Chevron

Human Energy™

# 2009 Annual Report

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**Contents**



In 2009, Chevron celebrated its 130th anniversary. As we look to the future, we do so with enthusiasm and optimism. We have a vast base of resources, a strong inventory of growth projects and a reputation for the innovative application of technology. Our vision is to be the energy company most admired for its people, partnership and performance. It is an aspiration that guides our activities the world over. We are proud to be a part of the energy industry. We know our work fuels economic development and improves the world's quality of life.

This year, we have streamlined our printed *Annual Report* and 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 Web site at: Chevron.com/AnnualReport2009.

**On the Cover:** The *Discoverer Clear Leader*, an ultra-deepwater drillship built to Chevron's specifications, has set sail and is now operating in the deepwater U.S. Gulf of Mexico. The state-of-the-art vessel offers the most advanced capabilities in the offshore drilling industry. It is capable of operating in water depths of 12,000 feet (3,650 meters) and to a total depth of 40,000 feet (12,200 meters). The *Discoverer Clear Leader* will help Chevron expand its search for crude oil and natural gas in the deepwater Gulf, where it is one of the top leaseholders and producers. To learn more, visit: Chevron.com/AnnualReport2009.

**This Page:** The sun sets over Barrow Island, offshore Western Australia. The island will be the site of a domestic natural gas plant and liquefied natural gas (LNG) facility to support the Gorgon Project, a vast natural gas development. Gorgon is expected to be a major contributor to Chevron's growth over the next four decades. A groundbreaking ceremony took place in 2009, with major construction planned in the second half of 2010. First LNG deliveries are expected in 2014. To learn more, visit: Chevron.com/AnnualReport2009.

# To Our Stockholders

Since Chevron was founded more than 130 years ago, crude oil, natural gas and other sources of energy have produced an unprecedented rise in living standards for billions of people. Over that time, our company has built an enduring legacy of industry leadership and value for investors while producing the energy that makes our quality of life possible.

As your Chairman, I'm committed to building on that legacy. It's an honor to lead Chevron into a future where energy will continue to be a foundation for global economic growth. >

*Chevron's core strengths – starting with the talent, dedication and values of our employees worldwide – position us to achieve growth while helping meet long-term global demand for energy. ... Our world grows more complex every day. We face increased challenges – geopolitical, environmental, regulatory and technical. But Chevron employees have risen to challenges for more than 130 years – with dedication, ingenuity and hard work.*

A company's strategies – and the abilities, values and focus of its people – are tested in tough times. In 2009, the people of Chevron delivered strong results in the face of a global economic downturn and difficult industry conditions.

We brought major capital projects online or to capacity and achieved industry-leading production growth. We made major new discoveries of crude oil and natural gas and continued to grow our natural gas business. Employees aggressively managed costs, resulting in about a 15 percent decrease in operating expenses over 2008. And we accomplished all this while recording fewer workplace injuries than ever before.

Our financial performance for 2009 contributed to a strong balance sheet and returns for investors. Total stockholder return – a critical measure of our performance – was No. 1 among our top competitors over the past five years. We increased our annual dividend in 2009 for the 22nd consecutive year. Net income in 2009 was $10.5 billion on sales and other operating revenues of $167 billion, reflecting lower prices from 2008 for crude oil and natural gas and lower sales margins and prices for refined products. Return on capital employed for the year was 10.6 percent.

We advanced our upstream growth strategy by bringing world-class deepwater projects online, including Tahiti in the U.S. Gulf of Mexico, Tombua-Landana offshore Angola and Frade offshore Brazil. Our Tengiz expansion in Kazakhstan and Agbami ramp-ups in Nigeria added significant production volumes. We also achieved impressive results managing our producing crude oil and natural gas assets to limit natural field declines.

In 2009, we made strong progress toward our goal to build a high-impact, global natural gas business. Construction of the Escravos gas-to-liquids and Angola liquefied natural gas (LNG) plants continued. Offshore Western Australia, we gave the go-ahead for the massive Gorgon LNG project and achieved important commercial milestones for the Wheatstone LNG development.

We added 1.1 billion barrels of net oil-equivalent proved reserves, replacing 112 percent of net oil-equivalent production in 2009. And we continue to build for our future: Our exploration expertise and applied technology resulted in a drilling success rate of 57 percent, one of the best in the industry.

The economic environment was challenging for refining and marketing in 2009. To manage our refining and marketing businesses in this environment, we are aggressively controlling costs. Our downstream and chemical businesses continued their strong focus on reliability and safety. Refineries continued to run at industry-leading levels of utilization. Restructuring in our lubricants and Oronite fuel additives businesses generated improved earnings.

In 2009, we progressed our renewable energy strategy, which is focused on enhancing our geothermal energy business – the largest in the world – while building our energy efficiency business and developing nonfood biofuels.

Chevron's performance and growth are intrinsically linked with the communities where we operate. Our projects generate thousands of jobs and support for businesses big and small around the world. Our community engagement programs are strategic investments in the future of our communities, focusing on health, education and sustainable socioeconomic development.

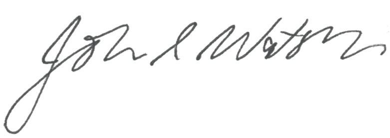
Chevron enters 2010 from a position of financial and operational strength, with solid potential for growth. Our $21.6 billion capital and exploratory budget for 2010 reflects our industry-leading queue of major capital projects that support future growth. Much of our 2010 spending will focus on large multiyear projects aligned with our upstream growth strategies, on improving our operating efficiency and reliability, and on aligning our downstream businesses with the strongest market opportunities.

Chevron's core strengths – starting with the talent, dedication and values of our employees worldwide – position us to achieve growth while helping meet long-term global demand for energy. The values of The Chevron Way – getting results the right way – guide us every day. We operate with the highest standards of integrity and respect for human rights. We are deeply committed to safe and efficient operations and to conducting our business in an environmentally sound manner. We build strong partnerships to produce energy and support communities.

Chevron's future holds great promise. We have world-class assets, strong market positions and an industry-leading queue of projects and opportunities. We have robust long-term strategies and a proven ability to deliver results. We have unassailable ethics and a culture that attracts and develops the best talent. Chevron's vision remains constant: to be the global energy company most admired for its people, partnership and performance.

Our world grows more complex every day. We face increased challenges – geopolitical, environmental, regulatory and technical. But Chevron employees have risen to challenges for more than 130 years – with dedication, ingenuity and hard work. And I'm confident we will continue to do so.

Thank you for investing in Chevron.



John S. Watson
Chairman of the Board and
Chief Executive Officer
February 25, 2010

### Dave O'Reilly's Legacy

Dave O'Reilly's career spanned 41 years with Chevron, with the past 10 years as Chairman and Chief Executive Officer. Under his leadership, Chevron's market capitalization increased by approximately $100 billion, oil-equivalent production climbed about 65 percent and proved reserves increased by 80 percent. Our portfolio of major capital projects grew larger than at any time in our history, and we set new records in safety and reliability. Dave led Chevron through two notable mergers – with Texaco and Unocal – both accomplished with near seamless integration and extraordinary execution. However, his contributions go well beyond delivering excellent operating and financial results. He proved that an energy company can partner with communities, governments and the private sector to help economies grow and people improve their quality of life. Dave retired December 31, 2009, and leaves our company with a legacy of achievement and a strong foundation for future growth.

