Chevron

Human Energy™

2010 Annual Report

Contents

Chevron is developing a portfolio of major capital projects that include some of the largest and most pioneering ventures in the industry. To be successful, we must perform at the highest possible level and deliver results the right way. That is why we are sharply focused on three enterprise strategies that define our priorities around people, execution and growth. We are investing in our people so that we recruit, develop and maintain a world-class workforce. We are following rigorous processes to ensure that we operate responsibly, make disciplined decisions and execute our projects with excellence. And we are using our competitive advantages to grow our company profitably.

In addition to the printed *Annual Report*, we have developed an online version that contains additional information about our company, as well as videos you can watch to learn more about our projects. We invite you to visit our website at: Chevron.com/AnnualReport2010.

A strong base business: 2010 not only was an excellent year for moving our major capital projects forward, but it also was an excellent year for our base business. It is our base business – the performance of our existing assets – that enables us to fund new opportunities for growth. Through the expertise of our people and their application of innovative technology, we are better managing reservoirs, slowing production declines, and producing more crude oil and natural gas from mature fields.

To Our Stockholders

2010 was an outstanding year for Chevron. Once again our people delivered strong results in a challenging environment. We made significant advances in our queue of major capital projects, exceeded our goals for production growth, restructured our downstream business to enhance competitive performance and maintained our long-term leadership in total stockholder return.

The company's performance was grounded in a strong safety culture, which resulted in our safest year ever. The Macondo incident in the U.S. Gulf of Mexico underscored that safe operations are fundamental to our ability to operate. Following Macondo, we led the industry in working with regulators to enhance operating standards in the Gulf. We remain vigilant about safety, reliability and environmental stewardship wherever we operate.

Our financial performance in 2010 contributed to a very strong balance sheet and competitive returns for investors. Net income in 2010 was $19 billion on sales and other operating revenues of $198 billion. We increased our annual dividend in 2010 for the 23rd consecutive year, initiated a stock repurchase program and maintained leadership in two key measures of financial performance. Return on capital employed was 17.4 percent – a direct outcome of disciplined capital investment – and the company led our major competitors in total stockholder return over the past five years.

Our upstream business continues to deliver major capital projects from our industry-leading queue. Tahiti, our world-class deepwater project in the Gulf of Mexico, marked the first full year of production, and we continued ramp-ups of several new projects, including Frade in Brazil, Tombua-Landana in Angola and our Tengizchevroil joint venture in Kazakhstan. In 2010, total net oil-equivalent production in our upstream business increased 2 percent over 2009, after increasing 7 percent the previous year. We continued to build for future growth by sanctioning development of four large deepwater projects – Jack/St. Malo, Big Foot and Tahiti 2 in the Gulf of Mexico, and Papa-Terra in Brazil.

We also continued building a high-impact natural gas business, most notably in Australia with two world-class liquefied natural gas (LNG) projects, Gorgon and Wheatstone. Construction of the Gorgon facility on Barrow Island progressed toward 2014 startup while Wheatstone engineering work continued. A majority of our equity natural gas resources in both Gorgon and Wheatstone has been committed under long-term LNG sales contracts. Almost half of our natural gas portfolio is located in the Asia-Pacific region, positioning us as a long-term supplier to growing Asian markets.

Our exploration and business development programs created significant growth opportunities in 2010. We added new resource opportunities in China, Liberia, the Black Sea, eastern Europe and Canada. In addition, we acquired Atlas Energy in February 2011 to develop shale gas reserves in the prolific U.S. Marcellus Shale in Pennsylvania, bringing our total acreage additions since late 2009 to 14 million acres.

In our downstream business, we responded to challenging market conditions by restructuring to achieve sustained improvement in competitive performance. We concluded sales of nonstrategic assets and implemented a leaner, more focused and lower-cost downstream organization. We started up projects at our refinery in Pascagoula, Mississippi, our affiliate refinery in South Korea, and at a chemicals facility in Qatar.

Chevron enters 2011 with a $26 billion capital and exploratory budget — a 19 percent increase over 2010 levels and a reflection of our financial strength and unparalleled growth opportunities. Our spending will focus largely on executing upstream crude oil and natural gas exploration and production projects worldwide. Downstream spending will focus on increasing refinery flexibility, product yields and energy efficiency.

At Chevron, technology is directly linked to creating value for our stockholders. Some key focus areas include our *i-field*™ program, which applies information technology to improve production from mature fields; enhanced heavy oil recovery through advanced steamflood and thermal management; and implementation of our next-generation reservoir simulation technology.

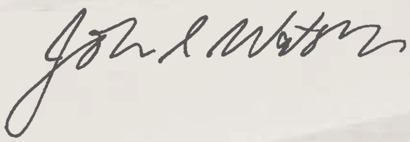
Technological innovation underpins our renewable energy strategy. We are investing in research projects with industry and university partners to explore promising pathways for renewables that may have the potential to be developed profitably at commercial scale. Our energy efficiency business, Chevron Energy Solutions, continues to apply advanced solar and other energy-saving technologies to lower costs for institutional customers. We also are exploring growth opportunities to develop new geothermal prospects in Indonesia and the Philippines.

In addition to operating capabilities, our success going forward is tied to the partnerships we build with our host communities. We focus our community partnerships and investments in three areas — health, education and economic development. We believe these areas are among the most promising avenues for creating mutual benefits for communities and our company. In 2010, we deployed approximately $180 million in community investments worldwide. Notable among our partnerships in 2010 was the launch of the Niger Delta Partnership Initiative, an innovative and multipartner approach to support sustained economic development and conflict resolution in the Niger Delta region. These types of social investments reflect our belief that our success as a business is tied directly to the economic vitality and health of the communities where we operate.

In 2010, we enhanced our core business strategies with three enterprise strategies: People, Execution and Growth. We are focused on recruiting and developing the best people in the business, flawlessly executing our projects and developing opportunities that will create long-term growth for the company. Above all else, the men and women of Chevron will continue to be guided by our company's values — getting results the right way — and our vision to be the company most admired for its people, partnership and performance.

I am confident that as we continue to produce the energy required for economic growth and human progress, our enduring values and proven strategies will continue to benefit our stockholders, our employees, our business partners and our communities.

Thank you for investing in Chevron.



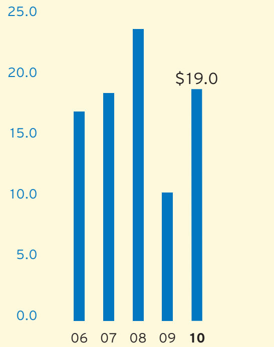
John S. Watson
Chairman of the Board and
Chief Executive Officer
February 24, 2011

Chevron Financial Highlights

Millions of dollars, except per-share amounts	**2010**	2009	% Change
Net income attributable to Chevron Corporation	**$ 19,024**	$ 10,483	81.5 %
Sales and other operating revenues	**$ 198,198**	$ 167,402	18.4 %
Noncontrolling interests income	**$ 112**	$ 80	40.0 %
Interest expense (after tax)	**$ 41**	$ 22	86.4 %
Capital and exploratory expenditures*	**$ 21,755**	$ 22,237	(2.2)%
Total assets at year-end	**$ 184,769**	$ 164,621	12.2 %
Total debt at year-end	**$ 11,476**	$ 10,514	9.2 %
Noncontrolling interests	**$ 730**	$ 647	12.8 %
Chevron Corporation stockholders' equity at year-end	**$ 105,081**	$ 91,914	14.3 %
Cash provided by operating activities	**$ 31,359**	$ 19,373	61.9 %
Common shares outstanding at year-end (Thousands)	**1,993,313**	1,993,554	0.0 %
Per-share data			
Net income – diluted	**$ 9.48**	$ 5.24	80.9 %
Cash dividends	**$ 2.84**	$ 2.66	6.8 %
Chevron Corporation stockholders' equity	**$ 52.72**	$ 46.11	14.3 %
Common stock price at year-end	**$ 91.25**	$ 76.99	18.5 %
Total debt to total debt-plus-equity ratio	**9.8%**	10.3%	
Return on average stockholders' equity	**19.3%**	11.7%	
Return on capital employed (ROCE)	**17.4%**	10.6%	

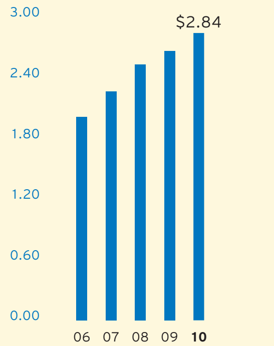
*Includes equity in affiliates

Net Income Attributable to Chevron Corporation
Billions of dollars



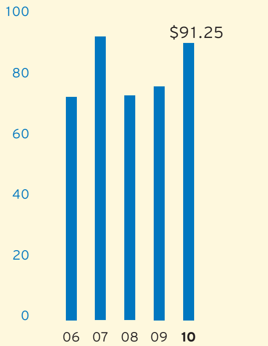
The increase in 2010 was due to higher earnings for both upstream and downstream, as a result of higher prices for crude oil, natural gas and refined products.

Annual Cash Dividends
Dollars per share



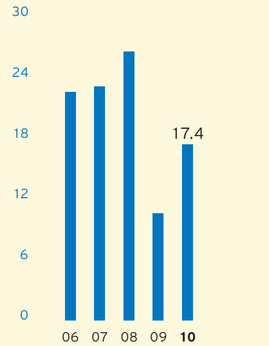
The company's annual dividend increased for the 23rd consecutive year.

Chevron Year-End Common Stock Price
Dollars per share



The company's stock price rose 18.5 percent in 2010.

Return on Capital Employed
Percent



Higher earnings improved Chevron's return on capital employed to 17.4 percent.

Chevron Operating Highlights[1]

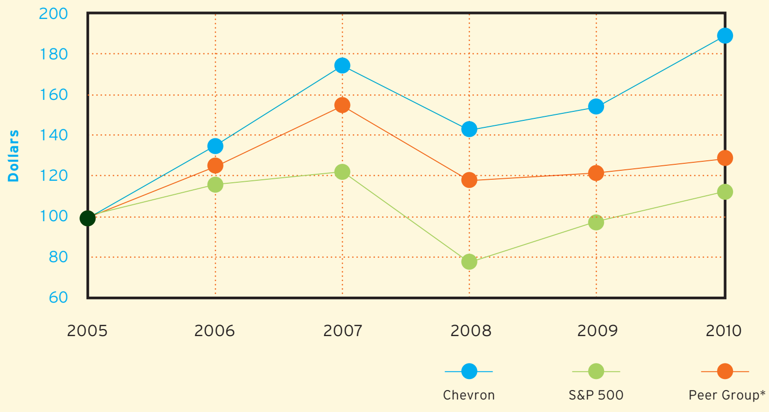
	2010	2009	% Change
Net production of crude oil and natural gas liquids (Thousands of barrels per day)	**1,923**	1,846	4.2 %
Net production of natural gas (Millions of cubic feet per day)	**5,040**	4,989	1.0 %
Net production of oil sands (Thousands of barrels per day)	**–**	26	(100.0)%
Total net oil-equivalent production (Thousands of oil-equivalent barrels per day)	**2,763**	2,704	2.2 %
Refinery input (Thousands of barrels per day)	**1,894**	1,878	0.9 %
Sales of refined products (Thousands of barrels per day)	**3,113**	3,254	(4.3)%
Net proved reserves of crude oil, condensate and natural gas liquids[2] (Millions of barrels)			
– Consolidated companies	**4,270**	4,610	(7.4)%
– Affiliated companies	**2,233**	2,363	(5.5)%
Net proved reserves of natural gas[2] (Billions of cubic feet)			
– Consolidated companies	**20,755**	22,153	(6.3)%
– Affiliated companies	**3,496**	3,896	(10.3)%
Net proved oil-equivalent reserves[2] (Millions of barrels)			
– Consolidated companies	**7,729**	8,302	(6.9)%
– Affiliated companies	**2,816**	3,012	(6.5)%
Number of employees at year-end[3]	**58,267**	59,963	(2.8)%

[1] Includes equity in affiliates, except number of employees
[2] At the end of the year
[3] Excludes service station personnel

Performance Graph

The stock performance graph at right shows how an initial investment of $100 in Chevron stock would have compared with an equal investment in the S&P 500 Index or the Competitor Peer Group. The comparison covers a five-year period beginning December 31, 2005, and ending December 31, 2010, and for the peer group is weighted by market capitalization as of the beginning of each year. It includes the reinvestment of all dividends that an investor would be entitled to receive and is adjusted for stock splits. The interim measurement points show the value of $100 invested on December 31, 2005, as of the end of each year between 2006 and 2010.

Five-Year Cumulative Total Returns
(Calendar years ended December 31)



	2005	2006	2007	2008	2009	2010
Chevron	**100**	**133.82**	**174.61**	**142.55**	**154.10**	**189.36**
S&P 500	100	115.80	122.09	76.92	97.26	111.90
Peer Group*	100	125.18	154.51	117.63	121.25	128.16

*Peer Group: BP p.l.c.-ADS, ExxonMobil, Royal Dutch Shell-ADR and ConocoPhillips

Chevron at a Glance

Chevron is one of the world's leading integrated energy companies, with subsidiaries that conduct business worldwide. Our success is driven by our people and their unrelenting focus on delivering results the right way — by operating responsibly, executing with excellence, applying innovative technologies and capturing new opportunities for profitable growth. We are involved in virtually every facet of the energy industry. We explore for, produce and transport crude oil and natural gas; refine, market and distribute transportation fuels and lubricants; manufacture and sell petrochemical products; generate power and produce geothermal energy; provide energy efficiency solutions; and develop the energy resources of the future, including biofuels.

Above, left to right:
Tengizchevroil Second Generation Plant, Tengiz, Kazakhstan; Tricia Padilla, environmental specialist, and Charles Odumah, process engineer, Richmond, California, refinery.

Upstream

Strategy:
Grow profitably in core areas and build new legacy positions.

Upstream explores for and produces crude oil and natural gas. At the end of 2010, worldwide net oil-equivalent reserves for consolidated operations and affiliated operations were 7.7 and 2.8 billion barrels, respectively. In 2010, net oil-equivalent production averaged 2.8 million barrels per day. Major producing areas include Angola, Australia, Azerbaijan, Bangladesh, Brazil, Canada, Denmark, Indonesia, Kazakhstan, Nigeria, the Partitioned Zone between Kuwait and Saudi Arabia, Thailand, the United Kingdom, the United States, and Venezuela. Major exploration areas include the U.S. Gulf of Mexico and the offshore areas of northwestern Australia and western Africa. Additional areas include the Gulf of Thailand, Black Sea, South China Sea, and the offshore areas of Canada, the United Kingdom, Norway, Brazil and Liberia. Shale gas exploration areas include Canada, Poland and Romania.

Gas and Midstream

Strategy:
Commercialize our equity gas resource base while growing a high-impact global gas business.

We are engaged in every aspect of the natural gas business – production, liquefaction, regasification, pipeline and marine transport, marketing and trading, power generation, and gas-to-liquids. We hold the largest natural gas resource position in Australia through the Gorgon, Wheatstone and Browse Basin projects; the North West Shelf Venture; and other deepwater blocks. We also have significant natural gas resources in western Africa, Bangladesh, Canada, China, Indonesia, Kazakhstan, the Philippines, South America, Thailand, the United Kingdom, the United States and Vietnam. Additionally, we have significant positions in shale gas in the United States.

Downstream and Chemicals

Strategy:
Improve returns and grow earnings across the value chain.

Our downstream operations include refining, fuels and lubricants marketing, petrochemicals manufacturing and marketing, supply and trading, and transportation. In 2010, we processed 1.9 million barrels of crude oil per day and averaged 3.1 million barrels per day of refined product sales worldwide. Our most significant areas of operations are the west coast of North America, the U.S. Gulf Coast, Southeast Asia, South Korea, Australia, South Africa and the United Kingdom. We hold interests in 16 fuel refineries and market under the Chevron, Texaco and Caltex motor fuel and lubricants brands. Products are sold through a network of approximately 20,000 retail stations, including those of affiliated companies. Our chemicals business includes Chevron Phillips Chemical Company LLC, a 50 percent-owned affiliate that is one of the world's leading manufacturers of commodity petrochemicals. Our subsidiary Chevron Oronite Company LLC also is part of our chemicals business. It develops, manufactures and markets quality additives that improve the performance of fuels and lubricants.

Technology

Strategy:
Differentiate performance through technology.

Technology advancements enable us to continue to overcome new and difficult business challenges. Our three technology companies – Energy Technology, Technology Ventures and Information Technology – support our base businesses and enable our most promising future opportunities. We have technology centers in Australia, Scotland and in California and Texas in the United States. Together they provide strategic research, technology development, and technical and computing infrastructure services to our global businesses.

Renewable Energy and Energy Efficiency

Strategy:
Invest in profitable renewable energy and energy efficiency solutions.

We are the largest producer of geothermal energy in the world, with leading positions in Indonesia and the Philippines. We are involved in developing emerging renewable sources of energy for the future, including advanced biofuels from nonfood sources. Our subsidiary Chevron Energy Solutions develops and builds sustainable energy projects for internal and external clients that increase efficiency and renewable power, reduce costs, and ensure high-quality energy.

Operational Excellence

Operational excellence (OE) is a critical driver for business success. We define OE as the systematic management of process safety, personal safety and health, environment, reliability and efficiency to achieve world-class performance. 2010 was our safest year ever. For the ninth consecutive year, we improved our safety performance, reducing the rate of injuries severe enough to require days away from work by 28 percent, compared with the previous year. Safety is our highest priority, and we will not be satisfied until we have zero incidents – no one injured. We also continue to make progress in energy efficiency, which has improved by 33 percent since 1992, the year we began tracking our efficiency progress.

Glossary of Energy and Financial Terms

Energy Terms

Additives Chemicals to control engine deposits and improve lubricating performance.

Barrels of oil-equivalent (BOE) A unit of measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content. See *oil-equivalent gas* and *production*.

Biofuel Any fuel that is derived from biomass — recently living organisms or their metabolic byproducts — from sources such as farming, forestry, and biodegradable industrial and municipal waste. See *renewables*.

Condensate Hydrocarbons that are in a gaseous state at reservoir conditions but condense into liquid as they travel up the wellbore and reach surface conditions.

Development Drilling, construction and related activities following discovery that are necessary to begin production and transportation of crude oil and natural gas.

Enhanced recovery Techniques used to increase or prolong production from crude oil and natural gas fields.

Exploration Searching for crude oil and/or natural gas by utilizing geologic and topographical studies, geophysical and seismic surveys, and drilling of wells.

Gas-to-liquids (GTL) A process that converts natural gas into high-quality transportation fuels and other products.

Greenhouse gases Gases that trap heat in Earth's atmosphere (e.g., water vapor, ozone, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride).

Integrated energy company A company engaged in all aspects of the energy industry, including exploring for and producing crude oil and natural gas; refining, marketing and transporting crude oil, natural gas and refined products; manufacturing and distributing petrochemicals; and generating power.

Liquefied natural gas (LNG) Natural gas that is liquefied under extremely cold temperatures to facilitate storage or transportation in specially designed vessels.

Natural gas liquids (NGL) Separated from natural gas, these include ethane, propane, butane and natural gasoline.

Oil-equivalent gas (OEG) The volume of natural gas needed to generate the equivalent amount of heat as a barrel of crude oil. Approximately 6,000 cubic feet of natural gas is equivalent to one barrel of crude oil.

Oil sands Naturally occurring mixture of bitumen (a heavy, viscous form of crude oil), water, sand and clay. Using hydroprocessing technology, bitumen can be refined to yield *synthetic oil*.

Petrochemicals Compounds derived from petroleum. These include aromatics, which are used to make plastics, adhesives, synthetic fibers and household detergents; and olefins, which are used to make packaging, plastic pipes, tires, batteries, household detergents and synthetic motor oils.

Production *Total production* refers to all the crude oil (including *synthetic oil*), natural gas liquids and natural gas produced from a property. *Gross production* is the company's share of total production before deducting both royalties paid to landowners and a government's agreed-upon share of production under a *production-sharing contract*. *Net production* is gross production minus both royalties paid to landowners and a government's agreed-upon share of production under a *production-sharing contract*. *Oil-equivalent production* is the sum of the barrels of liquids and the oil-equivalent barrels of natural gas produced. See *barrels of oil-equivalent* and *oil-equivalent gas*.

Production-sharing contract (PSC) An agreement between a government and a contractor (generally an oil and gas company) whereby production is shared between the parties in a prearranged manner. The contractor typically incurs all exploration, development and production costs that are subsequently recoverable out of an agreed-upon share of any future PSC production, referred to as cost recovery oil and/or gas. Any remaining production, referred to as profit oil and/or gas, is shared between the parties on an agreed-upon basis as stipulated in the PSC. The government also may retain a share of PSC production as a royalty payment, and the contractor may owe income taxes on its portion of the profit oil and/or gas. The contractor's share of PSC oil and/or gas production and reserves varies over time as it is dependent on prices, costs and specific PSC terms.

Renewables Energy resources that are not depleted when consumed or converted into other forms of energy (e.g., solar, geothermal, ocean and tide, wind, hydroelectric power, biofuels and hydrogen).

Reserves Crude oil or natural gas contained in underground rock formations called reservoirs and saleable hydrocarbons extracted from oil sands, shale, coalbeds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas. *Proved 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. Estimates change as additional information becomes available. *Oil-equivalent reserves* are the sum of the liquids reserves and the oil-equivalent gas reserves. See *barrels of oil-equivalent* and *oil-equivalent gas*.

The company only discloses proved reserves in its filings with the SEC. Certain terms, such as "probable" or "possible" reserves, "potentially recoverable" volumes, and "resources," among others, may be used to describe certain oil and gas properties in sections of this document that are not filed with the SEC. These other terms are used because they are common to the industry, are measures considered by management to be important in making capital investment and operating decisions, and provide some indication to stockholders of the potential ultimate recovery of oil and gas from properties in which the company has an interest. In that regard, potentially recoverable volumes are those that can be produced using all known primary and enhanced recovery methods.

Shale gas Natural gas produced from shale (clay-rich, very fine-grained) formations where the gas was sourced from within the shale itself and is trapped in rocks with low porosity and extremely low permeability. Production of shale gas requires the use of hydraulic fracturing (pumping a fluid-sand mixture into the formation under high pressure) to help produce the gas.

Synthetic oil A marketable and transportable hydrocarbon liquid, resembling crude oil, that is produced by upgrading highly viscous or solid hydrocarbons, such as extra-heavy crude oil or *oil sands*.

Financial Terms

Cash flow from operating activities Cash generated from the company's businesses; an indicator of a company's ability to pay dividends and fund capital and common stock repurchase programs. Excludes cash flows related to the company's financing and investing activities.

Earnings Net income attributable to Chevron Corporation as presented on the Consolidated Statement of Income.

Goodwill An asset representing the future economic benefits arising from the other assets acquired in a business combination that are not individually identified and separately recognized.

Margin The difference between the cost of purchasing, producing and/or marketing a product and its sales price.

Return on capital employed (ROCE) Ratio calculated by dividing *earnings* (adjusted for after-tax interest expense and noncontrolling interests) by the average of total debt, noncontrolling interests and Chevron Corporation stockholders' equity for the year.

Return on stockholders' equity Ratio calculated by dividing *earnings* by average Chevron Corporation stockholders' equity. Average Chevron Corporation stockholders' equity is computed by averaging the sum of the beginning-of-year and end-of-year balances.

Total stockholder return (TSR) The return to stockholders as measured by stock price appreciation and reinvested dividends for a period of time.

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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* of Chevron Corporation contains forward-looking statements relating to Chevron's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "schedules," "estimates," "budgets" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond 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. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Key Financial Results

Millions of dollars, except per-share amounts	**2010**	2009	2008
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
– Basic	**$ 9.53**	$ 5.26	$ 11.74
– Diluted	**$ 9.48**	$ 5.24	$ 11.67
Dividends	**$ 2.84**	$ 2.66	$ 2.53
Sales and Other Operating Revenues	**$ 198,198**	$ 167,402	$ 264,958
Return on:			
Capital Employed	**17.4%**	10.6%	26.6%
Stockholders' Equity	**19.3%**	11.7%	29.2%

Earnings by Major Operating Area

Millions of dollars	**2010**	2009	2008
Upstream[1]			
United States	**$ 4,122**	$ 2,262	$ 7,147
International	**13,555**	8,670	15,022
Total Upstream	**17,677**	10,932	22,169
Downstream[1]			
United States	**1,339**	(121)	1,369
International	**1,139**	594	1,783
Total Downstream	**2,478**	473	3,152
All Other	**(1,131)**	(922)	(1,390)
Net Income Attributable to Chevron Corporation[2,3]	**$ 19,024**	$ 10,483	$ 23,931

[1] 2009 and 2008 information has been revised to conform with the 2010 segment presentation.
[2] Includes foreign currency effects: **$ (423)** $ (744) $ 862
[3] Also referred to as "earnings" in the discussions that follow.

