CHEVRON CORP
Form 10-K
February 23, 2012

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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, 2011**
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 001-00368
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 No.)	(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.

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 $205,986,778,815 (As of June 30, 2011)

Number of Shares of Common Stock outstanding as of February 13, 2012 1,976,966,530

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2012 Annual Meeting and 2012 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company s 2012 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 29 through 31 in this report. In addition, such results could be affected by general domestic and international economic and political conditions. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

PART I

Item 1. Business

(a) General Development of Business

Summary Description of Chevron

Chevron Corporation,* 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. Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation and regasification associated with liquefied natural gas; transporting crude oil by major international oil export pipelines; transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations consist primarily of refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lubricant additives.

A list of the company s major subsidiaries is presented on pages E-4 and E-5. As of December 31, 2011, Chevron had approximately 61,000 employees (including about 3,800 service station employees). Approximately 30,000 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. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. 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. Laws and governmental policies, particularly in the areas of taxation, energy and the environment affect where and how companies conduct their operations and formulate their products and, in some cases, limit their profits directly.

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, transportation and chemicals 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-8 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 s Strategic Direction

Chevron s primary objective is to create shareholder 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 natural gas business. In the downstream, the strategies are to improve returns and grow earnings across the value chain. The company also continues to utilize technology across all its businesses to differentiate performance, and to invest in profitable renewable energy and energy efficiency solutions.

(b) Description of Business and Properties

The upstream and downstream activities of the company and its equity affiliates are widely dispersed geographically, with operations in North America, South America, Europe, Africa, Asia and Australia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2011, and assets as of the end of 2011 and 2010 for the United States and the company s international geographic areas are in Note 11 to the Consolidated Financial Statements beginning on page FS-37. 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-39 through FS-41.

Capital and Exploratory Expenditures

Total expenditures for 2011 were $29.1 billion, including $1.7 billion for the company s share of equity-affiliate expenditures. In 2010 and 2009, expenditures were $21.8 billion and $22.2 billion, respectively, including the company s share of affiliates expenditures of $1.4 billion in 2010 and $1.6 billion in 2009.

Of the $29.1 billion in expenditures for 2011, 89 percent, or $25.9 billion, was related to upstream activities. Approximately 87 and 80 percent was expended for upstream operations in 2010 and 2009, respectively. International upstream accounted for about 68 percent of the worldwide upstream investment in 2011, about 82 percent in 2010 and about 80 percent in 2009. These amounts exclude the acquisition of Atlas Energy, Inc. in 2011. Refer to a discussion of the acquisition of Atlas Energy, Inc., in Note 2 to the Consolidated Financial Statements on page FS-30.

In 2012, the company estimates capital and exploratory expenditures will be $32.7 billion, including $3 billion of spending by affiliates. Approximately 87 percent of the total, or $28.5 billion, is budgeted for exploration and production activities, with $22.3 billion, or about 78 percent, of this amount for projects outside the United States.

Refer also to a discussion of the company s capital and exploratory expenditures on pages FS-11 through FS-12.

Upstream

The table on the following page summarizes the net production of liquids and natural gas for 2011 and 2010 by the company and its affiliates. Worldwide oil-equivalent production was 2.673 million barrels per day, down about three percent from 2010. The decrease was mainly associated with normal field declines, maintenance-related downtime and the impact of higher prices on entitlement volumes. The start-up and ramp-up of several major capital projects the Perdido project in the U.S. Gulf of Mexico, the expansion at the Athabasca Oil Sands Project in Canada, the Frade Field in Brazil, and the Platong II natural gas project in Thailand as well as acquisitions in the Marcellus Shale, partially offset the decrease in net production from 2010. Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of the factors explaining the 2009 2011 changes in production for crude oil and natural gas liquids, and natural gas.

The company estimates its average worldwide oil-equivalent production in 2012 will be approximately 2.680 million barrels per day based on the average Brent price of $111 per barrel in 2011. This estimate is subject to many factors and uncertainties, including quotas that may be imposed by OPEC, price effects on entitlement volumes, 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, delays in completion of maintenance turnarounds, greater-than-expected declines in production from mature fields, 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. Refer to the Review of Ongoing Exploration and Production Activities in Key Areas, beginning on page 8, for a discussion of the company s major crude oil and natural gas development projects.

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

	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)	
	2011	**2010**	**2011**	**2010**	**2011**	**2010**
United States	**678**	708	**465**	489	**1,279**	1,314
Other Americas:						
Canada	**70**	54	**69**	53	**4**	4
Colombia	**39**	41			**234**	249
Brazil	**35**	24	**33**	23	**13**	7
Trinidad and Tobago	**31**	38		1	**183**	223
Argentina	**27**	32	**26**	31	**4**	5
Total Other Americas	**202**	189	**128**	108	**438**	488
Africa:						
Nigeria	**260**	253	**236**	239	**142**	86
Angola	**147**	161	**139**	152	**50**	52
Chad	**26**	28	**25**	27	**6**	6
Republic of the Congo	**23**	25	**21**	23	**10**	10
Democratic Republic of the Congo	**3**	2	**3**	2	**1**	1
Total Africa	**459**	469	**424**	443	**209**	155
Asia:						
Thailand	**209**	216	**65**	70	**867**	875
Indonesia	**208**	226	**166**	187	**253**	236
Partitioned Zone[2]	**91**	98	**88**	94	**20**	23
Bangladesh	**74**	69	**2**	2	**434**	404
Kazakhstan	**62**	64	**38**	39	**144**	149
Azerbaijan	**28**	30	**26**	28	**10**	11
Philippines	**25**	25	**4**	4	**126**	124
China	**22**	20	**20**	18	**10**	13
Myanmar	**14**	13			**86**	81
Total Asia	**733**	761	**409**	442	**1,950**	1,916
Australia	**101**	111	**26**	34	**448**	458
Europe:						
United Kingdom	**85**	97	**59**	64	**155**	194
Denmark	**44**	51	**29**	32	**91**	116

Netherlands	**7**	8	**2**	2	**31**	35
Norway	**3**	3	**3**	3	**1**	1
Total Europe	**139**	159	**93**	101	**278**	346
Total Consolidated Operations	**2,312**	2,397	**1,545**	1,617	**4,602**	4,677
Equity Affiliates[3]	**361**	366	**304**	306	**339**	363
Total Including Affiliates[4]	**2,673**	2,763	**1,849**	1,923	**4,941**	5,040

[1] Includes synthetic oil: Canada, net	**40**	24	**40**	24
Venezuelan affiliate, net	**32**	28	**32**	28

[2] Located between Saudi Arabia and Kuwait.

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

[4] Volumes include natural gas consumed in operations of 582 million and 537 million cubic feet per day in 2011 and 2010, respectively. Total as sold natural gas volumes were 4,359 million and 4,503 million cubic feet per day for 2011 and 2010, respectively.

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Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-67 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 2011, 2010 and 2009.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2011 for the company and its affiliates:

Productive Oil and Gas Wells at December 31, 2011

	Productive Oil Wells		Productive Gas Wells	
	Gross	Net	Gross	Net
United States	49,511	32,368	14,061	7,671
Other Americas	709	533	40	17
Africa	2,548	850	17	7
Asia	12,612	10,861	3,437	2,125
Australia	807	453	64	11
Europe	332	105	222	48
Total Consolidated Companies	66,519	45,170	17,841	9,879
Equity in Affiliates	1,231	434	7	2
Total Including Affiliates	67,750	45,604	17,848	9,881
Multiple completion wells included above:	887	573	378	280

Reserves

Refer to Table V beginning on page FS-67 for a tabulation of the company s proved net crude oil and natural gas reserves by geographic area, at the beginning of 2009 and each year-end from 2009 through 2011. Reserves governance, technologies used in establishing proved reserves additions, and major changes to proved reserves by geographic area for the three-year period ended December 31, 2011, are summarized in the discussion for Table V. Discussion is also provided regarding the nature of, status of and planned future activities associated with the development of proved undeveloped reserves. The company recognizes reserves for projects with various development periods, sometimes exceeding five years. The external factors that impact the duration of a project include scope and complexity, remoteness or adverse operating conditions, infrastructure constraints, and contractual limitations.

The net proved reserve balances at the end of each of the three years 2009 through 2011 are shown in the following table.

Net Proved Reserves at December 31

	2011	2010	2009
Liquids Millions of barrels			
Consolidated Companies	**4,295**	4,270	4,610
Affiliated Companies	**2,160**	2,233	2,363
Natural Gas Billions of cubic feet			
Consolidated Companies	**25,229**	20,755	22,153
Affiliated Companies	**3,454**	3,496	3,896
Total Oil-Equivalent Millions of barrels			
Consolidated Companies	**8,500**	7,729	8,303
Affiliated Companies	**2,736**	2,816	3,012

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Acreage

At December 31, 2011, the company owned or had under lease or similar agreements undeveloped and developed crude oil and natural gas properties throughout the world. The geographical distribution of the company s acreage is shown in the following table.

Acreage at December 31, 2011
(Thousands of Acres)

	Undeveloped*		Developed		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States	6,290	5,171	7,752	5,051	14,042	10,222
Other Americas	26,803	15,338	1,392	395	28,195	15,733
Africa	8,068	3,921	3,324	1,370	11,392	5,291
Asia	41,125	21,613	5,426	2,760	46,551	24,373
Australia	12,801	6,064	920	240	13,721	6,304
Europe	5,093	3,608	645	137	5,738	3,745
Total Consolidated Companies	100,180	55,715	19,459	9,953	119,639	65,668
Equity in Affiliates	419	191	252	100	671	291
Total Including Affiliates	110,599	55,906	19,711	10,053	120,310	65,959

* The gross undeveloped acres that will expire in 2012, 2013 and 2014 if production is not established by certain required dates are 4,675, 5,993 and 2,903, respectively.

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 is contractually committed to deliver to third parties 232 billion cubic feet of natural gas through 2014. The company believes it can satisfy these contracts through a combination of equity production from the company s proved developed U.S. reserves and third-party purchases. These contracts include a variety of pricing terms, including both indexed and fixed-price contracts.

Outside the United States, the company is contractually committed to deliver a total of 891 billion cubic feet of natural gas from 2012 through 2014 from operations in Australia, Colombia, Denmark and the Philippines to third parties. 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 these countries.

Development Activities

Refer to Table I on page FS-62 for details associated with the company s development expenditures and costs of proved property acquisitions for 2011, 2010 and 2009.

The table on the next page 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, 2011. 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.

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Development Well Activity

	Wells Drilling at 12/31/11		Net Wells Completed 2011		2010		2009	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**105**	**62**	**909**	**9**	634	7	582	3
Other Americas	**8**	**4**	**37**		32		36	
Africa	**7**	**3**	**29**		33		40	
Asia	**85**	**37**	**549**	**15**	445	15	580	10
Australia	**1**							
Europe	**5**		**6**		4		7	
Total Consolidated Companies	**211**	**106**	**1,530**	**24**	1,148	22	1,245	13
Equity in Affiliates	**1**	**1**	**25**		8		6	
Total Including Affiliates	**212**	**107**	**1,555**	**24**	1,156	22	1,251	13

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, 2011. 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 12/31/11		Net Wells Completed 2011		2010		2009	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**2**	**2**	**5**	**1**	1	1	4	5
Other Americas	**2**	**1**	**1**			1	1	2
Africa	**3**	**1**	**1**		1		2	1
Asia	**1**	**1**	**10**	**1**	5	5	9	1
Australia	**1**	**1**	**4**	**1**	5	2	4	2
Europe	**2**	**1**		**1**				
Total Consolidated Companies	**11**	**7**	**21**	**4**	12	9	20	11
Equity in Affiliates			**1**					
Total Including Affiliates	**11**	**7**	**22**	**4**	12	9	20	11

Refer to Table I on page FS-62 for detail of the company s exploration expenditures and costs of unproved property acquisitions for 2011, 2010 and 2009.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron s 2011 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-11.

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The discussion that follows references the status of proved reserves recognition for significant long-lead-time projects not on production and for projects recently placed on production. Reserves are not discussed for exploration activities or recent discoveries that have not advanced 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.

Chevron has exploration and production 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 exploration and production.

a) United States

Upstream activities in the United States are concentrated in California, the Gulf of Mexico, the Appalachian Basin, Colorado, Michigan, New Mexico, Ohio, Oklahoma, Texas, Wyoming and Alaska. Average net oil-equivalent production in the United States during 2011 was 678,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2011, average net oil-equivalent production was 183,000 barrels per day, composed of 165,000 barrels of crude oil, 83 million cubic feet of natural gas and 4,000 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 2011 for the company s combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region was 244,000 barrels per day. The daily oil-equivalent production was composed of 161,000 barrels of crude oil, 401 million cubic feet of natural gas and 16,000 barrels of natural gas liquids.

Chevron was engaged in various exploration and development activities in the deepwater Gulf of Mexico during 2011. The Jack and St. Malo fields are located within 25 miles of each other and are being jointly developed. Chevron has a 50 percent working interest in Jack and a 51 percent working interest in St. Malo. Both fields are company operated. All major installation contracts have been awarded and construction began for the floating production unit hull and topsides modules during 2011. Development drilling operations commenced in fourth quarter 2011. The facility is planned to have a design capacity of 177,000 barrels of oil-equivalent per day to accommodate production from the Jack/St. Malo development, which is estimated to have maximum total daily production of 94,000 barrels of oil equivalent, plus production from a nearby third-party field. Total project costs for the initial phase of development are estimated at $7.5 billion and start-up is expected in 2014. The project has an estimated production life of 30 years. The initial recognition of proved reserves for the project occurred in 2011.

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Work continued at the 60 percent-owned and operated Big Foot discovery. The development plan includes a 15-slot drilling and production tension leg platform with water injection facilities and a design capacity of 79,000 barrels of oil equivalent per day. Fabrication of topsides, hull and other components began in first-half 2011 and initial development drilling commenced in fourth quarter 2011. First production is anticipated in 2014. The field has an estimated production life of 20 years. Initial proved reserves were recognized in 2011.

Tahiti 2 is the second development phase for the 58 percent-owned and operated Tahiti Field and is designed to increase recovery and return well capacity to 125,000 barrels of oil per day. The project includes three water injection wells, two additional production wells and the water injection facilities required to deliver water to the injection wells. Two water injection wells have been completed and drilling commenced on the first production well in early 2012. The water injection facilities have been installed and water injection began in first quarter 2012. Start-up of the first production well of the second phase is expected by 2013. Initial proved reserves for the Tahiti 2 project were recognized in 2011, and the field has an estimated production life of 30 years.

The final investment decision was made for the Tubular Bells deepwater project in fourth quarter 2011. The company has a 42.9 percent nonoperated working interest in the Tubular Bells unitized area after receiving an additional 12.9 percent equity interest relinquished by a partner in 2011. Development drilling is scheduled to begin in second quarter 2012, and plans include three producing and two injection wells, with a subsea tieback to a third-party production facility. First oil is anticipated in 2014, and maximum total daily production is expected to reach 40,000 to 45,000 barrels of oil-equivalent. At the end of 2011, proved reserves had not been recognized for this project.

The company has a 20.3 percent nonoperated working interest in the Caesar and Tonga unitized area. Development plans include a total of four wells and a subsea tieback to a nearby third-party production facility. Three of the four development wells have been drilled and completed as of year-end 2011. Drilling of the fourth well is expected to begin in mid-2012. Work on the subsea system, commissioning of the topsides and the initial well completion program continued into 2012. Installation of the production riser and first production are expected in mid-2012. Maximum total production is expected to be 46,000 barrels of oil-equivalent per day. Proved reserves have been recognized for the project.

The company has a 15.6 percent nonoperated working interest in the Mad Dog II Project. Front-end engineering and design (FEED) is expected to commence by second quarter 2012. It is anticipated that this future development would require new production facilities to support planned maximum total daily production of 120,000 to 140,000 barrels of oil equivalent. At the end of 2011, proved reserves had not been recognized for this project.

Development planning and unitization talks with owners of an adjacent field continued in 2011 for the Knotty Head project. Chevron has a 25 percent nonoperated working interest in this subsalt, Green Canyon Block 512 discovery. At the end of 2011, proved reserves had not been recognized for this project.

Deepwater exploration activities in 2011 included participation in four exploratory wells two wildcats, one appraisal and one delineation. Following successful permitting under new, more stringent, U.S. Department of Interior guidelines, two wells resumed drilling activities after operations were halted in 2010 as a result of the deepwater drilling moratorium in the Gulf of Mexico. Drilling operations at the 43.8 percent-owned and operated Moccasin prospect resumed in first quarter 2011 and resulted in a new discovery in the Lower Tertiary Wilcox Trend. Drilling operations resumed in second quarter 2011 at the 55 percent-owned and operated Buckskin prospect, resulting in a successful appraisal well. These two discoveries, located 12 miles apart, could facilitate future co-development upon the successful completion of additional appraisal drilling planned at each prospect in 2012. Drilling was terminated at the Coronado wildcat well due to drilling conditions in the shallow section of the wellbore. The company plans to drill a replacement well at an alternate location by mid-2012.

Besides the activities connected with the development and exploration projects in the Gulf of Mexico, the company also has contracted capacity at the third-party Sabine Pass liquefied natural gas (LNG) regasification terminal in Louisiana and in a third-party pipeline system connecting the Sabine Pass LNG terminal to the natural gas pipeline grid. The pipeline provides access to two major salt dome storage fields and 10 major interstate pipeline systems, including access to Chevron s Sabine Pipeline, which connects to the Henry Hub. 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.

Company activities outside California and the Gulf of Mexico include operated and nonoperated interests in properties across the mid-continental United States, the Appalachian Basin, Michigan, Ohio and Alaska. During 2011, the company s U.S. production outside California and the Gulf of Mexico averaged 251,000 net oil-equivalent barrels per day, composed of 91,000 barrels of crude oil, 795 million cubic feet of natural gas and 28,000 barrels of natural gas liquids.

In West Texas, the company continues to pursue development of tight carbonates, tight sands, and liquids-rich shale resources in the Midland Basin s Wolfcamp play and several plays in the Delaware Basin through use of advanced drilling and completion technologies. Additional production growth is expected from interests in these formations in future years.

In February 2011, Chevron acquired Atlas Energy, Inc. The acquisition provided a natural gas resource position in the Marcellus Shale and Utica Shale, primarily located in southwestern Pennsylvania and Ohio. The acquisition also provided a 49 percent interest in Laurel Mountain Midstream, LLC, an affiliate that owns more than 1,000 miles of natural gas gathering lines servicing the Marcellus. In addition, the acquisition provided assets in Michigan, which include Antrim Shale producing assets and approximately 350,000 total acres in the Antrim and Collingwood/Utica Shale formations. Additional asset acquisitions in 2011 expanded the company s holdings in the Marcellus and Utica to approximately 700,000 and 600,000 total acres, respectively. In the Marcellus, 61 natural gas wells were completed in 2011.

b) Other Americas

Other Americas is composed of Argentina, Brazil, Canada, Colombia, Greenland, Trinidad and Tobago, and Venezuela. Net oil-equivalent production from these countries averaged 267,000 barrels per day during 2011, including the company s share of synthetic oil production.

Canada: Company activities in Canada include nonoperated working interests of 26.9 percent in the Hibernia Field, 26.6 percent in the Hebron Field and 23.6 percent in the unitized Hibernia South Extension, all offshore eastern Canada. In Alberta, the company holds a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP). Average net oil-equivalent production during 2011 was 70,000 barrels per day, composed of 69,000 barrels of crude oil, synthetic oil and natural gas liquids and 4 million cubic feet of natural gas.

Development of the Hibernia Southern Extension is expected to stem the production decline from the Hibernia Field. The project includes drilling of producing wells from the existing Hibernia platform and subsea drilling of water injection wells. All project approvals were in place by early 2011 and two producing wells were successfully drilled from the platform to obtain early reservoir information. Further drilling is anticipated to commence in 2013 with full production start-up expected in 2014. The initial recognition of proved reserves occurred in 2011 for this project.

FEED activities continued in 2011 for the development of the heavy-oil Hebron Field and a final investment decision is expected in 2013. The project has an expected economic life of 30 years. At the end of 2011, proved reserves had not been recognized for this project.

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At AOSP, oil sands are mined from both the Muskeg River and Jackpine mines and bitumen is extracted from the oil sands and upgraded into synthetic oil. The AOSP Expansion 1 Project activities continued in 2011 with completion of the Scotford Upgrader expansion, which increased daily production design capacity to approximately 255,000 barrels per day.

During 2011, the company increased its shale exploration acreage in Alberta in the Duvernay formation. In third quarter 2011, a multiwell drilling program commenced on these 100 percent-owned and operated leases. A long-term well test is expected to begin in fourth quarter 2012, when the first well is expected to be tied into third-party processing facilities. The company also holds exploration licenses and leases in the Flemish Pass and Orphan basins offshore Atlantic Canada, the Mackenzie Delta region of the Northwest Territories and the Beaufort Sea region of Canada s Arctic, including a 35.4 percent nonoperated working interest in the offshore Amauligak discovery.

In addition, Chevron holds interests in the Aitken Creek and Alberta Hub natural gas storage facilities with an approximate total capacity of 100 billion cubic feet. These facilities are located adjacent to the Duvernay, Horn River and Montney shale gas plays.

Greenland: In 2011, the Greenland government granted a one-year extension to the initial four-year term for License 2007/26, which includes Block 4 offshore West Greenland. Interpretation of seismic data continued into early 2012. Chevron has a 29.2 percent nonoperated working interest in this exploration license.

Argentina: Chevron holds operated interests in four concessions in the Neuquen Basin. Working interests range from 18.8 percent to 100 percent. Net oil-equivalent production in 2011 averaged 27,000 barrels per day, composed of 26,000 barrels of crude oil and natural gas liquids and 4 million cubic feet of natural gas. During 2011, the company reached an agreement to extend the El Trapial concession for an additional 10 years until 2032. The company expects to drill two exploratory wells in 2012 in the Vaca Muerta formation, targeting shale gas and tight oil resources.

Brazil: Chevron holds working interests in three deepwater fields in the Campos Basin. Net oil-equivalent production in 2011 averaged 35,000 barrels per day, composed of 33,000 barrels of crude oil and 13 million cubic feet of natural gas.

During 2011, development drilling continued at the 51.7 percent-owned and operated Frade Field, located in the Campos Basin. Eleven development wells and four injection wells had been completed as of year-end 2011. Development drilling is planned to continue through 2013, with one additional development well, one sidetrack well and several injection wells. 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 development following the end of the exploration phase of this block. During 2011, construction progressed on a floating production, storage and offloading (FPSO) vessel and tension leg well platform for the Papa-Terra project. Development drilling was initiated in fourth quarter 2011. The facility has a planned total daily capacity of 140,000 barrels of crude oil. First production is expected in 2013, and the initial recognition of proved reserves occurred during 2011. Evaluation of the field development concept for Maromba continued into early 2012. At the end of 2011, proved reserves had not been recognized for this project. These concessions expire in 2032.

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 based on prior Chuchupa capital contributions. During 2011, a gas export agreement with Venezuela was extended. An onshore, multiwell drilling program commenced in late 2011. Daily net production averaged 234 million cubic feet of natural gas in 2011.

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. Net production in 2011 averaged 183 million cubic feet of natural gas per day. Chevron also holds a

50 percent operated interest in the Manatee Area of Block 6(d), which includes a 2005 discovery. During 2011, work progressed to mature a development concept called the Regional Cooperative Agreement.

Venezuela: Chevron holds interests in two producing affiliates located in western Venezuela and one producing 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 net oil-equivalent production during 2011 from these operations, including synthetic oil from Hamaca, averaged 65,000 barrels per day, composed of 60,000 barrels of crude oil, synthetic oil and natural gas liquids and 27 million cubic feet of natural gas.

Chevron holds a 34 percent interest in the Petroindependencia affiliate that is working on a heavy-oil project in three blocks within the Carabobo Area of eastern Venezuela s Orinoco Belt. During 2011, work continued toward commercialization of the Carabobo 3 Project. Conceptual engineering for the potential development of the concession is in progress.

The company operates and has a working interest of 60 percent in Block 2 in the Plataforma Deltana area offshore eastern Venezuela. During 2011, work progressed to mature a development concept called the Regional Cooperative Agreement.

c) Africa

In Africa, the company is engaged in exploration and production activities in Angola, Chad, Democratic Republic of the Congo, Liberia, Nigeria and Republic of the Congo. Net oil-equivalent production in Africa averaged 459,000 barrels per day during 2011.

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 area. Net production from these operations in 2011 averaged 147,000 barrels of oil-equivalent per day.

The company operates the 39.2 percent-owned Block 0, which averaged 108,000 barrels per day of net liquids production in 2011. The Block 0 concession extends through 2030.

Work on the second development stage of the Mafumeira Field in Block 0 continued in 2011. Mafumeira Sul, a project to develop the southern portion of the field, is expected to reach a final investment decision in second quarter 2012. Maximum total production from Mafumeira Sul is expected to be 110,000 barrels of crude oil and 10,000 barrels of LPG per day. At year-end 2011, proved reserves had not been recognized for the Mafumeira Sul project.

In the Greater Vanza/Longui Area of Block 0, development concept studies continued during 2011 and the project is expected to enter FEED in second-half 2012. FEED activities continued on the south extension

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of the N Dola Field development with a final investment decision expected in late 2012. At year-end 2011, no proved reserves were recognized for these projects.

In Block 0, the Area A gas management projects at the Takula and Malongo reservoirs were designed to eliminate routine flaring of natural gas. The final project entered service in 2011, which together have reduced flaring by approximately 70 million cubic feet per day, as of year-end 2011. In Area B, the first stage of the Nemba Enhanced Secondary Recovery and Flare Reduction Project was completed in second quarter 2011. The final stage is expected to eliminate routine flaring at the North and South Nemba platforms and is scheduled to begin gas injection in 2014.

Also in Block 0, a two-well appraisal and exploration program was completed in 2011. The appraisal well completed in July 2011 in the Lifua Field was successful and development opportunities are being evaluated. The second well, completed in October 2011 in the pre-salt play, was not successful. Two additional exploratory wells are planned for second-half 2012.

In the 31 percent-owned Block 14, net production in 2011 averaged 29,000 barrels of liquids per day. Development and production rights for the various producing fields in Block 14 expire between 2023 and 2028.

For the Lucapa Field in Block 14, development alternatives continued to be evaluated during 2011. The project is expected to enter FEED in second quarter 2012. Development alternatives were evaluated during the year at the Malange Field and the preferred alternative is expected to enter FEED in mid-2012. As of the end of 2011, development of the Negage Field remained suspended until cooperative arrangements between Angola and Democratic Republic of the Congo are finalized. At the end of 2011, proved reserves had not been recognized for these projects.

In addition to the exploration and production activities in Angola, Chevron has a 36.4 percent ownership interest in the Angola LNG affiliate that began construction in 2008 of an onshore natural gas liquefaction plant at Soyo, Angola. The plant is designed to process 1.1 billion cubic feet of natural gas per day, with expected average total daily sales of 670 million cubic feet of regasified LNG and up to 63,000 barrels of natural gas liquids. Construction continued during 2011, reaching mechanical completion at year-end. The first LNG shipment from the plant is expected in second quarter 2012. The estimated total cost of the LNG plant is $10 billion, with an estimated life in excess of 20 years. The company also holds a 38.1 percent interest in a pipeline project that is expected to transport up to 250 million cubic feet of natural gas per day from Block 0 and Block 14 to the Angola LNG plant. The pipeline project entered construction in May 2011 and is expected to be completed in late 2013. Proved reserves have been recognized for the producing operations associated with the Angola LNG 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. A final investment decision for the Lianzi development project is expected in mid-2012. The project is expected to commence production in late 2014. At the end of 2011, proved reserves had not been recognized for the project.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2011 averaged 3,000 barrels of oil-equivalent.

Republic of the Congo: Chevron has a 31.5 percent nonoperated working interest in the Nkossa, Nsoko and Moho-Bilondo permit areas and a 29.3 percent nonoperated working interest in the Kitina permit area, all of which are offshore. The development and production rights for Kitina, Nsoko, Nkossa and Moho-Bilondo expire in 2014, 2018, 2027 and 2030, respectively. Net production averaged 23,000 barrels of oil-equivalent per day in 2011.

The Moho Nord Project, located in the Moho-Bilondo Development Area, entered FEED in fourth quarter 2011. The project is expected to reach a final investment decision in 2013. At the end of 2011, proved reserves had not been recognized for this project.

Chad/Cameroon: Chevron has a 25 percent nonoperated working interest in crude oil producing operations in southern Chad and an approximate 21 percent interest in two affiliates that own an export pipeline that transports the crude oil to the coast of Cameroon. Average daily net production from the Chad fields in 2011 was 26,000 barrels of oil-equivalent. The Chad producing operations are conducted under a concession that expires in 2030.

Nigeria: Chevron holds a 40 percent interest in 13 concessions predominantly 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 four operated and six nonoperated deepwater blocks. In 2011, the company s net oil-equivalent production in Nigeria averaged 260,000 barrels per day, composed of 236,000 barrels of liquids and 142 million cubic feet of natural gas.

Chevron operates and holds a 67.3 percent interest in the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128. During 2011, drilling continued on a 10-well, Phase 2 development program that is designed to offset field decline and maintain plateau production. The first well is expected to be completed and placed on production in second-half 2012. The leases that contain the Agbami Field expire in 2023 and 2024.

The company holds a 30 percent nonoperated working interest in the deepwater Usan project in OML 138. During 2011, development drilling continued and the FPSO vessel was moored on location. Production start-up is expected in early 2012, with maximum total production of 180,000 barrels of crude oil per day expected within one year of start-up. The production-sharing contract (PSC) expires in 2023. Proved reserves have been recognized for this project.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in OML 118 share a common geologic structure and are planned to be jointly developed. Initiation of FEED is expected in late 2012. At the end of 2011, no proved reserves were recognized for this project.

In the Niger Delta, ramp-up activity continued at the Escravos Gas Plant (EGP). During 2011, construction continued on Phase 3B of the EGP project, which is designed to gather 120 million cubic feet of natural gas per day from eight offshore fields and to compress and transport the natural gas to onshore facilities. The Phase 3B project is expected to be completed in 2016. Proved reserves associated with this project have been recognized.

The 40 percent-owned and operated Sonam Field Development includes facilities to produce natural gas from the Sonam natural gas field in the Escravos area. The project is designed to utilize EGP and to deliver 215 million cubic feet of natural gas per day to the domestic market, and produce an average of 30,000 barrels of liquids per day. A final investment decision was reached in late 2011, and first production is expected in 2016. Proved reserves associated with the project were recognized in 2011.

Chevron has a 75 percent-owned and operated interest in a gas-to-liquids facility at Escravos that is being developed with the Nigerian National Petroleum Corporation. The 33,000-barrel-per-day facility is designed to process 325 million cubic feet per day of natural gas supplied from the Phase 3A expansion of EGP. At the end of 2011, work on the project was more than 80 percent complete and start-up is planned for 2013. The estimated cost of the plant is $8.4 billion.

The company has a 40 percent-owned and operated interest in the Onshore Asset Gas Management project that 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. Construction activities continued through 2011, and start-up is scheduled for late 2012.

