combined total of about 90 percent of Chevron s share of LNG from the project.

The company awarded front-end engineering and design contracts for the first phase of the Wheatstone natural gas project, also located offshore northwest Australia. The 75 percent-owned and operated facilities will have LNG processing capacity of 8.6 million metric tons per year and a co-located domestic natural-gas plant. The facilities will support development of Chevron s interests in the Wheatstone Field and nearby Iago Field. Agreements were signed with two companies to join the Wheatstone Project as combined 25 percent owners and suppliers of natural gas for the project s first two LNG trains. In addition, nonbinding HOAs were signed with two Asian customers to take delivery of 4.9 million metric tons per year of LNG from the project (about 60 percent of the total LNG available from the foundation project) and to acquire a 16.8 percent equity interest in the Wheatstone Field licenses and a 12.6 percent interest in the foundation natural gas processing facilities at the final investment decision.

In May 2009 the company announced the successful completion of a well at the Clio prospect to further explore and appraise the 66.7 percent-owned Block WA-205-P. In 2009 and early 2010, the company also announced natural-gas discoveries at the Kentish Knock prospect in the 50 percent-owned Block WA-365-P, the Achilles and Satyr prospects in the 50 percent-owned Block WA-374-P and the

Yellowglen prospect in the 50 percent-owned WA-268-P Block. All prospects are Chevron-operated. Proved reserves have not been recognized for these discoveries.

Brazil Production started at the 51.7 percent-owned and operated deepwater Frade Field, which is projected to attain maximum total production of 72,000 oil-equivalent barrels per day in 2011. Also, in early 2010 a final investment decision was reached to develop the 37.5 percent-owned, partner-operated Papa-Terra Field, where first production is expected in 2013. Project facilities are designed with a capacity to handle up to 140,000 barrels of crude oil per day.

Republic of the Congo Crude oil was discovered in the northern portion of the 31.5 percent-owned, partner-operated Moho-Bilondo deepwater permit area. This discovery follows two others made in 2007 in the same permit area.

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Venezuela In February 2010, a Chevron-led consortium was named the operator of a heavy-oil project composed of three blocks in the Orinoco Oil Belt of eastern Venezuela.

United States First oil was achieved at the 58 percent-owned and operated Tahiti Field in the deepwater Gulf of Mexico, reaching maximum total production of 135,000 barrels of oil-equivalent per day. The company also discovered crude oil at the Chevron-operated and 55 percent-owned Buckskin prospect in the deepwater Gulf of Mexico. The first appraisal well is scheduled to begin drilling in the second quarter 2010.

Downstream

The company sold businesses during 2009 in Brazil, Haiti, Nigeria, Benin, Cameroon, Republic of the Congo, Côte d Ivoire, Togo, Kenya, Uganda, India, Italy, Peru and Chile.

Other

Common Stock Dividends The quarterly common stock dividend increased by 4.6 percent in July 2009, to $0.68 per share. 2009 was the 22nd consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program The company did not acquire any shares during 2009 under its $15 billion repurchase program, which began in 2007 and expires in September 2010. As of December 31, 2009, 119 million common shares had been acquired under this program for $10.1 billion.

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, the various companies and departments that are managed at the corporate level, and the company s investment in Dynegy prior to its sale in May 2007. Earnings are also presented for the U.S. and international geographic areas of the upstream and downstream business segments. (Refer to Note 11, beginning on page FS-40, for a discussion of the company s reportable segments, as defined in accounting standards for segment reporting (Accounting Standards Codification (ASC) 280)). 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	**2009**	2008	2007
Earnings	**$ 2,216**	$ 7,126	$ 4,532

U.S upstream earnings of $2.2 billion in 2009 decreased $4.9 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by about $5.2 billion between periods, and gains on asset sales declined by approximately $900 million. Partially offsetting these effects was a benefit of about $1.3 billion resulting from an increase in net oil-equivalent production. An approximate $600 million benefit to income from lower operating expenses was more than offset by higher depreciation expense. The benefit from lower operating expenses was largely associated with absence of charges for damages related to the 2008 hurricanes in the Gulf of Mexico.

U.S upstream earnings of $7.1 billion in 2008 increased $2.6 billion from 2007. Higher average prices for crude oil and natural gas increased earnings by $3.1 billion between periods. Also contributing to the higher earnings were gains of approximately $1 billion on asset sales, including a $600 million gain on an asset-exchange transaction. Partially offsetting these benefits were adverse effects of about $1.6 billion associated with lower oil-equivalent production and higher operating expenses, which included approximately $400 million of expenses resulting from damage to facilities in the Gulf of Mexico caused by hurricanes.

The company s average realization for crude oil and natural gas liquids in 2009 was $54.36 per barrel, compared with $88.43 in 2008 and $63.16 in 2007. The average natural-gas realization was $3.73 per thousand cubic feet in 2009, compared with $7.90 and $6.12 in 2008 and 2007, respectively.

Net oil-equivalent production in 2009 averaged 717,000 barrels per day, up 6.9 percent from 2008 and down 3.5 percent from 2007. The increase between 2008 and 2009 was mainly due to the start-up of the Blind Faith Field in late 2008 and the Tahiti Field in the second quarter 2009. The decrease between 2007 and 2008 was mainly due to normal field declines and the adverse impact of the hurricanes. The net liquids component of oil-equivalent production for 2009 averaged 484,000 barrels per day, up approximately 15 percent from 2008 and 5 percent compared with 2007. Net natural-gas production averaged 1.4 billion cubic feet per day in 2009, down approximately 7 percent from 2008 and about 18 percent from 2007.

Refer to the Selected Operating Data table on page FS-10 for the three-year comparative production volumes in the United States.

International Upstream Exploration and Production

Millions of dollars	**2009**	2008	2007
Earnings*	**$ 8,215**	$ 14,584	$ 10,284
*Includes foreign currency effects:	**$ (571)**	$ 873	$ (417)

International upstream earnings of $8.2 billion in 2009 decreased $6.4 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by $7.0 billion, while foreign-currency effects and higher operating and depreciation expenses decreased income by a total of $2.2 billion. Partially offsetting these items were benefits of $2.3 billion resulting from an increase in sales volumes of crude oil and about $500 million associated with asset sales and tax items related to the Gorgon Project in Australia.

Earnings of $14.6 billion in 2008 increased $4.3 billion from 2007. Higher prices for crude oil and natural gas increased earnings by $4.9 billion. Partially offsetting the benefit of higher prices was an impact of about $1.8 billion associated with a reduction of crude-oil sales volumes due to timing of certain cargo liftings and higher depreciation and operating expenses. Foreign-currency effects benefited earnings by $873 million in 2008, compared with a reduction to earnings of $417 million in 2007.

The company s average realization for crude oil and natural gas liquids in 2009 was $55.97 per barrel, compared with $86.51 in 2008 and $65.01 in 2007. The average natural-gas realization was $4.01 per thousand cubic feet in 2009, compared with $5.19 and $3.90 in 2008 and 2007, respectively.

Net oil-equivalent production of 1.99 million barrels per day in 2009 increased about 7 percent and 6 percent from 2008 and 2007, respectively. The volumes for each year included production from oil sands in Canada. Absent the impact of prices on certain production-sharing and variable-royalty agreements, net oil-equivalent production increased 4 percent in 2009 and 3 percent in 2008, when compared with prior years production.

The net liquids component of oil-equivalent production was 1.4 million barrels per day in 2009, an increase of approximately 11 percent from 2008 and 5 percent from 2007. Net natural-gas production of 3.6 billion cubic feet per day in 2009 was down 1 percent and up 8 percent from 2008 and 2007, respectively.

Refer to the Selected Operating Data table, on page FS-10, for the three-year comparative of international production volumes.

U.S. Downstream Refining, Marketing and Transportation

Millions of dollars	**2009**	2008	2007
Earnings	**$ (273)**	$ 1,369	$ 966

U.S downstream operations lost $273 million in 2009, an earnings decrease of approximately $1.6 billion from 2008. A decline in refined product margins resulted in a negative earnings variance of $1.7 billion. Partially offsetting were lower operating expenses, which benefited earnings by $300 million. Earnings of $1.4 billion in 2008 increased about $400 million from 2007 due mainly to improved
margins on the sale of refined products and gains on derivative commodity instruments. Operating expenses were higher between 2007 and 2008.

Sales volumes of refined products were 1.40 million barrels per day in 2009, a decrease of 1 percent from 2008. The decline was associated with reduced demand for jet fuel and fuel oil, principally associated with the downturn in the U.S. economy. Sales volumes of refined products were 1.41 million barrels per day in 2008, a decrease of 3 percent from 2007. Branded gasoline sales volumes of 617,000 barrels per day in 2009 were up about 3 percent and down 2 percent from 2008 and 2007, respectively.

Refer to the Selected Operating Data table on page FS-10 for a three-year comparison of sales volumes of gasoline and other refined products and refinery-input volumes.

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International Downstream Refining, Marketing and Transportation

Millions of dollars	**2009**	2008	2007
Earnings*	**$ 838**	$ 2,060	$ 2,536
*Includes foreign currency effects:	**$ (213)**	$ 193	$ 62

International downstream earnings of $838 million in 2009 decreased about $1.2 billion from 2008. An approximate $2.6 billion decline between periods was associated with weaker margins on the sale of gasoline and other refined products and the absence of gains recorded in 2008 on commodity derivative instruments. Foreign-currency effects produced a negative variance of $400 million. Partially offsetting these items was a $1.0 billion benefit from lower operating expenses associated mainly with contract labor, professional services and transportation costs and about a $550 million increase in gains on asset sales primarily in certain countries in Latin America and Africa. Earnings in 2008 of $2.1 billion decreased nearly $500 million from 2007. Earnings in 2007 included gains of approximately $1 billion on the sale of assets, which included marketing assets in the Benelux region of Europe and an interest in a refinery. The $500 million other improvement between years was associated primarily with a benefit from gains on derivative commodity instruments that was only partially offset by the impact of lower margins from sales of refined products. Foreign-currency effects increased earnings by $193 million in 2008, compared with $62 million in 2007.

Refined-product sales volumes were 1.85 million barrels per day in 2009, about 8 percent lower than in 2008 due mainly to the effects of asset sales and lower demand. Refined-product sales volumes were 2.02 million barrels per day in 2008, about level with 2007.

Refer to the Selected Operating Data table, on page FS-10, for a three-year comparison of sales volumes of gasoline and other refined products and refinery-input volumes.

Chemicals

Millions of dollars	**2009**	2008	2007
Earnings*	**$ 409**	$ 182	$ 396
*Includes foreign currency effects:	**$ 15**	$ (18)	$ (3)

The chemicals segment includes the company s Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem). In 2009, earnings were $409 million, compared with $182 million and $396 million in 2008 and 2007, respectively. For CPChem, the earnings improvement from 2008 to 2009 reflected lower utility and manufacturing costs as well as the absence of an impairment recorded in 2008. These benefits were partially offset by lower margins on the sale of commodity chemicals. For Oronite, earnings increased in 2009 due to higher margins on sales of lubricant and fuel additives, the effect of which more than offset the impact of lower sales volumes. In 2008, segment earnings were $182 million, compared with $396 million in 2007. Earnings declined in 2008 due to lower sales volumes of commodity chemicals by CPChem. Higher expenses for planned maintenance activities also contributed to the earnings decline. Earnings also declined for Oronite due to lower volumes and higher operating expenses.

All Other

Millions of dollars	**2009**	2008	2007
Net Charges*	**$ (922)**	$ (1,390)	$ (26)
*Includes foreign currency effects:	$ **25**	$ (186)	$ 6

All Other includes 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, and the company s interest in Dynegy, Inc. prior to its sale in May 2007.

Net charges in 2009 decreased $468 million from 2008 due to lower provisions for environmental remediation at sites

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that previously had been closed or sold, favorable foreign-currency effects and lower expenses for employee compensation and benefits. Net charges in 2008 increased $1.4 billion from 2007. Results in 2008 included net unfavorable corporate tax items and increased costs of environmental remediation. Foreign-currency effects also contributed to the increase in net charges from 2007 to 2008. Results in 2007 included a $680 million gain on the sale of the company s investment in Dynegy common stock and a loss of approximately $175 million associated with the early redemption of Texaco Capital Inc. bonds.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2009**	2008	2007
Sales and other operating revenues	**$ 167,402**	$ 264,958	$ 214,091

Sales and other operating revenues decreased in 2009, due mainly to lower prices for crude oil, natural gas and refined products. Higher 2008 prices resulted in increased revenues compared with 2007.

Millions of dollars	**2009**	2008	2007
Income from equity affiliates	**$ 3,316**	$ 5,366	$ 4,144

Income from equity affiliates decreased in 2009 from 2008. Upstream-related affiliate income declined about $1.3 billion mainly due to lower earnings for Tengizchevroil (TCO) in Kazakhstan as a result of lower prices for crude oil. Downstream-related affiliate earnings were lower by approximately $1.0 billion primarily due to weaker margins and an unfavorable swing in foreign-currency effects. Income from equity affiliates increased in 2008 from 2007 largely due to improved upstream-related earnings at TCO as a result of higher prices for crude oil. Refer to Note 12, beginning on page FS-43, for a discussion of Chevron s investments in affiliated companies.

Millions of dollars	**2009**	2008	2007
Other income	**$ 918**	$ 2,681	$ 2,669

Other income of $918 million in 2009 included gains of approximately $1.3 billion on asset sales. Other income of $2.7 billion in 2008 and 2007 included net gains from asset sales of $1.3 billion and $1.7 billion, respectively. Interest income was approximately $95 million in 2009, $340 million in 2008 and $600 million in 2007. Foreign-currency effects reduced other income by $466 million in 2009 while increasing other income by $355 million in 2008 and reducing other income by $352 million in 2007. In addition, other income in 2008 included approximately $700 million in favorable settlements and other items.

Millions of dollars	**2009**	2008	2007
Purchased crude oil and products	**$ 99,653**	$ 171,397	$ 133,309

Crude oil and product purchases in 2009 decreased $71.7 billion from 2008 due to lower prices for crude oil, natural gas and refined products. Crude oil and product purchases in 2008 increased $38.1 billion from 2007 due to higher prices for crude oil, natural gas and refined products.

Millions of dollars	**2009**	2008	2007

Operating, selling, general and administrative expenses	**$ 22,384**	$ 26,551	$ 22,858

Operating, selling, general and administrative expenses in 2009 decreased approximately $4.2 billion from 2008 primarily due to $1.4 billion of lower fuel and transportation expenses; $800 million of decreased costs for contract labor and professional services; absence of uninsured 2008 hurricane-related charges of $700 million; a decrease of about $500 million for environmental remediation activities; $200 million of lower costs for materials; and $600 million for other items. Total expenses for 2008 were about $3.7 billion higher than 2007 primarily due to $1.2 billion of higher costs for employee and contract labor and professional services; $600 million of increased transportation expenses; $700 million of uninsured losses associated with hurricanes in the Gulf of Mexico in 2008; an increase of about $300 million for environmental remediation activities; $200 million from higher material expenses; and $700 million from increases for other items.

Millions of dollars	**2009**	2008	2007
Exploration expense	**$ 1,342**	$ 1,169	$ 1,323

Exploration expenses in 2009 increased from 2008 due mainly to higher amounts for well write-offs in the United States and international operations. Expenses in 2008 declined from 2007 mainly due to lower amounts for well write-offs for operations in the United States.

Millions of dollars	**2009**	2008	2007
Depreciation, depletion and amortization	**$ 12,110**	$ 9,528	$ 8,708

Depreciation, depletion and amortization expenses increased in 2009 from 2008 due to incremental production related to start-ups for upstream projects in the United States and Africa and higher depreciation rates for certain other oil and gas producing fields. The increase in 2008 from 2007 was largely due to higher depreciation rates for certain crude-oil and natural-gas producing fields, reflecting completion of higher-cost development projects and asset-retirement obligations.

Millions of dollars	**2009**	2008	2007
Taxes other than on income	**$ 17,591**	$ 21,303	$ 22,266

Taxes other than on income decreased in 2009 from 2008 mainly due to lower import duties for the company s downstream operations in the United Kingdom. Taxes other than on income decreased in 2008 from 2007 mainly due to lower import duties as a result of the effects of the 2007 sales of the company s Benelux refining and marketing businesses and a decline in import volumes in the United Kingdom.

Millions of dollars	**2009**	2008	2007
Interest and debt expense	**$ 28**	$	$ 166

Interest and debt expense increased in 2009 due to an increase in long-term debt. Interest and debt expense decreased in 2008 because all interest-related amounts were being capitalized.

Millions of dollars	**2009**	2008	2007
Income tax expense	**$ 7,965**	$ 19,026	$ 13,479

Effective income tax rates were 43 percent in 2009, 44 percent in 2008 and 42 percent in 2007. The rate was lower in 2009 than in 2008 mainly due the effect in 2009 of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity-affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates. The rate was higher in 2008 compared with 2007 primarily due to a greater proportion of income earned in tax jurisdictions with higher income tax rates. In addition, the 2007 period included a relatively low effective tax rate on the sale of the company s investment in Dynegy common stock and the sale of downstream assets in Europe. Refer also to the discussion of income taxes in Note 15 beginning on page FS-46.

Selected Operating Data[1,2]

	2009	2008	2007
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**484**	421	460
Net Natural Gas Production (MMCFPD)[3]	**1,399**	1,501	1,699
Net Oil-Equivalent Production (MBOEPD)	**717**	671	743
Sales of Natural Gas (MMCFPD)	**5,901**	7,226	7,624
Sales of Natural Gas Liquids (MBPD)	**17**	15	25
Revenues From Net Production			
Liquids ($/Bbl)	**$ 54.36**	$ 88.43	$ 63.16
Natural Gas ($/MCF)	**$ 3.73**	$ 7.90	$ 6.12
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**1,362**	1,228	1,296
Net Natural Gas Production (MMCFPD)[3]	**3,590**	3,624	3,320
Net Oil-Equivalent Production (MBOEPD)[4]	**1,987**	1,859	1,876

Sales of Natural Gas (MMCFPD)	**4,062**	4,215	3,792
Sales of Natural Gas Liquids (MBPD)	**23**	17	22
Revenues From Liftings			
Liquids ($/Bbl)	**$ 55.97**	$ 86.51	$ 65.01
Natural Gas ($/MCF)	**$ 4.01**	$ 5.19	$ 3.90
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD)[3,4]			
United States	**717**	671	743
International	**1,987**	1,859	1,876
Total	**2,704**	2,530	2,619
U.S. Downstream			
Gasoline Sales (MBPD)[5]	**720**	692	728
Other Refined-Product Sales (MBPD)	**683**	721	729
Total Refined Product Sales (MBPD)	**1,403**	1,413	1,457
Sales of Natural Gas Liquids (MBPD)	**144**	144	135
Refinery Input (MBPD)	**899**	891	812
International Downstream			
Gasoline Sales (MBPD)[5]	**555**	589	581
Other Refined-Product Sales (MBPD)	**1,296**	1,427	1,446
Total Refined Product Sales (MBPD)[6]	**1,851**	2,016	2,027
Sales of Natural Gas Liquids (MBPD)	**88**	97	96
Refinery Input (MBPD)	**979**	967	1,021

[1] Includes company share of equity 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 natural gas = 1 barrel of oil.

[3] Includes natural gas consumed in operations (MMCFPD):			
United States	**58**	70	65
International	**463**	450	433
[4] Includes production from oil sands, Net (MBPD):	**26**	27	27
[5] Includes branded and unbranded gasoline.			
[6] Includes sales of affiliates (MBPD):	**516**	512	492

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Liquidity and Capital Resources

Cash, cash equivalents and marketable securities Total balances were $8.8 billion and $9.6 billion at December 31, 2009 and 2008, respectively. Cash provided by operating activities in 2009 was $19.4 billion, compared with $29.6 billion in 2008 and $25.0 billion in 2007.

Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.7 billion, $800 million and $300 million in 2009, 2008 and 2007, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.6 billion in 2009, $1.5 billion in 2008 and $3.3 billion in 2007.

Restricted cash of $123 million and $367 million associated with various capital-investment projects at December 31, 2009 and 2008, respectively, was invested in short-term marketable securities and recorded as Deferred charges and other assets on the Consolidated Balance Sheet.

Dividends Dividends paid to common stockholders were approximately $5.3 billion in 2009, $5.2 billion in 2008 and $4.8 billion in 2007. In July 2009, the company increased its quarterly common stock dividend by 4.6 percent to $0.68 per share.

Debt and capital lease obligations Total debt and capital lease obligations were $10.5 billion at December 31, 2009, up from $8.9 billion at year-end 2008.

The $1.6 billion increase in total debt and capital lease obligations during 2009 included the net effect of a $5 billion public bond issuance, a $350 million issuance of tax-exempt Gulf Opportunity Zone bonds, a $3.2 billion decrease in commercial paper, and a $400 million payment of principal for Texaco Capital Inc. bonds that matured in January 2009. 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 $4.6 billion at December 31, 2009, down from $7.8 billion at year-end 2008. Of these amounts, $4.2 billion and $5.0 billion were reclassified to long-term at the end of each period, respectively. At year-end 2009, settlement of these obligations was not expected to require the use of working capital in 2010, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

At year-end 2009, the company had $5.1 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and also can be used for general corporate purposes. The company s practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on 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, 2009. In addition, the company has an automatic shelf registration statement that expires in March 2010 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company. The company intends to file a new shelf registration statement when the current one expires.

The company has outstanding public bonds issued by Chevron Corporation, Chevron Corporation Profit Sharing/Savings Plan Trust Fund, Texaco Capital Inc. and Union Oil Company of California. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard and Poor s Corporation and Aa1 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. 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 In September 2007, the company authorized the acquisition of up to $15 billion of its common shares 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 (expiring in 2010) and may be discontinued at any time. The company did not acquire any shares during 2009 and does not plan to acquire any shares in the first quarter 2010. From the inception of the program, the company has acquired 119 million shares at a cost of $10.1 billion.