The activities reported in Chevron's upstream and downstream operating segments have changed effective January 1, 2010. Results for the chemicals businesses are now reported as part of the downstream segment. In addition, the company's significant upstream-enabling operations, primarily a gas-to-liquids project and major international export pipelines, have been reclassified from the downstream segment to the upstream segment. Prior period information in this report has been revised to conform to the 2010 presentation.

Refer to the "Results of Operations" section beginning on page 15 for a discussion of financial results by major operating area for the three years ended December 31, 2010.

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 both segments is movement in the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. The overall trend in earnings is typically less affected by results from the company's other activities and investments. Earnings for the company in any period may also be influenced by events or transactions that are infrequent or unusual in nature.

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

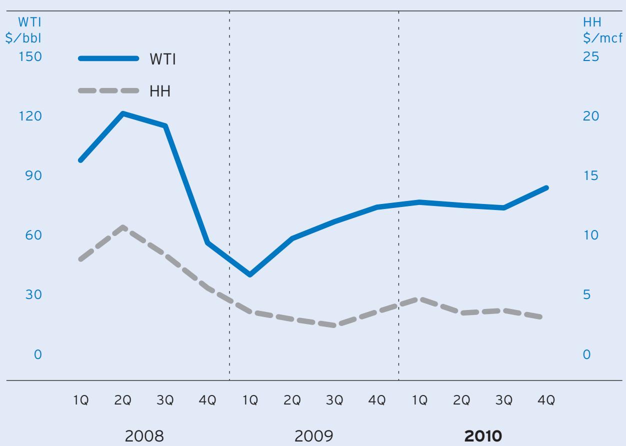
To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer attractive financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments. From time to time, certain governments have sought to renegotiate contracts or impose additional costs on the company. Governments may attempt to do so in the future. The company will continue to monitor these developments, take them into account in evaluating future investment opportunities, and otherwise seek to mitigate any risks to the company's current operations or future prospects.

The company also continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company's financial performance and growth. Refer to the "Results of Operations" section beginning on page 15 for discussions of net gains on asset sales during 2010. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

In recent years, Chevron and the oil and gas industry generally experienced an increase in certain costs that exceeded the general trend of inflation in many areas of the world. This increase in costs affected the company's operating expenses and capital programs for all business segments, but particularly for Upstream. Softening of these cost pressures started in late 2008 and continued through most of 2009. Industry costs began to level out in fourth quarter 2009 and rose slightly in 2010. The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs.

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. The company remains confident of its underlying financial strength to address potential challenges presented in the current environment. (Refer also to the "Liquidity and Capital Resources" section beginning on page 20.)

WTI Crude Oil and Henry Hub Natural Gas Spot Prices — Quarterly Average



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

Upstream Earnings for the upstream segment are closely aligned with industry price levels for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry inventory levels, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and regional supply interruptions or fears thereof that may be caused by military conflicts, civil unrest or political uncertainty. Moreover, any of these factors could also inhibit the company's production capacity in an affected region. The company monitors developments closely in the countries in which it operates and holds investments and seeks to manage risks in operating its facilities and businesses. Besides the impact of the fluctuation in prices for crude oil and natural gas, the longer-term trend in earnings for the upstream segment is also a function of other factors, including the company's ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms of contracts and changes in tax laws and regulations.

Price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can also be subject to external factors beyond the company's control. External factors include not only the general level of inflation, but also commodity prices and prices charged by the industry's material and service providers, which can be affected by the volatility of the industry's own supply-and-demand conditions for such materials and services. Capital and exploratory expenditures and operating expenses can also be affected by damage to production facilities caused by severe weather or civil unrest.

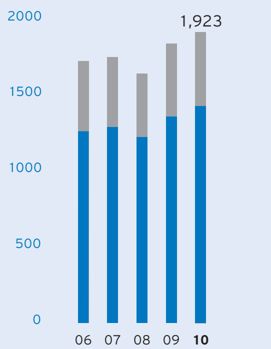
The chart at the left shows the trend in benchmark prices for West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. The WTI price averaged $79 per barrel for the full-year 2010, compared to $62 in 2009. As of mid-February 2011, the WTI price was about $85.

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 number of refineries that are able to process this lower quality feedstock into light products (motor gasoline, jet fuel, aviation gasoline and diesel fuel). The differential widened during 2010 primarily due to both strong diesel prices and relatively weaker fuel oil prices.

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 19 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 $4.50 per thousand cubic feet (MCF) during 2010, compared with about $3.80 during 2009. As of mid-February 2011, the Henry Hub spot price was about $4.20 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 and the level of inventory in underground storage.

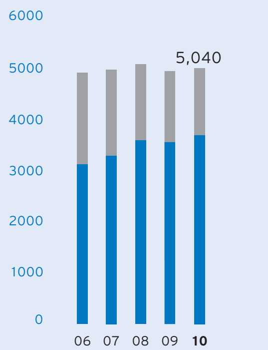
Net Liquids Production*
Thousands of barrels per day



Net liquids production increased 4 percent in 2010 mainly due to new projects in the United States, Brazil and Nigeria, expansion of capacity at TCO in Kazakhstan and inclusion of Canada synthetic oil in 2010.

*Includes equity in affiliates.

Net Natural Gas Production*
Millions of cubic feet per day



Net natural gas production increased 1 percent in 2010. International production increase more than offset decline in United States.

*Includes equity in affiliates.

Certain international natural gas markets in which the company operates have different supply, demand and regulatory circumstances, which historically have resulted in lower average sales prices for the company's production of natural gas in these locations. In some of these locations Chevron is investing in long-term projects to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets where greater demand results in higher prices. International natural gas realizations averaged about $4.60 per MCF during 2010, compared with about $4.00 per MCF during 2009. These realizations reflect a strong demand for energy in certain Asian markets. (See page 19 for the company's average natural gas realizations for the U.S. and international regions.)

The company's worldwide net oil-equivalent production in 2010 averaged 2.763 million barrels per day. About one-fifth of the company's net oil-equivalent production in 2010 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 2010, while production in 2009 was reduced by an average of 20,000 barrels per day due to quotas imposed by OPEC. All of the imposed curtailments took place during the first half of 2009. At the December 2010 meeting, members of OPEC supported maintaining production quotas in effect since December 2008.

The company estimates that oil-equivalent production in 2011 will average approximately 2.790 million barrels per day. This estimate is subject to many factors and uncertainties, including additional quotas that may be imposed by OPEC, price effects on production volumes calculated under production sharing and variable-royalty provisions of certain agreements, 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 15 through 16 for additional discussion of the company's upstream business.

Refer to Table V beginning on page 79 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2008 and each year-end from 2008 through 2010, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2010.

Gulf of Mexico Update In April 2010, an accident occurred on the Transocean Deepwater Horizon, a deepwater drilling rig in the Gulf of Mexico, resulting in a loss of life, the sinking of the rig and a significant oil spill. The rig was drilling an exploratory well at the BP-operated Macondo prospect. Chevron was not a participant in the well. Subsequent to the event, the U.S. Department of the Interior put in place a moratorium on the drilling of wells using subsea blowout preventers (BOPs) or surface BOPs on a floating facility in the Gulf of Mexico and the Pacific regions. In October 2010, the Secretary of the Interior lifted the drilling moratorium, provided that operators certify compliance with all the newly expanded rules and requirements, and demonstrate the availability of adequate blowout containment resources.

The moratorium and the ensuing slowdown in issuing drilling permits since the moratorium was lifted have resulted in delays in shallow water drilling activity, delayed the drilling of exploratory deepwater wells and impacted development drilling on both operated and nonoperated projects in the Gulf of Mexico. The company's daily net oil-equivalent production in the Gulf of Mexico was reduced by about 10,000 barrels per day for the full year. The company has submitted several deepwater drilling permit applications and plans to submit additional applications in 2011. Two deepwater drillships are on stand-by, pending issuance of permits from the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), to drill wells in the Gulf of Mexico. A third deepwater drillship is drilling a water injection well at the Tahiti Field. Additionally, the completion of previously drilled wells has recommenced at the nonoperated Perdido and Caesar/Tonga projects. The future effects of this incident, including any new or additional regulations that may be adopted and the timing of BOEMRE issuing drilling permits, are not fully known at this time. Chevron remains committed to deepwater exploration and development in the Gulf of Mexico and other deepwater basins around the world.

During the moratorium, Chevron participated in a number of industry efforts to identify opportunities to improve industry standards in prevention, intervention and spill response. In July 2010, Chevron and several other companies announced plans to build and deploy a rapid response system that will be available to capture and contain crude oil in the unlikely event of a future well blowout in the deepwater Gulf of Mexico. The new system will be engineered to be used in water depths up to 10,000 feet and designed to have capacity to contain 100,000 barrels per day, with potential for expansion. The companies committed to equally fund the initial $1 billion investment in the system. There will be additional ongoing costs for operations and maintenance of the system components. An initial agreement to secure containment equipment has been announced, and other equipment is expected to be secured and available in the coming months, with the new system targeted for completion in early 2012. The companies have formed an organization, the Marine Well Containment Company, to operate and maintain this system. Other companies have been invited and encouraged to participate in this organization.

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, cost 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 the 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, Latin America, Asia, southern Africa and the United Kingdom. Chevron operates or has significant ownership interests in refineries in each of these areas except Latin America. In third quarter 2010, the company completed its exit from the District of Columbia, Delaware, Indiana, Kentucky, North Carolina, New Jersey, Maryland, Ohio, Pennsylvania, South Carolina, Virginia, West Virginia and parts of Tennessee, where the company sold Chevron- and Texaco-branded motor fuels to retail customers through approximately 1,100 stations, and to commercial and industrial customers through supply arrangements. Sales in these markets represented approximately 8 percent of the company's total 2009 U.S. retail fuel sales volumes.

The company's refining and marketing margins in 2010 improved over 2009, but remain relatively weak due to the economic slowdown, excess refined product supplies and surplus refining capacity. Expecting these conditions to continue for several years, in first quarter 2010 the company announced that its downstream businesses would be restructured to improve operating efficiency and achieve sustained improvement in financial performance. As part of this restructuring, employee-reduction programs were announced for the United States and international downstream operations. The initial estimate included approximately 3,200 employees. Due to redeployment efforts within the company, it is currently expected that approximately 2,800 employees in the downstream operations will be terminated under these programs before the end of 2011. About 1,100 of the affected employees are located in the United States. During 2010, 1,400 employees were terminated worldwide. Refer to Note 23 of the Consolidated Financial Statements, beginning on page 67, for further discussion. In 2010, the company solicited bids for 13 U.S. terminals and certain operations in Europe (including the company's Pembroke Refinery), the Caribbean, and select Central America and Africa markets. These sales are part of the company's ongoing effort to concentrate downstream resources and capital on strategic global assets. These potential market exits, dispositions of assets, and other actions may result in gains or losses in future periods. Through fourth quarter 2010, the company completed the sale of six U.S. terminals and certain marketing businesses in Africa, which resulted in gains that were not material to the company. Also, in late 2010 the company completed the sale of its 23.4 percent ownership interest in the Colonial Pipeline Company, which resulted in a gain on sale of nearly $400 million.

Refer to the "Results of Operations" section on page 17 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, alternative fuels, and technology companies. In first quarter 2010, employee-reduction programs were announced for the corporate staffs. As of year-end, it was expected that approximately 400 employees from the corporate staffs will be terminated under the programs by the end of 2011, including approximately 100 who were terminated in 2010. Refer to Note 23 of the Consolidated Financial Statements, beginning on page 67, for further discussion.

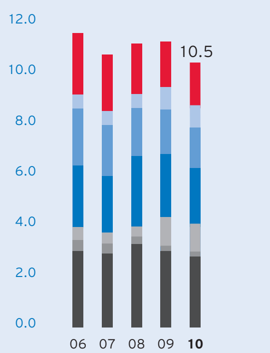
Operating Developments

Key operating developments and other events during 2010 and early 2011 included the following:

Upstream

Australia Construction activities on Barrow Island and other activities for the Gorgon Project progressed on schedule during 2010 with the award of approximately $25 billion of contracts for materials and services, clearing of the plant site, completion of the first stage of the construction village, commencement of module fabrication, and progression of studies on the possible expansion of the project. In early 2011, the company signed an additional binding liquefied natural gas (LNG) Sales and Purchase Agreement (SPA) with an Asian customer. The company has signed five binding LNG SPAs with Asian customers for delivery of about 4.7 million metric tons of LNG per year. Negotiations continue to finalize the two remaining nonbinding Heads of Agreement (HOAs) as binding SPAs, which would bring LNG delivery commitments to a combined total of about 90 percent of Chevron's share of LNG from the project.

Net Proved Reserves
Billions of BOE*



- United States
- Other Americas
- Africa
- Asia
- Australia
- Europe
- Affiliates

Net proved reserves for both consolidated companies and affiliated companies decreased 7 percent in 2010.

*2010 and 2009 include barrels of oil-equivalent reserves for Canadian synthetic oil.

Through the end of 2010, the company has signed nonbinding HOAs with three Asian customers for the delivery of about 80 percent of Chevron's net LNG offtake from the Chevron-operated Wheatstone Project. Negotiations continue to move the three HOAs to binding SPAs with these customers. These three customers have also agreed to acquire a combined 21.8 percent nonoperated working interest in the Wheatstone field licenses and a 17.5 percent interest in the foundation natural gas processing facilities at the time of the final investment decision. The project, currently undergoing front-end engineering and design (FEED), has a planned capacity of 8.9 million metric tons per year.

During 2010, the company announced additional deepwater natural gas discoveries, including the Clio and Acme prospects in 67 percent-owned Block WA-205-P, Yellowglen prospect in 50 percent-owned Block WA-268-P, Brederode prospect in 50 percent-owned Block WA-364-P, and Sappho prospect in 50 percent-owned Block WA-392-P. In February 2011, the company announced a natural gas discovery in the Orthrus prospect in 50 percent-owned Block WA-24-R. These discoveries are expected to contribute to further growth at company-operated LNG projects in Australia.

Cambodia The company completed three successful exploration wells during 2010. In the first-half 2011, a 30-year production permit for the production sharing contract is expected to be approved by the government. A final investment decision for construction of a wellhead platform and a floating storage and offloading vessel is expected in 2011.

Canada First production was achieved from the Jackpine Mine in third quarter 2010 as a result of Athabasca Oil Sands Project Expansion 1 activities. In addition, through 2010 the company acquired approximately 200,000 acres of shale gas leasehold in western Canada. The appraisal of this acreage is expected to begin by the second-half 2011.

China The company acquired a 100 percent interest in Blocks 53-30 and 64-18, and a 59 percent interest in Block 42-05, covering a combined total exploratory acreage of approximately 5.2 million acres in the South China Sea's Pearl River Mouth Basin.

Indonesia A final investment decision was reached for Development Area 13 of the Duri Field, where Chevron holds a 100 percent working interest.

The company awarded FEED contracts in December 2010 for the Gendalo-Gehem natural gas development in the Makassar Strait offshore East Kalimantan, Indonesia. Contracts for floating production units, subsea and flowline systems, export pipelines, and an onshore receiving facility were awarded for the project.

Kazakhstan/Russia Approval was obtained from the shareholders and governing bodies of the Caspian Pipeline Consortium for a $5.4 billion expansion of the Caspian Pipeline. The capacity of the 935-mile pipeline, which carries crude oil from western Kazakhstan to a dedicated terminal on the Black Sea, will increase to 1.4 million barrels per day.

Liberia The company acquired a 70 percent interest and operatorship in three deepwater blocks covering 2.4 million acres off the coast of Liberia in western Africa. A three-year exploratory program began in fourth quarter 2010.

Poland Acquisition work commenced in October 2010 on a 2-D seismic survey across the company's four shale gas licenses in southeast Poland. Chevron has a 100 percent-owned and operated interest in these four concessions, totalling 1.1 million acres.

Republic of the Congo Discoveries were confirmed at the Bilondo Marine 2 and 3 wells within the Moho-Bilondo license. Chevron has a 31.5 percent interest in the permit area.

Romania The company successfully bid on three shale gas exploration blocks, comprising approximately 670,000 acres, in the southeast region of the country. In February

2011, the company acquired a 100 percent interest in the EV-2 Barlad shale gas concession, covering 1.5 million acres in the northeast region of the country.

Russia The company signed a nonbinding HOA for a deepwater development partnership on the Shatsky Ridge in the eastern Black Sea.

Turkey The company signed a Joint Operation Agreement for an exploration license in the Black Sea. Chevron acquired a 50 percent interest in a western portion of License 3921, a 5.6 million-acre block located 220 miles northwest of the capital city of Ankara.

United States In March 2010, first oil was achieved at the nonoperated Perdido Regional Development in the Gulf of Mexico. Located in nearly 8,000 feet of water, Perdido is also the world's deepest offshore oil and gas drilling and production spar. Chevron has a 37.5 percent working interest in the Perdido regional host facility.

The company sanctioned development of the Jack/St. Malo project in October 2010, the company's first operated project located in the Lower Tertiary trend in the deepwater Gulf of Mexico. Seven exploration and appraisal wells have been successfully and safely drilled at these fields since 2003. Chevron has a working interest of 50 percent in the Jack Field and 51 percent in the St. Malo Field.

In December 2010, the company sanctioned development of the 60 percent-owned and operated Big Foot project in the deepwater Gulf of Mexico.

In April 2010, the company successfully bid for new exploration acreage in a central Gulf of Mexico lease sale.

In February 2011, the company completed the acquisition of Atlas Energy, Inc., for $4.47 billion including assumed debt. Atlas holds one of the premier acreage positions in the Marcellus Shale, concentrated in southwestern Pennsylvania.

Venezuela In February 2010, a Chevron-led consortium was named the operator of the Carabobo 3 heavy-oil project, composed of three blocks in the Orinoco Oil Belt of eastern Venezuela. A joint operating company, Petroindependencia, was formed in May 2010, and work toward commercialization of the Carabobo 3 project was initiated. The consortium holds a combined 40 percent interest in the project.

Downstream

Africa In December 2010 and February 2011, the company completed the sale of its marketing businesses in Malawi, Mauritius, Réunion, Tanzania and Zambia.

Caribbean and Central America In November 2010, the company announced an agreement to sell its fuels marketing and aviation fuels businesses in Antigua, Barbados, Belize, Costa Rica, Dominica, French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Nicaragua, St. Kitts, St. Lucia, St. Vincent, and Trinidad and Tobago. The transactions are expected to close by third quarter 2011, following receipt of required local regulatory and government approvals. This sale is part of the company's ongoing effort to concentrate downstream resources and capital on strategic global assets.

Europe In February 2011, the company announced an agreement to sell its fuels, finished lubricants and aviation fuels businesses in Spain.

South Korea A new, 60,000-barrel-per-day heavy-oil hydrocracker was commissioned and reached full capacity in third quarter 2010 at the 50 percent-owned GS Caltex Yeosu Refinery in South Korea. Also at the Yeosu Refinery, GS Caltex announced plans to construct a 53,000-barrel-per-day gas oil fluid catalytic cracking unit. The unit is scheduled for start-up in 2013. Both units are designed to increase high-value product yield and lower feedstock costs.

United States In October 2010, the company sold its 23.4 percent ownership interest in the Colonial Pipeline Company.

In January 2011, the company announced the final investment decision on a $1.4 billion project to construct a lubricants manufacturing facility at the Pascagoula refinery. The facility will manufacture 25,000 barrels per day of premium base oil.

Other

Common Stock Dividends The quarterly common stock dividend increased by 5.9 percent in April 2010, to $0.72 per common share, making 2010 the 23rd consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program In July 2010, the company terminated the three-year $15 billion share repurchase program that had been initiated in September 2007. In its place, the Board of Directors approved a new, ongoing share repurchase program with no set term or monetary limits. The company began purchases of its common stock in the fourth quarter, and as of December 31, 2010, 8.8 million common shares had been acquired under the program for $750 million.

Results of Operations

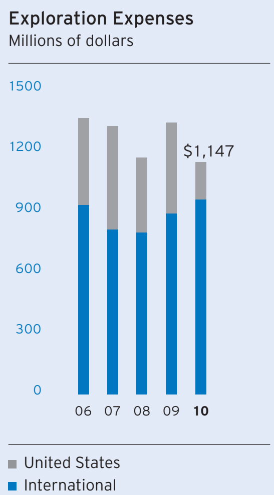
Major Operating Areas The following section presents the results of operations for the company's business segments – Upstream and Downstream – as well as for "All Other." Earnings are also presented for the U.S. and international geographic areas of the Upstream and Downstream business segments. (Refer to Note 11, beginning on page 49, 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 10 through 13.

U.S. Upstream

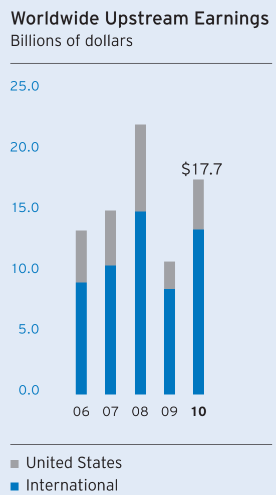
Millions of dollars	2010	2009	2008
Earnings	**$ 4,122**	$ 2,262	$ 7,147

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.

U.S. upstream earnings of $2.3 billion in 2009 decreased $4.9 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by about $5.2 billion between periods,



Exploration expenses decreased 15 percent from 2009 mainly due to lower well write-offs in the United States.



Earnings increased in 2010 on higher average prices for crude oil and natural gas.

and gains on asset sales declined by approximately $900 million. Partially offsetting these effects was a benefit of about $1.3 billion resulting from an increase in net oil equivalent production. An approximate $600 million benefit to income from lower operating expenses was more than offset by higher depreciation expense. The benefit from lower operating expenses was largely associated with an absence of charges for damages related to the 2008 hurricanes in the Gulf of Mexico.

The company's average realization for U.S. crude oil and natural gas liquids in 2010 was $71.59 per barrel, compared with $54.36 in 2009 and $88.43 in 2008. The average natural gas realization was $4.26 per thousand cubic feet in 2010, compared with $3.73 and $7.90 in 2009 and 2008, respectively.

Net oil-equivalent production in 2010 averaged 708,000 barrels per day, down 1 percent from 2009 and up 6 percent from 2008. Natural field declines between 2010 and 2009 were mostly offset by increased production from the Tahiti Field. The increase between 2009 and 2008 was mainly due to the start-up of the Blind Faith Field in late 2008 and the Tahiti Field in second quarter 2009. The net liquids component of oil-equivalent production for 2010 averaged 489,000 barrels per day, up 1 percent from 2009 and up 16 percent compared with 2008. Net natural gas production averaged 1.3 billion cubic feet per day in 2010, down approximately 6 percent from 2009 and down about 12 percent from 2008. Refer to the "Selected Operating Data" table on page 19 for the three-year comparative production volumes in the United States.

International Upstream

Millions of dollars	**2010**	2009	2008
Earnings*	**$ 13,555**	$ 8,670	$ 15,022
*Includes foreign currency effects:	**$ (293)**	$ (578)	$ 937

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.

International upstream earnings of $8.7 billion in 2009 decreased $6.4 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by $7.0 billion, while foreign currency effects and higher operating and depreciation expenses decreased income by a total of $2.2 billion. Partially offsetting these items were benefits of $2.3 billion resulting from an increase in sales volumes of crude oil and about $500 million associated with asset sales and tax items related to the Gorgon Project.

The company's average realization for international crude oil and natural gas liquids in 2010 was $72.68 per barrel, compared with $55.97 in 2009 and $86.51 in 2008. The average natural gas realization was $4.64 per thousand cubic feet in 2010, compared with $4.01 and $5.19 in 2009 and 2008, respectively.

International net oil-equivalent production of 2.06 million barrels per day in 2010 increased about 3 percent and 11 percent from 2009 and 2008, respectively. The volumes in 2010 include synthetic oil that was reported in 2009 and 2008 as production from oil sands in Canada. Absent the impact of prices on certain production-sharing and variable-royalty agreements, net oil-equivalent production increased 5 percent in 2010 and 4 percent in 2009, when compared with the prior year's production.