# Chevron Financial Highlights

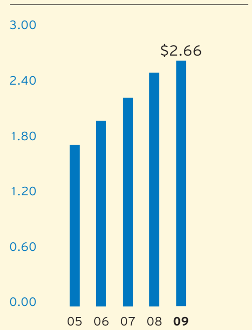
| Millions of dollars, except per-share amounts | **2009** | 2008 | % Change |
|---|---|---|---|
| Net income attributable to Chevron Corporation | **$ 10,483** | $ 23,931 | (56.2)% |
| Sales and other operating revenues | **$ 167,402** | $ 264,958 | (36.8)% |
| Noncontrolling interests income | **$ 80** | $ 100 | (20.0)% |
| Interest expense (after tax) | **$ 22** | $ – | N/A |
| Capital and exploratory expenditures* | **$ 22,237** | $ 22,775 | (2.4)% |
| Total assets at year-end | **$ 164,621** | $ 161,165 | 2.1 % |
| Total debt at year-end | **$ 10,514** | $ 8,901 | 18.1 % |
| Noncontrolling interests | **$ 647** | $ 469 | 38.0 % |
| Chevron Corporation stockholders' equity at year-end | **$ 91,914** | $ 86,648 | 6.1 % |
| Cash provided by operating activities | **$ 19,373** | $ 29,632 | (34.6)% |
| Common shares outstanding at year-end (Thousands) | **1,993,554** | 1,990,064 | 0.2 % |
| Per-share data | | | |
| Net income attributable to Chevron Corporation – diluted | **$ 5.24** | $ 11.67 | (55.1)% |
| Cash dividends | **$ 2.66** | $ 2.53 | 5.1 % |
| Chevron Corporation stockholders' equity | **$ 46.11** | $ 43.54 | 5.9 % |
| Common stock price at year-end | **$ 76.99** | $ 73.97 | 4.1 % |
| Total debt to total debt-plus-equity ratio | **10.3%** | 9.3% | |
| Return on stockholders' equity | **11.7%** | 29.2% | |
| Return on capital employed (ROCE) | **10.6%** | 26.6% | |

*Includes equity in affiliates

**Net Income Attributable to Chevron Corporation**
Billions of dollars

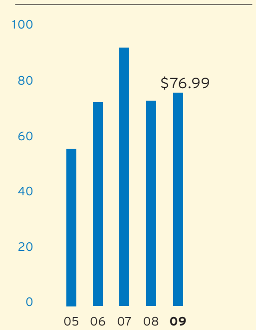

The decrease in 2009 was due mainly to the decline in earnings for upstream, as a result of lower prices for crude oil and natural gas.

**Annual Cash Dividends**
Dollars per share



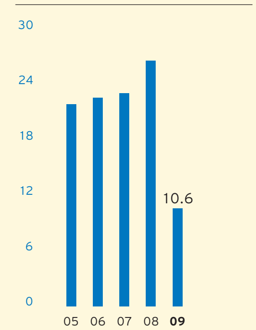

The company's annual dividend increased for the 22nd consecutive year.

**Chevron Year-End Common Stock Price**
Dollars per share




The company's stock price rose 4.1 percent in 2009.

**Return on Capital Employed**
Percent




Lower earnings reduced Chevron's return on capital employed to 10.6 percent.



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## Chevron Operating Highlights[1]

| | 2009 | 2008 | % Change |
|---|---|---|---|
| Net production of crude oil and natural gas liquids (Thousands of barrels per day) | **1,846** | 1,649 | 11.9 % |
| Net production of natural gas (Millions of cubic feet per day) | **4,989** | 5,125 | (2.7)% |
| Net production of oil sands (Thousands of barrels per day) | **26** | 27 | (3.7)% |
| Total net oil-equivalent production (Thousands of oil-equivalent barrels per day) | **2,704** | 2,530 | 6.9 % |
| Refinery input (Thousands of barrels per day) | **1,878** | 1,858 | 1.1 % |
| Sales of refined products (Thousands of barrels per day) | **3,254** | 3,429 | (5.1)% |
| Net proved reserves of liquids[2,3] (Millions of barrels) | | | |
| – Consolidated companies | **4,610** | 4,735 | (2.6)% |
| – Affiliated companies | **2,363** | 2,615 | (9.6)% |
| Net proved reserves of natural gas[3] (Billions of cubic feet) | | | |
| – Consolidated companies | **22,153** | 19,022 | 16.5 % |
| – Affiliated companies | **3,896** | 4,053 | (3.9)% |
| Net proved oil-equivalent reserves[2,3] (Millions of barrels) | | | |
| – Consolidated companies | **8,303** | 7,905 | 5.0 % |
| – Affiliated companies | **3,012** | 3,291 | (8.5)% |
| Number of employees at year-end[4] | **59,963** | 61,604 | (2.7)% |

[1] Includes equity in affiliates, except number of employees

[2] Liquids consist of crude oil, condensate, natural gas liquids and synthetic oil. For 2009, includes 460 million barrels of synthetic oil from Canadian oil sands. None are included for 2008.

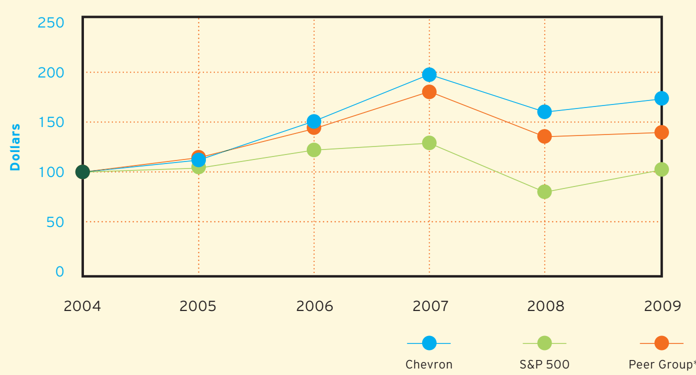
[3] At the end of the year

[4] 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, 2004, and ending December 31, 2009, 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, 2004, as of the end of each year between 2005 and 2009.

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




| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|
| **Chevron** | **100** | **111.34** | **148.99** | **194.40** | **158.71** | **171.57** |
| S&P 500 | 100 | 104.90 | 121.47 | 128.07 | 80.69 | 102.03 |
| Peer Group* | 100 | 114.25 | 143.51 | 177.99 | 134.76 | 138.37 |

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



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# 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 the ingenuity and commitment of our employees and their application of the most innovative technologies in the world. 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 other energy products; 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:** Floating production, storage and offloading vessel, Agbami Field, offshore Nigeria; Stephanie Gutierrez, Process Engineer, Salt Lake Refinery, Utah.

## Exploration and Production

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

Our upstream business explores for and produces crude oil and natural gas. At the end of 2009, worldwide net oil-equivalent reserves for consolidated operations and affiliated operations were 8.3 and 3.0 billion barrels, respectively. In 2009, net oil-equivalent production averaged 2.7 million barrels per day, including volumes produced from oil sands in Canada. 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, with additional activity in the Gulf of Thailand and the offshore areas of Canada, the United Kingdom, Norway and Brazil.

### Gas

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

Chevron is engaged in every aspect of the natural gas business – production, liquefaction, shipping, regasification, pipelines, marketing and trading, power generation, and gas-to-liquids. We hold the largest natural gas resource position in Australia through the Gorgon and Wheatstone projects, the Browse Basin, and the North West Shelf Venture. We also have significant natural gas holdings in western Africa, Bangladesh, China, Indonesia, Kazakhstan, North America, the Philippines, South America, Thailand, the United Kingdom and Vietnam.

## Refining and Marketing

**Strategy:**
Improve returns and selectively grow with a focus on integrated value creation.

Our downstream operations include refining, fuels and lubricants marketing, supply and trading, and transportation. In 2009, we processed approximately 1.9 million barrels of crude oil per day and averaged approximately 3.3 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 extending into Latin America, Southeast Asia, South Korea, southern 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 22,000 retail stations, including those of affiliated companies.