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Management s Discussion and Analysis of
Financial Condition and Results of Operations

Capital and Exploratory Expenditures

			2009			2008			2007
Millions of dollars	U.S.	Int l.	Total	U.S.	Int l.	Total	U.S.	Int l.	Total
Upstream Exploration and Production	**$ 3,261**	**$ 13,848**	**$ 17,109**	$ 5,516	$ 11,944	$ 17,460	$ 4,558	$ 10,980	$ 15,538
Downstream Refining, Marketing and Transportation	**1,910**	**2,511**	**4,421**	2,182	2,023	4,205	1,576	1,867	3,443
Chemicals	**210**	**92**	**302**	407	78	485	218	53	271
All Other	**402**	**3**	**405**	618	7	625	768	6	774
Total	**$ 5,783**	**$ 16,454**	**$ 22,237**	$ 8,723	$ 14,052	$ 22,775	$ 7,120	$ 12,906	$ 20,026
Total, Excluding Equity in Affiliates	**$ 5,558**	**$ 15,094**	**$ 20,652**	$ 8,241	$ 12,228	$ 20,469	$ 6,900	$ 10,790	$ 17,690

Capital and exploratory expenditures Total expenditures for 2009 were $22.2 billion, including $1.6 billion for the company s share of equity-affiliate expenditures and $2 billion for the extension of an upstream concession. In 2008 and 2007, expenditures were $22.8 billion and $20.0 billion, respectively, including the company s share of affiliates expenditures of $2.3 billion in both periods.

Of the $22.2 billion of expenditures in 2009, about three-fourths, or $17.1 billion, is related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2008 and 2007. International upstream accounted for about 80 percent of the worldwide upstream investment in 2009 and about 70 percent in 2008 and 2007, reflecting the company s continuing focus on opportunities available outside the United States.

The company estimates that in 2010, capital and exploratory expenditures will be $21.6 billion, including $1.6 billion of spending by affiliates. About 80 percent of the total, or $17.3 billion, is budgeted for exploration and production activities, with $13.2 billion of this amount for projects outside the United States. Spending in 2010 is primarily targeted for exploratory prospects in the U.S. Gulf of Mexico and major development projects in Angola, Australia, Brazil, Canada, China, Nigeria, Thailand and the U.S. Gulf of Mexico. Also included is funding for base business improvements and focused appraisals in core hydrocarbon basins.

Worldwide downstream spending in 2010 is estimated at $3.4 billion, with about $1.6 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and South Korea and construction of gas-to-liquids facilities in support of associated upstream projects.

Investments in chemicals, technology and other corporate businesses in 2010 are budgeted at $900 million. Technology investments include projects related to unconventional hydrocarbon technologies, oil and gas reservoir management, and gas-fired and renewable power generation.

Noncontrolling interests The company had noncontrolling interests of $647 million and $469 million at December 31, 2009 and 2008, respectively. Distributions to noncontrolling interests totaled $71 million and

$99 million in 2009 and 2008, respectively.

Pension Obligations In 2009, the company s pension plan contributions were $1.7 billion (including $1.5 billion to the U.S. plans and $200 million to the international plans). The company estimates contributions in 2010 will be approximately $900 million ($600 million for the U.S. plans and $300 million for the international plans). Actual contribution amounts are dependent upon 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. Refer also to the discussion of pension accounting in Critical Accounting Estimates and Assumptions, beginning on page FS-18.

Financial Ratios

Financial Ratios

	At December 31		
	2009	2008	2007
Current Ratio	**1.4**	1.1	1.2
Interest Coverage Ratio	**62.3**	166.9	69.2
Debt Ratio	**10.3%**	9.3%	8.6%

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 2009, the book value of inventory

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was lower than replacement costs, based on average acquisition costs during the year, by approximately $5.5 billion.

Interest Coverage Ratio income before income tax expense, plus interest and debt expense and amortization of capitalized interest, less net income attributable to noncontrolling interests, divided by before-tax interest costs. The company s interest coverage ratio in 2009 was lower than 2008 and 2007 due to lower before-tax income.

Debt Ratio total debt as a percentage of total debt plus Chevron Corporation Stockholders Equity. The increase in 2009 over 2008 and 2007 was primarily due to the increase in debt as a result of the $5 billion issuance of public bonds in 2009.

Guarantees, Off-Balance-Sheet Arrangements and Contractual Obligations, and Other Contingencies

Direct Guarantee

Millions of dollars			Commitment Expiration by Period		
	Total	2010	2011 2012	2013 2014	After 2014
Guarantee of non-consolidated affiliate or joint-venture obligation	$ 613	$	$ 38	$ 77	$ 498

The company s guarantee of approximately $600 million is associated with certain payments under a terminal use agreement entered into by a company affiliate. The terminal is expected to be operational by 2012. Over the approximate 16-year term of the guarantee, the maximum guarantee amount will be reduced over time as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of any amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

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 2009, the company had paid $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 had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. In February 2009, Shell delivered a letter to the company purporting to preserve unmatured claims for certain Equilon indemnities. The letter itself provides no estimate of the ultimate claim amount. Management does not believe this letter or any other information provides a basis to estimate the amount, if any, of a range of loss or potential range of loss with respect to either the Equilon or the Motiva indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described in the preceding paragraph 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. The acquirer of those assets shared in certain environmental remediation costs up to a maximum obligation of $200 million, which had been reached at December 31, 2009. Under the indemnification agreement, after reaching the $200 million obligation, Chevron is solely responsible until April 2022, when the indemnification expires. The environmental conditions or events that are subject to these indemnities must have arisen prior to the sale of the assets in 1997.

Although the company has provided for known obligations under this indemnity 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.

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: 2010 $7.5 billion; 2011 $4.3 billion; 2012 $1.4 billion; 2013 $1.4 billion; 2014 $1.0 billion; 2015 and after $4.1 billion. A portion of these commitments may ultimately be shared with project

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partners. Total payments under the agreements were approximately $8.1 billion in 2009, $5.1 billion in 2008 and $3.7 billion in 2007.

The following table summarizes the company s significant contractual obligations:

Contractual Obligations[1]

Millions of dollars			Payments Due by Period		
	Total	2010	2011 2012	2013 2014	After 2014
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 384	$ 384	$	$	$
Long-Term Debt[3]	9,829		5,743	2,041	2,045
Noncancelable Capital Lease Obligations	499	90	168	104	137
Interest	2,590	317	566	426	1,281
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	3,364	568	844	719	1,233
Throughput and Take-or-Pay Agreements	15,130	6,555	3,825	819	3,931
Other Unconditional Purchase Obligations[4]	4,617	1,024	1,906	1,538	149

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page FS-52.

2 Does not include amounts related to the company s income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates for the periods in which these liabilities may become payable. The company does not expect settlement of such liabilities will have a material effect on its results of operations, consolidated financial position or liquidity in any single period.

3 $4.2 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 2011 2012 period.

4 Does not include obligations to purchase the company s share of natural gas liquids and regasified natural gas associated with operations of the 36.4 percent-owned Angola LNG affiliate. The LNG plant is expected to commence operations in 2012 and is designed to produce 5.2 million metric tons of LNG and related natural gas liquids per year. Volumes and prices associated with these purchase obligations are neither fixed nor determinable.

Financial and Derivative Instruments

The market risk associated with the company s portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk discussed below do not represent the company s projection of future 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 2009 Annual Report on Form 10-K.

Derivative Commodity 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 these activities were not material to the company s financial position, results of operations or cash flows in 2009.

The company s market exposure positions are monitored and managed on a daily basis by an internal Risk Control group in accordance with the company s risk management policies, which have been approved by the Audit Committee of the company s Board of Directors.

The derivative commodity instruments used in the company s risk management and trading activities consist mainly of futures, options and swap contracts traded on the New York Mercantile Exchange and on electronic platforms of the Inter-Continental Exchange and 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. The change in fair value from Chevron s derivative commodity instruments in 2009 was a quarterly average decrease of $168 million in total assets and a quarterly average decrease of $104 million in total liabilities.

The company uses a Value-at-Risk (VaR) model to estimate the potential loss in fair value on a single day from the effect of adverse changes in market conditions on derivative commodity instruments held or issued, which are recorded on the balance sheet at
December 31, 2009, as derivative commodity instruments in accordance with accounting standards for derivatives (ASC 815). VaR is the maximum loss not to be exceeded within a given probability or confidence level over a given period of time. The company s VaR model uses the Monte Carlo simulation method that involves generating hypothetical scenarios from the specified probability distribution and constructing a full distribution of a portfolio s potential values.

The VaR model utilizes an exponentially weighted moving average for computing historical volatilities and correlations, a 95 percent confidence level, and a one-day holding period. That is, the company s 95 percent, one-day VaR corresponds to the unrealized loss in portfolio value that would not be exceeded on average more than one in every 20 trading days, if the portfolio were held constant for one day.

The one-day holding period is based on the assumption that market-risk positions can be liquidated or hedged within one day. For hedging and risk management, the company uses conventional exchange-traded instruments such as futures and options as well as non-exchange-traded swaps,

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most of which can be liquidated or hedged effectively within one day. The table below presents the 95 percent/one-day VaR for each of the company s primary risk exposures in the area of derivative commodity instruments at December 31, 2009 and 2008. The lower amounts in 2009 were primarily associated with a decrease in price volatility for these commodities during the year.

Millions of dollars	**2009**	2008
Crude Oil	**$ 17**	$ 39
Natural Gas	**4**	5
Refined Products	**19**	45

Foreign Currency The company may enter into foreign-currency derivative contracts to manage some of its foreign-currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign-currency capital expenditures and lease commitments. The foreign-currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open foreign-currency derivative contracts at December 31, 2009.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Historically, under the terms of the swaps, net cash settlements were 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, if any, may be accounted for as fair value hedges. Interest rate swaps related to floating-rate debt, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2009, the company had no interest rate swaps on floating-rate debt. The company s only interest rate swaps on fixed-rate debt matured in January 2009 and the company had no interest rate swaps on fixed-rate debt at year-end 2009.

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 and long-term purchase agreements. Refer to Other Financial Information in Note 24 of the Consolidated Financial Statements, page FS-61, for further discussion. Management believes these agreements 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 50 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims 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 pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

Ecuador Chevron is a defendant in a civil lawsuit before the Superior Court of Nueva Loja in Lago Agrio, Ecuador, brought in May 2003 by plaintiffs who claim to be representatives of certain residents of an area where an oil production consortium formerly had operations. The lawsuit alleges damage to the environment from the oil exploration and production operations and seeks unspecified damages to fund environmental remediation and restoration of the alleged environmental harm, plus a health monitoring program. Until 1992, Texaco Petroleum Company (Texpet), a subsidiary of Texaco Inc., was a minority member of this consortium with Petroecuador, the Ecuadorian state-owned oil company, as the majority partner; since 1990, the operations have been conducted solely by Petroecuador. At the conclusion of the consortium and following an independent third-party environmental audit of the concession area, Texpet entered into a formal agreement with the Republic of Ecuador and Petroecuador for

Texpet to remediate specific sites assigned by the government in proportion to Texpet s ownership share of the consortium. Pursuant to that agreement, Texpet conducted a three-year remediation program at a cost of $40 million. After certifying that the sites were properly remediated, the government granted Texpet and all related corporate entities a full release from any and all environmental liability arising from the consortium operations.

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously given to Texpet by the Republic of Ecuador and Petroecuador. With regard to the facts, the company believes that the evidence confirms that Texpet s remediation was properly conducted and that the remaining environmental damage reflects Petroecuador s failure to timely fulfill its legal obligations and Petroecuador s further conduct since assuming full control over the operations.

In April 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $8 billion, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer s report also asserted that an additional $8.3 billion could be assessed against Chevron for unjust enrichment. The engineer s report is not binding on the court. Chevron also believes that the engineer s work was performed and his report prepared in a manner contrary to law and in violation of the court s orders. Chevron submitted a rebuttal to the report in which it asked the court to strike the report in its entirety. In November 2008, the engineer revised the report and, without additional evidence, recommended an increase in the financial compensation for purported damages to a total of $18.9 billion and an increase in the assessment for purported unjust enrichment to a total of $8.4 billion. Chevron submitted a rebuttal to the revised report, which the court dismissed. In September 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case petitioned to be recused. In late September 2009, the judge was recused, and in October 2009, the full chamber of the provincial court affirmed the recusal, resulting in the appointment of a new judge. Chevron filed motions to annul all of the rulings made by the prior judge, but the new judge denied these motions. The court has completed most of the procedural aspects of the case and could render a judgment at any time. Chevron will continue a vigorous defense of any attempted imposition of liability.

In the event of an adverse judgment, Chevron would expect to pursue its appeals and vigorously defend against enforcement of any such judgment; therefore, the ultimate outcome and any financial effect on Chevron remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this case. Due to the defects associated with the engineer s report, management does not believe the report has any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

Environmental The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or 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	**2009**	2008	2007
Balance at January 1	**$ 1,818**	$ 1,539	$ 1,441
Net Additions	**351**	784	562
Expenditures	**(469)**	(505)	(464)

Balance at December 31	**$ 1,700**	$ 1,818	$ 1,539

Included in the $1,700 million year-end 2009 reserve balance were remediation activities at approximately 250 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 2009 was $185 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 results of operations, consolidated financial position or liquidity.

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Of the remaining year-end 2009 environmental reserves balance of $1,515 million, $820 million related to the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), and pipelines. The remaining $695 million was associated with various sites in international downstream ($107 million), upstream ($369 million), chemicals ($149 million) and other businesses ($70 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 and local regulations. No single remediation site at year-end 2009 had a recorded liability that was material to the company s results of operations, consolidated financial position 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.

Under accounting standards for asset retirement obligations
(ASC 410), 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 $10.2 billion for asset retirement obligations at year-end 2009 related primarily to upstream properties.

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

Refer also to Note 23 on page FS-60, related to the company s asset retirement obligations and the discussion of Environmental Matters on page FS-18.

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and 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.
Refer to Note 15 beginning on page FS-46 for a discussion of the periods for which tax returns have been audited for the company s major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

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, 2009, the company had approximately $2.4 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $317 million from 2008. The 2008 balance reflected an increase of $458 million from 2007.

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 $2.4 billion of suspended wells at year-end 2009 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page FS-50, 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 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 2009 at approximately $3.5 billion for its consolidated companies. Included in these expenditures were approximately $1.7 billion of environmental capital expenditures and $1.8 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 2010, total worldwide environmental capital expenditures are estimated at $2.1 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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

Critical Accounting Estimates and Assumptions

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

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

1. the nature of the estimates and 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, which, effective December 31, 2009, require ...by analysis of geosciences and engineering data, (the reserves) can be estimated with reasonable certainty to be economically producible...under existing economic conditions where existing economic conditions include prices based on the average price during the

12-month period. Refer to Table V, Reserve Quantity Information, beginning on page FS-69, for the changes in these estimates for the three years ending December 31, 2009, and to Table VII, Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves on page FS-77 for estimates of proved-reserve values for each of the three years ended December 31, 2009. 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 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, beginning on page FS-20, 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 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-52, includes information on the funded status of the company s pension and OPEB plans at the end of 2009 and 2008; the components of pension and OPEB expense for the three years ending December 31, 2009; and the underlying assumptions for those periods.

Pension and OPEB expense is reported on the Consolidated Statement of Income as Operating expenses or Selling, general and administrative expenses and applies to all business segments. The year-end 2009 and 2008 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 differences related to overfunded pension plans are reported as a long-term asset in Deferred charges and other assets. The differences associated with underfunded or unfunded pension and OPEB plans are reported as Accrued liabilities or Reserves for employee benefit plans. Amounts yet to be recognized as components of pension or OPEB expense are reported in Accumulated other comprehensive loss.

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 69 percent of the company s pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2009, actual asset returns averaged 3.7 percent for this plan. The actual return for 2009 was 15.7 percent and was associated with the broad recovery in the financial markets.

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 year-end 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, 2009, the company selected a 5.3 percent discount rate for the major U.S. pension plan and 5.8 percent for its OPEB plan. These rates were selected based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2009. The discount rates at the end of 2008 and 2007 were 6.3 percent for both years for the U.S. pension and OPEB plans.

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 2009 was $1.1 billion. 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 2009 by approximately $50 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 61 percent of the companywide pension obligation, would have reduced total pension plan expense for 2009 by approximately $150 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan reported on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2009, for underfunded plans was approximately $3.8 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 $300 million, which would have decreased the plan s underfunded status from approximately $1.6 billion to $1.3 billion. 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 2009, the company s pension plan contributions were $1.7 billion (including $1.5 billion to the U.S. plans). In 2010, the company estimates contributions will be approximately $900 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 2009 was $164 million and the total liability, which reflected the unfunded status of the plans at the end of 2009, was $3.1 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2009, a 1 percent increase in the discount rate for the company s primary U.S. OPEB plan, which accounted for about 69 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $11 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 84 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2009 by approximately $65 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. 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 7 percent in 2010 and gradually drop to 5 percent for 2018 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2009, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for 84 percent of the companywide OPEB liabilities, 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-52, for information on the $6.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2009; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2010.

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 estimated 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 individual impairments of PP&E and Investments were recorded for the three years ending December 31, 2009. A sensitivity analysis of the impact on 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 the amount of the impairment, and are not subject to sensitivity analysis.

From time to time, the company performs impairment reviews and determines whether any 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.

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by accounting standards for goodwill (ASC 350), 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.

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 generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as Operating expenses or Selling, general and administrative expenses on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is more likely than not (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 15 beginning on page FS-46. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2009.

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

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162 (FAS 168) In June 2009, the FASB issued FAS 168, which became effective for the company in the quarter ending September 30, 2009. This standard established the FASB Accounting Standards Codification (ASC) system as the single authoritative source of U.S. generally accepted accounting principles (GAAP) and superseded existing literature of the FASB, Emerging Issues Task Force, American Institute of CPAs and other sources. The ASC did not change GAAP, but organized the literature into about 90 accounting Topics. Adoption of the ASC did not affect the company s accounting.

Employer s Disclosures About Postretirement Benefit Plan Assets (FSP FAS 132(R)-1) In December 2008, the FASB issued FSP FAS 132(R)-1, which was subsequently codified into ASC 715, *Compensation Retirement Benefits,* and became effective with the company s reporting at December 31, 2009. This standard amended and expanded the disclosure requirements for the plan assets of defined benefit pension and other postretirement plans. Refer to information beginning on page FS-52 in Note 21, Employee Benefits, for these disclosures.

Transfers and Servicing (ASC 860), Accounting for Transfers of Financial Assets (ASU 2009-16) The FASB issued ASU 2009-16 in December 2009. This standard became effective for the company on January 1, 2010. ASU 2009-16 changes how companies account for transfers of financial assets and eliminates the concept of qualifying special-purpose entities. Adoption of the guidance is not expected to have an impact on the company s results of operations, financial position or liquidity.

Consolidation (ASC 810), Improvements to Financial Reporting by Enterprises Involved With Variable Interest Entities (ASU 2009-17) The FASB issued ASU 2009-17 in December 2009. This standard became effective for the company January 1, 2010. ASU 2009-17 requires the enterprise to qualitatively assess if it is the primary beneficiary of a variable-interest entity (VIE), and, if so, the VIE must be consolidated. Adoption of the standard is not expected to have a material impact on the company s results of operations, financial position or liquidity.

Extractive Industries Oil and Gas (ASC 932), Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03) In January 2010, the FASB issued ASU 2010-03, which became effective for the company on December 31, 2009. The standard amends certain sections of ASC 932, *Extractive Industries Oil and Gas,* to align them with the requirements in the Securities and Exchange Commission s final rule, *Modernization of the Oil and Gas Reporting Requirements* (the final rule). The final rule was issued on December 31, 2008. Refer to Table V Reserve Quantity Information, beginning on page FS-69, for additional information on the final rule and the impact of adoption.

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Quarterly Results and Stock Market Data
Unaudited

				2009				2008
illions of dollars, except per-share amounts	**4th Q**	**3rd Q**	**2nd Q**	**1st Q**	4th Q	3rd Q	2nd Q	1st Q
evenues and Other Income								
ales and other operating revenues[1]	**$ 47,588**	**$ 45,180**	**$ 39,647**	**$ 34,987**	$ 43,145	$ 76,192	$ 80,962	$ 64,659
ncome from equity affiliates	**898**	**1,072**	**735**	**611**	886	1,673	1,563	1,244
ther income	**190**	**373**	**(177)**	**532**	1,172	1,002	464	43
otal Revenues and Other Income	**48,676**	**46,625**	**40,205**	**36,130**	45,203	78,867	82,989	65,946
osts and Other Deductions								
urchased crude oil and products	**28,606**	**26,969**	**23,678**	**20,400**	23,575	49,238	56,056	42,528
perating expenses	**4,899**	**4,403**	**4,209**	**4,346**	5,416	5,676	5,248	4,455
elling, general and administrative expenses	**1,330**	**1,177**	**1,043**	**977**	1,492	1,278	1,639	1,347
xploration expenses	**281**	**242**	**438**	**381**	338	271	307	253
epreciation, depletion and amortization	**3,156**	**2,988**	**3,099**	**2,867**	2,589	2,449	2,275	2,215
axes other than on income[1]	**4,583**	**4,644**	**4,386**	**3,978**	4,547	5,614	5,699	5,443
nterest and debt expense		**14**	**6**	**8**				
otal Costs and Other Deductions	**42,855**	**40,437**	**36,859**	**32,957**	37,957	64,526	71,224	56,241
ncome Before Income Tax Expense	**5,821**	**6,188**	**3,346**	**3,173**	7,246	14,341	11,765	9,705
ncome Tax Expense	**2,719**	**2,342**	**1,585**	**1,319**	2,345	6,416	5,756	4,509
et Income	**$ 3,102**	**$ 3,846**	**$ 1,761**	**$ 1,854**	$ 4,901	$ 7,925	$ 6,009	$ 5,196
ess: Net income attributable to noncontrolling nterests	**32**	**15**	**16**	**17**	6	32	34	28
et Income Attributable to Chevron Corporation	**$ 3,070**	**$ 3,831**	**$ 1,745**	**$ 1,837**	$ 4,895	$ 7,893	$ 5,975	$ 5,168
er-Share of Common Stock								
et Income Attributable to Chevron Corporation								
Basic	**$ 1.54**	**$ 1.92**	**$ 0.88**	**$ 0.92**	$ 2.45	$ 3.88	$ 2.91	$ 2.50
Diluted	**$ 1.53**	**$ 1.92**	**$ 0.87**	**$ 0.92**	$ 2.44	$ 3.85	$ 2.90	$ 2.48
ividends	**$ 0.68**	**$ 0.68**	**$ 0.65**	**$ 0.65**	$ 0.65	$ 0.65	$ 0.65	$ 0.58
ommon Stock Price Range High[2]	**$ 79.64**	**$ 72.64**	**$ 72.67**	**$ 77.35**	$ 82.20	$ 99.08	$ 103.09	$ 94.61
Low[2]	**$ 68.14**	**$ 61.40**	**$ 63.75**	**$ 56.46**	$ 57.83	$ 77.50	$ 86.74	$ 77.51
Includes excise, value-added and similar taxes:	**$ 2,086**	**$ 2,079**	**$ 2,034**	**$ 1,910**	$ 2,080	$ 2,577	$ 2,652	$ 2,537

End of day price.