In deepwater exploration, the company has 20 percent and 27 percent nonoperated working interests in Oil Prospecting License (OPL) 214 and OPL 223, respectively. Drilling of two exploration wells commenced in fourth quarter 2011 in OPL 214, and one exploration well is planned in OPL 223 for second-half 2012. In addition, Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery in OML 140 where further exploration activities are planned.

Shallow-water exploration activities in 2011 included reprocessing 3-D seismic data from OML 86 and OML 88. In November 2011, the company began drilling a well in OML 86. In January 2012, while drilling the well, there was a release of natural gas that led to a fire. Drilling of a relief well commenced in February 2012. A root cause investigation is under way.

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 West African Gas Pipeline. The pipeline supplies Nigerian natural gas to customers in Benin, Ghana and Togo for industrial applications and power generation and has the capacity to transport 170 million cubic feet per day.

Liberia: In 2010, Chevron acquired a 70 percent interest and operatorship in three deepwater blocks off the coast of Liberia. Exploration drilling prospects were identified during 2011 based on 3-D seismic data. Two exploration wells are planned to be drilled in 2012.

d) Asia

In Asia, the company is engaged in upstream activities in Azerbaijan, Bangladesh, Cambodia, China, Indonesia, Kazakhstan, Myanmar, the Partitioned Zone located between Saudi Arabia and Kuwait, the Philippines, Russia, Thailand, Turkey, and Vietnam. During 2011, net oil-equivalent production averaged 1,029,000 barrels per day.

Azerbaijan: Chevron holds an 11.3 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. The company s daily net production from AIOC averaged 28,000 barrels of oil-equivalent in 2011. AIOC operations are conducted under a PSC that expires in 2024.

During 2011, construction progressed on the next development phase of the ACG project, which will further develop the deepwater Gunashli Field. Production is expected to begin in 2013. Proved reserves have been recognized for this project. The total estimated cost of the project is $6 billion, with maximum total daily production of 140,000 barrels of oil-equivalent.

Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate, which owns and operates a crude oil export pipeline from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities at Ceyhan, Turkey. The BTC Pipeline has a capacity of 1.2 million barrels per day and transports the majority of ACG production. Another production export route for crude oil is the Western Route Export Pipeline, wholly owned by AIOC, with capacity to transport 100,000 barrels per day from Baku, Azerbaijan, to a marine terminal at Supsa, Georgia.

Kazakhstan: Chevron participates in two major upstream developments in western Kazakhstan. The company holds a 50 percent interest in the Tengizchevroil (TCO) affiliate, which is operating and developing the Tengiz and Korolev crude oil fields under a concession that expires in 2033. Chevron s net oil-equivalent production in 2011 from these fields averaged 296,000 barrels per day, composed of 244,000 barrels of crude oil and natural gas liquids and 312 million cubic feet of natural gas. During 2011, 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 exported via rail to Black Sea ports.

Also during 2011, TCO continued to evaluate alternatives for another expansion project to increase total daily crude oil production between 250,000 and 300,000 barrels. The expansion project will rely on sour gas injection technology utilized in current operations. Approval of FEED is anticipated in 2012. As of year-end 2011, proved reserves had not been recognized for this expansion project.

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Chevron holds a 20 percent nonoperated working interest in the Karachaganak project, which is conducted under a PSC that expires in 2038. During 2011, Karachaganak net oil-equivalent production averaged 62,000 barrels per day, composed of 38,000 barrels of liquids and 144 million cubic feet of natural gas. In 2011, access to the CPC and Atyrau-Samara (Russia) pipelines enabled approximately 204,000 barrels per day (34,000 net barrels) of Karachaganak liquids to be sold at world-market prices. The remaining liquids were sold into local and Russian markets. During 2011, a fourth train entered production and increased total liquids-stabilization capacity by 56,000 barrels per day, allowing increased sales of condensate into world markets. Karachaganak project partners have reached an agreement allowing the government of Kazakhstan to become a 10 percent equity owner in the Karachaganak project. The transfer of equity to the government is anticipated to occur in June 2012 and will result in Chevron s working interest being reduced to 18 percent.

During 2011, Chevron and its partners continued to evaluate alternatives for a Phase III development of Karachaganak. The timing of the project remains uncertain until a project design is finalized. At the end of 2011, proved reserves had not been recognized for the project.

Kazakhstan/Russia: Chevron has a 15 percent interest in the CPC affiliate. During 2011, CPC transported an average of approximately 684,000 barrels of crude oil per day, including 608,000 barrels per day from Kazakhstan and 76,000 barrels per day from Russia. During 2011, the partners began construction on a project to increase pipeline capacity by 670,000 barrels per day. The total estimated cost of the project is $5.4 billion. The project is expected to be implemented in three phases, with capacity increasing progressively until reaching maximum capacity of 1.4 million barrels per day in 2016.

Turkey: In 2010, Chevron signed a Joint Operating Agreement for a 50 percent working interest in a 5.6 million acre exploration block located in the Black Sea. The initial exploration well completed in 2010 was unsuccessful. Future plans are under evaluation.

Bangladesh: Chevron holds a 98 percent interest in two operated PSCs covering Blocks 12, 13 and 14. Net oil-equivalent production from these operations in 2011 averaged 74,000 barrels per day, composed of 434 million cubic feet of natural gas and 2,000 barrels of liquids. In 2011, the Muchai compression project achieved mechanical completion and is expected to support additional production starting in second quarter 2012 from the Bibiyana, Jalalabad and Moulavi Bazar natural gas fields. Proved reserves have been recognized for this project. The Bibiyana Expansion Project entered FEED in July 2011. Project scope includes expansion of the gas plant, additional development drilling and an enhanced liquids recovery unit, with an estimated total maximum daily production of 57,000 barrels of oil equivalent. A final investment decision is expected in mid-2012. At the end of 2011, proved reserves had not been recognized for this project. Also in 2011, the company relinquished its interest in Block 7 subsequent to the completion of an unsuccessful exploratory well.

Cambodia: Chevron owns a 30 percent interest and operates the 1.2 million-acre Block A, located in the Gulf of Thailand. In 2011, the company progressed discussions on the production permit. Government approval and a final investment decision are expected by the end of 2012. At the end of 2011, proved reserves had not been recognized for the project.

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, within Blocks M5 and M6, in the Andaman Sea. The PSC expires in 2028. The company also has a 28.3 percent nonoperated interest in a pipeline company that transports the natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. The company s average net natural gas production in 2011 was 86 million cubic feet per day.

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Thailand: Chevron has operated and nonoperated working interests in multiple offshore blocks. The company s net oil-equivalent production in 2011 averaged 209,000 barrels per day, composed of 65,000 barrels of crude oil and condensate and 867 million cubic feet of natural gas. All of the company s natural gas production is sold to PTT Public Company Limited, Thailand s national oil company, under long-term sales contracts.

Operated interests are in the Pattani Basin with ownership interests ranging from 35 percent to 80 percent. Concessions for producing areas within this basin expire between 2020 and 2035. Chevron has a 16 percent nonoperated working interest in the Arthit and North Arthit fields located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040.

Start-up of the 69.9 percent-owned and operated Platong II natural gas project occurred in October 2011, and total average daily production ramped up to 377 million cubic feet of natural gas and 11,000 barrels of condensate as of the end of 2011. Proved reserves have been recognized for this project.

During 2011, the company drilled nine exploration wells in the Pattani Basin. All of the wells were successful and development alternatives are being evaluated. The company also holds exploration interests in a number of blocks that are inactive, pending resolution of border issues between Thailand and Cambodia.

Vietnam: Chevron is the operator of two PSCs in the Malay Basin off the southwest coast of Vietnam. The company has a 42.4 percent interest in a PSC that includes Blocks B and 48/95, and a 43.4 percent interest in a PSC for Block 52/97.

In the blocks off the southwest coast, the Block B Gas Development is designed to produce natural gas from the Malay Basin for delivery to state-owned Petrovietnam. The project includes installation of wellhead and hub platforms, a floating storage and offloading vessel, a central processing platform and a pipeline to shore. FEED continued during 2011. Maximum total daily production is expected to be 490 million cubic feet of natural gas and 4,000 barrels of condensate. A final investment decision is expected to be reached in 2012. At the end of 2011, proved reserves had not been recognized for the development project.

During the year, work continued on preparations for a 2012 exploration drilling program to further evaluate the potential of the three company-operated blocks in the Malay Basin. The company also completed the evaluation of Block 122 offshore eastern Vietnam and reached a decision to exit the block.

China: Chevron has operated and nonoperated working interests in several areas in China. The company s net oil-equivalent production in 2011 averaged 22,000 barrels per day, composed of 20,000 barrels of crude oil and condensate and 10 million cubic feet of natural gas.

The company operates and holds a 49 percent interest in the Chuandongbei PSC, located in the onshore Sichuan Basin. The project includes two sour-gas processing plants with an aggregate design capacity of 740 million cubic feet per day connected by a natural gas gathering system to five fields. During 2011, the company continued construction on the first natural gas processing plant. In 2012, construction is expected to start at the second natural gas processing plant. Start-up of the initial phase of the project is expected in 2013, with planned maximum total natural gas production of 558 million cubic feet per day. Proved reserves have been recognized for this project. The PSC for Chuandongbei expires in 2037.

The company holds operating interests in three deepwater exploration blocks in the South China Sea. During the exploration phase, the company has a 100 percent

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working interest in Blocks 53/30 and 64/18, and a 59.2 percent working interest in Block 42/05 under three separate PSCs. The three deepwater blocks cover approximately 4.8 million acres. During 2011, a 3-D seismic acquisition program was completed for Blocks 64/18 and 53/30 and a three-well exploration program was initiated. The first well was unsuccessful. The second and third wells are expected to be completed by mid-2012.

The company signed a joint study agreement to explore for natural gas from shale resources in the Qiannan Basin in April 2011 and commenced seismic operations in July 2011.

The company also has nonoperated working interests of 32.7 percent in Blocks 16/08 and 16/19 in the Pearl River Mouth Basin and nonoperated working interests of 24.5 percent in the QHD 32-6 Field and 16.2 percent in Block 11/19 in the Bohai Bay.

Indonesia: Chevron holds operated and nonoperated working interests in Indonesia. The company has 100 percent-owned and operated interests in the Rokan and Siak PSCs onshore Sumatra. Chevron also operates four PSCs in the Kutei Basin, located offshore East Kalimantan. These interests range from 62 percent to 92.5 percent. Chevron also has a 51 percent operated working interests in two exploration blocks in western Papua, West Papua I and West Papua III, and a 25 percent nonoperated working interest in a joint venture in Block B in the South Natuna Sea.

The company s net oil-equivalent production in 2011 from its interests in Indonesia averaged 208,000 barrels per day, composed of 166,000 barrels of liquids and 253 million cubic feet of natural gas. The largest producing field is Duri, located in the Rokan PSC. Duri has been under steamflood since 1985 and is one of the world s largest steamflood developments. The North Duri Development is divided into multiple expansion areas. Government approval of the construction contract bid awards for North Duri Area 13 expansion project is expected in mid-2012 with start-up scheduled for 2013. The Rokan PSC expires in 2021.

During 2011, two deepwater development projects in the Kutei Basin progressed under a single plan of development. In the first of these projects, Chevron advanced FEED for the Gendalo-Gehem deepwater natural gas project. The project includes two separate hub developments, natural gas and condensate pipelines, and an onshore receiving facility. Maximum daily total production from the project is expected to be about 1.1 billion cubic feet of natural gas and 31,000 barrels of condensate. Gas from the project is expected to be used domestically and for LNG export. The company s working interest is approximately 63 percent. At the end of 2011, proved reserves had not been recognized for this project.

In the second of these projects, FEED was completed in December 2011 for the Bangka deepwater natural gas project and the contracting approval process began with the government of Indonesia. The project scope includes a subsea tie back to a floating production unit. The company s working interest is 62 percent. At year-end 2011, proved reserves had not been recognized for this project.

Exploration activities continued in the Central Sumatra Basin where six successful appraisal wells were drilled in the Bekasap, Duri and Kulin fields in 2011, and evaluation of a well drilled in the Jorang Field continued in 2012. Also in 2011, seismic data acquisition was completed for West Papua I and is under way for West Papua III. Processing of the seismic data is planned for 2012.

In West Java, Chevron operates the wholly owned Salak geothermal field with a total power-generation capacity of 377 megawatts and 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 the company s operation in Duri, Sumatra. In the Suoh-Sekincau prospect area of Sumatra, the company holds a 95 percent-owned and operated interest in a license to explore and develop a geothermal prospect.

Partitioned Zone (PZ): Chevron holds a concession with the Kingdom of Saudi Arabia to operate the kingdom s 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 until 2039.

During 2011, the company s average net oil-equivalent production was 91,000 barrels per day, composed of 88,000 barrels of crude oil and 20 million cubic feet of natural gas. During 2011, the company continued a steam injection pilot project in the First Eocene carbonate reservoir that was initiated in 2009. A project to expand the steam injection pilot to the Second Eocene reservoir progressed during 2011 and is expected to enter FEED in second-half 2012. At the end of 2011, proved reserves had not been recognized for these projects.

Also in 2011, the Central Gas Utilization Project entered FEED. The project is intended to increase natural gas utilization and eliminate routine flaring. A final investment decision is expected in 2013. At year-end 2011, proved reserves had not been recognized for this project.

Philippines: The company holds a 45 percent nonoperated working interest in the Malampaya natural gas field located 50 miles offshore Palawan Island. Net oil-equivalent production in 2011 averaged 25,000 barrels per day, composed of 126 million cubic feet of natural gas and 4,000 barrels of condensate. During 2011, studies were progressed to maintain capacity.

Chevron also develops and produces geothermal resources under an agreement with the Philippine government. During 2011, efforts continued to seek a new 25-year contract with the government for the continued operation of the steam fields, which supply geothermal resources to third-party, 637-megawatt power generation facilities in southern Luzon. Chevron also has a 90 percent-owned and operated interest in the Kalinga geothermal prospect area in northern Luzon and is in the early phase of geological and geophysical assessments.

e) Australia

In Australia, the company s exploration and production efforts are concentrated off the northwest coast. During 2011, the average net oil-equivalent production from Australia was 101,000 barrels per day.

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 2011 averaged 18,000 barrels of crude oil and condensate, 445 million cubic feet of natural gas, and 4,000 barrels of LPG. Approximately 70 percent of the natural gas was sold in the form of LNG to major utilities in Asia, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market. The concession for the NWS Venture expires in 2034.

The NWS Venture continues to progress two major capital projects North Rankin 2 and NWS Oil Redevelopment. The North Rankin 2 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 maintain production capacity of NWS. The North Rankin B platform was completed and installed during 2011. Maximum total daily production is expected to be about 2 billion cubic feet of natural gas and 39,000 barrels of condensate. Total estimated projects costs are $5.4 billion and start-up is expected in 2013. Proved reserves have been recognized for the project.

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The NWS Oil Redevelopment Project recommenced production from the Cossack, Hermes, Lambert and Wanaea fields in September 2011. The project included replacement of an FPSO vessel and a portion of existing subsea infrastructure. The project is expected to extend production from these fields beyond 2020.

Chevron holds a 47.3 percent ownership interest across most of the Greater Gorgon Area and is the operator of the Gorgon Project, which combines the development of the Gorgon and nearby Io/Jansz natural gas field. 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. Maximum total daily production from the project is expected to reach about 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate. Total estimated project costs for the first phase of development are $37 billion.

Work on the Gorgon Project progressed on schedule. As of year-end 2011, more than one-third of the construction activities across numerous fronts on Barrow Island and in fabrication yards in various countries had been completed. The development drilling program also commenced in July 2011.

Through year-end 2011, Chevron has signed binding LNG Sales and Purchase Agreements (SPAs) with six Asian customers for delivery of about 4.7 million metric tons of LNG per year, which brings delivery commitments to about 70 percent of Chevron s share of LNG from this project. Discussions continue with potential customers to increase long-term sales to 85 to 90 percent of Chevron s net LNG off-take. Binding SPAs were also signed in 2011 for delivery of about 55 million cubic feet per day of natural gas to two Western Australian state-owned utilities starting in 2015. Proved reserves have been recognized for the Greater Gorgon Area fields included in the project, and first production of natural gas from the fields is expected in late 2014. The project s estimated economic life exceeds 40 years from the time of start-up.

A project for development of a fourth train at the Gorgon LNG facility is expected to enter FEED in late 2012. At the end of 2011, proved reserves had not been recognized for the fields associated with this expansion.

Chevron and its joint-venture partners are proceeding with development of the Wheatstone Project. In September 2011, the company announced the final investment decision. Construction started in late 2011. Chevron holds a 72.1 percent interest in the foundation natural gas processing facilities, which include a two-train, 8.9 million-metric-ton-per-year LNG facility and a separate domestic gas plant located at Ashburton North, along the northwest coast of Australia. The company plans to supply natural gas to the foundation project from the company-operated and 90.2 percent-owned Wheatstone and Iago fields. Maximum total daily production is expected to be about 1.4 billion cubic feet of natural gas and 25,000 barrels of condensate. The LNG facilities will also be a destination for third-party natural gas. Total estimated project costs for the first phase of development are $29 billion.

Through the end of 2011, Chevron has signed binding SPAs with two Asian customers for the delivery of about 60 percent of Chevron s net LNG off-take from the Wheatstone Project. Discussions continue with potential customers to increase long-term sales to 85 to 90 percent of Chevron s net LNG off-take and to sell down equity. Start-up of the first LNG train is expected in 2016. During 2011, the company recognized proved reserves for this project.

In the Browse Basin, the Browse LNG development participants entered FEED in 2011, undertaking environmental, geophysical, geotechnical and engineering and design studies for the Brecknock, Calliance and Torosa fields. At the end of 2011, proved reserves had not been recognized for any of the Browse Basin fields.

During 2011, the company announced a natural gas discovery at the 50 percent-owned and operated Orthrus Deep prospect in Block WA-24-R. The company also announced natural gas discoveries at the 50 percent-owned and operated Vos prospect in WA-439-P and the 67 percent-owned and operated Acme West prospect in Block WA-205-P in 2011, and at the 50 percent-owned and operated Satyr-3 prospect in WA-374-P in January 2012. These discoveries are expected to support potential expansion opportunities at company-operated LNG facilities.

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f) Europe

In Europe, the company is engaged in exploration and production activities in Bulgaria, Denmark, the Netherlands, Norway, Poland, Romania and the United Kingdom. Net oil-equivalent production in Europe averaged 139,000 barrels per day during 2011.

Denmark: Chevron has a 15 percent working interest in the partner-operated Danish Underground Consortium (DUC), which produces crude oil and natural gas from 13 fields in the Danish North Sea. Net oil-equivalent production in 2011 from DUC averaged 44,000 barrels per day, composed of 29,000 barrels of crude oil and 91 million cubic feet of natural gas.

Netherlands: Chevron operates and holds interests ranging from 34.1 percent to 80 percent in 10 blocks in the Dutch sector of the North Sea. In 2011, the company s net oil-equivalent production from the producing blocks was 7,000 barrels per day, composed of 2,000 barrels of crude oil and 31 million cubic feet of natural gas. In fourth quarter 2011, the second stage of the A/B Gas Project achieved first gas.

Norway: The company holds a 7.6 percent nonoperated working interest in the Draugen Field. The company s net production averaged 3,000 barrels of oil-equivalent per day during 2011. Chevron is the operator and has a 40 percent working interest in exploration license PL 527. In 2011, Chevron was awarded a 40 percent-owned and operated interest in exploration license PL 598. Both licenses are in the deepwater portion of the Norwegian Sea.

United Kingdom: The company s average net oil-equivalent production in 2011 from 10 offshore fields was 85,000 barrels per day, composed of 59,000 barrels of crude oil and natural gas liquids and 155 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.

The final investment decision was reached in fourth quarter 2011 for the Clair Ridge Project, located west of the Shetland Islands, in which the company has a 19.4 percent nonoperated working interest. Total design capacity is planned to be 120,000 barrels of crude oil per day, and total estimated projects costs are $7 billion. Production is scheduled to begin in 2016. Initial proved reserves were recognized for this phase of the project in 2011.

At the 70 percent-owned and operated Alder discovery, FEED activities progressed during 2011 and a final investment decision is planned for late 2012. In the 40 percent-owned and operated Rosebank area northwest of the Shetland Islands, seismic, geophysical, geotechnical and environmental surveys were completed during 2011, and FEED is expected to begin in the second-half 2012. At the end of 2011, proved reserves have not been recognized for these projects.

Also west of the Shetland Islands, a three-well exploration and appraisal drilling program continued through 2011 and was completed in early 2012. This program comprised exploration wells on the Lagavulin and Aberlour prospects and appraisal drilling and well testing of the Cambo discovery. The Lagavulin well was unsuccessful and the results from the other wells are under evaluation. Licenses P1196 (Lagavulin) and P1165 (Talisker) were relinquished in November 2011 at the termination of the license period.

In addition, the company entered into a master regasification agreement for access to available capacity at the South Hook LNG terminal in southwest Wales in 2011.

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Bulgaria: In June 2011, the Bulgarian government advised that Chevron had submitted a winning tender for a permit for exploration in a 1.1 million-acre area in northeast Bulgaria. In January 2012, prior to execution of the license agreement, the Bulgarian government announced the withdrawal of the decision awarding the permit and the Bulgarian parliament imposed a ban on hydraulic fracturing, a technology commonly used for shale exploration and production. Chevron is continuing to work closely with the government of Bulgaria to provide the necessary assurances to the government and the public that hydrocarbons from shale can be developed safely and responsibly.

Poland: Chevron holds four shale concessions in southeast Poland (Grabowiec, Zwierzyniec, Krasnik and Frampol). All four exploration licenses are 100 percent-owned and operated and comprise a total of 1.1 million acres. In 2011, Chevron focused on processing data from a 2-D seismic survey. The data is being used to plan a multiwell drilling program that commenced in fourth quarter 2011.

Romania: The company holds a 100 percent interest in the EV-2 Barlad shale concession. This license, located in northeast Romania, covers 1.6 million acres. In 2011, the company acquired 2-D seismic data across the EV-2 Barlad concession. A multiwell drilling program is expected to begin in late 2012. Also during 2011, the company continued negotiations on license agreements for three shale exploration blocks in southeast Romania, Blocks 17, 18 and 19, which comprise approximately 670,000 acres.

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.

During 2011, U.S. and international sales of natural gas were 5.8 billion and 4.4 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, Europe, Kazakhstan, Indonesia, Latin America, the Philippines and Thailand.

U.S. and international sales of natural gas liquids were 161 thousand and 87 thousand barrels per day, respectively, in 2011. Substantially all of the international sales of natural gas liquids are from company operations in Africa, Kazakhstan, Indonesia and the United Kingdom.

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 7 for information related to the company s delivery commitments for the sale of crude oil and natural gas.

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Downstream

Refining Operations

At the end of 2011, the company had a refining network capable of processing about 2 million barrels of crude oil per day. Operable capacity at December 31, 2011, and daily refinery inputs for 2009 through 2011 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, 2011		Refinery Inputs		
Locations		**Number**	**Operable Capacity**	**2011**	**2010**	**2009**
Pascagoula	Mississippi	**1**	**330**	**327**	325	345
El Segundo	California	**1**	**269**	**244**	250	247
Richmond	California	**1**	**257**	**192**	228	218
Kapolei	Hawaii	**1**	**54**	**47**	46	49
Salt Lake City	Utah	**1**	**45**	**44**	41	40
Perth Amboy[1]	New Jersey	**1**	**80**			
Total Consolidated Companies	**United States**	**6**	**1,035**	**854**	890	899
Pembroke[2]	United Kingdom			**122**	211	205
Cape Town[3]	South Africa	**1**	**110**	**77**	70	72
Burnaby, B.C.	Canada	**1**	**55**	**43**	40	49
Total Consolidated Companies	**International**	**2**	**165**	**242**	321	326
Affiliates[4]	Various Locations	**7**	**767**	**691**	683	653
Total Including Affiliates	**International**	**9**	**932**	**933**	1,004	979
Total Including Affiliates	**Worldwide**	**15**	**1,967**	**1,787**	1,894	1,878

[1] Perth Amboy has been idled since early 2008 and is operated as a terminal.
[2] Pembroke was sold in August 2011.
[3] 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 2012.
[4] Includes 1,000, 2,000 and 4,000 barrels per day of refinery inputs in 2011, 2010 and 2009, respectively, for interests in refineries that were sold during those periods.

Average crude oil distillation capacity utilization during 2011 was 89 percent, compared with 92 percent in 2010. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 89 percent in 2011, compared with

95 percent in 2010. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 85 percent and 84 percent of Chevron s U.S. refinery inputs in 2011 and 2010, respectively.

At the Pascagoula Refinery, construction progressed on a facility to produce approximately 25,000 barrels per day of premium base oil for use in manufacturing high-performance finished lubricants, such as motor oils for consumer and commercial applications. Project completion is expected by year-end 2013. In February 2012, the company signed an agreement to sell its idled 80,000-barrel-per-day refinery, which is operating as a terminal, at Perth Amboy. The sale is expected to close in second quarter 2012.

At the refinery in El Segundo, construction progressed on a new processing unit designed to further improve the facility s overall reliability, enhance high-value product yield and provide additional flexibility to process a broad range of crude slates. Project completion is expected in third quarter 2012. At the Richmond Refinery, the company filed an application for a conditional use permit for a revised project and the City of Richmond published its Notice of Preparation of the revised Environmental Impact Report in second quarter 2011. The project is designed to improve the refinery s ability to process higher sulfur crudes, without changing the refinery s capacity to process crude blends in the intermediate-light gravity range. Improved ability to process higher sulfur crudes is expected to provide increased flexibility to process lower API-gravity crudes within the refinery s existing capacity range. Refer also to a discussion of contingencies related to this project in Note 24 to the Consolidated Financial Statements on page FS-57.

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Outside the United States, GS Caltex, the company s 50 percent-owned affiliate, progressed the construction of a 53,000-barrel-per-day gas oil fluid catalytic cracking unit at the Yeosu Refinery in South Korea. The unit is scheduled for start-up in 2013. The unit is designed to increase high-value product yield and lower feedstock costs. Construction continued on modifications to the 64 percent-owned Star Petroleum Refinery in Thailand to meet regional specifications for cleaner fuels. Project completion is scheduled for 2012. During August 2011, the company completed the sale of the Pembroke Refinery in the United Kingdom. Also in 2011, Caltex Australia Ltd., the company s 50 percent-owned affiliate, initiated a review of its refining operations in Australia, which is ongoing.

Marketing Operations

The company markets petroleum products under the principal brands of Chevron, Texaco and Caltex throughout many parts 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, 2011.

Refined Products Sales Volumes
(Thousands of Barrels per Day)

	2011	2010	2009
United States			
Gasoline	**649**	700	720
Jet Fuel	**209**	223	254
Gas Oil and Kerosene	**213**	232	226
Residual Fuel Oil	**87**	99	110
Other Petroleum Products[1]	**99**	95	93
Total United States	**1,257**	1,349	1,403
International[2]			
Gasoline	**447**	521	555
Jet Fuel	**269**	271	264
Gas Oil and Kerosene	**543**	583	647
Residual Fuel Oil	**233**	197	209
Other Petroleum Products[1]	**200**	192	176
Total International	**1,692**	1,764	1,851
Total Worldwide[2]	**2,949**	3,113	3,254

[1] Principally naphtha, lubricants, asphalt and coke.			
[2] Includes share of equity affiliates sales:	**556**	562	516

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2011, the company supplied directly or through retailers and marketers approximately 8,170 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 490 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 9,660 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. The company markets in 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.

The company continued its ongoing effort to concentrate downstream resources and capital on strategic assets. In 2011, the company completed the sale of its fuels marketing and aviation businesses in 16 countries in the Caribbean and Latin America and certain marketing businesses in five countries in Africa. In August 2011, the company also completed the sale of its marketing businesses in Ireland and the United Kingdom. In 2012, the company expects to complete the sale of its fuels marketing, finished lubricants and aviation fuels businesses in Spain as well as certain fuels marketing and aviation businesses in the central Caribbean, following receipt of required local regulatory and government approvals. In addition, the company converted more than 240 company-operated service stations into retailer-owned sites in various countries outside the United States.

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Chevron markets commercial aviation fuel at approximately 170 airports worldwide. The company also markets an extensive line of lubricant and coolant products under the brand names Havoline, Delo, Ursa, Meropa and Taro.

Chemicals Operations

Chevron owns a 50 percent interest in its Chevron Phillips Chemical Company LLC (CPChem) affiliate. At the end of 2011, CPChem owned or had joint-venture interests in 38 manufacturing facilities and four research and technical centers around the world.

CPChem s 35 percent-owned Saudi Polymers Company expects to commence commercial operations on a new petrochemical project in Al Jubail, Saudi Arabia, in 2012. The joint-venture project includes olefins, polyethylene, polypropylene, 1-hexene and polystyrene units.

In the United States, CPChem continued with plans to construct a 1-hexene plant at the company s Cedar Bayou complex in Baytown, Texas, capable of producing in excess of 200,000 tons per year. Start-up is expected in 2014. The plant is expected to be the largest 1-hexene unit in the world and will utilize CPChem s proprietary 1-hexene technology. CPChem is also conducting a feasibility study to evaluate a potential U.S. Gulf Coast ethylene cracker and derivatives complex to capitalize on advantaged feedstock sourced from emerging shale gas development in North America.

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 primarily in engine applications such as passenger car, heavy-duty diesel, marine, locomotive and motorcycle engines, and additives for fuels that are blended to improve engine performance and extend engine life. In February 2012, the company reached a final investment decision to significantly increase the capacity of the existing additives plant in Singapore.

Transportation

Pipelines: Chevron owns and operates an extensive network of crude oil, refined product, chemical, natural gas liquid and natural gas pipelines and other infrastructure assets in the United States. The company also has direct and 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, 2011

	Net Mileage[1,2]
United States:	
Crude Oil	2,115
Natural Gas	2,282
Petroleum Products	6,125
Total United States	10,522
International:	
Crude Oil	700
Natural Gas	699

Petroleum Products	311
Total International	1,710
Worldwide	12,232

[1] Includes company s share of pipeline mileage owned by equity affiliates.

[2] Excludes gathering pipelines relating to the crude oil and natural gas production function.

Work was completed in first quarter 2012 to return the Cal-Ky Pipeline to 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 company is leading the construction of a 136 mile, 24-inch pipeline from the Jack/St. Malo facility to Green Canyon 19 in the U.S. Gulf of Mexico, where there is an interconnect to pipelines delivering crude oil into Texas and Louisiana.

Refer to pages 14, 16 and 17 in the Upstream section for information on the Chad/Cameroon pipeline, the West Africa Gas Pipeline, the Baku-Tbilisi-Ceyhan Pipeline, the Western Route Export Pipeline and the Caspian Pipeline Consortium.

Tankers: All tankers in Chevron s controlled seagoing fleet were utilized during 2011. During 2011, the company had 48 deep-sea vessels chartered on a voyage basis, or for a period of less than one year. The table below summarizes the capacity of the company s controlled fleet.