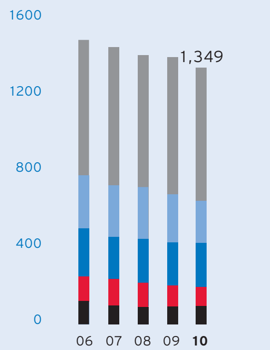
The net liquids component of international oil-equivalent production was 1.4 million barrels per day in 2010, an increase of approximately 3 percent from 2009 and 14 percent from 2008. International net natural gas production of 3.7 billion cubic feet per day in 2010 was up 4 percent and 3 percent from 2009 and 2008, respectively.

Refer to the "Selected Operating Data" table, on page 19, for the three-year comparative of international production volumes.

U.S. Downstream

Millions of dollars	**2010**	2009	2008
Earnings	**$ 1,339**	$ (121)	$ 1,369

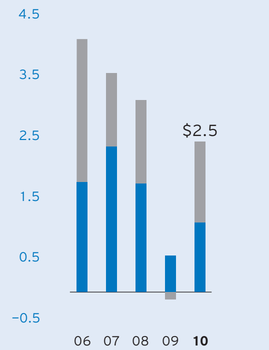
U.S. Gasoline & Other Refined Product Sales
Thousands of barrels per day



- Gasoline
- Jet Fuel
- Gas Oils & Kerosene
- Residual Fuel Oil
- Other

Refined-product sales volumes decreased about 4 percent from 2009 on lower sales of gasoline and jet fuel.

Worldwide Downstream Earnings*
Billions of dollars



- United States
- International

Downstream earnings increased more than 400 percent from 2009 due to higher margins on the sale of refined products.

*Includes equity in affiliates

U.S. downstream earned $1,339 million in 2010, compared with a loss of $121 million in 2009. Improved margins on refined products increased earnings by about $550 million. Also contributing to the increase was a nearly $400 million gain on the sale of a 23.4 percent ownership interest in the Colonial Pipeline Company. Higher earnings from chemicals operations increased earnings by about $300 million, largely from improved margins at the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem).

Earnings decreased approximately $1.5 billion in 2009 from 2008. Lower refined product margins resulted in an earnings decline of $1.7 billion. Partially offsetting the effects of lower refined product margins was a decrease in operating expenses, which benefited earnings by $300 million, and an increase of about $100 million in earnings from CPChem. The improvement for CPChem reflected lower utility and manufacturing costs, as well as the absence of an impairment recorded in 2008. These benefits more than offset lower margins on the sale of commodity chemicals.

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. Sales volumes of refined products were 1.40 million barrels per day in 2009, a decrease of 1 percent from 2008. U.S. branded gasoline sales decreased to 573,000 barrels per day in 2010, representing approximately 7 percent and 5 percent declines from 2009 and 2008, respectively. The decline in 2010, relative to 2009 and 2008, was primarily due to the previously announced exits from selected eastern U.S. retail markets.

Refer to the "Selected Operating Data" table on page 19 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

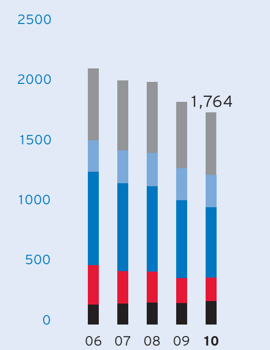
International Downstream

Millions of dollars	**2010**	2009	2008
Earnings*	**$ 1,139**	$ 594	$ 1,783
*Includes foreign currency effects:	**$ (135)**	$ (191)	$ 111

International downstream earned $1,139 million in 2010, compared with $594 million in 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 reduction and transportation costs. Foreign currency effects reduced earnings by $135 million in 2010, compared with a reduction of $191 million in 2009.

Earnings of $594 million in 2009 decreased about $1.2 billion from 2008. A decline of approximately $2.6 billion between periods was associated with weaker margins on the manufacture and sale of gasoline and other refined products and the absence of gains recorded in 2008 on derivative instruments. Foreign currency effects produced an unfavorable variance of about $300 million. Partially offsetting these items were a $1.0 billion benefit from lower operating expenses associated mainly with contract labor, professional services and transportation costs, and about a $550 million increase in gains on asset sales related to refined products marketing operations, primarily in certain countries in Latin America and Africa.

International Gasoline & Other Refined Product Sales*
Thousands of barrels per day



- Gasoline
- Jet Fuel
- Gas Oils & Kerosene
- Residual Fuel Oil
- Other

Sales volumes of refined products were down 5 percent from 2009 due to asset sales in Africa and Latin America.

*Includes equity in affiliates

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

Refer to the "Selected Operating Data" table, on page 19, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars	2010	2009	2008
Net charges*	**$ (1,131)**	$ (922)	$ (1,390)
*Includes foreign currency effects:	**$ 5**	$ 25	$ (186)

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

Net charges in 2010 increased $209 million from 2009, mainly due to higher expenses for employee compensation and benefits and higher corporate tax items, partly offset by lower provisions for environmental remediation at sites that previously had been closed or sold. Net charges in 2009 decreased $468 million from 2008 due to lower provisions for environmental remediation at sites that previously had been closed or sold, favorable foreign currency effects and lower expenses for employee compensation and benefits.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	2010	2009	2008
Sales and other operating revenues	**$ 198,198**	$ 167,402	$ 264,958

Sales and other operating revenues increased in 2010, mainly due to higher prices for crude oil, natural gas and refined products. Lower 2009 prices resulted in decreased revenues compared with 2008.

Millions of dollars	2010	2009	2008
Income from equity affiliates	**$ 5,637**	$ 3,316	$ 5,366

Income from equity affiliates increased in 2010 from 2009 largely due to higher upstream-related earnings from Tengizchevroil (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. Income from equity affiliates decreased in 2009 from 2008. Upstream-related affiliate income declined about $1.3 billion mainly due to lower earnings for TCO as a result of lower prices for crude oil. Downstream-related affiliate earnings were lower by approximately $1.0 billion primarily due to weaker margins and an unfavorable swing in foreign currency effects. Refer to Note 12, beginning on page 51, for a discussion of Chevron's investments in affiliated companies.

Millions of dollars	2010	2009	2008
Other income	**$ 1,093**	$ 918	$ 2,681

Other income of $1.1 billion in 2010 included net gains of approximately $1.1 billion on asset sales. Other income in both 2009 and 2008 included net gains from asset sales of $1.3 billion. Interest income was approximately $120 million in 2010, $95 million in 2009 and $340 million in 2008. Foreign currency effects decreased other income by $251 million in 2010 and $466 million in 2009, while increasing other income by $355 million in 2008. In addition, other income in 2008 included approximately $700 million in favorable settlements and other items.

Millions of dollars	2010	2009	2008
Purchased crude oil and products	**$ 116,467**	$ 99,653	$ 171,397

Crude oil and product purchases in 2010 increased $16.8 billion from 2009 due to higher prices for crude oil, natural gas and refined products. Crude oil and product purchases in 2009 decreased $71.7 billion from 2008 due to lower prices for crude oil, natural gas and refined products.

Millions of dollars	2010	2009	2008
Operating, selling, general and administrative expenses	**$ 23,955**	$ 22,384	$ 26,551

Operating, selling, general and administrative 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. Total expenses for 2009 decreased approximately $4.2 billion from 2008 primarily due to $1.4 billion of lower fuel and transportation expenses; $800 million of decreased costs for contract labor and professional services; the absence of uninsured 2008 hurricane-related charges of $700 million; a decrease of about $500 million for environmental remediation activities; $200 million of lower costs for materials; and $600 million for other items.

Millions of dollars	2010	2009	2008
Exploration expense	**$ 1,147**	$ 1,342	$ 1,169

Exploration expenses in 2010 declined from 2009 mainly due to lower amounts for geological and geophysical costs and well write-offs. Exploration expenses in 2009 increased from 2008 mainly due to higher amounts for well write-offs in the United States and international operations.

Millions of dollars	**2010**	2009	2008
Depreciation, depletion and amortization	**$ 13,063**	$ 12,110	$ 9,528

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. Depreciation, depletion and amortization expenses increased in 2009 from 2008 due to incremental production related to start-ups for upstream projects in the United States and Africa and higher depreciation rates for certain other oil and gas producing fields.

Millions of dollars	**2010**	2009	2008
Taxes other than on income	**$ 18,191**	$ 17,591	$ 21,303

Taxes other than on income increased in 2010 from 2009 mainly due to higher excise taxes in Canada and the United Kingdom. Taxes other than on income decreased in 2009 from 2008 mainly due to lower import duties for the company's downstream operations in the United Kingdom.

Millions of dollars	**2010**	2009	2008
Interest and debt expense	**$ 50**	$ 28	$ –

Interest and debt expense, net of capitalized interest, increased in 2010 from 2009 primarily due to slightly higher average effective interest rates. The increase in 2009 over 2008 was due to an increase in long-term debt.

Millions of dollars	**2010**	2009	2008
Income tax expense	**$ 12,919**	$ 7,965	$ 19,026

Effective income tax rates were 40 percent in 2010, 43 percent in 2009 and 44 percent in 2008. The rate was lower in 2010 than in 2009 primarily due to international upstream impacts. A lower effective tax rate in international upstream in 2010 was primarily driven by 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. The rate was lower in 2009 than in 2008 mainly due to the effect in 2009 of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates. Refer also to the discussion of income taxes in Note 15 beginning on page 55.

Selected Operating Data[1,2]

	2010	2009	2008
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**489**	484	421
Net Natural Gas Production (MMCFPD)[3]	**1,314**	1,399	1,501
Net Oil-Equivalent Production (MBOEPD)	**708**	717	671
Sales of Natural Gas (MMCFPD)	**5,932**	5,901	7,226
Sales of Natural Gas Liquids (MBPD)	**22**	17	15
Revenues From Net Production			
Liquids ($/Bbl)	**$ 71.59**	$ 54.36	$ 88.43
Natural Gas ($/MCF)	**$ 4.26**	$ 3.73	$ 7.90
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)[4]	**1,434**	1,362	1,228
Net Natural Gas Production (MMCFPD)[3]	**3,726**	3,590	3,624
Net Oil-Equivalent Production (MBOEPD)[5]	**2,055**	1,987	1,859
Sales of Natural Gas (MMCFPD)	**4,493**	4,062	4,215
Sales of Natural Gas Liquids (MBPD)	**27**	23	17
Revenues From Liftings			
Liquids ($/Bbl)	**$ 72.68**	$ 55.97	$ 86.51
Natural Gas ($/MCF)	**$ 4.64**	$ 4.01	$ 5.19
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD)[3,5]			
United States	**708**	717	671
International	**2,055**	1,987	1,859
Total	**2,763**	2,704	2,530
U.S. Downstream			
Gasoline Sales (MBPD)[6]	**700**	720	692
Other Refined Product Sales (MBPD)	**649**	683	721
Total Refined Product Sales (MBPD)	**1,349**	1,403	1,413
Sales of Natural Gas Liquids (MBPD)	**139**	144	144
Refinery Input (MBPD)	**890**	899	891
International Downstream			
Gasoline Sales (MBPD)[6]	**521**	555	589
Other Refined Product Sales (MBPD)	**1,243**	1,296	1,427
Total Refined Product Sales (MBPD)[7]	**1,764**	1,851	2,016
Sales of Natural Gas Liquids (MBPD)	**78**	88	97
Refinery Input (MBPD)	**1,004**	979	967

[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.

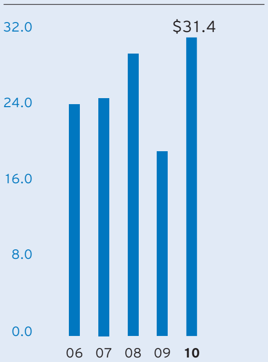
[3] Includes natural gas consumed in operations (MMCFPD):			
United States	**62**	58	70
International	**475**	463	450
[4] Includes: Canada – synthetic oil	**24**	–	–
Venezuela affiliate – synthetic oil	**28**	–	–
[5] Includes Canada oil sands	–	26	27
[6] Includes branded and unbranded gasoline.			
[7] Includes sales of affiliates (MBPD):	**562**	516	512

Liquidity and Capital Resources

Cash, cash equivalents, time deposits and marketable securities Total balances were $17.1 billion and $8.8 billion at December 31, 2010 and 2009, respectively. Cash provided by operating activities in 2010 was $31.4 billion, compared with $19.4 billion in 2009 and $29.6 billion in 2008. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.4 billion, $1.7 billion and $800 million in 2010, 2009 and 2008, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.0 billion in 2010, $2.6 billion in 2009 and $1.5 billion in 2008. Cash provided by operating activities during 2010 was more than sufficient to fund the company's $21.8 billion capital and exploratory program, pay $5.7 billion of dividends to shareholders and repurchase $750 million of common stock.

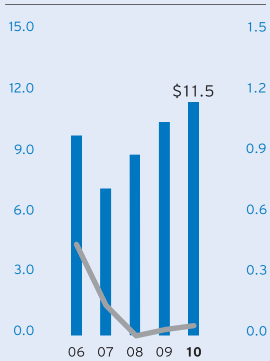
Restricted cash of $855 million and $123 million associated with various capital-investment projects at December 31, 2010 and 2009, respectively, was invested in short-term marketable securities and recorded as "Deferred charges and other assets" on the Consolidated Balance Sheet.

Cash Provided by Operating Activities
Billions of dollars



Operating cash flows were approximately $12.0 billion higher than 2009 primarily due to higher crude oil and natural gas prices.

Total Interest Expense & Total Debt at Year-End
Billions of dollars



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

Total debt increased $1.0 billion during 2010 to $11.5 billion. Most interest cost was capitalized as part of the cost of major projects.

Dividends Dividends paid to common stockholders were approximately $5.7 billion in 2010, $5.3 billion in 2009 and $5.2 billion in 2008. In April 2010, the company increased its quarterly common stock dividend by 5.9 percent, to $0.72 per share.

Debt and capital lease obligations Total debt and capital lease obligations were $11.5 billion at December 31, 2010, up from $10.5 billion at year-end 2009.

The $1.0 billion increase in total debt and capital lease obligations during 2010 included issuance of $1.25 billion of tax-exempt bonds, partially offset by a decrease in short-term obligations. 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 $5.6 billion at December 31, 2010, up from $4.6 billion at year-end 2009. Of this amount, $5.4 billion and $4.2 billion were reclassified to long-term at the end of each period, respectively. At year-end 2010, settlement of these obligations was not expected to require the use of working capital in 2011, 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, 2010, the company had $6.0 billion in committed credit facilities with various major banks, expiring in May 2013, 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, 2010. 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, Texaco Capital Inc. and Union Oil Company of California. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard and Poor's Corporation and Aa1 by Moody's Investors Service. The company's U.S. commercial paper is rated A-1+ by Standard and Poor's and P-1 by Moody's. All of these ratings denote high-quality, investment-grade securities.

The company's future debt level is dependent primarily on results of operations, the capital 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 periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity

Capital and Exploratory Expenditures

Millions of dollars	2010 U.S.	2010 Int'l.	2010 Total	2009 U.S.	2009 Int'l.	2009 Total	2008 U.S.	2008 Int'l.	2008 Total
Upstream	**$ 3,450**	**$ 15,454**	**$ 18,904**	$ 3,294	$15,002	$ 18,296	$ 5,648	$ 12,713	$ 18,361
Downstream	**1,456**	**1,096**	**2,552**	2,087	1,449	3,536	2,457	1,332	3,789
All Other	**286**	**13**	**299**	402	3	405	618	7	625
Total	**$ 5,192**	**$ 16,563**	**$ 21,755**	$ 5,783	$16,454	$ 22,237	$ 8,723	$ 14,052	$ 22,775
Total, Excluding Equity in Affiliates	**$ 4,934**	**$ 15,433**	**$ 20,367**	$ 5,558	$15,094	$ 20,652	$ 8,241	$ 12,228	$ 20,469

chemicals to provide flexibility to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

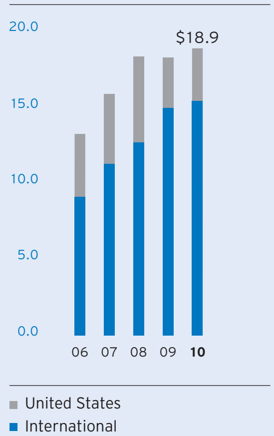
Common stock repurchase program In July 2010, the company terminated the $15 billion share repurchase program initiated in September 2007. No share repurchases occurred in 2010 under the program prior to its termination. From the inception of the program, the company acquired 119 million shares at a cost of $10.1 billion. In its place, the Board of Directors approved a new, ongoing share repurchase program with no set term or monetary limits. The company expects to repurchase between $500 million and $1 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. The company began purchases of its common stock in the fourth quarter, and through December 31, 2010, 8.8 million shares were purchased under the new program for $750 million.

Capital and exploratory expenditures Total expenditures for 2010 were $21.8 billion, including $1.4 billion for the company's share of equity-affiliate expenditures. In 2009 and 2008, expenditures were $22.2 billion and $22.8 billion, respectively, including the company's share of affiliates' expenditures of $1.6 billion and $2.3 billion, respectively, and $2 billion for the extension of an upstream concession in 2009.

Of the $21.8 billion of expenditures in 2010, 87 percent, or $18.9 billion, was related to upstream activities. Approximately 80 percent was expended for upstream operations in 2009 and 2008. International upstream accounted for about 82 percent of the worldwide upstream investment in 2010, about 80 percent in 2009 and about 70 percent in 2008, reflecting the company's continuing focus on opportunities available outside the United States.

The company estimates that in 2011, capital and exploratory expenditures will be $26.0 billion, including $2.0 billion of spending by affiliates. Approximately 85 percent of the total, or $22.6 billion, is budgeted for exploration and production activities, with $17.2 billion of this amount for projects outside the United States. Spending in 2011 is primarily focused on major development projects in Angola, Australia, Brazil, Canada, China, Nigeria, Thailand, the United Kingdom and the U.S. Gulf of Mexico. Also included is funding for base business improvements and focused exploration and appraisal programs in core hydrocarbon basins.

Upstream – Capital & Exploratory Expenditures*
Billions of dollars



Exploration and production expenditures were slightly higher than 2009.

*Includes equity in affiliates

Worldwide downstream spending in 2011 is estimated at $2.9 billion, with about $1.7 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and South Korea.

Investments in technology, power generation and other corporate businesses in 2011 are budgeted at $500 million.

Noncontrolling interests The company had noncontrolling interests of $730 million and $647 million at December 31, 2010 and 2009, respectively. Distributions to noncontrolling interests totaled $72 million and $71 million in 2010 and 2009, respectively.

Pension Obligations In 2010, the company's pension plan contributions were $1.4 billion (including $1.19 billion to the U.S. plans and $258 million to the international plans). The company estimates contributions in 2011 will be approximately $950 million ($650 million for the U.S. plans and $300 million for the international plans). Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in "Critical Accounting Estimates and Assumptions," beginning on page 28.

Financial Ratios

Financial Ratios

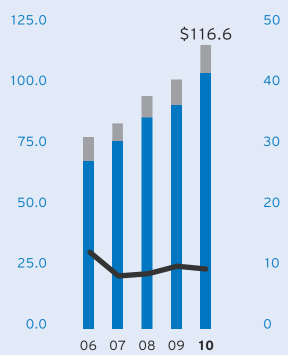
	At December 31		
	2010	2009	2008
Current Ratio	**1.7**	1.4	1.1
Interest Coverage Ratio	**101.7**	62.3	166.9
Debt Ratio	**9.8%**	10.3%	9.3%

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 2010, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $7.0 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 2010 was higher than 2009 due to higher before-tax income. The company's interest coverage ratio in 2009 was lower than 2008 due to lower 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 2010 and 2009 was due to a higher Chevron Corporation stockholders' equity balance. The increase in 2009 over 2008 was primarily due to the increase in debt.

Debt Ratio
Billions of dollars/Percent



In spite of higher debt, the ratio of total debt to total debt-plus-Chevron Corporation Stockholders' Equity decreased to 9.8 percent at the end of 2010 due to an increase in Stockholders' Equity.

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

Direct Guarantee

Millions of dollars		Commitment Expiration by Period			
	Total	2011	2012–2013	2014–2015	After 2015
Guarantee of non-consolidated affiliate or joint-venture obligation	$ 613	$ –	$ 76	$ 77	$ 460

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

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300 million. Through the end of 2010, the company had paid $48 million under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. The company posts no assets as collateral and has made no payments under the indemnities.

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

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. The acquirer of those assets shared in certain environmental remediation costs up to a maximum obligation of $200 million, which had been reached at December 31, 2009. Under the indemnification agreement, after reaching the $200 million obligation, Chevron is solely responsible until April 2022, when the indemnification expires. The environmental conditions or events that are subject to these indemnities must have arisen prior to the sale of the assets in 1997.

Although the company has provided for known obligations under this indemnity that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities 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: 2011 – $17.2 billion; 2012 – $4.1 billion; 2013 – $3.5 billion; 2014 – $3.1 billion; 2015 – $3.0 billion; 2016 and after – $7.7 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $6.5 billion in 2010, $8.1 billion in 2009 and $5.1 billion in 2008.

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

Contractual Obligations[1]

Millions of dollars			Payments Due by Period		
	Total	2011	2012–2013	2014–2015	After 2015
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 187	$ 187	$ –	$ –	$ –
Long-Term Debt[3]	11,003	–	6,940	2,020	2,043
Noncancelable Capital Lease Obligations	488	99	161	91	137
Interest	2,208	299	486	320	1,103
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,836	650	900	561	725
Throughput and Take-or-Pay Agreements	34,127	16,305	5,592	4,727	7,503
Other Unconditional Purchase Obligations[4]	4,420	913	2,004	1,343	160

[1] Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page 60.
[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] $5.4 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 2012–2013 period.
[4] Does not include obligations to purchase the company's share of natural gas liquids and regasified natural gas associated with operations of the 36.4 percent-owned Angola LNG affiliate. The LNG plant is expected to commence operations in 2012 and is designed to produce 5.2 million metric tons of LNG and related natural gas liquids per year. Volumes and prices associated with these purchase obligations are neither fixed nor determinable.

Financial and Derivative Instruments

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk discussed below do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2010 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 2010.

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

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

Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes. The change in fair value of Chevron's derivative commodity instruments in 2010 was a quarterly average decrease of $1 million in total assets and a quarterly average increase of $18 million in total liabilities.

The company uses a Value-at-Risk (VaR) model to estimate the potential loss in fair value on a single day from the effect of adverse changes in market conditions on derivative commodity instruments held or issued, which are recorded on the balance sheet at December 31, 2010, as derivative commodity instruments in accordance with accounting standards for derivatives (ASC 815). VaR is the maximum loss not to be exceeded within a given probability or confidence level over a given period of time. The company's VaR model uses the Monte Carlo simulation method that involves generating hypothetical scenarios from the specified probability 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, 2010 and 2009.

Millions of dollars	2010	2009
Crude Oil	$ 15	$ 17
Natural Gas	4	4
Refined Products	14	19

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, 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, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2010, 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 51, for further discussion. Management believes these agreements have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

Litigation and Other Contingencies

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 19 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

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

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously given to Texpet by the Republic of Ecuador and Petroecuador 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 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 $18.9 billion, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer's report also asserted that an additional $8.4 billion 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 billion and $76 billion and that unjust enrichment should be assessed in an amount between approximately $5 billion and $38 billion. 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 remain 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.

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before 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 Permanent Court of Arbitration 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. 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 February 8, 2011, the Court issued a temporary restraining order 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 until March 8, 2011. Chevron's motion for a preliminary injunction is presently before the Court.

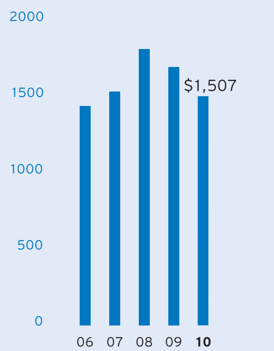
On February 14, 2011, the Provincial Court in Lago Agrio rendered an adverse judgment in the case. The Provincial Court rejected Chevron's defenses to the extent the Court addressed them in its opinion. The judgment assesses approximately $8.6 billion in damages and about $0.9 billion for the plaintiffs' representatives. It also assesses an additional amount of approximately $8.6 billion in punitive damages unless the company provides a public apology. Chevron continues to believe the 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 will appeal this decision in Ecuador. 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. Because Chevron has no substantial assets in Ecuador, Chevron would expect enforcement actions as a result of this judgment to be brought in other jurisdictions. Chevron expects to contest any such actions.