## Renewable Energy

**Strategy:**
Invest in renewable energy technologies and capture profitable positions.

Chevron is the world's largest producer of geothermal energy, with operations in Indonesia and the Philippines. The company has forged a number of alliances to develop renewable energy, including biofuels from nonfood plant sources. Our subsidiary Chevron Energy Solutions helps internal and external clients improve energy efficiency, conserve energy and utilize alternative power technologies, including solar, fuel cells and biomass.

## Other Businesses

Chevron Phillips Chemical Company LLC, a 50-percent owned affiliate, is one of the world's leading manufacturers of commodity petrochemicals. Chevron Oronite Company LLC develops, manufactures and markets worldwide quality additives that improve the performance of fuels and lubricants. Other businesses include research and technology, mining, and power generation. For more information, visit our Web site: Chevron.com.

## Operational Excellence

We define operational excellence as protecting the safety and health of people, safeguarding the environment, and ensuring reliable and efficient operations. We have systematic processes in place that drive our performance and our quest for operational excellence. 2009 was our safest year ever. For the eighth consecutive year, we improved our safety performance, reducing the rate of injuries severe enough to require days away from work by 11 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. Energy efficiency, also a company priority, has improved by 30 percent since 1992, the year we began tracking.

# 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: exploring for and producing crude oil and natural gas *(upstream)*; refining, marketing and transporting crude oil, natural gas and refined products *(downstream)*; manufacturing and distributing petrochemicals *(chemicals)*; 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, effective for 2009, 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.

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

## Earnings by Major Operating Area

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

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

Refer to the "Results of Operations" section beginning on page 14 for a discussion of financial results by major operating area for the three years ended December 31, 2009.

## Business Environment and Outlook

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

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

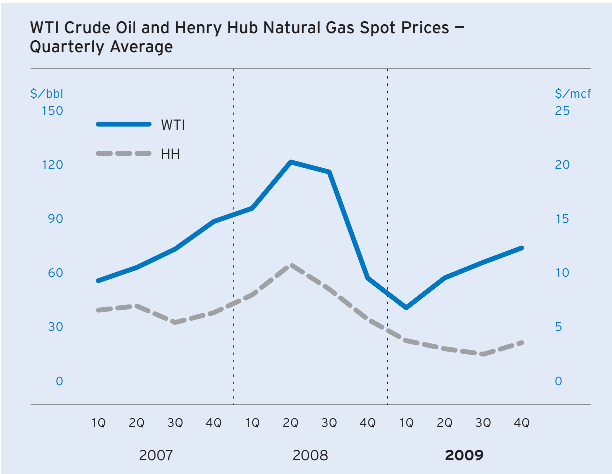
The company's operations, especially upstream, can also be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. Civil unrest, acts of violence or strained relations between a government and the company or other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

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

The company also continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company's financial performance and growth. Refer to the "Results of Operations" section beginning on page 14 for discussions of net gains on asset sales during 2009. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

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

The company continues to closely monitor developments in the financial and credit markets, the level of worldwide economic activity and the implications to the company of movements in prices for crude oil and natural gas. Management is taking these developments into account in the conduct of daily operations and for business planning. The company remains confident of its underlying financial strength to address potential challenges presented in this environment. (Refer also to the "Liquidity and Capital Resources" section beginning on page 19.)




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

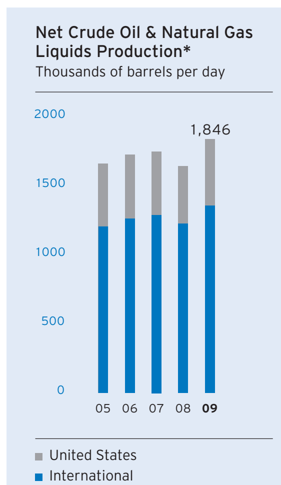
*Upstream* Earnings for the upstream segment are closely aligned with industry price levels for crude oil and natural gas. Crude-oil and natural-gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry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

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

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

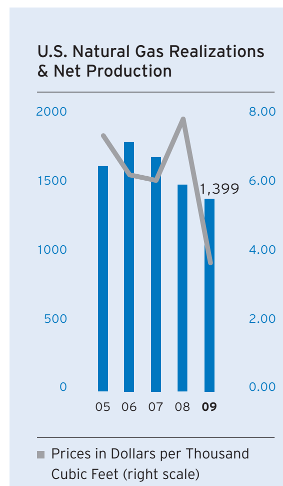
A differential in crude-oil prices exists between high-quality (high-gravity, low-sulfur) crudes and those of lower-quality (low-gravity, high-sulfur). The amount of the differential in any period is associated with the supply of heavy crude available versus the demand that is a function of the number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

Chevron produces or shares in the production of heavy crude oil in California, Chad, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom




Net liquids production increased 12 percent in 2009 due mainly to new projects in the United States and Nigeria and expansion of capacity at TCO in Kazakhstan.

*Includes equity in affiliates, but excludes other produced volumes.




Average prices decreased 53 percent to $3.73 during 2009. Production was 7 percent lower due to natural field declines and sales of properties.



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sector of the North Sea. (See page 18 for the company's average U.S. and international crude-oil realizations.)

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

Certain international natural-gas markets in which the company operates have different supply, demand and regulatory circumstances, which historically have resulted in lower average sales prices for the company's production of natural gas in these locations. Chevron continues to invest in long-term projects in these locations to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets where greater demand results in higher prices. International natural-gas realizations averaged about $4.00 per MCF during 2009, compared with about $5.20 per MCF during 2008. Unlike prior years, these realizations compared favorably with those in the United States during 2009, primarily as a result of the deterioration of U.S. supply-and-demand conditions resulting from the economic slowdown. (See page 18 for the company's average natural gas realizations for the U.S. and international regions.)

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

The company estimates that oil-equivalent production in 2010 will average approximately 2.73 million barrels per day. This estimate is subject to many factors and uncertainties, including additional quotas that may be imposed by OPEC, price effects on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, changes in fiscal terms or restrictions on the scope of company operations, delays in project startups, fluctuations in demand for natural gas in various markets, weather conditions that may shut in production, civil unrest, changing geopolitics, or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and, for new large-scale projects, the time lag between initial exploration and the beginning of production. Investments in upstream projects generally begin well in advance of the start of the associated crude-oil and natural-gas production. A significant majority of Chevron's upstream investment is made outside the United States.

Refer to the "Results of Operations" section on pages 14 through 15 for additional discussion of the company's upstream business.

Refer to Table V beginning on page 76 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2007 and each year-end from 2007 through 2009, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2009.

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

Other factors affecting profitability for downstream operations include the reliability and efficiency of the company's refining and marketing network and the effectiveness of the crude-oil and product-supply functions. Profitability can also be affected by the volatility of tanker-charter rates for the company's shipping operations, which are driven by the industry's demand for crude-oil and product tankers. Other factors beyond the company's control include the general level of inflation and energy costs to operate the company's refinery and distribution network.

The company's most significant marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia, southern Africa and the United Kingdom. Chevron operates or has significant ownership interests in refineries in each of these areas except Latin America. The company completed sales of marketing businesses during 2009 in certain countries in Latin America and Africa. The company plans to discontinue, by mid-2010, sales of Chevron- and Texaco-branded motor fuels in the mid-Atlantic and other eastern states, where the company sold to retail customers through approximately 1,100 stations and to commercial and industrial customers through supply arrangements. Sales in these markets represent approximately 8 percent of the company's total U.S. retail fuel sales volumes. Additionally, in January 2010, the company sold the rights to the Gulf trademark in the United States and its territories that it had previously licensed for use in the U.S. Northeast and Puerto Rico.

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

Refer to the "Results of Operations" section on pages 15 and 16 for additional discussion of the company's downstream operations.