Controlled Tankers at December 31, 2011[1]

	U.S. Flag		Foreign Flag	
	Number	**Cargo Capacity (Millions of Barrels)**	**Number**	**Cargo Capacity (Millions of Barrels)**
Owned			1	1.1
Bareboat-Chartered	4	1.4	17	25.0
Time-Chartered[2]			13	10.5
Total	4	1.4	31	36.6

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.

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. The company retired one U.S.-flagged product tanker in 2011.

The foreign-flagged vessels are engaged primarily in transporting crude oil from the Middle East, Southeast Asia, the Black Sea, South America, 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.

In addition to the vessels described above, the company has contracts in place to build LNG carriers and a dynamic-positioning shuttle tanker to support future upstream projects. The company also owns a one-sixth interest in each of seven LNG carriers transporting cargoes for the North West Shelf Venture in Australia.

Other Businesses

Mining

Chevron s U.S.-based mining company continues its efforts to divest its remaining coal mining operations. The company completed the sale of the North River Mine and other coal-related assets in Alabama in second quarter 2011, and the sale of its Kemmerer, Wyoming, surface coal mine in first quarter 2012. The company is pursuing the sale of its 50 percent interest in Youngs Creek Mining Company, LLC, which was formed to develop a coal mine in northern Wyoming. Activities related to final reclamation continued in 2011 at the company-operated surface coal mine in McKinley, New Mexico, which ceased coal production at the end of 2009.

At year-end 2011, Chevron had 153 million tons of proven and probable coal reserves in the United States, including reserves of low-sulfur coal. Coal sales from wholly owned mines in 2011 were 6 million tons, down about 2 million tons from 2010.

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In addition to the coal operations, Chevron owns and operates the Questa molybdenum mine in New Mexico. At year-end 2011, Chevron had 53 million pounds of proven molybdenum reserves at Questa. Production and underground development at Questa continued at reduced levels in 2011 in response to weak prices for molybdenum.

Power Generation

Chevron s Global Power Company manages 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 recovered waste heat to produce electricity and support industrial thermal hosts. The 13th facility is a wind farm, located in Casper, Wyoming, that is designed to optimize the use of a decommissioned refinery site for delivery of clean, renewable energy to the local utility.

The company has major geothermal operations in Indonesia and the Philippines and is investigating several advanced solar technologies for use in oil field operations as part of its renewable energy strategy. For additional information on the company s geothermal operations and renewable energy projects, refer to pages 19 and 20 and Research and Technology below.

Chevron Energy Solutions (CES)

CES is a wholly owned subsidiary that develops and builds sustainable energy projects that increase energy efficiency and production of renewable power, reduce energy costs, and ensure reliable, high-quality energy for government, education and business facilities. Since 2000, CES has developed hundreds of projects that have helped customers reduce their energy costs and environmental impact. Projects announced in 2011 include the City of Dinuba solar project in California; the Houston Independent School District renewable and energy efficiency project in Texas; the Eglin Air Force Base energy management systems upgrade project in Florida; and the Oceanic Time Warner solar project in Hawaii.

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 disciplines. 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 2011, CTV continued to explore technologies such as next-generation biofuels and advanced solar. In 2011, the company completed construction and commissioned the world s largest solar-to-steam generation project for use in enhanced-oil-recovery operations in Coalinga, California. The project will test the viability of using solar power to produce steam to improve oil recovery.

Chevron s research and development expenses were $627 million, $526 million and $603 million for the years 2011, 2010 and 2009, 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.

Environmental Protection

The company designs, operates and maintains its facilities to avoid potential spills or leaks and minimize the impact of those that may occur. Chevron requires its facilities and operations to have operating standards and processes and emergency response plans that address all credible and significant risks identified by site-specific risk and impact assessments. Chevron also requires that sufficient resources be available to execute these plans. In the unlikely event that a major spill or leak occurs, Chevron also maintains a Worldwide Emergency Response Team comprised of employees who are trained in various aspects of emergency response, including post-incident remediation.

To complement the company s capabilities, Chevron maintains active membership in international oil spill response cooperatives, including the Marine Spill Response Corporation, which operates in U.S. territorial waters, and Oil Spill Response, Ltd. (OSRL), which operates globally. The company is a founding member of the Marine Well Containment Company, whose primary mission is to expediently deploy containment equipment and systems to capture and contain crude oil in the unlikely event of a future loss of control of a deepwater well in the Gulf of Mexico. In addition, the company is a member of the Subsea Well Response Project (SWRP). SWRP s objective is to further develop the industry s capability to contain and shut in subsea well control incidents in different regions of the world. In late 2011, upon detection of ocean floor oil seeps in the deepwater Frade Field in Brazil, Chevron rapidly deployed capabilities and processes in coordination with OSRL. In early 2012, the company rapidly deployed response capabilities to address a natural gas well control incident in Nigeria.

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 the company s operations are, or are expected to become, embedded in the normal costs of conducting business.

In 2011, the company s U.S. capitalized environmental expenditures were $345 million, representing about 3 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 2012, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $410 million. The future annual capital costs are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Regulations intended to protect the environment, including those intended to address concerns about greenhouse gas emissions and global climate change, continue to evolve. Legislation, regulations and market-based programs that could affect the company s operations exist at the international or multinational (such as the Kyoto Protocol and the European Union s Emissions Trading System), national (such as the U.S. Environmental Protection Agency s rules for stricter emission standards and increased renewable fuel content for transportation fuels), and regional (such as California s Global Warming Solutions Act) levels.

Refer to Management s Discussion and Analysis of Financial Condition and Results of Operations on pages FS-14 through FS-16 for additional information on environmental matters and their impact on Chevron and on the company s 2011 environmental expenditures, remediation provisions and year-end environmental reserves. Refer also to Item 1A. Risk Factors on pages 29 through 31 for a discussion of greenhouse gas regulation and climate change.

Web Site Access to SEC Reports

The company s Internet Web site is 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 on the SEC s Web site at www.sec.gov.

Item 1A. Risk Factors

Chevron is a global energy company with a diversified business portfolio, a strong balance sheet, and a history of generating sufficient cash to pay dividends and fund capital and exploratory expenditures. 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, industry inventory levels, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices and geopolitical risk. Chevron accepts the risk of changing commodity prices as part of its business planning process. As such, an investment in the company carries significant exposure to fluctuations in crude oil prices.

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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 on 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 beyond its control, including hurricanes, floods and other forms of severe weather, war, civil unrest and other political events, fires, earthquakes, system failures, cyber threats and terrorist acts, any of which could result in suspension of operations or harm to people or the natural environment.

The company s operations have inherent risks and hazards that require significant and continuous oversight.

Chevron s results depend on its ability to identify and mitigate the risks and hazards inherent to operating in the crude oil and natural gas industry. The company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these risks effectively could result in unexpected incidents, including releases, explosions or mechanical failures resulting in personal injury, loss of life, environmental damage, loss of revenues, legal liability and/or disruption to operations. Chevron has implemented and maintains a system of corporate policies, behaviors and compliance mechanisms to manage safety, health, environmental, reliability and efficiency risks; to verify compliance with applicable laws and policies; and to respond to and learn from unexpected incidents. Nonetheless, in certain situations where Chevron is not the operator, the company may have limited influence and control over third parties, which may limit its ability to manage and control such risks.

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 its 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 or significant delays in operations 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.

The company does not insure against all potential losses, which could result in significant financial exposure.

The company does not have commercial insurance or third-party indemnities to cover fully all operational risks or potential liability in the event of a significant incident or series of incidents causing catastrophic loss. As a result the company is, to a substantial extent, self-insured for such events. The company relies on existing liquidity, financial resources and borrowing capacity to meet short-term obligations that would arise from such an event or series of events. The occurrence of a significant incident or unforeseen liability for which the company is not fully insured or for which insurance recovery is significantly delayed could have a material adverse effect on the company s results of operations or financial condition.

Political instability and significant changes in the regulatory environment 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 or proposed restrictions on the company s operations, export and exchange controls, burdensome taxes, and public disclosure requirements that might harm the company s competitiveness or relations with other governments or third parties. In other countries, political conditions have existed that may threaten the safety of employees and the company s continued presence in those countries and internal unrest, acts of violence or strained relations between a government and the company or other governments may adversely 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, 2011, 22 percent of the company s net proved reserves were located in Kazakhstan. The company also has significant interests in 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, 2011.

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. 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 depending on the laws enacted in each jurisdiction, the company s activities in it and market conditions. Greenhouse gas emissions that could be regulated include those arising from the company s exploration and production of crude oil and natural gas; 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. 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 would 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.

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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-62 through FS-76. Note 13, Properties, Plant and Equipment, to the company s financial statements is on page FS-41.

Item 3. Legal Proceedings

Ecuador
Information related to Ecuador matters is included in Note 14 to the Consolidated Financial Statements under the heading Ecuador, beginning on page FS-41.

Certain Governmental Proceedings
In November 2008, the California Air Resources Board (CARB) proposed a civil penalty against Chevron 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 allegedly failed to inject additive detergent into a gasoline line. It appears that the resolution of these notices of violation may result in the payment of a civil penalty exceeding $100,000.

In November 2008, CARB proposed a civil penalty against Chevron s Richmond, California, refinery for a notice of violation relating to gasoline that was not properly certified as to composition. The composition certificates for the gasoline were corrected 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 continue. It appears that the resolution of these notices of violation may result in the payment of a civil penalty exceeding $100,000.

In July 2009, CARB issued a notice of violation against Chevron Products Company for alleged violations of CARB s regulations governing the certification of gasoline that occurred during storage at a third-party facility and which had been self-reported by Chevron on discovery. Chevron believes that this matter will not result in the payment of a civil penalty exceeding $100,000.

In 2011, CARB made penalty demands with respect to four notices of violation against Chevron for alleged violations of CARB s fuel blend regulations at certain California terminals and refineries. It appears that the resolution of these notices of violation may result in the payment of a civil penalty exceeding $100,000.

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 Chevron undertook to install and operate certain air emission control equipment at its Hawaii Refinery pursuant to a Clean Air Act settlement with the United States Environmental Protection Agency (EPA) and DOH. Chevron has disputed many of the allegations.

Chevron has entered into negotiations with the EPA with respect to alleged air quality violations at Chevron s Perth Amboy, New Jersey refinery identified in a September 16, 2008 Compliance Order issued by the EPA. The alleged violations relate to certain management and reporting requirements set forth in the EPA s Leak Detection and Repair regulations (these regulations pertain to the control and monitoring of fugitive emissions from refinery process equipment). Based on discussions with the EPA, it appears that the resolution of this matter may result in the payment of a civil penalty exceeding $100,000.

The EPA indicated that it would assess Chevron s Salt Lake City Refinery a civil penalty for alleged violations of federal requirements and Utah s air pollution laws. These alleged violations were the subject of an August 20, 2008 EPA Notice of Violation (NOV) for which no penalty was assessed at the time. It appears that the resolution of this NOV may result in the payment of a civil penalty exceeding $100,000.

The South Coast Air Quality Management District (SCAQMD) issued a NOV to Chevron s Huntington Beach, California, terminal seeking a civil penalty for alleged violations involving the repair of two holes in the roof of a tank at the terminal. Based on a July 8, 2011, settlement communication with the SCAQMD, it appears that the resolution of this NOV may result in the payment of a civil penalty exceeding $100,000.

Chevron reached a final resolution of an administrative penalty proceeding brought by the Utah Department of Environmental Quality by agreeing to pay the State of Utah a civil penalty of $500,000 as the result of two crude oil releases. The first release occurred in June 2010 and the second occurred in December 2010. In addition, Chevron agreed to pay the State of Utah and the Salt Lake City Corporation $4 million in damages and restoration projects. The public review period passed and the penalty has been paid.

Item 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 C.F.R. § 229.104) is included in Exhibit 95 of this Annual Report on Form 10-K.

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-20.

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, 2011	**4,379,887**	**99.86**	**4,378,905**	
Nov. 1 Nov. 30, 2011	**4,173,725**	**102.18**	**4,170,000**	
Dec. 1 Dec. 31, 2011	**3,738,606**	**103.63**	**3,730,500**	
Total Oct. 1 Dec. 31, 2011	**12,292,218**	**101.80**	**12,279,405**	

(1) Pertains to common shares repurchased during the three-month period ended December 31, 2011, from company employees for required personal income tax withholdings on the exercise of the stock options issued to management under long-term incentive plans and former Texaco Inc. and Unocal 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, 2011.

(2)

In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits, under which common shares would be acquired by the company through open market purchases (some pursuant to a Rule 10b5-1 plan) at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. As of December 31, 2011, 51,064,679 shares had been acquired under this program for $5.0 billion.

Item 6. Selected Financial Data

The selected financial data for years 2007 through 2011 are presented on page FS-61.

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

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Instruments, beginning on page FS-13 and in Note 10 to the Consolidated Financial Statements, Financial and Derivative Instruments, beginning on page FS-36.

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.

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 the 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 the Chief Financial Officer concluded that the company s disclosure controls and procedures were effective as of December 31, 2011.

(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 the 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, 2011.

The effectiveness of the company s internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page FS-22.

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

During the quarter ended December 31, 2011, 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 23, 2012

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	55	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	61	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.R. Blackwell	53	Executive Vice President (since 2011) President of Chevron Asia Pacific Exploration and Production Company (2008 through 2011) Managing Director of Chevron Southern Africa Strategic Business Unit (2003 to 2007)	Technology; Mining; Project Resources Company; Procurement
M.K. Wirth	51	Executive Vice President (since 2006) President of Global Supply and Trading (2004 to 2006)	Worldwide Refining, Marketing, Lubricants, and Supply and Trading Activities, excluding Natural Gas Trading; Chemicals
R.I. Zygocki	54	Executive Vice President (since 2011) Vice President, Policy, Government and Public Affairs (2007 through 2011) Vice President, Health, Environment and Safety (2003 through 2007)	Strategy and Planning; Health, Environment and Safety; Policy, Government and Public Affairs
P.E. Yarrington	55	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	49	Vice President and General Counsel (since 2009) Partner and Head of Global Competition Practice of Hunton & Williams LLP, a major U.S. law firm (2005 to 2009)	Law, Governance and Compliance

The information about directors required by Item 401(a), (d), (e) and (f) of Regulation S-K and contained under the heading Election of Directors in the Notice of the 2012 Annual Meeting and 2012 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 2012 Annual Meeting of Stockholders (the 2012 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 2012 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 2012 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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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 2012 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.

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 2012 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 2012 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 2012 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 2012 Proxy Statement shall not be deemed to be solicited material, or to be filed with the Commission, or subject to Regulation 14A or 14C or the liabilities 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 2012 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 2012 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 2012 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 2012 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 Appointment of the Independent Registered Public Accounting Firm in the 2012 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

(1) Financial Statements:

(2) Financial Statement Schedules:

Included on page 38 is Schedule II Valuation and Qualifying Accounts.

(3) Exhibits:

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

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Schedule

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS
Millions of Dollars

	Year Ended December 31		
	2011	**2010**	**2009**
Employee Termination Benefits:			
Balance at January 1	**$ 145**	$ 13	$ 44
Additions (deductions) charged (credited) to expense		235	(12)
Payments	**(82)**	(103)	(19)
Balance at December 31	**$ 63**	$ 145	$ 13
Allowance for Doubtful Accounts:			
Balance at January 1	**$ 239**	$ 293	$ 275
Additions (reductions) to expense	**4**	(13)	92
Bad debt write-offs	**(76)**	(41)	(74)
Balance at December 31	**$ 167**	$ 239	$ 293
Deferred Income Tax Valuation Allowance:*			
Balance at January 1	**$ 9,185**	$ 7,921	$ 7,535
Additions to deferred income tax expense	**2,216**	1,454	2,204
Reduction of deferred income tax expense	**(305)**	(190)	(1,818)
Balance at December 31	**$ 11,096**	$ 9,185	$ 7,921

* See also Note 15 to the Consolidated Financial Statements, beginning on page FS-43.

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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 23rd day of February, 2012.

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 23rd day of February, 2012.

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/Matthew J. Foehr
Matthew J. Foehr, Vice President and Comptroller

Directors

Linnet F. Deily*
Linnet F. Deily

Robert E. Denham*
Robert E. Denham

Robert J. Eaton*
Robert J. Eaton

Chuck Hagel*
Chuck Hagel

Enrique Hernandez, Jr.*
Enrique Hernandez, Jr.

Donald B. Rice*
Donald B. Rice

Kevin W. Sharer*
Kevin W. Sharer

Charles R. Shoemate*
Charles R. Shoemate

John G. Stumpf*
John G. Stumpf

*By: /s/Lydia I. Beebe Lydia I. Beebe, Attorney-in-Fact	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	**2011**	2010	2009
Net Income Attributable to Chevron Corporation	**$ 26,895**	$ 19,024	$ 10,483
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
Basic	**$ 13.54**	$ 9.53	$ 5.26
Diluted	**$ 13.44**	$ 9.48	$ 5.24
Dividends	**$ 3.09**	$ 2.84	$ 2.66
Sales and Other Operating Revenues	**$ 244,371**	$ 198,198	$ 167,402
Return on:			
Capital Employed	**21.6%**	17.4%	10.6%
Stockholders Equity	**23.8%**	19.3%	11.7%

Earnings by Major Operating Area

Millions of dollars	**2011**	2010	2009
Upstream[1]			
United States	**$ 6,512**	$ 4,122	$ 2,262
International	**18,274**	13,555	8,670
Total Upstream	**24,786**	17,677	10,932
Downstream[1]			
United States	**1,506**	1,339	(121)
International	**2,085**	1,139	594
Total Downstream	**3,591**	2,478	473
All Other	**(1,482)**	(1,131)	(922)
Net Income Attributable to Chevron Corporation[2,3]	**$ 26,895**	$ 19,024	$ 10,483

[1] 2009 information has been revised to conform with the 2011 and 2010 segment presentation.

[2] Includes foreign currency effects: **$ 121** $ (423) $ (744)

[3] 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, 2011.

Business Environment and Outlook

Chevron is a global energy company with substantial 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 mostly on the profitability of its upstream and downstream business segments. The single biggest factor that affects the results of operations for the company is movement in the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. Seasonality is not a primary driver of changes in the company s quarterly earnings during the year.

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.

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. 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. 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.

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 page FS-6 for discussions of net gains on asset sales during 2011. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of movements in prices for crude oil and natural gas. Management takes these developments into account in the conduct of daily operations and for business planning.

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. 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 seeks to manage risks in operating its facilities and businesses. 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.

The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. However, price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can 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 can also be affected by damage to production facilities caused by severe weather or civil unrest.

The chart above shows the trend in benchmark prices for West Texas Intermediate (WTI) crude oil, Brent crude oil and U.S. Henry Hub natural gas. The WTI price averaged $95 per barrel for the full-year 2011, compared to $79 in 2010. As of mid-February 2012, the WTI price was about $99 per barrel. The Brent price averaged $111 per barrel for the full-year 2011, compared to $80 in 2010. As of mid-February 2012, the Brent price was about $118 per barrel. The majority of the company s equity crude production is priced based on the Brent benchmark. WTI traded at a discount to Brent throughout 2011 due to excess crude supply in the U.S. Midcontinent market. The discount narrowed in fourth quarter 2011 as crude inventories declined.

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, which is a function of the capacity 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 widened during 2011 primarily due to rising diesel prices and lower availability of light, sweet crude oil due to supply disruptions in Libya.

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 $4.00 per thousand cubic feet (MCF) during 2011, compared with about $4.50 during 2010. As of mid-February 2012, the Henry Hub spot price was about $2.50 per MCF. 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.

Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. In some locations, Chevron is investing in long-term projects to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets. International natural gas realizations averaged about $5.40 per MCF during 2011, compared with about $4.60 per MCF during 2010. (See page FS-10 for the company s average natural gas realizations for the U.S. and international regions.)

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The company s worldwide net oil-equivalent production in 2011 averaged 2.673 million barrels per day. About one-fifth of the company s net oil-equivalent production in 2011 occurred in the OPEC-member countries of Angola, Nigeria, Venezuela and the Partitioned Zone between Saudi Arabia and Kuwait. OPEC quotas had no effect on the company s net crude oil production in 2011 or 2010. At their December 2011 meeting, members of OPEC supported maintaining the current production level of 30 million barrels per day and made no change to the production quotas in effect since December 2008.

The company estimates that oil-equivalent production in 2012 will average approximately 2.680 million barrels per day based on the average Brent price of $111 per barrel for the full-year 2011. This estimate is subject to many factors and uncertainties, including quotas that may be imposed by OPEC, price effects on entitlement volumes, 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, delays in completion of maintenance turnarounds, greater-than-expected declines in production from mature fields, 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-67 for a tabulation of the company s proved net oil and gas reserves by geographic area, at the beginning of 2009 and each year-end from 2009 through 2011, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2011.

In early November 2011, while drilling a development well in the deepwater Frade Field in Brazil, an unanticipated pressure spike caused oil to migrate from the well bore through a series of fissures to the sea floor, emitting approximately 2,400 barrels of oil. The resulting surface sheen has since dissipated and there have been no coastal or wildlife impacts. Upon detection, the company immediately took steps to stop the release. Chevron s emergency plan, approved by the Brazilian environment and natural resources regulatory agency IBAMA, was implemented according to the law and industry standards. The source of the seep was contained within four days. As of December 31, 2011 the financial impact of the incident was not material to the company s annual net income. However, the company s ultimate exposure related to fines and penalties is not currently determinable, and could be significant to net income in any one period.

Downstream Earnings for the downstream segment are closely tied to margins on the refining, manufacturing and marketing of products that include gasoline, diesel, jet fuel, lubricants, fuel oil, fuel and lubricant additives, and petrochemicals. Industry margins are sometimes volatile and can be affected by the global and regional supply-and-demand balance for refined products and petrochemicals and by changes in the price of crude oil, other refinery and petrochemical feedstocks, and natural gas. Industry margins can also be influenced by inventory levels, geopolitical events, costs of materials and services, refinery or chemical plant capacity utilization, maintenance programs, and disruptions at refineries or chemical plants 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, marketing and petrochemical assets, the effectiveness of its crude oil and product supply functions, and 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 refining, marketing and petrochemical assets.

The company s most significant marketing areas are the West Coast of North America, the U.S. Gulf Coast, Asia, and southern Africa. Chevron operates or has significant ownership interests in refineries in each of these areas. In

2011, the company s margins improved over 2010, supported by higher global product demand and tighter global refined product supplies. The company made further progress during 2011 implementing the previously-announced restructuring of its downstream businesses, including the employee-reduction programs for the United States and international operations. Approximately 2,300 employees in the downstream operations are currently expected to be released under these programs. About 2,100 employees have been released through December 31, 2011, with the programs being substantially completed. Substantially all of the remaining employees designated for release under the programs are expected to leave in 2012. About 900 of the affected employees were located in the United States. Refer to Note 23 of the Consolidated Financial Statements, on pages FS-55 through FS-56, for further discussion.

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The company progressed its ongoing effort to concentrate downstream resources and capital on strategic assets. On August 1, 2011, the company completed the sale of its 220,000-barrel-per-day Pembroke Refinery and its fuels marketing and aviation assets in the United Kingdom and Ireland. Through year-end 2011, the company had also completed the sale of 13 U.S. terminals, certain marketing businesses in Africa, LPG storage and distribution operations in China, and its fuels marketing and aviation businesses in 16 countries in the Caribbean and Latin America regions. In 2012, the company also expects to complete the sale of its fuels, finished lubricants and aviation businesses in Spain and certain fuels marketing and aviation businesses in the central Caribbean, pending customary regulatory approvals.

Also in 2011, Caltex Australia Ltd. (CAL), the company s 50 percent-owned affiliate, initiated a review of its refining operations in Australia, which is ongoing. Upon completion, should the review result in a decision to significantly alter the operational role of CAL s refineries, Chevron may recognize a loss that could be significant to net income in any one period.

Refer to the Results of Operations section on pages FS-7 through FS-8 for additional discussion of the company s downstream operations.

All Other consists of mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, alternative fuels, and technology companies. In first quarter 2010, employee-reduction programs were announced for the corporate staffs. As of 2011 year-end, 400 employees from the corporate staffs were released under the programs. Refer to Note 23 of the Consolidated Financial Statements, beginning on page FS-55, for further discussion.

Operating Developments

Key operating developments and other events during 2011 and early 2012 included the following:

Upstream

Australia Chevron and its joint-venture partners reached the final investment decision to proceed with development of the Wheatstone Project. Construction started in late 2011. Chevron holds a 72.1 percent interest in the foundation natural gas processing facilities, which are located at Ashburton North, along the northwest coast of Australia. The company plans to supply natural gas to the foundation project from the Chevron-operated and 90.2 percent-owned Wheatstone and Iago fields. The LNG facilities will also be a destination for third-party natural gas.

Through the end of 2011, Chevron has signed binding Sales and Purchase Agreements with two Asian customers for the delivery of about 60 percent of Chevron s net LNG off-take from the Wheatstone Project. Discussions continue with potential customers to increase sales to 85 to 90 percent of Chevron s net LNG off-take and to sell down equity.

During 2011, the company announced natural gas discoveries at the 50 percent-owned and operated Orthrus Deep prospect in Block WA-24-R, the 50 percent-owned and operated Vos prospect in Block WA-439-P, and the 67 percent-owned and operated Acme West prospect in Block WA-205-P. In January 2012, the company also announced a natural gas discovery at the 50 percent-owned and operated Satyr-3 prospect in Block WA-374-P. These discoveries are expected to contribute to potential expansion at company-operated LNG projects.

Kazakhstan/Russia During 2011, the Caspian Pipeline Consortium began construction on a project to increase the pipeline design capacity by 670,000 barrels per day. The project is expected to be implemented in three phases, with capacity increasing progressively until reaching maximum capacity of 1.4 million barrels per day in 2016.

Nigeria In December 2011, a final investment decision was reached to develop the 40 percent-owned and operated Sonam natural gas field in the Escravos area. The project is designed to deliver 215 million cubic feet of natural gas per day to the domestic market and produce 30,000 barrels of liquids per day.

Thailand In October 2011, the 69.9 percent-owned and operated Platong II natural gas project commenced production. The project ramped up to total average daily production of 377 million cubic feet of natural gas and 11,000 barrels of condensate as of the end of 2011.

United Kingdom In fourth quarter 2011, the company reached a final investment decision for the Clair Ridge Project, located west of the Shetland Islands. Chevron has a 19.4 percent nonoperated working interest in the project.

United States In fourth quarter 2011, a final investment decision was made for the Tubular Bells project in the deepwater Gulf of Mexico. The development includes a 42.9 percent nonoperated working interest in the Tubular

Bells unitized area.

Drilling operations at the 43.8 percent-owned and operated Moccasin prospect resulted in a new discovery of crude oil. The company also drilled a successful appraisal well at the 55 percent-owned Buckskin prospect. Both prospects are in the deepwater Gulf of Mexico.

In February 2011, Chevron acquired Atlas Energy, Inc. The acquisition provided a natural gas resource position in the Marcellus Shale and Utica Shale, primarily located in southwestern Pennsylvania and Ohio. The acquisition also provided a 49 percent interest in Laurel Mountain Midstream, LLC, an affiliate that owns more than 1,000 miles of natural gas gathering lines servicing the Marcellus. In addition, the acquisition provided assets in Michigan, which include Antrim Shale producing assets and approximately

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350,000 total acres in the Antrim and Collingwood/Utica Shale formations. Additional asset acquisitions in 2011 expanded the company s holdings in the Marcellus and Utica to approximately 700,000 and 600,000 total acres, respectively.

Downstream

Africa During 2011, the company completed the sale of certain marketing businesses in five countries in Africa.

Caribbean and Latin America In 2011, the company completed the sale of its fuels marketing and aviation businesses in 16 countries in the Caribbean and Latin America. In fourth quarter 2011, the company signed agreements to sell certain fuels marketing and aviation businesses in the Central Caribbean. The company expects to complete these sales in 2012 following receipt of required local regulatory and government approvals.

Europe In August 2011, the company completed the sale of its refining and marketing assets in the United Kingdom and Ireland, including the Pembroke Refinery.

Singapore In February 2012, the company reached a final investment decision to significantly increase the capacity of the existing additives plant in Singapore.

United States In January 2011, the company announced the final investment decision on a $1.4 billion project to construct a base oil manufacturing facility at the Pascagoula, Mississippi, refinery. The facility is expected to produce approximately 25,000 barrels per day of premium base oil.

Other

Common Stock Dividends The quarterly common stock dividend increased by 8.3 percent in April 2011 and by 3.8 percent in October 2011, to $0.81 per common share, making 2011 the 24th consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program The company purchased $4.25 billion of its common stock in 2011 under its share repurchase program. The program began in 2010 and has no set term or monetary limits.

Results of Operations

Major Operating Areas The following section presents the results of operations for the company s business segments Upstream and Downstream as well as for All Other. 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-37, 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

Millions of dollars	**2011**	2010	2009
Earnings	**$ 6,512**	$ 4,122	$ 2,262

U.S. upstream earnings of $6.51 billion in 2011 increased $2.4 billion from 2010. The benefit of higher crude oil realizations increased earnings by $2.8 billion between periods. Partly offsetting this effect were lower net oil-equivalent production which decreased earnings by about $400 million and higher operating expenses of $200 million.

U.S. upstream earnings of $4.1 billion in 2010 increased $1.9 billion from 2009. Higher prices for crude oil and natural gas increased earnings by $2.1 billion between periods. Partly offsetting these effects were higher operating expenses of $200 million, in part due to the Gulf of Mexico drilling moratorium. Lower exploration expenses were essentially offset by higher tax items and higher depreciation expenses.

The company s average realization for U.S. crude oil and natural gas liquids in 2011 was $97.51 per barrel, compared with $71.59 in 2010 and $54.36 in 2009. The average natural gas realization was $4.04 per thousand cubic feet in 2011, compared with $4.26 and $3.73 in 2010 and 2009, respectively.

Net oil-equivalent production in 2011 averaged 678,000 barrels per day, down 4 percent from 2010 and 5 percent from 2009. Between 2011 and 2010, the decrease in production was associated with normal field declines and maintenance-related downtime. Partially offsetting this decrease were new production from acquisitions in the Marcellus Shale and increases at the Perdido project in the Gulf of Mexico. Natural field declines between 2010 and 2009 were mostly offset by increased production from the Tahiti Field. The net liquids component of oil-equivalent production for 2011 averaged 465,000 barrels per day, down 5 percent from 2010 and 4 percent from 2009. Net natural gas production averaged about 1.3 billion cubic feet per day in 2011, down approximately 3 percent from 2010 and about 9 percent from 2009. Refer to the Selected Operating Data table on page FS-10 for a three-year comparative of production volumes in the United States.

International Upstream

Millions of dollars	**2011**	2010	2009
Earnings*	**$ 18,274**	$ 13,555	$ 8,670
*Includes foreign currency effects:	**$ 211**	$ (293)	$ (578)

International upstream earnings of $18.3 billion in 2011 increased $4.7 billion from 2010. Higher prices for crude oil increased earnings by $7.1 billion. This benefit was partly offset by higher tax items of about $1.7 billion and higher operating expenses, including fuel, of about $1.0 billion. Foreign currency effects increased earnings by $211 million in 2011, compared with a decrease of $293 million a year earlier.