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 judgment, the 2008 engineer's report and the September 2010 plaintiffs' submission, 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).

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.

Year-End Environmental Remediation Reserves
Millions of dollars



Reserves for environmental remediation at the end of 2010 were down 11 percent from the prior year.

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	**2010**	2009	2008
Balance at January 1	**$ 1,700**	$ 1,818	$ 1,539
Net Additions	**220**	351	784
Expenditures	**(413)**	(469)	(505)
Balance at December 31	**$ 1,507**	$ 1,700	$ 1,818

Included in the $1,507 million year-end 2010 reserve balance were remediation activities at approximately 182 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 2010 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 2010 environmental reserves balance of $1,322 million, $814 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 $508 million was associated with various sites in international downstream ($100 million), upstream ($329 million) and other businesses ($79 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2010 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 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 $12.5 billion for asset retirement obligations at year-end 2010 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 70, related to the company's asset retirement obligations and the discussion of "Environmental Matters" on page 27.

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 55 for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

Suspended Wells The company suspends the costs of exploratory wells pending a final determination of the commercial potential of the related crude oil and natural gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity or development decisions or both. At December 31, 2010, the company had approximately $2.7 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $283 million from 2009. The 2009 balance reflected an increase of $317 million from 2008.

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 $2.7 billion of suspended wells at year-end 2010 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page 58, for additional discussion of suspended wells.

Equity Redetermination For crude oil and natural gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately $200 million, and the possible maximum net amount that could be owed to Chevron is estimated at about $150 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies 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 the company continues to evaluate its options going forward, which may include requesting the city to revise the EIR to address the issues identified by the Court of Appeal or other actions. Management believes the outcomes associated with the potential options for 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, of the ruling 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.

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 2010 at approximately $2.9 billion for its consolidated companies. Included in these expenditures were approximately $1.4 billion of environmental capital expenditures and $1.5 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 2011, total worldwide environmental capital expenditures are estimated at $1.5 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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

Critical Accounting Estimates and Assumptions

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

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

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

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

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be "more likely than not." Another example is the estimation of crude oil and natural gas reserves under SEC rules, which require "…by analysis of geosciences and engineering data, (the reserves) can be estimated with reasonable certainty to be economically producible…under existing economic conditions" where existing economic conditions include prices based on the average price during the 12-month period prior to the end of the reporting period. Refer to Table V, "Reserve Quantity Information," beginning on page 79, for the changes in these estimates for the three years ending December 31, 2010, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 88 for estimates of proved-reserve values for each of the three years ended December 31, 2010. Note 1 to the Consolidated Financial Statements, beginning on page 40, 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 30, 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 40. 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 60, includes information on the funded status of the company's pension and OPEB plans at the end of 2010 and 2009; the components of pension and OPEB expense for the three years ending December 31, 2010; 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 2010 and 2009 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, 2010, actual asset returns averaged 4.7 percent for this plan. The actual return for 2010 was 11.6 percent and was associated with the broad recovery in the financial markets.

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

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2010, the company selected a 4.8 percent discount rate for the major U.S. pension plan and 5.0 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 2010. The discount rates at the end of 2009 were 5.3 percent for the major U.S. pension plan and 5.8 percent for the company's U.S. OPEB plan, and 6.3 percent at the end of 2008 for both the U.S. pension and OPEB plans.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2010 was $1.1 billion. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the company's primary U.S. pension plan would have reduced total pension plan expense for 2010 by approximately $65 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 61 percent of the companywide pension obligation, would have reduced total pension plan expense for 2010 by approximately $140 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan reported on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2010, for underfunded plans was approximately $3.3 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan would have reduced the plan obligation by approximately $300 million, which would have decreased the plan's underfunded status from approximately $0.9 billion to $0.6 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 2010, the company's pension plan contributions were $1.45 billion (including $1.19 billion to the U.S. plans). In 2011, the company estimates contributions will be approximately $950 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 2010 was $166 million and the total liability, which reflected the unfunded status of the plans at the end of 2010, was $3.6 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2010, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 69 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $15 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 85 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2010 by approximately $80 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 2011 and gradually drop to 5 percent for 2018 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2010, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for 85 percent of the companywide OPEB liabilities, would have increased OPEB expense by $8 million.

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are not included in benefit plan costs in the year the difference occurs. Instead, the differences are included in actuarial gain/loss and unamortized amounts have been reflected in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet. Refer to Note 21, beginning on page 60, for information on the $6.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2010; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2011.

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 45.

No major individual impairments of PP&E and Investments were recorded for the three years ending December 31, 2010. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for impairment when the fair value of the investment falls below the company's carrying value. When such a decline is deemed to be other than temporary, an impairment charge is recorded to the income statement for the difference between the investment's carrying value and its estimated fair value at the time.

In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. Differing assumptions could affect whether an investment is impaired in any period or the amount of the impairment, and are not subject to sensitivity analysis.

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

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by accounting standards for goodwill (ASC 350), the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is "more likely than not" (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 15 beginning on page 55. 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, 2010.

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

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

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

Receivables (ASC 310), Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses (ASU 2010-20) In July 2010, the FASB issued ASU 2010-20, which became effective with the company's reporting at December 31, 2010. This standard amends and expands disclosure requirements about the credit quality of financing receivables and the related allowance for credit losses. As a result of these amendments, companies are required to disaggregate, by portfolio segment or class of financing receivable, certain existing disclosures and provide certain new disclosures about financing receivables and related allowance for credit losses. Adoption of the standard did not change the company's existing disclosures.

Quarterly Results and Stock Market Data

Unaudited

Millions of dollars, except per-share amounts	2010 4th Q	2010 3rd Q	2010 2nd Q	2010 1st Q	2009 4th Q	2009 3rd Q	2009 2nd Q	2009 1st Q
Revenues and Other Income								
Sales and other operating revenues[1]	**$ 51,852**	**$ 48,554**	**$ 51,051**	**$ 46,741**	$ 47,588	$ 45,180	$ 39,647	$ 34,987
Income from equity affiliates	**1,510**	**1,242**	**1,650**	**1,235**	898	1,072	735	611
Other income	**665**	**(78)**	**303**	**203**	190	373	(177)	532
Total Revenues and Other Income	**54,027**	**49,718**	**53,004**	**48,179**	48,676	46,625	40,205	36,130
Costs and Other Deductions								
Purchased crude oil and products	**30,109**	**28,610**	**30,604**	**27,144**	28,606	26,969	23,678	20,400
Operating expenses	**5,343**	**4,665**	**4,591**	**4,589**	4,899	4,403	4,209	4,346
Selling, general and administrative expenses	**1,408**	**1,181**	**1,136**	**1,042**	1,330	1,177	1,043	977
Exploration expenses	**335**	**420**	**212**	**180**	281	242	438	381
Depreciation, depletion and amortization	**3,439**	**3,401**	**3,141**	**3,082**	3,156	2,988	3,099	2,867
Taxes other than on income[1]	**4,623**	**4,559**	**4,537**	**4,472**	4,583	4,644	4,386	3,978
Interest and debt expense	**4**	**9**	**17**	**20**	–	14	6	8
Total Costs and Other Deductions	**45,261**	**42,845**	**44,238**	**40,529**	42,855	40,437	36,859	32,957
Income Before Income Tax Expense	**8,766**	**6,873**	**8,766**	**7,650**	5,821	6,188	3,346	3,173
Income Tax Expense	**3,446**	**3,081**	**3,322**	**3,070**	2,719	2,342	1,585	1,319
Net Income	**$ 5,320**	**$ 3,792**	**$ 5,444**	**$ 4,580**	$ 3,102	$ 3,846	$ 1,761	$ 1,854
Less: Net income attributable to noncontrolling interests	**25**	**24**	**35**	**28**	32	15	16	17
Net Income Attributable to Chevron Corporation	**$ 5,295**	**$ 3,768**	**$ 5,409**	**$ 4,552**	$ 3,070	$ 3,831	$1,745	$ 1,837
Per Share of Common Stock								
Net Income Attributable to Chevron Corporation								
– Basic	**$ 2.65**	**$ 1.89**	**$ 2.71**	**$ 2.28**	$ 1.54	$ 1.92	$ 0.88	$ 0.92
– Diluted	**$ 2.64**	**$ 1.87**	**$ 2.70**	**$ 2.27**	$ 1.53	$ 1.92	$ 0.87	$ 0.92
Dividends	**$ 0.72**	**$ 0.72**	**$ 0.72**	**$ 0.68**	$ 0.68	$ 0.68	$ 0.65	$ 0.65
Common Stock Price Range – High[2,3]	**$ 92.39**	**$ 82.19**	**$ 83.41**	**$ 81.09**	$ 79.82	$ 73.37	$ 72.75	$ 78.45
– Low[2,3]	**$ 80.41**	**$ 66.83**	**$ 67.80**	**$ 69.55**	$ 67.87	$ 60.88	$ 63.06	$ 56.12
[1] Includes excise, value-added and similar taxes:	**$ 2,136**	**$ 2,182**	**$ 2,201**	**$ 2,072**	$ 2,086	$ 2,079	$ 2,034	$ 1,910

[2] Intraday price.
[3] 2009 conformed with 2010 presentation.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 18, 2011, stockholders of record numbered approximately 186,000. 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, 2010.

The effectiveness of the company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

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

Patricia E. Yarrington
Vice President
and Chief Financial Officer

Matthew J. Foehr
Vice President
and Comptroller

February 24, 2011

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, 2010 and December 31, 2009 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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, 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 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.

PricewaterhouseCoopers LLP

San Francisco, California
February 24, 2011

Consolidated Statement of Income

Millions of dollars, except per-share amounts

			Year ended December 31
	2010	2009	2008
Revenues and Other Income			
Sales and other operating revenues*	**$ 198,198**	$ 167,402	$ 264,958
Income from equity affiliates	**5,637**	3,316	5,366
Other income	**1,093**	918	2,681
Total Revenues and Other Income	**204,928**	171,636	273,005
Costs and Other Deductions			
Purchased crude oil and products	**116,467**	99,653	171,397
Operating expenses	**19,188**	17,857	20,795
Selling, general and administrative expenses	**4,767**	4,527	5,756
Exploration expenses	**1,147**	1,342	1,169
Depreciation, depletion and amortization	**13,063**	12,110	9,528
Taxes other than on income*	**18,191**	17,591	21,303
Interest and debt expense	**50**	28	–
Total Costs and Other Deductions	**172,873**	153,108	229,948
Income Before Income Tax Expense	**32,055**	18,528	43,057
Income Tax Expense	**12,919**	7,965	19,026
Net Income	**19,136**	10,563	24,031
Less: Net income attributable to noncontrolling interests	**112**	80	100
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
– Basic	**$ 9.53**	$ 5.26	$ 11.74
– Diluted	**$ 9.48**	$ 5.24	$ 11.67
*Includes excise, value-added and similar taxes.	**$ 8,591**	$ 8,109	$ 9,846

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2010	2009	2008
Net Income	**$ 19,136**	$ 10,563	$ 24,031
Currency translation adjustment			
Unrealized net change arising during period	**6**	60	(112)
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(4)**	2	(6)
Derivatives			
Net derivatives gain (loss) on hedge transactions	**25**	(69)	139
Reclassification to net income of net realized loss (gain)	**5**	(23)	32
Income taxes on derivatives transactions	**(10)**	32	(61)
Total	**20**	(60)	110
Defined benefit plans			
Actuarial loss			
Amortization to net income of net actuarial loss	**635**	575	483
Actuarial loss arising during period	**(857)**	(1,099)	(3,228)
Prior service cost			
Amortization to net income of net prior service credits	**(61)**	(65)	(64)
Prior service cost arising during period	**(12)**	(34)	(32)
Defined benefit plans sponsored by equity affiliates	**(12)**	65	(97)
Income taxes on defined benefit plans	**140**	159	1,037
Total	**(167)**	(399)	(1,901)
Other Comprehensive Loss, Net of Tax	**(145)**	(397)	(1,909)
Comprehensive Income	**18,991**	10,166	22,122
Comprehensive income attributable to noncontrolling interests	**(112)**	(80)	(100)
Comprehensive Income Attributable to Chevron Corporation	**$ 18,879**	$ 10,086	$ 22,022

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amounts

	At December 31 2010	2009
Assets		
Cash and cash equivalents	**$ 14,060**	$ 8,716
Time deposits	**2,855**	–
Marketable securities	**155**	106
Accounts and notes receivable (less allowance: 2010 – $184; 2009 – $228)	**20,759**	17,703
Inventories:		
Crude oil and petroleum products	**3,589**	3,680
Chemicals	**395**	383
Materials, supplies and other	**1,509**	1,466
Total inventories	**5,493**	5,529
Prepaid expenses and other current assets	**5,519**	5,162
Total Current Assets	**48,841**	37,216
Long-term receivables, net	**2,077**	2,282
Investments and advances	**21,520**	21,158
Properties, plant and equipment, at cost	**207,367**	188,288
Less: Accumulated depreciation, depletion and amortization	**102,863**	91,820
Properties, plant and equipment, net	**104,504**	96,468
Deferred charges and other assets	**3,210**	2,879
Goodwill	**4,617**	4,618
Total Assets	**$ 184,769**	$ 164,621
Liabilities and Equity		
Short-term debt	**$ 187**	$ 384
Accounts payable	**19,259**	16,437
Accrued liabilities	**5,324**	5,375
Federal and other taxes on income	**2,776**	2,624
Other taxes payable	**1,466**	1,391
Total Current Liabilities	**29,012**	26,211
Long-term debt	**11,003**	9,829
Capital lease obligations	**286**	301
Deferred credits and other noncurrent obligations	**19,264**	17,390
Noncurrent deferred income taxes	**12,697**	11,521
Reserves for employee benefit plans	**6,696**	6,808
Total Liabilities	**78,958**	72,060
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	**–**	–
Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2010 and 2009)	**1,832**	1,832
Capital in excess of par value	**14,796**	14,631
Retained earnings	**119,641**	106,289
Accumulated other comprehensive loss	**(4,466)**	(4,321)
Deferred compensation and benefit plan trust	**(311)**	(349)
Treasury stock, at cost (2010 – 435,195,799 shares; 2009 – 434,954,774 shares)	**(26,411)**	(26,168)
Total Chevron Corporation Stockholders' Equity	**105,081**	91,914
Noncontrolling interests	**730**	647
Total Equity	**105,811**	92,561
Total Liabilities and Equity	**$ 184,769**	$ 164,621

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Millions of dollars

		Year ended December 31	
	2010	2009	2008
Operating Activities			
Net Income	**$ 19,136**	$ 10,563	$ 24,031
Adjustments			
Depreciation, depletion and amortization	**13,063**	12,110	9,528
Dry hole expense	**496**	552	375
Distributions less than income from equity affiliates	**(501)**	(103)	(440)
Net before-tax gains on asset retirements and sales	**(1,004)**	(1,255)	(1,358)
Net foreign currency effects	**251**	466	(355)
Deferred income tax provision	**559**	467	598
Net decrease (increase) in operating working capital	**76**	(2,301)	(1,673)
Increase in long-term receivables	**(12)**	(258)	(161)
Decrease (increase) in other deferred charges	**48**	201	(84)
Cash contributions to employee pension plans	**(1,450)**	(1,739)	(839)
Other	**697**	670	10
Net Cash Provided by Operating Activities	**31,359**	19,373	29,632
Investing Activities			
Capital expenditures	**(19,612)**	(19,843)	(19,666)
Proceeds and deposits related to asset sales	**1,995**	2,564	1,491
Net purchases of time deposits	**(2,855)**	–	–
Net (purchases) sales of marketable securities	**(49)**	127	483
Repayment of loans by equity affiliates	**338**	336	179
Net (purchases) sales of other short-term investments	**(732)**	244	432
Net Cash Used for Investing Activities	**(20,915)**	(16,572)	(17,081)
Financing Activities			
Net (payments) borrowings of short-term obligations	**(212)**	(3,192)	2,647
Proceeds from issuances of long-term debt	**1,250**	5,347	–
Repayments of long-term debt and other financing obligations	**(156)**	(496)	(965)
Cash dividends – common stock	**(5,674)**	(5,302)	(5,162)
Distributions to noncontrolling interests	**(72)**	(71)	(99)
Net (purchases) sales of treasury shares	**(306)**	168	(6,821)
Net Cash Used for Financing Activities	**(5,170)**	(3,546)	(10,400)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**70**	114	(166)
Net Change in Cash and Cash Equivalents	**5,344**	(631)	1,985
Cash and Cash Equivalents at January 1	**8,716**	9,347	7,362
Cash and Cash Equivalents at December 31	**$ 14,060**	$ 8,716	$ 9,347

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2010		2009		2008	
	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		**$ 14,631**		$ 14,448		$ 14,289
Treasury stock transactions		**165**		183		159
Balance at December 31		**$ 14,796**		$ 14,631		$ 14,448
Retained Earnings						
Balance at January 1		**$ 106,289**		$101,102		$ 82,329
Net income attributable to Chevron Corporation		**19,024**		10,483		23,931
Cash dividends on common stock		**(5,674)**		(5,302)		(5,162)
Tax benefit from dividends paid on unallocated ESOP shares and other		**2**		6		4
Balance at December 31		**$ 119,641**		$106,289		$101,102
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (111)**		$ (171)		$ (59)
Change during year		**6**		60		(112)
Balance at December 31		**$ (105)**		$ (111)		$ (171)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (4,308)**		$ (3,909)		$ (2,008)
Change to defined benefit plans during year		**$ (167)**		(399)		(1,901)
Balance at December 31		**$ (4,475)**		$ (4,308)		$ (3,909)
Unrealized net holding gain on securities						
Balance at January 1		**$ 15**		$ 13		$ 19
Change during year		**(4)**		2		(6)
Balance at December 31		**$ 11**		$ 15		$ 13
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 83**		$ 143		$ 33
Change during year		**20**		(60)		110
Balance at December 31		**$ 103**		$ 83		$ 143
Balance at December 31		**$ (4,466)**		$ (4,321)		$ (3,924)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ (109)**		$ (194)		$ (214)
Net reduction of ESOP debt and other		**38**		85		20
Balance at December 31		**(71)**		(109)		(194)
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240)
Balance at December 31	**14,168**	**$ (311)**	14,168	$ (349)	14,168	$ (434)
Treasury Stock at Cost						
Balance at January 1	**434,955**	**$ (26,168)**	438,445	$ (26,376)	352,243	$(18,892)
Purchases	**9,091**	**(775)**	85	(6)	95,631	(8,011)
Issuances – mainly employee benefit plans	**(8,850)**	**532**	(3,575)	214	(9,429)	527
Balance at December 31	**435,196**	**$ (26,411)**	434,955	$ (26,168)	438,445	$(26,376)
Total Chevron Corporation Stockholders' Equity at December 31		**$ 105,081**		$ 91,914		$ 86,648
Noncontrolling Interests		**$ 730**		$ 647		$ 469
Total Equity		**$ 105,811**		$ 92,561		$ 87,117

See accompanying Notes to the Consolidated Financial Statements.

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.

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

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

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

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

Derivatives The majority of the company's activity in derivative commodity instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's commodity trading activity, 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

(LIFO) method. In the aggregate, these costs are below market. "Materials, supplies and other" inventories generally are stated at average cost.

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs 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 58, 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 generally done on the basis of a refinery, a plant, a marketing area or marketing assets by country. Impairment amounts are recorded as incremental "Depreciation, depletion and amortization" expense.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value. Refer to Note 9, beginning on page 45, relating to fair value measurements.

As required under accounting standards for asset retirement obligations (Accounting Standards Codification (ASC) 410), the fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 25, on page 70, relating to AROs.

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

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

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

Expenditures for maintenance (including those for planned major maintenance projects), repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by accounting standards for goodwill (ASC 350), the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company's U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and mineral-producing properties, a liability for an ARO is made, following accounting standards for asset retirement and environmental obligations. Refer to Note 25, on page 70, for a discussion of the company's AROs.

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

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

Currency Translation The U.S. dollar is the functional currency for substantially all of the company's consolidated operations and those of its equity affiliates. For those operations, all gains and losses from currency 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 35. 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

Agreement to Acquire Atlas Energy, Inc.

In November 2010, Chevron announced plans to acquire Atlas Energy, Inc. The acquisition was completed in February 2011 for $4,470, including assumed debt. The acquisition will be accounted for as a business combination (ASC 805). Atlas holds one of the premier acreage positions in the Marcellus Shale, concentrated in southwestern Pennsylvania.

Note 3

Noncontrolling Interests

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

Activity for the equity attributable to noncontrolling interests for 2010, 2009 and 2008 is as follows:

	2010	2009	2008
Balance at January 1	**$ 647**	$ 469	$ 204
Net income	**112**	80	100
Distributions to noncontrolling interests	**(72)**	(71)	(99)
Other changes, net	**43**	169	264
Balance at December 31	**$ 730**	$ 647	$ 469

Note 4

Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2010	2009	2008
Net decrease (increase) in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	**$ (2,767)**	$ (1,476)	$ 6,030
Decrease (increase) in inventories	**15**	1,213	(1,545)
Increase in prepaid expenses and other current assets	**(542)**	(264)	(621)
Increase (decrease) in accounts payable and accrued liabilities	**3,049**	(1,121)	(4,628)
Increase (decrease) in income and other taxes payable	**321**	(653)	(909)
Net decrease (increase) in operating working capital	**$ 76**	$ (2,301)	$ (1,673)
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	**$ 11,749**	$ 7,537	$ 19,130
Net sales of marketable securities consisted of the following gross amounts:			
Marketable securities sold	**$ 41**	$ 157	$ 3,719
Marketable securities purchased	**(90)**	(30)	(3,236)
Net (purchases) sales of marketable securities	**$ (49)**	$ 127	$ 483
Net purchases of time deposits consisted of the following gross amounts:			
Time deposits purchased	**$ (5,060)**	$ –	$ –
Time deposits matured	**2,205**	–	–
Net purchases of time deposits	**$ (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 $67, $25 and $106 for excess income tax benefits associated with stock options exercised during 2010, 2009 and 2008, respectively. These amounts are offset by an equal amount in "Net (purchases) sales of treasury shares."

The "Net (purchases) sales of treasury shares" represents the cost of common shares purchased less the cost of shares issued for share-based compensation plans. Purchases totaled $775, $6 and $8,011 in 2010, 2009 and 2008, respectively. Purchases in 2010 and 2008 included shares purchased under the company's common stock repurchase programs.

In 2010, "Net (purchases) sales of other short-term investments" consist of restricted cash associated with capital-investment projects at the company's Pascagoula and El Segundo refineries and the Angola liquefied natural gas project that was invested in short-term securities and reclassified from "Cash and cash equivalents" to "Deferred charges and other assets" on the Consolidated Balance Sheet. The company issued $1,250 and $350, in 2010 and 2009, respectively, of tax exempt bonds as a source of funds for U.S. refinery projects.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2008, "Net (purchases) sales of treasury shares" excludes $680 of treasury shares acquired in exchange for a U.S. upstream property and $280 in cash. The carrying value of this property in "Properties, plant and equipment" on the Consolidated Balance Sheet was not significant. In 2008, a $2,450 increase in "Accrued liabilities" and a corresponding increase to "Properties, plant and equipment, at cost" were considered noncash transactions and excluded from "Net decrease (increase) in operating working capital" and "Capital expenditures." In 2009, the payments related to these "Accrued liabilities" were excluded from "Net decrease (increase) in operating working capital" and were reported as "Capital expenditures." The amount is related to upstream operating agreements outside the United States. "Capital expenditures" in 2008 excludes a $1,400 increase in "Properties, plant and equipment" related to the acquisition of an additional interest in an equity affiliate that required a change to the consolidated method of accounting for the investment during 2008. This addition was offset primarily by reductions in "Investments and advances" and working capital and an increase in "Non-current deferred income tax" liabilities. Refer also to Note 25, on page 70, 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, 2010.