The company s common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 19, 2010, stockholders of record numbered approximately 195,000. There are no restrictions on the company s ability to pay dividends.

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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 the company s 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 internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the company s internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

John S. Watson	Patricia E. Yarrington	Mark A. Humphrey
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 25, 2010

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2009 and December 31, 2008 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our
audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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 25, 2010

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Consolidated Statement of Income
Millions of dollars, except per-share amounts

	Year ended December 31		
	2009	2008	2007
Revenues and Other Income			
Sales and other operating revenues*	**$ 167,402**	$ 264,958	$ 214,091
Income from equity affiliates	**3,316**	5,366	4,144
Other income	**918**	2,681	2,669
Total Revenues and Other Income	**171,636**	273,005	220,904
Costs and Other Deductions			
Purchased crude oil and products	**99,653**	171,397	133,309
Operating expenses	**17,857**	20,795	16,932
Selling, general and administrative expenses	**4,527**	5,756	5,926
Exploration expenses	**1,342**	1,169	1,323
Depreciation, depletion and amortization	**12,110**	9,528	8,708
Taxes other than on income*	**17,591**	21,303	22,266
Interest and debt expense	**28**		166
Total Costs and Other Deductions	**153,108**	229,948	188,630
Income Before Income Tax Expense	**18,528**	43,057	32,274
Income Tax Expense	**7,965**	19,026	13,479
Net Income	**10,563**	24,031	18,795
Less: Net income attributable to noncontrolling interests	**80**	100	107
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688
Per-Share of Common Stock			
Net Income Attributable to Chevron Corporation			
Basic	**$ 5.26**	$ 11.74	$ 8.83
Diluted	**$ 5.24**	$ 11.67	$ 8.77
*Includes excise, value-added and similar taxes.	**$ 8,109**	$ 9,846	$ 10,121

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2009	2008	2007
Net Income	**$ 10,563**	$ 24,031	$ 18,795
Currency translation adjustment			
Unrealized net change arising during period	**60**	(112)	31
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	**2**	(6)	17
Reclassification to net income of net realized loss			2
Total	**2**	(6)	19
Derivatives			
Net derivatives (loss) gain on hedge transactions	**(69)**	139	(10)
Reclassification to net income of net realized (gain) loss	**(23)**	32	7
Income taxes on derivatives transactions	**32**	(61)	(3)
Total	**(60)**	110	(6)
Defined benefit plans			
Actuarial loss			
Amortization to net income of net actuarial loss	**575**	483	356
Actuarial (loss) gain arising during period	**(1,099)**	(3,228)	530
Prior service cost			
Amortization to net income of net prior service credits	**(65)**	(64)	(15)
Prior service (cost) credit arising during period	**(34)**	(32)	204
Defined benefit plans sponsored by equity affiliates	**65**	(97)	19
Income taxes on defined benefit plans	**159**	1,037	(409)
Total	**(399)**	(1,901)	685
Other Comprehensive (Loss) Gain, Net of Tax	**(397)**	(1,909)	729
Comprehensive Income	**10,166**	22,122	19,524
Comprehensive income attributable to noncontrolling interests	**(80)**	(100)	(107)
Comprehensive Income Attributable to Chevron Corporation	**$ 10,086**	$ 22,022	$ 19,417

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Balance Sheet

Millions of dollars, except per-share amounts

	At December 31 2009	2008
Assets		
Cash and cash equivalents	**$ 8,716**	$ 9,347
Marketable securities	**106**	213
Accounts and notes receivable (less allowance: 2009 $228; 2008 $246)	**17,703**	15,856
Inventories:		
Crude oil and petroleum products	**3,680**	5,175
Chemicals	**383**	459
Materials, supplies and other	**1,466**	1,220
Total inventories	**5,529**	6,854
Prepaid expenses and other current assets	**5,162**	4,200
Total Current Assets	**37,216**	36,470
Long-term receivables, net	**2,282**	2,413
Investments and advances	**21,158**	20,920
Properties, plant and equipment, at cost	**188,288**	173,299
Less: Accumulated depreciation, depletion and amortization	**91,820**	81,519
Properties, plant and equipment, net	**96,468**	91,780
Deferred charges and other assets	**2,879**	4,711
Goodwill	**4,618**	4,619
Assets held for sale		252
Total Assets	**$ 164,621**	$ 161,165
Liabilities and Equity		
Short-term debt	**$ 384**	$ 2,818
Accounts payable	**16,437**	16,580
Accrued liabilities	**5,375**	8,077
Federal and other taxes on income	**2,624**	3,079
Other taxes payable	**1,391**	1,469
Total Current Liabilities	**26,211**	32,023
Long-term debt	**9,829**	5,742
Capital lease obligations	**301**	341
Deferred credits and other noncurrent obligations	**17,390**	17,678
Noncurrent deferred income taxes	**11,521**	11,539
Reserves for employee benefit plans	**6,808**	6,725
Total Liabilities	**72,060**	74,048
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	**1,832**	1,832

Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2009 and 2008)		
Capital in excess of par value	**14,631**	14,448
Retained earnings	**106,289**	101,102
Accumulated other comprehensive loss	**(4,321)**	(3,924)
Deferred compensation and benefit plan trust	**(349)**	(434)
Treasury stock, at cost (2009 434,954,774 shares; 2008 438,444,795 shares)	**(26,168)**	(26,376)
Total Chevron Corporation Stockholders Equity	**91,914**	86,648
Noncontrolling interests	**647**	469
Total Equity	**92,561**	87,117
Total Liabilities and Equity	**$ 164,621**	$ 161,165

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2009	2008	2007
Operating Activities			
Net Income	**$ 10,563**	$ 24,031	$ 18,795
Adjustments			
Depreciation, depletion and amortization	**12,110**	9,528	8,708
Dry hole expense	**552**	375	507
Distributions less than income from equity affiliates	**(103)**	(440)	(1,439)
Net before-tax gains on asset retirements and sales	**(1,255)**	(1,358)	(2,315)
Net foreign currency effects	**466**	(355)	378
Deferred income tax provision	**467**	598	261
Net (increase) decrease in operating working capital	**(2,301)**	(1,673)	685
Increase in long-term receivables	**(258)**	(161)	(82)
Decrease (increase) in other deferred charges	**201**	(84)	(530)
Cash contributions to employee pension plans	**(1,739)**	(839)	(317)
Other	**670**	10	326
Net Cash Provided by Operating Activities	**19,373**	29,632	24,977
Investing Activities			
Capital expenditures	**(19,843)**	(19,666)	(16,678)
Proceeds and deposits related to asset sales	**2,564**	1,491	3,338
Net sales of marketable securities	**127**	483	185
Repayment of loans by equity affiliates	**336**	179	21
Net sales (purchases) of other short-term investments	**244**	432	(799)
Net Cash Used for Investing Activities	**(16,572)**	(17,081)	(13,933)
Financing Activities			
Net (payments) borrowings of short-term obligations	**(3,192)**	2,647	(345)
Proceeds from issuances of long-term debt	**5,347**		650
Repayments of long-term debt and other financing obligations	**(496)**	(965)	(3,343)
Cash dividends common stock	**(5,302)**	(5,162)	(4,791)
Distributions to noncontrolling interests	**(71)**	(99)	(77)
Net sales (purchases) of treasury shares	**168**	(6,821)	(6,389)
Net Cash Used for Financing Activities	**(3,546)**	(10,400)	(14,295)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**114**	(166)	120
Net Change in Cash and Cash Equivalents	**(631)**	1,985	(3,131)
Cash and Cash Equivalents at January 1	**9,347**	7,362	10,493
Cash and Cash Equivalents at December 31	**$ 8,716**	$ 9,347	$ 7,362

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity
Shares in thousands; amounts in millions of dollars

	2009		2008		2007	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred Stock		**$**		$		$
Common Stock	**2,442,677**	**$ 1,832**	2,442,677	$ 1,832	2,442,677	$ 1,832
Capital in Excess of Par						
Balance at January 1		**$ 14,448**		$ 14,289		$ 14,126
Treasury stock transactions		**183**		159		163
Balance at December 31		**$ 14,631**		$ 14,448		$ 14,289
Retained Earnings						
Balance at January 1		**$ 101,102**		$ 82,329		$ 68,464
Net income attributable to Chevron Corporation		**10,483**		23,931		18,688
Cash dividends on common stock		**(5,302)**		(5,162)		(4,791)
Adoption of new accounting standard for uncertain income tax positions						(35)
Tax benefit from dividends paid on unallocated ESOP shares and other		**6**		4		3
Balance at December 31		**$ 106,289**		$ 101,102		$ 82,329
Notes Receivable Key Employees		**$**		$		$ (1)
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (171)**		$ (59)		$ (90)
Change during year		**60**		(112)		31
Balance at December 31		**$ (111)**		$ (171)		$ (59)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (3,909)**		$ (2,008)		$ (2,585)
Change to defined benefit plans during year		**(399)**		(1,901)		685
Adoption of new accounting standard for defined benefit pension and other postretirement plans						(108)
Balance at December 31		**$ (4,308)**		$ (3,909)		$ (2,008)
Unrealized net holding gain on securities						
Balance at January 1		**$ 13**		$ 19		$
Change during year		**2**		(6)		19
Balance at December 31		**$ 15**		$ 13		$ 19

Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 143**		$ 33		$ 39
Change during year		**(60)**		110		(6)
Balance at December 31		**$ 83**		$ 143		$ 33
Balance at December 31		**$ (4,321)**		$ (3,924)		$ (2,015)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ (194)**		$ (214)		$ (214)
Net reduction of ESOP debt and other		**85**		20		
Balance at December 31		**(109)**		(194)		(214)
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240)
Balance at December 31	**14,168**	**$ (349)**	14,168	$ (434)	14,168	$ (454)
Treasury Stock at Cost						
Balance at January 1	**438,445**	**$ (26,376)**	352,243	$ (18,892)	278,118	$ (12,395)
Purchases	**85**	**(6)**	95,631	(8,011)	85,429	(7,036)
Issuances mainly employee benefit plans	**(3,575)**	**214**	(9,429)	527	(11,304)	539
Balance at December 31	**434,955**	**$ (26,168)**	438,445	$ (26,376)	352,243	$ (18,892)
Total Chevron Corporation Stockholders Equity at December 31		**$ 91,914**		$ 86,648		$ 77,088
Noncontrolling Interests		**$ 647**		$ 469		$ 204
Total Equity		**$ 92,561**		$ 87,117		$ 77,292

See accompanying Notes to the Consolidated Financial Statements.

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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 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.

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.

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. When appropriate, the company s share of the affiliate s reported earnings is adjusted quarterly to reflect the difference between these allocated values and the affiliate s historical book values.

Derivatives The majority of the company s activity in derivative commodity 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 commodity trading activity and foreign currency exposures, gains and losses from derivative instruments 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. Where Chevron is a party to master netting arrangements, fair value receivable and payable amounts recognized for derivative instruments executed with the same counterparty are offset on the balance sheet.

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 is 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 also are 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 19, beginning on page FS-50, 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 chemicals 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 accounting standards for asset retirement and environmental obligations (Accounting Standards Codification (ASC) 410), 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 23, on page FS-60, 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 generally 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 proved reserves are produced. The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method generally is used to depreciate international plant and equipment and to amortize all capitalized leased assets.

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

Expenditures for maintenance (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 resulting from a business combination is not subject to amortization. As required by accounting standards for goodwill (ASC 350), 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.

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 ARO is made,

Note 1 Summary of Significant Accounting Policies - Continued

following accounting standards for asset retirement and environmental obligations. Refer to Note 23, on page FS-60, for a discussion of the company s AROs.

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 Currency translation adjustment on the Consolidated Statement of 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 entitlement method. Excise, value-added and 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. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in Purchased crude oil and products on the Consolidated Statement of Income.

Stock Options and Other Share-Based Compensation The company issues stock options and other share-based compensation to its employees and accounts for these transactions under the accounting standards for share-based compensation (ASC 718). For equity awards, such as stock options, total compensation cost is based on the grant date fair value
and for liability awards, such as stock appreciation rights, total compensation cost is based on the settlement value. The company recognizes stock-based compensation expense for all awards over the service period required to earn the award, which is the shorter of the vesting period or the time period an employee becomes eligible to retain the award at retirement. Stock options and stock appreciation rights granted under the company s Long-Term Incentive Plan have graded vesting provisions by which one-third of each award vests on the first, second and third anniversaries of the date of grant. The company amortizes these graded awards on a straight-line basis.

Note 2

Noncontrolling Interests

The company adopted accounting standards for noncontrolling interests (ASC 810) in the consolidated financial statements effective January 1, 2009, and retroactive to the earliest period presented. Ownership interests in the company s subsidiaries held by parties other than the parent are presented separately from the parent s equity on the Consolidated Balance Sheet. The amount of consolidated net income attributable to the parent and the noncontrolling interests are both presented on the face of the Consolidated Statement of Income. The term earnings is defined as Net Income Attributable to Chevron Corporation.

Activity for the equity attributable to noncontrolling interests for 2009, 2008 and 2007 is as follows:

	2009	2008	2007
Balance at January 1	**$ 469**	$ 204	$ 209

Net income	**80**	100	107
Distributions to noncontrolling interests	**(71)**	(99)	(77)
Other changes, net	**169**	264	(35)
Balance at December 31	**$ 647**	$ 469	$ 204

Note 3

Equity

Retained earnings at December 31, 2009 and 2008, included approximately $8,122 and $7,951, respectively, for the company s share of undistributed earnings of equity affiliates.

At December 31, 2009, about 94 million shares of Chevron s common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP). In addition, approximately 342,000 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).

Note 4
Information Relating to the Consolidated Statements of Cash Flows

	Year ended December 31		
	2009	2008	2007
Net (increase) decrease in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	**$ (1,476)**	$ 6,030	$ (3,867)
Decrease (increase) in inventories	**1,213**	(1,545)	(749)
Increase in prepaid expenses and other current assets	**(264)**	(621)	(370)
(Decrease) increase in accounts payable and accrued liabilities	**(1,121)**	(4,628)	4,930
(Decrease) increase in income and other taxes payable	**(653)**	(909)	741
Net (increase) decrease in operating working capital	**$ (2,301)**	$ (1,673)	$ 685
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$**	$	$ 203
Income taxes	**$ 7,537**	$ 19,130	$ 12,340
Net sales of marketable securities consisted of the following gross amounts:			
Marketable securities sold	**$ 157**	$ 3,719	$ 2,160
Marketable securities purchased	**(30)**	(3,236)	(1,975)
Net sales of marketable securities	**$ 127**	$ 483	$ 185

In accordance with accounting standards for cash-flow classifications for stock options (ASC 718), the Net (increase) decrease in operating working capital includes reductions of $25, $106 and $96 for excess income tax benefits associated with stock options exercised during 2009, 2008 and 2007, respectively. These amounts are offset by an equal amount in Net sales (purchases) of treasury shares.

The Net sales (purchases) of treasury shares represents the cost of common shares purchased less the cost of shares issued for share-based compensation plans. Purchases totaled $6, $8,011 and $7,036 in 2009, 2008 and 2007, respectively. Purchases in 2008 and 2007 included shares purchased under the company s common stock repurchase programs.

In 2009, Net sales (purchases) of other short-term investments consisted of $123 in restricted cash associated with capital-investment projects at the company s Pascagoula, Mississippi refinery and the Angola liquefied-natural-gas project that was invested in short-term securities and reclassified from Cash and cash equivalents to Deferred charges and other assets on the Consolidated Balance Sheet. The company issued $350 and $650, in 2009 and 2007 respectively, of tax exempt Mississippi Gulf Opportunity Zone Bonds as a source of funds for Pascagoula Refinery projects.

The Consolidated Statement of Cash Flows for 2009 excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2008, Net sales (purchases) of treasury shares excludes $680 of treasury shares acquired in exchange for a U.S. upstream property and $280 in cash. The carrying value of this property in Properties, plant and equipment on the Consolidated Balance Sheet was not significant. In 2008, a $2,450 increase in Accrued liabilities and a corresponding increase to Properties, plant and equipment, at cost were considered non-cash transactions and excluded from Net (increase) decrease in operating working capital and Capital expenditures. In 2009, the payments related to these Accrued liabilities were excluded from Net (increase) decrease in operating working capital and were reported as Capital expenditures. The amount is related to upstream operating agreements outside the United States.

Capital expenditures in 2008 excludes a $1,400 increase in Properties, plant and equipment related to the acquisition of an additional interest in an equity affiliate that required a change to the consolidated method of accounting for the investment during 2008. This addition was offset primarily by reductions in Investments and advances and working capital and an increase in Non-current deferred income tax liabilities. Refer also to Note 23, on page FS-60, for a discussion of revisions to the company s AROs that also did not involve cash receipts or payments for the three years ending December 31, 2009.

The major components of Capital expenditures and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, are presented in the following table:

	Year ended December 31		
	2009	2008	2007
Additions to properties, plant and equipment[1]	**$ 16,107**	$ 18,495	$ 16,127
Additions to investments	**942**	1,051	881
Current-year dry-hole expenditures	**468**	320	418
Payments for other liabilities and assets, net[2]	**2,326**	(200)	(748)
Capital expenditures	**19,843**	19,666	16,678
Expensed exploration expenditures	**790**	794	816
Assets acquired through capital lease obligations and other financing obligations	**19**	9	196
Capital and exploratory expenditures, excluding equity affiliates	**20,652**	20,469	17,690
Company s share of expenditures by equity affiliates	**1,585**	2,306	2,336
Capital and exploratory expenditures, including equity affiliates	**$ 22,237**	$ 22,775	$ 20,026

[1] Excludes noncash additions of $985 in 2009, $5,153 in 2008 and $3,560 in 2007.

[2] 2009 includes payments of $2,450 for accruals recorded in 2008.

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Note 5

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, excluding most of the regulated pipeline operations of Chevron. CUSA also holds the company s investment in the Chevron Phillips Chemical Company LLC joint venture, which is accounted for using the equity method.

During 2008, Chevron implemented legal reorganizations in which certain Chevron subsidiaries transferred assets to or under CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the table below gives retroactive effect to the reorganizations as if they had occurred on January 1, 2007. However, the financial information in the following table may not reflect the financial position and operating results in the future or the historical results in the periods presented if the reorganization actually had occurred on that date. The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2009	2008	2007
Sales and other operating revenues	**$ 121,553**	$ 195,593	$ 153,574
Total costs and other deductions	**120,053**	185,788	147,509
Net income attributable to CUSA	**1,141**	7,318	5,191

	At December 31	
	2009	2008
Current assets	**$ 23,286**	$ 32,760
Other assets	**32,827**	31,806
Current liabilities	**16,098**	14,322
Other liabilities	**14,625**	14,049
Total CUSA net equity	**25,390**	36,195
Memo: Total debt	**$ 6,999**	$ 6,813

The amount for the years ended December 31, 2008, and December 31, 2007, for Net income attributable to CUSA and the balances at December 31, 2008, for Other liabilities and Total CUSA net equity have been adjusted by immaterial amounts associated with the allocation of income-tax liabilities among Chevron Corporation subsidiaries.

Note 6

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 as follows:

	Year ended December 31		
	2009	2008	2007
Sales and other operating revenues	**$ 683**	$ 1,022	$ 667
Total costs and other deductions	**810**	947	713
Net income attributable to CTC	**(124)**	120	(39)

	At December 31	
	2009	2008
Current assets	**$ 377**	$ 482
Other assets	**173**	172
Current liabilities	**115**	98
Other liabilities	**90**	88
Total CTC net equity	**345**	468

There were no restrictions on CTC s ability to pay dividends or make loans or advances at December 31, 2009.

Note 7

Summarized Financial Data Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 12, on page FS-43, for a discussion of TCO operations.