Earnings of $13.6 billion in 2010 increased $4.9 billion from 2009. Higher prices for crude oil and natural gas increased earnings by $4.3 billion, and an increase in net oil-equivalent production in the 2010 period benefited income by about $1.2 billion. This net benefit was partly offset by higher operating expenses of $500 million. A favorable change in tax items of about $450 million was mostly offset by higher depreciation expenses. The 2009 period included gains of about $500 million on asset sales and tax items related to the Gorgon Project in Australia. Foreign currency effects decreased earnings by $293 million in the 2010 period, compared with a reduction of $578 million a year earlier, primarily reflecting noncash losses on balance sheet remeasurement.

The company s average realization for international crude oil and natural gas liquids in 2011 was $101.53 per barrel, compared with $72.68 in 2010 and $55.97 in 2009. The average natural gas realization was $5.39 per thousand cubic feet in 2011, compared with $4.64 and $4.01 in 2010 and 2009, respectively.

International net oil-equivalent production of 2.0 million barrels per day in 2011 decreased about 3 percent from 2010 and remained relatively flat with 2009. The volumes in 2011 and 2010 include synthetic oil that was reported in 2009 as production from oil sands in Canada. Absent price effects on entitlement volumes, net oil-equivalent production decreased 1 percent in 2011 and increased 5 percent in 2010, when compared with the prior year s production.

The net liquids component of international oil-equivalent production was about 1.4 million barrels per day in 2011, a decrease of approximately 3 percent from 2010 and an increase of approximately 2 percent from 2009. International net natural gas production of 3.7 billion cubic feet per day in 2011 was down 2 percent from 2010 and up 2 percent from 2009.

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

U.S. Downstream

Millions of dollars	**2011**	2010	2009
Earnings	**$ 1,506**	$ 1,339	$ (121)

U.S. downstream operations earned $1.5 billion in 2011, compared with $1.3 billion in 2010. Earnings benefited by $300 million from improved margins on refined products, $200 million from higher earnings from the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem), and $50 million from the absence of 2010 charges related to employee reductions. These benefits were partly offset by the absence of a $400 million gain on the sale of the company s ownership interest in the Colonial Pipeline Company recognized in 2010.

Earnings increased $1.5 billion in 2010 from 2009. Improved margins on refined products increased earnings by about $550 million. Also contributing to the increase was the nearly $400 million gain on the sale of the company s ownership interest in the Colonial Pipeline Company. Higher earnings from chemicals operations increased earnings by about $300 million, largely from improved margins at CPChem.

Refined product sales of 1.26 million barrels per day in 2011 declined 7 percent, mainly due to lower gasoline, gas oil, and kerosene sales. Sales volumes of refined products were 1.35 million barrels per day in 2010, a decrease of 4 percent from 2009. The decline was mainly in gasoline and jet fuel sales. U.S. branded gasoline sales decreased to 514,000 barrels per day in 2011, representing approximately 10 percent and 17 percent declines from 2010 and 2009, respectively. The decline in 2011, relative to 2010 and 2009, was primarily

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due to weaker demand and previously completed exits from selected eastern U.S. retail markets.

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.

International Downstream

Millions of dollars	**2011**	2010	2009
Earnings*	**$ 2,085**	$ 1,139	$ 594
*Includes foreign currency effects:	**$ (65)**	$ (135)	$ (191)

International downstream earned $2.1 billion in 2011, compared with $1.1 billion in 2010. Gains on asset sales benefited earnings by $700 million, primarily from the sale of the Pembroke Refinery and related marketing assets in the United Kingdom and Ireland. Also contributing to earnings were improved margins of $200 million and the absence of 2010 charges of $90 million related to employee reductions. These benefits were partly offset by unfavorable mark-to-market effects of derivative instruments of about $180 million. Foreign currency effects decreased earnings by $65 million in 2011, compared with a decrease of $135 million a year earlier.

Earnings of $1.1 billion in 2010 increased $545 million from 2009. Higher margins on the manufacture and sale of gasoline and other refined products increased earnings by about $1.0 billion, and a favorable swing in mark-to-market effects on derivative instruments benefited earnings by about $300 million. Partially offsetting these items was the absence of 2009 gains on asset sales of about $550 million and higher expenses of about $200 million, primarily related to employee reductions and transportation costs. Foreign currency effects reduced earnings by $135 million in 2010, compared with a reduction of $191 million in 2009.

Total refined product sales of 1.69 million barrels per day in 2011 declined 4 percent, primarily due to the sale of the company s refining and marketing assets in the United Kingdom and Ireland. Excluding the impact of 2011 asset sales, sales volumes were up 3 percent between the comparative periods. International refined product sales volumes of 1.76 million barrels per day in 2010 were 5 percent lower than in 2009, mainly due to asset sales in certain countries in Africa and Latin America.

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.

All Other

Millions of dollars	**2011**	2010	2009
Net charges*	**$ (1,482)**	$ (1,131)	$ (922)
*Includes foreign currency effects:	**$ (25)**	$ 5	$ 25

All Other includes mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, alternative fuels, and technology companies.

Net charges in 2011 increased $351 million from 2010, mainly due to higher expenses for employee compensation and benefits, and higher net corporate tax expenses.

Net charges in 2010 increased $209 million from 2009, mainly due to higher expenses for employee compensation and benefits, and higher corporate tax expenses, partly offset by lower provisions for environmental remediation at sites that previously had been closed or sold.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2011**	2010	2009
Sales and other operating revenues	**$ 244,371**	$ 198,198	$ 167,402

Sales and other operating revenues increased in 2011, mainly due to higher prices for crude oil and refined products. Higher 2010 prices resulted in increased revenues compared with 2009.

Millions of dollars	**2011**	2010	2009
Income from equity affiliates	**$ 7,363**	$ 5,637	$ 3,316

Income from equity affiliates increased in 2011 from 2010 mainly due to higher upstream-related earnings from Tengizchevroil (TCO) in Kazakhstan as a result of higher prices for crude oil. Downstream-related earnings were also higher between the comparative periods, primarily due to higher earnings from CPChem as a result of higher margins on sales of commodity chemicals.

Income from equity affiliates increased in 2010 from 2009 largely due to higher upstream-related earnings from

TCO in Kazakhstan and Petropiar in Venezuela, principally related to higher prices for crude oil and increased crude oil production. Downstream-related affiliate earnings were also higher between the comparative periods, primarily due to higher earnings from CPChem, as a result of higher margins on sales of commodity chemicals. Improved margins on refined products and a favorable swing in foreign currency effects at GS Caltex in South Korea also contributed to the increase in downstream affiliate earnings in the 2010 period. Refer to Note 12, beginning on page FS-39, for a discussion of Chevron s investments in affiliated companies.

Millions of dollars	**2011**	2010	2009
Other income	**$ 1,972**	$ 1,093	$ 918

Other income of $2.0 billion in 2011 included net gains of approximately $1.5 billion on asset sales. Other income in both 2010 and 2009 included net gains from asset sales of $1.1 billion and $1.3 billion, respectively. Interest income was approximately $145 million in 2011, $120 million in 2010 and $95 million in 2009. Foreign currency effects increased other income by $103 million in 2011, while decreasing other income by $251 million and $466 million in 2010 and 2009, respectively.

Millions of dollars	**2011**	2010	2009
Purchased crude oil and products	**$ 149,923**	$ 116,467	$ 99,653

Crude oil and product purchases in 2011 and 2010 increased by $33.5 billion and $16.8 billion from prior years due to higher prices for crude oil, natural gas and refined products.

Millions of dollars	**2011**	2010	2009
Operating, selling, general and administrative expenses	**$ 26,394**	$ 23,955	$ 22,384

Operating, selling, general and administrative expenses increased $2.4 billion between 2011 and 2010. This increase was primarily related to higher fuel expenses of $1.5 billion and higher employee compensation and benefits of $700 million. In part, increased fuel purchases reflected a new commercial arrangement that replaced a prior product exchange agreement for upstream operations in Indonesia.

Total expenses in 2010 were about $1.6 billion higher than 2009, primarily due to $600 million of higher fuel expenses; $500 million for employee compensation and benefits; $200 million of increased construction, repair and maintenance expense; and an increase of about $200 million associated with higher tanker charter rates. In addition, charges of $234 million related to employee reductions were included in the 2010 period.

Millions of dollars	**2011**	2010	2009
Exploration expense	**$ 1,216**	$ 1,147	$ 1,342

Exploration expenses in 2011 increased from 2010 mainly due to higher geological and geophysical costs, partly offset by lower well write-offs.

Exploration expenses in 2010 declined from 2009 mainly due to lower amounts for geological and geophysical costs and well write-offs.

Millions of dollars	**2011**	2010	2009

Depreciation, depletion and amortization	**$ 12,911**	$ 13,063	$ 12,110

The decrease in 2011 from 2010 mainly reflected lower production levels and the sale of the Pembroke Refinery, partially offset by higher depreciation rates for certain oil and gas producing fields. The increase in 2010 from 2009 was largely due to higher depreciation rates and higher production for certain oil and gas fields, partly offset by lower impairments.

Millions of dollars	**2011**	2010	2009
Taxes other than on income	**$ 15,628**	$ 18,191	$ 17,591

Taxes other than on income decreased in 2011 from 2010 primarily due to lower import duties in the United Kingdom reflecting the sale of the Pembroke Refinery and other downstream assets, partly offset by higher excise taxes in the company s South Africa downstream operations. Taxes other than on income increased in 2010 from 2009 mainly due to higher excise taxes in Canada and the United Kingdom.

Millions of dollars	**2011**	2010	2009
Interest and debt expense	**$**	$ 50	$ 28

Interest and debt expense, net of capitalized interest, decreased in 2011 from 2010 due to lower average effective interest rates. The increase in 2010 from 2009 was primarily due to slightly higher average effective interest rates.

Millions of dollars	**2011**	2010	2009
Income tax expense	**$ 20,626**	$ 12,919	$ 7,965

Effective income tax rates were 43 percent in 2011, 40 percent in 2010 and 43 percent in 2009. The rate was higher in 2011 than in 2010 primarily due to higher effective tax rates in certain international upstream jurisdictions. The higher international upstream effective tax rates were driven primarily by lower utilization of non-U.S. tax credits in 2011 and the effect of changes in income tax rates between periods, which were partially offset by foreign currency remeasurement impacts. The rate was lower in 2010 than in 2009 primarily due to international upstream effects, including an increased utilization of tax credits, which had a greater impact on the rate than one-time deferred tax benefits and relatively low tax rates on asset sales in 2009. Also, a smaller portion of company income was earned in higher tax rate international upstream jurisdictions in 2010 than in 2009. Finally, foreign currency remeasurement impacts caused a reduction in the effective tax rate between periods.

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Selected Operating Data[1,2]

	2011	2010	2009
U.S. Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	**465**	489	484
Net Natural Gas Production (MMCFPD)[3]	**1,279**	1,314	1,399
Net Oil-Equivalent Production (MBOEPD)	**678**	708	717
Sales of Natural Gas (MMCFPD)	**5,836**	5,932	5,901
Sales of Natural Gas Liquids (MBPD)	**15**	22	17
Revenues From Net Production			
Liquids ($/Bbl)	**$ 97.51**	$ 71.59	$ 54.36
Natural Gas ($/MCF)	**$ 4.04**	$ 4.26	$ 3.73
International Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)[4]	**1,384**	1,434	1,362
Net Natural Gas Production (MMCFPD)[3]	**3,662**	3,726	3,590
Net Oil-Equivalent			
Production (MBOEPD)[5]	**1,995**	2,055	1,987
Sales of Natural Gas (MMCFPD)	**4,361**	4,493	4,062
Sales of Natural Gas Liquids (MBPD)	**24**	27	23
Revenues From Liftings			
Liquids ($/Bbl)	**$ 101.53**	$ 72.68	$ 55.97
Natural Gas ($/MCF)	**$ 5.39**	$ 4.64	$ 4.01
Worldwide Upstream			
Net Oil-Equivalent Production			
(MBOEPD)[3,5]			
United States	**678**	708	717
International	**1,995**	2,055	1,987
Total	**2,673**	2,763	2,704
U.S. Downstream			
Gasoline Sales (MBPD)[6]	**649**	700	720
Other Refined Product Sales (MBPD)	**608**	649	683
Total Refined Product Sales (MBPD)	**1,257**	1,349	1,403
Sales of Natural Gas Liquids (MBPD)	**146**	139	144
Refinery Input (MBPD)	**854**	890	899
International Downstream			
Gasoline Sales (MBPD)[6]	**447**	521	555
Other Refined Product Sales (MBPD)	**1,245**	1,243	1,296

Total Refined Product Sales (MBPD)[7]	**1,692**	1,764	1,851
Sales of Natural Gas Liquids (MBPD)	**63**	78	88
Refinery Input (MBPD)	**933**	1,004	979

[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	**69**	62	58
International	**513**	475	463
[4] Includes: Canada synthetic oil	**40**	24	
Venezuela affiliate synthetic oil	**32**	28	
[5] Includes Canada oil sands			26
[6] Includes branded and unbranded gasoline.			
[7] Includes sales of affiliates (MBPD):	**556**	562	516

Liquidity and Capital Resources

Cash, cash equivalents, time deposits and marketable securities Total balances were $20.1 billion and $17.1 billion at December 31, 2011 and 2010, respectively. Cash provided by operating activities in 2011 was $41.1 billion, compared with $31.4 billion in 2010 and $19.4 billion in 2009. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.5 billion, $1.4 billion and $1.7 billion in 2011, 2010 and 2009, respectively. Cash provided by operating activities during 2011 was more than sufficient to fund the $27.4 billion cash component of the company s capital and exploratory program and pay $6.1 billion of dividends to shareholders. In addition, the company completed the $4.5 billion acquisition of Atlas Energy, Inc., funded from the company s operating cash flows. Cash provided by investing activities included proceeds and deposits related to asset sales of $3.5 billion in 2011, $2.0 billion in 2010, and $2.6 billion in 2009.

Restricted cash of $1.2 billion and $855 million associated with various capital-investment projects, acquisitions pending tax deferred exchanges, and Upstream abandonment activities at December 31, 2011 and 2010, 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 $6.1 billion in 2011, $5.7 billion in 2010 and $5.3 billion in 2009. In October 2011, the company increased its quarterly dividend by 3.8 percent to 81 cents per common share. This followed an increase of 8.3 percent announced in second quarter 2011.

Capital and Exploratory Expenditures

			2011			2010			2009
Millions of dollars	U.S.	Int l.	Total	U.S.	Int l.	Total	U.S.	Int l.	Total
Upstream[1]	**$ 8,318**	**$ 17,554**	**$ 25,872**	$ 3,450	$ 15,454	$ 18,904	$ 3,294	$ 15,002	$ 18,296
Downstream	**1,461**	**1,150**	**2,611**	1,456	1,096	2,552	2,087	1,449	3,536
All Other	**575**	**8**	**583**	286	13	299	402	3	405
Total	**$ 10,354**	**$ 18,712**	**$ 29,066**	$ 5,192	$ 16,563	$ 21,755	$ 5,783	$ 16,454	$ 22,237
Total, Excluding Equity in Affiliates	**$ 10,077**	**$ 17,294**	**$ 27,371**	$ 4,934	$ 15,433	$ 20,367	$ 5,558	$ 15,094	$ 20,652

[1] Excludes the acquisition of Atlas Energy, Inc. in 2011.

Debt and capital lease obligations Total debt and capital lease obligations were $10.2 billion at December 31, 2011, down from $11.5 billion at year-end 2010.

The $1.3 billion decrease in total debt and capital lease obligations during 2011 included the early redemption of a $1.5 billion bond due to mature in March 2012. The company s debt and capital lease obligations due within one year, consisting primarily of commercial paper, redeemable long-term obligations and the current portion of long-term debt, totaled $5.9 billion at December 31, 2011, compared with $5.6 billion at year-end 2010. Of these amounts, $5.6 billion and $5.4 billion were reclassified to long-term at the end of each period, respectively. At year-end 2011, settlement of these obligations was not expected to require the use of working capital in 2012, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

At December 31, 2011, the company had $6.0 billion in committed credit facilities with various major banks, expiring in December 2016, which enable the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and can also be used for general corporate purposes. The company s practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company s strong credit rating. No borrowings were outstanding under these facilities at December 31, 2011. In addition, the company has an automatic shelf registration statement that expires in March 2013 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

The major debt rating agencies routinely evaluate the company s debt, and the company s cost of borrowing can increase or decrease depending on these debt ratings. The company has outstanding public bonds issued by Chevron Corporation, Chevron Corporation Profit Sharing/Savings Plan Trust Fund and Texaco Capital Inc. 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-l 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 program and cash that may be generated from asset dispositions. Based on its high-quality debt ratings, the company believes that it has substantial borrowing capacity to meet unanticipated cash requirements. The company also can modify capital spending plans during any extended periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals to provide flexibility to continue paying the common stock dividend and maintain the company s high-quality debt ratings.

Common stock repurchase program In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits. The company expects to repurchase between $500 million and $2 billion of its common shares per quarter, at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. During 2011, the company purchased 42.3 million common shares for $4.25 billion. From the inception of the program through 2011, the company had purchased 51.1 million shares for $5.0 billion.

Capital and exploratory expenditures Total expenditures for 2011 were $29.1 billion, including $1.7 billion for the company s share of equity-affiliate expenditures.
In 2010 and 2009, expenditures were $21.8 billion and $22.2 billion, respectively, including the company s share of affiliates expenditures of $1.4 billion and $1.6 billion, respectively.

Of the $29.1 billion of expenditures in 2011, 89 percent, or $25.9 billion, was related to upstream activities. Approximately 87 percent and 80 percent were expended for upstream operations in 2010 and 2009. International upstream accounted for about 68 percent of the worldwide upstream investment in 2011, about 82 percent in 2010 and about 80 percent in 2009. These amounts exclude the acquisition of Atlas Energy, Inc. in 2011.

The company estimates that in 2012 capital and exploratory expenditures will be $32.7 billion, including $3.0 billion of spending

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by affiliates. Approximately 87 percent of the total, or $28.5 billion, is budgeted for exploration and production activities. Approximately $22.3 billion, or 78 percent, of this amount is for projects outside the United States. Spending in 2012 is primarily focused on major development projects in Angola, Australia, Brazil, Canada, China, Kazakhstan, Nigeria, Russia, the United Kingdom and the U.S. Gulf of Mexico. Also included is funding for enhancing recovery and mitigating natural field declines for currently-producing assets, and for focused exploration and appraisal activities.

Worldwide downstream spending in 2012 is estimated at $3.6 billion, with about $2.1 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and South Korea, expansion of additives production capacity in Singapore, and chemicals projects in the United States and Saudi Arabia.

Investments in technology, power generation and other corporate businesses in 2012 are budgeted at $600 million.

Noncontrolling interests The company had noncontrolling interests of $799 million and $730 million at December 31, 2011 and 2010, respectively. Distributions to noncontrolling interests totaled $71 million and $72 million in 2011 and 2010, respectively.

Pension Obligations Information related to pension plan contributions is included on page FS-54 in Note 21 to the Consolidated Financial Statements under the heading Cash Contributions and Benefit Payments. Refer also to the discussion of pension accounting in Critical Accounting Estimates and Assumptions, beginning on page FS-16.

Financial Ratios

Financial Ratios

	At December 31		
	2011	2010	2009
Current Ratio	**1.6**	1.7	1.4
Interest Coverage Ratio	**165.4**	101.7	62.3
Debt Ratio	**7.7%**	9.8%	10.3%

Current Ratio current assets divided by current liabilities, which indicates the company s ability to repay its short-term liabilities with short-term assets. 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 2011, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $9.0 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. This ratio indicates the company s ability to pay interest on outstanding debt. The company s interest coverage ratio in 2011 was higher than 2010 and 2009 due to higher before-tax income.

Debt Ratio total debt as a percentage of total debt plus Chevron Corporation Stockholders Equity, which indicates the company s leverage. The decrease between 2011 and 2010 was due to lower debt and a higher Chevron Corporation stockholders equity balance. The decrease between 2010 and 2009 was due to a higher Chevron Corporation stockholders equity balance.

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

Direct Guarantee

Millions of dollars			Commitment Expiration by Period		
			2013	2015	After
	Total	2012	2014	2016	2016

Guarantee of non-consolidated affiliate or joint-venture obligation	$ 601	$ 38	$ 77	$ 77	$ 409

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 commenced operations in third quarter 2011. 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 amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

Indemnifications Information related to indemnifications is included on page FS-56 in Note 24 to the Consolidated Financial Statements under the heading Indemnifications.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities with respect 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: 2012 $6.0 billion; 2013 $4.0 billion; 2014 $3.9 billion; 2015 $3.2 billion; 2016 $1.9 billion; 2017 and after $7.4 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $6.6 billion in 2011, $6.5 billion in 2010 and $8.1 billion in 2009.

The following table summarizes the company s significant contractual obligations:

Contractual Obligations[1]

Millions of dollars				Payments Due by Period	
	Total	2012	2013 2014	2015 2016	After 2016
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 340	$ 340	$	$	$
Long-Term Debt[3]	9,684		7,641		2,043
Noncancelable Capital Lease Obligations	251	70	79	34	68
Interest	1,764	223	366	264	911
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	3,509	693	1,155	868	793
Throughput and Take-or-Pay Agreements[4]	21,664	4,912	5,382	4,218	7,152
Other Unconditional Purchase Obligations[4]	4,759	1,102	2,524	906	227

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page FS-49.

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 $5.6 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 2013 2014 period.

4 Does not include commodity purchase obligations that are not fixed or determinable. These obligations are generally monetized in a relatively short period of time through sales transactions or

similar agreements with third parties. Examples include obligations to purchase LNG, regasified natural gas and refinery products at indexed prices.

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 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 2011 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 2011.

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.

Derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet in accordance with accounting standards for derivatives (ASC 815), 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 of Chevron s derivative commodity instruments in 2011 was a quarterly average increase of $22 million in total assets and a quarterly average decrease of $17 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. VaR is the maximum projected 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 distributions 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, most of which can be liquidated or hedged effectively within one day. The following table 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, 2011 and 2010.

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Millions of dollars	**2011**	2010
Crude Oil	**$ 22**	$ 15
Natural Gas	**4**	4
Refined Products	**11**	14

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, 2011.

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. Interest rate swaps, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2011, the company had no interest rate swaps.

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 Information in Note 12 of the Consolidated Financial Statements, page FS-40, 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 Information related to methyl tertiary butyl ether (MTBE) matters is included on page FS-41 in Note 14 to the Consolidated Financial Statements under the heading MTBE.

Ecuador Information related to Ecuador matters is included in Note 14 to the Consolidated Financial Statements under the heading Ecuador , beginning on page FS-41.

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	**2011**	2010	2009

Balance at January 1	**$ 1,507**	$ 1,700	$ 1,818
Net Additions	**343**	220	351
Expenditures	**(446)**	(413)	(469)
Balance at December 31	**$ 1,404**	$ 1,507	$ 1,700

Included in the $1,404 million year-end 2011 reserve balance were remediation activities at approximately 180 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 2011 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.

Of the remaining year-end 2011 environmental reserves balance of $1,219 million, $675 million related to the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facilities, and pipelines. The remaining $544 million was associated with various sites in international downstream ($95 million), upstream ($368 million) and other businesses ($81 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 2011 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.

The company records asset retirement obligations when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. These asset retirement obligations include costs related to environmental issues. The liability balance of approximately $12.8 billion for asset retirement obligations at year-end 2011 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 25 on page FS-58, related to the company s asset retirement obligations and the discussion of Environmental Matters beginning on page FS-15.

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, 2011, the company had approximately $2.4 billion of suspended exploratory wells included in properties, plant and equipment, a decrease
of $284 million from 2010. The 2010 balance reflected an increase of $283 million from 2009.

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 2011 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page FS-47, for additional discussion of suspended wells.

Income Taxes Information related to income tax contingencies is included on pages FS-43 through FS-45 in Note 15 and page FS-56 in Note 24 to the Consolidated Financial Statements under the heading Income Taxes.

Other Contingencies Information related to other contingencies is included on pages FS-57 through FS-58 in Note 24 to the Consolidated Financial Statements under the heading Other Contingencies.

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 2011 at approximately $2.7 billion for its consolidated companies. Included in these expenditures were approximately $1.0 billion of environmental capital expenditures and $1.7 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 2012, total worldwide environmental capital expenditures are estimated at $1.0 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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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 require ... by analysis of geosciences and engineering data, (the reserves) can be estimated with reasonable certainty to be economi-
cally producible... under existing economic conditions where existing economic conditions include prices based on the average price during the 12-month period prior to the end of the reporting period. Refer to Table V, Reserve Quantity Information, beginning on page FS-67, for the changes in these estimates for the three years ending December 31, 2011, and to Table VII, Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves on page FS-76 for estimates of proved-reserve values for each of the three years ended December 31, 2011. Note 1 to the Consolidated Financial Statements, beginning on page FS-28, 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-18, 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-28. 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-49, includes information on the funded status of the company s pension and OPEB plans at the end of 2011 and 2010; the components of pension and OPEB expense for the three years ended December 31, 2011; 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 2011 and 2010 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 70 percent of the company s pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2011, actual asset returns averaged 5.0 percent for this plan. The actual return for 2011 was slightly negative and was associated with the broad decline in the financial markets in the second half of the year. Additionally, with the exception of two other years within this 10 year period, actual asset returns for this plan equaled or exceeded 7.8 percent.

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, 2011, the company selected a 3.8 percent discount rate for the major U.S. pension plan and 4.0 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 2011. The discount rates at the end of 2010 and 2009 were 4.8 percent and 5.3 percent, respectively, for the major U.S. pension plan, and 5.0 percent and 5.8 percent, respectively, for the company s U.S. OPEB plan.

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 2011 was $1.2 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 2011 by approximately $75 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 63 percent of the companywide pension obligation, would have reduced total pension plan expense for 2011 by approximately $145 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 aggregate funded status recognized on the Consolidated Balance Sheet at December 31, 2011, was a net liability of approximately $5.4 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 $375 million, which would have decreased the plan s underfunded status from approximately $2.5 billion to $2.1 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 2011, the company s pension plan contributions were $1.5 billion (including $1.2 billion to the U.S. plans). In 2012, the company estimates contributions will be approximately $900 million. Actual contribution amounts are dependent upon 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 2011 was $220 million, and the total liability, which reflected the unfunded status of the plans at the end of 2011, was $3.8 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2011, a 1 percent increase in the discount rate for the company s primary U.S. OPEB plan, which accounted for about 76 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $10 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 81 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2011 by approximately $75 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 8 percent in 2012 and gradually drop to 5 percent for 2023 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2011, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for 81 percent of the companywide OPEB liabilities, would have increased OPEB expense by $8 million.

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

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-49, for information on the $9.6 billion of before-tax actuarial losses recorded by the company as of December 31, 2011; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2012.

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. Refer also to the discussion of impairments of properties, plant and equipment in Note 9 beginning on page FS-34.

No major individual impairments of PP&E and Investments were recorded for the three years ending December 31, 2011. 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

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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-43. 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, 2011.

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

Refer to Note 18, on page FS-47 in the Notes to Consolidated Financial Statements, for information regarding new accounting standards.

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Quarterly Results and Stock Market Data
Unaudited

				2011				2010
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]	**$ 58,027**	**$ 61,261**	**$ 66,671**	**$ 58,412**	$ 51,852	$ 48,554	$ 51,051	$ 46,741
ncome from equity affiliates	**1,567**	**2,227**	**1,882**	**1,687**	1,510	1,242	1,650	1,235
ther income	**391**	**944**	**395**	**242**	665	(78)	303	203
otal Revenues and Other Income	**59,985**	**64,432**	**68,948**	**60,341**	54,027	49,718	53,004	48,179
osts and Other Deductions								
urchased crude oil and products	**36,363**	**37,600**	**40,759**	**35,201**	30,109	28,610	30,604	27,144
perating expenses	**5,948**	**5,378**	**5,260**	**5,063**	5,343	4,665	4,591	4,589
elling, general and administrative expenses	**1,330**	**1,115**	**1,200**	**1,100**	1,408	1,181	1,136	1,042
xploration expenses	**386**	**240**	**422**	**168**	335	420	212	180
epreciation, depletion and amortization	**3,313**	**3,215**	**3,257**	**3,126**	3,439	3,401	3,141	3,082
axes other than on income[1]	**2,680**	**3,544**	**4,843**	**4,561**	4,623	4,559	4,537	4,472
nterest and debt expense					4	9	17	20
otal Costs and Other Deductions	**50,020**	**51,092**	**55,741**	**49,219**	45,261	42,845	44,238	40,529
ncome Before Income Tax Expense	**9,965**	**13,340**	**13,207**	**11,122**	8,766	6,873	8,766	7,650
ncome Tax Expense	**4,813**	**5,483**	**5,447**	**4,883**	3,446	3,081	3,322	3,070
et Income	**$ 5,152**	**$ 7,857**	**$ 7,760**	**$ 6,239**	$ 5,320	$ 3,792	$ 5,444	$ 4,580
ess: Net income attributable to oncontrolling interests	**29**	**28**	**28**	**28**	25	24	35	28
et Income Attributable to Chevron Corporation	**$ 5,123**	**$ 7,829**	**$ 7,732**	**$ 6,211**	$ 5,295	$ 3,768	$ 5,409	$ 4,552
er Share of Common Stock								
et Income Attributable to Chevron Corporation								
Basic	**$ 2.61**	**$ 3.94**	**$ 3.88**	**$ 3.11**	$ 2.65	$ 1.89	$ 2.71	$ 2.28
Diluted	**$ 2.58**	**$ 3.92**	**$ 3.85**	**$ 3.09**	$ 2.64	$ 1.87	$ 2.70	$ 2.27
ividends	**$ 0.81**	**$ 0.78**	**$ 0.78**	**$ 0.72**	$ 0.72	$ 0.72	$ 0.72	$ 0.68
ommon Stock Price Range High[2]	**$ 110.01**	**$ 109.75**	**$ 109.94**	**$ 109.65**	$ 92.39	$ 82.19	$ 83.41	$ 81.09
Low[2]	**$ 86.68**	**$ 87.30**	**$ 97.00**	**$ 90.12**	$ 80.41	$ 66.83	$ 67.80	$ 69.55
Includes excise, value-added and similar taxes:	**$ 1,713**	**$ 1,974**	**$ 2,264**	**$ 2,134**	$ 2,136	$ 2,182	$ 2,201	$ 2,072

Intraday price.

The company s common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 13, 2012, stockholders of record numbered approximately 178,000. There are no restrictions on the company s ability to pay dividends.

Management s Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

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

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

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

Management s Report on Internal Control Over Financial Reporting

The company s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company s management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of 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, 2011.

The effectiveness of the company s internal control over financial reporting as of December 31, 2011, 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	Matthew J. Foehr
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 23, 2012

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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 sheet and the related consolidated statements of income, comprehensive income, equity and of cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2011, and December 31, 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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.