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		
	2010	2009	2008
Additions to properties, plant and equipment[1]	**$ 18,474**	$ 16,107	$ 18,495
Additions to investments	**861**	942	1,051
Current year dry hole expenditures	**414**	468	320
Payments for other liabilities and assets, net[2]	**(137)**	2,326	(200)
Capital expenditures	**19,612**	19,843	19,666
Expensed exploration expenditures	**651**	790	794
Assets acquired through capital lease obligations and other financing obligations	**104**	19	9
Capital and exploratory expenditures, excluding equity affiliates	**20,367**	20,652	20,469
Company's share of expenditures by equity affiliates	**1,388**	1,585	2,306
Capital and exploratory expenditures, including equity affiliates	**$ 21,755**	$ 22,237	$ 22,775

[1]Excludes noncash additions of $2,753 in 2010, $985 in 2009 and $5,153 in 2008.
[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.

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

	Year ended December 31		
	2010	2009	2008
Sales and other operating revenues	**$ 145,381**	$ 121,553	$ 195,593
Total costs and other deductions	**139,984**	120,053	185,788
Net income attributable to CUSA	**4,159**	1,141	7,318

	At December 31	
	2010	2009
Current assets	**$ 29,211**	$ 23,286
Other assets	**35,294**	32,827
Current liabilities	**18,098**	16,098
Other liabilities	**16,785**	14,625
Total CUSA net equity	**29,622**	25,390
Memo: Total debt	**$ 8,284**	$ 6,999

The "Net income attributable to CUSA" for the year ended December 31, 2008, has been adjusted by an immaterial amount associated with the allocation of income-tax liabilities among Chevron Corporation subsidiaries.

Note 6

Summarized Financial Data – Chevron Transport Corporation Ltd.

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

	Year ended December 31		
	2010	2009	2008
Sales and other operating revenues	**$ 885**	$ 683	$ 1,022
Total costs and other deductions	**1,008**	810	947
Net (loss) income attributable to CTC	**(116)**	(124)	120

	At December 31	
	2010	2009
Current assets	**$ 209**	$ 377
Other assets	**201**	173
Current liabilities	**101**	115
Other liabilities	**75**	90
Total CTC net equity	**234**	345

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2010.

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 51, for a discussion of TCO operations.

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

	Year ended December 31		
	2010	2009	2008
Sales and other operating revenues	**$ 17,812**	$ 12,013	$ 14,329
Costs and other deductions	**8,394**	6,044	5,621
Net income attributable to TCO	**6,593**	4,178	6,134

	At December 31	
	2010	2009
Current assets	**$ 3,376**	$ 3,190
Other assets	**11,813**	12,022
Current liabilities	**2,402**	2,426
Other liabilities	**4,130**	4,484
Total TCO net equity	**8,657**	8,302

Note 8

Lease Commitments

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

	At December 31	
	2010	2009
Upstream	**$ 561**	$ 510
Downstream	**316**	334
All Other	**169**	169
Total	**1,046**	1,013
Less: Accumulated amortization	**573**	585
Net capitalized leased assets	**$ 473**	$ 428

Rental expenses incurred for operating leases during 2010, 2009 and 2008 were as follows:

	Year ended December 31		
	2010	2009	2008
Minimum rentals	**$ 2,373**	$ 2,179	$ 2,984
Contingent rentals	**10**	7	6
Total	**2,383**	2,186	2,990
Less: Sublease rental income	**41**	41	41
Net rental expense	**$ 2,342**	$ 2,145	$ 2,949

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, 2010, 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: 2011	650	99
2012	530	93
2013	370	68
2014	288	51
2015	273	40
Thereafter	725	137
Total	$ 2,836	$ 488
Less: Amounts representing interest and executory costs		(105)
Net present values		383
Less: Capital lease obligations included in short-term debt		(97)
Long-term capital lease obligations		$ 286

Note 9

Fair Value Measurements

Accounting standards for fair value measurement (ASC 820) establish a framework for measuring fair value and stipulate disclosures about fair value measurements. The standards apply to recurring and nonrecurring financial and nonfinancial assets and liabilities that require or permit fair value measurements. 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. In 2010, the company used Level 3 inputs to determine the fair value of certain nonrecurring nonfinancial assets.

Note 9 Fair Value Measurements – Continued

The fair value hierarchy for recurring assets and liabilities measured at fair value at December 31, 2010, and December 31, 2009, is as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31 2010	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	At December 31 2009	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Marketable securities	**$ 155**	**$ 155**	**$ –**	**$ –**	$ 106	$ 106	$ –	$ –
Derivatives	**122**	**11**	**111**	**–**	127	14	113	–
Total Recurring Assets at Fair Value	**$ 277**	**$ 166**	**$ 111**	**$ –**	$ 233	$ 120	$ 113	$ –
Derivatives	**$ 171**	**$ 75**	**$ 96**	**$ –**	$ 101	$ 20	$ 81	$ –
Total Recurring Liabilities at Fair Value	**$ 171**	**$ 75**	**$ 96**	**$ –**	$ 101	$ 20	$ 81	$ –

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, 2010.

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

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

Derivatives classified as Level 2 include swaps, options, and forward contracts principally with financial institutions and other oil and gas companies, the fair values for which are obtained from third-party broker quotes, industry 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" In accordance with the accounting standard for the impairment or disposal of long-lived assets (ASC 360), during 2010 and 2009 long-lived assets "held and used" with carrying amounts of $142 and $949 were written down to fair values of $57 and $490 resulting in before-tax losses of $85 and $459, respectively. The fair values were determined from internal cash flow models, using discount rates consistent with those used by the company to evaluate cash flows of other assets of a similar nature.

Long-lived assets "held for sale" with carrying amounts of $49 and $160 were written down to a fair value of $13 and $68, resulting in a before-tax loss of $36 and $92 in 2010 and 2009, respectively. The fair values were determined based on bids received from prospective buyers and from internal cash-flow models consistent with those used by the company to evaluate cash flows of other assets of a similar nature.

Impairments of "Investments and advances" In accordance with the accounting standards under the equity method of accounting (ASC 323) and the cost method of accounting (ASC 325), during 2010 and 2009 investments with carrying amounts of $15 and $81 were written down to fair values of $0 and $39 resulting in before-tax losses of $15 and $42, respectively. The fair values were determined using discount rates consistent with those used by the company to evaluate cash flows of other investments of a similar nature.

The fair value hierarchy for nonrecurring assets and liabilities measured at fair value during 2010 is presented in the following table:

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

	Year ended December 31 2010	Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Loss (Before Tax) Year ended December 31 2010	Year ended December 31 2009	Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Loss (Before Tax) Year ended December 31 2009
Properties, plant and equipment, net (held and used)	**$ 57**	**$ –**	**$ –**	**$ 57**	**$ 85**	$ 490	$ –	$ –	$ 490	$ 459
Properties, plant and equipment, net (held for sale)	**13**	**–**	**–**	**13**	**36**	68	–	68	–	92
Investments and advances	**–**	**–**	**–**	**–**	**15**	39	–	–	39	42
Total Nonrecurring Assets at Fair Value	**$ 70**	**$ –**	**$ –**	**$ 70**	**$ 136**	$ 597	$ –	$ 68	$ 529	$ 593

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 $14,060 and $8,716 at December 31, 2010 and December 31, 2009, respectively. The instruments held in “Time deposits” are bank time deposits with maturities greater than 90 days and had carrying/fair values of $2,855 at December 31, 2010. The fair values of cash, cash equivalents and bank time deposits reflect the cash that would have been received or paid if the instruments were settled at year-end.

“Cash and cash equivalents” do not include investments with a carrying/fair value of $855 and $123 at December 31, 2010 and December 31, 2009, respectively. These investments are restricted funds related to an international upstream development project and U.S. refinery projects, which are reported in “Deferred charges and other assets” on the Consolidated Balance Sheet. Long-term debt of $5,636 and $5,705 had estimated fair values of $6,311 and $6,229 at December 31, 2010 and December 31, 2009, respectively.

The carrying values of short-term financial assets and liabilities on the balance sheet approximate their fair values. Fair values of other financial instruments at the end of 2010 and 2009 were not material.

Note 10

Financial and Derivative Instruments

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

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. From time to time, the company also uses derivative commodity instruments for limited trading purposes.

The company’s derivative commodity instruments principally include crude oil, natural gas and refined product futures, swaps, options, and forward contracts. None of the company’s derivative instruments is designated as a hedging instrument, although certain of the company’s affiliates make such designation. The company’s derivatives are not material to the company’s financial position, results of operations or liquidity. The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its 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, 2010, December 31, 2009 and December 31, 2008, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are as follows:

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

		Asset Derivatives – Fair Value			Liability Derivatives – Fair Value	
Type of Derivative Contract	Balance Sheet Classification	At December 31 2010	At December 31 2009	Balance Sheet Classification	At December 31 2010	At December 31 2009
Commodity	Accounts and notes receivable, net	**$ 58**	$ 99	Accounts payable	**$ 131**	$ 73
Commodity	Long-term receivables, net	**64**	28	Deferred credits and other noncurrent obligations	**40**	28
		$ 122	$ 127		**$ 171**	$ 101

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 2010	2009	2008
Foreign Exchange	Other income	**$ –**	$ 26	$ (314)
Commodity	Sales and other operating revenues	**(98)**	(94)	706
Commodity	Purchased crude oil and products	**(36)**	(353)	424
Commodity	Other income	**(1)**	–	(3)
		$ (135)	$ (421)	$ 813

Foreign Currency The company may enter into currency derivative contracts to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments. The currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open currency derivative contracts at December 31, 2010 or 2009.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. 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 2010 and 2009, the company had no interest rate swaps.

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. These 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, and 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 activities reported in Chevron's upstream and downstream operating segments have changed effective January 1, 2010. Chemicals businesses are now reported as part of the downstream segment. In addition, the company's significant upstream-enabling operations, primarily a gas-to-liquids project and major international export pipelines, have been reclassified from the downstream segment to the upstream segment. Prior period information in this report has been revised to conform to the 2010 presentation.

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

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

	Year ended December 31		
	2010	2009	2008
Segment Earnings			
Upstream			
United States	**$ 4,122**	$ 2,262	$ 7,147
International	**13,555**	8,670	15,022
Total Upstream	**17,677**	10,932	22,169
Downstream			
United States	**1,339**	(121)	1,369
International	**1,139**	594	1,783
Total Downstream	**2,478**	473	3,152
Total Segment Earnings	**20,155**	11,405	25,321
All Other			
Interest expense	**(41)**	(22)	–
Interest income	**70**	46	192
Other	**(1,160)**	(946)	(1,582)
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2010 and 2009 are as follows:

	At December 31	
	2010	2009
Upstream		
United States	**$ 26,319**	$ 25,478
International	**89,306**	81,209
Goodwill	**4,617**	4,618
Total Upstream	**120,242**	111,305
Downstream		
United States	**21,406**	20,317
International	**20,559**	19,618
Total Downstream	**41,965**	39,935
Total Segment Assets	**162,207**	151,240
All Other*		
United States	**11,125**	7,125
International	**11,437**	6,256
Total All Other	**22,562**	13,381
Total Assets – United States	**58,850**	52,920
Total Assets – International	**121,302**	107,083
Goodwill	**4,617**	4,618
Total Assets	**$ 184,769**	$ 164,621

*"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 2010, 2009 and 2008, are presented in the table at the right. 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 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 2010, 2009 and 2008.

	Year ended December 31		
	2010	2009	2008
Upstream			
United States	**$ 10,316**	$ 9,225	$ 23,566
Intersegment	**13,839**	10,297	15,162
Total United States	**24,155**	19,522	38,728
International	**17,300**	13,463	19,531
Intersegment	**23,834**	18,477	24,205
Total International	**41,134**	31,940	43,736
Total Upstream	**65,289**	51,462	82,464
Downstream			
United States	**70,436**	58,056	87,759
Excise and similar taxes	**4,484**	4,573	4,748
Intersegment	**115**	98	242
Total United States	**75,035**	62,727	92,749
International	**90,922**	77,845	123,389
Excise and similar taxes	**4,107**	3,536	5,098
Intersegment	**93**	87	80
Total International	**95,122**	81,468	128,567
Total Downstream	**170,157**	144,195	221,316
All Other			
United States	**610**	665	815
Intersegment	**947**	964	917
Total United States	**1,557**	1,629	1,732
International	**23**	39	52
Intersegment	**39**	33	33
Total International	**62**	72	85
Total All Other	**1,619**	1,701	1,817
Segment Sales and Other Operating Revenues			
United States	**100,747**	83,878	133,209
International	**136,318**	113,480	172,388
Total Segment Sales and Other Operating Revenues	**237,065**	197,358	305,597
Elimination of intersegment sales	**(38,867)**	(29,956)	(40,639)
Total Sales and Other Operating Revenues	**$ 198,198**	$ 167,402	$ 264,958

Segment Income Taxes Segment income tax expense for the years 2010, 2009 and 2008 is as follows:

	Year ended December 31		
	2010	2009	2008
Upstream			
United States	**$ 2,285**	$ 1,251	$ 3,705
International	**10,480**	7,451	15,122
Total Upstream	**12,765**	8,702	18,827
Downstream			
United States	**680**	(83)	780
International	**462**	463	871
Total Downstream	**1,142**	380	1,651
All Other	**(988)**	(1,117)	(1,452)
Total Income Tax Expense	**$ 12,919**	$ 7,965	$ 19,026

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page 51. Information related to properties, plant and equipment by segment is contained in Note 13, on page 53.

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		
	2010	2009	**2010**	2009	2008
Upstream					
Tengizchevroil	**$ 5,789**	$ 5,938	**$ 3,398**	$ 2,216	$ 3,220
Petropiar/Hamaca	**973**	1,139	**262**	122	317
Caspian Pipeline Consortium	**974**	852	**124**	105	103
Petroboscan	**937**	832	**222**	171	244
Angola LNG Limited	**2,481**	1,853	**(21)**	(12)	(8)
Other	**1,922**	1,947	**319**	287	424
Total Upstream	**13,076**	12,561	**4,304**	2,889	4,300
Downstream					
GS Caltex Corporation	**2,496**	2,406	**158**	(191)	444
Chevron Phillips Chemical Company LLC	**2,419**	2,327	**704**	328	158
Star Petroleum Refining Company Ltd.	**947**	873	**122**	(4)	22
Caltex Australia Ltd.	**767**	740	**101**	11	250
Colonial Pipeline Company	**–**	514	**43**	51	32
Other	**602**	540	**151**	149	140
Total Downstream	**7,231**	7,400	**1,279**	344	1,046
All Other					
Other	**509**	507	**54**	83	20
Total equity method	**$ 20,816**	$ 20,468	**$ 5,637**	$ 3,316	$ 5,366
Other at or below cost	**704**	690			
Total investments and advances	**$ 21,520**	$ 21,158			
Total United States	**$ 3,769**	$ 4,195	**$ 846**	$ 511	$ 307
Total International	**$ 17,751**	$ 16,963	**$ 4,791**	$ 2,805	$ 5,059

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, 2010, the company's carrying value of its investment in TCO was about $190 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 44, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company formed in 2008 to operate the Hamaca heavy-oil production and upgrading project. The project, located in Venezuela's Orinoco Belt, has a 25-year contract term. Prior to the formation of Petropiar, Chevron had a 30 percent interest in the Hamaca project. At December 31, 2010, the company's carrying value of its investment in Petropiar was approximately $190 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 $974 which includes long-term loans of $1,046 at year-end 2010. The loans were provided to fund 30 percent of the 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, 2010, the company's carrying value of its investment in Petroboscan was approximately $250 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.

Note 12 Investments and Advances – Continued

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, 2010, the fair value of Chevron's share of CAL common stock was approximately $1,970.

Colonial Pipeline Company In October 2010, the company sold its 23.4 percent equity interest in the Colonial Pipeline Company.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $13,672, $10,391 and $15,390 with affiliated companies for 2010, 2009 and 2008, respectively. "Purchased crude oil and products" includes $5,559, $4,631 and $6,850 with affiliated companies for 2010, 2009 and 2008, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,718 and $1,125 due from affiliated companies at December 31, 2010 and 2009, respectively. "Accounts payable" includes $377 and $345 due to affiliated companies at December 31, 2010 and 2009, 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 $1,543, $2,422 and $2,820 at December 31, 2010, 2009 and 2008, respectively.

	Affiliates			Chevron Share		
Year ended December 31	**2010**	2009	2008	**2010**	2009	2008
Total revenues	**$ 107,505**	$ 81,995	$ 112,707	**$ 52,088**	$ 39,280	$ 54,055
Income before income tax expense	**18,468**	11,083	17,500	**7,966**	4,511	7,532
Net income attributable to affiliates	**12,831**	8,261	12,705	**5,683**	3,285	5,524
At December 31						
Current assets	**$ 30,335**	$ 27,111	$ 25,194	**$ 12,845**	$ 11,009	$ 10,804
Noncurrent assets	**57,491**	55,363	51,878	**21,401**	21,361	20,129
Current liabilities	**20,428**	17,450	17,727	**9,363**	7,833	7,474
Noncurrent liabilities	**19,749**	21,531	21,049	**4,459**	5,106	4,533
Total affiliates' net equity	**$ 47,649**	$ 43,493	$ 38,296	**$ 20,424**	$ 19,431	$ 18,926

Note 13

Properties, Plant and Equipment[1]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expense[3]		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Upstream												
United States	**$ 62,523**	$ 58,328	$ 54,878	**$ 23,277**	$ 22,273	$ 22,701	**$ 4,934**	$ 3,518	$ 5,395	**$ 4,078**	$ 3,992	$ 2,704
International	**110,578**	96,557	86,676	**64,388**	57,450	53,371	**14,381**	10,803	14,997	**7,448**	6,669	5,461
Total Upstream	**173,101**	154,885	141,554	**87,665**	79,723	76,072	**19,315**	14,321	20,392	**11,526**	10,661	8,165
Downstream												
United States	**19,820**	18,962	17,397	**10,379**	10,032	8,908	**1,199**	1,874	2,061	**741**	666	627
International	**9,697**	9,852	10,021	**3,948**	4,154	4,266	**361**	456	537	**451**	454	482
Total Downstream	**29,517**	28,814	27,418	**14,327**	14,186	13,174	**1,560**	2,330	2,598	**1,192**	1,120	1,109
All Other[4]												
United States	**4,722**	4,569	4,310	**2,496**	2,548	2,523	**259**	354	598	**341**	325	250
International	**27**	20	17	**16**	11	11	**11**	3	5	**4**	4	4
Total All Other	**4,749**	4,589	4,327	**2,512**	2,559	2,534	**270**	357	603	**345**	329	254
Total United States	**87,065**	81,859	76,585	**36,152**	34,853	34,132	**6,392**	5,746	8,054	**5,160**	4,983	3,581
Total International	**120,302**	106,429	96,714	**68,352**	61,615	57,648	**14,753**	11,262	15,539	**7,903**	7,127	5,947
Total	**$ 207,367**	$ 188,288	$ 173,299	**$104,504**	$ 96,468	$ 91,780	**$ 21,145**	$ 17,008	$ 23,593	**$ 13,063**	$ 12,110	$ 9,528

[1] Other than the United States and Nigeria, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2010, 2009 and 2008. Nigeria had net PP&E of $13,896, $12,463 and $10,730 for 2010, 2009 and 2008, respectively.
[2] Net of dry hole expense related to prior years' expenditures of $82, $84 and $55 in 2010, 2009 and 2008, respectively.
[3] Depreciation expense includes accretion expense of $513, $463 and $430 in 2010, 2009 and 2008, respectively.
[4] Primarily mining operations, power generation businesses, real estate assets and management information systems.

Note 14

Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 19 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 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 remain 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.

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before 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 Permanent Court of Arbitration 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. 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 February 8, 2011, the Court issued a temporary restraining order 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 until March 8, 2011. Chevron's motion for a preliminary injunction is presently before the Court.

On February 14, 2011, the Provincial Court in Lago Agrio rendered an adverse judgment in the case. The Provincial Court rejected Chevron's defenses to the extent the Court addressed them in its opinion. The judgment assesses approximately $8,600 in damages and about $900 for the plaintiffs' representatives. It also assesses an additional amount of approximately $8,600 in punitive damages unless the company provides a public apology. Chevron continues to believe the 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 will appeal this decision in Ecuador. 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. Because Chevron has no substantial assets in Ecuador, Chevron would expect enforcement actions as a result of this judgment to be brought in other jurisdictions. Chevron expects to contest any such actions.

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 judgement, the 2008 engineer's report and the September 2010 plaintiffs' submission, 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		
	2010	2009	2008
Taxes on income			
U.S. Federal			
Current	**$ 1,501**	$ 128	$ 2,879
Deferred	**162**	(147)	274
State and local			
Current	**376**	216	528
Deferred	**20**	14	141
Total United States	**2,059**	211	3,822
International			
Current	**10,483**	7,154	15,021
Deferred	**377**	600	183
Total International	**10,860**	7,754	15,204
Total taxes on income	**$ 12,919**	$ 7,965	$ 19,026

In 2010, before-tax income for U.S. operations, including related corporate and other charges, was $6,528, compared with before-tax income of $1,310 and $10,765 in 2009 and 2008, respectively. For international operations, before-tax income was $25,527, $17,218 and $32,292 in 2010, 2009 and 2008, respectively. U.S. federal income tax expense was reduced by $162, $204 and $198 in 2010, 2009 and 2008, respectively, for business tax credits.

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

	Year ended December 31		
	2010	2009	2008
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	**5.2**	10.4	10.1
State and local taxes on income, net of U.S. federal income tax benefit	**0.8**	0.9	1.0
Prior year tax adjustments	**(0.6)**	(0.3)	(0.1)
Tax credits	**(0.5)**	(1.1)	(0.5)
Effects of enacted changes in tax laws	**0.0**	0.1	(0.6)
Other	**0.4**	(2.0)	(0.7)
Effective tax rate	**40.3%**	43.0%	44.2%

The company's effective tax rate decreased from 43.0 percent in 2009 to 40.3 percent in 2010. The rate was lower in 2010 than in 2009 primarily due to international upstream impacts. A lower effective tax rate in international upstream in 2010 was primarily driven by 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.

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	
	2010	2009
Deferred tax liabilities		
Properties, plant and equipment	**$ 19,855**	$ 18,545
Investments and other	**2,401**	2,350
Total deferred tax liabilities	**22,256**	20,895
Deferred tax assets		
Foreign tax credits	**(6,669)**	(5,387)
Abandonment/environmental reserves	**(5,004)**	(4,424)
Employee benefits	**(3,627)**	(3,499)
Deferred credits	**(2,176)**	(3,469)
Tax loss carryforwards	**(882)**	(819)
Other accrued liabilities	**(486)**	(553)
Inventory	**(483)**	(431)
Miscellaneous	**(1,676)**	(1,681)
Total deferred tax assets	**(21,003)**	(20,263)
Deferred tax assets valuation allowance	**9,185**	7,921
Total deferred taxes, net	**$ 10,438**	$ 8,553

Deferred tax liabilities at the end of 2010 increased by almost $1,400 from year-end 2009. The increase was primarily related to increased temporary differences for property, plant and equipment.

Deferred tax assets increased by approximately $700 in 2010. 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 asset retirement obligations, environmental reserves and 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. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2011 through 2036. Foreign tax credit carryforwards of $6,669 will expire between 2011 and 2020.

At December 31, 2010 and 2009, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2010	2009
Prepaid expenses and other current assets	**$ (1,624)**	$ (1,825)
Deferred charges and other assets	**(851)**	(1,268)
Federal and other taxes on income	**216**	125
Noncurrent deferred income taxes	**12,697**	11,521
Total deferred income taxes, net	**$ 10,438**	$ 8,553

Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled $21,347 at December 31, 2010. This amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of earnings that are intended to be reinvested indefinitely. At the end of 2010, deferred income taxes were recorded for the undistributed earnings of certain international operations for which the company no longer intends to indefinitely reinvest the earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

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

The following table indicates the changes to the company's unrecognized tax benefits for the years ended December 31, 2010, 2009 and 2008. The term "unrecognized tax benefits" in the accounting standards for income taxes (ASC 740-10-20) refers to the differences between a tax position taken or expected to be taken in a tax return and the benefit measured and recognized in the financial statements. Interest and penalties are not included.

	2010	2009	2008
Balance at January 1	**$ 3,195**	$ 2,696	$ 2,199
Foreign currency effects	**17**	(1)	(1)
Additions based on tax positions taken in current year	**334**	459	522
Reductions based on tax positions taken in current year	**–**	–	(17)
Additions/reductions resulting from current-year asset acquisitions/sales	**–**	–	175
Additions for tax positions taken in prior years	**270**	533	337
Reductions for tax positions taken in prior years	**(165)**	(182)	(246)
Settlements with taxing authorities in current year	**(136)**	(300)	(215)
Reductions as a result of a lapse of the applicable statute of limitations	**(8)**	(10)	(58)
Balance at December 31	**$ 3,507**	$ 3,195	$ 2,696

Approximately 80 percent of the $3,507 of unrecognized tax benefits at December 31, 2010, 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, 2010. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2005, Nigeria – 1994, Angola – 2001 and Saudi Arabia – 2003.