Summarized financial information for 100 percent of TCO is presented in the following table:

	Year ended December 31		
	2009	2008	2007
Sales and other operating revenues	**$ 12,013**	$ 14,329	$ 8,919
Costs and other deductions	**6,044**	5,621	3,387
Net income attributable to TCO	**4,178**	6,134	3,952

	At December 31	
	2009	2008
Current assets	**$ 3,190**	$ 2,740
Other assets	**12,022**	12,240
Current liabilities	**2,426**	1,867
Other liabilities	**4,484**	4,759
Total TCO net equity	**8,302**	8,354

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Note 8

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 on the Consolidated Balance Sheet. Such leasing arrangements involve tanker charters, crude-oil production and processing equipment, service stations, office buildings, 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	
	2009	2008
Upstream	**$ 510**	$ 491
Downstream	**332**	399
Chemicals and all other	**171**	171
Total	**1,013**	1,061
Less: Accumulated amortization	**585**	522
Net capitalized leased assets	**$ 428**	$ 539

Rental expenses incurred for operating leases during 2009, 2008 and 2007 were as follows:

	Year ended December 31		
	2009	2008	2007
Minimum rentals	**$ 2,179**	$ 2,984	$ 2,419
Contingent rentals	**7**	6	6
Total	**2,186**	2,990	2,425
Less: Sublease rental income	**41**	41	30
Net rental expense	**$ 2,145**	$ 2,949	$ 2,395

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, 2009, 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: 2010	568	90
2011	438	81
2012	406	87
2013	372	60
2014	347	44
Thereafter	1,233	137
Total	$ 3,364	$ 499
Less: Amounts representing interest and executory costs		(104)
Net present values		395
Less: Capital lease obligations included in short-term debt		(94)
Long-term capital lease obligations		$ 301

Note 9

Fair Value Measurements

Accounting standards for fair-value measurement (ASC 820) establish a framework for measuring fair value and stipulate disclosures about fair-value measurements. The standards apply to recurring and nonrecurring financial and nonfinancial assets and liabilities that require or permit fair-value measurements. ASC 820 became effective for Chevron on January 1, 2008, for all financial assets and liabilities and recurring nonfinancial assets and liabilities. On January 1, 2009, the standard became effective for nonrecurring nonfinancial assets and liabilities. Among the required disclosures is the fair-value hierarchy of inputs the company uses to value an asset or a liability. The three levels of the fair-value hierarchy are described as follows:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities. For the company, Level 1 inputs include exchange-traded futures contracts for which the parties are willing to transact at the exchange-quoted price and marketable securities that are actively traded.

Level 2: Inputs other than Level 1 that are observable, either directly or indirectly. For the company, Level 2 inputs include quoted prices for similar assets or liabilities, prices obtained through third-party broker quotes, and prices that can be corroborated with other observable inputs for substantially the complete term of a contract.

Note 9 Fair Value Measurements - Continued

Level 3: Unobservable inputs. The company does not use Level 3 inputs for any of its recurring fair-value measurements. Level 3 inputs may be required for the determination of fair value associated with certain nonrecurring measurements of nonfinancial assets and liabilities. In 2009, the company used Level 3 inputs to determine the fair value of certain nonrecurring nonfinancial assets.

The fair-value hierarchy for recurring assets and liabilities measured at fair value at December 31, 2009, and December 31, 2008, is as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, **2009**	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	At December 31, 2008	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Marketable Securities	**$ 106**	**$106**	**$**	**$**	$ 213	$213	$	$
Derivatives	**127**	**14**	**113**		805	529	276	
Total Recurring Assets at Fair Value	**$ 233**	**$120**	**$ 113**	**$**	$ 1,018	$742	$ 276	$
Derivatives	**$ 101**	**$ 20**	**$ 81**	**$**	$ 516	$ 98	$ 418	$
Total Recurring Liabilities at Fair Value	**$ 101**	**$ 20**	**$ 81**	**$**	$ 516	$ 98	$ 418	$

Marketable Securities The company calculates fair value for its marketable securities based on quoted market prices for identical assets and liabilities. The fair values reflect the cash that would have been received if the instruments were sold at December 31, 2009. Marketable securities had average maturities of less than one year.

Derivatives The company records its derivative instruments other than any commodity derivative contracts that are designated as normal purchase and normal sale on the Consolidated Balance Sheet at fair value, with virtually all the offsetting amount to the Consolidated Statement of Income. For derivatives with identical or similar provisions as contracts that are publicly traded on a regular basis, the company uses the market values of the publicly traded instruments as an input for fair-value calculations.

The company s derivative instruments principally include crude-oil, natural-gas and refined-product futures, swaps, options and forward contracts. Derivatives classified as Level 1 include futures, swaps and options contracts traded in active markets such as the New York Mercantile Exchange.

Derivatives classified as Level 2 include swaps, options, and forward contracts principally with financial institutions and other oil and gas companies, the fair values for which are obtained from third-party broker quotes, industry pric-
ing services and exchanges. The company obtains multiple sources of pricing information for the Level 2 instruments. Since this pricing information is generated from observable market data, it has historically been very consistent. The company does not materially adjust this information. The company incorporates internal review, evaluation and assessment procedures, including a comparison of Level 2 fair values derived from the company s internally developed forward curves (on a sample basis) with the pricing information to document reasonable, logical and supportable fair-value determinations and proper level of classification.

Impairments of Properties, plant and equipment During 2009 and in accordance with the accounting standard for the impairment or disposal of long-lived assets (ASC 360), long-lived assets held and used with a carrying amount of \$949 were written down to a fair value of \$490, resulting in a before-tax loss of \$459. The fair values were determined from internal cash-flow models, using discount rates consistent with those used by the company to evaluate cash flows of other assets of a similar nature. Long-lived assets held for sale with a carrying amount of \$160 were written down to a fair value of \$68, resulting in a before-tax loss of \$92. The fair values were determined based on bids received from prospective buyers.

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Note 9 Fair Value Measurements - Continued

The fair-value hierarchy for nonrecurring assets and liabilities measured at fair value during 2009 is presented in the following table.

Assets and Liabilities Measured at Fair Value on a Non-recurring Basis

	Year Ended December 31 2009	Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Loss (Before Tax) Year Ended December 31 2009
Properties, plant and equipment, net (held and used)	**$ 490**	$	$	$ 490	$ 459
Properties, plant and equipment, net (held for sale)	**68**		68		92
Total Nonrecurring Assets at Fair Value	**$ 558**	$	$ 68	$ 490	$ 551

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents in U.S. and non-U.S. portfolios. The instruments held are primarily time deposits and money market funds. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end. Cash equivalents had carrying/fair values of $6,396 and $7,058 at December 31, 2009 and 2008, respectively, and average maturities under 90 days. The balance at December 31, 2009, includes $123 of investments for restricted funds related to an international upstream development project and Pascagoula Refinery projects, which are included in Deferred charges and other assets on the Consolidated Balance Sheet. Long-term debt of $5,705 and $1,221 had estimated fair values of $6,229 and $1,414 at December 31, 2009 and 2008, respectively.

Fair values of other financial instruments at the end of 2009 and 2008 were not material.

Note 10

Financial and Derivative Instruments

Derivative Commodity 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. From time to time, the company also uses derivative commodity instruments for limited trading purposes.

The company s derivative commodity instruments principally include crude-oil, natural-gas and refined-product futures, swaps, options and forward contracts. None of the company s derivative instruments is designated as a hedging instrument, although certain of the company s affiliates make such designation. The company s derivatives are not material to the company s financial position, results of operations or liquidity. The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodities and other derivatives activities.

The company uses International Swaps and Derivatives 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 mark-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.

Derivative instruments measured at fair value at December 31, 2009, and December 31, 2008, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are as follows:

Consolidated Balance Sheet: Fair Value of Derivatives Not Designated as Hedging Instruments

	Asset Derivatives	Fair Value		Liability Derivatives	Fair Value	
Type of Derivative Contract	Balance Sheet Classification	At December 31 **2009**	At December 31 2008	Balance Sheet Classification	At December 31 **2009**	At December 31 2008
Foreign Exchange	Accounts and notes receivable, net	**$**	$ 11	Accrued liabilities	**$**	$ 89
Commodity	Accounts and notes receivable, net	**99**	764	Accounts payable	**73**	344
Commodity	Long-term receivables, net	**28**	30	Deferred credits and other noncurrent obligations	**28**	83
		$ 127	$ 805		**$ 101**	$ 516

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Note 10 Financial and Derivative Instruments - Continued

Consolidated Statement of Income:
The Effect of Derivatives Not Designated as Hedging Instruments

Type of Derivative Contract	Statement of Income Classification	Gain/(Loss) Year Ended December 31 **2009**	2008
Foreign Exchange	Other income	**$ 26**	$ (314)
Commodity	Sales and other operating revenues	**(94)**	706
Commodity	Purchased crude oil and products	**(353)**	424
Commodity	Other income		(3)
		$ (421)	$ 813

Foreign Currency The company may enter into currency derivative contracts to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments. The currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open currency derivative contracts at December 31, 2009.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Historically, under the terms of the swaps, net cash settlements were 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, if any, may be accounted for as fair value hedges. Interest rate swaps related to floating-rate debt, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2009, the company had no interest rate swaps. The company s only interest rate swaps on fixed-rate debt matured in January 2009.

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

The trade receivable balances, reflecting the company s diversified sources of revenue, are dispersed among the company s broad customer base worldwide. As a result, 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 11

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 accounting standards for segment reporting (ASC 280).

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 ASC 280). 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 accounting standards for segment reporting (ASC 280), that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and to assess their performance; and (c) for which discrete financial information is available.

Segment managers for the reportable segments are directly accountable to and maintain regular contact with the company s CODM to discuss the segment s operating activities and financial performance. The CODM approves annual capital and exploratory budgets at the reportable segment level, as well as reviews capital and exploratory funding for major projects and approves major changes to the annual capital and exploratory budgets. However, business-unit managers within the operating segments are directly responsible for decisions relating to project implementation and all other matters connected with daily operations. Company officers who are

Note 11 Operating Segments and Geographic Data - Continued

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 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, and the company s interest in Dynegy (through May 2007, when Chevron sold its interest).

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. Earnings by major operating area are presented in the following table:

	Year ended December 31		
	2009	2008	2007
Segment Earnings			
Upstream			
United States	**$ 2,216**	$ 7,126	$ 4,532
International	**8,215**	14,584	10,284
Total Upstream	**10,431**	21,710	14,816
Downstream			
United States	**(273)**	1,369	966
International	**838**	2,060	2,536
Total Downstream	**565**	3,429	3,502
Chemicals			
United States	**198**	22	253
International	**211**	160	143
Total Chemicals	**409**	182	396
Total Segment Earnings	**11,405**	25,321	18,714
All Other			
Interest expense	**(22)**		(107)
Interest income	**46**	192	385
Other	**(946)**	(1,582)	(304)
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2009 and 2008 are as follows:

	At December 31	
	2009	2008
Upstream		
United States	**$ 24,918**	$ 26,071
International	**74,937**	72,530
Goodwill	**4,618**	4,619
Total Upstream	**104,473**	103,220
Downstream		
United States	**18,067**	15,869
International	**24,824**	23,572
Total Downstream	**42,891**	39,441
Chemicals		
United States	**2,810**	2,535
International	**1,066**	1,086
Total Chemicals	**3,876**	3,621
Total Segment Assets	**151,240**	146,282
All Other*		
United States	**7,125**	8,984
International	**6,256**	5,899
Total All Other	**13,381**	14,883
Total Assets United States	**52,920**	53,459
Total Assets International	**107,083**	103,087
Goodwill	**4,618**	4,619
Total Assets	**$ 164,621**	$ 161,165

* All Other assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, mining operations, power generation businesses, alternative fuels and 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 2009, 2008 and 2007, are presented in the table on the following page. 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, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of refined products, crude oil and natural gas liquids. Revenues

Note 11 Operating Segments and Geographic Data - Continued

for the chemicals segment are derived primarily from the manufacture and sale of additives for lubricants and fuels.
All Other activities include revenues from mining operations, 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 2009, 2008 and 2007.

	Year ended December 31		
	2009	2008	2007
Upstream			
United States	**$ 9,164**	$ 23,503	$ 18,736
Intersegment	**10,278**	15,142	11,625
Total United States	**19,442**	38,645	30,361
International	**13,409**	19,469	15,213
Intersegment	**18,477**	24,204	19,647
Total International	**31,886**	43,673	34,860
Total Upstream	**51,328**	82,318	65,221
Downstream			
United States	**57,846**	87,515	70,535
Excise and similar taxes	**4,573**	4,746	4,990
Intersegment	**190**	447	491
Total United States	**62,609**	92,708	76,016
International	**76,668**	122,064	97,178
Excise and similar taxes	**3,471**	5,044	5,042
Intersegment	**106**	122	38
Total International	**80,245**	127,230	102,258
Total Downstream	**142,854**	219,938	178,274
Chemicals			
United States	**271**	305	351
Excise and similar taxes	**-**	2	2
Intersegment	**194**	266	235
Total United States	**465**	573	588
International	**1,231**	1,388	1,143

Excise and similar taxes	**65**	55	86
Intersegment	**132**	154	142
Total International	**1,428**	1,597	1,371
Total Chemicals	**1,893**	2,170	1,959
All Other			
United States	**665**	815	757
Intersegment	**964**	917	760
Total United States	**1,629**	1,732	1,517
International	**39**	52	58
Intersegment	**33**	33	31
Total International	**72**	85	89
Total All Other	**1,701**	1,817	1,606
Segment Sales and Other Operating Revenues			
United States	**84,145**	133,658	108,482
International	**113,631**	172,585	138,578
Total Segment Sales and Other Operating Revenues	**197,776**	306,243	247,060
Elimination of intersegment sales	**(30,374)**	(41,285)	(32,969)
Total Sales and Other Operating Revenues	**$ 167,402**	$ 264,958	$ 214,091

Segment Income Taxes Segment income tax expense for the years 2009, 2008 and 2007 is as follows:

	Year ended December 31		
	2009	2008	2007
Upstream			
United States	**$ 1,225**	$ 3,693	$ 2,541
International	**7,686**	15,132	11,307
Total Upstream	**8,911**	18,825	13,848
Downstream			
United States	**(111)**	815	520
International	**182**	813	400
Total Downstream	**71**	1,628	920
Chemicals			
United States	**54**	(22)	6

International	**46**	47	36
Total Chemicals	**100**	25	42
All Other	**(1,117)**	(1,452)	(1,331)
Total Income Tax Expense	**$ 7,965**	$ 19,026	$ 13,479

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page FS-43. Information related to properties, plant and equipment by segment is contained in Note 13, on page FS-45.

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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, is 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 does 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		
	2009	2008	**2009**	2008	2007
Upstream					
Tengizchevroil	**$ 5,938**	$ 6,290	**$ 2,216**	$ 3,220	$ 2,135
Petropiar/Hamaca	**1,139**	1,130	**122**	317	327
Petroboscan	**832**	816	**171**	244	185
Angola LNG Limited	**1,853**	1,191	**(12)**	(8)	21
Other	**686**	725	**118**	206	204
Total Upstream	**10,448**	10,152	**2,615**	3,979	2,872
Downstream					
GS Caltex Corporation	**2,406**	2,601	**(191)**	444	217
Caspian Pipeline Consortium	**852**	749	**105**	103	102
Star Petroleum Refining Company Ltd.	**873**	877	**(4)**	22	157
Caltex Australia Ltd.	**740**	723	**11**	250	129
Colonial Pipeline Company	**514**	536	**51**	32	39
Other	**1,773**	1,664	**311**	354	318
Total Downstream	**7,158**	7,150	**283**	1,205	962
Chemicals					
Chevron Phillips Chemical Company LLC	**2,327**	2,037	**328**	158	380
Other	**28**	25	**7**	4	6
Total Chemicals	**2,355**	2,062	**335**	162	386
All Other					
Other	**507**	567	**83**	20	(76)
Total equity method	**$ 20,468**	$ 19,931	**$ 3,316**	$ 5,366	$ 4,144
Other at or below cost	**690**	989			

Total investments and advances	**$ 21,158**	$ 20,920			
Total United States	**$ 4,195**	$ 4,002	**$ 511**	$ 307	$ 478
Total International	**$ 16,963**	$ 16,918	**$ 2,805**	$ 5,059	$ 3,666

Descriptions of major affiliates, including significant differences between the company s carrying value of its investments and its underlying equity in the net assets of the 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. At December 31, 2009, the company s carrying value of its investment in TCO was about $200 higher than the amount of underlying equity in TCO s net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO s net assets. See Note 7, on page FS-36, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company formed in 2008 to operate the Hamaca heavy-oil production and upgrading project. The project, located in Venezuela s Orinoco Belt, has a 25-year contract term. Prior to the formation of Petropiar, Chevron had a 30 percent interest in the Hamaca project. At December 31, 2009, the company s carrying value of its investment in Petropiar was approximately $195 less than the amount of underlying equity in Petropiar s net assets. The difference represents the excess of Chevron s underlying equity in Petropiar s net assets over the net book value of the assets contributed to the venture.

Petroboscan Chevron has a 39 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela until 2026. Chevron previously operated the field under an operating service agreement. At December 31, 2009, the company s carrying value of its investment in Petroboscan was approximately $275 higher than the amount of underlying equity in Petroboscan s net assets. The difference reflects the excess of the net book value of the assets contributed by Chevron over its underlying equity in Petroboscan s net assets.

Angola LNG Ltd. Chevron has a 36 percent interest in Angola LNG Ltd., which will process and liquefy natural gas produced in Angola for delivery to international markets.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex Corporation, a joint venture with GS Holdings. The joint venture 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, which provides the critical export route for crude oil from both TCO and Karachaganak.

Star Petroleum Refining Company Ltd. Chevron has a 64 percent equity ownership interest in Star Petroleum Refining Company Ltd. (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 Ltd. (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2009,

Note 12 Investments and Advances - Continued

the fair value of Chevron s share of CAL common stock was approximately $1,120.

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, 2009, the company s carrying value of its investment in Colonial Pipeline was approximately $550 higher than the amount of underlying equity in Colonial Pipeline net assets. This difference primarily relates to purchase price adjustments from the acquisition of Unocal Corporation.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC. The other half is owned by ConocoPhillips Corporation.

Other Information Sales and other operating revenues on the Consolidated Statement of Income includes $10,391, $15,390 and $11,555 with affiliated companies for 2009, 2008 and 2007, respectively. Purchased crude oil and products includes
$4,631, $6,850 and $5,464 with affiliated companies for 2009, 2008 and 2007, respectively.

Accounts and notes receivable on the Consolidated Balance Sheet includes $1,125 and $701 due from affiliated companies at December 31, 2009 and 2008, respectively. Accounts payable includes $345 and $289 due to affiliated companies at December 31, 2009 and 2008, respectively.

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 $2,422 at December 31, 2009.

			Affiliates			Chevron Share
Year ended December 31	**2009**	2008	2007	**2009**	2008	2007
Total revenues	**$ 81,995**	$ 112,707	$ 94,864	**$ 39,280**	$ 54,055	$ 46,579
Income before income tax expense	**11,083**	17,500	12,510	**4,511**	7,532	5,836
Net income attributable to affiliates	**8,261**	12,705	9,743	**3,285**	5,524	4,550
At December 31						
Current assets	**$ 27,111**	$ 25,194	$ 26,360	**$ 11,009**	$ 10,804	$ 11,914
Noncurrent assets	**55,363**	51,878	48,440	**21,361**	20,129	19,045
Current liabilities	**17,450**	17,727	19,033	**7,833**	7,474	9,009
Noncurrent liabilities	**21,531**	21,049	22,757	**5,106**	4,533	3,745
Total affiliates net equity	**$ 43,493**	$ 38,296	$ 33,010	**$ 19,431**	$ 18,926	$ 18,205

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Note 13
Properties, Plant and Equipment[1]

				At December 31						Year ended December		
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expens		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	20
stream												
ted States	**$ 57,645**	$ 54,156	$ 50,991	**$ 21,885**	$ 22,294	$ 19,850	**$ 3,496**	$ 5,374	$ 5,725	**$ 3,963**	$ 2,683	$ 2,7
ernational	**93,177**	84,282	71,408	**54,253**	51,140	43,431	**9,750**	13,177	10,512	**6,651**	5,441	4,6
al stream	**150,822**	138,438	122,399	**76,138**	73,434	63,281	**13,246**	18,551	16,237	**10,614**	8,124	7,3
wnstream												
ted States	**18,915**	17,394	15,807	**10,089**	8,977	7,685	**1,871**	2,032	1,514	**664**	629	5
ernational	**12,319**	11,587	10,471	**6,806**	6,001	4,690	**1,424**	2,285	519	**437**	469	6
al wnstream	**31,234**	28,981	26,278	**16,895**	14,978	12,375	**3,295**	4,317	2,033	**1,101**	1,098	1,1
emicals												
ted States	**730**	725	678	**331**	338	308	**25**	50	40	**31**	19	
ernational	**913**	828	815	**545**	496	453	**85**	72	53	**35**	33	
al emicals	**1,643**	1,553	1,493	**876**	834	761	**110**	122	93	**66**	52	
Other[4]												
ted States	**4,569**	4,310	3,873	**2,548**	2,523	2,179	**354**	598	680	**325**	250	2
ernational	**20**	17	41	**11**	11	14	**3**	5	5	**4**	4	
al All er	**4,589**	4,327	3,914	**2,559**	2,534	2,193	**357**	603	685	**329**	254	2
al United tes	**81,859**	76,585	71,349	**34,853**	34,132	30,022	**5,746**	8,054	7,959	**4,983**	3,581	3,4
al ernational	**106,429**	96,714	82,735	**61,615**	57,648	48,588	**11,262**	15,539	11,089	**7,127**	5,947	5,2
al	**$ 188,288**	$ 173,299	$ 154,084	**$ 96,468**	$ 91,780	$ 78,610	**$ 17,008**	$ 23,593	$ 19,048	**$ 12,110**	$ 9,528	$ 8,7

[1] Other than the United States and Nigeria, no other country accounted for 10 percent or more of the company s net properties, plant and equipment (PP&E) in 2009 and 2008. Only the United States had more than 10 percent in 2007. Nigeria had net PP&E of $12,463 and $10,730 for 2009 and 2008, respectively.

[2] Net of dry hole expense related to prior years   expenditures of $84, $55 and $89 in 2009, 2008 and 2007, respectively.

[3] Depreciation expense includes accretion expense of $463, $430 and $399 in 2009, 2008 and 2007, respectively.

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

Note 14

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 50 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims 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 pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

Ecuador Chevron is a defendant in a civil lawsuit before the Superior Court of Nueva Loja in Lago Agrio, Ecuador, brought in May 2003 by plaintiffs who claim to be representatives of certain residents of an area where an oil production consortium formerly had operations. The lawsuit alleges damage to the environment from the oil exploration and production operations and seeks unspecified damages to fund environmental remediation and restoration of the alleged environmental harm, plus a health monitoring program. Until 1992, Texaco Petroleum Company (Texpet), a subsidiary of Texaco Inc., was a minority member of this consortium with Petroecuador, the Ecuadorian state-owned oil company, as the majority partner; since 1990, the operations have been conducted solely by Petroecuador. At the conclusion of the consortium and following an independent third-party environmental audit of the concession area, Texpet entered into a formal agreement with the Republic of Ecuador and Petroecuador for Texpet to remediate specific sites assigned by the government in proportion to Texpet   s ownership share of the consortium. Pursuant to that agreement, Texpet conducted a three-year remediation program at a cost of $40. After certifying that the sites were properly remediated, the government granted Texpet and all related corporate entities a full release from any and all environmental liability arising from the consortium operations.