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

Refer to the "Results of Operations" section on page 16 for additional discussion of chemical earnings.

### Operating Developments

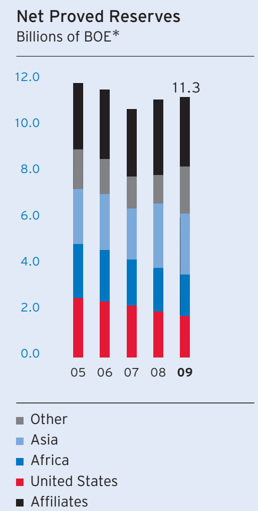
Key operating developments and other events during 2009 and early 2010 included the following:

#### Upstream

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

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

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




Net proved reserves for consolidated companies increased 5 percent in 2009, while affiliated companies' reserves were 8 percent lower.

*2009 includes barrels of oil-equivalent reserves for Canadian oil sands.

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

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

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



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

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

### Downstream

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

### Other

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

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

## Results of Operations

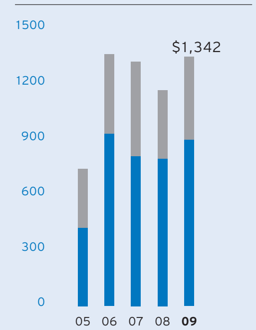
*Major Operating Areas* The following section presents the results of operations for the company's business segments – upstream, downstream and chemicals – as well as for "all other," which includes mining, power generation businesses, the various companies and departments that are managed at the corporate level, and the company's investment in Dynegy prior to its sale in May 2007. Earnings are also presented for the U.S. and international geographic areas of the upstream and downstream business segments. (Refer to Note 11, beginning on page 47, 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 – Exploration and Production*

| *Millions of dollars* | **2009** | 2008 | 2007 |
|---|---|---|---|
| **Earnings** | **$ 2,216** | $ 7,126 | $ 4,532 |

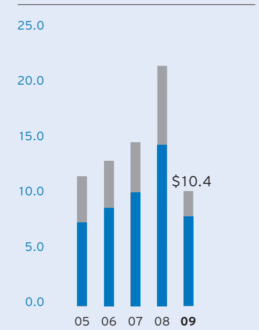
U.S. upstream earnings of $2.2 billion in 2009 decreased $4.9 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by about $5.2 billion between periods, and gains on asset sales declined by approximately $900 million. Partially offsetting these effects was a benefit of about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

**Exploration Expenses**
Millions of dollars




Exploration expenses increased 15 percent from 2008 due mainly to higher well write-offs.

**Worldwide Exploration & Production Earnings**
Billions of dollars




Earnings decreased in 2009 on lower average prices for crude oil and natural gas.

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

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

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

Refer to the "Selected Operating Data" table on page 18 for the three-year comparative production volumes in the United States.

*International Upstream – Exploration and Production*

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

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

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

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

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

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

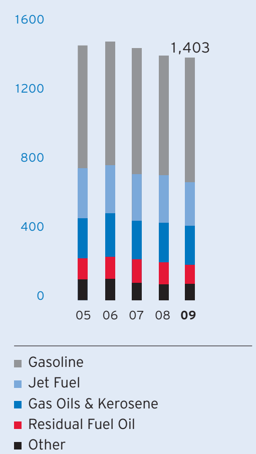
Refer to the "Selected Operating Data" table, on page 18, for the three-year comparative of international production volumes.

*U.S. Downstream – Refining, Marketing and Transportation*

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

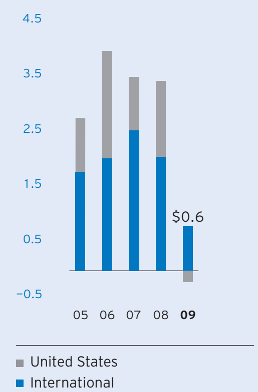
U.S. downstream operations lost $273 million in 2009, an earnings decrease of approximately $1.6 billion from 2008. A decline in refined product margins resulted in a negative earnings variance of $1.7 billion. Partially offsetting were lower operating expenses, which benefited earnings by $300 million.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

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




Refined-product sales volumes decreased about 1 percent from 2008 on lower sales of jet fuel and fuel oil.

**Worldwide Refining, Marketing & Transportation Earnings***
Billions of dollars




Downstream earnings decreased 84 percent from 2008 due to lower margins on the sale of refined products.

*Includes equity in affiliates

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

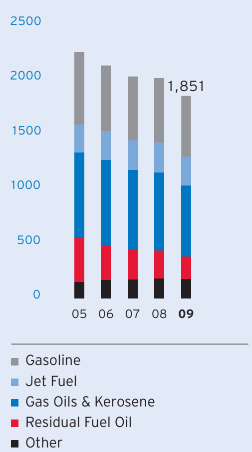
Refer to the "Selected Operating Data" table on page 18 for a three-year comparison of sales volumes of gasoline and other refined products and refinery-input volumes.

*International Downstream – Refining, Marketing and Transportation*

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

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

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




Sales volumes of refined products were down 8 percent from 2008 due to asset sales and weak economic conditions which depressed demand.

*Includes equity in affiliates

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

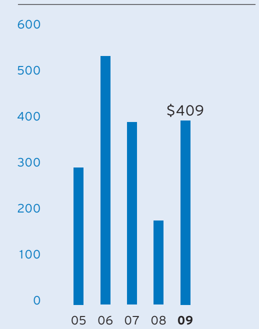
Refer to the "Selected Operating Data" table, on page 18, for a three-year comparison of sales volumes of gasoline and other refined products and refinery-input volumes.

*Chemicals*

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

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

**Worldwide Chemicals Earnings***
Millions of dollars




Chemicals earnings increased about 125 percent from 2008 due to higher margins on select commodity chemical products and lower utility and manufacturing expenses.

*Includes equity in affiliates

*All Other*

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

All Other includes mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels and technology companies, and the company's interest in Dynegy, Inc. prior to its sale in May 2007.

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



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

## Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

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

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

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

Income from equity affiliates decreased in 2009 from 2008. Upstream-related affiliate income declined about $1.3 billion mainly due to lower earnings for Tengizchevroil (TCO) in Kazakhstan as a result of lower prices for crude oil. Downstream-related affiliate earnings were lower by approximately $1.0 billion primarily due to weaker margins and an unfavorable swing in foreign-currency effects. Income from equity affiliates increased in 2008 from 2007 largely due to improved upstream-related earnings at TCO as a result of higher prices for crude oil. Refer to Note 12, beginning on page 50, for a discussion of Chevron's investments in affiliated companies.

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

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

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

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

| *Millions of dollars* | 2009 | 2008 | 2007 |
|---|---|---|---|
| **Operating, selling, general and administrative expenses** | **$ 22,384** | $ 26,551 | $ 22,858 |

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

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

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

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

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

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

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

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

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

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

Effective income tax rates were 43 percent in 2009, 44 percent in 2008 and 42 percent in 2007. The rate was lower in 2009 than in 2008 mainly due the effect in 2009 of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity-affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates. The rate was higher in 2008 compared with 2007 primarily due to a greater proportion of income earned in tax jurisdictions with higher income tax rates. In addition, the 2007 period included a relatively low effective tax rate on the sale of the company's investment in Dynegy common stock and the sale of downstream assets in Europe. Refer also to the discussion of income taxes in Note 15 beginning on page 53.