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, we are 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, 2010, accruals of $225 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $232 as of year-end 2009. Income tax expense (benefit) associated with interest and penalties was $40, $(20) and $79 in 2010, 2009 and 2008, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2010	2009	2008
United States			
Excise and similar taxes on products and merchandise	**$ 4,484**	$ 4,573	$ 4,748
Import duties and other levies	**–**	(4)	1
Property and other miscellaneous taxes	**567**	584	588
Payroll taxes	**219**	223	204
Taxes on production	**271**	135	431
Total United States	**5,541**	5,511	5,972
International			
Excise and similar taxes on products and merchandise	**4,107**	3,536	5,098
Import duties and other levies	**6,183**	6,550	8,368
Property and other miscellaneous taxes	**2,000**	1,740	1,557
Payroll taxes	**133**	134	106
Taxes on production	**227**	120	202
Total International	**12,650**	12,080	15,331
Total taxes other than on income	**$ 18,191**	$ 17,591	$ 21,303

Note 16

Short-Term Debt

	At December 31	
	2010	2009
Commercial paper*	**$ 2,471**	$ 2,499
Notes payable to banks and others with originating terms of one year or less	**43**	213
Current maturities of long-term debt	**33**	66
Current maturities of long-term capital leases	**81**	76
Redeemable long-term obligations		
Long-term debt	**2,943**	1,702
Capital leases	**16**	18
Subtotal	**5,587**	4,574
Reclassified to long-term debt	**(5,400)**	(4,190)
Total short-term debt	**$ 187**	$ 384

*Weighted-average interest rates at December 31, 2010 and 2009, were 0.16 percent and 0.08 percent, respectively.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders within one year following the balance sheet date. In 2010, $1,250 of tax-exempt bonds related to projects at the Pascagoula and El Segundo refineries were issued.

The company periodically enters into interest rate swaps on a portion of its short-term debt. At December 31, 2010, the company had no interest rate swaps on short-term debt.

At December 31, 2010, the company had $6,000 in committed credit facilities with various major banks, expiring in May 2013, 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, 2010.

At December 31, 2010 and 2009, the company classified $5,400 and $4,190, 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, 2010, was $11,003. The company's long-term debt outstanding at year-end 2010 and 2009 was as follows:

	At December 31	
	2010	2009
3.95% notes due 2014	**$ 1,998**	$ 1,997
3.45% notes due 2012	**1,500**	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]	**72**	109
9.75% debentures due 2020	**54**	56
8.875% debentures due 2021	**40**	40
8.625% debentures due 2010	**–**	30
Medium-term notes, maturing from 2021 to 2038 (5.97%)[2]	**38**	38
Fixed interest rate notes, maturing 2011 (9.378%)[2]	**19**	19
Other foreign currency obligations	**–**	–
Other long-term debt (5.66%)[2]	**4**	5
Total including debt due within one year	**5,636**	5,705
Debt due within one year	**(33)**	(66)
Reclassified from short-term debt	**5,400**	4,190
Total long-term debt	**$ 11,003**	$ 9,829

[1] Guarantee of ESOP debt.
[2] Weighted-average interest rate at December 31, 2010.

Long-term debt of $5,636 matures as follows: 2011 – $33; 2012– $1,520; 2013 – $20; 2014 – $2,020; 2015 – $0; and after 2015 – $2,043.

In 2010, $30 of bonds matured. In 2009, $5,000 of public bonds was issued, and $400 of Texaco Capital Inc. bonds matured.

See Note 9, beginning on page 45, for information concerning the fair value of the company's long-term debt.

Note 18

New Accounting Standards

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

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

Receivables (ASC 310), Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses (ASU 2010-20) In July 2010, the FASB issued ASU 2010-20, which became effective with the company's reporting at December 31, 2010. This standard amends and expands disclosure requirements about the credit quality of financing receivables and the related allowance for credit losses. As a result of these amendments, companies are required to disaggregate, by portfolio segment or class of financing receivable, certain existing disclosures and provide certain new disclosures about financing receivables and related allowance for credit losses. Adoption of the standard did not change the company's existing disclosures.

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 or exploratory-type stratigraphic 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, 2010:

	2010	2009	2008
Beginning balance at January 1	**$ 2,435**	$ 2,118	$ 1,660
Additions to capitalized exploratory well costs pending the determination of proved reserves	**482**	663	643
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(129)**	(174)	(49)
Capitalized exploratory well costs charged to expense	**(70)**	(172)	(136)
Ending balance at December 31	**$ 2,718**	$ 2,435	$ 2,118

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		
	2010	2009	2008
Exploratory well costs capitalized for a period of one year or less	**$ 419**	$ 564	$ 559
Exploratory well costs capitalized for a period greater than one year	**2,299**	1,871	1,559
Balance at December 31	**$ 2,718**	$ 2,435	$ 2,118
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**53**	46	50

*Certain projects have multiple wells or fields or both.

Of the $2,299 of exploratory well costs capitalized for more than one year at December 31, 2010, $982 (26 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $1,317 balance is related to 27 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 $1,317 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $501 (three projects) – project sanction approved and construction is in progress, with initial recognition of proved reserves expected upon reaching "economic producibility" per SEC guidelines; (b) $263 (six projects) – development alternatives under review; (c) $178 (three projects) – in process of entering contracts for front-end engineering and design; (d) $154 (three projects) – progression of development concept selection and unitization agreement; (e) $109 (five projects) – undergoing front-end engineering and design with final investment decision expected in 2011; (f) $73 (two projects) – development concept under review by government; $39 – miscellaneous activities for five projects with smaller amounts suspended. While progress was being made on all 53 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 $2,299 of suspended well costs capitalized for a period greater than one year as of December 31, 2010, represents 176 exploratory wells in 53 projects. The tables below contain the aging of these costs on a well and project basis:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1992	$ 8	3
1997–1999	27	6
2000–2004	442	54
2005–2009	1,822	113
Total	$ 2,299	176

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
1992	$ 8	1
1999	8	1
2003–2005	340	9
2006–2010	1,943	42
Total	$ 2,299	53

Note 20

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2010, 2009 and 2008 was $229 ($149 after tax), $182 ($119 after tax) and $168 ($109 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was $194 ($126 after tax), $170 ($110 after tax) and $132 ($86 after tax) for 2010, 2009 and 2008, respectively. No significant stock-based compensation cost was capitalized at December 31, 2010 and 2009.

Cash received in payment for option exercises under all share-based payment arrangements for 2010, 2009 and 2008 was $385, $147 and $404, respectively. Actual tax benefits realized for the tax deductions from option exercises were $66, $25 and $103 for 2010, 2009 and 2008, respectively.

Cash paid to settle performance units and stock appreciation rights was $140, $89 and $136 for 2010, 2009 and 2008, 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, 2010, 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 have 10-year contractual lives extending into 2011, retained a provision for being restored. This provision enables a participant who exercises a stock option to receive new options equal to the number of shares exchanged or who has shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant, and the exercise price is the market value of the common stock on the day the restored option is granted. Beginning in 2007, restored options were issued under the LTIP. No further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) When Chevron acquired Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights. These awards retained the same provisions as the original Unocal Plans. Unexercised awards began expiring in early 2010 and will continue to expire through early 2015.

The fair market values of stock options and stock appreciation rights granted in 2010, 2009 and 2008 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2010	2009	2008
Stock Options			
Expected term in years[1]	**6.1**	6.0	6.1
Volatility[2]	**30.8%**	30.2%	22.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**2.9%**	2.1%	3.0%
Dividend yield	**3.9%**	3.2%	2.7%
Weighted-average fair value per option granted	**$ 16.28**	$ 15.36	$ 15.97
Restored Options			
Expected term in years[1]	**1.2**	1.2	1.2
Volatility[2]	**38.9%**	45.0%	23.1%
Risk-free interest rate based on zero coupon U.S. treasury note	**0.6%**	1.1%	1.9%
Dividend yield	**3.8%**	3.5%	2.7%
Weighted-average fair value per option granted	**$ 12.91**	$ 12.38	$ 10.01

[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 2010 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	69,463	$ 63.70		
Granted	15,454	$ 73.70		
Exercised	(8,133)	$ 49.82		
Restored	27	$ 78.41		
Forfeited	(1,959)	$ 73.34		
Outstanding at December 31, 2010	74,852	$ 67.04	6.4 yrs	$ 1,813
Exercisable at December 31, 2010	48,174	$ 63.29	5.2 yrs	$ 1,348

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2010, 2009 and 2008 was $259, $91 and $433, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2010, there was $242 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 1.7 years.

At January 1, 2010, the number of LTIP performance units outstanding was equivalent to 2,679,108 shares. During 2010, 1,104,000 units were granted, 881,759 units vested with cash proceeds distributed to recipients and 173,475 units were forfeited. At December 31, 2010, units outstanding were 2,727,874, and the fair value of the liability recorded for these instruments was $266. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 1.6 million equivalent shares as of December 31, 2010. A liability of $40 was recorded for these awards.

In March 2009, Chevron granted all eligible LTIP employees restricted stock units in lieu of an annual cash bonus. A total of 453,965 units were granted at $69.70 per unit at the time of the grant. The expense associated with these special restricted stock units was recognized in 2009. All of the special restricted stock units were distributed in November 2010.

Note 21

Employee Benefit Plans

The company has defined benefit pension plans for many employees. The company typically prefunds defined benefit plans as required by local regulations or in certain situations where prefunding provides economic advantages. In the United States, all qualified plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund U.S. nonqualified pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be less economic and investment returns may be less attractive than the company's other investment alternatives.

The company also sponsors other postretirement (OPEB) plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and retirees share the costs. Medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the company contribution for retiree medical coverage is limited to no more than 4 percent 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.

The funded status of the company's pension and other postretirement benefit plans for 2010 and 2009 is on the following page:

	Pension Benefits 2010 U.S.	Pension Benefits 2010 Int'l.	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Other Benefits 2010	Other Benefits 2009
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 9,664**	**$ 4,715**	$ 8,127	$ 3,891	**$ 3,065**	$ 2,931
Service cost	**337**	**153**	266	128	**39**	43
Interest cost	**486**	**307**	481	292	**175**	180
Plan participants' contributions	**–**	**7**	–	7	**147**	145
Plan amendments	**–**	**–**	1	10	**12**	20
Curtailments	**–**	**–**	–	–	**–**	(5)
Actuarial loss (gain)	**568**	**200**	1,391	299	**486**	56
Foreign currency exchange rate changes	**–**	**(17)**	–	333	**11**	27
Benefits paid	**(784)**	**(295)**	(602)	(245)	**(330)**	(332)
Benefit obligation at December 31	**10,271**	**5,070**	9,664	4,715	**3,605**	3,065
Change in Plan Assets						
Fair value of plan assets at January 1	**7,304**	**3,235**	5,448	2,600	**–**	–
Actual return on plan assets	**867**	**361**	964	402	**–**	–
Foreign currency exchange rate changes	**–**	**(63)**	–	226	**–**	–
Employer contributions	**1,192**	**258**	1,494	245	**183**	187
Plan participants' contributions	**–**	**7**	–	7	**147**	145
Benefits paid	**(784)**	**(295)**	(602)	(245)	**(330)**	(332)
Fair value of plan assets at December 31	**8,579**	**3,503**	7,304	3,235	**–**	–
Funded Status at December 31	**$ (1,692)**	**$ (1,567)**	$ (2,360)	$ (1,480)	**$ (3,605)**	$ (3,065)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2010 and 2009, include:

	Pension Benefits 2010 U.S.	Pension Benefits 2010 Int'l.	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Other Benefits 2010	Other Benefits 2009
Deferred charges and other assets	**$ 7**	**$ 77**	$ 6	$ 37	**$ –**	$ –
Accrued liabilities	**(134)**	**(71)**	(66)	(67)	**(225)**	(208)
Reserves for employee benefit plans	**(1,565)**	**(1,573)**	(2,300)	(1,450)	**(3,380)**	(2,857)
Net amount recognized at December 31	**$ (1,692)**	**$ (1,567)**	$ (2,360)	$ (1,480)	**$ (3,605)**	$ (3,065)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were $6,749 and $6,454 at the end of 2010 and 2009, respectively. These amounts consisted of:

	Pension Benefits 2010 U.S.	Pension Benefits 2010 Int'l.	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Other Benefits 2010	Other Benefits 2009
Net actuarial loss	**$ 3,919**	**$ 1,903**	$ 4,181	$ 1,889	**$ 935**	$ 465
Prior service (credit) costs	**(52)**	**179**	(60)	201	**(135)**	(222)
Total recognized at December 31	**$ 3,867**	**$ 2,082**	$ 4,121	$ 2,090	**$ 800**	$ 243

The accumulated benefit obligations for all U.S. and international pension plans were $9,535 and $4,161, respectively, at December 31, 2010, and $8,707 and $4,029, respectively, at December 31, 2009.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2010 and 2009, was:

	Pension Benefits 2010 U.S.	Pension Benefits 2010 Int'l.	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.
Projected benefit obligations	**$ 10,265**	**$ 3,668**	$ 9,658	$ 3,550
Accumulated benefit obligations	**9,528**	**3,113**	8,702	3,102
Fair value of plan assets	**8,566**	**2,190**	7,292	2,116

The components of net periodic benefit cost and amounts recognized in other comprehensive income for 2010, 2009 and 2008 are shown in the table below:

	Pension Benefits						Other Benefits		
	2010		2009		2008				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2010**	2009	2008
Net Periodic Benefit Cost									
Service cost	**$ 337**	**$ 153**	$ 266	$ 128	$ 250	$ 132	**$ 39**	$ 43	$ 44
Interest cost	**486**	**307**	481	292	499	292	**175**	180	178
Expected return on plan assets	**(538)**	**(241)**	(395)	(203)	(593)	(273)	**–**	–	–
Amortization of prior service (credits) costs	**(8)**	**22**	(7)	23	(7)	24	**(75)**	(81)	(81)
Recognized actuarial losses	**318**	**98**	298	108	60	77	**27**	27	38
Settlement losses	**186**	**6**	141	1	306	2	**–**	–	–
Curtailment losses	**–**	**–**	–	–	–	–	**–**	(5)	–
Special termination benefit recognition	**–**	**–**	–	–	–	1	**–**	–	–
Total net periodic benefit cost	**781**	**345**	784	349	515	255	**166**	164	179
Changes Recognized in Other Comprehensive Income									
Net actuarial loss (gain) during period	**242**	**118**	823	194	2,624	646	**497**	82	(42)
Amortization of actuarial loss	**(504)**	**(104)**	(439)	(109)	(366)	(79)	**(27)**	(27)	(38)
Prior service cost during period	**–**	**–**	1	13	–	32	**12**	20	–
Amortization of prior service credits (costs)	**8**	**(22)**	7	(23)	7	(24)	**75**	81	81
Total changes recognized in other comprehensive income	**(254)**	**(8)**	392	75	2,265	575	**557**	156	1
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 527**	**$ 337**	$1,176	$ 424	$ 2,780	$ 830	**$ 723**	$ 320	$ 180

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2010, 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 10 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2011, the company estimates actuarial losses of $314, $114 and $64 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 $250 will be recognized from "Accumulated other comprehensive loss" during 2011 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, 2010, was approximately seven and 11 years for U.S. and international pension plans, respectively, and 12 years for other postretirement benefit plans. During 2011, the company estimates prior service (credits) costs of $(8), $27 and $(72) will be amortized from "Accumulated other comprehensive loss" for U.S. pension, international pension and OPEB plans, respectively.

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		
	2010		2009		2008				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2010**	2009	2008
Assumptions used to determine benefit obligations:									
Discount rate	**4.8%**	**6.5%**	5.3%	6.8%	6.3%	7.5%	**5.2%**	5.9%	6.3%
Rate of compensation increase	**4.5%**	**6.7%**	4.5%	6.3%	4.5%	6.8%	**N/A**	N/A	4.0%
Assumptions used to determine net periodic benefit cost:									
Discount rate	**5.3%**	**6.8%**	6.3%	7.5%	6.3%	6.7%	**5.9%**	6.3%	6.3%
Expected return on plan assets	**7.8%**	**7.8%**	7.8%	7.5%	7.8%	7.4%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**6.3%**	4.5%	6.8%	4.5%	6.4%	**N/A**	N/A	4.5%

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

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 70 percent of the company's pension plan assets. At December 31, 2010, 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, 2010, the company selected a 4.8 percent discount rate for the U.S. pension plan and 5.0 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 2010. The discount rates at the end of 2009 were 5.3 percent and 5.8 percent for the U.S. pension plan and the U.S. OPEB plan, respectively. The discount rate at the end of 2008 was 6.3 percent for both the U.S. pension plan and the U.S. OPEB plan.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2010, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 8 percent in 2011 and gradually decline to 5 percent for 2018 and beyond. For this measurement at December 31, 2009, the assumed health care cost-trend rates started with 7 percent in 2010 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	$ 11	$ (9)
Effect on postretirement benefit obligation	$ 146	$ (125)

Plan Assets and Investment Strategy The accounting standards for defined benefit pension and OPEB plans (ASC 715) provide users of financial statements with an understanding of: how investment allocation decisions are made; the major classes of plan assets; the inputs and valuation techniques used to measure the fair value of plan assets; the effect of fair value measurements using unobservable inputs on changes in plan assets for the period; and significant concentrations of risk within plan assets.

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

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

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

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

The fair value measurements of the company's pension plans for 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, 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**
At December 31, 2009								
Equities								
U.S.[1]	$ 2,115	$ 2,115	$ –	$ –	$ 370	$ 370	$ –	$ –
International	977	977	–	–	492	492	–	–
Collective Trusts/Mutual Funds[2,6]	1,264	3	1,261	–	786	91	695	–
Fixed Income								
Government	713	149	564	–	506	54	452	–
Corporate	430	–	430	–	371	17	336	18
Mortgage-Backed Securities	149	–	149	–	2	–	–	2
Other Asset Backed	90	–	90	–	19	–	19	–
Collective Trusts/Mutual Funds[2]	326	–	326	–	230	14	216	–
Mixed Funds[3,6]	8	8	–	–	105	17	88	–
Real Estate[4]	479	–	–	479	131	–	–	131
Cash and Cash Equivalents	743	743	–	–	207	207	–	–
Other[5]	10	(57)	16	51	16	(3)	18	1
Total at December 31, 2009	$ 7,304	$ 3,938	$ 2,836	$ 530	$ 3,235	$ 1,259	$ 1,824	$ 152

[1] U.S. equities include investments in the company's common stock in the amount of $38 at December 31, 2010 and $29 at December 31, 2009.
[2] Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is 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).
[6] Certain amounts have been reclassified to conform to their 2010 presentation.

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

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

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. There are no significant concentrations of risk in plan assets due to the diversification of investment classes.

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2010, the company contributed $1,192 and $258 to its U.S. and international pension plans, respectively. In 2011, the company expects contributions to be approximately $650 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 $225 in 2011, as compared with $183 paid in 2010.

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

	Pension Benefits U.S.	Pension Benefits Int'l.	Other Benefits
2011	$ 994	$ 247	$ 225
2012	$ 926	$ 298	$ 230
2013	$ 924	$ 300	$ 238
2014	$ 934	$ 320	$ 246
2015	$ 937	$ 346	$ 253
2016–2020	$ 4,687	$ 2,095	$ 1,345

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 $253, $257, and $231 in 2010, 2009 and 2008, respectively. This cost was reduced by the value of shares released from the LESOP totaling $97, $184 and $40 in 2010, 2009 and 2008, respectively. The remaining amounts, totaling $156, $73 and $191 in 2010, 2009 and 2008, 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, $3 and $1 in 2010, 2009 and 2008, respectively. The net credit for the respective years was composed of credits to compensation expense of $6, $15 and $15 and charges to interest expense for LESOP debt of $5, $12 and $14.

Of the dividends paid on the LESOP shares, $46, $110 and $35 were used in 2010, 2009 and 2008, respectively, to service LESOP debt. No contributions were required in 2010, 2009 or 2008, 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, 2010 and 2009, were as follows:

Thousands	**2010**	2009
Allocated shares	**20,718**	21,211
Unallocated shares	**2,374**	3,636
Total LESOP shares	**23,092**	24,847

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 2010, 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, 2010 and 2009, trust assets of $57 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 $766, $561 and $757 in 2010, 2009 and 2008, 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, on page 59.

Note 22
Equity

Retained earnings at December 31, 2010 and 2009, included approximately $9,159 and $8,122, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2010, about 81 million shares of Chevron's common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP).

In addition, approximately 280,000 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. The initial estimate included approximately 3,200 employees in Downstream and 600 employees from corporate staffs that were expected to be terminated under the programs. Due to redeployment efforts within the company, total employee terminations under the programs are expected to be reduced from approximately 3,800 employees to approximately 3,200 employees. About 1,500 of the affected employees are located in the United States. About 1,500 employees have been terminated to date, and the programs are expected to be completed by the end of 2011.

A before-tax charge of $244 ($175 after tax) was recorded in first quarter 2010, with $191 reported as "Operating expenses" and $53 as "Selling, general and administrative expenses" on the Consolidated Statement of Income. Due to the reduction in terminations resulting from reassignments within the company, an adjustment to total charges was made in fourth quarter 2010, which effectively reduced the total before-tax charge from $244 to $234 ($167 after tax). The accrued liability is classified as current on the Consolidated Balance Sheet. Approximately $71 ($45 after tax) is associated with terminations in U.S. Downstream, $119 ($92 after tax) in International Downstream and $44 ($30 after tax) in All Other.

During the last nine months of 2010, the company made payments of $96 associated with these liabilities. The majority of the payments were in Downstream.

	Amounts Before Tax
Balance at January 1, 2010	$ –
Accruals	244
Adjustments	(10)
Payments	(96)
Balance at December 31, 2010	$ 138

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 55, for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

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

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300. Through the end of 2010, the company paid $48 under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. 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 various commitments are: 2011 – $17,200; 2012 – $4,100; 2013 – $3,500; 2014 – $3,100; 2015 – $3,000; 2016 and after – $7,700. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $6,500 in 2010, $8,100 in 2009 and $5,100 in 2008.

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, 2010, was $1,507. Included in this balance were remediation activities at approximately 182 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 2010 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 2010 environmental reserves balance of $1,322, $814 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 $508 was associated with various sites in international downstream ($100), upstream ($329) and other businesses ($79). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2010 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 for a discussion of the company's asset retirement obligations.

Equity Redetermination For crude oil and natural gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately $200, and the possible maximum net amount that could be owed to Chevron is estimated at about $150. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies 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 the company continues to evaluate its options going forward, which may include requesting the city to revise the EIR to address the issues identified by the Court of Appeal or other actions. Management believes the outcomes associated with the potential options for 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, of the ruling 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

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

Accounting standards for asset retirement obligations primarily affect the company's accounting for crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire 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 2010, 2009 and 2008:

	2010	2009	2008
Balance at January 1	**$ 10,175**	$ 9,395	$ 8,253
Liabilities incurred	**129**	144	308
Liabilities settled	**(755)**	(757)	(973)
Accretion expense	**513**	463	430
Revisions in estimated cash flows	**2,426**	930	1,377
Balance at December 31	**$ 12,488**	$ 10,175	$ 9,395

In the table above, the amounts associated with "Revisions in estimated cash flows" reflect increasing costs to abandon wells, equipment and facilities. The long-term portion of the $12,488 balance at the end of 2010 was $11,788.

Note 26

Other Financial Information

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. Earnings in 2009 included gains of approximately $1,000 relating to the sale of nonstrategic properties. Of this amount, approximately $600 and $400 related to downstream and upstream assets, respectively. Earnings in 2008 included gains of approximately $1,200 relating to the sale of nonstrategic properties. Of this amount, approximately $1,000 related to upstream assets.