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously

Note 14 Litigation - Continued

given to Texpet by the Republic of Ecuador and Petroecuador. With regard to the facts, the company believes that the evidence confirms that Texpet s remediation was properly conducted and that the remaining environmental damage reflects Petroecuador s failure to timely fulfill its legal obligations and Petroecuador s further conduct since assuming full control over the operations.

In April 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $8,000, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer s report also asserted that an additional $8,300 could be assessed against Chevron for unjust enrichment. The engineer s report is not binding on the court. Chevron also believes that the engineer s work was performed and his report prepared in a manner contrary to law and in violation of the court s orders. Chevron submitted a rebuttal to the report in which it asked the court to strike the report in its entirety. In November 2008, the engineer revised the report and, without additional evidence, recommended an increase in the financial compensation for purported damages to a total of $18,900 and an increase in the assessment for purported unjust enrichment to a total of $8,400. Chevron submitted a rebuttal to the revised report, which the court dismissed. In September 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case petitioned to be recused. In late September 2009, the judge was recused, and in October 2009, the full chamber of the provincial court affirmed the recusal, resulting in the appointment of a new judge. Chevron filed motions to annul all of the rulings made by the prior judge, but the new judge denied these motions. The court has completed most of the procedural aspects of the case and could render a judgment at any time. Chevron will continue a vigorous defense of any attempted imposition of liability.

In the event of an adverse judgment, Chevron would expect to pursue its appeals and vigorously defend against enforcement of any such judgment; therefore, the ultimate outcome and any financial effect on Chevron remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this

case. Due to the defects associated with the engineer s report, management does not believe the report has any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

Note 15

Taxes

Income Taxes

	Year ended December 31		
	2009	2008	2007
Taxes on income			
U.S. Federal			
Current	**$ 128**	$ 2,879	$ 1,446
Deferred	**(147)**	274	225
State and local			
Current	**216**	528	356
Deferred	**14**	141	(18)
Total United States	**211**	3,822	2,009

International			
Current	**7,154**	15,021	11,416
Deferred	**600**	183	54
Total International	**7,754**	15,204	11,470
Total taxes on income	**$ 7,965**	$ 19,026	$ 13,479

In 2009, before-tax income for U.S. operations, including related corporate and other charges, was $1,310, compared with before-tax income of $10,765 and $7,886 in 2008 and 2007, respectively. For international operations, before-tax income was $17,218, $32,292 and $24,388 in 2009, 2008 and 2007, respectively. U.S. federal income tax expense was reduced by $204, $198 and $132 in 2009, 2008 and 2007, 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 following table:

	Year ended December 31		
	2009	2008	2007
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	**10.4**	10.1	8.2
State and local taxes on income, net of U.S. federal income tax benefit	**0.9**	1.0	0.8
Prior-year tax adjustments	**(0.3)**	(0.1)	0.3
Tax credits	**(1.1)**	(0.5)	(0.4)
Effects of enacted changes in tax laws	**0.1**	(0.6)	(0.3)
Other	**(2.0)**	(0.7)	(1.8)
Effective tax rate	**43.0%**	44.2%	41.8%

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Note 15 Taxes - Continued

The company s effective tax rate decreased from 44.2 percent in 2008 to 43.0 percent in 2009. The rate was lower in 2009 mainly due to the effect of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity-affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates.

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	
	2009	2008
Deferred tax liabilities		
Properties, plant and equipment	**$ 18,545**	$ 18,271
Investments and other	**2,350**	2,225
Total deferred tax liabilities	**20,895**	20,496
Deferred tax assets		
Foreign tax credits	**(5,387)**	(4,784)
Abandonment/environmental reserves	**(4,424)**	(4,338)
Employee benefits	**(3,499)**	(3,488)
Deferred credits	**(3,469)**	(3,933)
Tax loss carryforwards	**(819)**	(1,139)
Other accrued liabilities	**(553)**	(445)
Inventory	**(431)**	(260)
Miscellaneous	**(1,681)**	(1,732)
Total deferred tax assets	**(20,263)**	(20,119)
Deferred tax assets valuation allowance	**7,921**	7,535
Total deferred taxes, net	**$ 8,553**	$ 7,912

Deferred tax liabilities at the end of 2009 increased by approximately $400 from year-end 2008. The increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets were essentially unchanged in 2009. Increases related to additional foreign tax credits arising from earnings in high-tax-rate international jurisdictions (which were substantially offset by valuation allowances) and to inventory-related temporary differences. These effects were offset by reductions in deferred credits and tax loss carryforwards primarily resulting from the usage of tax benefits in international tax jurisdictions.

The overall valuation allowance relates to deferred tax assets for foreign tax credit carryforwards, tax loss carryforwards and temporary differences. It reduces the deferred tax assets to amounts that are, in management s assessment, more likely than not 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 2010 through 2036. Foreign tax credit carryforwards of $5,387 will expire between 2010 and 2019.

At December 31, 2009 and 2008, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2009	2008
Prepaid expenses and other current assets	**$ (1,825)**	$ (1,130)
Deferred charges and other assets	**(1,268)**	(2,686)
Federal and other taxes on income	**125**	189
Noncurrent deferred income taxes	**11,521**	11,539
Total deferred income taxes, net	**$ 8,553**	$ 7,912

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 $20,458 at December 31, 2009. 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 earnings that are intended to be reinvested indefinitely. At the end of 2009, deferred income taxes were recorded for the undistributed earnings of certain international operations for which the company no longer intends to indefinitely reinvest the earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

Uncertain Income Tax Positions Under accounting standards for uncertainty in income taxes (ASC 740-10), a company recognizes a tax benefit in the financial statements for an uncertain tax position only if management s assessment is that the position is more likely than not (i.e., a likelihood greater than 50 percent) to be allowed by the tax jurisdiction based solely on the technical merits of the position. The term tax position in the accounting standards for income taxes (ASC 740-10-20) refers to a position in a previously filed tax return or a position expected to be taken in a future tax return that is reflected in measuring current or deferred income tax assets and liabilities for interim or annual periods.

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

Note 15 Taxes - Continued

The following table indicates the changes to the company s unrecognized tax benefits for the year ended December 31, 2009. The term unrecognized tax benefits in the accounting standards for income taxes (ASC 740-10-20) refers to the differences between a tax position taken or expected to be taken in a tax return and the benefit measured and recognized in the financial statements. Interest and penalties are not included.

	2009	2008	2007
Balance at January 1	**$ 2,696**	$ 2,199	$ 2,296
Foreign currency effects	**(1)**	(1)	19
Additions based on tax positions taken in current year	**459**	522	418
Reductions based on tax positions taken in current year		(17)	
Additions/reductions resulting from current-year asset acquisitions/sales		175	
Additions for tax positions taken in prior years	**533**	337	120
Reductions for tax positions taken in prior years	**(182)**	(246)	(225)
Settlements with taxing authorities in current year	**(300)**	(215)	(255)
Reductions as a result of a lapse of the applicable statute of limitations	**(10)**	(58)	
Reductions due to tax positions previously expected to be taken but subsequently not taken on prior-year tax returns			(174)
Balance at December 31	**$ 3,195**	$ 2,696	$ 2,199

Although unrecognized tax benefits for individual tax positions may increase or decrease during 2010, the company believes that no change will be individually significant during 2010. Approximately 90 percent of the $3,195 of unrecognized tax benefits at December 31, 2009, would have an impact on the effective tax rate if subsequently recognized.

Tax positions for Chevron and its subsidiaries and affiliates are subject to income tax audits by many tax jurisdictions throughout the world. For the company s major tax jurisdictions, examinations of tax returns for certain prior tax years had not been completed as of December 31, 2009. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States 2005, Nigeria 1994, Angola 2001 and Saudi Arabia 2003.

On the Consolidated Statement of Income, the company reports interest and penalties related to liabilities for uncertain tax positions as Income tax expense. As of December 31, 2009, accruals of $232 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet,
compared with accruals of $276 as of year-end 2008. Income tax (benefit) expense associated with interest and penalties was $(20), $79 and $70 in 2009, 2008 and 2007, respectively.

Taxes Other Than on Income

Year ended December 31

	2009	2008	2007
United States			
Excise and similar taxes on products and merchandise	**$ 4,573**	$ 4,748	$ 4,992
Import duties and other levies	**(4)**	1	12
Property and other miscellaneous taxes	**584**	588	491
Payroll taxes	**223**	204	185
Taxes on production	**135**	431	288
Total United States	**5,511**	5,972	5,968
International			
Excise and similar taxes on products and merchandise	**3,536**	5,098	5,129
Import duties and other levies	**6,550**	8,368	10,404
Property and other miscellaneous taxes	**1,740**	1,557	528
Payroll taxes	**134**	106	89
Taxes on production	**120**	202	148
Total International	**12,080**	15,331	16,298
Total taxes other than on income	**$ 17,591**	$ 21,303	$ 22,266

Note 16
Short-Term Debt

	At December 31	
	2009	2008
Commercial paper*	**$ 2,499**	$ 5,742
Notes payable to banks and others with originating terms of one year or less	**213**	149
Current maturities of long-term debt	**66**	429
Current maturities of long-term capital leases	**76**	78
Redeemable long-term obligations		
Long-term debt	**1,702**	1,351
Capital leases	**18**	19
Subtotal	**4,574**	7,768
Reclassified to long-term debt	**(4,190)**	(4,950)
Total short-term debt	**$ 384**	$ 2,818

* Weighted-average interest rates at December 31, 2009 and 2008,

were 0.08 percent
and 0.67 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 within one year following the balance sheet date. In 2009, $350 of tax-exempt Gulf Opportunity Zone bonds related to projects at the Pascagoula Refinery were issued.

The company periodically enters into interest rate swaps on a portion of its short-term debt. At December 31, 2009, the company had no interest rate swaps on short-term debt. See Note 10, beginning on page FS-39, for information concerning the company s debt-related derivative activities.

At December 31, 2009, the company had $5,100 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company s commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2009 or at year-end.

At December 31, 2009 and 2008, the company classified $4,190 and $4,950, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2010, as the company has both the intent and the ability to refinance this debt on a long-term basis.

Note 17

Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2009, was $9,829. The company s long-term debt outstanding at year-end 2009 and 2008 was as follows:

	At December 31	
	2009	2008
3.95% notes due 2014	**$ 1,997**	$
3.45% notes due 2012	**1,500**	
4.95% notes due 2019	**1,500**	
5.5% notes due 2009		400
8.625% debentures due 2032	**147**	147
7.327% amortizing notes due 2014[1]	**109**	194
8.625% debentures due 2031	**107**	108
7.5% debentures due 2043	**83**	85
8% debentures due 2032	**74**	74
9.75% debentures due 2020	**56**	56
8.875% debentures due 2021	**40**	40
8.625% debentures due 2010	**30**	30
Medium-term notes, maturing from 2021 to 2038 (5.97%)[2]	**38**	38
Fixed interest rate notes, maturing 2011 (9.378%)[2]	**19**	21
Other foreign currency obligations		13
Other long-term debt (6.69%)[2]	**5**	15
Total including debt due within one year	**5,705**	1,221
Debt due within one year	**(66)**	(429)
Reclassified from short-term debt	**4,190**	4,950
Total long-term debt	**$ 9,829**	$ 5,742

1 Guarantee of ESOP debt.

[2] Weighted-average interest rate at December 31, 2009.

Long-term debt of $5,705 matures as follows: 2010 $66; 2011 $33; 2012 $1,520; 2013 $21; 2014 $2,020; and after 2014 $2,045.

In 2009, $5,000 of public bonds was issued, and $400 of Texaco Capital Inc. bonds matured. In 2008, debt totaling $822 matured, including $749 of Chevron Canada Funding Company notes.

Note 18

New Accounting Standards

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162 (FAS 168) In June 2009, the FASB issued FAS 168, which became effective for the company in the quarter ending September 30, 2009. This standard established the FASB Accounting Standards Codification (ASC) system as the single authoritative source of U.S. generally accepted accounting principles (GAAP) and superseded existing literature of the FASB, Emerging Issues Task Force, American Institute of CPAs and other sources. The ASC did not change GAAP, but organized the literature into about 90 accounting Topics. Adoption of the ASC did not affect the company s accounting.

Employer s Disclosures About Postretirement Benefit Plan Assets (FSP FAS 132(R)-1) In December 2008, the FASB issued FSP FAS 132(R)-1, which was subsequently codified into ASC 715, *Compensation Retirement Benefits,* and became effective with the company s reporting at December 31, 2009. This standard amended and expanded the disclosure requirements for the plan assets of defined benefit pension and other postretirement plans. Refer to information beginning on page FS-52 in Note 21, Employee Benefits, for these disclosures.

Transfers and Servicing (ASC 860), Accounting for Transfers of Financial Assets (ASU 2009-16) The FASB issued ASU 2009-16 in December 2009. This standard became effective for the company on January 1, 2010. ASU 2009-16 changes how companies account for transfers of financial assets and eliminates the concept of qualifying special-purpose entities. Adoption of the guidance is not expected to have an impact on the company s results of operations, financial position or liquidity.

Consolidation (ASC 810), Improvements to Financial Reporting by Enterprises Involved With Variable Interest Entities (ASU 2009-17) The FASB issued ASU 2009-17 in December 2009. This standard became effective for the company January 1, 2010. ASU 2009-17 requires the enterprise to qualitatively

Note 18 New Accounting Standards - Continued

assess if it is the primary beneficiary of a variable-interest entity (VIE), and, if so, the VIE must be consolidated. Adoption of the standard is not expected to have a material impact on the company s results of operations, financial position or liquidity.

Extractive Industries Oil and Gas (ASC 932), Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03) In January 2010, the FASB issued ASU 2010-03, which became effective for the company on December 31, 2009. The standard amends certain sections of ASC 932, *Extractive Industries Oil and Gas,* to align them with the requirements in the Securities and Exchange Commission s final rule, *Modernization of the Oil and Gas Reporting Requirements* (the final rule). The final rule was issued on December 31, 2008. Refer to Table V Reserve Quantity Information, beginning on page FS-69, for additional information on the final rule and the impact of adoption.

Note 19

Accounting for Suspended Exploratory Wells

Accounting standards for the costs of exploratory wells (ASC 932) provide 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. The accounting standards provide a number of indicators that can assist an entity in demonstrating that 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, 2009:

	2009	2008	2007
Beginning balance at January 1	**$ 2,118**	$ 1,660	$ 1,239
Additions to capitalized exploratory well costs pending the determination of proved reserves	**663**	643	486
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(174)**	(49)	(23)
Capitalized exploratory well costs charged to expense	**(172)**	(136)	(42)
Ending balance at December 31	**$ 2,435**	$ 2,118	$ 1,660

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.

		At December 31	
	2009	2008	2007
Exploratory well costs capitalized for a period of one year or less	**$ 564**	$ 559	$ 449
	1,871	1,559	1,211

Exploratory well costs capitalized for a period greater than one year			
Balance at December 31	**$ 2,435**	$ 2,118	$ 1,660
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**46**	50	54

* Certain projects have multiple wells or fields or both.

Of the $1,871 of exploratory well costs capitalized for more than one year at December 31, 2009, $1,143 (28 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $728 balance is related to 18 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.

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Note 19 Accounting for Suspended Exploratory Wells - Continued

The projects for the $728 referenced above had the following activities associated with assessing the reserves and the projects economic viability: (a) $330 (one project) negotiation of crude-oil and natural-gas transportation contracts and construction agreements; (b) $107 (two projects) discussion with possible natural-gas purchasers ongoing; (c) $73 (two projects) continued unitization efforts on adjacent discoveries that span international boundaries while planning on an LNG facility has commenced; (d) $49 (one project) progression of development concept selection; (e) $47 (one project) subsurface and facilities engineering studies concluding with front-end engineering and design expected to begin in early 2010; (f) $34 (one project) reviewing development alternatives; $88 miscellaneous activities for 10 projects with smaller amounts suspended. While progress was being made on all 46 projects, 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 $1,871 of suspended well costs capitalized for a period greater than one year as of December 31, 2009, represents 149 exploratory wells in 46 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
1992	$ 8	3
1997 1998	15	3
1999 2003	271	42
2004 2008	1,577	101
Total	$ 1,871	149

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
1992	$ 8	1
1999	8	1
2003 2004	242	5
2005 2009	1,613	39
Total	$ 1,871	46

Note 20

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2009, 2008 and 2007 was $182 ($119 after tax), $168 ($109 after tax) and $146 ($95 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was $170 ($110 after tax), $132 ($86 after tax) and $205 ($133 after tax) for 2009, 2008 and 2007, respectively. No significant stock-based compensation cost was capitalized at December 31, 2009 and 2008.

Cash received in payment for option exercises under all share-based payment arrangements for 2009, 2008 and 2007 was $147, $404 and $445, respectively. Actual tax benefits realized for the tax deductions from option exercises were $25, $103 and $94 for 2009, 2008 and 2007, respectively.

Cash paid to settle performance units and stock appreciation rights was $89, $136 and $88 for 2009, 2008 and 2007, respectively.

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 nonstock 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 option, stock appreciation right or award requiring full payment for shares by the award recipient.

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, which have 10-year contractual lives extending into 2011, retained a provision for being restored. This provision 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. Beginning in 2007, restored options were issued under the LTIP. No further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) When Chevron acquired 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. These awards retained the same provisions as the original Unocal Plans. If not exercised, these awards will expire between early 2010 and early 2015.

Note 20 Stock Options and Other Share-Based Compensation - Continued

The fair market values of stock options and stock appreciation rights granted in 2009, 2008 and 2007 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2009	2008	2007
Stock Options			
Expected term in years[1]	**6.0**	6.1	6.3
Volatility[2]	**30.2%**	22.0%	22.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**2.1%**	3.0%	4.5%
Dividend yield	**3.2%**	2.7%	3.2%
Weighted-average fair value per option granted	**$ 15.36**	$ 15.97	$ 15.27
Restored Options			
Expected term in years[1]	**1.2**	1.2	1.6
Volatility[2]	**45.0%**	23.1%	21.2%
Risk-free interest rate based on zero coupon U.S. treasury note	**1.1%**	1.9%	4.5%
Dividend yield	**3.5%**	2.7%	3.2%
Weighted-average fair value per option granted	**$ 12.38**	$ 10.01	$ 8.61

1 Expected term is based on historical exercise and postvesting cancellation data.

2 Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

A summary of option activity during 2009 is presented below:

Weighted-

	Shares (Thousands)	Weighted-Average Exercise Price	Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2009	59,013	$ 61.36		
Granted	14,709	$ 69.69		
Exercised	(3,418)	$ 45.75		
Restored	1	$ 70.40		
Forfeited	(842)	$ 76.02		
Outstanding at December 31, 2009	69,463	$ 63.70	6.4 yrs	$ 1,019
Exercisable at December 31, 2009	44,120	$ 57.34	5.1 yrs	$ 904

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2009, 2008 and 2007 was $91, $433 and $423, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2009, there was $233 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 1.8 years.

At January 1, 2009, the number of LTIP performance units outstanding was equivalent to 2,400,555 shares. During 2009, 992,800 units were granted, 668,953 units vested with cash proceeds distributed to recipients and 45,294 units were forfeited. At December 31, 2009, units outstanding were 2,679,108, and the fair value of the liability recorded for these instruments was $233. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 1.5 million equivalent shares as of December 31, 2009. A liability of $45 was recorded for these awards.

In March 2009, Chevron granted all eligible LTIP employees restricted stock units in lieu of annual cash bonus. The expense associated with these special restricted stock units was recognized at the time of the grants. A total of 453,965 units were granted at $69.70 per unit at the time of the grant. Total fair value of the special restricted stock units was $32 as of December 31, 2009. All of the special restricted stock units will be payable in November 2010.

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 (OPEB) 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 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. Certain life insurance benefits are paid by the company.

Under accounting standards for postretirement benefits (ASC 715), the company recognizes the overfunded or underfunded status of each of its defined benefit pension and OPEB as an asset or liability on the Consolidated Balance Sheet.