San Francisco, California
February 23, 2012

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Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2011	2010	2009
Revenues and Other Income			
Sales and other operating revenues*	**$ 244,371**	$ 198,198	$ 167,402
Income from equity affiliates	**7,363**	5,637	3,316
Other income	**1,972**	1,093	918
Total Revenues and Other Income	**253,706**	204,928	171,636
Costs and Other Deductions			
Purchased crude oil and products	**149,923**	116,467	99,653
Operating expenses	**21,649**	19,188	17,857
Selling, general and administrative expenses	**4,745**	4,767	4,527
Exploration expenses	**1,216**	1,147	1,342
Depreciation, depletion and amortization	**12,911**	13,063	12,110
Taxes other than on income*	**15,628**	18,191	17,591
Interest and debt expense		50	28
Total Costs and Other Deductions	**206,072**	172,873	153,108
Income Before Income Tax Expense	**47,634**	32,055	18,528
Income Tax Expense	**20,626**	12,919	7,965
Net Income	**27,008**	19,136	10,563
Less: Net income attributable to noncontrolling interests	**113**	112	80
Net Income Attributable to Chevron Corporation	**$ 26,895**	$ 19,024	$ 10,483
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
Basic	**$ 13.54**	$ 9.53	$ 5.26
Diluted	**$ 13.44**	$ 9.48	$ 5.24
*Includes excise, value-added and similar taxes.	**$ 8,085**	$ 8,591	$ 8,109

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2011	2010	2009
Net Income	**$ 27,008**	$ 19,136	$ 10,563
Currency translation adjustment			
Unrealized net change arising during period	**17**	6	60
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(11)**	(4)	2
Derivatives			
Net derivatives gain (loss) on hedge transactions	**20**	25	(69)
Reclassification to net income of net realized loss (gain)	**9**	5	(23)
Income taxes on derivatives transactions	**(10)**	(10)	32
Total	**19**	20	(60)
Defined benefit plans			
Actuarial loss			
Amortization to net income of net actuarial loss	**773**	635	575
Actuarial loss arising during period	**(3,250)**	(857)	(1,099)
Prior service cost			
Amortization to net income of net prior service credits	**(26)**	(61)	(65)
Prior service cost arising during period	**(27)**	(12)	(34)
Defined benefit plans sponsored by equity affiliates	**(81)**	(12)	65
Income taxes on defined benefit plans	**1,030**	140	159
Total	**(1,581)**	(167)	(399)
Other Comprehensive Loss, Net of Tax	**(1,556)**	(145)	(397)
Comprehensive Income	**25,452**	18,991	10,166
Comprehensive income attributable to noncontrolling interests	**(113)**	(112)	(80)
Comprehensive Income Attributable to Chevron Corporation	**$ 25,339**	$ 18,879	$ 10,086

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	
	2011	2010
Assets		
Cash and cash equivalents	**$ 15,864**	$ 14,060
Time deposits	**3,958**	2,855
Marketable securities	**249**	155
Accounts and notes receivable (less allowance: 2011 $98; 2010 $184)	**21,793**	20,759
Inventories:		
Crude oil and petroleum products	**3,420**	3,589
Chemicals	**502**	395
Materials, supplies and other	**1,621**	1,509
Total inventories	**5,543**	5,493
Prepaid expenses and other current assets	**5,827**	5,519
Total Current Assets	**53,234**	48,841
Long-term receivables, net	**2,233**	2,077
Investments and advances	**22,868**	21,520
Properties, plant and equipment, at cost	**233,432**	207,367
Less: Accumulated depreciation, depletion and amortization	**110,824**	102,863
Properties, plant and equipment, net	**122,608**	104,504
Deferred charges and other assets	**3,889**	3,210
Goodwill	**4,642**	4,617
Total Assets	**$ 209,474**	$ 184,769
Liabilities and Equity		
Short-term debt	**$ 340**	$ 187
Accounts payable	**22,147**	19,259
Accrued liabilities	**5,287**	5,324
Federal and other taxes on income	**4,584**	2,776
Other taxes payable	**1,242**	1,466
Total Current Liabilities	**33,600**	29,012
Long-term debt	**9,684**	11,003
Capital lease obligations	**128**	286
Deferred credits and other noncurrent obligations	**19,181**	19,264
Noncurrent deferred income taxes	**15,544**	12,697
Reserves for employee benefit plans	**9,156**	6,696
Total Liabilities	**87,293**	78,958
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; $0.75 par value; 2,442,676,580 shares issued at December 31, 2011 and 2010)		
Capital in excess of par value	**15,156**	14,796
Retained earnings	**140,399**	119,641
Accumulated other comprehensive loss	**(6,022)**	(4,466)
Deferred compensation and benefit plan trust	**(298)**	(311)
Treasury stock, at cost (2011 461,509,656 shares; 2010 435,195,799 shares)	**(29,685)**	(26,411)
Total Chevron Corporation Stockholders Equity	**121,382**	105,081
Noncontrolling interests	**799**	730
Total Equity	**122,181**	105,811
Total Liabilities and Equity	**$ 209,474**	$ 184,769

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2011	2010	2009
Operating Activities			
Net Income	**$ 27,008**	$ 19,136	$ 10,563
Adjustments			
Depreciation, depletion and amortization	**12,911**	13,063	12,110
Dry hole expense	**377**	496	552
Distributions less than income from equity affiliates	**(570)**	(501)	(103)
Net before-tax gains on asset retirements and sales	**(1,495)**	(1,004)	(1,255)
Net foreign currency effects	**(103)**	251	466
Deferred income tax provision	**1,589**	559	467
Net decrease (increase) in operating working capital	**2,318**	76	(2,301)
Increase in long-term receivables	**(150)**	(12)	(258)
Decrease in other deferred charges	**341**	48	201
Cash contributions to employee pension plans	**(1,467)**	(1,450)	(1,739)
Other	**339**	697	670
Net Cash Provided by Operating Activities	**41,098**	31,359	19,373
Investing Activities			
Acquisition of Atlas Energy	**(3,009)**		
Advance to Atlas Energy	**(403)**		
Capital expenditures	**(26,500)**	(19,612)	(19,843)
Proceeds and deposits related to asset sales	**3,517**	1,995	2,564
Net purchases of time deposits	**(1,104)**	(2,855)	
Net (purchases) sales of marketable securities	**(74)**	(49)	127
Repayment of loans by equity affiliates	**339**	338	336
Net (purchases) sales of other short-term investments	**(255)**	(732)	244
Net Cash Used for Investing Activities	**(27,489)**	(20,915)	(16,572)
Financing Activities			
Net borrowings (payments) of short-term obligations	**23**	(212)	(3,192)
Proceeds from issuances of long-term debt	**377**	1,250	5,347
Repayments of long-term debt and other financing obligations	**(2,769)**	(156)	(496)
Cash dividends common stock	**(6,139)**	(5,674)	(5,302)
Distributions to noncontrolling interests	**(71)**	(72)	(71)
Net (purchases) sales of treasury shares	**(3,193)**	(306)	168
Net Cash Used for Financing Activities	**(11,772)**	(5,170)	(3,546)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(33)**	70	114
Net Change in Cash and Cash Equivalents	**1,804**	5,344	(631)

Cash and Cash Equivalents at January 1	**14,060**	8,716	9,347
Cash and Cash Equivalents at December 31	**$ 15,864**	$ 14,060	$ 8,716

See accompanying Notes to the Consolidated Financial Statements.

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

	2011		2010		2009	
	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		**$ 14,796**		$ 14,631		$ 14,448
Treasury stock transactions		**360**		165		183
Balance at December 31		**$ 15,156**		$ 14,796		$ 14,631
Retained Earnings						
Balance at January 1		**$ 119,641**		$ 106,289		$ 101,102
Net income attributable to Chevron Corporation		**26,895**		19,024		10,483
Cash dividends on common stock		**(6,139)**		(5,674)		(5,302)
Tax benefit from dividends paid on unallocated ESOP shares and other		**2**		2		6
Balance at December 31		**$ 140,399**		$ 119,641		$ 106,289
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (105)**		$ (111)		$ (171)
Change during year		**17**		6		60
Balance at December 31		**$ (88)**		$ (105)		$ (111)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (4,475)**		$ (4,308)		$ (3,909)
Change during year		**(1,581)**		(167)		(399)
Balance at December 31		**$ (6,056)**		$ (4,475)		$ (4,308)
Unrealized net holding gain on securities						
Balance at January 1		**$ 11**		$ 15		$ 13
Change during year		**(11)**		(4)		2
Balance at December 31		**$**		$ 11		$ 15
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 103**		$ 83		$ 143
Change during year		**19**		20		(60)
Balance at December 31		**$ 122**		$ 103		$ 83
Balance at December 31		**$ (6,022)**		$ (4,466)		$ (4,321)

Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ (71)**		$ (109)		$ (194)
Net reduction of ESOP debt and other		**13**		38		85
Balance at December 31		**(58)**		(71)		(109)
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240)
Balance at December 31	**14,168**	**$ (298)**	14,168	$ (311)	14,168	$ (349)
Treasury Stock at Cost						
Balance at January 1	**435,196**	**$ (26,411)**	434,955	$ (26,168)	438,445	$ (26,376)
Purchases	**42,424**	**(4,262)**	9,091	(775)	85	(6)
Issuances mainly employee benefit plans	**(16,110)**	**988**	(8,850)	532	(3,575)	214
Balance at December 31	**461,510**	**$ (29,685)**	435,196	$ (26,411)	434,955	$ (26,168)
Total Chevron Corporation Stockholders Equity at December 31		**$ 121,382**		$ 105,081		$ 91,914
Noncontrolling Interests		**$ 799**		$ 730		$ 647
Total Equity		**$ 122,181**		$ 105,811		$ 92,561

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 Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; liquefaction, transportation and regasification associated with liquefied natural gas (LNG); transporting crude oil by major international oil export pipelines; processing, transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations relate primarily to refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and additives for fuels and lubricant oils.

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.

Subsidiary and Affiliated Companies The Consolidated Financial Statements include the accounts of controlled subsidiary companies more than 50 percent-owned and any 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, gains and losses from derivative instruments are reported in current income. 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. 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. 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 generally 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. Bank time deposits with maturities greater than 90 days are reported as Time deposits. The balance of 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 inventories are generally stated at cost, using a last-in, first-out method. In the aggregate, these costs are below market. Materials, supplies and other inventories generally are stated at average cost.

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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-47, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted, future net before-tax cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset, significant change in the extent or manner of use of or a physical change in an asset, and a more-likely-than-not expectation that a long-lived asset or asset group will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted future net before-tax cash flows. For proved crude oil and natural gas properties in the United States, the company generally performs the impairment review on an individual field basis. Outside the United States, reviews are performed on a country, concession, development area or field basis, as appropriate. In Downstream, impairment reviews are performed on the basis of a refinery, a plant, a marketing/lubricants area or distribution area, as appropriate. 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. Refer to Note 9, beginning on page FS-34, relating to fair value measurements.

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 25, on page FS-58, relating to AROs.

Depreciation and depletion of all capitalized costs of proved crude oil and natural gas producing properties, except mineral interests, are expensed using the unit-of-production method, 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.

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 is generally 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 the 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 in accordance with accounting standards for asset retirement and environmental obligations. Refer to Note 25, on page FS-58, for a discussion of the company s AROs.

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Note 1 Summary of Significant Accounting Policies - Continued

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 remeasurement are included in current period 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-23. 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

Acquisition of Atlas Energy, Inc.

On February 17, 2011, the company acquired Atlas Energy, Inc. (Atlas), which held one of the premier acreage positions in the Marcellus Shale, concentrated in southwestern Pennsylvania. The aggregate purchase price of Atlas was approximately $4,500, which included $3,009 cash for all the common shares of Atlas, a $403 cash advance to facilitate Atlas purchase of a 49 percent interest in Laurel Mountain Midstream LLC and about $1,100 of assumed debt. Subsequent to the close of the transaction, the company paid off the assumed debt and made payments of $184 in connection with Atlas equity awards. As part of the acquisition, Chevron assumed the terms of a carry arrangement whereby Reliance Marcellus, LLC, funds 75 percent of Chevron s drilling costs, up to $1,300.

The acquisition was accounted for as a business combination (ASC 805) which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Provisional fair value measurements were made in first quarter 2011 for acquired assets and assumed liabilities, and the measurement process was finalized in fourth quarter 2011.

Proforma financial information is not presented as it would not be materially different from the information presented in the Consolidated Statement of Income.

The following table summarizes the measurement of the assets acquired and liabilities assumed:

Millions of Dollars	At February 17, 2011
Current assets	$ 155
Investments and long-term receivables	456
Properties	6,051
Goodwill	27
Other assets	5
Total assets acquired	6,694
Current liabilities	(560)
Long-term debt and capital leases	(761)
Deferred income taxes	(1,915)
Other liabilities	(25)
Total liabilities assumed	(3,261)
Net assets acquired	$ 3,433

Note 2 Acquisition of Atlas Energy Inc. - Continued

Properties were measured primarily using an income approach. The fair values of the acquired oil and gas properties were based on significant inputs not observable in the market and thus represent Level 3 measurements. Refer to Note 9, beginning on page FS-34 for a definition of fair value hierarchy levels. Significant inputs included estimated resource volumes, assumed future production profiles, estimated future commodity prices, a discount rate of 8 percent, and assumptions on the timing and amount of future operating and development costs. All the properties are in the United States and are included in the Upstream segment.

The acquisition date fair value of the consideration transferred was $3,400 in cash. The $27 of goodwill was assigned to the Upstream segment and represents the amount of the consideration transferred in excess of the values assigned to the individual assets acquired and liabilities assumed. Goodwill represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. None of the goodwill is deductible for tax purposes. Goodwill recorded in the acquisition is not subject to amortization, but will be tested periodically for impairment as required by the applicable accounting standard (ASC 350).

Note 3

Noncontrolling Interests

The company adopted the accounting standard 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 2011, 2010 and 2009 is as follows:

	2011	2010	2009
Balance at January 1	**$ 730**	$ 647	$ 469
Net income	**113**	112	80
Distributions to noncontrolling interests	**(71)**	(72)	(71)
Other changes, net	**27**	43	169
Balance at December 31	**$ 799**	$ 730	$ 647

Note 4

Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2011	2010	2009
Net decrease (increase) in operating working capital was composed of the following:			
Increase in accounts and notes receivable	**$ (2,156)**	$ (2,767)	$ (1,476)
(Increase) decrease in inventories	**(404)**	15	1,213
Increase in prepaid expenses and other current assets	**(853)**	(542)	(264)
Increase (decrease) in accounts payable and accrued liabilities	**3,839**	3,049	(1,121)

Increase (decrease) in income and other taxes payable	**1,892**	321	(653)
Net decrease (increase) in operating working capital	**$ 2,318**	$ 76	$ (2,301)
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$**	$ 34	$
Income taxes	**$ 17,374**	$ 11,749	$ 7,537
Net sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (112)**	$ (90)	$ (30)
Marketable securities sold	**38**	41	157
Net (purchases) sales of marketable securities	**$ (74)**	$ (49)	$ 127
Net purchases of time deposits consisted of the following gross amounts:			
Time deposits purchased	**$ (6,439)**	$ (5,060)	$
Time deposits matured	**5,335**	2,205	
Net purchases of time deposits	**$ (1,104)**	$ (2,855)	$

In accordance with accounting standards for cash-flow classifications for stock options (ASC 718), the Net decrease (increase) in operating working capital includes reductions of $121, $67 and $25 for excess income tax benefits associated with stock options exercised during 2011, 2010 and 2009, respectively. These amounts are offset by an equal amount in Net (purchases) sales of treasury shares.

The Acquisition of Atlas Energy reflects the $3,009 of cash paid for all the common shares of Atlas. An Advance to Atlas Energy of $403 was made to facilitate the purchase of a 49 percent interest in Laurel Mountain Midstream LLC on the day of closing. The Net decrease (increase) in operating working capital includes $184 for payments made in connection with Atlas equity awards subsequent to the acquisition. Refer to Note 2, beginning on page FS-30 for additional discussion of the Atlas acquisition.

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Note 4 Information Relating to the Consolidated Statement of Cash Flows - Continued

The Repayments of long-term debt and other financing obligations includes $761 for repayment of Atlas debt and $271 for payoff of the Atlas revolving credit facility.

The Net (purchases) sales of treasury shares represents the cost of common shares acquired less the cost of shares issued for share-based compensation plans. Purchases totaled $4,262, $775 and $6 in 2011, 2010 and 2009, respectively. In 2011 and 2010, the company purchased 42.3 million and 8.8 million common shares for $4,250 and $750 under its ongoing share repurchase program, respectively.

In 2011 and 2010, Net sales (purchases) of other short-term investments consist of restricted cash associated with capital-investment projects at the company s Pascagoula and El Segundo refineries, acquisitions pending tax deferred exchanges, and Upstream abandonment activities 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 $374, $1,250 and $350 in 2011, 2010 and 2009, respectively, of tax exempt bonds as a source of funds for U.S. refinery projects, which is included in Proceeds from issuance of long-term debt.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2009, payments related to Accrued liabilities were excluded from Net decrease (increase) in operating working capital and were reported as Capital expenditures. The Accrued liabilities were related to upstream operating agreements outside the United States recorded in 2008. Refer also to Note 25, on page FS-58, 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, 2011.

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		
	2011	2010	2009
Additions to properties, plant and equipment[1]	**$ 25,440**	$ 18,474	$ 16,107
Additions to investments	**900**	861	942
Current year dry hole expenditures	**332**	414	468
Payments for other liabilities and assets, net[2]	**(172)**	(137)	2,326
Capital expenditures	**26,500**	19,612	19,843
Expensed exploration expenditures	**839**	651	790
Assets acquired through capital lease obligations and other financing obligations	**32**	104	19
Capital and exploratory expenditures, excluding equity affiliates	**27,371**	20,367	20,652
Company s share of expenditures by equity affiliates	**1,695**	1,388	1,585
Capital and exploratory expenditures, including equity affiliates	**$ 29,066**	$ 21,755	$ 22,237

[1] Excludes noncash additions of $945 in 2011, $2,753 in 2010 and $985 in 2009.

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

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.

Note 5 Summarized Financial Data - Chevron U.S.A. Inc. - Continued

The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2011	2010	2009
Sales and other operating revenues	**$ 187,917**	$ 145,381	$ 121,553
Total costs and other deductions	**178,498**	139,984	120,053
Net income attributable to CUSA	**6,899**	4,159	1,141

	At December 31	
	2011	2010
Current assets	**$ 34,478**	$ 29,211
Other assets	**47,556**	35,294
Current liabilities	**19,082**	18,098
Other liabilities	**26,153**	16,785
Total CUSA net equity	**36,799**	29,622
Memo: Total debt	**$ 14,763**	$ 8,284

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		
	2011	2010	2009
Sales and other operating revenues	**$ 793**	$ 885	$ 683
Total costs and other deductions	**974**	1,008	810
Net loss attributable to CTC	**(177)**	(116)	(124)

	At December 31	
	2011	2010*
Current assets	**$ 290**	$ 309
Other assets	**228**	201
Current liabilities	**114**	101
Other liabilities	**346**	175

Total CTC net equity	**58**	234

* 2010 current assets and other liabilities conformed with 2011 presentation.

There were no restrictions on CTC s ability to pay dividends or make loans or advances at December 31, 2011.

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-39, for a discussion of TCO operations.

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

	Year ended December 31		
	2011	2010	2009
Sales and other operating revenues	**$ 25,278**	$ 17,812	$ 12,013
Costs and other deductions	**10,941**	8,394	6,044
Net income attributable to TCO	**10,039**	6,593	4,178

	At December 31	
	2011	2010
Current assets	**$ 3,477**	$ 3,376
Other assets	**11,619**	11,813
Current liabilities	**2,995**	2,402
Other liabilities	**3,759**	4,130
Total TCO net equity	**8,342**	8,657

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 crude oil production and processing equipment, service stations, bareboat charters, 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	
	2011	2010
Upstream	**$ 585**	$ 561
Downstream	**316**	316
All Other		169
Total	**901**	1,046
Less: Accumulated amortization	**568**	573
Net capitalized leased assets	**$ 333**	$ 473

Rental expenses incurred for operating leases during 2011, 2010 and 2009 were as follows:

	Year ended December 31		
	2011	2010*	2009*
Minimum rentals	**$ 892**	$ 931	$ 933
Contingent rentals	**11**	10	7
Total	**903**	941	940
Less: Sublease rental income	**39**	41	41
Net rental expense	**$ 864**	$ 900	$ 899

* Prior years have been adjusted to exclude cost of certain charters from rental expenses.

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

Note 8 Lease Commitments - Continued

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, 2011, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2012	693	70
2013	632	47
2014	523	32
2015	475	21
2016	393	13
Thereafter	793	68
Total	$ 3,509	$ 251
Less: Amounts representing interest and executory costs		(55)
Net present values		196
Less: Capital lease obligations included in short-term debt		(68)
Long-term capital lease obligations		$ 128

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 fair value measurements of financial and 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.

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.

The table below shows the fair value hierarchy for assets and liabilities measured at fair value on a recurring basis at December 31, 2011 and December 31, 2010.

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, 2011.

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 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 futures, swaps, options and forward contracts for crude oil, natural gas and refined products. Derivatives classified as Level 1 include futures, swaps and options contracts traded in active markets such as the New York Mercantile Exchange.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2011				At December 31, 2010			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	**249**	**249**			155	155		
Derivatives	**208**	**104**	**104**		122	11	111	
Total Assets at Fair Value	**$ 457**	**$ 353**	**$ 104**	**$**	$ 277	$ 166	$ 111	$
Derivatives	**102**	**101**	**1**		171	75	96	
Total Liabilities at Fair Value	**$ 102**	**$ 101**	**$ 1**	**$**	$ 171	$ 75	$ 96	$

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Note 9 Fair Value Measurements - Continued

Derivatives classified as Level 2 include swaps, options, and forward contracts principally with financial institutions and other oil and gas companies, the fair values of which are obtained from third-party broker quotes, industry pricing 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 The company did not have any material long-lived assets measured at fair value on a nonrecurring basis to report in 2011 or 2010.

Impairments of Investments and advances The company did not have any material investments and advances measured at fair value on a nonrecurring basis to report in 2011 or 2010.

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents and bank time deposits in U.S. and non-U.S. portfolios. The instruments classified as cash equivalents are primarily bank time deposits with maturities of 90 days or less and money market funds. Cash and cash equivalents had carrying/fair values of $15,864 and $14,060 at December 31, 2011, and December 31, 2010, respectively. The instruments held in Time deposits are bank time deposits with maturities greater than 90 days, and had carrying/fair values of $3,958 and $2,855 at December 31, 2011, and December 31, 2010, respectively. The fair values of cash, cash equivalents and bank time deposits reflect the cash that would have been received if the instruments were settled at December 31, 2011.

Cash and cash equivalents do not include investments with a carrying/fair value of $1,240 and $855 at December 31, 2011, and December 31, 2010, respectively. At December 31, 2011, these investments include restricted funds related to various capital-investment projects, acquisitions pending tax deferred exchanges, and Upstream abandonment activities which are reported in Deferred charges and other assets on the Consolidated Balance Sheet. Long-term debt of $4,101 and $5,636 at December 31, 2011, and December 31, 2010, had estimated fair values of $4,928 and $6,311, respectively.

The carrying values of short-term financial assets and liabilities on the Consolidated Balance Sheet approximate their fair values. Fair value remeasurements of other financial instruments at December 31, 2011 and 2010 were not material.

The fair value hierarchy for assets and liabilities measured at fair value on a nonrecurring basis at December 31, 2011, is as follows:

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

	At December 31					At December 31				
	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2011	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2010
Properties, plant and equipment, net (held and used)	**$ 67**	**$**	**$**	**$ 67**	**$ 81**	$ 57	$	$	$ 57	$ 85
Properties, plant and equipment, net (held for sale)	**167**		**167**		**54**	13			13	36
					108					15

Investments and advances										
Total Nonrecurring Assets at Fair Value	**$ 234**	**$**	**$ 167**	**$ 67**	**$ 243**	$ 70	$	$	$ 70	$ 136

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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 commodity derivative 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, 2011, December 31, 2010, and December 31, 2009, 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

Type of Contract	Balance Sheet Classification	At December 31 **2011**	At December 31 2010
Commodity	Accounts and notes receivable, net	**$ 133**	$ 58
Commodity	Long-term receivables, net	**75**	64
Total Assets at Fair Value		**$ 208**	$ 122
Commodity	Accounts payable	**$ 36**	$ 131
Commodity	Deferred credits and other noncurrent obligations	**66**	40
Total Liabilities at Fair Value		**$ 102**	$ 171

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 **2011**	2010	2009
Foreign Exchange	Other income	**$**	$	$ 26
Commodity	Sales and other operating revenues	**(255)**	(98)	(94)
Commodity	Purchased crude oil and products	**15**	(36)	(353)
Commodity	Other income	**(2)**	(1)	
		$ (242)	$ (135)	$ (421)

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, 2011 or 2010.

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. 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 2011 and 2010, the company had no interest rate swaps.

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Note 10 Financial and Derivative Instruments - Continued

Concentrations of Credit Risk The company s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, time deposits, 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. Company investment policies limit the company s exposure both to credit risk and to concentrations of credit risk. Similar policies on diversification 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. The investments are grouped into two business segments, Upstream and Downstream, representing the company s reportable segments and operating segments as defined in accounting standards for segment reporting (ASC 280). Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; liquefaction, transportation and regasification associated with liquefied natural gas (LNG); transporting crude oil by major international oil export pipelines; processing, transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations consist primarily of refining of crude oil into petroleum products; marketing of crude oil and refined products; transporting of crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant additives. All Other activities of the company include mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, alternative fuels and technology.

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 (EXCOM), a committee of senior officers that includes the Chief Executive Officer, and EXCOM 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 assesses their performance; and (c) for which discrete financial information is available.

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

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

Note 11 Operating Segments and Geographic Data - Continued

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

	Year ended December 31		
	2011	2010	2009
Segment Earnings			
Upstream			
United States	**$ 6,512**	$ 4,122	$ 2,262
International	**18,274**	13,555	8,670
Total Upstream	**24,786**	17,677	10,932
Downstream			
United States	**1,506**	1,339	(121)
International	**2,085**	1,139	594
Total Downstream	**3,591**	2,478	473
Total Segment Earnings	**28,377**	20,155	11,405
All Other			
Interest expense		(41)	(22)
Interest income	**78**	70	46
Other	**(1,560)**	(1,160)	(946)
Net Income Attributable to Chevron Corporation	**$ 26,895**	$ 19,024	$ 10,483

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2011 and 2010 are as follows:

	At December 31	
	2011	2010
Upstream		
United States	**$ 37,108**	$ 26,319
International	**98,540**	89,306
Goodwill	**4,642**	4,617
Total Upstream	**140,290**	120,242
Downstream		
United States	**22,182**	21,406
International	**20,517**	20,559
Total Downstream	**42,699**	41,965

Total Segment Assets	**182,989**	162,207
All Other*		
United States	**8,824**	11,125
International	**17,661**	11,437
Total All Other	**26,485**	22,562
Total Assets United States	**68,114**	58,850
Total Assets International	**136,718**	121,302
Goodwill	**4,642**	4,617
Total Assets	**$ 209,474**	$ 184,769

* All Other assets consist primarily of worldwide cash, cash equivalents, time deposits and marketable securities, real estate, energy services, 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 2011, 2010 and 2009, are presented in the table that follows. 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 manufacture and sale of additives for fuels and lubricant oils and the transportation and trading of refined products, crude oil and natural gas liquids. All Other activities include revenues from mining operations, power generation businesses, insurance operations, real estate activities, energy services, alternative fuels 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 2011, 2010 and 2009.

		Year ended December 31	
	2011	2010	2009*
Upstream			
United States	**$ 9,623**	$ 10,316	$ 9,225
Intersegment	**18,115**	13,839	10,297
Total United States	**27,738**	24,155	19,522
International	**20,086**	17,300	13,463
Intersegment	**35,012**	23,834	18,477
Total International	**55,098**	41,134	31,940
Total Upstream	**82,836**	65,289	51,462
Downstream			
United States	**86,793**	70,436	58,056
Excise and similar taxes	**4,199**	4,484	4,573
Intersegment	**86**	115	98

Total United States	**91,078**	75,035	62,727
International	**119,254**	90,922	77,845
Excise and similar taxes	**3,886**	4,107	3,536
Intersegment	**81**	93	87
Total International	**123,221**	95,122	81,468
Total Downstream	**214,299**	170,157	144,195
All Other			
United States	**526**	610	665
Intersegment	**1,072**	947	964
Total United States	**1,598**	1,557	1,629
International	**4**	23	39
Intersegment	**42**	39	33
Total International	**46**	62	72
Total All Other	**1,644**	1,619	1,701
Segment Sales and Other Operating Revenues			
United States	**120,414**	100,747	83,878
International	**178,365**	136,318	113,480
Total Segment Sales and Other Operating Revenues	**298,779**	237,065	197,358
Elimination of intersegment sales	**(54,408)**	(38,867)	(29,956)
Total Sales and Other Operating Revenues	**$ 244,371**	$ 198,198	$ 167,402

*2009 conformed with 2010 and 2011 presentation.

Note 11 Operating Segments and Geographic Data - Continued

Segment Income Taxes Segment income tax expense for the years 2011, 2010 and 2009 is as follows:

	Year ended December 31		
	2011	2010	2009
Upstream			
United States	**$ 3,701**	$ 2,285	$ 1,251
International	**16,743**	10,480	7,451
Total Upstream	**20,444**	12,765	8,702
Downstream			
United States	**785**	680	(83)
International	**416**	462	463
Total Downstream	**1,201**	1,142	380
All Other	**(1,019)**	(988)	(1,117)
Total Income Tax Expense	**$ 20,626**	$ 12,919	$ 7,965

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page FS-39. Information related to properties, plant and equipment by segment is contained in Note 13, on page FS-41.

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 following table. 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		
	2011	2010	**2011**	2010	2009
Upstream					
Tengizchevroil	**$ 5,306**	$ 5,789	**$ 5,097**	$ 3,398	$ 2,216
Petropiar	**909**	973	**116**	262	122
Caspian Pipeline Consortium	**1,094**	974	**122**	124	105
Petroboscan	**1,032**	937	**247**	222	171
Angola LNG Limited	**2,921**	2,481	**(42)**	(21)	(12)
Other	**2,420**	1,922	**166**	319	287
Total Upstream	**13,682**	13,076	**5,706**	4,304	2,889

Downstream					
GS Caltex Corporation	**2,572**	2,496	**248**	158	(191)
Chevron Phillips Chemical Company LLC	**2,909**	2,419	**985**	704	328
Star Petroleum Refining Company Ltd.	**1,022**	947	**75**	122	(4)
Caltex Australia Ltd.	**819**	767	**117**	101	11
Colonial Pipeline Company				43	51
Other	**630**	602	**183**	151	149
Total Downstream	**7,952**	7,231	**1,608**	1,279	344
All Other					
Other	**516**	509	**49**	54	83
Total equity method	**$ 22,150**	$ 20,816	**$ 7,363**	$ 5,637	$ 3,316
Other at or below cost	**718**	704			
Total investments and advances	**$ 22,868**	$ 21,520			
Total United States	**$ 4,847**	$ 3,769	**$ 1,119**	$ 846	$ 511
Total International	**$ 18,021**	$ 17,751	**$ 6,244**	$ 4,791	$ 2,805

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, 2011, the company s carrying value of its investment in TCO was about $180 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-33, for summarized financial information for 100 percent of TCO.