Other financial information is as follows:

	Year ended December 31		
	2010	2009	2008
Total financing interest and debt costs	**$ 317**	$ 301	$ 256
Less: Capitalized interest	**267**	273	256
Interest and debt expense	**$ 50**	$ 28	$ –
Research and development expenses	**$ 526**	$ 603	$ 702
Foreign currency effects*	**$ (423)**	$ (744)	$ 862

*Includes $(71), $(194) and $420 in 2010, 2009 and 2008, 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 $6,975 and $5,491 at December 31, 2010 and 2009, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO profits (charges) of $21, $(168) and $210 were included in earnings for the years 2010, 2009 and 2008, respectively.

The company has $4,617 in goodwill on the Consolidated Balance Sheet related to the 2005 acquisition of Unocal. Under the accounting standard for goodwill (ASC 350), the company tested this goodwill for impairment during 2010 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 and the company's share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company's retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (refer to Note 20, "Stock Options and Other Share-Based Compensation," beginning on page 59). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2010	2009	2008
Basic EPS Calculation			
Earnings available to common stockholders – Basic*	**$ 19,024**	$ 10,483	$ 23,931
Weighted-average number of common shares outstanding	**1,996**	1,991	2,037
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,997**	1,992	2,038
Earnings per share of common stock – Basic	**$ 9.53**	$ 5.26	$ 11.74
Diluted EPS Calculation			
Earnings available to common stockholders – Diluted*	**$ 19,024**	$ 10,483	$ 23,931
Weighted-average number of common shares outstanding	**1,996**	1,991	2,037
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**10**	9	12
Total weighted-average number of common shares outstanding	**2,007**	2,001	2,050
Earnings per share of common stock – Diluted	**$ 9.48**	$ 5.24	$ 11.67

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

Unaudited

Millions of dollars, except per-share amounts	**2010**	2009	2008	2007	2006
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues[1,2]	**$ 198,198**	$ 167,402	$ 264,958	$ 214,091	$ 204,892
Income from equity affiliates and other income	**6,730**	4,234	8,047	6,813	5,226
Total Revenues and Other Income	**204,928**	171,636	273,005	220,904	210,118
Total Costs and Other Deductions	**172,873**	153,108	229,948	188,630	178,072
Income Before Income Tax Expense	**32,055**	18,528	43,057	32,274	32,046
Income Tax Expense	**12,919**	7,965	19,026	13,479	14,838
Net Income	**19,136**	10,563	24,031	18,795	17,208
Less: Net income attributable to noncontrolling interests	**112**	80	100	107	70
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931	$ 18,688	$ 17,138
Per Share of Common Stock					
Net Income Attributable to Chevron[2]					
– Basic	**$ 9.53**	$ 5.26	$ 11.74	$ 8.83	$ 7.84
– Diluted	**$ 9.48**	$ 5.24	$ 11.67	$ 8.77	$ 7.80
Cash Dividends Per Share	**$ 2.84**	$ 2.66	$ 2.53	$ 2.26	$ 2.01
Balance Sheet Data (at December 31)					
Current assets	**$ 48,841**	$ 37,216	$ 36,470	$ 39,377	$ 36,304
Noncurrent assets	**135,928**	127,405	124,695	109,409	96,324
Total Assets	**184,769**	164,621	161,165	148,786	132,628
Short-term debt	**187**	384	2,818	1,162	2,159
Other current liabilities	**28,825**	25,827	29,205	32,636	26,250
Long-term debt and capital lease obligations	**11,289**	10,130	6,083	6,070	7,679
Other noncurrent liabilities	**38,657**	35,719	35,942	31,626	27,396
Total Liabilities	**78,958**	72,060	74,048	71,494	63,484
Total Chevron Corporation Stockholders' Equity	**$ 105,081**	$ 91,914	$ 86,648	$ 77,088	$ 68,935
Noncontrolling interests	**730**	647	469	204	209
Total Equity	**$ 105,811**	$ 92,561	$ 87,117	$ 77,292	$ 69,144
[1] Includes excise, value-added and similar taxes:	**$ 8,591**	$ 8,109	$ 9,846	$ 10,121	$ 9,551
[2] Includes amounts in revenues for buy/sell contracts; associated costs are in "Total Costs and Other Deductions."	**$ –**	$ –	$ –	$ –	$ 6,725

Five-Year Operating Summary

Unaudited

Worldwide – Includes Equity in Affiliates

Thousands of barrels per day, except natural gas data, which is millions of cubic feet per day	**2010**	2009	2008	2007	2006
United States					
Gross production of crude oil and natural gas liquids[1]	**527**	523	459	507	510
Net production of crude oil and natural gas liquids[1]	**489**	484	421	460	462
Gross production of natural gas	**1,507**	1,611	1,740	1,983	2,115
Net production of natural gas[2]	**1,314**	1,399	1,501	1,699	1,810
Net oil-equivalent production	**708**	717	671	743	763
Refinery input	**890**	899	891	812	939
Sales of refined products[3]	**1,349**	1,403	1,413	1,457	1,494
Sales of natural gas liquids	**161**	161	159	160	124
Total sales of petroleum products	**1,510**	1,564	1,572	1,617	1,618
Sales of natural gas	**5,932**	5,901	7,226	7,624	7,051
International					
Gross production of crude oil and natural gas liquids[1,4]	**1,989**	1,857	1,751	1,751	1,739
Net production of crude oil and natural gas liquids[1]	**1,434**	1,362	1,228	1,296	1,270
Other produced volumes[5]	**–**	26	27	27	109
Gross production of natural gas	**4,732**	4,519	4,525	4,099	3,767
Net production of natural gas[2]	**3,726**	3,590	3,624	3,320	3,146
Net oil-equivalent production	**2,055**	1,987	1,859	1,876	1,904
Refinery input	**1,004**	979	967	1,021	1,050
Sales of refined products[3]	**1,764**	1,851	2,016	2,027	2,127
Sales of natural gas liquids	**105**	111	114	118	102
Total sales of petroleum products	**1,869**	1,962	2,130	2,145	2,229
Sales of natural gas	**4,493**	4,062	4,215	3,792	3,478
Total Worldwide					
Gross production of crude oil and natural gas liquids[1]	**2,516**	2,380	2,210	2,258	2,249
Net production of crude oil and natural gas liquids[1]	**1,923**	1,846	1,649	1,756	1,732
Other produced volumes	**–**	26	27	27	109
Gross production of natural gas	**6,239**	6,130	6,265	6,082	5,882
Net production of natural gas[2]	**5,040**	4,989	5,125	5,019	4,956
Net oil-equivalent production	**2,763**	2,704	2,530	2,619	2,667
Refinery input	**1,894**	1,878	1,858	1,833	1,989
Sales of refined products[3]	**3,113**	3,254	3,429	3,484	3,621
Sales of natural gas liquids	**266**	272	273	278	226
Total sales of petroleum products	**3,379**	3,526	3,702	3,762	3,847
Sales of natural gas	**10,425**	9,963	11,441	11,416	10,529
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net)[6]					
Oil and gas	**1,160**	1,265	1,648	1,633	1,575
Dry	**31**	24	12	30	32
Productive oil and gas wells (net)[6]	**52,683**	50,817	51,291	51,528	50,695

[1] Gross production represents the company's share of total production before deducting lessors' royalties and government's agreed-upon share of production under a production-sharing contract. Net production is gross production minus royalties paid to lessors and the government.

[2] Includes natural gas consumed in operations:					
United States	**62**	58	70	65	56
International	**475**	463	450	433	419
Total	**537**	521	520	498	475
[3] Includes volumes for buy/sell contracts (MBPD):					
United States	**–**	–	–	–	26
International	**–**	–	–	–	24
[4] Includes: Canada-synthetic oil	**24**	–	–	–	–
Venezuela affiliate-synthetic oil	**28**	–	–	–	–
[5] Includes Canada oil sands	**–**	26	27	27	27
Boscan operating service agreement in Venezuela	**–**	–	–	–	82

[6] Net wells include wholly owned and the sum of fractional interests in partially owned wells.

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, 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[4]	**$ 5,116**	**$ 2,243**	**$ 3,381**	**$ 3,961**	**$ 3,019**	**$ 557**	**$ 18,277**	**$ 230**	**$ 343**
Year Ended December 31, 2009[5]									
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
Year Ended December 31, 2008[5]									
Exploration									
Wells	$ 519	$ 47	$ 197	$ 85	$ 248	$ 19	$ 1,115	$ –	$ –
Geological and geophysical	66	75	90	42	28	28	329	–	–
Rentals and other	143	135	60	70	46	31	485	–	–
Total exploration	728	257	347	197	322	78	1,929	–	–
Property acquisitions[2]									
Proved	88	–	–	169	–	–	257	–	–
Unproved	579	–	–	280	–	–	859	–	–
Total property acquisitions	667	–	–	449	–	–	1,116	–	–
Development[3]	4,348	1,334	3,723	4,697	540	545	15,187	643	120
Total Costs Incurred[6]	$ 5,743	$ 1,591	$ 4,070	$ 5,343	$ 862	$ 623	$ 18,232	$ 643	$ 120

[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 70.
[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired in nonmonetary transactions.
[3] Includes $745, $121 and $224 costs incurred prior to assignment of proved reserves for consolidated companies in 2010, 2009 and 2008, respectively. Also includes $12 in 2009 for affiliated Other.
[4] Reconciliation of consolidated companies total cost incurred to Upstream capital and exploratory (C&E) expenditures – $ billions.

Total cost incurred	$ 18.3	
ARO	(2.5)	
Non oil and gas activities	3.1	(Includes LNG and gas-to-liquids $2.3, transportation $0.4, affiliate $0.3, other $0.1)
Upstream C&E	$ 18.9	Reference page 21 upstream total

[5] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.
[6] Excludes costs incurred for oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries – Oil and Gas* (Topic 932).

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 51, for a discussion of the company's major equity affiliates.

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

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
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**
At December 31, 2009[1]									
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

[1] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

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

Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Consolidated Companies Total	Affiliated Companies TCO	Affiliated Companies Other
At December 31, 2008[1,2]									
Unproved properties	$ 2,495	$ 900	$ 294	$ 3,300	$ 139	$ 12	$ 7,140	$ 113	$ –
Proved properties and related producing assets	46,280	4,492	17,495	27,607	2,237	8,548	106,659	5,991	837
Support equipment	717	338	967	1,321	95	137	3,575	888	–
Deferred exploratory wells	602	246	499	198	404	169	2,118	–	–
Other uncompleted projects	4,275	1,585	4,226	2,461	904	154	13,605	501	101
Gross Capitalized Costs	54,369	7,561	23,481	34,887	3,779	9,020	133,097	7,493	938
Unproved properties valuation	845	441	202	150	137	(2)	1,773	29	–
Proved producing properties – Depreciation and depletion	30,780	2,743	6,602	13,617	1,289	5,617	60,648	831	163
Support equipment depreciation	382	216	523	690	49	91	1,951	307	–
Accumulated provisions	32,007	3,400	7,327	14,457	1,475	5,706	64,372	1,167	163
Net Capitalized Costs[3]	$ 22,362	$ 4,161	$ 16,154	$ 20,430	$ 2,304	$ 3,314	$ 68,725	$ 6,326	$ 775

[1] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.
[2] Amounts for Affiliated Companies – Other conformed to agreements entered in 2007 and 2008 for Venezuelan affiliates.
[3] Excludes net capitalized costs for oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries — Oil and Gas* (Topic 932).

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 2010, 2009 and 2008 are shown in the following table. Net income from exploration and production activities as reported on page 49 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 49.

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
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)**	**(895)**	**(103)**	**(205)**	**109**	**165**	**(1,083)**	**(65)**	**191**
Results before income taxes	**6,483**	**503**	**8,365**	**7,004**	**1,317**	**2,475**	**26,147**	**4,814**	**1,109**
Income tax expense	**(2,273)**	**(304)**	**(5,735)**	**(3,844)**	**(391)**	**(1,477)**	**(14,024)**	**(1,445)**	**(615)**
Results of Producing Operations	**$ 4,210**	**$ 199**	**$ 2,630**	**$ 3,160**	**$ 926**	**$ 998**	**$ 12,123**	**$ 3,369**	**$ 494**
Year Ended December 31, 2009[4]									
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 70.
[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.
[4] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

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

Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Consolidated Companies Total	Affiliated Companies TCO	Affiliated Companies Other
Year Ended December 31, 2008[2]									
Revenues from net production									
Sales	$ 4,882	$ 1,088	$ 2,578	$ 7,969	$ 508	$ 2,938	$ 19,963	$ 4,971	$ 1,599
Transfers	12,868	1,286	8,373	7,179	1,499	2,365	33,570	–	–
Total	17,750	2,374	10,951	15,148	2,007	5,303	53,533	4,971	1,599
Production expenses excluding taxes	(3,822)	(254)	(1,228)	(2,096)	(95)	(620)	(8,115)	(376)	(125)
Taxes other than on income	(716)	(42)	(163)	(263)	(323)	(5)	(1,512)	(41)	(278)
Proved producing properties:									
Depreciation and depletion	(2,286)	(402)	(1,176)	(2,299)	(122)	(928)	(7,213)	(237)	(77)
Accretion expense[3]	(242)	(15)	(60)	(48)	(5)	(39)	(409)	(2)	(1)
Exploration expenses	(370)	(156)	(223)	(178)	(148)	(94)	(1,169)	–	–
Unproved properties valuation	(114)	(7)	(13)	(36)	(1)	–	(171)	–	–
Other income (expense)[4]	707	(227)	(350)	198	36	509	873	184	105
Results before income taxes	10,907	1,271	7,738	10,426	1,349	4,126	35,817	4,499	1,223
Income tax expense	(3,856)	(591)	(6,051)	(5,697)	(425)	(2,425)	(19,045)	(1,357)	(612)
Results of Producing Operations[5]	$ 7,051	$ 680	$ 1,687	$ 4,729	$ 924	$ 1,701	$ 16,772	$ 3,142	$ 611

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.
[3] Represents accretion of ARO liability. Refer to Note 25, "Asset Retirement Obligations," on page 70.
[4] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.
[5] Excludes results of producing operations for oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries – Oil and Gas* (Topic 932).

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, 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[3]									
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
Year Ended December 31, 2008[3]									
Average sales prices									
Liquids, per barrel	$ 88.43	$ 71.45	$ 91.71	$ 83.67	$ 90.50	$ 93.74	$ 87.44	$ 79.11	$ 69.65
Natural gas, per thousand cubic feet	7.90	2.84	–	4.55	7.22	9.84	6.02	1.56	3.98
Average production costs, per barrel[2,4]	15.85	4.67	10.00	8.12	2.89	9.59	10.49	5.24	5.32

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.
[3] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.
[4] Excludes oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries – Oil and Gas* (Topic 932).

Table V Reserve Quantity Information

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting – three deemed commercial and three noncommercial. Within the commercial classification are proved reserves and two categories of unproved: probable and possible. The noncommercial categories are also referred to as contingent resources. For reserves estimates to be classified as proved, they must meet all SEC and company standards.

Proved oil and gas reserves are the estimated quantities that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future from known reservoirs under existing economic conditions, operating methods and government regulations. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

Proved reserves are classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

Due to the inherent uncertainties and the limited nature of reservoir data, estimates of reserves are subject to change as additional information becomes available.

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the 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 15 years of managing oil and gas reserves processes. He is the acting 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 accounting policy and financial reporting. The members are knowledgeable in SEC guidelines for proved reserves classification and receive annual training on the preparation of reserves estimates. The RAC manages its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

The RAC has the following primary responsibilities: establish the policies and processes used within the operating units to estimate reserves; provide independent reviews and oversight of the business units' recommended reserves estimates and changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that

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*	2010[1] Crude Oil Condensate NGLs	2010[1] Synthetic Oil	2010[1] Natural Gas	2009[1,2] Crude Oil Condensate NGLs	2009[1,2] Synthetic Oil	2009[1,2] Natural Gas	2008[2,3] Crude Oil Condensate NGLs	2008[2,3] Natural Gas
Proved Developed								
Consolidated Companies								
U.S.	**1,045**	**–**	**2,113**	1,122	–	2,314	1,158	2,709
Other Americas	**84**	**352**	**1,490**	66	190	1,678	77	1,853
Africa	**830**	**–**	**1,304**	820	–	978	789	1,209
Asia	**826**	**–**	**4,836**	926	–	5,062	1,094	4,758
Australia	**39**	**–**	**881**	50	–	1,071	46	918
Europe	**136**	**–**	**235**	151	–	302	172	392
Total Consolidated	**2,960**	**352**	**10,859**	3,135	190	11,405	3,336	11,839
Affiliated Companies								
TCO	**1,128**	**–**	**1,484**	1,256	–	1,830	1,369	1,999
Other	**95**	**53**	**70**	97	56	73	263	124
Total Consolidated and Affiliated Companies	**4,183**	**405**	**12,413**	4,488	246	13,308	4,968	13,962
Proved Undeveloped								
Consolidated Companies								
U.S.	**230**	**–**	**359**	239	–	384	312	441
Other Americas	**24**	**114**	**325**	38	270	307	72	515
Africa	**338**	**–**	**1,640**	426	–	2,043	596	1,847
Asia	**187**	**–**	**2,357**	245	–	2,798	362	3,238
Australia	**49**	**–**	**5,175**	48	–	5,174	27	1,044
Europe	**16**	**–**	**40**	19	–	42	30	98
Total Consolidated	**844**	**114**	**9,896**	1,015	270	10,748	1,399	7,183
Affiliated Companies								
TCO	**692**	**–**	**902**	690	–	1,003	807	1,176
Other	**62**	**203**	**1,040**	54	210	990	176	754
Total Consolidated and Affiliated Companies	**1,598**	**317**	**11,838**	1,759	480	12,741	2,382	9,113
Total Proved Reserves	**5,781**	**722**	**24,251**	6,247	726	26,049	7,350	23,075

[1] Based on 12-month average price.
[2] Geographic presentation conformed to 2010.
[3] Based on year-end prices.

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 the largest proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their compliance with the *Corporate Reserves Manual*.

Revised Oil and Gas Reporting In December 2008, the SEC issued its final rule, *Modernization of Oil and Gas Reporting*. The disclosure requirements under the final rule became effective for the company with its Form 10-K filing for the year ending December 31, 2009. The final rule changed a number of oil and gas reserve estimation and disclosure requirements under SEC Regulations S-K and S-X. Subsequently, the FASB updated *Extractive Industries – Oil and Gas* (Topic 932) to align the oil and gas reserves estimation and disclosure requirements with the SEC's final rule. The new disclosure requirements have been applied to data reported for 2009 and 2010.

Proved Undeveloped Reserve Quantities At the end of 2010, proved undeveloped reserves for consolidated companies totaled 2.6 billion barrels of oil-equivalent (BOE). Approximately 63 percent of these reserves are attributed to natural gas, of which about half were located in Australia. Crude oil, condensate and natural gas liquids (NGLs) accounted for about 32 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 59 percent of these reserves, with TCO accounting for the majority of this amount. Natural gas represented 25 percent of the total, with approximately 45 percent of those reserves from TCO. The balance is attributed to synthetic oil in Venezuela in the Other region.

In 2010, a total of 447 million BOE was transferred from proved undeveloped to proved developed for consolidated companies. In Other Americas, 171 million BOE were transferred, primarily due to start-up of a synthetic crude expansion project in Canada. In the Africa region, 135 million BOE were transferred to proved developed as a result of development drilling in Nigeria and Angola and the start-up of a natural gas processing plant in Nigeria. Transfers in Asia and the United States accounted for most of the remainder. Proved undeveloped reserves for affiliated companies declined slightly, with 13 million BOE transferred to proved developed.

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

Investment to Convert Proved Undeveloped to Proved Developed Reserves During 2010, investments totaling approximately $8.3 billion were made by consolidated companies and equity affiliates to advance the development of proved undeveloped reserves. In Australia, $2.6 billion was expended, which was primarily driven by construction activities at the Gorgon LNG project. In the Africa region, $2.1 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 the United States, expenditures totaled $1.1 billion for three offshore development projects in the Gulf of Mexico and various smaller development projects. In the Asia region, expenditures during the year totaled $0.9 billion, which included construction of a gas processing facility in Thailand, a gas development project in China and the completion of a steam-flood project in Indonesia. In Other Americas, development expenditures totaled $0.8 billion for a variety of projects, including a synthetic crude project in Canada. In Europe, $0.1 billion was expended on various development projects. Affiliated companies expended $0.7 billion, primarily on an LNG project in Angola.

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

At year-end 2010, the company held approximately 1.7 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 under construction and is expected to enter production in 2012. Also in Nigeria, various fields and infrastructure associated with the Escravos Gas Projects are currently under development. In Angola, the Tombua-Landana deepwater project became operational in 2009. Ongoing development drilling is expected to bring this field to maximum production in 2011.

In Asia, approximately 230 million BOE are related to continued development of the Pattani Field in the Gulf of Thailand and contractual constraints at the Malampaya Field (Philippines). The timing of compression installation aligns with natural field declines and/or to meet contractual requirements. Ongoing development is scheduled to maintain production within the infrastructure constraints.

In Australia, approximately 130 million BOE remain undeveloped over five years due to future compression projects at the North West Shelf Venture, scheduled for 2013.

In the United States, approximately 70 million BOE remain proved undeveloped, primarily related to a steamflood expansion.

Affiliated companies hold approximately 940 million BOE of proved undeveloped reserves held for five years or more. The TCO affiliate in Kazakhstan accounts for approximately 800 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 140 million BOE of proved undeveloped reserves held over five years. 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 2010, this assessment did not result in any material changes in reserves classified as proved undeveloped. Over the past three years, the ratio of proved undeveloped reserves to total proved reserves has ranged between 35 percent and 39 percent. The consistent completion of major capital projects has kept the ratio in a narrow range over this time period.

Proved Reserve Quantities At December 31, 2010, proved reserves for the company's consolidated operations were 7.7 billion BOE. (Refer to the term "Reserves" on page 8 for the definition of oil-equivalent reserves.) Approximately 22 percent of the total reserves were located in the United States. For the company's interests in equity affiliates, proved reserves were 2.8 billion BOE, 79 percent of which were associated with the company's 50 percent ownership in TCO.

Aside from the Tengiz Field in the TCO affiliate, no single property accounted for more than 5 percent of the company's total oil-equivalent proved reserves. About 25 other individual properties in the company's portfolio of assets each contained between 1 percent and 5 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for 49 percent of the company's total oil-equivalent proved reserves. These properties were geographically dispersed, located in the United States, Canada, South America, West Africa, Asia, and Australia.

In the United States, total proved reserves at year-end 2010 were 1.7 billion BOE. California properties accounted for 43 percent of the U.S. reserves, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company's heavy-oil fields in California employ a continuous steamflooding process. The Gulf of Mexico region contains 21 percent of the U.S. reserves, with liquids representing about 15 percent of reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Other U.S. areas represent the remaining 36 percent of U.S. reserves, which are about evenly split between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO_2 injection.

For the three years ending December 31, 2010, the pattern of net reserve changes shown in the following tables are not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties and civil unrest.

The company's estimated net proved reserves of crude oil, condensate, natural gas liquids and synthetic oil, and changes thereto for the years 2008, 2009 and 2010 are shown in the table on the following page. The company's estimated net proved reserves of natural gas are shown on page 85.

Net Proved Reserves of Crude Oil, Condensate, Natural Gas Liquids and Synthetic Oil

Millions of barrels	U.S.	Other Americas[1]	Africa	Asia	Australia	Europe	Synthetic Oil[2,3]	Total	TCO	Synthetic Oil[2,4]	Other[5]	Total Consolidated and Affiliated Companies
	Consolidated Companies								Affiliated Companies			
Reserves at January 1, 2008[6]	1,624	165	1,500	1,023	84	269		4,665	1,989		433	7,087
Changes attributable to:												
Revisions	(16)	(1)	2	574	1	(24)		536	249		18	803
Improved recovery	5	3	1	18	–	–		27	–		10	37
Extensions and discoveries	17	8	3	5	–	–		33	–		–	33
Purchases	1	–	–	–	–	–		1	–		–	1
Sales[7]	(7)	–	–	–	–	–		(7)	–		–	(7)
Production	(154)	(26)	(121)	(164)	(12)	(43)		(520)	(62)		(22)	(604)
Reserves at December 31, 2008[6,8]	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[6,8]	**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[8]	**1,275**	**108**	**1,168**	**1,013**	**88**	**152**	**466**	**4,270**	**1,820**	**256**	**157**	**6,503**

[1] Ending reserve balances in North America and South America were 14, 12, 19 and 94, 92, 130 in 2010, 2009 and 2008, respectively.
[2] Prospective reporting effective December 31, 2009.
[3] Reserves associated with Canada.
[4] Reserves associated with Venezuela that were reported in affiliated Other as heavy oil in 2008.
[5] Ending reserve balances in Africa and South America were 36, 31, 19 and 121, 120, 420 in 2010, 2009 and 2008, respectively.
[6] Geographic presentation conformed to 2010.
[7] Includes reserves disposed of through nonmonetary transactions.
[8] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 8 for the definition of a PSC). PSC-related reserve quantities are 24 percent, 26 percent and 32 percent for consolidated companies for 2010, 2009 and 2008, respectively.