The funded status of the company s pension and other postretirement benefit plans for 2009 and 2008 is on the following page:

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Note 21 Employee Benefit Plans - Continued

	Pension Benefits					
	2009		2008		Other Benefits	
	U.S.	Int l.	U.S.	Int l.	**2009**	2008
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 8,127**	**$ 3,891**	$ 8,395	$ 4,633	**$ 2,931**	$ 2,939
Service cost	**266**	**128**	250	132	**43**	44
Interest cost	**481**	**292**	499	292	**180**	178
Plan participants contributions		**7**		9	**145**	152
Plan amendments	**1**	**10**		32	**20**	
Curtailments					**(5)**	
Actuarial loss (gain)	**1,391**	**299**	(62)	(104)	**56**	(14)
Foreign currency exchange rate changes		**333**		(858)	**27**	(28)
Benefits paid	**(602)**	**(245)**	(955)	(246)	**(332)**	(340)
Special termination benefits				1		
Benefit obligation at December 31	**9,664**	**4,715**	8,127	3,891	**3,065**	2,931
Change in Plan Assets						
Fair value of plan assets at January 1	**5,448**	**2,600**	7,918	3,892		
Actual return on plan assets	**964**	**402**	(2,092)	(655)		
Foreign currency exchange rate changes		**226**		(662)		
Employer contributions	**1,494**	**245**	577	262	**187**	188
Plan participants contributions		**7**		9	**145**	152
Benefits paid	**(602)**	**(245)**	(955)	(246)	**(332)**	(340)
Fair value of plan assets at December 31	**7,304**	**3,235**	5,448	2,600		
Funded Status at December 31	**$ (2,360)**	**$ (1,480)**	$ (2,679)	$ (1,291)	**$ (3,065)**	$ (2,931)

Amounts recognized on the Consolidated Balance Sheet for the company s pension and other postretirement benefit plans at December 31, 2009 and 2008, include:

	Pension Benefits					
	2009		2008		Other Benefits	
	U.S.	Int l.	U.S.	Int l.	**2009**	2008
Deferred charges and other assets	**$ 6**	**$ 37**	$ 6	$ 31	**$**	$
Accrued liabilities	**(66)**	**(67)**	(72)	(61)	**(208)**	(209)

Reserves for employee benefit plans	**(2,300)**	**(1,450)**	(2,613)	(1,261)	**(2,857)**	(2,722)
Net amount recognized at December 31	**$ (2,360)**	**$ (1,480)**	$ (2,679)	$ (1,291)	**$ (3,065)**	$ (2,931)

Amounts recognized on a before-tax basis in Accumulated other comprehensive loss for the company s pension and OPEB plans were $6,454 and $5,831 at the end of 2009 and 2008, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2009		2008			
	U.S.	Int l.	U.S.	Int l.	**2009**	2008
Net actuarial loss	**$ 4,181**	**$ 1,889**	$ 3,797	$ 1,804	**$ 465**	$ 410
Prior-service (credit) costs	**(60)**	**201**	(68)	211	**(222)**	(323)
Total recognized at December 31	**$ 4,121**	**$ 2,090**	$ 3,729	$ 2,015	**$ 243**	$ 87

The accumulated benefit obligations for all U.S. and international pension plans were $8,707 and $4,029, respectively, at December 31, 2009, and $7,376 and $3,273, respectively, at December 31, 2008.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2009 and 2008, was:

	Pension Benefits			
	2009		2008	
	U.S.	Int l.	U.S.	Int l.
Projected benefit obligations	**$ 9,658**	**$ 3,550**	$ 8,121	$ 2,906
Accumulated benefit obligations	**8,702**	**3,102**	7,371	2,539
Fair value of plan assets	**7,292**	**2,116**	5,436	1,698

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

Note 21 Employee Benefit Plans - Continued

The components of net periodic benefit cost and amounts recognized in other comprehensive income for 2009, 2008 and 2007 are shown in the table below:

	Pension Benefits						Other Benefits		
	2009		2008		2007				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2009**	2008	2007
Net Periodic Benefit Cost									
Service cost	**$ 266**	**$ 128**	$ 250	$ 132	$ 260	$ 125	**$ 43**	$ 44	$ 49
Interest cost	**481**	**292**	499	292	483	255	**180**	178	184
Expected return on plan assets	**(395)**	**(203)**	(593)	(273)	(578)	(266)			
Amortization of prior-service (credits) costs	**(7)**	**23**	(7)	24	46	17	**(81)**	(81)	(81)
Recognized actuarial losses	**298**	**108**	60	77	128	82	**27**	38	81
Settlement losses	**141**	**1**	306	2	65				
Curtailment losses						3	**(5)**		
Special termination benefit recognition				1					
Total net periodic benefit cost	**784**	**349**	515	255	404	216	**164**	179	233
Changes Recognized in Other Comprehensive Income									
Net actuarial loss (gain) during period	**823**	**194**	2,624	646	(160)	31	**82**	(42)	(401)
Amortization of actuarial loss	**(439)**	**(109)**	(366)	(79)	(193)	(82)	**(27)**	(38)	(81)
Prior service cost (credit) during period	**1**	**13**		32	(301)	97	**20**		
Amortization of prior-service credits (costs)	**7**	**(23)**	7	(24)	(46)	(20)	**81**	81	81
Total changes recognized in other comprehensive income	**392**	**75**	2,265	575	(700)	26	**156**	1	(401)
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 1,176**	**$ 424**	$ 2,780	$ 830	$ (296)	$ 242	**$ 320**	$ 180	$ (168)

Net actuarial losses recorded in Accumulated other comprehensive loss at December 31, 2009, for the company s U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 11, 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 2010, the company estimates actuarial losses of $318, $102 and $26 will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and OPEB plans, respec-
tively. In addition, the company estimates an additional $220 will be recognized from Accumulated other comprehensive loss during 2010 related to lump-sum settlement costs from U.S. pension plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded in Accumulated other comprehensive loss at December 31, 2009, was approximately eight and 12 years for U.S. and international pension plans, respectively, and eight years for other postretirement benefit plans. During 2010, the company estimates prior service (credits) costs of $(7), $27 and $(74) will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and OPEB plans, respectively.

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						Other Benefits		
	2009		2008		2007				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2009**	2008	2007
Assumptions used to determine benefit obligations									
Discount rate	**5.3%**	**6.8%**	6.3%	7.5%	6.3%	6.7%	**5.9%**	6.3%	6.3%
Rate of compensation increase	**4.5%**	**6.3%**	4.5%	6.8%	4.5%	6.4%	**N/A**	4.0%	4.5%
Assumptions used to determine net periodic benefit cost									
Discount rate	**6.3%**	**7.5%**	6.3%	6.7%	5.8%	6.0%	**6.3%**	6.3%	5.8%
Expected return on plan assets	**7.8%**	**7.5%**	7.8%	7.4%	7.8%	7.5%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**6.8%**	4.5%	6.4%	4.5%	6.1%	**N/A**	4.5%	4.5%

Expected Return on Plan Assets The company s estimated long-term rates of return on pension assets are 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 company s estimated 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 69 percent of the company s pension plan assets. At December 31, 2009, 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 year-end 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, 2009, the company selected a 5.3 percent discount rate for the U.S. pension plan and 5.8 percent for the U.S. postretirement benefit plan. This rate was based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2009. The discount rates at the end of 2008 and 2007 were 6.3 percent for the U.S. pension plan and the OPEB plan.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2009, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 7 percent in 2010 and gradually decline to 5 percent for 2018 and beyond. For this measurement at December 31, 2008, the assumed health care cost-trend rates started with 7 percent in 2009 and gradually declined to 5 percent for 2017 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	$	10	$	(9)
Effect on postretirement benefit obligation	$	102	$	(87)

Plan Assets and Investment Strategy Effective December 31, 2009, the company implemented the expanded disclosure requirements for the plan assets of defined benefit pension and OPEB plans (ASC 715) to provide users of financial statements with an understanding of: how investment allocation decisions are made; the major categories of plan assets; the inputs and valuation techniques used to measure the fair value of plan assets; the effect of fair-value measurements using unobservable inputs on changes in plan assets for the period; and significant concentrations of risk within plan assets.

The fair-value hierarchy of inputs the company uses to value the pension assets is divided into three levels:

Note 21 Employee Benefit Plans - Continued

Level 1: Fair values of these assets are measured using unadjusted quoted prices for the assets or the prices of identical assets in active markets that the plans have the ability to access.

Level 2: Fair values of these assets are measured based on quoted prices for similar assets in active markets; quoted prices for identical or similar assets in inactive markets; inputs other than quoted prices that are observable for the asset; and inputs that are derived principally from or corroborated by observable market data by correlation or other means. If the
asset has a contractual term, the Level 2 input is observable for substantially the full term of the asset. The fair values for Level 2 assets are generally obtained from third-party broker quotes, independent pricing services and exchanges.

Level 3: Inputs to the fair value measurement are unobservable for these assets. Valuation may be performed using a financial model with estimated inputs entered into the model.

The fair value measurements of the company s pension plans for 2009 are below:

	U.S.				Int l			
	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
Equities								
U.S.[1]	$2,115	$ 2,115	$	$	$ 370	$ 370	$	$
International	977	977			492	492		
Collective Trusts/Mutual Funds[2]	1,264	3	1,261		789	94	695	
Fixed Income								
Government	713	149	564		506	54	452	
Corporate	430		430		371	17	336	18
Mortgage-Backed Securities	149		149		2			2
Other Asset Backed	90		90		19		19	
Collective Trusts/Mutual Funds[2]	326		326		230	14	216	
Mixed Funds[3]	8	8			102	14	88	
Real Estate[4]	479			479	131			131
Cash and Cash Equivalents	743	743			207	207		
Other[5]	10	(57)	16	51	16	(3)	18	1
Total at December 31, 2009	**$7,304**	$ 3,938	$ 2,836	$ 530	**$3,235**	$ 1,259	$ 1,824	$ 152

1 U.S. equities include investments in the company s common stock in the amount of $29 at December 31, 2009.

2 Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is based on the restriction that advance notification of redemptions, typically two business days, is required.

3

Mixed funds are composed of funds that invest in both equity and fixed income instruments in order to diversify and lower risk.

[4] The year-end valuations of the U.S. real estate assets are based on internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.

[5] The Other asset category includes net payables for securities purchased but not yet settled (Level 1); dividends, interest- and tax-related receivables (Level 2); insurance contracts and investments in private-equity limited partnerships (Level 3).

The effect of fair-value measurements using significant unobservable inputs on changes in Level 3 plan assets for the period are outlined below:

	U.S. Equities	Corporate	Fixed Income Mortgage-Backed Securities	Real Estate	Other	Total
Total at December 31, 2008	$ 1	$ 23	$ 2	$ 763	$ 52	$ 841
Actual Return on Plan Assets:						
Assets held at the reporting date	(1)	2		(178)		(177)
Assets sold during the period		5		8		13
Purchases, Sales and Settlements		(12)		17		5
Transfers in and/or out of Level 3						
Total at December 31, 2009	$	$ 18	$ 2	$ 610	$ 52	$ 682

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Note 21 Employee Benefit Plans - Continued

The primary investment objectives of the pension plans are to achieve the highest rate of total return within prudent levels of risk and liquidity, to diversify and mitigate potential downside risk associated with the investments, and to provide adequate liquidity for benefit payments and portfolio management.

The company s U.S. and U.K. pension plans comprise 84 percent of the total pension assets. Both the U.S. and U.K. plans have an Investment Committee that regularly meets during the year to review the asset holdings and their returns. To assess the plan s 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 and Cash 20-60 percent, Real Estate 0-15 percent, and Other 0-5 percent. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines, which are reviewed regularly: Equities 60-80 percent and Fixed Income and Cash 20 40 percent. The other significant international pension plans also have established maximum and minimum asset allocation ranges that vary by 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. There are no significant concentrations of risk in plan assets due to the diversification of investment categories.

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2009, the company contributed $1,494 and $245 to its U.S. and international pension plans, respectively. In 2010, the company expects contributions to be approximately $600 and $300 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 $208 in 2010, as compared with $187 paid in 2009.

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

	Pension Benefits		Other
	U.S.	Int l.	Benefits
2010	$ 855	$ 242	$ 208
2011	$ 851	$ 271	$ 213
2012	$ 861	$ 284	$ 217
2013	$ 884	$ 296	$ 222
2014	$ 913	$ 317	$ 229
2015 2019	$ 4,707	$ 1,969	$ 1,197

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 described in the section that follows. Total company matching contributions to employee accounts within the ESIP were $257, $231 and $206 in 2009, 2008 and 2007, respectively. This cost was reduced by the value of shares released from the LESOP totaling $184, $40 and $33 in 2009, 2008 and 2007, respectively. The remaining amounts, totaling $73, $191 and $173 in 2009, 2008 and 2007, 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 accounting standards for share-based compensation (ASC 718), 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 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 to expense for the LESOP were $3, $1 and $1 in 2009, 2008 and 2007, respectively. The net credit for the respective years was composed of credits to compensation expense of $15, $15 and $17 and charges to interest expense for LESOP debt of $12, $14 and $16.

Of the dividends paid on the LESOP shares, $110, $35 and $8 were used in 2009, 2008 and 2007, respectively, to service LESOP debt. No contributions were required in 2009, 2008 or 2007 as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Note 21 Employee Benefit Plans - Continued

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, 2009 and 2008, were as follows:

Thousands	**2009**	2008
Allocated shares	**21,211**	19,651
Unallocated shares	**3,636**	6,366
Total LESOP shares	**24,847**	26,017

Benefit Plan Trusts Prior to its acquisition by Chevron, Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2009, the trust contained 14.2 million shares of Chevron treasury stock. 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 company intends to continue to pay its obligations under the benefit plans. 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.

Prior to its acquisition by Chevron, 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, 2009 and 2008, trust assets of $57 and $60, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans Effective January 2008, the company established the Chevron Incentive Plan (CIP), a single annual cash bonus plan for eligible employees that links awards to corporate, unit and individual performance in the prior year. This plan replaced other cash bonus programs, which primarily included the Management Incentive Plan (MIP) and the Chevron Success Sharing program. In 2009 and 2008, charges to expense for cash bonuses were $561 and $757, respectively. In 2007, charges to expense for MIP were $184 and charges for other cash bonus programs were $431. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 20, on page FS-51.

Note 22

Other Contingencies and Commitments

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and 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. Refer to
Note 15 beginning on page FS-46 for a discussion of the periods for which tax returns have been audited for the company s major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

Guarantees The company s guarantee of approximately $600 is associated with certain payments under a terminal use agreement entered into by a company affiliate. The terminal is expected to be operational by 2012. Over the approximate 16-year term of the guarantee, the maximum guarantee amount will be reduced over time as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of any amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company s interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300. Through the end of 2009, the company paid $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 had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. In February 2009, Shell delivered a letter to the company purporting to preserve unmatured claims for certain Equilon indemnities. The letter itself provides no estimate of the ultimate claim amount. Management does not believe this letter or any other information provides a basis to estimate the amount, if any, of a range of loss or potential range of loss with respect to either the Equilon or the Motiva indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

Note 22 Other Contingencies and Commitments - Continued

The amounts payable for the indemnities described in the preceding paragraph 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. The acquirer of those assets shared in certain environmental remediation costs up to a maximum obligation of $200, which had been reached at December 31, 2009. Under the indemnification agreement, after reaching the $200 obligation, Chevron is solely responsible until April 2022, when the indemnification expires. The environmental conditions or events that are subject to these indemnities must have arisen prior to the sale of the assets in 1997.

Although the company has provided for known obligations under this indemnity 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.

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: 2010 $7,500; 2011 $4,300; 2012 $1,400; 2013 $1,400; 2014 $1,000; 2015 and after $4,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $8,100 in 2009, $5,100 in 2008 and $3,700 in 2007.

Environmental The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or 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, 2009, was $1,700. Included in this balance were remediation activities at approximately 250 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 2009 was $185. 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 results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2009 environmental reserves balance of $1,515, $820 related to the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), and pipelines. The remaining $695 was associated with various sites in international downstream ($107), upstream ($369), chemicals ($149) and other businesses ($70). 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

Note 22 Other Contingencies and Commitments - Continued

States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2009 had a recorded liability that was material to the company s results of operations, consolidated financial position 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.

Refer to Note 23 for a discussion of the company s asset retirement obligations.

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, 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 23

Asset Retirement Obligations

In accordance with accounting standards for asset retirement obligations (ASC 410), the company records the fair value of a liability for an asset retirement obligation (ARO) when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company s control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. The legal obligations associated with the retirement of the tangible long-lived assets require recognition in certain circumstances including: (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.

Accounting standards for asset retirement obligations 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 prevent 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 2009, 2008 and 2007:

	2009	2008	2007
Balance at January 1	**$ 9,395**	$ 8,253	$ 5,773
Liabilities incurred	**144**	308	178
Liabilities settled	**(757)**	(973)	(818)
Accretion expense	**463**	430	399*
Revisions in estimated cash flows	**930**	1,377	2,721
Balance at December 31	**$ 10,175**	$ 9,395	$ 8,253

* Includes $175 for revision to the ARO liability retained on properties that had been sold.

In the table above, the amounts associated with Revisions in estimated cash flows reflect increasing costs to abandon onshore and offshore wells, equipment and facilities. The long-term portion of the $10,175 balance at the end of 2009 was $9,289.

Note 24

Other Financial Information

Earnings in 2009 included gains of approximately $1,000 relating to the sale of nonstrategic properties. Of this amount, approximately $600 and $400 related to downstream and upstream assets, respectively. Earnings in 2008 included gains of approximately $1,200 relating to the sale of nonstrategic properties. Of this amount, approximately $1,000 related to upstream assets. Earnings in 2007 included gains of approximately $2,000 relating to the sale of nonstrategic properties. Of this amount, approximately $1,100 related to downstream assets and $680 related to the sale of the company s investment in Dynegy, Inc.

Other financial information is as follows:

	Year ended December 31		
	2009	2008	2007
Total financing interest and debt costs	**$ 301**	$ 256	$ 468
Less: Capitalized interest	**273**	256	302
Interest and debt expense	**$ 28**	$	$ 166
Research and development expenses	**$ 603**	$ 702	$ 510
Foreign currency effects*	**$ (744)**	$ 862	$ (352)

* Includes $(194), $420 and $18 in 2009, 2008 and 2007, respectively, for the company s share of equity affiliates foreign currency effects.

The excess of replacement cost over the carrying value of inventories for which the Last-In, First-Out (LIFO) method is used was $5,491 and $9,368 at December 31, 2009 and 2008, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO (charges) profits of $(168), $210 and $113 were included in earnings for the years 2009, 2008 and 2007, respectively.

The company has $4,618 in goodwill on the Consolidated Balance Sheet related to its 2005 acquisition of Unocal. Under the accounting standard for goodwill (ASC 350), the company tested this goodwill for impairment during 2009 and concluded no impairment was necessary.

Events subsequent to December 31, 2009, were evaluated until the time of the Form 10-K filing with the Securities and Exchange Commission on February 25, 2010.

Note 25

Assets Held for Sale

At December 31, 2009, the company reported no assets as Assets held for sale (AHS) on the Consolidated Balance Sheet. At December 31, 2008, $252 of net properties, plant and equipment were reported as AHS. Assets in this category are related to groups of service stations, aviation facilities, lubricants blending plants, and commercial and industrial fuels business. These assets were sold in 2009.

Note 26

Earnings Per Share

Basic earnings per share (EPS) is based upon Net Income Attributable to Chevron Corporation (earnings) 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 20, Stock Options and Other Share-Based Compensation, beginning on page FS-51). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2009	2008	2007
Basic EPS Calculation			
Earnings available to common stockholders Basic[1]	**$ 10,483**	$ 23,931	$ 18,688
Weighted-average number of common shares outstanding	**1,991**	2,037	2,117
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,992**	2,038	2,118
Per share of common stock			
Earnings Basic	**$ 5.26**	$ 11.74	$ 8.83
Diluted EPS Calculation			
Earnings available to common stockholders Diluted[1]	**$ 10,483**	$ 23,931	$ 18,688
Weighted-average number of common shares outstanding	**1,991**	2,037	2,117
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**9**	12	14
Total weighted-average number of common shares outstanding	**2,001**	2,050	2,132
Per share of common stock			
Earnings Diluted	**$ 5.24**	$ 11.67	$ 8.77

[1] There was no effect of dividend equivalents paid on stock units or dilutive impact of employee stock-based awards on earnings.

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Five-Year Financial Summary
Unaudited

Millions of dollars, except per-share amounts	**2009**	2008	2007	2006	2005
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues[1,2]	**$ 167,402**	$ 264,958	$ 214,091	$ 204,892	$ 193,641
Income from equity affiliates and other income	**4,234**	8,047	6,813	5,226	4,559
Total Revenues and Other Income	**171,636**	273,005	220,904	210,118	198,200
Total Costs and Other Deductions	**153,108**	229,948	188,630	178,072	172,907
Income Before Income Tax Expense	**18,528**	43,057	32,274	32,046	25,293
Income Tax Expense	**7,965**	19,026	13,479	14,838	11,098
Net Income	**10,563**	24,031	18,795	17,208	14,195
Less: Net income attributable to noncontrolling interests	**80**	100	107	70	96
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688	$ 17,138	$ 14,099
Per Share of Common Stock					
Net Income Attributable to Chevron[2]					
Basic	**$ 5.26**	$ 11.74	$ 8.83	$ 7.84	$ 6.58
Diluted	**$ 5.24**	$ 11.67	$ 8.77	$ 7.80	$ 6.54
Cash Dividends Per Share	**$ 2.66**	$ 2.53	$ 2.26	$ 2.01	$ 1.75
Balance Sheet Data (at December 31)					
Current assets	**$ 37,216**	$ 36,470	$ 39,377	$ 36,304	$ 34,336
Noncurrent assets	**127,405**	124,695	109,409	96,324	91,497
Total Assets	**164,621**	161,165	148,786	132,628	125,833
Short-term debt	**384**	2,818	1,162	2,159	739
Other current liabilities	**25,827**	29,205	32,636	26,250	24,272
Long-term debt and capital lease obligations	**10,130**	6,083	6,070	7,679	12,131
Other noncurrent liabilities	**35,719**	35,942	31,626	27,396	25,815
Total Liabilities	**72,060**	74,048	71,494	63,484	62,957
Total Chevron Corporation Stockholders Equity	**$ 91,914**	$ 86,648	$ 77,088	$ 68,935	$ 62,676
Noncontrolling interests	**647**	469	204	209	200
Total Equity	**$ 92,561**	$ 87,117	$ 77,292	$ 69,144	$ 62,876

[1] Includes excise, value-added and similar taxes:	**$ 8,109**	$ 9,846	$ 10,121	$ 9,551	$ 8,719
[2] Includes amounts in revenues for buy/sell contracts; associated costs are in Total Costs and Other Deductions.	**$**	$	$	$ 6,725	$ 23,822

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Supplemental Information on Oil and Gas Producing Activities
Unaudited

In accordance with FASB and SEC disclosure and reporting requirements for 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 Angola, Chad, Nigeria, Republic of the Congo and Democratic Republic

Table I - Costs Incurred in Exploration, Property Acquisitions and Development[1]

				Consolidated Companies			Affiliated Companies
Millions of dollars	U.S.	Africa	Asia	Other	Total	TCO	Other
Year Ended Dec. 31, 2009							
Exploration							
Wells	**$ 361**	**$ 140**	**$ 45**	**$ 429**	**$ 975**	**$**	**$**
Geological and geophysical	**62**	**114**	**49**	**103**	**328**		
Rentals and other	**153**	**92**	**60**	**316**	**621**		
Total exploration	**576**	**346**	**154**	**848**	**1,924**		
Property acquisitions[2]							
Proved	**3**				**3**		
Unproved	**29**				**29**		
Total property acquisitions	**32**				**32**		
Development[3]	**3,338**	**3,426**	**2,698**	**2,365**	**11,827**	**265**	**69**
Total Costs Incurred[4]	**$ 3,946**	**$ 3,772**	**$ 2,852**	**$ 3,213**	**$ 13,783**	**$ 265**	**$ 69**
Year Ended Dec. 31, 2008[5]							
Exploration							
Wells	$ 519	$ 197	$ 85	$ 314	$ 1,115	$	$
Geological and geophysical	66	90	42	131	329		
Rentals and other	143	60	70	212	485		
Total exploration	728	347	197	657	1,929		

Property acquisitions[2]							
Proved	88		169		257		
Unproved	579		280		859		
Total property acquisitions	667		449		1,116		
Development[3]	4,348	3,723	4,697	2,419	15,187	643	120
Total Costs Incurred	$ 5,743	$ 4,070	$ 5,343	$ 3,076	$ 18,232	$ 643	$ 120
Year Ended Dec. 31, 2007[5]							
Exploration							
Wells	$ 452	$ 202	$ 62	$ 292	$ 1,008	$	$ 7
Geological and geophysical	73	136	24	133	366		
Rentals and other	133	70	101	148	452		
Total exploration	658	408	187	573	1,826		7
Property acquisitions[2]							
Proved	243	5	92	(2)	338		
Unproved	113	8	35	24	180		
Total property acquisitions	356	13	127	22	518		
Development[3]	5,210	4,176	2,190	1,831	13,407	832	64
Total Costs Incurred	$ 6,224	$ 4,597	$ 2,504	$ 2,426	$ 15,751	$ 832	$ 71

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 23, Asset Retirement Obligations, on page FS-60.