Note 12 Investments and Advances - Continued

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, 2011, the company s carrying value of its investment in Petropiar was approximately $180 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.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, a variable interest entity, which provides the critical export route for crude oil from both TCO and Karachaganak. The company joined the consortium in 1997 and has investments and advances totaling $1,094 which includes long-term loans of $l,111 at year-end 2011. The loans were provided to fund 30 percent of the initial pipeline construction. The company is not the primary beneficiary of the consortium because it does not direct activities of the consortium and only receives its proportionate share of the financial returns.

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, 2011, the company s carrying value of its investment in Petroboscan was approximately $220 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.

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

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. PTT Public Company Limited 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, 2011, the fair value of Chevron s share of CAL common stock was approximately $1,600.

Other Information Sales and other operating revenues on the Consolidated Statement of Income includes $20,164, $13,672 and $10,391 with affiliated companies for 2011, 2010 and 2009, respectively. Purchased crude oil and products includes $7,489, $5,559 and $4,631 with affiliated companies for 2011, 2010 and 2009, respectively.

Accounts and notes receivable on the Consolidated Balance Sheet includes $1,968 and $1,718 due from affiliated companies at December 31, 2011 and 2010, respectively. Accounts payable includes $519 and $377 due to affiliated companies at December 31, 2011 and 2010, 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 $957, $1,543 and $2,422 at December 31, 2011, 2010 and 2009, respectively.

			Affiliates			Chevron Share
Year ended December 31	**2011**	2010	2009	**2011**	2010	2009
Total revenues	**$ 140,107**	$ 107,505	$ 81,995	**$ 68,632**	$ 52,088	$ 39,280

Income before income tax expense	**23,054**	18,468	11,083	**10,555**	7,966	4,511
Net income attributable to affiliates	**16,663**	12,831	8,261	**7,413**	5,683	3,285
At December 31						
Current assets	**$ 35,573**	$ 30,335	$ 27,111	**$ 14,695**	$ 12,845	$ 11,009
Noncurrent assets	**61,855**	57,491	55,363	**22,422**	21,401	21,361
Current liabilities	**24,671**	20,428	17,450	**11,040**	9,363	7,833
Noncurrent liabilities	**19,267**	19,749	21,531	**4,491**	4,459	5,106
Total affiliates net equity	**$ 53,490**	$ 47,649	$ 43,493	**$ 21,586**	$ 20,424	$ 19,431

Note 13

Properties, Plant and Equipment[1]

	At December 31									Year ended Decemb		
	Gross Investment at Cost			Net Investment			Additions at Cost[2,3]			Depreciation Expe		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	
ream												
d States	**$ 74,369**	$ 62,523	$ 58,328	**$ 33,461**	$ 23,277	$ 22,273	**$ 14,404**	$ 4,934	$ 3,518	**$ 3,870**	$ 4,078	$ 3
ational	**125,795**	110,578	96,557	**72,543**	64,388	57,450	**15,722**	14,381	10,803	**7,590**	7,448	6
ream	**200,164**	173,101	154,885	**106,004**	87,665	79,723	**30,126**	19,315	14,231	**11,460**	11,526	10
nstream												
d States	**20,699**	19,820	18,962	**10,723**	10,379	10,032	**1,226**	1,199	1,874	**776**	741	
ational	**7,422**	9,697	9,852	**2,995**	3,948	4,154	**443**	361	456	**332**	451	
nstream	**28,121**	29,517	28,814	**13,718**	14,327	14,186	**1,669**	1,560	2,330	**1,108**	1,192	1
ther[5]												
d States	**5,117**	4,722	4,569	**2,872**	2,496	2,548	**591**	259	354	**338**	341	
ational	**30**	27	20	**14**	16	11	**5**	11	3	**5**	4	
All												
r	**5,147**	4,749	4,589	**2,886**	2,512	2,559	**596**	270	357	**343**	345	
United												
s	**100,185**	87,065	81,859	**47,056**	36,152	34,853	**16,221**	6,392	5,746	**4,984**	5,160	4
ational	**133,247**	120,302	106,429	**75,552**	68,352	61,615	**16,170**	14,753	11,262	**7,927**	7,903	7
	$ 233,432	$ 207,367	$ 188,288	**$ 122,608**	$ 104,504	$ 96,468	**$ 32,391**	$ 21,145	$ 17,008	**$ 12,911**	$ 13,063	$ 12

[1] Other than the United States, Nigeria and Australia, no other country accounted for 10 percent or more of the company s net properties, plant and equipment (PP&E) in 2011. Nigeria had PP&E of $15,601, $13,896 and $12,463 for 2011, 2010 and 2009, respectively. Australia had $12,423 in 2011.

[2] Net of dry hole expense related to prior years expenditures of $45, $82 and $84 in 2011, 2010 and 2009, respectively.

[3] Includes properties acquired with the acquisition of Atlas Energy, Inc. in 2011.

[4] Depreciation expense includes accretion expense of $628, $513 and $463 in 2011, 2010 and 2009, respectively.

[5] 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 eight 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 given to Texpet by the Republic of Ecuador and Petroecuador and by the pertinent provincial and municipal governments. With regard to the facts, the company believes that the evidence confirms that Texpet s remediation was properly conducted and that the

Note 14 Litigation - Continued

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 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 $18,900, 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 $8,400 could be assessed against Chevron for unjust enrichment. In 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 was recused. In 2010, Chevron moved to strike the mining engineer s report and to dismiss the case based on evidence obtained through discovery in the United States indicating that the report was prepared by consultants for the plaintiffs before being presented as the mining engineer s independent and impartial work and showing further evidence of misconduct. In August 2010, the judge issued an order stating that he was not bound by the mining engineer s report and requiring the parties to provide their positions on damages within 45 days. Chevron subsequently petitioned for recusal of the judge, claiming that he had disregarded evidence of fraud and misconduct and that he had failed to rule on a number of motions within the statutory time requirement.

In September 2010, Chevron submitted its position on damages, asserting that no amount should be assessed against it. The plaintiffs submission, which relied in part on the mining engineer s report, took the position that damages are between approximately $16,000 and $76,000 and that unjust enrichment should be assessed in an amount between approximately $5,000 and $38,000. The next day, the judge issued an order closing the evidentiary phase of the case and notifying the parties that he had requested the case file so that he could prepare a judgment. Chevron petitioned to have that order declared a nullity in light of Chevron s prior recusal petition, and because procedural and evidentiary matters remained unresolved. In October 2010, Chevron s motion to recuse the judge was granted. A new judge took charge of the case and revoked the prior judge s order closing the evidentiary phase of the case. On December 17, 2010, the judge issued an order closing the evidentiary phase of the case and notifying the parties that he had requested the case file so that he could prepare a judgment.

On February 14, 2011, the provincial court in Lago Agrio rendered an adverse judgment in the case. The court rejected Chevron s defenses to the extent the court addressed them in its opinion. The judgment assessed approximately $8,600 in damages and approximately $900 as an award for the plaintiffs representatives. It also assessed an additional amount of approximately $8,600 in punitive damages unless the company issued a public apology within 15 days of the judgment, which Chevron did not do. On February 17, 2011, the plaintiffs appealed the judgment, seeking increased damages, and on March 11, 2011, Chevron appealed the judgment seeking to have the judgment nullified. On January 3, 2012, an appellate panel in the provincial court affirmed the February 14, 2011 decision and ordered that Chevron pay additional attorneys fees in the amount of .10% of the values that are derived from the decisional act of this judgment. The plaintiffs filed a petition to clarify and amplify the appellate decision on January 6, 2012, and the court issued a ruling in response on January 13, 2012, purporting to clarify and amplify its January 3, 2012 ruling, which included clarification that the deadline for the company to issue a public apology to avoid the additional amount of approximately $8,600 in punitive damages was within fifteen days of the clarification ruling, or February 3, 2012. Chevron did not issue an apology because doing so might be mischaracterized as an admission of liability and would be contrary to facts and evidence submitted at trial. On January 20, 2012, Chevron appealed (called a petition for cassation) the appellate panel s decision to Ecuador s National Court of Justice. As part of the appeal, Chevron requested the suspension of any requirement that Chevron post a bond to prevent enforcement under Ecuadorian law of the judgment during the cassation appeal. On February 17, 2012, the appellate panel of the provincial court admitted Chevron s cassation appeal in a procedural step necessary for the National Court of Justice to hear the appeal. The provincial court appellate panel denied Chevron s request for a suspension of the requirement that Chevron post a bond and stated that it would not comply with the first Interim Award of the international arbitration tribunal discussed below. Chevron continues to believe the provincial court s judgment is illegitimate and unenforceable in Ecuador, the United States and other countries. The company also believes the judgment is the product of fraud, and contrary to the legitimate scientific evidence. Chevron cannot predict the timing or ultimate outcome of the appeals process in Ecuador. Chevron will continue a vigorous defense of any imposition of liability. Chevron has no assets in Ecuador and the Lago Agrio plaintiffs lawyers have stated in press releases and through other media that they will seek to enforce the Ecuadorian judgement in various countries and otherwise disrupt Chevron s operations. Chevron expects to contest and defend against any such actions.

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before an arbitral tribunal presiding in the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador s obligations under the United States Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador s obligations under the BIT. On February 9, 2011, the Tribunal issued an Order for Interim Measures requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. On January 25, 2012, the Tribunal converted the Order for Interim Measures into an Interim Award. Chevron filed a renewed application for further interim measures on January 4, 2012, and the Republic of Ecuador opposed Chevron s application and requested that the existing Order for Interim Measures be vacated on January 9, 2012. On February 16, 2012, the Tribunal issued a second Interim Award mandating that the Republic of Ecuador take all measures necessary (whether by its judicial, legislative or executive branches) to suspend or cause to be suspended the enforcement and recognition within and without Ecuador of the judgment against Chevron and, in particular, to preclude any certification by the Republic of Ecuador that would cause the judgment to be enforceable against Chevron. Chevron expects to continue seeking permanent injunctive relief and monetary relief before the Tribunal.

Through a series of recent U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron has obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters, alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron is seeking relief that includes an award of damages and a declaration that any judgment against Chevron in the Lago Agrio
litigation is the result of fraud and other unlawful conduct and is therefore unenforceable. On March 7, 2011, the Federal District Court issued a preliminary injunction prohibiting the Lago Agrio plaintiffs and persons acting in concert with them from taking any action in furtherance of recognition or enforcement of any judgment against Chevron in the Lago Agrio case pending resolution of Chevron s civil lawsuit by the Federal District Court. On May 31, 2011, the Federal District Court severed claims one through eight of Chevron s complaint from the ninth claim for declaratory relief and imposed a discovery stay on claims one through eight pending a trial on the ninth claim for declaratory relief. On September 19, 2011, the U.S. Court of Appeals for the Second Circuit vacated the preliminary injunction, stayed the trial on Chevron s ninth claim, a claim for declaratory relief, that had been set for November 14, 2011, and denied the defendants mandamus petition to recuse the judge hearing the lawsuit. The Second Circuit issued its opinion on January 26, 2012 ordering the dismissal of Chevron s ninth claim for declaratory relief. On February 16, 2012, the Federal District Court lifted the stay on claims one through eight.

The ultimate outcome of the foregoing matters, including 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 Ecuadorian judgment, the 2008 engineer s report on alleged damages and the September 2010 plaintiffs submission on alleged damages, management does not believe these documents have 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		
	2011	2010	2009
Taxes on income			
U.S. Federal			
Current	**$ 1,893**	$ 1,501	$ 128
Deferred	**877**	162	(147)
State and local			
Current	**596**	376	216
Deferred	**41**	20	14
Total United States	**3,407**	2,059	211
International			
Current	**16,548**	10,483	7,154
Deferred	**671**	377	600
Total International	**17,219**	10,860	7,754
Total taxes on income	**$ 20,626**	$ 12,919	$ 7,965

In 2011, before-tax income for U.S. operations, including related corporate and other charges, was $10,222, compared

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

Note 15 Taxes - Continued

with before-tax income of $6,528 and $1,310 in 2010 and 2009, respectively. For international operations, before-tax income was $37,412, $25,527 and $17,218 in 2011, 2010 and 2009, respectively. U.S. federal income tax expense was reduced by $191, $162 and $204 in 2011, 2010 and 2009, 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 detailed in the following table:

	Year ended December 31		
	2011	2010	2009
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	**7.5**	5.2	10.4
State and local taxes on income, net of U.S. federal income tax benefit	**0.9**	0.8	0.9
Prior year tax adjustments	**(0.1)**	(0.6)	(0.3)
Tax credits	**(0.4)**	(0.5)	(1.1)
Effects of changes in tax rates	**0.5**		0.1
Other	**(0.1)**	0.4	(2.0)
Effective tax rate	**43.3%**	40.3%	43.0%

The company s effective tax rate increased from 40.3 percent in 2010 to 43.3 percent in 2011. This increase primarily reflected higher effective tax rates in international upstream jurisdictions. The higher international upstream effective tax rates were driven primarily by lower utilization of non-U.S. tax credits in 2011 and the effect of changes in income tax rates between periods, which were partially offset by foreign currency remeasurement impacts between periods.

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	
	2011	2010
Deferred tax liabilities		
Properties, plant and equipment	**$ 23,597**	$ 19,855
Investments and other	**2,271**	2,401
Total deferred tax liabilities	**25,868**	22,256
Deferred tax assets		
Foreign tax credits	**(8,476)**	(6,669)
Abandonment/environmental reserves	**(5,387)**	(5,004)
Employee benefits	**(4,773)**	(3,627)
Deferred credits	**(1,548)**	(2,176)
Tax loss carryforwards	**(828)**	(882)

Other accrued liabilities	**(531)**	(486)
Inventory	**(360)**	(483)
Miscellaneous	**(1,595)**	(1,676)
Total deferred tax assets	**(23,498)**	(21,003)
Deferred tax assets valuation allowance	**11,096**	9,185
Total deferred taxes, net	**$ 13,466**	$ 10,438

Deferred tax liabilities at the end of 2011 increased by approximately $3,600 from year-end 2010. The increase was related to increased temporary differences for property, plant and equipment.

Deferred tax assets increased by approximately $2,500 in 2011. Increases primarily related to additional foreign tax credits arising from earnings in high-tax-rate international jurisdictions (which were substantially offset by valuation allowances) and to increased temporary differences for employee benefits. These effects were partially offset by reductions in deferred credits resulting primarily 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. At the end of 2011, tax loss carryforwards were approximately $2,160, primarily related to various international tax jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2012 through 2036. Foreign tax credit carryforwards of $8,476 will expire between 2012 and 2021.

At December 31, 2011 and 2010, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2011	2010
Prepaid expenses and other current assets	**$ (1,149)**	$ (1,624)
Deferred charges and other assets	**(1,224)**	(851)
Federal and other taxes on income	**295**	216
Noncurrent deferred income taxes	**15,544**	12,697
Total deferred income taxes, net	**$ 13,466**	$ 10,438

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 $24,376 at December 31, 2011. 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 possible remittance of earnings that are intended to be reinvested indefinitely. At the end of 2011, deferred income taxes were recorded for the undistributed earnings of certain international operations where indefinite reinvestment of the earnings is not planned. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

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Note 15 Taxes - Continued

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 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.

The following table indicates the changes to the company s unrecognized tax benefits for the years ended December 31, 2011, 2010 and 2009. The term unrecognized tax benefits in the accounting standards for income taxes 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.

	2011	2010	2009
Balance at January 1	**$ 3,507**	$ 3,195	$ 2,696
Foreign currency effects	**(2)**	17	(1)
Additions based on tax positions taken in current year	**469**	334	459
Reductions based on tax positions taken in current year			
Additions/reductions resulting from current-year asset acquisitions/sales	**(41)**		
Additions for tax positions taken in prior years	**236**	270	533
Reductions for tax positions taken in prior years	**(366)**	(165)	(182)
Settlements with taxing authorities in current year	**(318)**	(136)	(300)
Reductions as a result of a lapse of the applicable statute of limitations	**(4)**	(8)	(10)
Balance at December 31	**$ 3,481**	$ 3,507	$ 3,195

Approximately 80 percent of the $3,481 of unrecognized tax benefits at December 31, 2011, would have an impact on the effective tax rate if subsequently recognized. Certain of these unrecognized tax benefits relate to tax carryforwards that may require a full valuation allowance at the time of any such recognition.

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, 2011. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States 2007, Nigeria 2000, Angola 2001, Saudi Arabia 2003 and Kazakhstan 2005.

The company engages in ongoing discussions with tax authorities regarding the resolution of tax matters in the various jurisdictions. Both the outcome of these tax matters and the timing of resolution and/or closure of the tax audits are highly uncertain. However, it is reasonably possible that developments on tax matters in certain tax jurisdictions may result in significant increases or decreases in the company s total unrecognized tax benefits within the next 12 months. Given the number of years that still remain subject to examination and the number of matters being examined in the various tax jurisdictions, the company is unable to estimate the range of possible adjustments to the balance of unrecognized tax benefits.

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, 2011, accruals of $118 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $225 as of year-end 2010. Income tax expense (benefit) associated with interest and penalties was $(64), $40 and $(20) in 2011, 2010 and 2009, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2011	2010	2009
United States			
Excise and similar taxes on products and merchandise	**$ 4,199**	$ 4,484	$ 4,573
Import duties and other levies	**4**		(4)
Property and other miscellaneous taxes	**726**	567	584
Payroll taxes	**236**	219	223
Taxes on production	**308**	271	135
Total United States	**5,473**	5,541	5,511
International			
Excise and similar taxes on products and merchandise	**3,886**	4,107	3,536
Import duties and other levies	**3,511**	6,183	6,550
Property and other miscellaneous taxes	**2,354**	2,000	1,740
Payroll taxes	**148**	133	134
Taxes on production	**256**	227	120
Total International	**10,155**	12,650	12,080
Total taxes other than on income	**$ 15,628**	$ 18,191	$ 17,591

Note 16
Short-Term Debt

	At December 31	
	2011	2010
Commercial paper*	**$ 2,498**	$ 2,471
Notes payable to banks and others with originating terms of one year or less	**40**	43
Current maturities of long-term debt	**17**	33
Current maturities of long-term capital leases	**54**	81
Redeemable long-term obligations		
Long-term debt	**3,317**	2,943
Capital leases	**14**	16
Subtotal	**5,940**	5,587
Reclassified to long-term debt	**(5,600)**	(5,400)
Total short-term debt	**$ 340**	$ 187

* Weighted-average interest rates at December 31, 2011 and 2010, were 0.04 percent and 0.16 percent, respectively.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date. In 2011, $374 of tax-exempt bonds related to projects at the Pascagoula, Mississippi, refinery were issued.

The company may periodically enter into interest rate swaps on a portion of its short-term debt. At December 31, 2011, the company had no interest rate swaps on short-term debt.

At December 31, 2011, the company had $6,000 in committed credit facilities with various major banks, expiring in December 2016, that enable the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and can also be used for general corporate purposes. The company s practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company s strong credit rating. No borrowings were outstanding under these facilities at December 31, 2011.

At December 31, 2011 and 2010, the company classified $5,600 and $5,400, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital within one year, as the company has both the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Note 17
Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2011, was $9,684. The company s long-term debt outstanding at year-end 2011 and 2010 was as follows:

	At December 31	
	2011	2010
3.95% notes due 2014	**$ 1,998**	$ 1,998
3.45% notes due 2012		1,500
4.95% notes due 2019	**1,500**	1,500
8.625% debentures due 2032	**147**	147
8.625% debentures due 2031	**107**	107
7.5% debentures due 2043	**83**	83
8% debentures due 2032	**74**	74
7.327% amortizing notes due 2014[1]	**59**	72
9.75% debentures due 2020	**54**	54
8.875% debentures due 2021	**40**	40
Medium-term notes, maturing from 2021 to 2038 (6.02%)[2]	**38**	38
Fixed interest rate notes, maturing 2011 (9.378%)[2]		19
Other long-term debt (8.07%)[2]	**1**	4
Total including debt due within one year	**4,101**	5,636
Debt due within one year	**(17)**	(33)
Reclassified from short-term debt	**5,600**	5,400
Total long-term debt	**$ 9,684**	$ 11,003

1 Guarantee of ESOP debt.

2 Weighted-average interest rate at December 31, 2011 and 2010.

In March 2010, the company filed with the SEC an automatic registration statement that expires on February 28, 2013. This registration statement is for an unspecified amount of non-convertible debt securities issued or guaranteed by the company.

Long-term debt of $4,101 matures as follows: 2012 $17; 2013 $20; 2014 $2,021; 2015 - $0; 2016 $0; and after 2016 $2,043.

In September 2011, $1,500 of Chevron Corp. bonds were redeemed early. In June 2010, $30 of Texaco Capital Inc. bonds matured.

See Note 9, beginning on page FS-34, for information concerning the fair value of the company s long-term debt.

Note 18

New Accounting Standards

Fair Value Measurement (Topic 820), Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU 2011-04) In May 2011, the FASB issued ASU 2011-04, which becomes effective for the company on January 1, 2012. The amendments in ASU 2011-04 result in common fair value measurement and disclosure requirements in U.S. GAAP and IFRS. As a result of these amendments, the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements were changed. The company does not anticipate changes to its existing classification and measurement of fair value when the amended standard becomes effective. However, the company s disclosures on certain items not required to be measured at fair value are expected to be expanded when the amended standard becomes effective.

Comprehensive Income (Topic 220) Presentation of Comprehensive Income (ASU 2011-05) The FASB issued ASU 2011-05 in June 2011. This standard becomes effective for the company on January 1, 2012. ASU 2011-05 changes the presentation requirements for comprehensive income. Adoption of the standard is not expected to have a significant impact on the company s current financial statement presentation.

Intangibles Goodwill and Other (Topic 350) Testing Goodwill for Impairment (ASU 2011-08) In September 2011, the FASB issued ASU 2011-08, which becomes effective for the company on January 1, 2012. The standard simplifies how companies test goodwill for impairment. The company does not anticipate any impact to its results of operations, financial position or liquidity when the guidance becomes effective.

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 entity 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. (Note that an entity is not required to complete the exploratory well as a producing well.) 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, 2011:

	2011	2010	2009
Beginning balance at January 1	**$ 2,718**	$ 2,435	$ 2,118
Additions to capitalized exploratory well costs pending the determination of proved reserves	**652**	482	663
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(828)**	(129)	(174)
Capitalized exploratory well costs charged to expense	**(45)**	(70)	(172)
Other reductions*	**(63)**		
Ending balance at December 31	**$ 2,434**	$ 2,718	$ 2,435

* Represents property sales.

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		
	2011	2010	2009
Exploratory well costs capitalized for a period of one year or less	**$ 557**	$ 419	$ 564
Exploratory well costs capitalized for a period greater than one year	**1,877**	2,299	1,871
Balance at December 31	**$ 2,434**	$ 2,718	$ 2,435
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**47**	53	46

* Certain projects have multiple wells or fields or both.

Of the $1,877 of exploratory well costs capitalized for more than one year at December 31, 2011, $939 (26 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $938 balance is related to 21 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the $938 referenced above had the following activities associated with assessing the reserves and the projects economic viability: (a) $322 (six projects) development alternatives under review; (b) $283 (five projects) development concept under review by government; (c) $208 (seven projects) undergoing front-end engineering and design with final investment decision expected within three years; (d) $111 (one project) project sanction approved and

Note 19 Accounting for Suspended Exploratory Wells - Continued

construction is in progress, with initial recognition of proved reserves expected upon reaching economic producibility per SEC guidelines; (e) $14 miscellaneous activities for two projects with smaller amounts suspended. While progress was being made on all 47 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 $1,877 of suspended well costs capitalized for a period greater than one year as of December 31, 2011, represents 161 exploratory wells in 47 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
1997 2000	$ 49	16
2001 2005	396	47
2006 2010	1,432	98
Total	$ 1,877	161

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
1999	$ 8	1
2003 2006	345	10
2007 2011	1,524	36
Total	$ 1,877	47

Note 20
Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2011, 2010 and 2009 was $265 ($172 after tax), $229 ($149 after tax) and $182 ($119 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was $214 ($139 after tax), $194 ($126 after tax) and $170 ($110 after tax) for 2011, 2010 and 2009, respectively. No significant stock-based compensation cost was capitalized at December 31, 2011 and 2010.

Cash received in payment for option exercises under all share-based payment arrangements for 2011, 2010 and 2009 was $948, $385 and $147, respectively. Actual tax benefits realized for the tax deductions from option exercises were $121, $66 and $25 for 2011, 2010 and 2009, respectively.

Cash paid to settle performance units and stock appreciation rights was $151, $140 and $89 for 2011, 2010 and 2009, 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. For the major types of awards outstanding as of December 31, 2011, the contractual terms vary between three years for the performance units and 10 years for the stock options and stock appreciation rights.

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 had 10-year contractual lives extending into 2011, retained a provision for being restored. This provision enabled a participant who exercised a stock option to receive new options equal to the number of shares exchanged or who had shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options were fully exercisable six months after the date of grant, and the exercise price was the market value of the common stock on the day the restored option was 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. Unexercised awards began expiring in early 2010 and will continue to expire through early 2015.

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

The fair market values of stock options and stock appreciation rights granted in 2011, 2010 and 2009 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2011	2010	2009
Stock Options			
Expected term in years[1]	**6.2**	6.1	6.0
Volatility[2]	**31.0%**	30.8%	30.2%
Risk-free interest rate based on zero coupon U.S. treasury note	**2.6%**	2.9%	2.1%
Dividend yield	**3.6%**	3.9%	3.2%
Weighted-average fair value per option granted	**$ 21.24**	$ 16.28	$ 15.36
Restored Options			
Expected term in years[1]	**1.2**	1.2	1.2
Volatility[2]	**20.6%**	38.9%	45.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**0.7%**	0.6%	1.1%
Dividend yield	**3.4%**	3.8%	3.5%
Weighted-average fair value per option granted	**$ 7.55**	$ 12.91	$ 12.38

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 2011 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2011	74,852	$ 67.04		
Granted	14,260	$ 94.46		
Exercised	(15,844)	$ 60.20		
Restored	33	$ 103.96		
Forfeited	(953)	$ 85.79		
Outstanding at December 31, 2011	72,348	$ 73.71	6.4 yrs	$ 2,365
Exercisable at December 31, 2011	45,494	$ 67.84	5.3 yrs	$ 1,755

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2011, 2010 and 2009 was $668, $259 and $91, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2011, there was $265 of total unrecognized before-tax compensation cost related to non-vested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 1.7 years.

At January 1, 2011, the number of LTIP performance units outstanding was equivalent to 2,727,874 shares. During 2011, 1,011,200 units were granted, 810,071 units vested with cash proceeds distributed to recipients and 47,167 units were forfeited. At December 31, 2011, units outstanding were 2,881,836, and the fair value of the liability recorded for these instruments was $294. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 2.2 million equivalent shares as of December 31, 2011. A liability of $62 was recorded for these awards.

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 each 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 plans as an asset or liability on the Consolidated Balance Sheet.

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

Note 21 Employee Benefit Plans - Continued

The funded status of the company s pension and other postretirement benefit plans for 2011 and 2010 follows:

	Pension Benefits				Other Benefits	
	2011		2010			
	U.S.	Int l.	U.S.	Int l.	**2011**	2010
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 10,271**	**$ 5,070**	$ 9,664	$ 4,715	**$ 3,605**	$ 3,065
Service cost	**374**	**174**	337	153	**58**	39
Interest cost	**463**	**325**	486	307	**180**	175
Plan participants contributions		**6**		7	**148**	147
Plan amendments		**27**				12
Actuarial loss (gain)	**1,920**	**318**	568	200	**149**	486
Foreign currency exchange rate changes		**(98)**		(17)	**(19)**	11
Benefits paid	**(863)**	**(303)**	(784)	(295)	**(346)**	(330)
Curtailment					**(10)**	
Benefit obligation at December 31	**12,165**	**5,519**	10,271	5,070	**3,765**	3,605
Change in Plan Assets						
Fair value of plan assets at January 1	**8,579**	**3,503**	7,304	3,235		
Actual return on plan assets	**(143)**	**118**	867	361		
Foreign currency exchange rate changes		**(66)**		(63)		
Employer contributions	**1,147**	**319**	1,192	258	**198**	183
Plan participants contributions		**6**		7	**148**	147
Benefits paid	**(863)**	**(303)**	(784)	(295)	**(346)**	(330)
Fair value of plan assets at December 31	**8,720**	**3,577**	8,579	3,503		
Funded Status at December 31	**$ (3,445)**	**$ (1,942)**	$ (1,692)	$ (1,567)	**$ (3,765)**	$ (3,605)

Amounts recognized on the Consolidated Balance Sheet for the company s pension and other postretirement benefit plans at December 31, 2011 and 2010, include:

	Pension Benefits				Other Benefits	
	2011		2010			
	U.S.	Int l.	U.S.	Int l.	**2011**	2010
Deferred charges and other assets	**$ 5**	**$ 116**	$ 7	$ 77	**$**	$

Accrued liabilities	**(72)**	**(84)**	(134)	(71)	**(222)**	(225)
Reserves for employee benefit plans	**(3,378)**	**(1,974)**	(1,565)	(1,573)	**(3,543)**	(3,380)
Net amount recognized at December 31	**$ (3,445)**	**$ (1,942)**	$ (1,692)	$ (1,567)	**$ (3,765)**	$ (3,605)

Amounts recognized on a before-tax basis in Accumulated other comprehensive loss for the company s pension and OPEB plans were $9,279 and $6,749 at the end of 2011 and 2010, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2011		2010			
	U.S.	Int l.	U.S.	Int l.	**2011**	2010
Net actuarial loss	**$ 5,982**	**$ 2,250**	$ 3,919	$ 1,903	**$ 1,002**	$ 935
Prior service (credit) costs	**(44)**	**152**	(52)	179	**(63)**	(135)
Total recognized at December 31	**$ 5,938**	**$ 2,402**	$ 3,867	$ 2,082	**$ 939**	$ 800

The accumulated benefit obligations for all U.S. and international pension plans were $11,198 and $4,518, respectively, at December 31, 2011, and $9,535 and $4,161, respectively, at December 31, 2010.