## Selected Operating Data[1,2]

| | 2009 | 2008 | 2007 |
|---|---|---|---|
| **U.S. Upstream** | | | |
| Net Crude Oil and Natural Gas | | | |
| Liquids Production (MBPD) | **484** | 421 | 460 |
| Net Natural Gas Production (MMCFPD)[3] | **1,399** | 1,501 | 1,699 |
| Net Oil-Equivalent Production (MBOEPD) | **717** | 671 | 743 |
| Sales of Natural Gas (MMCFPD) | **5,901** | 7,226 | 7,624 |
| Sales of Natural Gas Liquids (MBPD) | **17** | 15 | 25 |
| Revenues From Net Production | | | |
| Liquids ($/Bbl) | **$ 54.36** | $ 88.43 | $ 63.16 |
| Natural Gas ($/MCF) | **$ 3.73** | $ 7.90 | $ 6.12 |
| **International Upstream** | | | |
| Net Crude Oil and Natural Gas | | | |
| Liquids Production (MBPD) | **1,362** | 1,228 | 1,296 |
| Net Natural Gas Production (MMCFPD)[3] | **3,590** | 3,624 | 3,320 |
| Net Oil-Equivalent | | | |
| Production (MBOEPD)[4] | **1,987** | 1,859 | 1,876 |
| Sales of Natural Gas (MMCFPD) | **4,062** | 4,215 | 3,792 |
| Sales of Natural Gas Liquids (MBPD) | **23** | 17 | 22 |
| Revenues From Liftings | | | |
| Liquids ($/Bbl) | **$ 55.97** | $ 86.51 | $ 65.01 |
| Natural Gas ($/MCF) | **$ 4.01** | $ 5.19 | $ 3.90 |
| **Worldwide Upstream** | | | |
| Net Oil-Equivalent Production | | | |
| (MBOEPD)[3,4] | | | |
| United States | **717** | 671 | 743 |
| International | **1,987** | 1,859 | 1,876 |
| Total | **2,704** | 2,530 | 2,619 |
| **U.S. Downstream** | | | |
| Gasoline Sales (MBPD)[5] | **720** | 692 | 728 |
| Other Refined-Product Sales (MBPD) | **683** | 721 | 729 |
| Total Refined Product Sales (MBPD) | **1,403** | 1,413 | 1,457 |
| Sales of Natural Gas Liquids (MBPD) | **144** | 144 | 135 |
| Refinery Input (MBPD) | **899** | 891 | 812 |
| **International Downstream** | | | |
| Gasoline Sales (MBPD)[5] | **555** | 589 | 581 |
| Other Refined-Product Sales (MBPD) | **1,296** | 1,427 | 1,446 |
| Total Refined Product Sales (MBPD)[6] | **1,851** | 2,016 | 2,027 |
| Sales of Natural Gas Liquids (MBPD) | **88** | 97 | 96 |
| Refinery Input (MBPD) | **979** | 967 | 1,021 |

[1] Includes company share of equity affiliates.
[2] MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day; MBOEPD – thousands of barrels of oil-equivalents per day; Bbl – Barrel; MCF = Thousands of cubic feet. Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of oil.
[3] Includes natural gas consumed in operations (MMCFPD):

| | 2009 | 2008 | 2007 |
|---|---|---|---|
| United States | **58** | 70 | 65 |
| International | **463** | 450 | 433 |

[4] Includes production from oil sands, Net (MBPD): **26** 27 27
[5] Includes branded and unbranded gasoline.
[6] Includes sales of affiliates (MBPD): **516** 512 492

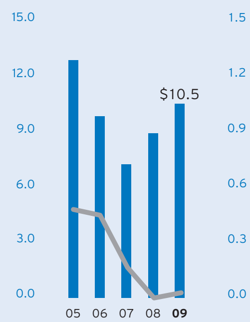
## Liquidity and Capital Resources

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

**Cash Provided by Operating Activities**
Billions of dollars


Operating cash flows were approximately $10.3 billion lower than 2008 due to lower 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 $1.6 billion during 2009 to $10.5 billion. Essentially all of the interest was capitalized as part of the cost of major projects.

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

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

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

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

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

At year-end 2009, the company had $5.1 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and also can be used for general corporate purposes. The company's practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company's strong credit rating. No borrowings were outstanding under these facilities at December 31, 2009. In addition, the company has an automatic shelf registration statement that expires in March 2010 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company. The company intends to file a new shelf registration statement when the current one expires.

The company has outstanding public bonds issued by Chevron Corporation, Chevron Corporation Profit Sharing/Savings Plan Trust Fund, Texaco Capital Inc. and Union Oil Company of California. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard and Poor's Corporation and Aa1 by Moody's Investors Service. The company's U.S. commercial paper is rated A-1+ by Standard and Poor's and P-1 by Moody's. All of these ratings denote high-quality, investment-grade securities.

The company's future debt level is dependent primarily on results of operations, the capital-spending program and cash that may be generated from asset dispositions. The company believes that it has substantial borrowing capacity to meet unanticipated cash requirements and that during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, it has the flexibility to increase borrowings and/or modify capital-spending plans to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

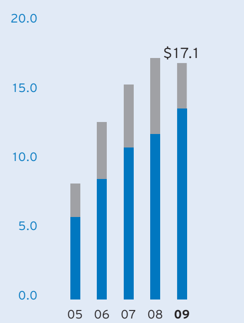
*Common stock repurchase program* In September 2007, the company authorized the acquisition of up to $15 billion of its common shares at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. The program is for a period of up to three years (expiring in 2010) and may be discontinued at any time. The company did not acquire any shares during 2009 and does not plan to acquire any shares in the first quarter 2010. From the inception of the program, the company has acquired 119 million shares at a cost of $10.1 billion.

*Capital and Exploratory Expenditures*

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

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

**Exploration & Production – Capital & Exploratory Expenditures***
Billions of dollars




Exploration and production expenditures were about the same as 2008, reflecting the capital-intensive phase of many significant projects.

*Includes equity in affiliates

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

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

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

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

*Noncontrolling interests* The company had noncontrolling interests of $647 million and $469 million at December 31, 2009 and 2008, respectively. Distributions to noncontrolling interests totaled $71 million and $99 million in 2009 and 2008, respectively.

*Pension Obligations* In 2009, the company's pension plan contributions were $1.7 billion (including $1.5 billion to the U.S. plans and $200 million to the international plans). The company estimates contributions in 2010 will be approximately $900 million ($600 million for the U.S. plans and $300 million for the international plans). Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in "Critical Accounting Estimates and Assumptions," beginning on page 26.

## Financial Ratios

*Financial Ratios*

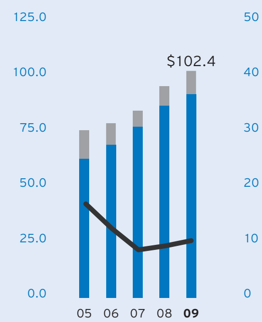
| | | | At December 31 |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| Current Ratio | **1.4** | 1.1 | 1.2 |
| Interest Coverage Ratio | **62.3** | 166.9 | 69.2 |
| Debt Ratio | **10.3%** | 9.3% | 8.6% |

*Current Ratio* – current assets divided by current liabilities. The current ratio in all periods was adversely affected by the fact that Chevron's inventories are valued on a Last-In, First-Out basis. At year-end 2009, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $5.5 billion.

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

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

**Debt Ratio**
Billions of dollars/Percent




■ Debt (left scale)
■ CVX Stockholders' Equity (left scale)
■ Ratio (right scale)

The ratio of total debt to total debt-plus-Chevron Corporation Stockholders' Equity increased to 10.3 percent at the end of 2009 due to the issuance of $5 billion in public bonds.

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

*Direct Guarantee*

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

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

*Indemnifications* The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300 million. Through the end of 2009, the company had paid $48 million under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. In February 2009, Shell delivered a letter to the company purporting to preserve unmatured claims for certain Equilon indemnities. The letter itself provides no estimate of the ultimate claim amount. Management does not believe this letter or any other information provides a basis to estimate the amount, if any, of a range of loss or potential range of loss with respect to either the Equilon or the Motiva indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

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

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

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

*Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements* The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2010 – $7.5 billion; 2011 – $4.3 billion; 2012 – $1.4 billion; 2013 – $1.4 billion; 2014 – $1.0 billion; 2015 and after – $4.1 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $8.1 billion in 2009, $5.1 billion in 2008 and $3.7 billion in 2007.