[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired in nonmonetary transactions.

[3] Includes $121, $224 and $99 costs incurred prior to assignment of proved reserves in 2009, 2008 and 2007, respectively. Also includes $104 and $12 in 2009 for consolidated Other and affiliated Other, respectively.

[4] Includes cost incurred for oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries Oil and Gas* (Topic 932).

[5] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

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Supplemental Information on Oil and Gas Producing Activities
Table II Capitalized Costs Related to Oil and
Gas Producing Activities

of the Congo. The Asia geographic area includes activities principally in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, Myanmar, the Partitioned Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The Other geographic regions include activities in Argentina, Australia, 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 the company s equity interests in Venezuela and Angola. Refer to Note 12, beginning on page FS-43, for a discussion of the company s major equity affiliates.

Table II - Capitalized Costs Related to Oil and Gas Producing Activities

							Affiliated
				Consolidated Companies			Companies
Millions of dollars	U.S.	Africa	Asia	Other	Total	TCO	Other
At Dec. 31, 2009							
Unproved properties	**$ 2,320**	**$ 321**	**$ 3,355**	**$ 963**	**$ 6,959**	**$ 113**	**$**
Proved properties and related producing assets	**51,582**	**20,967**	**29,637**	**17,267**	**119,453**	**6,404**	**1,759**
Support equipment	**810**	**1,012**	**1,383**	**648**	**3,853**	**947**	
Deferred exploratory wells	**762**	**603**	**209**	**861**	**2,435**		
Other uncompleted projects	**2,384**	**3,960**	**2,936**	**5,572**	**14,852**	**284**	**58**
Gross Capitalized Costs	**57,858**	**26,863**	**37,520**	**25,311**	**147,552**	**7,748**	**1,817**
Unproved properties valuation	**915**	**163**	**170**	**390**	**1,638**	**32**	
Proved producing properties Depreciation and depletion	**34,574**	**8,823**	**15,783**	**11,243**	**70,423**	**1,150**	**282**
Support equipment depreciation	**424**	**526**	**773**	**357**	**2,080**	**356**	
Accumulated provisions	**35,913**	**9,512**	**16,726**	**11,990**	**74,141**	**1,538**	**282**
Net Capitalized Costs[1]	**$ 21,945**	**$ 17,351**	**$ 20,794**	**$ 13,321**	**$ 73,411**	**$ 6,210**	**$ 1,535**
At Dec. 31, 2008[2,3]							
Unproved properties	$ 2,495	$ 294	$ 3,300	$ 1,051	$ 7,140	$ 113	$
Proved properties and related producing assets	46,280	17,495	27,607	15,277	106,659	5,991	837
Support equipment	717	967	1,321	570	3,575	888	
Deferred exploratory wells	602	499	198	819	2,118		
Other uncompleted projects	4,275	4,226	2,461	2,643	13,605	501	101

Gross Capitalized Costs	54,369	23,481	34,887	20,360	133,097	7,493	938
Unproved properties valuation	845	202	150	576	1,773	29	
Proved producing properties							
Depreciation and depletion	30,780	6,602	13,617	9,649	60,648	831	163
Support equipment depreciation	382	523	690	356	1,951	307	
Accumulated provisions	32,007	7,327	14,457	10,581	64,372	1,167	163
Net Capitalized Costs	$ 22,362	$ 16,154	$ 20,430	$ 9,779	$ 68,725	$ 6,326	$ 775

[1] Includes net capitalized cost for oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries Oil and Gas* (Topic 932).

[2] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

[3] Amounts for Affiliated Companies Other conformed to agreements entered in 2007 and 2008 for Venezuelan affiliates.

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Table II Capitalized Costs Related to Oil and Gas Producing Activities - Continued

Millions of dollars	U.S.	Africa	Asia	Consolidated Companies Other	Total	TCO	Affiliated Companies Other
At Dec. 31, 2007[2,3]							
Unproved properties	$ 2,050	$ 314	$ 3,125	$ 1,159	$ 6,648	$ 112	$
Proved properties and related producing assets	44,088	11,894	23,100	13,286	92,368	4,247	1,127
Support equipment	637	850	1,355	491	3,333	758	
Deferred exploratory wells	413	368	214	665	1,660		
Other uncompleted projects	4,009	6,430	2,039	2,024	14,502	1,633	55
Gross Capitalized Costs	51,197	19,856	29,833	17,625	118,511	6,750	1,182
Unproved properties valuation	833	201	120	567	1,721	23	
Proved producing properties Depreciation and depletion	30,097	5,427	11,329	8,237	55,090	644	183
Support equipment depreciation	349	464	678	298	1,789	267	
Accumulated provisions	31,279	6,092	12,127	9,102	58,600	934	183
Net Capitalized Costs	$ 19,918	$ 13,764	$ 17,706	$ 8,523	$ 59,911	$ 5,816	$ 999

[2] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

[3] Amounts for Affiliated Companies Other conformed to agreements entered in 2007 and 2008 for Venezuelan affiliates.

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Supplemental Information on Oil and Gas Producing Activities
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 2009, 2008 and 2007 are shown in the following table. Net income from exploration and production activities as reported on page FS-41 reflects income taxes computed on an effective rate basis.
Income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page FS-41.

	Consolidated Companies					Affiliated Companies	
Millions of dollars	U.S.	Africa	Asia	Other	Total	TCO	Other
Year Ended Dec. 31, 2009[2]							
Revenues from net production							
Sales	**$ 2,278**	**$ 1,767**	**$ 5,648**	**$ 3,173**	**$ 12,866**	**$ 4,043**	**$ 938**
Transfers	**9,133**	**7,304**	**4,926**	**3,866**	**25,229**		
Total	**11,411**	**9,071**	**10,574**	**7,039**	**38,095**	**4,043**	**938**
Production expenses excluding taxes	**(3,281)**	**(1,345)**	**(2,208)**	**(1,390)**	**(8,224)**	**(363)**	**(240)**
Taxes other than on income	**(367)**	**(132)**	**(53)**	**(284)**	**(836)**	**(50)**	**(96)**
Proved producing properties:							
Depreciation and depletion	**(3,493)**	**(2,175)**	**(2,279)**	**(1,598)**	**(9,545)**	**(381)**	**(88)**
Accretion expense[3]	**(194)**	**(66)**	**(70)**	**(79)**	**(409)**	**(7)**	**(3)**
Exploration expenses	**(451)**	**(236)**	**(113)**	**(542)**	**(1,342)**		
Unproved properties valuation	**(228)**	**(11)**	**(44)**	**(28)**	**(311)**		
Other income (expense)[4]	**156**	**98**	**(327)**	**(340)**	**(413)**	**(131)**	**9**
Results before income taxes	**3,553**	**5,204**	**5,480**	**2,778**	**17,015**	**3,111**	**520**
Income tax expense	**(1,258)**	**(3,214)**	**(2,921)**	**(1,360)**	**(8,753)**	**(935)**	**(258)**
Results of Producing Operations	**$ 2,295**	**$ 1,990**	**$ 2,559**	**$ 1,418**	**$ 8,262**	**$ 2,176**	**$ 262**
Year Ended Dec. 31, 2008[5]							
Revenues from net production							

Sales	$ 4,882	$ 2,578	$ 7,969	$ 4,534	$ 19,963	$ 4,971	$ 1,599
Transfers	12,868	8,373	7,179	5,150	33,570		
Total	17,750	10,951	15,148	9,684	53,533	4,971	1,599
Production expenses excluding taxes	(3,822)	(1,228)	(2,096)	(969)	(8,115)	(376)	(125)
Taxes other than on income	(716)	(163)	(263)	(370)	(1,512)	(41)	(278)
Proved producing properties:							
Depreciation and depletion	(2,286)	(1,176)	(2,299)	(1,452)	(7,213)	(237)	(77)
Accretion expense[3]	(242)	(60)	(48)	(59)	(409)	(2)	(1)
Exploration expenses	(370)	(223)	(178)	(398)	(1,169)		
Unproved properties valuation	(114)	(13)	(36)	(8)	(171)		
Other income (expense)[4]	707	(350)	198	318	873	184	105
Results before income taxes	10,907	7,738	10,426	6,746	35,817	4,499	1,223
Income tax expense	(3,856)	(6,051)	(5,697)	(3,441)	(19,045)	(1,357)	(612)
Results of Producing Operations	$ 7,051	$ 1,687	$ 4,729	$ 3,305	$ 16,772	$ 3,142	$ 611

[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] Includes results of producing operations for oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries Oil and Gas* (Topic 932).

[3] Represents accretion of ARO liability. Refer to Note 23, Asset Retirement Obligations, on page FS-60.

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

[5] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

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Table III Results of Operations for Oil and Gas Producing Activities[1] - Continued

Millions of dollars	U.S.	Africa	Asia	Consolidated Companies Other	Total	TCO	Affiliated Companies Other
Year Ended Dec. 31, 2007[2]							
Revenues from net production							
Sales	$ 4,233	$ 1,810	$ 6,836	$ 3,413	$ 16,292	$ 3,327	$ 1,290
Transfers	10,008	6,778	5,923	3,851	26,560		
Total	14,241	8,588	12,759	7,264	42,852	3,327	1,290
Production expenses excluding taxes[3]	(3,399)	(892)	(1,753)	(920)	(6,964)	(248)	(92)
Taxes other than on income	(522)	(49)	(79)	(273)	(923)	(31)	(163)
Proved producing properties:							
Depreciation and depletion	(2,276)	(646)	(2,201)	(1,070)	(6,193)	(127)	(94)
Accretion expense[4]	(258)	(33)	(49)	(35)	(375)	(1)	(2)
Exploration expenses	(511)	(267)	(171)	(374)	(1,323)		
Unproved properties valuation	(132)	(12)	(41)	(259)	(444)		
Other income (expense)[5]	36	(447)	(351)	(115)	(877)	18	7
Results before income taxes	7,179	6,242	8,114	4,218	25,753	2,938	946
Income tax expense	(2,599)	(4,907)	(4,135)	(1,992)	(13,633)	(887)	(462)
Results of Producing Operations	$ 4,580	$ 1,335	$ 3,979	$ 2,226	$ 12,120	$ 2,051	$ 484

[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] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

[3] Includes $10 costs incurred prior to assignment of proved reserves in 2007.

[4] Represents accretion of ARO liability. Refer to Note 23, Asset Retirement Obligations, on page FS-60.

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

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Supplemental Information on Oil and Gas Producing Activities
Table IV Results of Operations for Oil and Gas Producing Activities - Unit Prices and Costs[1,2]

				Consolidated Companies		Affiliated Companies	
	U.S.	Africa	Asia	Other	Total	TCO	Other
Year Ended Dec. 31, 2009							
Average sales prices							
Liquids, per barrel	**$ 54.36**	**$ 60.35**	**$ 54.76**	**$ 59.83**	**$ 56.92**	**$ 47.33**	**$ 50.18**
Natural gas, per thousand cubic feet	**3.73**	**0.20**	**4.07**	**4.10**	**3.94**	**1.54**	**1.85**
Average production costs, per barrel[3]	**12.71**	**8.85**	**8.82**	**8.63**	**9.97**	**3.71**	**12.42**
Year Ended Dec. 31, 2008[4]							
Average sales prices							
Liquids, per barrel	$ 88.43	$ 91.71	$ 83.67	$ 85.95	$ 87.44	$ 79.11	$ 69.65
Natural gas, per thousand cubic feet	7.90		4.55	6.36	6.02	1.56	3.98
Average production costs, per barrel	15.85	10.00	8.12	6.42	10.49	5.24	5.32
Year Ended Dec. 31, 2007[4]							
Average sales prices							
Liquids, per barrel	$ 63.16	$ 69.90	$ 62.52	$ 64.48	$ 64.71	$ 62.47	$ 51.98
Natural gas, per thousand cubic feet	6.12		3.98	4.08	4.79	0.89	0.44
Average production costs, per barrel	12.72	7.26	6.52	6.01	8.58	3.98	3.56

[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.

[3] Includes oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries Oil and Gas* (Topic 932).

[4] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

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 oil and gas reserves are the estimated quantities that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future from known reservoirs under existing economic conditions, operating methods, and government regulations. 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 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 com-
pany 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 vice chairman responsible for the company s worldwide exploration and production activities. The corporate reserves manager has more than 30 years experience working in the oil and gas industry and a Master s of Science in Petroleum Engineering. All RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC manages its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

The RAC has the following primary responsibilities: provide independent reviews of the business units recommended reserve changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual,* which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

During the year, the RAC is represented in meetings with each of the company s upstream business units to review and discuss reserve changes recommended by the various asset teams. Major changes are also reviewed with the company s Strategy and Planning Committee and the Executive Committee, whose members include the Chief Executive Officer and the Chief Financial Officer. The company s annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

Table V Reserve Quantity Information - Continued

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.*

Summary of Net Oil and Gas Reserves

			2009[1]		2008[2]		2007[2]
Liquids and Synthetic Oil in Millions of Barrels *Natural Gas in Billions of Cubic Feet*	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Natural Gas	Crude Oil Condensate NGLs	Natural Gas
Proved Developed							
Consolidated Companies							
U.S.	1,122		2,314	1,158	2,709	1,238	3,226
Africa	820		978	789	1,209	758	1,151
Asia	926		5,062	1,094	4,758	722	4,344
Other	267	190	3,051	295	3,163	368	2,978
Total Consolidated	**3,135**	**190**	**11,405**	3,336	11,839	3,086	11,699
Affiliated Companies							
TCO	1,256		1,830	1,369	1,999	1,273	1,762
Other	97	56	73	263	124	263	117
Total Consolidated and Affiliated Companies	**4,488**	**246**	**13,308**	4,968	13,962	4,622	13,578
Proved Undeveloped							
Consolidated Companies							
U.S.	239		384	312	441	386	451
Africa	426		2,043	596	1,847	742	1,898
Asia	245		2,798	362	3,238	301	2,863
Other	105	270	5,523	129	1,657	150	2,226
Total Consolidated	**1,015**	**270**	**10,748**	1,399	7,183	1,579	7,438
Affiliated Companies							
TCO	690		1,003	807	1,176	716	986
Other	54	210	990	176	754	170	138
Total Consolidated and Affiliated Companies	**1,759**	**480**	**12,741**	2,382	9,113	2,465	8,562
Total Proved Reserves	**6,247**	**726**	**26,049**	7,350	23,075	7,087	22,140

[1] Based on 12-month

average price.

[2] Based on
year-end prices.

Revised Oil and Gas Reporting In December 2008, the SEC issued its final rule, *Modernization of Oil and Gas Reporting* (Release Nos. 33-8995; 34-59192; FR-78). The disclosure requirements under the final rule became effective for the company with its Form 10-K filing for the year ending December 31, 2009. The final rule changes a number of oil and gas reserve estimation and disclosure requirements under SEC Regulations S-K and S-X. Subsequently, the FASB updated *Extractive Industries Oil and Gas* (Topic 932) to align the oil and gas reserves estimation and disclosure requirements with the SEC s final rule.

Among the principal changes in the final rule are requirements to use a price based on a 12-month average for reserve estimation and disclosure instead of a single end-of-year price; expanding the definition of oil and gas producing activities to include nontraditional sources such as bitumen extracted from oil sands; permitting the use of new reliable technologies to establish reasonable certainty of proved reserves; allowing optional disclosure of probable and possible reserves; modifying the definition of geographic area for disclosure of reserve estimates and production; amending disclosures of proved reserve quantities to include separate disclosures of synthetic oil and gas; expanding proved undeveloped reserves disclosures, including discussion of proved undeveloped reserves that have remained undeveloped for five years or more; and disclosure of the qualifications of the chief technical person who oversees the company s overall reserves estimation process.

Effect of New Rules The most significant effect of the company s adopting the new guidance was the inclusion of Canadian oil sands as synthetic oil in the consolidated companies reserves. As indicated in Table V, on page FS-72, an additional 460 million BOE were included at year-end 2009. The synthetic oil reported for affiliated companies represents volumes reclassified from heavy crude oil to synthetic oil, and does not represent additional reserves. It was impracticable to estimate the remaining impact of the new rules because of the cost and resources required to prepare detailed field-level calculations. However, the use of the 12-month average price had an upward effect on reserves related to production-sharing and variable-royalty contracts as the 12-month average price for crude oil and

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Supplemental Information on Oil and Gas Producing Activities
Table V Reserve Quantity Information - Continued

natural gas for 2009 was lower than the 2009 year-end spot prices applicable under the old rules. The ability to use new technologies in reserves determination did not impact reserves significantly, as most reserve additions and revisions were based on conventional technologies.

Proved Undeveloped Reserve Quantities At the end of 2009, proved undeveloped oil-equivalent reserves for consolidated companies totaled 3.1 billion barrels. Approximately 58 percent of the reserves are attributed to natural gas, of which about half were located in Australia in the Other regions. Crude oil, condensate and NGLs accounted for about 33 percent of the total, with the largest concentration of these reserves in Africa, Asia and the United States. Synthetic oil accounted for the balance of the reserves and were located in Canada in the Other regions.

Proved undeveloped reserves of equity affiliates amounted to 1.3 billion oil-equivalent barrels. At year-end, crude oil, condensate and NGLs represented 58 percent of the total reserves, with the TCO affiliate accounting for the majority of the amount. Natural gas represented 26 percent of the total, with over half of these reserves at TCO. The balance is attributed to synthetic oil in Venezuela in the Other regions.

In 2009, worldwide proved undeveloped oil-equivalent reserves increased by 480 million barrels for consolidated companies and decreased 19 million barrels for equity affiliates. The largest increase for consolidated companies was in the Other regions, resulting primarily from initial recognition of reserves for the Gorgon Project in Australia and addition of synthetic oil reserves related to Canadian oil sands with adoption of the new definition of oil and gas activity. Proved undeveloped reserves decreased in Asia, Africa, and the United States, as a result of development drilling and other activities, which reclassified reserves to proved developed.

Proved undeveloped reserves decreased for affiliated companies. This was primarily associated with a 146 million barrel reclassification to proved developed as a result of the TCO production capacity added with the completion of the Sour Gas Injection/Second Generation Plant Projects (SGI/SGP). The decrease at TCO was partially offset by increased proved undeveloped reserves in Venezuela and for Angola LNG due to reservoir performance and additional drilling opportunities.

There were no material downward revisions of proved undeveloped reserves for consolidated or affiliated companies.

Investment to Convert Proved Undeveloped to Proved Developed Reserves During 2009, investments totaling about $6.9 billion were made by consolidated companies and equity affiliates to advance the development of proved undeveloped reserves. In the Africa region, $2.5 billion was expended on various projects, including offshore development projects in Nigeria and Angola, which advanced development drilling, and the completion of a Nigerian natural gas processing project. In the Asia region, expenditures during the year totaled $1.5 billion, which included construction on a gas processing facility in Thailand and development drilling at a steam-flood project in Indonesia. In the United States, expenditures totaled $1.7 billion for three offshore development projects in the Gulf of Mexico and various smaller development projects. In the Other regions, development expenditures totaled $1.2 billion for a variety of projects including development activities in Australia and the United Kingdom.

During the year, eight major development projects that were placed into service resulted in the recognition of proved developed reserves.

Proved Undeveloped Reserves for 5 Years or More Reserves that remain proved undeveloped for five or more years are a result of several physical factors that affect optimal project development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructure or plant capacities that dictate project timing, compression projects that are pending reservoir pressure declines, and contractual limitations that dictate production levels.

Proved undeveloped oil-equivalent reserves for consolidated and affiliated companies totaled 4.4 billion barrels at year-end 2009. Of this total, 1.7 billion barrels corresponds to proved undeveloped oil-equivalent reserves that have remained undeveloped for five years or more.

Consolidated companies held approximately 700 million barrels of the proved undeveloped reserves over five years. In Africa, approximately 400 million barrels were related to deepwater projects under development. The Asia region held approximately 100 million barrels related to compression and contract restrictions. The Other regions held about 100 million barrels related to compression projects in Australia. The balance relates to capacity constraints and various projects in the United States.

At year end, affiliated companies held about 1.0 billion barrels of proved undeveloped reserves over five years. TCO accounted for 800 million oil-equivalent barrels of reserves, which was primarily related to plant capacity limitations. The balance related to capacity limitations at a synthetic oil project in Venezuela.