Noteworthy amounts in the categories of liquids proved reserve changes for 2008 through 2010 are discussed below:

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

In 2009, net revisions increased reserves by 355 million barrels for worldwide consolidated companies and decreased reserves by 187 million barrels for equity affiliates. For consolidated companies, the largest increase was 460 million barrels in the Other Americas region 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 and recovery factors accounted for a majority of the 63 million barrel increase in the United States. Increases in the other regions were partially offset by the Asia region, 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.

Improved Recovery In 2008, improved recovery increased worldwide liquids volumes by 37 million barrels. For consolidated companies, the largest addition was in the Asia region related to gas reinjection in Kazakhstan. Affiliated companies increased reserves 10 million barrels due to improved secondary recovery at Boscan.

In 2009, improved recovery increased liquids volumes by 86 million barrels worldwide. Consolidated companies accounted for 50 million barrels. The largest addition was related to improved secondary recovery in Nigeria. Affiliated companies increased reserves 36 million barrels due to improvements related to the TCO 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.

Extensions and Discoveries In 2008, extensions and discoveries increased consolidated company reserves 33 million barrels worldwide. The United States increased reserves 17 million barrels, primarily in the Gulf of Mexico. The Africa, Asia, and Other Americas regions increased reserves 16 million barrels with no one country resulting in additions greater than 5 million barrels.

In 2009, extensions and discoveries increased liquids volumes by 52 million barrels worldwide. The largest additions were 20 million barrels in the Australia region related to the Gorgon Project and 13 million barrels in the Other Americas region 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.

Table V Reserve Quantity Information – Continued

Net Proved Reserves of Natural Gas

Billions of cubic feet (BCF)	U.S.	Other Americas[1]	Africa	Asia	Australia	Europe	Consolidated Companies Total	Affiliated Companies TCO	Affiliated Companies Other[2]	Total Consolidated and Affiliated Companies
Reserves at January 1, 2008[3]	3,677	2,378	3,049	7,207	2,105	721	19,137	2,748	255	22,140
Changes attributable to:										
Revisions	(28)	154	60	1,073	(5)	(88)	1,166	498	632	2,296
Improved recovery	–	–	–	–	–	–	–	–	–	–
Extensions and discoveries	108	1	–	23	–	–	132	–	–	132
Purchases	66	–	–	441	–	–	507	–	–	507
Sales[4]	(124)	–	–	–	–	–	(124)	–	–	(124)
Production[5]	(549)	(165)	(53)	(748)	(138)	(143)	(1,796)	(71)	(9)	(1,876)
Reserves at December 31, 2008[3,6]	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[5]	(511)	(174)	(42)	(683)	(159)	(139)	(1,708)	(105)	(8)	(1,821)
Reserves at December 31, 2009[3,6]	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[5]	**(479)**	**(179)**	**(57)**	**(699)**	**(167)**	**(126)**	**(1,707)**	**(123)**	**(9)**	**(1,839)**
Reserves at December 31, 2010[6]	**2,472**	**1,815**	**2,944**	**7,193**	**6,056**	**275**	**20,755**	**2,386**	**1,110**	**24,251**

[1] Ending reserve balances in North America and South America were 21, 23, 24 and 1,794, 1,962 and 2,344 in 2010, 2009 and 2008, respectively.
[2] Ending reserve balances in Africa and South America were 953, 898, 700 and 157, 165, 178 in 2010, 2009 and 2008, respectively.
[3] Geographic presentation conformed to 2010.
[4] Includes reserves disposed of through nonmonetary transactions.
[5] Total "as sold" volumes are 4.5 BCF, 4.5 BCF and 4.6 BCF for 2010, 2009 and 2008, respectively.
[6] Includes reserve quantities related to production-sharing contracts (PSC) (refer to page 8 for the definition of a PSC). PSC-related reserve quantities are 29 percent, 31 percent and 40 percent for consolidated companies for 2010, 2009 and 2008, respectively.

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2008 through 2010 are discussed below:

Revisions In 2008, net revisions increased reserves for consolidated companies by 1,166 BCF and increased reserves for affiliated companies by 1,130 BCF. In the Asia region, positive revisions totaled 1,073 BCF for consolidated companies. Almost half of the increase was attributed to the Karachaganak Field in Kazakhstan, due mainly to the effects of low year-end prices on the production-sharing contract and the results of development drilling and improved recovery. Other large upward revisions were recorded for the Pattani Field in Thailand due to a successful drilling campaign. In the Other Americas region, improved field performance and new contracts in Colombia, and Trinidad and Tobago, respectively, accounted for most of the 154 BCF increase.

For the TCO affiliate in Kazakhstan, an increase of 498 BCF reflected the impacts of lower year-end prices on royalty determination and facility optimization. Reserves associated with the Angola LNG project accounted for a majority of the 632 BCF increase in Other affiliated companies.

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 the Australia region, the 166 BCF increase in reserves resulted from improved reservoir performance and compression. In the Other Americas region, 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 the Asia region. 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.

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.

Sales In 2009, worldwide sales of 117 BCF were related to consolidated companies. For the Other Americas region, the sale of properties in Argentina accounted for 84 BCF. The sale of properties in the Gulf of Mexico accounted for the majority of the 33 BCF decrease in the United States.

Table VI Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of the FASB. Estimated future cash inflows from production are computed by applying 12-month average prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The 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 Companies
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other	
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
10 percent midyear annual discount for timing of estimated cash flows	(8,822)	(2,275)	(5,882)	(11,722)	(14,764)	(467)	(43,932)	(34,937)	(4,450)	(83,319)
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
At December 31, 2008										
Future cash inflows from production[2]	$ 66,174	$ 12,051	$ 52,344	$ 75,855	$ 14,368	$ 10,989	$ 231,781	$ 51,252	$ 13,968	$ 297,001
Future production costs	(45,738)	(3,369)	(20,302)	(33,817)	(5,989)	(6,005)	(115,220)	(14,502)	(2,319)	(132,041)
Future development costs	(6,099)	(1,367)	(19,001)	(15,298)	(909)	(1,132)	(43,806)	(10,140)	(1,551)	(55,497)
Future income taxes	(5,091)	(3,095)	(9,581)	(10,278)	(2,241)	(2,257)	(32,543)	(7,517)	(5,223)	(45,283)
Undiscounted future net cash flows	9,246	4,220	3,460	16,462	5,229	1,595	40,212	19,093	4,875	64,180
10 percent midyear annual discount for timing of estimated cash flows	(2,318)	(1,406)	(1,139)	(7,042)	(2,455)	(191)	(14,551)	(11,261)	(2,966)	(28,778)
Standardized Measure Net Cash Flows	$ 6,928	$ 2,814	$ 2,321	$ 9,420	$ 2,774	$ 1,404	$ 25,661	$ 7,832	$ 1,909	$ 35,402

[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, 2008	$ 97,049	$ 41,758	$ 138,807
Sales and transfers of oil and gas produced net of production costs	(43,906)	(5,750)	(49,656)
Development costs incurred	13,682	763	14,445
Purchases of reserves	233	–	233
Sales of reserves	(542)	–	(542)
Extensions, discoveries and improved recovery less related costs	646	83	729
Revisions of previous quantity estimates	37,853	3,718	41,571
Net changes in prices, development and production costs	(169,046)	(51,696)	(220,742)
Accretion of discount	17,458	5,976	23,434
Net change in income tax	72,234	14,889	87,123
Net change for 2008	(71,388)	(32,017)	(103,405)
Present Value at December 31, 2008	$ 25,661	$ 9,741	$ 35,402
Sales and transfers of oil and gas produced net of production costs	(27,559)	(4,209)	(31,768)
Development costs incurred	10,791	335	11,126
Purchases of reserves	–	–	–
Sales of reserves	(285)	–	(285)
Extensions, discoveries and improved recovery less related costs	3,438	697	4,135
Revisions of previous quantity estimates	3,230	(4,343)	(1,113)
Net changes in prices, development and production costs	51,528	30,915	82,443
Accretion of discount	4,282	1,412	5,694
Net change in income tax	(20,810)	(7,312)	(28,122)
Net change for 2009	24,615	17,495	42,110
Present Value at December 31, 2009	$ 50,276	$ 27,236	$ 77,512
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**

Chevron History

1879	Incorporated in San Francisco, California, as the Pacific Coast Oil Company.
1900	Acquired by the West Coast operations of John D. Rockefeller's original Standard Oil Company.
1911	Emerged as an autonomous entity — Standard Oil Company (California) — following U.S. Supreme Court decision to divide the Standard Oil conglomerate into 34 independent companies.
1926	Acquired Pacific Oil Company to become Standard Oil Company of California (Socal).
1936	Formed the Caltex Group of Companies, jointly owned by Socal and The Texas Company (later became Texaco), to manage exploration and production interests of the two companies in the Middle East and Indonesia and provide an outlet for crude oil through The Texas Company's European markets.
1947	Acquired Signal Oil Company, obtaining the Signal brand name and adding 2,000 retail stations in the western United States.
1961	Acquired Standard Oil Company (Kentucky), a major petroleum products marketer in five southeastern states, to provide outlets for crude oil from southern Louisiana and the U.S. Gulf of Mexico, where the company was a major producer.
1984	Acquired Gulf Corporation — nearly doubling the size of crude oil and natural gas activities — and gained significant presence in industrial chemicals, natural gas liquids and coal. Changed name to Chevron Corporation to identify with the name under which most products were marketed.
1988	Purchased Tenneco Inc.'s U.S. Gulf of Mexico crude oil and natural gas properties, becoming one of the largest U.S. natural gas producers.
1993	Formed Tengizchevroil, a joint venture with the Republic of Kazakhstan, to develop and produce the giant Tengiz Field, becoming the first major Western oil company to enter newly independent Kazakhstan.
1999	Acquired Rutherford-Moran Oil Corporation. This acquisition provided inroads to Asian natural gas markets.
2001	Merged with Texaco Inc. and changed name to ChevronTexaco Corporation. Became the second-largest U.S.-based energy company.
2002	Relocated corporate headquarters from San Francisco, California, to San Ramon, California.
2005	Acquired Unocal Corporation, an independent crude oil and natural gas exploration and production company. Unocal's upstream assets bolstered Chevron's already-strong position in the Asia-Pacific, U.S. Gulf of Mexico and Caspian regions. Changed name to Chevron Corporation to convey a clearer, stronger and more unified presence in the global marketplace.
2011	Acquired Atlas Energy, Inc., an independent U.S. developer and producer of shale gas resources. The acquired assets provide a targeted, high-quality core acreage position primarily in the Marcellus Shale.

Board of Directors

John S. Watson, 54
Chairman of the Board and Chief Executive Officer since 2010. Previously he was elected a Director and Vice Chairman in 2009; Executive Vice President, Strategy and Development; Corporate Vice President and President, Chevron International Exploration and Production Company; Vice President and Chief Financial Officer; and Corporate Vice President, Strategic Planning. He is Chairman of the Board of Directors and the Executive Committee of the American Petroleum Institute. Joined Chevron in 1980.

George L. Kirkland, 60
Vice Chairman of the Board since 2010 and **Executive Vice President, Upstream and Gas,** since 2005. In addition to Board responsibilities, he is responsible for global exploration, production and gas activities. Previously Corporate Vice President and President, Chevron Overseas Petroleum Inc., and President, Chevron U.S.A. Production Company. Joined Chevron in 1974.

Linnet F. Deily, 65
Director since 2006. She served as a Deputy U.S. Trade Representative and U.S. Ambassador to the World Trade Organization from 2001 to June 2005. Previously she was Vice Chairman of Charles Schwab Corporation. She is a Director of Honeywell International Inc. (2, 4)

Robert E. Denham, 65
Director since 2004. He is a Partner in the law firm of Munger, Tolles & Olson LLP. Previously he was Chairman and Chief Executive Officer of Salomon Inc. He also is a Director of The New York Times Company; Wesco Financial Corporation; and Fomento Económico Mexicano, S.A. de C.V. (3, 4)

Robert J. Eaton, 71
Director since 2000. He is retired Chairman of the Board of Management of DaimlerChrysler AG, a manufacturer of automobiles. Previously he was Chairman of the Board and Chief Executive Officer of Chrysler Corporation. (2, 4)

Chuck Hagel, 64
Director since 2010. Since 2009, he has been Distinguished Professor at Georgetown University and the University of Nebraska at Omaha. He served as a U.S. Senator from Nebraska from 1997 to 2009 and participated in numerous committees, including Foreign Relations; Banking, Housing and Urban Affairs; Intelligence; and Energy and Natural Resources. (2, 3)

Enrique Hernandez Jr., 55
Director since 2008. He is Chairman, Chief Executive Officer and President of Inter-Con Security Systems, Inc., a global security services provider. Previously he was an associate in the law firm of Brobeck, Phleger & Harrison. He is a Director of McDonald's Corporation; Nordstrom, Inc.; and Wells Fargo & Company. (1)

Donald B. Rice, 71
Director since 2005. He is retired President and Chief Executive Officer of Agensys, Inc., a private biotechnology company and an affiliate of Astellas Pharma Inc. Previously he was President and Chief Operating Officer of Teledyne, Inc. He is a Director of Vulcan Materials Company. (3, 4)

Kevin W. Sharer, 63
Director since 2007. He is Chairman of the Board and Chief Executive Officer of Amgen Inc., a global biotechnology medicines company. Previously he was President and Chief Operating Officer of Amgen and President of the Business Markets Division of MCI Communications Corporation. He is a Director of Northrop Grumman Corporation. (3, 4)

Charles R. Shoemate, 71
Director since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods, a manufacturer of food products. (1)

John G. Stumpf, 57
Director since 2010. He is Chairman of the Board, Chief Executive Officer and President of Wells Fargo & Company, a financial services and bank holding company. Previously he served as Group Executive Vice President of Community Banking at Wells Fargo. He is a Director of Target Corporation. (1)

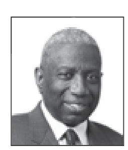
Ronald D. Sugar, 62
Director since 2005. He is retired Chairman of the Board and Chief Executive Officer of Northrop Grumman Corporation, a global defense and technology company. Previously he was President and Chief Operating Officer of Northrop Grumman. He is a Director of Amgen, Inc. and Apple Inc. (1)

Carl Ware, 67
Director since 2001. He is retired Executive Vice President of The Coca-Cola Company, a manufacturer of beverages. Previously he was Senior Adviser to the Chief Executive Officer of The Coca-Cola Company and President of The Coca-Cola Company's Africa Group. He is a Director of Cummins Inc. (3, 4)

Committees of the Board
1) Audit: Charles R. Shoemate, Chair
2) Public Policy: Sam Nunn, Chair
3) Board Nominating and Governance: Samuel H. Armacost, Chair
4) Management Compensation: Robert J. Eaton, Chair

Retiring Directors

Three Directors have reached the Board's mandatory retirement age and will not stand for re-election at the Annual Meeting in May: (left to right) **Samuel H. Armacost,** Lead Director since 2006 and a Director since 1982, (2, 3); **Franklyn G. Jenifer,** a Director since 1993, (2, 3); and **Sam Nunn,** a Director since 1997, (2, 3). Armacost is retired Chairman of the Board of SRI International; Jenifer is President Emeritus of The University of Texas at Dallas; and Nunn is Co-Chairman and Chief Executive Officer of the Nuclear Threat Initiative and Distinguished Professor at the Sam Nunn School of International Affairs. He served as a U.S. Senator from Georgia for 24 years.


Corporate Officers

Lydia I. Beebe, 58
Corporate Secretary and Chief Governance Officer since 1995. Responsible for managing the Corporate Governance Department, counseling the Board of Directors and senior management on corporate governance, and overseeing stockholder services for Chevron and its subsidiaries. Previously Senior Manager, Chevron Tax Department. Joined Chevron in 1977.

John E. Bethancourt, 59*
Executive Vice President since 2003. Previously Executive Vice President, Technology and Services, and also responsible for health, environment and safety; project resources; procurement; and mining operations. Joined the company in 1974.
*Retiring effective July 2011.

James R. Blackwell, 52
Executive Vice President, Technology and Services, since March 2011. Responsible also for major capital project management, procurement, and other corporate operating and support functions. Previously President, Chevron Asia Pacific Exploration and Production Company; Managing Director, Chevron Southern Africa Strategic Business Unit; and President, Chevron Pipe Line Company. Joined the company in 1980.

Pierre R. Breber, 46
Vice President and Treasurer since 2009. Previously Vice President, Finance, Global Downstream; Comptroller, International Upstream; Manager, Finance, Europe Upstream Strategic Business Unit; and Manager, Investor Relations. Joined the company in 1989.

Matthew J. Foehr, 53
Vice President and Comptroller since 2010. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, and Finance Shared Services. Previously Vice President, Finance, Global Upstream and Gas, and Vice President, Finance, Global Downstream. Joined Chevron in 1982.

John D. Gass, 59
Corporate Vice President and President, Gas and Midstream, since 2003. Responsible for the company's natural gas business, including shipping, pipeline and power operations. Previously Managing Director, Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined the company in 1974.

Stephen W. Green, 53
Vice President, Policy, Government and Public Affairs, since March 2011. Oversees U.S. and international government relations, all aspects of communications, and the company's worldwide efforts to protect and enhance its reputation. Previously President, Chevron Indonesia Company and Managing Director, IndoAsia Business Unit, Chevron Asia Pacific Exploration and Production Company, and Managing Director, Asia South Business Unit, Chevron International Exploration and Production Company. Joined the company in 1998.

Joe W. Laymon, 58
Vice President, Human Resources, since 2008. Responsible for the company's global human resources, medical services and security functions. Previously Group Vice President, Corporate Human Resources and Labor Affairs, Ford Motor Company. Joined the company in 2008.

Wesley E. Lohec, 51
Vice President, Health, Environment and Safety (HES), since March 2011. Responsible for corporate HES strategy and management systems and Chevron Environmental Management Company. Previously Managing Director, Latin America, Chevron Africa and Latin America Exploration and Production Company. Joined the company in 1981.

Charles N. Macfarlane, 56
General Tax Counsel since December 2010. He is responsible for directing Chevron's worldwide tax activities. Previously the company's Assistant General Tax Counsel. Joined Chevron in 1986.

John W. McDonald, 59
Vice President and Chief Technology Officer since 2008. Responsible for Chevron's three technology companies: Energy Technology, Information Technology and Technology Ventures. Previously Corporate Vice President, Strategic Planning; President and Managing Director, Chevron Upstream Europe, Chevron Overseas Petroleum Inc.; and Vice President, Gulf of Mexico Offshore Division, Texaco Exploration and Production. Joined the company in 1975.

R. Hewitt Pate, 48
Vice President and General Counsel since 2009. Responsible for directing the company's worldwide legal affairs and compliance. Previously Chair, Competition Practice, Hunton & Williams LLP, Washington, D.C., and Assistant Attorney General, Antitrust Division, U.S. Department of Justice. Joined Chevron in 2009.

Jay R. Pryor, 53
Vice President, Corporate Business Development, since 2006. Responsible for identifying and developing new, large-scale upstream and downstream business opportunities, including mergers and acquisitions. Previously Managing Director, Nigeria/Mid-Africa Strategic Business Unit and Chevron Nigeria Ltd., and Managing Director, Asia South Business Unit and Chevron Offshore (Thailand) Ltd. Joined Chevron in 1979.

Charles A. Taylor, 53
Vice President, Strategic Planning, since March 2011. Responsible for advising senior corporate executives in setting strategic direction for the company, allocating capital and other resources, and determining operating-unit performance measures and targets. Previously Corporate Vice President, Health, Environment and Safety. Joined the company in 1980.

Michael K. Wirth, 50
Executive Vice President, Downstream and Chemicals, since 2006. Responsible for worldwide refining, marketing, lubricants, supply and trading businesses, chemicals, and Oronite additives. Previously President, Global Supply and Trading; President, Marketing, Asia/Middle East/Africa Strategic Business Unit; and President, Marketing, Caltex Corporation. Joined Chevron in 1982.

Patricia E. Yarrington, 55
Vice President and Chief Financial Officer since 2009. Serves on the San Francisco Federal Reserve's Board of Directors. Previously a Director, Chevron Phillips Chemical Company LLC; Corporate Vice President and Treasurer; Corporate Vice President, Policy, Government and Public Affairs; Corporate Vice President, Strategic Planning; President, Chevron Canada Limited; and Comptroller, Chevron Products Company. Joined Chevron in 1980.

Rhonda I. Zygocki, 53
Executive Vice President, Policy and Planning, since March 2011. Responsible for Strategic Planning; Health, Environment and Safety; and oversight of Policy, Government and Public Affairs. Previously Corporate Vice President, Policy, Government and Public Affairs; Corporate Vice President, Health, Environment and Safety; and Managing Director, Chevron Australia Pty Ltd. Joined Chevron in 1980.

Executive Committee

John S. Watson, George L. Kirkland, John E. Bethancourt, James R. Blackwell, R. Hewitt Pate, Michael K. Wirth, Patricia E. Yarrington and Rhonda I. Zygocki. Lydia I. Beebe, Secretary.

Stockholder and Investor Information

Stock Exchange Listing

Chevron common stock is listed on the New York Stock Exchange. The symbol is "CVX."

Stockholder Information

Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to Chevron's transfer agent and registrar:
BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015
800 368 8357
www.bnymellon.com/shareowner/equityaccess

The BNY Mellon Shareowner Services Program features dividend reinvestment, optional cash investments of $50 to $100,000 a year and automatic stock purchase.

Dividend Payment Dates

Quarterly dividends on common stock are paid, following declaration by the Board of Directors, on or about the 10th day of March, June, September and December. Direct deposit of dividends is available to stockholders. For information, contact BNY Mellon Shareowner Services. (See *Stockholder Information*.)

Electronic Access

In an effort to conserve natural resources and reduce the cost of printing and shipping proxy materials next year, we encourage stockholders to register to receive these documents via email and vote their shares on the Internet. Stockholders of record may sign up on our website, www.icsdelivery.com/cvx/index.html, for electronic access. Enrollment is revocable until each year's Annual Meeting record date. Beneficial stockholders may be able to request electronic access by contacting their broker or bank, or Broadridge Financial Solutions at: www.icsdelivery.com/cvx/index.html.

Investor Information

Securities analysts, portfolio managers and representatives of financial institutions may contact:
Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

Publications and Other News Sources

The *Annual Report*, distributed in April, summarizes the company's financial performance in the preceding year and provides an overview of the company's major activities.

Chevron's Annual Report to the United States Securities and Exchange Commission on Form 10-K and the *Supplement to the Annual Report*, containing additional financial and operating data, are available on the company's website, Chevron.com, or copies may be requested by writing to:
Comptroller's Department
Chevron Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

The *Corporate Responsibility Report* is available in May on the company's website, Chevron.com, or a copy may be requested by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2098
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2010 are available on the company's website, Chevron.com, or by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, L4062
San Ramon, CA 94583-2324

Information about *charitable contributions* is available in the second half of the year on Chevron's website, Chevron.com.

For additional information about the company and the energy industry, visit Chevron's website, Chevron.com. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

Notice

As used in this report, the term "Chevron" and such terms as "the company," "the corporation," "our," "we" and "us" may refer to one or more of its consolidated subsidiaries or to all of them taken as a whole. 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.

Corporate Headquarters

6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 1000

2010 Annual Report

2010 Supplement to the Annual Report

2010 Corporate Responsibility Report

This *Annual Report* contains forward-looking statements – identified by words such as "expects," "intends," "projects," etc. – that reflect management's current estimates and beliefs, but are not guarantees of future results. Please see "Cautionary Statement Relevant to Forward-Looking Information for the Purpose of 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" on Page 9 for a discussion of some of the factors that could cause actual results to differ materially.

PHOTOGRAPHY **Inside Front Cover:** Robert Garvey; **Page 2:** Eric Myer; **Page 6: (left)** Peter Cannon/GeoMedia, **(right)** Jim Karageorge.

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