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

*Contractual Obligations*[1]

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

[1] Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page 59.
[2] Does not include amounts related to the company's income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates for the periods in which these liabilities may become payable. The company does not expect settlement of such liabilities will have a material effect on its results of operations, consolidated financial position or liquidity in any single period.
[3] $4.2 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2011–2012 period.
[4] Does not include obligations to purchase the company's share of natural gas liquids and regasified natural gas associated with operations of the 36.4 percent-owned Angola LNG affiliate. The LNG plant is expected to commence operations in 2012 and is designed to produce 5.2 million metric tons of LNG and related natural gas liquids per year. Volumes and prices associated with these purchase obligations are neither fixed nor determinable.

## Financial and Derivative Instruments

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk discussed below do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2009 Annual Report on Form 10-K.

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

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of these activities were not material to the company's financial position, results of operations or cash flows in 2009.

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

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

Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes. The change in fair value from Chevron's derivative commodity instruments in 2009 was a quarterly average decrease of $168 million in total assets and a quarterly average decrease of $104 million in total liabilities.

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

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

The one-day holding period is based on the assumption that market-risk positions can be liquidated or hedged within one day. For hedging and risk management, the company uses conventional exchange-traded instruments such as futures and options as well as non-exchange-traded swaps, most of which can be liquidated or hedged effectively within one day. The table below presents the 95 percent/one-day VaR for each of the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2009 and 2008. The lower amounts in 2009 were primarily associated with a decrease in price volatility for these commodities during the year.

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

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

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

### Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements and long-term purchase agreements. Refer to Other Financial Information in Note 24 of the Consolidated Financial Statements, page 68, for further discussion. Management believes these agreements have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

### Litigation and Other Contingencies

*MTBE* Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 50 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

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

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

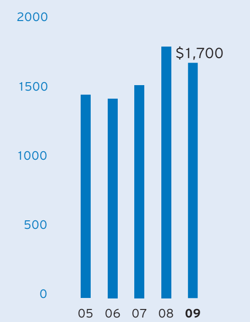
In April 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $8 billion, which would, according to the engineer, provide financial compensation for purported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

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

*Environmental* The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude-oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemical companies.

**Year-End Environmental Remediation Reserves**
Millions of dollars




Reserves for environmental remediation at the end of 2009 were down 6 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* | **2009** | 2008 | 2007 |
|---|---|---|---|
| Balance at January 1 | **$ 1,818** | $ 1,539 | $ 1,441 |
| Net Additions | **351** | 784 | 562 |
| Expenditures | **(469)** | (505) | (464) |
| **Balance at December 31** | **$ 1,700** | $ 1,818 | $ 1,539 |

Included in the $1,700 million year-end 2009 reserve balance were remediation activities at approximately 250 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation reserve for these sites at year-end 2009 was $185 million. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2009 environmental reserves balance of $1,515 million, $820 million related to the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), and pipelines. The remaining $695 million was associated with various sites in international downstream ($107 million), upstream ($369 million), chemicals ($149 million) and other businesses ($70 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state and local regulations. No single remediation site at year-end 2009 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Under accounting standards for asset retirement obligations (ASC 410), the fair value of a liability for an asset retirement obligation is recorded when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. The liability balance of approximately $10.2 billion for asset retirement obligations at year-end 2009 related primarily to upstream properties.

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

Refer also to Note 23 on page 67, related to the company's asset retirement obligations and the discussion of "Environmental Matters" on page 26.

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

*Suspended Wells* The company suspends the costs of exploratory wells pending a final determination of the commercial potential of the related crude-oil and natural-gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity or development decisions or both. At December 31, 2009, the company had approximately $2.4 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $317 million from 2008. The 2008 balance reflected an increase of $458 million from 2007.

The future trend of the company's exploration expenses can be affected by amounts associated with well write-offs, including wells that had been previously suspended pending determination as to whether the well had found reserves that could be classified as proved. The effect on exploration expenses in future periods of the $2.4 billion of suspended wells at year-end 2009 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page 57, for additional discussion of suspended wells.

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

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

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

**Environmental Matters**

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

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

Using definitions and guidelines established by the American Petroleum Institute, Chevron estimated its worldwide environmental spending in 2009 at approximately $3.5 billion for its consolidated companies. Included in these expenditures were approximately $1.7 billion of environmental capital expenditures and $1.8 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

For 2010, total worldwide environmental capital expenditures are estimated at $2.1 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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

**Critical Accounting Estimates and Assumptions**

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

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

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

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

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be "more likely than not." Another example is the estimation of crude-oil and natural-gas reserves under SEC rules, which, effective December 31, 2009, require "…by analysis of geosciences and engineering data, (the reserves) can be estimated with reasonable certainty to be economically producible…under existing economic conditions" where existing economic conditions include prices based on the average price during the

12-month period. Refer to Table V, "Reserve Quantity Information," beginning on page 76, for the changes in these estimates for the three years ending December 31, 2009, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 84 for estimates of proved-reserve values for each of the three years ended December 31, 2009. Note 1 to the Consolidated Financial Statements, beginning on page 39, 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 28, 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 39. 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 59, includes information on the funded status of the company's pension and OPEB plans at the end of 2009 and 2008; the components of pension and OPEB expense for the three years ending December 31, 2009; and the underlying assumptions for those periods.

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

To estimate the long-term rate of return on pension assets, the company uses a process that incorporates actual historical asset-class returns and an assessment of expected future performance and takes into consideration external actuarial advice and asset-class factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies. The expected long-term rate of return on U.S. pension plan assets, which account for 69 percent of the company's pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2009, actual asset returns averaged 3.7 percent for this plan. The actual return for 2009 was 15.7 percent and was associated with the broad recovery in the financial markets.

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

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2009, the company selected a 5.3 percent discount rate for the major U.S. pension plan and 5.8 percent for its OPEB plan. These rates were selected based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2009. The discount rates at the end of 2008 and 2007 were 6.3 percent for both years for the U.S. pension and OPEB plans.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2009 was \$1.1 billion. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the company's primary U.S. pension plan would have reduced total pension plan expense for 2009 by approximately \$50 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 61 percent of the companywide pension obligation, would have reduced total pension plan expense for 2009 by approximately $150 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan reported on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2009, for underfunded plans was approximately $3.8 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan would have reduced the plan obligation by approximately $300 million, which would have decreased the plan's underfunded status from approximately $1.6 billion to $1.3 billion. Other plans would be less underfunded as discount rates increase. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

In 2009, the company's pension plan contributions were $1.7 billion (including $1.5 billion to the U.S. plans). In 2010, the company estimates contributions will be approximately $900 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

For the company's OPEB plans, expense for 2009 was $164 million and the total liability, which reflected the unfunded status of the plans at the end of 2009, was $3.1 billion.

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

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 7 percent in 2010 and gradually drop to 5 percent for 2018 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2009, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for 84 percent of the companywide OPEB liabilities, would have increased OPEB expense $8 million.

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are not included in benefit plan costs in the year the difference occurs. Instead, the differences are included in actuarial gain/loss and unamortized amounts have been reflected in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet. Refer to Note 21, beginning on page 59, for information on the $6.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2009; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2010.

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

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

No major individual impairments of PP&E and Investments were recorded for the three years ending December 31, 2009. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

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

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

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

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

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

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is "more likely than not" (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 15 beginning on page 53. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2009.