Annually, the company assesses whether any changes have occurred in facts or circumstances, such as changes to development plans, regulations or government policies, which would warrant a revision to reserve estimates. For 2009, this assessment did not result in any material changes in reserves classified as proved undeveloped. Over the past three years, the ratio of proved undeveloped reserves to total proved reserves has ranged between 35 and 39 percent. The consistent completion of major capital projects has kept the ratio in a narrow range over this time period.

Proved Reserve Quantities At December 31, 2009, oil-equivalent reserves for the company s consolidated operations were 8.3 billion barrels. (Refer to the term Reserves on page E-42 for the definition of oil-equivalent reserves.) Approximately 22 percent of the total reserves were located

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Table V Reserve Quantity Information - Continued

in the United States. For the company s interests in equity affiliates, oil-equivalent reserves were 3.0 billion barrels, 80 percent of which were associated with the company s 50 percent ownership in TCO.

Aside from the Tengiz Field in the TCO affiliate, no single property accounted for more than 5 percent of the company s total oil-equivalent proved reserves. About 25 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 approximately 48 percent of the company s total proved reserves. These properties were geographically dispersed, located in the United States, Canada, South America, West Africa, the Middle East, Southeast Asia, and Australia.

In the United States, total oil-equivalent reserves at year-end 2009 were 1.8 billion barrels. California properties accounted for approximately 44 percent of the U.S. reserves, 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. The Gulf of Mexico region contains about 22 percent of the U.S. reserves, with liquids representing about 15 percent of reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Other U.S. areas represent the remaining 34 percent of U.S. reserves, which are about evenly split between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including water-flood and CO_2 injection.

For the three years ending December 31, 2009, the pattern of net reserve changes shown in the following tables are 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 oil and natural gas reserves and changes thereto for the years 2007, 2008 and 2009 are shown in the following table and on page FS-74.

Net Proved Reserves of Crude Oil, Condensate, Natural Gas Li qui ds and Synthetic Oil

	Consolidated Companies						Affiliated Companies			Total Consolidated and Affiliated
Millions of barrels	U.S.	Africa	Asia	Synthetic Oil[1,2]	Other	Total	TCO	Synthetic Oil[1,3]	Other	Companies
Reserves at Jan. 1, 2007	1,751	1,698	1,259		586	5,294	1,950		562	7,806
Changes attributable to:										
Revisions	(5)	(89)	(54)		2	(146)	92		11	(43)
Improved recovery	9	7	4			20				20
Extensions and discoveries	36	6			18	60				60
Purchases[5]	10					10			316	326
Sales[6]	(9)					(9)			(432)	(441)
Production	(168)	(122)	(186)		(88)	(564)	(53)		(24)	(641)
Reserves at Dec. 31, 2007[4]	1,624	1,500	1,023		518	4,665	1,989		433	7,087

Changes attributable to:										
Revisions	(16)	2	574		(24)	536	249		18	803
Improved recovery	5	1	18		3	27			10	37
Extensions and discoveries	17	3	5		8	33				33
Purchases	1					1				1
Sales[6]	(7)					(7)				(7)
Production	(154)	(121)	(164)		(81)	(520)	(62)		(22)	(604)
Reserves at Dec. 31, 2008[4]	1,470	1,385	1,456		424	4,735	2,176		439	7,350
Changes attributable to:										
Revisions	63	(46)	(121)	460	(1)	355	(184)	266	(269)	168
Improved recovery	2	48				50	36			86
Extensions and discoveries	6	10	3		33	52				52
Purchases										
Sales[6]	(3)				(6)	(9)				(9)
Production	(177)	(151)	(167)		(78)	(573)	(82)		(19)	(674)
Reserves at Dec. 31, 2009[4]	1,361	1,246	1,171	460	372	4,610	1,946	266	151	6,973

[1] Prospective reporting effective December 31, 2009.

[2] Reserves associated with Canada.

[3] Reserves associated with Venezuela that were reported in other as heavy oil in 2008 and 2007.

[4] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-42 for the definition of a PSC). PSC-related reserve quantities are 26 percent, 32 percent and 26 percent for consolidated companies for 2009, 2008 and 2007, respectively.

[5] Includes reserves acquired through nonmonetary transactions.

[6] Includes reserves disposed of through nonmonetary transactions.

Supplemental Information on Oil and Gas Producing Activities

Table V Reserve Quantity Information - Continued

Noteworthy amounts in the categories of liquids proved-reserve changes for 2007 through 2009 are discussed below:

Revisions In 2007, net revisions decreased reserves by 146 million barrels for worldwide consolidated companies and increased reserves by 103 million barrels for equity affiliates. For consolidated companies, the largest downward net revisions were 89 million barrels in Africa and 54 million barrels in Asia.

In 2008, net revisions increased reserves by 536 million barrels for worldwide consolidated companies and increased reserves by 267 million barrels for equity affiliates. For consolidated companies, the largest increase was in the Asia region, which added 574 million barrels. The majority of the increase was in the Partitioned Zone, as a result of a concession extension, and Indonesia, due to lower year-end prices. Upward revisions were also recorded in Kazakhstan and Azerbaijan and were mainly associated with the effect of lower year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. In Indonesia, reserves increased due mainly to the impact of lower year-end prices on the reserve calculations for production-sharing contracts, as well as a result of development drilling and improved waterflood and steam-flood performance. These increases were offset by downward revisions in the United States and Other regions. For affiliated companies, the 249 million-barrel increase for TCO was due to the effect of lower year-end prices on the royalty determination and facility optimization at the Tengiz and Korolev fields.

In 2009, net revisions increased reserves by 355 million barrels for worldwide consolidated companies and decreased reserves by 187 million barrels for equity affiliates. For consolidated companies, the largest increase was 460 million barrels in the Other regions due to the inclusion of synthetic oil related to Canadian oil sands. In the United States, reserves increased 63 million barrels as a result of development drilling and performance revisions. The increases were partially offset by decreases of 121 million barrels in Asia and 46 million barrels in Africa. In Asia, decreases in Indonesia and Azerbaijan were driven by the effect of higher 12-month average prices on the calculation of reserves associated with production-sharing contracts and the effect of reservoir performance revisions. In Africa, reserves in Nigeria declined as a result of higher prices on production-sharing contracts and reservoir performance.

For affiliated companies, TCO declined by 184 million-barrels primarily due to the effect of higher 12-month average prices on royalty determination. For Other affiliated companies, 266 million barrels of heavy crude oil were reclassified to synthetic oil for the activities in Venezuela.

Improved Recovery In 2007, improved recovery increased liquids volumes by 20 million barrels worldwide. No addition was individually significant.

In 2008, improved recovery increased worldwide liquids volumes by 37 million barrels. For consolidated companies, the largest addition was in the Asia region related to gas reinjection in Kazakhstan. Affiliated companies increased reserves 10 million barrels due to improved secondary recovery at Boscan.

In 2009, improved recovery increased liquids volumes by 86 million barrels worldwide. Consolidated companies accounted for 50 million barrels. The largest addition was related to improved secondary recovery in Nigeria. Affiliated companies increased reserves 36 million barrels due to improvements related to the TCO SGI/SGP facilities.

Extensions and Discoveries In 2007, extensions and discoveries increased liquids volumes by 60 million barrels worldwide. The largest additions were 36 million barrels in the United States, mainly for the deepwater Tahiti and Mad Dog fields in the Gulf of Mexico.

In 2008, extensions and discoveries increased consolidated company reserves 33 million barrels worldwide. The United States increased reserves 17 million barrels, primarily in the Gulf of Mexico. The Africa, Asia, and Other regions increased reserves 16 million barrels with no one country resulting in additions greater than 5 million barrels.

In 2009, extensions and discoveries increased liquids volumes by 52 million barrels worldwide. The largest additions were 33 million barrels in Other regions related to the Gorgon Project in Australia and delineation drilling in Argentina. Africa and the United States accounted for 10 million barrels and 6 million barrels, respectively.

Purchases In 2007, acquisitions of 316 million barrels for equity affiliates related to the formation of a new Hamaca equity affiliate in Venezuela.

Sales In 2007, affiliated company sales of 432 million barrels related to the dissolution of a Hamaca equity affiliate in Venezuela.

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Table V Reserve Quantity Information - Continued
Net Proved Reserves of Natural Gas

Billions of cubic feet	Consolidated Companies U.S.	Africa	Asia	Other	Total	Affiliated Companies TCO	Other	Total Consolidated and Affiliated Companies
Reserves at Jan 1, 2007	4,028	3,206	7,102	5,574	19,910	2,743	231	22,884
Changes attributable to:								
Revisions	209	(141)	346	(19)	395	75	(2)	468
Improved recovery				1	1			1
Extensions and discoveries	86	11	358	63	518			518
Purchases[1]	50		91		141		211	352
Sales[3]	(76)				(76)		(175)	(251)
Production	(620)	(27)	(690)	(415)	(1,752)	(70)	(10)	(1,832)
Reserves at Dec. 31, 2007[2]	3,677	3,049	7,207	5,204	19,137	2,748	255	22,140
Changes attributable to:								
Revisions	(28)	60	1,073	61	1,166	498	632	2,296
Improved recovery								
Extensions and discoveries	108		23	1	132			132
Purchases	66		441		507			507
Sales[3]	(124)				(124)			(124)
Production	(549)	(53)	(748)	(446)	(1,796)	(71)	(9)	(1,876)
Reserves at Dec. 31, 2008[2]	3,150	3,056	7,996	4,820	19,022	3,175	878	23,075
Changes attributable to:								
Revisions	39	4	493	33	569	(237)	193	525
Improved recovery								
Extensions and discoveries	53	3	54	4,277	4,387			4,387
Purchases								
Sales	(33)			(84)	(117)			(117)
Production	(511)	(42)	(683)	(472)	(1,708)	(105)	(8)	(1,821)
Reserves at Dec. 31, 2009[2,4]	2,698	3,021	7,860	8,574	22,153	2,833	1,063	26,049

[1] Includes reserves acquired through nonmonetary transactions.

[2] Includes year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-42 for the definition of a PSC). PSC-related reserve quantities are 31 percent, 40 percent and 37 percent for consolidated companies for 2009, 2008 and 2007, respectively.

[3] Includes reserves disposed of through nonmonetary transactions.

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2007 through 2009 are discussed below:

Revisions In 2007, net revisions increased reserves for consolidated companies by 395 BCF and increased reserves for affiliated companies by 73 BCF. For consolidated companies, net increases of 346 BCF in Asia and 209 BCF in the United States were partially offset by downward revisions of 160 BCF in Africa and Other regions. In the Asia region, drilling activities in Thailand added 360 BCF, which were partially offset by downward revisions in Azerbaijan and Kazakhstan due to the impact of higher prices. In the United States, improved reservoir performance for many fields contributed to the increase with the largest portion in the mid-continent areas. Decreases in Africa were primarily due to a 136 BCF downward revision in Nigeria resulting from field performance. The Other regions had net downward revisions of 19 BCF. A 185 BCF downward revision in Australia due to drilling results and other smaller declines were mostly offset by improved reservoir performance in Trinidad and Tobago which added 188 BCF.

TCO had an upward revision of 75 BCF associated with improved reservoir performance and development activities. This upward revision was net of a negative impact due to higher year-end prices on royalty determination.

In 2008, net revisions increased reserves for consolidated companies by 1,166 BCF and increased reserves for affiliated companies by 1,130 BCF. In the Asia region, positive revisions totaled 1,073 BCF for consolidated companies. Almost half of the increase was attributed to the Karachaganak Field in Kazakhstan, due mainly to the effects of low year-end prices on the production-sharing contract and the results of development drilling and improved recovery. Other large upward revisions were recorded for the Pattani Field in Thailand due to a successful drilling campaign.

For the TCO affiliate in Kazakhstan, an increase of 498 BCF reflected the impacts of lower year-end prices on royalty determination and facility optimization. Reserves associated

Supplemental Information on Oil and Gas Producing Activities

with the Angola LNG project accounted for a majority of the 632 BCF increase in Other affiliated companies.

In 2009, net revisions increased reserves by 569 BCF for consolidated companies and decreased reserves by 44 BCF for affiliated companies. For consolidated companies, net increases were 493 BCF in Asia primarily as a result of reservoir studies in Bangladesh and development drilling in Thailand. These results were partially offset by a downward revision due to the impact of higher prices on production-sharing contracts in Myanmar. The United States and Other regions increased reserves 39 BCF and 33 BCF, respectively. In the United States, development drilling in the Gulf of Mexico was partially offset by performance revisions in the California and mid-continent areas. In Other regions, improved reservoir performance and compression in Australia was partially offset by the effect of higher prices on production-sharing contracts in Trinidad.

For equity affiliates, a downward revision of 237 BCF at TCO was due to the effect of higher prices on royalty determination and an increase in gas injection for SGI/SGP facilities. This decline was partially offset by performance and drilling opportunities related to the Angola LNG project.

Extensions and Discoveries In 2007, extensions and discoveries accounted for an increase of 518 BCF worldwide. The largest addition was 330 BCF in Bangladesh, the result of drilling activities. Other additions were not individually significant.

In 2009, worldwide extensions and discoveries of 4,387 BCF were attributed to consolidated companies. The Gorgon Project in Australia accounted for essentially all of the 4,277 BCF additions in the Other regions. In Asia, development drilling in Thailand accounted for the majority of the increase. In the United States, delineation drilling in California accounted for the majority of the increase.

Purchases In 2007, purchases of natural gas reserves were 141 BCF for consolidated companies, which include the acquisition of an additional interest in the Bibiyana Field in Bangladesh. Affiliated company purchases of 211 BCF related to the formation of a new Hamaca equity affiliate in Venezuela and an initial booking related to the Angola LNG project.

Sales In 2007, sales were 76 BCF and 175 BCF for consolidated companies and equity affiliates, respectively. The affiliated company sales related to the dissolution of a Hamaca equity affiliate in Venezuela.

In 2009, worldwide sales of 117 BCF were related to consolidated companies. For the Other regions, the sale of properties in Argentina accounted for 84 BCF. The sale of properties in the Gulf of Mexico accounted for the majority of the 33 BCF decrease in the United States.

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 the FASB. Estimated future cash inflows from production are computed by applying
12 month-average 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 by the FASB requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company s future cash flows or value of its oil and gas reserves. In the following table, Standardized Measure Net Cash Flows refers to the standardized measure of discounted future net cash flows.

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Table VI Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves - Continued

	Consolidated Companies						Affiliated Companies	Total Consolidated and Affiliated Companies
Millions of dollars	U.S.	Africa	Asia	Other	Total	TCO	Other	
At December 31, 2009								
Future cash inflows from production[1]	$ 81,332	$ 75,338	$ 91,993	$ 101,114	$ 349,777	$ 97,793	$ 23,825	$ 471,395
Future production costs	(35,295)	(22,459)	(31,843)	(42,206)	(131,803)	(6,923)	(4,765)	(143,491)
Future development costs	(7,027)	(14,715)	(12,884)	(16,643)	(51,269)	(8,190)	(3,986)	(63,445)
Future income taxes	(13,662)	(22,503)	(18,905)	(17,427)	(72,497)	(23,357)	(7,774)	(103,628)
Undiscounted future net cash flows	25,348	15,661	28,361	24,838	94,208	59,323	7,300	160,831
10 percent midyear annual discount for timing of estimated cash flows	(8,822)	(5,882)	(11,722)	(17,506)	(43,932)	(34,937)	(4,450)	(83,319)
Standardized Measure Net Cash Flows	$ 16,526	$ 9,779	$ 16,639	$ 7,332	$ 50,276	$ 24,386	$ 2,850	$ 77,512
At December 31, 2008								
Future cash inflows from production[2]	$ 66,174	$ 52,344	$ 75,855	$ 37,408	$ 231,781	$ 51,252	$ 13,968	$ 297,001
Future production costs	(45,738)	(20,302)	(33,817)	(15,363)	(115,220)	(14,502)	(2,319)	(132,041)
Future development costs	(6,099)	(19,001)	(15,298)	(3,408)	(43,806)	(10,140)	(1,551)	(55,497)
Future income taxes	(5,091)	(9,581)	(10,278)	(7,593)	(32,543)	(7,517)	(5,223)	(45,283)
Undiscounted future net cash flows	9,246	3,460	16,462	11,044	40,212	19,093	4,875	64,180
10 percent midyear annual discount for timing of estimated cash flows	(2,318)	(1,139)	(7,042)	(4,052)	(14,551)	(11,261)	(2,966)	(28,778)
	$ 6,928	$ 2,321	$ 9,420	$ 6,992	$ 25,661	$ 7,832	$ 1,909	$ 35,402

Standardized Measure Net Cash Flows								
At December 31, 2007								
Future cash inflows from production[2]	$ 162,138	$ 132,450	$ 110,749	$ 62,883	$ 468,220	$ 159,078	$ 29,845	$ 657,143
Future production costs	(41,861)	(15,707)	(29,150)	(17,132)	(103,850)	(10,408)	(1,529)	(115,787)
Future development costs	(8,080)	(11,516)	(10,989)	(4,754)	(35,339)	(8,580)	(1,175)	(45,094)
Future income taxes	(39,840)	(74,172)	(29,367)	(18,791)	(162,170)	(39,575)	(13,600)	(215,345)
Undiscounted future net cash flows	72,357	31,055	41,243	22,206	166,861	100,515	13,541	280,917
10 percent midyear annual discount for timing of estimated cash flows	(31,133)	(14,171)	(16,091)	(8,417)	(69,812)	(64,519)	(7,779)	(142,110)
Standardized Measure Net Cash Flows	$ 41,224	$ 16,884	$ 25,152	$ 13,789	$ 97,049	$ 35,996	$ 5,762	$ 138,807

[1] Based on 12-month average price.

[2] Based on year-end prices.

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Supplemental Information on Oil and Gas Producing Activities

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.

Millions of dollars	Consolidated Companies	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2007	$ 65,820	$ 26,535	$ 92,355
Sales and transfers of oil and gas produced net of production costs	(34,957)	(4,084)	(39,041)
Development costs incurred	10,468	889	11,357
Purchases of reserves	780	7,711	8,491
Sales of reserves	(425)	(7,767)	(8,192)
Extensions, discoveries and improved recovery less related costs	3,664		3,664
Revisions of previous quantity estimates	(7,801)	(1,333)	(9,134)
Net changes in prices, development and production costs	74,900	23,616	98,516
Accretion of discount	12,196	3,745	15,941
Net change in income tax	(27,596)	(7,554)	(35,150)
Net change for the year	31,229	15,223	46,452
Present Value at December 31, 2007	$ 97,049	$ 41,758	$ 138,807
Sales and transfers of oil and gas produced net of production costs	(43,906)	(5,750)	(49,656)
Development costs incurred	13,682	763	14,445
Purchases of reserves	233		233
Sales of reserves	(542)		(542)
Extensions, discoveries and improved recovery less related costs	646	83	729
Revisions of previous quantity estimates	37,853	3,718	41,571
Net changes in prices, development and production costs	(169,046)	(51,696)	(220,742)
Accretion of discount	17,458	5,976	23,434
Net change in income tax	72,234	14,889	87,123
Net change for 2008	(71,388)	(32,017)	(103,405)
Present Value at December 31, 2008	$ 25,661	$ 9,741	$ 35,402

Sales and transfers of oil and gas produced net of production costs		(27,559)		(4,209)		(31,768)
Development costs incurred		10,791		335		11,126
Purchases of reserves						
Sales of reserves		(285)				(285)
Extensions, discoveries and improved recovery less related costs		3,438		697		4,135
Revisions of previous quantity estimates		3,230		(4,343)		(1,113)
Net changes in prices, development and production costs		51,528		30,915		82,443
Accretion of discount		4,282		1,412		5,694
Net change in income tax		(20,810)		(7,312)		(28,122)
Net change for 2009		24,615		17,495		42,110
Present Value at December 31, 2009	$	50,276	$	27,236	$	77,512

EXHIBIT INDEX

Exhibit No.	Description
3.1	Restated Certificate of Incorporation of Chevron Corporation, dated May 30, 2008, filed as Exhibit 3.1 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2008, and incorporated herein by reference.
3.2	By-Laws of Chevron Corporation, as amended January 30, 2008, filed as Exhibit 3.1 to Chevron Corporation s Current Report on Form 8-K dated February 1, 2008, and incorporated herein by reference.
4.1	Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company 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.
4.2	Confidential Stockholder Voting Policy of Chevron Corporation, filed as Exhibit 4.2 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.1	Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan, filed as Exhibit 10.1 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.2	Chevron Incentive Plan, filed as Exhibit 10.2 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.3	Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.3 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.4	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.
10.5	Chevron Corporation Deferred Compensation Plan for Management Employees II, filed as Exhibit 10.5 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.6	Chevron Corporation Retirement Restoration Plan, filed as Exhibit 10.6 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.7	Chevron Corporation ESIP Restoration Plan, filed as Exhibit 10.7 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, 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	Summary of Chevron Incentive Plan Award Criteria, filed as Exhibit 10.13 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.13	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.
10.14	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.
10.15*	Form of Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.
10.16*	Form of Restricted Stock Unit Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.

Exhibit No.	Description
10.17*	Form of Retainer Stock Option Agreement under the Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan.
10.18	Form of Stock Units Agreement under the Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan, filed as Exhibit 10.19 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.19*	Employment Agreement, dated October 3, 2002, between Chevron Corporation and Charles A. James.
10.20*	Termination Agreement, dated January 5, 2010, between Chevron Corporation and Charles A. James.
12.1*	Computation of Ratio of Earnings to Fixed Charges (page E-22).
21.1*	Subsidiaries of Chevron Corporation (pages E-23 through E-24).
23.1*	Consent of PricewaterhouseCoopers LLP (page E-25).
24.1 to 24.12*	Powers of Attorney for directors and certain officers of Chevron Corporation, authorizing the signing of the Annual Report on Form 10-K on their behalf.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Executive Officer (page E-38).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Financial Officer (page E-39).
32.1*	Section 1350 Certification of the company s Chief Executive Officer (page E- 40).
32.2*	Section 1350 Certification of the company s Chief Financial Officer (page E- 41).
99.1*	Definitions of Selected Energy and Financial Terms (pages E- 42 through E-44).
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and is otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

* 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.