Note 21 Employee Benefit Plans - Continued

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2011 and 2010, was:

	Pension Benefits			
		2011		2010
	U.S.	Int l.	U.S.	Int l.
Projected benefit obligations	**$ 12,157**	**$ 4,207**	$ 10,265	$ 3,668
Accumulated benefit obligations	**11,191**	**3,586**	9,528	3,113
Fair value of plan assets	**8,707**	**2,357**	8,566	2,190

The components of net periodic benefit cost and amounts recognized in other comprehensive income for 2011, 2010 and 2009 are shown in the table below:

	Pension Benefits						Other Benefits		
	2011		2010		2009				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2011**	2010	2009
Net Periodic Benefit Cost									
Service cost	**$ 374**	**$ 174**	$ 337	$ 153	$ 266	$ 128	**$ 58**	$ 39	$ 43
Interest cost	**463**	**325**	486	307	481	292	**180**	175	180
Expected return on plan assets	**(613)**	**(283)**	(538)	(241)	(395)	(203)			
Amortization of prior service (credits) costs	**(8)**	**19**	(8)	22	(7)	23	**(72)**	(75)	(81)
Recognized actuarial losses	**310**	**101**	318	98	298	108	**64**	27	27
Settlement losses	**298**		186	6	141	1			
Curtailment losses (gains)		**35**					**(10)**		(5)
Total net periodic benefit cost	**824**	**371**	781	345	784	349	**220**	166	164
Changes Recognized in Other Comprehensive Income									
Net actuarial loss during period	**2,671**	**448**	242	118	823	194	**131**	497	82
Amortization of actuarial loss	**(608)**	**(101)**	(504)	(104)	(439)	(109)	**(64)**	(27)	(27)
Prior service cost during period		**27**			1	13		12	20
Amortization of prior service credits (costs)	**8**	**(54)**	8	(22)	7	(23)	**72**	75	81
Total changes recognized in other comprehensive income	**2,071**	**320**	(254)	(8)	392	75	**139**	557	156
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 2,895**	**$ 691**	$ 527	$ 337	$ 1,176	$ 424	**$ 359**	$ 723	$ 320

Net actuarial losses recorded in Accumulated other comprehensive loss at December 31, 2011, for the company s U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 10, 12 and eight 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 2012, the company estimates actuarial losses of $476, $142 and $75 will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and
OPEB plans, respectively. In addition, the company estimates an additional $260 will be recognized from Accumulated other comprehensive loss during 2012 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, 2011, was approximately six and seven years for U.S. and international pension plans, respectively, and two years for other postretirement benefit plans. During 2012, the company estimates prior service (credits) costs of $(8), $21 and $(72) 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		
	2011		2010		2009				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2011**	2010	2009
Assumptions used to determine benefit obligations:									
Discount rate	**3.8%**	**5.9%**	4.8%	6.5%	5.3%	6.8%	**4.2%**	5.2%	5.9%
Rate of compensation increase	**4.5%**	**5.7%**	4.5%	6.7%	4.5%	6.3%	**N/A**	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate	**4.8%**	**6.5%**	5.3%	6.8%	6.3%	7.5%	**5.2%**	5.9%	6.3%
Expected return on plan assets	**7.8%**	**7.8%**	7.8%	7.8%	7.8%	7.5%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**6.7%**	4.5%	6.3%	4.5%	6.8%	**N/A**	N/A	N/A

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 70 percent of the company s pension plan assets. At December 31, 2011, 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, 2011, the company selected a 3.8 percent discount rate for the U.S. pension plans and 4.0 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 2011. The discount rates at the end of 2010 and 2009 were 4.8 and 5.3 percent and 5.0 and 5.8 percent for the U.S. pension plans and the U.S. OPEB plan, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2011, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 8 percent in 2012 and gradually decline to 5 percent for 2023 and beyond. For this measurement at December 31, 2010, the assumed health care cost-trend rates started with 8 percent in 2011 and gradually declined to 5 percent for 2018 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	$ 17	$ (15)
Effect on postretirement benefit obligation	$ 177	$ (150)

Plan Assets and Investment Strategy The fair value hierarchy of inputs the company uses to value the pension assets is divided into three levels:

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 through 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.

Note 21 Employee Benefit Plans - Continued

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 2011 and 2010 are below:

	U.S.				Int l.			
	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
At December 31, 2011								
Equities								
U.S.[1]	**$1,470**	**$ 1,470**	**$**	**$**	**$ 497**	**$ 497**	**$**	**$**
International	**1,203**	**1,203**			**693**	**693**		
Collective Trusts/Mutual Funds[2]	**2,633**	**14**	**2,619**		**596**	**28**	**568**	
Fixed Income								
Government	**622**	**146**	**476**		**635**	**25**	**610**	
Corporate	**338**		**338**		**319**	**16**	**276**	**27**
Mortgage-Backed Securities	**107**		**107**		**2**			**2**
Other Asset Backed	**61**		**61**		**5**		**5**	
Collective Trusts/Mutual Funds[2]	**1,046**		**1,046**		**345**	**61**	**284**	
Mixed Funds[3]	**10**	**10**			**102**	**13**	**89**	
Real Estate[4]	**843**			**843**	**155**			**155**
Cash and Cash Equivalents	**404**	**404**			**211**	**211**		
Other[5]	**(17)**	**(79)**	**8**	**54**	**17**	**(2)**	**17**	**2**
Total at December 31, 2011	**$8,720**	**$ 3,168**	**$ 4,655**	**$ 897**	**$ 3,577**	**$ 1,542**	**$ 1,849**	**$ 186**
At December 31, 2010								
Equities								
U.S.[1]	$2,121	$ 2,121	$	$	$ 465	$ 465	$	$
International	1,405	1,405			721	721		
Collective Trusts/Mutual Funds[2]	2,068	5	2,063		578	80	498	
Fixed Income								
Government	659	19	640		568	38	530	
Corporate	314		314		351	24	299	28
Mortgage-Backed Securities	82		82		2			2
Other Asset Backed	74		74		16		16	

Collective Trusts/Mutual Funds[2]	1,064		1,064		332	19	313	
Mixed Funds[3]	9	9			105	16	89	
Real Estate[4]	596			596	142			142
Cash and Cash Equivalents	213	213			217	217		
Other[5]	(26)	(87)	8	53	6	(5)	9	2
Total at December 31, 2010	$8,579	$ 3,685	$ 4,245	$ 649	$ 3,503	$ 1,575	$ 1,754	$ 174

[1] U.S. equities include investments in the company s common stock in the amount of $35 at December 31, 2011, and $38 at December 31, 2010.

[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 partially 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 class includes net payables for securities purchased but not yet settled (Level 1); dividends and interest- and tax-related receivables (Level 2); insurance contracts and investments in private-equity limited partnerships (Level 3).

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Note 21 Employee Benefit Plans - Continued

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

	Fixed Income Corporate	Fixed Income Mortgage-Backed Securities	Real Estate	Other	Total
Total at December 31, 2009	$ 18	$ 2	$ 610	$ 52	$ 682
Actual Return on Plan Assets:					
Assets held at the reporting date	3		34	1	38
Assets sold during the period			1		1
Purchases, Sales and Settlements	7		93	2	102
Transfers in and/or out of Level 3					
Total at December 31, 2010	$ 28	$ 2	$ 738	$ 55	$ 823
Actual Return on Plan Assets:					
Assets held at the reporting date			**103**	**4**	**107**
Assets sold during the period			**1**	**(2)**	**(1)**
Purchases, Sales and Settlements	**(1)**		**156**	**(1)**	**154**
Transfers in and/or out of Level 3					
Total at December 31, 2011	$ **27**	$ **2**	$ **998**	$ **56**	$**1,083**

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 86 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 plans investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has established the following approved asset allocation ranges: Equities 40 70 percent, Fixed Income and Cash 20 65 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 class risk. To mitigate concentration and other risks, assets are invested across multiple asset classes with active investment managers and passive index funds.

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2011, the company contributed $1,147 and $319 to its U.S. and international pension plans, respectively. In 2012, 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 investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment

returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately $223 in 2012, compared with $198 paid in 2011.

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
2012	$ 1,053	$ 268	$ 223
2013	$ 1,043	$ 316	$ 229
2014	$ 1,046	$ 320	$ 234
2015	$ 1,050	$ 344	$ 240
2016	$ 1,062	$ 375	$ 245
2017 2021	$ 5,261	$ 2,153	$ 1,287

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 $263, $253 and $257 in 2011, 2010 and 2009, respectively. This cost was reduced by the value of shares released from the

Note 21 Employee Benefit Plans - Continued

LESOP totaling $38, $97 and $184 in 2011, 2010 and 2009, respectively. The remaining amounts, totaling $225, $156 and $73 in 2011, 2010 and 2009, 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 $1, $1 and $3 in 2011, 2010 and 2009, respectively. The net credit for the respective years was composed of credits to compensation expense of $5, $6 and $15 and charges to interest expense for LESOP debt of $4, $5 and $12.

Of the dividends paid on the LESOP shares, $18, $46 and $110 were used in 2011, 2010 and 2009, respectively, to service LESOP debt. No contributions were required in 2011, 2010 or 2009, as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Shares held in the LESOP are released and allocated to the accounts of plan participants based on debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. LESOP shares as of December 31, 2011 and 2010, were as follows:

Thousands	**2011**	2010
Allocated shares	**19,047**	20,718
Unallocated shares	**1,864**	2,374
Total LESOP shares	**20,911**	23,092

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 2011, 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, 2011 and 2010, trust assets of $51 and $57, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans The Chevron Incentive Plan is an annual cash bonus plan for eligible employees that links awards to corporate, unit and individual performance in the prior year. Charges to expense for cash bonuses were $1,217, $766 and $561 in 2011, 2010 and 2009, respectively. 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, beginning on page FS-48.

Note 22

Equity

Retained earnings at December 31, 2011 and 2010, included approximately $10,127 and $9,159, respectively, for the company s share of undistributed earnings of equity affiliates.

At December 31, 2011, about 67 million shares of Chevron s common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron LTIP. In addition, approximately 258,000 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.

Note 23

Restructuring and Reorganization

In the first quarter 2010, the company announced employee reduction programs related to the restructuring and reorganization of its downstream businesses and corporate staffs. Total terminations under the programs are expected to be approximately 2,700 employees. About 1,300 of the affected employees are located in the United States. About 2,500 employees have been terminated through December 31, 2011, and the programs were substantially completed by the end of 2011. Substantially all of the remaining employees designated for termination under the programs are expected to leave in 2012.

A before-tax charge of $244 was recorded in first quarter 2010 associated with these programs, of which $138 remained outstanding at December 31, 2010. During 2011,

Note 23 Restructuring and Reorganization - Continued

the company made payments of $74 associated with these liabilities. The majority of the payments were in Downstream. The balance at December 31, 2011, was classified as a current liability on the Consolidated Balance Sheet.

	Amounts Before Tax
Balance at January 1, 2011	$ 138
Adjustments	(28)
Payments	(74)
Balance at December 31, 2011	$ 36

Note 24

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-43, 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 to 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 commenced operations in third quarter 2011. 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 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. Through the end of 2011, the company paid $48 under these indemnities and continues to be obligated up to $250 for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities of 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. In February 2012, Motiva Enterprises LLC delivered a letter to the company purporting to preserve unmatured claims for certain Motiva 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. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. 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, 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 with respect 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

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Note 24 Other Contingencies and Commitments - Continued

various commitments are: 2012 $6,000; 2013 $4,000; 2014 $3,900; 2015 $3,200; 2016 $1,900; 2017 and after $7,400. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $6,600 in 2011, $6,500 in 2010 and $8,100 in 2009.

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, 2011, was $1,404. Included in this balance were remediation activities at approximately 180 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 2011 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 2011 environmental reserves balance of $1,219, $675 related to the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facilities, and pipelines. The remaining $544 was associated with various sites in international downstream ($95), upstream ($368) and other businesses ($81). 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 2011 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 25 on page FS-58 for a discussion of the company s asset retirement obligations.

Other Contingencies On April 26, 2010, a California appeals court issued a ruling related to the adequacy of an Environmental Impact Report (EIR) supporting the issuance of certain permits by the city of Richmond, California, to replace and upgrade certain facilities at Chevron s refinery in Richmond. Settlement discussions with plaintiffs in the case ended late fourth quarter 2010, and on March 3, 2011, the trial court entered a final judgment and peremptory writ ordering the City to set aside the project EIR and conditional use permits and enjoining Chevron from any further work. On May 23, 2011, the company filed an application with the City Planning Department for a conditional use permit for a revised project to complete construction of the hydrogen plant, certain sulfur removal facilities and related infrastructure. On June 10, 2011, the City published its Notice of Preparation of the revised EIR for the project. The revised

Note 24 Other Contingencies and Commitments - Continued

and recirculated EIR is intended to comply with the appeals court decision. Management believes the outcomes associated with the project are uncertain. Due to the uncertainty of the company s future course of action, or potential outcomes of any action or combination of actions, management does not believe an estimate of the financial effects, if any, can be made at this time. However, the company s ultimate exposure may be significant to net income in any one future period.

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 25

Asset Retirement Obligations

The company records the fair value of a liability for an asset retirement obligation (ARO) as an asset and liability 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. Recognition of the ARO includes: (1) the present value of a liability and offsetting asset, (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.

AROs are primarily recorded for the company s crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire downstream 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 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 2011, 2010 and 2009:

	2011	2010	2009
Balance at January 1	**$ 12,488**	$ 10,175	$ 9,395
Liabilities incurred	**62**	129	144
Liabilities settled	**(1,316)**	(755)	(757)
Accretion expense	**628**	513	463
Revisions in estimated cash flows	**905**	2,426	930
Balance at December 31	**$ 12,767**	$ 12,488	$ 10,175

The long-term portion of the $12,767 balance at the end of 2011 was $11,999.

Note 26

Other Financial Information

Earnings in 2011 included gains of approximately $1,300 relating to the sale of nonstrategic properties. Of this amount, approximately $800 and $500 related to downstream and upstream assets, respectively. Earnings in 2010 included gains of approximately $700 relating to the sale of nonstrategic properties. Of this amount, approximately $400 and $300 related to downstream and upstream assets, respectively. The revenues and earnings contributions of these assets were not material to periods presented.

Other financial information is as follows:

	Year ended December 31		
	2011	2010	2009
Total financing interest and debt costs	**$ 288**	$ 317	$ 301
Less: Capitalized interest	**288**	267	273
Interest and debt expense	**$**	$ 50	$ 28
Research and development expenses	**$ 627**	$ 526	$ 603
Foreign currency effects*	**$ 121**	$ (423)	$ (744)

* Includes $(27), $(71) and $(194) in 2011, 2010 and 2009, 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 $9,025 and $6,975 at December 31, 2011 and 2010, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO profits (charges) of $193, $21 and $(168) were included in earnings for the years 2011, 2010 and 2009, respectively.

The company has $4,642 in goodwill on the Consolidated Balance Sheet related to the 2005 acquisition of Unocal and to the 2011 acquisition of Atlas Energy, Inc. Under the accounting standard for goodwill (ASC 350), the company tested this goodwill for impairment during 2011 and concluded no impairment was necessary.

Note 27

Earnings Per Share

Basic earnings per share (EPS) is based upon Net Income Attributable to Chevron Corporation (earnings) 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. 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-48). The table below sets forth the computation of basic and diluted EPS:

		Year ended December 31	
	2011	2010	2009
Basic EPS Calculation			
Earnings available to common stockholders Basic*	**$ 26,895**	$ 19,024	$ 10,483
Weighted-average number of common shares outstanding	**1,986**	1,996	1,991
Add: Deferred awards held as stock units		1	1
Total weighted-average number of common shares outstanding	**1,986**	1,997	1,992
Earnings per share of common stock Basic	**$ 13.54**	$ 9.53	$ 5.26
Diluted EPS Calculation			
Earnings available to common stockholders Diluted*	**$ 26,895**	$ 19,024	$ 10,483
Weighted-average number of common shares outstanding	**1,986**	1,996	1,991
Add: Deferred awards held as stock units		1	1
Add: Dilutive effect of employee stock-based awards	**15**	10	9
Total weighted-average number of common shares outstanding	**2,001**	2,007	2,001
Earnings per share of common stock Diluted	**$ 13.44**	$ 9.48	$ 5.24

* 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	**2011**	2010	2009	2008	2007
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	**$ 244,371**	$ 198,198	$ 167,402	$ 264,958	$ 214,091
Income from equity affiliates and other income	**9,335**	6,730	4,234	8,047	6,813
Total Revenues and Other Income	**253,706**	204,928	171,636	273,005	220,904
Total Costs and Other Deductions	**206,072**	172,873	153,108	229,948	188,630
Income Before Income Tax Expense	**47,634**	32,055	18,528	43,057	32,274
Income Tax Expense	**20,626**	12,919	7,965	19,026	13,479
Net Income	**27,008**	19,136	10,563	24,031	18,795
Less: Net income attributable to noncontrolling interests	**113**	112	80	100	107
Net Income Attributable to Chevron Corporation	**$ 26,895**	$ 19,024	$ 10,483	$ 23,931	$ 18,688
Per Share of Common Stock					
Net Income Attributable to Chevron					
Basic	**$ 13.54**	$ 9.53	$ 5.26	$ 11.74	$ 8.83
Diluted	**$ 13.44**	$ 9.48	$ 5.24	$ 11.67	$ 8.77
Cash Dividends Per Share	**$ 3.09**	$ 2.84	$ 2.66	$ 2.53	$ 2.26
Balance Sheet Data (at December 31)					
Current assets	**$ 53,234**	$ 48,841	$ 37,216	$ 36,470	$ 39,377
Noncurrent assets	**156,240**	135,928	127,405	124,695	109,409
Total Assets	**209,474**	184,769	164,621	161,165	148,786
Short-term debt	**340**	187	384	2,818	1,162
Other current liabilities	**33,260**	28,825	25,827	29,205	32,636
Long-term debt and capital lease obligations	**9,812**	11,289	10,130	6,083	6,070
Other noncurrent liabilities	**43,881**	38,657	35,719	35,942	31,626
Total Liabilities	**87,293**	78,958	72,060	74,048	71,494
Total Chevron Corporation Stockholders Equity	**$ 121,382**	$ 105,081	$ 91,914	$ 86,648	$ 77,088
Noncontrolling interests	**799**	730	647	469	204
Total Equity	**$ 122,181**	$ 105,811	$ 92,561	$ 87,117	$ 77,292

* Includes excise, value-added and similar taxes:	**$ 8,085**	$ 8,591	$ 8,109	$ 9,846	$ 10,121

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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

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

							Consolidated Companies	Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2011									
Exploration									
Wells	**$ 321**	**$ 71**	**$ 104**	**$ 146**	**$ 242**	**$ 188**	**$ 1,072**	**$**	**$**
Geological and geophysical	**76**	**59**	**65**	**121**	**23**	**43**	**387**		
Rentals and other	**109**	**45**	**83**	**67**	**71**	**78**	**453**		
Total exploration	**506**	**175**	**252**	**334**	**336**	**309**	**1,912**		
Property acquisitions[2]									
Proved	**1,174**	**16**		**1**			**1,191**		
Unproved	**7,404**	**228**				**25**	**7,657**		
Total property acquisitions	**8,578**	**244**		**1**		**25**	**8,848**		
Development[3]	**5,517**	**1,537**	**2,698**	**2,867**	**2,638**	**633**	**15,890**	**379**	**368**
Total Costs Incurred[4]	**$ 14,601**	**$ 1,956**	**$ 2,950**	**$ 3,202**	**$ 2,974**	**$ 967**	**$ 26,650**	**$ 379**	**$ 368**
Year Ended December 31, 2010									
Exploration									
Wells	$ 99	$ 118	$ 94	$ 244	$ 293	$ 61	$ 909	$	$
Geological and geophysical	67	46	87	29	8	18	255		
Rentals and other	121	39	55	47	95	57	414		

Total exploration	287	203	236	320	396	136	1,578		
Property acquisitions[2]									
Proved	24			129			153		
Unproved	359	429	160	187		10	1,145		
Total property acquisitions	383	429	160	316		10	1,298		
Development[3]	4,446	1,611	2,985	3,325	2,623	411	15,401	230	343
Total Costs Incurred	$ 5,116	$ 2,243	$ 3,381	$ 3,961	$ 3,019	$ 557	$ 18,277	$ 230	$ 343
Year Ended December 31, 2009									
Exploration									
Wells	$ 361	$ 70	$ 140	$ 45	$ 275	$ 84	$ 975	$	$
Geological and geophysical	62	70	114	49	17	16	328		
Rentals and other	153	146	92	60	127	43	621		
Total exploration	576	286	346	154	419	143	1,924		
Property acquisitions[2]									
Proved	3						3		
Unproved	29						29		
Total property acquisitions	32						32		
Development[3]	3,338	1,515	3,426	2,698	565	285	11,827	265	69
Total Costs Incurred	$ 3,946	$ 1,801	$ 3,772	$ 2,852	$ 984	$ 428	$ 13,783	$ 265	$ 69

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations.

See Note 25, Asset Retirement Obligations, on page FS-58.

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

[3] Includes $1,035, $745 and $121 costs incurred prior to assignment of proved reserves for consolidated companies in 2011, 2010 and 2009, respectively.

[4] Reconciliation of consolidated and affiliated companies total cost incurred to Upstream capital and exploratory (C&E) expenditures $ billions.

Total cost incurred for 2011	$ 27.4	
Non oil and gas activities	5.4	(Includes LNG and gas-to-liquids $4.3, transportation $0.5, affiliate $0.5, other $0.1)
Atlas properties	(6.1)	
ARO	(0.8)	
Upstream C&E	$ 25.9	Reference Page FS-11 upstream total

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Table II Capitalized Costs Related to Oil and
Gas Producing Activities

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, Democratic Republic of the Congo, Nigeria, and Republic 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 Europe geographic area includes activity in Denmark,
the Netherlands, Norway and the United Kingdom. The Other Americas geographic region includes activities in Argentina, Brazil, Canada, Colombia, and Trinidad and Tobago. 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-39, for a discussion of the company s major equity affiliates.

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

								Affiliated Companies	
	Consolidated Companies								
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
At December 31, 2011									
Unproved properties	**$ 9,806**	**$ 1,417**	**$ 368**	**$ 2,408**	**$ 6**	**$ 33**	**$ 14,038**	**$ 109**	**$**
Proved properties and related producing assets	**57,674**	**11,029**	**25,549**	**36,740**	**2,244**	**9,549**	**142,785**	**6,583**	**1,607**
Support equipment	**1,071**	**292**	**1,362**	**1,544**	**533**	**169**	**4,971**	**1,018**	
Deferred exploratory wells	**565**	**63**	**629**	**260**	**709**	**208**	**2,434**		
Other uncompleted projects	**4,887**	**2,408**	**4,773**	**3,109**	**6,076**	**492**	**21,745**	**605**	**1,466**
Gross Capitalized Costs	**74,003**	**15,209**	**32,681**	**44,061**	**9,568**	**10,451**	**185,973**	**8,315**	**3,073**
Unproved properties valuation	**1,085**	**498**	**178**	**262**	**2**	**13**	**2,038**	**38**	
Proved producing properties									
Depreciation and depletion	**39,210**	**4,826**	**13,173**	**20,991**	**1,574**	**7,742**	**87,516**	**1,910**	**436**
Support equipment depreciation	**530**	**175**	**715**	**1,192**	**238**	**129**	**2,979**	**451**	

Accumulated provisions	**40,825**	**5,499**	**14,066**	**22,445**	**1,814**	**7,884**	**92,533**	**2,399**	**436**
Net Capitalized Costs	**$ 33,178**	**$ 9,710**	**$ 18,615**	**$ 21,616**	**$ 7,754**	**$ 2,567**	**$ 93,440**	**$ 5,916**	**$ 2,637**
At December 31, 2010									
Unproved properties	$ 2,553	$ 1,349	$ 359	$ 2,561	$ 6	$ 8	$ 6,836	$ 108	$
Proved properties and related producing assets	55,601	7,747	23,683	33,316	2,585	9,035	131,967	6,512	1,594
Support equipment	975	265	1,282	1,421	259	165	4,367	985	
Deferred exploratory wells	743	210	611	224	732	198	2,718		
Other uncompleted projects	2,299	3,844	4,061	3,627	3,631	362	17,824	357	1,001
Gross Capitalized Costs	62,171	13,415	29,996	41,149	7,213	9,768	163,712	7,962	2,595
Unproved properties valuation	967	436	150	200	2		1,755	34	
Proved producing properties Depreciation and depletion	37,682	3,986	10,986	18,197	1,718	7,162	79,731	1,530	249
Support equipment depreciation	518	153	600	1,126	84	114	2,595	402	
Accumulated provisions	39,167	4,575	11,736	19,523	1,804	7,276	84,081	1,966	249
Net Capitalized Costs	$ 23,004	$ 8,840	$ 18,260	$ 21,626	$ 5,409	$ 2,492	$ 79,631	$ 5,996	$ 2,346

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

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
At December 31, 2009									
Unproved properties	$ 2,320	$ 946	$ 321	$ 3,355	$ 7	$ 10	$ 6,959	$ 113	$
Proved properties and related producing assets	51,582	6,033	20,967	29,637	2,507	8,727	119,453	6,404	1,759
Support equipment	810	323	1,012	1,383	162	163	3,853	947	
Deferred exploratory wells	762	216	603	209	440	205	2,435		
Other uncompleted projects	2,384	4,106	3,960	2,936	1,274	192	14,852	284	58
Gross Capitalized Costs	57,858	11,624	26,863	37,520	4,390	9,297	147,552	7,748	1,817
Unproved properties valuation	915	391	163	170	1	(2)	1,638	32	
Proved producing properties Depreciation and depletion	34,574	3,182	8,823	15,783	1,579	6,482	70,423	1,150	282
Support equipment depreciation	424	197	526	773	58	102	2,080	356	
Accumulated provisions	35,913	3,770	9,512	16,726	1,638	6,582	74,141	1,538	282
Net Capitalized Costs	$ 21,945	$ 7,854	$ 17,351	$ 20,794	$ 2,752	$ 2,715	$ 73,411	$ 6,210	$ 1,535

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

The company s results of operations from oil and gas producing activities for the years 2011, 2010 and 2009 are shown in the following table. Net income from exploration and production activities as reported on page FS-38 reflects income taxes computed on an effective rate basis.
Income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page FS-38.

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2011									
Revenues from net production									
Sales	**$ 2,508**	**$ 1,672**	**$ 1,174**	**$ 9,431**	**$ 1,474**	**$ 1,868**	**$ 18,127**	**$ 8,581**	**$ 1,988**
Transfers	**15,811**	**3,724**	**15,726**	**8,962**	**1,012**	**2,672**	**47,907**		
Total	**18,319**	**5,396**	**16,900**	**18,393**	**2,486**	**4,540**	**66,034**	**8,581**	**1,988**
Production expenses excluding taxes	**(3,668)**	**(1,061)**	**(1,526)**	**(4,489)**	**(117)**	**(564)**	**(11,425)**	**(449)**	**(235)**
Taxes other than on income	**(597)**	**(137)**	**(153)**	**(242)**	**(396)**	**(2)**	**(1,527)**	**(429)**	**(815)**
Proved producing properties:									
Depreciation and depletion	**(3,366)**	**(796)**	**(2,225)**	**(2,923)**	**(136)**	**(580)**	**(10,026)**	**(442)**	**(140)**
Accretion expense[2]	**(291)**	**(27)**	**(106)**	**(81)**	**(18)**	**(39)**	**(562)**	**(8)**	**(4)**
Exploration expenses	**(207)**	**(144)**	**(188)**	**(271)**	**(128)**	**(277)**	**(1,215)**		
Unproved properties valuation	**(134)**	**(146)**	**(27)**	**(60)**		**(14)**	**(381)**		
Other income (expense)[3]	**163**	**(1,191)**	**(409)**	**231**	**(18)**	**(74)**	**(1,298)**	**(8)**	**(29)**
Results before income taxes	**10,219**	**1,894**	**12,266**	**10,558**	**1,673**	**2,990**	**39,600**	**7,245**	**765**
Income tax expense	**(3,728)**	**(535)**	**(7,802)**	**(5,374)**	**(507)**	**(1,913)**	**(19,859)**	**(2,176)**	**(392)**
Results of Producing Operations	**$ 6,491**	**$ 1,359**	**$ 4,464**	**$ 5,184**	**$ 1,166**	**$ 1,077**	**$ 19,741**	**$ 5,069**	**$ 373**
Year Ended December 31, 2010									
Revenues from net production									
Sales	$ 2,540	$ 2,441	$ 2,278	$ 7,221	$ 994	$ 1,519	$ 16,993	$ 6,031	$ 1,307
Transfers	12,172	1,038	10,306	6,242	985	2,138	32,881		
Total	14,712	3,479	12,584	13,463	1,979	3,657	49,874	6,031	1,307
Production expenses excluding taxes	(3,338)	(805)	(1,413)	(2,996)	(96)	(534)	(9,182)	(347)	(152)
Taxes other than on income	(542)	(102)	(130)	(85)	(334)	(2)	(1,195)	(360)	(101)
Proved producing properties:									
Depreciation and depletion	(3,639)	(907)	(2,204)	(2,816)	(151)	(681)	(10,398)	(432)	(131)
Accretion expense[2]	(240)	(23)	(102)	(35)	(15)	(53)	(468)	(8)	(5)

Exploration expenses	(193)	(173)	(242)	(289)	(175)	(75)	(1,147)	(5)	
Unproved properties valuation	(123)	(71)	(25)	(33)		(2)	(254)		
Other income (expense)[3]	(154)	(818)	(103)	(282)	109	165	(1,083)	(65)	191
Results before income taxes	6,483	580	8,365	6,927	1,317	2,475	26,147	4,814	1,109
Income tax expense[4]	(2,273)	(223)	(4,535)	(3,886)	(325)	(1,455)	(12,697)	(1,445)	(615)
Results of Producing Operations	$ 4,210	$ 357	$ 3,830	$ 3,041	$ 992	$ 1,020	$ 13,450	$ 3,369	$ 494

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

[2] Represents accretion of ARO liability. Refer to Note 25, Asset Retirement Obligations, on page FS-58.

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

technical service agreements.

[4] Income tax expense for 2010 conformed to 2011 presentation for certain tax items.

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

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2009									
Revenues from net production									
Sales	$ 2,278	$ 918	$ 1,767	$ 5,648	$ 543	$ 1,712	$ 12,866	$ 4,043	$ 938
Transfers	9,133	1,555	7,304	4,926	765	1,546	25,229		
Total	11,411	2,473	9,071	10,574	1,308	3,258	38,095	4,043	938
Production expenses excluding taxes	(3,281)	(731)	(1,345)	(2,208)	(94)	(565)	(8,224)	(363)	(240)
Taxes other than on income	(367)	(90)	(132)	(53)	(190)	(4)	(836)	(50)	(96)
Proved producing properties:									
Depreciation and depletion	(3,493)	(486)	(2,175)	(2,279)	(214)	(898)	(9,545)	(381)	(88)
Accretion expense[2]	(194)	(27)	(66)	(70)	(2)	(50)	(409)	(7)	(3)
Exploration expenses	(451)	(203)	(236)	(113)	(224)	(115)	(1,342)		
Unproved properties valuation	(228)	(28)	(11)	(44)			(311)		
Other income (expense)[3]	156	(508)	98	(327)	350	(182)	(413)	(131)	9
Results before income taxes	3,553	400	5,204	5,480	934	1,444	17,015	3,111	520
Income tax expense	(1,258)	(203)	(3,214)	(2,921)	(256)	(901)	(8,753)	(935)	(258)
Results of Producing Operations	$ 2,295	$ 197	$ 1,990	$ 2,559	$ 678	$ 543	$ 8,262	$ 2,176	$ 262

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no

effect on the results of producing operations.

[2] Represents accretion of ARO liability. Refer to Note 25, Asset Retirement Obligations, on page FS-58.