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

**New Accounting Standards**

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

*Employer's Disclosures About Postretirement Benefit Plan Assets (FSP FAS 132(R)-1)* In December 2008, the FASB issued FSP FAS 132(R)-1, which was subsequently codified into ASC 715, *Compensation – Retirement Benefits,* and became effective with the company's reporting at December 31, 2009. This standard amended and expanded the disclosure requirements for the plan assets of defined benefit pension and other postretirement plans. Refer to information beginning on page 59 in Note 21, Employee Benefits, for these disclosures.

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

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

*Extractive Industries – Oil and Gas (ASC 932), Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03)* In January 2010, the FASB issued ASU 2010-03, which became effective for the company on December 31, 2009. The standard amends certain sections of ASC 932, *Extractive Industries – Oil and Gas,* to align them with the requirements in the Securities and Exchange Commission's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the final rule). The final rule was issued on December 31, 2008. Refer to Table V – Reserve Quantity Information, beginning on page 76, for additional information on the final rule and the impact of adoption.

## Quarterly Results and Stock Market Data

Unaudited

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

[2] End of day price.

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



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## Management's Responsibility for Financial Statements

*To the Stockholders of Chevron Corporation*

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

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

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

## Management's Report on Internal Control Over Financial Reporting

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company's internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2009.

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

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

**Patricia E. Yarrington**
Vice President
and Chief Financial Officer

**Mark A. Humphrey**
Vice President
and Comptroller

February 25, 2010

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2009 and December 31, 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, 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 25, 2010*

## Consolidated Statement of Income

Millions of dollars, except per-share amounts

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

See accompanying Notes to the Consolidated Financial Statements.



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## Consolidated Statement of Comprehensive Income

Millions of dollars

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

See accompanying Notes to the Consolidated Financial Statements.



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## Consolidated Balance Sheet

Millions of dollars, except per-share amounts

| | At December 31 | |
|---|---|---|
| | **2009** | 2008 |
| **Assets** | | |
| Cash and cash equivalents | **$ 8,716** | $ 9,347 |
| Marketable securities | **106** | 213 |
| Accounts and notes receivable (less allowance: 2009 – $228; 2008 – $246) | **17,703** | 15,856 |
| Inventories: | | |
| Crude oil and petroleum products | **3,680** | 5,175 |
| Chemicals | **383** | 459 |
| Materials, supplies and other | **1,466** | 1,220 |
| Total inventories | **5,529** | 6,854 |
| Prepaid expenses and other current assets | **5,162** | 4,200 |
| **Total Current Assets** | **37,216** | 36,470 |
| Long-term receivables, net | **2,282** | 2,413 |
| Investments and advances | **21,158** | 20,920 |
| Properties, plant and equipment, at cost | **188,288** | 173,299 |
| Less: Accumulated depreciation, depletion and amortization | **91,820** | 81,519 |
| Properties, plant and equipment, net | **96,468** | 91,780 |
| Deferred charges and other assets | **2,879** | 4,711 |
| Goodwill | **4,618** | 4,619 |
| Assets held for sale | **–** | 252 |
| **Total Assets** | **$ 164,621** | $ 161,165 |
| **Liabilities and Equity** | | |
| Short-term debt | **$ 384** | $ 2,818 |
| Accounts payable | **16,437** | 16,580 |
| Accrued liabilities | **5,375** | 8,077 |
| Federal and other taxes on income | **2,624** | 3,079 |
| Other taxes payable | **1,391** | 1,469 |
| **Total Current Liabilities** | **26,211** | 32,023 |
| Long-term debt | **9,829** | 5,742 |
| Capital lease obligations | **301** | 341 |
| Deferred credits and other noncurrent obligations | **17,390** | 17,678 |
| Noncurrent deferred income taxes | **11,521** | 11,539 |
| Reserves for employee benefit plans | **6,808** | 6,725 |
| **Total Liabilities** | **72,060** | 74,048 |
| Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued) | **–** | – |
| Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2009 and 2008) | **1,832** | 1,832 |
| Capital in excess of par value | **14,631** | 14,448 |
| Retained earnings | **106,289** | 101,102 |
| Accumulated other comprehensive loss | **(4,321)** | (3,924) |
| Deferred compensation and benefit plan trust | **(349)** | (434) |
| Treasury stock, at cost (2009 – 434,954,774 shares; 2008 – 438,444,795 shares) | **(26,168)** | (26,376) |
| **Total Chevron Corporation Stockholders' Equity** | **91,914** | 86,648 |
| Noncontrolling interests | **647** | 469 |
| **Total Equity** | **92,561** | 87,117 |
| **Total Liabilities and Equity** | **$ 164,621** | $ 161,165 |

See accompanying Notes to the Consolidated Financial Statements.

## Consolidated Statement of Cash Flows

Millions of dollars

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

See accompanying Notes to the Consolidated Financial Statements.



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## Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

| | 2009 Shares | 2009 Amount | 2008 Shares | 2008 Amount | 2007 Shares | 2007 Amount |
|---|---|---|---|---|---|---|
| **Preferred Stock** | – | $ – | – | $ – | – | $ – |
| **Common Stock** | 2,442,677 | $ 1,832 | 2,442,677 | $ 1,832 | 2,442,677 | $ 1,832 |
| **Capital in Excess of Par** | | | | | | |
| Balance at January 1 | | $ 14,448 | | $ 14,289 | | $ 14,126 |
| Treasury stock transactions | | 183 | | 159 | | 163 |
| **Balance at December 31** | | $ 14,631 | | $ 14,448 | | $ 14,289 |
| **Retained Earnings** | | | | | | |
| Balance at January 1 | | $101,102 | | $ 82,329 | | $ 68,464 |
| Net income attributable to Chevron Corporation | | 10,483 | | 23,931 | | 18,688 |
| Cash dividends on common stock | | (5,302) | | (5,162) | | (4,791) |
| Adoption of new accounting standard for uncertain income tax positions | | – | | – | | (35) |
| Tax benefit from dividends paid on unallocated ESOP shares and other | | 6 | | 4 | | 3 |
| **Balance at December 31** | | $106,289 | | $101,102 | | $ 82,329 |
| **Notes Receivable – Key Employees** | | $ – | | $ – | | $ (1) |
| **Accumulated Other Comprehensive Loss** | | | | | | |
| Currency translation adjustment | | | | | | |
| Balance at January 1 | | $ (171) | | $ (59) | | $ (90) |
| Change during year | | 60 | | (112) | | 31 |
| Balance at December 31 | | $ (111) | | $ (171) | | $ (59) |
| Pension and other postretirement benefit plans | | | | | | |
| Balance at January 1 | | $ (3,909) | | $ (2,008) | | $ (2,585) |
| Change to defined benefit plans during year | | (399) | | (1,901) | | 685 |
| Adoption of new accounting standard for defined benefit pension and other postretirement plans | | – | | – | | (108) |
| Balance at December 31 | | $ (4,308) | | $ (3,909) | | $ (2,008) |
| Unrealized net holding gain on securities | | | | | | |
| Balance at January 1 | | $ 13 | | $ 19 | | $ – |
| Change during year | | 2 | | (6) | | 19 |
| Balance at December 31 | | $ 15 | | $ 13 | | $ 19 |
| Net derivatives gain (loss) on hedge transactions | | | | | | |
| Balance at January 1 | | $ 143 | | $ 33 | | $ 39 |
| Change during year | | (60) | | 110 | | (6) |
| Balance at December 31 | | $ 83 | | $ 143 | | $ 33 |
| **Balance at December 31** | | $ (4,321) | | $ (3,924) | | $ (2,015) |
| **Deferred Compensation and Benefit Plan Trust** | | | | | | |
| **Deferred Compensation** | | | | | | |
| Balance at January 1 | | $ (194) | | $ (214) | | $ (214) |
| Net reduction of ESOP debt and other | | 85 | | 20 | | – |
| **Balance at December 31** | | (109) | | (194) | | (214) |
| **Benefit Plan Trust (Common Stock)** | 14,168 | (240) | 14,168 | (240) | 14,168 | (240) |
| **Balance at December 31** | 14,168 | $ (349) | 14,168 | $ (434) | 14,168 | $ (454) |
| **Treasury Stock at Cost** | | | | | | |
| Balance at January 1 | 438,445 | $ (26,376) | 352,243 | $(18,892) | 278,118 | $(12,395) |
| Purchases | 85 | (6) | 95,631 | (8,011) | 85,429 | (7,036) |
| Issuances – mainly employee benefit plans | (3,575) | 214 | (9,429) | 527 | (11,304) | 539 |
| **Balance at December 31** | 434,955 | $ (26,168) | 438,445 | $(26,376) | 352,243 | $(18,892) |
| **Total Chevron Corporation Stockholders' Equity at December 31** | | $ 91,914 | | $ 86,648 | | $ 77,088 |
| **Noncontrolling Interests** | | $ 647 | | $ 469 | | $ 204 |
| **Total Equity** | | $ 92,561 | | $ 87,117 | | $ 77,292 |