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

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Table IV Results of Operations for Oil and Gas Producing Activities - Unit Prices and Costs[1]

	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2011									
Average sales prices									
Liquids, per barrel	**$ 97.51**	**$ 105.33**	**$ 109.45**	**$ 100.55**	**$ 103.70**	**$ 107.11**	**$ 102.92**	**$ 94.60**	**$ 90.90**
Natural gas, per thousand cubic feet	**4.02**	**2.97**	**0.41**	**5.28**	**9.98**	**9.91**	**5.29**	**1.60**	**6.57**
Average production costs, per barrel[2]	**15.08**	**14.62**	**9.48**	**17.47**	**3.41**	**11.44**	**13.98**	**4.23**	**10.54**
Year Ended December 31, 2010									
Average sales prices									
Liquids, per barrel	$ 71.59	$ 77.77	$ 78.00	$ 70.96	$ 76.43	$ 76.10	$ 74.02	$ 63.94	$ 64.92
Natural gas, per thousand cubic feet	4.25	2.52	0.73	4.45	6.76	7.09	4.55	1.41	4.20
Average production costs, per barrel[2]	13.11	11.86	8.57	11.71	2.55	9.42	10.96	3.14	7.37
Year Ended December 31, 2009									
Average sales prices									
Liquids, per barrel	$ 54.36	$ 65.28	$ 60.35	$ 54.76	$ 54.58	$ 57.19	$ 56.92	$ 47.33	$ 50.18
Natural gas, per thousand cubic feet	3.73	2.01	0.20	4.07	4.24	6.61	3.94	1.54	1.85
Average production costs, per barrel[2]	12.71	12.04	8.85	8.82	2.57	8.87	9.97	3.71	12.42

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost.

This has no effect on the results of producing operations.

[2] Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

Table V Reserve Quantity Information

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting three deemed commercial and three potentially recoverable. Within the commercial classification are proved reserves and two categories of unproved: probable and possible. The potentially recoverable 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 company maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the vice chairman responsible for the company s worldwide exploration and production activities. The corporate reserves manager, who acts as chairman of the RAC, has more than 30 years experience working in the oil and gas industry and a Master of Science in Petroleum Engineering degree from Stanford University. His experience includes more than 15 years of managing oil and gas reserves processes. He was the chairman of the Society of Petroleum Engineers Oil and Gas Reserves Committee, currently serves on the United Nations Expert Group on Resources Classification, and is an active member of the Society of Petroleum Evaluation Engineers. He is also a past member of the Joint Committee on Reserves Evaluator Training and the California Conservation Committee.

All RAC members are degreed professionals, each with more than 15 years experience in various aspects of reserves estimation relating to reservoir engineering, petroleum engineering, earth science, or finance. The members are knowledgeable in SEC guidelines for proved reserves classification and receive annual training on the preparation of reserves estimates. The reserves activities are managed by 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: establish the policies and processes used within the operating units to estimate reserves; provide independent reviews and oversight of the business units recommended reserves

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Table V Reserve Quantity Information - Continued

Summary of Net Oil and Gas Reserves

Liquids and Synthetic Oil in Millions of Barrels *Natural Gas in Billions of Cubic Feet*	2011* Crude Oil Condensate NGLs	2011* Synthetic Oil	2011* Natural Gas	2010* Crude Oil Condensate NGLs	2010* Synthetic Oil	2010* Natural Gas	2009* Crude Oil Condensate NGLs	2009* Synthetic Oil	2009* Natural Gas
Proved Developed									
Consolidated Companies									
U.S.	**990**		**2,486**	1,045		2,113	1,122		2,314
Other Americas	**82**	**403**	**1,147**	84	352	1,490	66	190	1,678
Africa	**792**		**1,276**	830		1,304	820		978
Asia	**703**		**4,300**	826		4,836	926		5,062
Australia	**39**		**813**	39		881	50		1,071
Europe	**116**		**204**	136		235	151		302
Total Consolidated	**2,722**	**403**	**10,226**	2,960	352	10,859	3,135	190	11,405
Affiliated Companies									
TCO	**1,019**		**1,400**	1,128		1,484	1,256		1,830
Other	**93**	**50**	**75**	95	53	70	97	56	73
Total Consolidated and Affiliated Companies	**3,834**	**453**	**11,701**	4,183	405	12,413	4,488	246	13,308
Proved Undeveloped									
Consolidated Companies									
U.S.	**321**		**1,160**	230		359	239		384
Other Americas	**31**	**120**	**517**	24	114	325	38	270	307
Africa	**363**		**1,920**	338		1,640	426		2,043
Asia	**191**		**2,421**	187		2,357	245		2,798
Australia	**101**		**8,931**	49		5,175	48		5,174
Europe	**43**		**54**	16		40	19		42
Total Consolidated	**1,050**	**120**	**15,003**	844	114	9,896	1,015	270	10,748
Affiliated Companies									
TCO	**740**		**851**	692		902	690		1,003
Other	**64**	**194**	**1,128**	62	203	1,040	54	210	990
Total Consolidated and Affiliated Companies	**1,854**	**314**	**16,982**	1,598	317	11,838	1,759	480	12,741
Total Proved Reserves	**5,688**	**767**	**28,683**	5,781	722	24,251	6,247	726	26,049

* Based on 12-month average price.

estimates and 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, whose members include the Chief Executive Officer and the Chief Financial Officer. The company s annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

RAC subteams also conduct in-depth reviews during the year of many of the fields that have large proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their compliance with the *Corporate Reserves Manual.*

Technologies Used in Establishing Proved Reserves Additions in 2011 In 2011, additions to Chevron s proved reserves were based on a wide range of geologic and engineering technologies. Information generated from wells, such as well logs, wire line sampling, production and pressure testing, fluid analysis, and core analysis, was integrated with seismic, regional geologic studies, and information from analogous reservoirs to provide reasonably certain proved reserves estimates. Both proprietary and commercially available analytic tools including reservoir simulation, geologic modeling, and seismic processing have been used in the interpretation of the subsurface data. These technologies have been utilized extensively by the company in the past, and the company believes that they provide a high degree of confidence in establishing reliable and consistent reserves estimates.

Proved Undeveloped Reserve Quantities At the end of 2011, proved undeveloped reserves for consolidated companies totaled 3.7 billion barrels of oil-equivalent (BOE). Approximately 68 percent of these reserves are attributed to natural gas, of which about 60 percent were located in Australia. Crude oil, condensate and natural gas liquids

Table V Reserve Quantity Information - Continued

(NGLs) accounted for about 29 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 proved undeveloped reserves and was located in Canada in the Other Americas region.

Proved undeveloped reserves of equity affiliates amounted to 1.3 billion BOE. At year-end, crude oil, condensate and NGLs represented 61 percent of these reserves, with TCO accounting for the majority of this amount. Natural gas represented 25 percent of the total, with approximately 43 percent of those reserves from TCO. The remaining proved undeveloped reserves are attributed to synthetic oil in Venezuela.

In 2011, a total of 220 million BOE was transferred from proved undeveloped to proved developed for consolidated companies. In the United States, approximately 90 million BOE were transferred, primarily due to ongoing drilling activities in California and other locations. In Asia, 55 million BOE were transferred to proved developed primarily driven by the start-up of a gas project in Thailand. The start up of several small projects in Africa, Europe and Other Americas accounted for the remainder.

Affiliated companies had transfers of 25 million BOE from proved undeveloped to proved developed.

Investment to Convert Proved Undeveloped to Proved Developed Reserves During 2011, investments totaling approximately $6.7 billion were made by consolidated companies and equity affiliates to advance the development of proved undeveloped reserves. In Australia, $2.1 billion was expended, which was primarily driven by construction activities at the Gorgon LNG project. In Africa, $1.4 billion was expended on various projects, including offshore development projects in Nigeria and Angola. In Nigeria, construction progressed on a deepwater project and development activities continued at a natural gas processing plant. In Angola, offshore development drilling was progressed along with several gas injection projects. In Asia, expenditures during the year totaled $1.0 billion, which included construction of a gas processing facility in Thailand, a gas development project in China and development activities in Indonesia. In the United States, expenditures totaled $0.9 billion for offshore development projects in the Gulf of Mexico. In Other Americas, development expenditures totaled $0.9 billion for a variety of projects, including an offshore development project in Brazil. In Europe, $0.1 billion was expended on various development projects.

The company s share of affiliated companies expenditures was $0.3 billion, primarily on an LNG project in Angola and development activities in Kazakhstan.

Proved Undeveloped Reserves for Five Years or More Reserves that remain proved undeveloped for five or more years are a result of several 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.

At year-end 2011, the company held approximately 1.8 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more. The reserves are held by consolidated and affiliated companies and the majority of these reserves are in locations where the company has a proven track record of developing major projects.

In Africa, approximately 330 million BOE is related to deepwater and natural gas developments in Nigeria and Angola. Major Nigerian deepwater development projects include Agbami, which started production in 2008 and has ongoing development activities to maintain full utilization of infrastructure capacity, and the Usan development, which is expected to start production in 2012. Also in Nigeria, various fields and infrastructure associated with the Escravos Gas Projects are currently under development.

In Asia, approximately 240 million BOE remain classified as proved undeveloped. The majority of the volumes relate to ongoing development activities in the Pattani Field (Thailand) and the Malampaya Field (Philippines) that are scheduled to maintain production within contractual and infrastructure constraints. The balance relates to infrastructure constraints in Azerbaijan.

In Australia, approximately 110 million BOE remain classified as undeveloped due to a compression project at the North West Shelf Venture, which is scheduled for start-up in 2013.

In the United States, approximately 70 million BOE remain proved undeveloped, primarily related to a steamflood expansion and deepwater development projects. In Other Americas and Europe, approximately 50 million BOE is related to contractual constraints, infrastructure limitations and future compression projects.

Affiliated companies have approximately 1.0 billion BOE of proved undeveloped reserves held for five years or more. The TCO affiliate in Kazakhstan accounts for approximately 880 million BOE. Field production is constrained by plant capacity limitations. Further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion.

In Venezuela, the affiliate that operates the Hamaca Field s synthetic heavy oil upgrading operation accounts for about 120 million BOE of these proved undeveloped reserves. Development drilling continues at Hamaca to optimize utilization of upgrader capacity.

Annually, the company assesses whether any changes have occurred in facts or circumstances, such as changes to development plans, regulations or government policies, that would warrant a revision to reserve estimates. For 2011, this assessment did not result in any material changes in reserves classified as proved undeveloped. Over the past three years,

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Table V Reserve Quantity Information - Continued

the ratio of proved undeveloped reserves to total proved reserves has ranged between 37 percent and 44 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, 2011, proved reserves for the company s consolidated operations were 8.5 billion BOE. (Refer to the term Reserves on page E-11 for the definition of oil-equivalent reserves.) Approximately 23 percent of the total reserves were located in the United States. For the company s interests in equity affiliates, proved reserves were 2.7 billion BOE, 78 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 22 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 47 percent of the company s total oil-equivalent proved reserves. These properties were geographically dispersed, located in the United States, Canada, South America, Africa, Asia and Australia.

In the United States, total proved reserves at year-end 2011 were 1.9 billion BOE. California properties accounted for 35 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, most of the company s heavy-oil fields in California employ a continuous steamflooding process. The Gulf of Mexico region contains 24 percent of the U.S. reserves, with liquids representing about 77 percent of reserves in the Gulf. Production operations are mostly offshore and, as a result, are also capital intensive. Other U.S. areas represent the remaining 41 percent of U.S. reserves, with liquids accounting for about 42 percent of the total. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO_2 injection.

For the three years ending December 31, 2011, 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, changes in oil and gas prices, OPEC constraints, geopolitical uncertainties, and civil unrest.

The company s estimated net proved reserves of crude oil, condensate, natural gas liquids and synthetic oil and changes thereto for the years 2009, 2010 and 2011 are shown in the table on the following page. The company s estimated net proved reserves of natural gas are shown on page FS-73.

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Table V Reserve Quantity Information - Continued
Net Proved Reserves of Crude Oil, Condensate, Natural Gas Liquids and Synthetic Oil

	Consolidated Companies								Affiliated Companies			Total Consolidated and Affiliated Companies
Millions of barrels	U.S.	Other Americas[1]	Africa	Asia	Australia	Europe	Synthetic Oil[2,3]	Total	TCO	Synthetic Oil[2]	Other[4]	
Reserves at January 1, 2009	1,470	149	1,385	1,456	73	202		4,735	2,176		439	7,350
Changes attributable to:												
Revisions	63	(29)	(46)	(121)	18	10	460	355	(184)	266	(269)	168
Improved recovery	2		48					50	36			86
Extensions and discoveries	6	13	10	3	20			52				52
Purchases												
Sales	(3)	(6)						(9)				(9)
Production	(177)	(23)	(151)	(167)	(13)	(42)		(573)	(82)		(19)	(674)
Reserves at December 31, 2009[5]	1,361	104	1,246	1,171	98	170	460	4,610	1,946	266	151	6,973
Changes attributable to:												
Revisions	63	12	17	(26)	3	19	15	103	(33)		12	82
Improved recovery	11	3	58	2				74			3	77
Extensions and discoveries	19	19	9	16				63				63
Purchases				11				11				11
Sales	(1)							(1)				(1)
Production	(178)	(30)	(162)	(161)	(13)	(37)	(9)	(590)	(93)	(10)	(9)	(702)
Reserves at December 31, 2010[5]	1,275	108	1,168	1,013	88	152	466	4,270	1,820	256	157	6,503
Changes attributable to:												
Revisions	**63**	**4**	**60**	**25**	**(2)**	**15**	**32**	**197**	**28**		**10**	**235**
Improved recovery	**6**	**4**	**48**					**58**				**58**
Extensions and discoveries	**140**	**30**	**34**	**4**	**65**	**26**		**299**				**299**
Purchases	**2**						**40**	**42**				**42**
Sales	**(5)**				**(1)**			**(6)**				**(6)**
Production	**(170)**	**(33)**	**(155)**	**(148)**	**(10)**	**(34)**	**(15)**	**(565)**	**(89)**	**(12)**	**(10)**	**(676)**
Reserves at December 31, 2011[5]	**1,311**	**113**	**1,155**	**894**	**140**	**159**	**523**	**4,295**	**1,759**	**244**	**157**	**6,455**

[1] Ending reserve balances in North America were 13, 14 and 12 and in South America were 100, 94 and 92 in 2011, 2010 and 2009, respectively.

[2]

Prospective reporting effective December 31, 2009, in accordance with the SEC rule on *Modernization of Oil and Gas Reporting*.

[3] Reserves associated with Canada.

[4] Ending reserve balances in Africa were 38, 36 and 31 and in South America were 119, 121 and 120 in 2011, 2010 and 2009, respectively.

[5] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-11 for the definition of a PSC). PSC-related reserve quantities are 22 percent, 24 percent and 26 percent for consolidated companies for 2011, 2010 and 2009, respectively.

Noteworthy amounts in the categories of liquids proved reserve changes for 2009 through 2011 are discussed below:

Revisions 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 Other Americas 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 as well as 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.

In 2010, net revisions increased reserves 103 million barrels for consolidated companies and decreased reserves 21 million barrels for affiliated companies. For consolidated companies, improved reservoir performance accounted for a majority of the 63 million barrel increase in the United States. Increases in the other regions were partially offset by Asia, which decreased as a result of the effect of higher prices on production-sharing contracts in Kazakhstan. For affiliated companies, the price effect on royalty determination at TCO decreased reserves by 33 million barrels. This was partially offset by improved reservoir performance and development drilling in Venezuela.

Table V Reserve Quantity Information - Continued

In 2011, net revisions increased reserves 197 million barrels for consolidated companies and increased reserves 38 million barrels for affiliated companies. For consolidated companies, improved reservoir performance accounted for a majority of the 63 million barrel increase in the United States. In Africa, improved field performance drove the 60 million barrel increase. In Asia, increases from improved reservoir performance were partially offset by the effects of higher prices on production-sharing contracts. Synthetic oil reserves in Canada increased by 32 million barrels, primarily due to geotechnical revisions. For affiliated companies, improved facility and reservoir performance was partially offset by the price effect on royalty determination at TCO. Continued development drilling increased reserves in Venezuela.

Improved Recovery 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 Sour Gas Injection/Second Generation Plant (SGI/SGP) facilities.

In 2010, improved recovery increased volumes by 77 million barrels worldwide. For consolidated companies, reserves in Africa increased 58 million barrels due primarily to secondary recovery performance in Nigeria. Reserves in the United States increased 11 million, primarily in California. Affiliated companies increased reserves 3 million barrels.

In 2011, improved recovery increased volumes by 58 million barrels worldwide. For consolidated companies, reserves in Africa increased 48 million barrels due primarily to secondary recovery performance in Nigeria. Reserves in the United States increased by 6 million, primarily in California. Other Americas increased 4 million barrels.

Extensions and Discoveries In 2009, extensions and discoveries increased liquids volumes by 52 million barrels worldwide. The largest additions were 20 million barrels in Australia related to the Gorgon Project and 13 million barrels in Other Americas related to delineation drilling in Argentina. Africa and the United States accounted for 10 million barrels and 6 million barrels, respectively.

In 2010, extensions and discoveries increased consolidated companies reserves 63 million barrels worldwide. The United States and Other Americas each increased reserves 19 million barrels, and Asia increased reserves 16 million barrels. No single area in the United States was individually significant. Drilling activity in Argentina and Brazil accounted for the majority of the increase in Other Americas. In Asia, the increase was primarily related to activity in Azerbaijan.

In 2011, extensions and discoveries increased consolidated companies reserves 299 million barrels worldwide. In the United States, additions related to two Gulf of Mexico projects resulted in the majority of the 140 million barrel increase. In Australia, the Wheatstone Project increased liquid volumes 65 million barrels. Africa and Other Americas increased reserves 34 million and 30 million barrels, respectively, following the start of new projects in these areas. In Europe, a new project in the United Kingdom increased reserves 26 million barrels. In Asia, reserves increased 4 million barrels.

Purchases In 2011, purchases increased worldwide liquid volumes 42 million barrels. The acquisition of additional acreage in Canada increased synthetic oil reserves 40 million barrels.

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Table V Reserve Quantity Information - Continued
Net Proved Reserves of Natural Gas

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated
Billions of cubic feet (BCF)	U.S.	Other Americas[1]	Africa	Asia	Australia	Europe	Total	TCO	Other[2]	Companies
Reserves at January 1, 2009	3,150	2,368	3,056	7,996	1,962	490	19,022	3,175	878	23,075
Changes attributable to:										
Revisions	39	(126)	4	493	166	(7)	569	(237)	193	525
Improved recovery										
Extensions and discoveries	53	1	3	54	4,276		4,387			4,387
Purchases										
Sales	(33)	(84)					(117)			(117)
Production[3]	(511)	(174)	(42)	(683)	(159)	(139)	(1,708)	(105)	(8)	(1,821)
Reserves at December 31, 2009[4]	2,698	1,985	3,021	7,860	6,245	344	22,153	2,833	1,063	26,049
Changes attributable to:										
Revisions	220	4	(20)	(31)	(22)	46	197	(324)	56	(71)
Improved recovery	1	1					2			2
Extensions and discoveries	36	4		59		11	110			110
Purchases	3			4			7			7
Sales	(7)						(7)			(7)
Production[3]	(479)	(179)	(57)	(699)	(167)	(126)	(1,707)	(123)	(9)	(1,839)
Reserves at December 31, 2010[4]	2,472	1,815	2,944	7,193	6,056	275	20,755	2,386	1,110	24,251
Changes attributable to:										
Revisions	**217**	**(4)**	**39**	**196**	**(107)**	**74**	**415**	**(21)**	**103**	**497**
Improved recovery		**1**					**1**			**1**
Extensions and discoveries	**287**	**13**	**290**	**46**	**4,035**	**9**	**4,680**			**4,680**
Purchases	**1,231**			**2**			**1,233**			**1,233**
Sales	**(95)**			**(2)**	**(77)**		**(174)**			**(174)**
Production[3]	**(466)**	**(161)**	**(77)**	**(714)**	**(163)**	**(100)**	**(1,681)**	**(114)**	**(10)**	**(1,805)**
Reserves at December 31, 2011[4]	**3,646**	**1,664**	**3,196**	**6,721**	**9,744**	**258**	**25,229**	**2,251**	**1,203**	**28,683**

[1] Ending reserve balances in North America and South America were 19, 21, 23 and 1,645, 1,794, 1,962 in 2011, 2010 and 2009, respectively.

[2] Ending reserve balances in Africa and South America were 1,016, 953, 898 and 187, 157, 165 in 2011, 2010 and 2009, respectively.

[3] Total as sold volumes are 4.4 BCF, 4.5 BCF and 4.5 BCF for 2011, 2010 and 2009, respectively.

[4] Includes reserve quantities related to production-sharing contracts (PSC) (refer to page E-11 for the definition of a PSC). PSC-related reserve quantities are 21 percent, 29 percent and 31 percent for consolidated companies for 2011, 2010 and 2009, respectively.

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2009 through 2011 are discussed below:

Revisions In 2009, net revisions increased reserves 569 BCF for consolidated companies and decreased reserves 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. In Australia, the 166 BCF increase in reserves resulted from improved reservoir performance and compression. In Other Americas, reserves decreased 126 BCF, driven primarily by the effect of higher prices on production-sharing contracts in Trinidad and Tobago. In the United States, a net increase of 39 BCF was the result of development drilling in the Gulf of Mexico, partially offset by performance revisions in the California and mid-continent areas.

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.

In 2010, net revisions increased reserves by 197 BCF for consolidated companies, which was more than offset by a 268 BCF decrease in net revisions for affiliated companies. For consolidated companies, a net increase in the United States of 220 BCF, primarily in the mid-continent area and the Gulf of Mexico, was the result of a number of small upward revisions related to improved reservoir performance and drilling activity, none of which were individually significant. The increase was partially offset by downward revisions due to the impact of higher prices on production-sharing contracts in Asia. For equity affiliates, a downward revision of 324 BCF at TCO was due to the price effect on royalty determination and a change in the variable-royalty calculation. This decline was partially offset by the recognition of additional reserves related to the Angola LNG project.

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Table V Reserve Quantity Information - Continued

In 2011, net revisions increased reserves 415 BCF for consolidated companies and increased reserves 82 BCF for affiliated companies. For consolidated companies, improved reservoir performance accounted for a majority of the 217 BCF increase in the United States. In Asia, a net increase of 196 BCF was driven by development drilling and improved field performance in Thailand, partially offset by the effects of higher prices on production-sharing contracts in Kazakhstan. In Other Americas, a negative performance revision in Trinidad and Tobago was partially offset by increases in Colombia from drilling activities and the reactivation of an existing field. For affiliated companies, ongoing reservoir assessment resulted in the recognition of additional reserves related to the Angola LNG project. At TCO, improved facility and reservoir performance was more than offset by the price effect on royalty determination.

Extensions and Discoveries In 2009, worldwide extensions and discoveries of 4,387 BCF were attributed to consolidated companies. In Australia, the Gorgon Project accounted for all of the 4,276 BCF additions. 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.

In 2011, extensions and discoveries increased consolidated companies reserves 4,680 BCF worldwide. In Australia, the Wheatstone Project accounted for the 4,035 BCF in additions. In Africa, the start of a new natural gas development project in Nigeria resulted in the 290 BCF increase. In the United States, development drilling accounted for the majority of the 287 BCF increase.

Purchases In 2011, purchases increased worldwide reserves 1,233 BCF. In the United States, acquisitions in the Marcellus Shale increased reserves 1,230 BCF.

Sales In 2009, worldwide sales of 117 BCF were related to consolidated companies. For Other Americas, 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.

In 2011, sales decreased consolidated companies reserves 174 BCF worldwide. In Australia, the Wheatstone Project unitization and equity sales agreements reduced reserves 77 BCF. In the United States, sales in Alaska and other smaller fields reduced reserves 95 BCF.

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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 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.

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other	Companies
At December 31, 2011										
Future cash inflows from production[1]	**$ 143,633**	**$ 63,579**	**$ 124,077**	**$ 124,972**	**$ 113,773**	**$ 19,704**	**$ 589,738**	**$ 171,588**	**$ 42,212**	**$ 803,538**
Future production costs	**(39,523)**	**(22,856)**	**(22,703)**	**(35,579)**	**(15,411)**	**(7,467)**	**(143,539)**	**(7,976)**	**(19,430)**	**(170,945)**
Future development costs	**(11,272)**	**(9,345)**	**(10,695)**	**(15,035)**	**(29,489)**	**(676)**	**(76,512)**	**(10,778)**	**(2,836)**	**(90,126)**
Future income taxes	**(34,050)**	**(9,121)**	**(53,103)**	**(33,884)**	**(20,661)**	**(7,229)**	**(158,048)**	**(43,176)**	**(10,833)**	**(212,057)**
Undiscounted future net cash flows	**58,788**	**22,257**	**37,576**	**40,474**	**48,212**	**4,332**	**211,639**	**109,658**	**9,113**	**330,410**
10 percent midyear annual	**(25,013)**	**(15,082)**	**(13,801)**	**(14,627)**	**(35,051)**	**(1,117)**	**(104,691)**	**(61,675)**	**(4,883)**	**(171,249)**

discount for timing of estimated cash flows										
Standardized Measure Net Cash Flows	**$ 33,775**	**$ 7,175**	**$ 23,775**	**$ 25,847**	**$ 13,161**	**$ 3,215**	**$ 106,948**	**$ 47,983**	**$ 4,230**	**$ 159,161**
At December 31, 2010										
Future cash inflows from production[1]	$ 101,281	$ 48,068	$ 90,402	$ 101,553	$ 52,635	$ 13,618	$ 407,557	$ 124,970	$ 31,188	$ 563,715
Future production costs	(36,609)	(22,118)	(19,591)	(30,793)	(9,191)	(5,842)	(124,144)	(7,298)	(4,172)	(135,614)
Future development costs	(6,661)	(6,953)	(12,239)	(11,690)	(13,160)	(708)	(51,411)	(8,777)	(2,254)	(62,442)
Future income taxes	(20,307)	(7,337)	(34,405)	(26,355)	(9,085)	(4,031)	(101,520)	(30,763)	(12,919)	(145,202)
Undiscounted future net cash flows	37,704	11,660	24,167	32,715	21,199	3,037	130,482	78,132	11,843	220,457
10 percent midyear annual discount for timing of estimated cash flows	(13,218)	(6,751)	(9,221)	(12,287)	(15,282)	(699)	(57,458)	(43,973)	(6,574)	(108,005)
Standardized Measure Net Cash Flows	$ 24,486	$ 4,909	$ 14,946	$ 20,428	$ 5,917	$ 2,338	$ 73,024	$ 34,159	$ 5,269	$ 112,452
At December 31, 2009										
Future cash inflows from production[2]	$ 81,332	$ 39,251	$ 75,338	$ 91,993	$ 49,875	$ 11,988	$ 349,777	$ 97,793	$ 23,825	$ 471,395
Future production costs	(35,295)	(27,716)	(22,459)	(31,843)	(8,648)	(5,842)	(131,803)	(6,923)	(4,765)	(143,491)
Future development costs	(7,027)	(3,711)	(14,715)	(12,884)	(12,371)	(561)	(51,269)	(8,190)	(3,986)	(63,445)
Future income taxes	(13,662)	(3,674)	(22,503)	(18,905)	(10,484)	(3,269)	(72,497)	(23,357)	(7,774)	(103,628)
Undiscounted future net cash flows	25,348	4,150	15,661	28,361	18,372	2,316	94,208	59,323	7,300	160,831
	(8,822)	(2,275)	(5,882)	(11,722)	(14,764)	(467)	(43,932)	(34,937)	(4,450)	(83,319)

10 percent midyear annual discount for timing of estimated cash flows										
Standardized Measure Net Cash Flows	$ 16,526	$ 1,875	$ 9,779	$ 16,639	$ 3,608	$ 1,849	$ 50,276	$ 24,386	$ 2,850	$ 77,512

[1] Based on 12-month average price.

[2] Based on year-end prices.

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, 2009	$ 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
Sales and transfers of oil and gas produced net of production costs	(39,499)	(6,377)	(45,876)
Development costs incurred	12,042	572	12,614
Purchases of reserves	513		513
Sales of reserves	(47)		(47)
Extensions, discoveries and improved recovery less related costs	5,194	63	5,257
Revisions of previous quantity estimates	10,156	974	11,130
Net changes in prices, development and production costs	43,887	19,878	63,765
Accretion of discount	8,391	3,797	12,188
Net change in income tax	(17,889)	(6,715)	(24,604)
Net change for 2010	22,748	12,192	34,940

Present Value at December 31, 2010	$ 73,024	$ 39,428	$ 112,452
Sales and transfers of oil and gas produced net of production costs	**(53,063)**	**(8,679)**	**(61,742)**
Development costs incurred	**13,869**	**729**	**14,598**
Purchases of reserves	**1,212**		**1,212**
Sales of reserves	**(803)**		**(803)**
Extensions, discoveries and improved recovery less related costs	**12,288**		**12,288**
Revisions of previous quantity estimates	**16,750**	**791**	**17,541**
Net changes in prices, development and production costs	**61,428**	**19,097**	**80,525**
Accretion of discount	**11,943**	**5,563**	**17,506**
Net change in income tax	**(29,700)**	**(4,716)**	**(34,416)**
Net change for 2011	**33,924**	**12,785**	**46,709**
Present Value at December 31, 2011	**$ 106,948**	**$ 52,213**	**$ 159,161**

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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 September 29, 2010, filed as Exhibit 3.1 to Chevron Corporation s Current Report on Form 8-K filed September 30, 2010, 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 Securities and Exchange 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, filed as Exhibit 10.5 to Chevron Corporation s Current Report on Form 8-K filed December 13, 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. Director and Employee Deferral Plan, 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.
10.9*	Summary of Chevron Incentive Plan Award Criteria.
10.10	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 filed December 12, 2006, and incorporated herein by reference.
10.11	Chevron Corporation Benefit Protection Program, filed as Exhibit 10.2 to Chevron Corporation s Current Report on Form 8-K filed December 12, 2006, and incorporated herein by reference.
10.12	

	Form of Terms and Conditions for Awards under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.1 to Chevron Corporation s Current Report on Form 8-K filed February 1, 2011, and incorporated herein by reference.
10.13*	Form of Restricted Stock Unit Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.
10.14	Form of Retainer Stock Option Agreement under the Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan, filed as Exhibit 10.17 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference.
10.15	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.
10.16*	Agreement between Chevron Corporation and R. Hewitt Pate.
12.1*	Computation of Ratio of Earnings to Fixed Charges (page E-6).
21.1*	Subsidiaries of Chevron Corporation (pages E-7 through E-8).

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Exhibit No.	Description
23.1*	Consent of PricewaterhouseCoopers LLP (page E-9).
24.1 to 24.11*	Powers of Attorney for directors and certain officers of Chevron Corporation, authorizing the signing of the Annual Report on Form 10-K on their behalf.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Executive Officer (page E-21).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Financial Officer (page E-22).
32.1*	Section 1350 Certification of the company s Chief Executive Officer (page E-23).
32.2*	Section 1350 Certification of the company s Chief Financial Officer (page E-24).
95*	Mine Safety Disclosure.
99.1*	Definitions of Selected Energy and Financial Terms (pages E-26 through E-28).
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). The financial information contained in the XBRL-related documents is unaudited or unreviewed.

* Filed herewith.

Copies of above the 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.