See accompanying Notes to the Consolidated Financial Statements.

## Note 1

### Summary of Significant Accounting Policies

*General* Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemical operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant oil additives.

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

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

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

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

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

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

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

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

*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 57, for additional discussion of accounting for suspended exploratory well costs.

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

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

As required under accounting standards for asset retirement and environmental obligations (Accounting Standards Codification (ASC) 410), the fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 23, on page 67, 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 23, on page 67, for a discussion of the company's AROs.

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

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

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

*Revenue Recognition* Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized on the entitlement method. Excise, value-added and similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income on page 34 Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in "Purchased crude oil and products" on the Consolidated Statement of Income.

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

## Note 2

### Noncontrolling Interests

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

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

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| Balance at January 1 | **$ 469** | $ 204 | $ 209 |
| Net income | **80** | 100 | 107 |
| Distributions to noncontrolling interests | **(71)** | (99) | (77) |
| Other changes, net | **169** | 264 | (35) |
| Balance at December 31 | **$ 647** | $ 469 | $ 204 |

## Note 3

### Equity

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

At December 31, 2009, about 94 million shares of Chevron's common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP). In addition, approximately 342,000 shares remain available for issuance from the 800,000 shares of the company's common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan (Non-Employee Directors' Plan).

## Note 4

### Information Relating to the Consolidated Statement of Cash Flows

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

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

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

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

The Consolidated Statement of Cash Flows for 2009 excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2008, "Net sales (purchases) of treasury shares" excludes $680 of treasury shares acquired in exchange for a U.S. upstream property and $280 in cash. The carrying value of this property in "Properties, plant and equipment" on the Consolidated Balance Sheet was not significant. In 2008, a $2,450 increase in "Accrued liabilities" and a corresponding increase to "Properties, plant and equipment, at cost" were considered non-cash transactions and excluded from "Net (increase) decrease in operating working capital" and "Capital expenditures." In 2009, the payments related to these "Accrued liabilities" were excluded from "Net (increase) decrease in operating working capital" and were reported as "Capital expenditures." The amount is related to upstream operating agreements outside the United States. "Capital expenditures" in 2008 excludes a $1,400 increase in "Properties, plant and equipment" related to the acquisition of an additional interest in an equity affiliate that required a change to the consolidated method of accounting for the investment during 2008. This addition was offset primarily by reductions in "Investments and advances" and working capital and an increase in "Non-current deferred income tax" liabilities. Refer also to Note 23, on page 67, for a discussion of revisions to the company's AROs that also did not involve cash receipts or payments for the three years ending December 31, 2009.

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

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

[1]Excludes noncash additions of $985 in 2009, $5,153 in 2008 and $3,560 in 2007.
[2]2009 includes payments of $2,450 for accruals recorded in 2008.

## Note 5

### Summarized Financial Data – Chevron U.S.A. Inc.

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

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

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

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

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

## Note 6

### Summarized Financial Data – Chevron Transport Corporation Ltd.

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

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

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

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

## Note 7

### Summarized Financial Data – Tengizchevroil LLP

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

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

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

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

## Note 8

### Lease Commitments

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

| | At December 31 | |
|---|---|---|
| | **2009** | 2008 |
| Upstream | **$ 510** | $ 491 |
| Downstream | **332** | 399 |
| Chemicals and all other | **171** | 171 |
| Total | **1,013** | 1,061 |
| Less: Accumulated amortization | **585** | 522 |
| Net capitalized leased assets | **$ 428** | $ 539 |

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

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

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

At December 31, 2009, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

| | At December 31 | |
|---|---|---|
| | Operating Leases | Capital Leases |
| Year: 2010 | 568 | 90 |
| 2011 | 438 | 81 |
| 2012 | 406 | 87 |
| 2013 | 372 | 60 |
| 2014 | 347 | 44 |
| Thereafter | 1,233 | 137 |
| Total | $ 3,364 | $ 499 |
| Less: Amounts representing interest and executory costs | | (104) |
| Net present values | | 395 |
| Less: Capital lease obligations included in short-term debt | | (94) |
| Long-term capital lease obligations | | $ 301 |

## Note 9

### Fair Value Measurements

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

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

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



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

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

*Assets and Liabilities Measured at Fair Value on a Recurring Basis*

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

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

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

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

Derivatives classified as Level 2 include swaps, options, and forward contracts principally with financial institutions and other oil and gas companies, the fair values for which are obtained from third-party broker quotes, industry 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"* During 2009 and in accordance with the accounting standard for the impairment or disposal of long-lived assets (ASC 360), long-lived assets "held and used" with a carrying amount of $949 were written down to a fair value of $490, resulting in a before-tax loss of $459. The fair values were determined from internal cash-flow models, using discount rates consistent with those used by the company to evaluate cash flows of other assets of a similar nature. Long-lived assets "held for sale" with a carrying amount of $160 were written down to a fair value of $68, resulting in a before-tax loss of $92. The fair values were determined based on bids received from prospective buyers.

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

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

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

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

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

## Note 10

### Financial and Derivative Instruments

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

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

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

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

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

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

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

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

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

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

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

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

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

## Note 11

### Operating Segments and Geographic Data

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. For this purpose, the investments are grouped as follows: upstream – exploration and production; downstream – refining, marketing and transportation; chemicals; and all other. The first three of these groupings represent the company's "reportable segments" and "operating segments" as defined in accounting standards for segment reporting (ASC 280).

The segments are separately managed for investment purposes under a structure that includes "segment managers" who report to the company's "chief operating decision maker" (CODM) (terms as defined in ASC 280). The CODM is the company's Executive Committee, a committee of senior officers that includes the Chief Executive Officer and that, in turn, reports to the Board of Directors of Chevron Corporation.

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

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

"All Other" activities include mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels and technology companies, and the company's interest in Dynegy (through May 2007, when Chevron sold its interest).

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

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

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

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

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

*"All Other" assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, mining operations, power generation businesses, alternative fuels and technology companies, and assets of the corporate administrative functions.

*Segment Sales and Other Operating Revenues* Operating segment sales and other operating revenues, including internal transfers, for the years 2009, 2008 and 2007, are presented in the table on the following page. Products are transferred between operating segments at internal product values that approximate market prices.

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

Other than the United States, no single country accounted for 10 percent or more of the company's total sales and other operating revenues in 2009, 2008 and 2007.

| | Year ended December 31 | | |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| **Upstream** | | | |
| United States | **$ 9,164** | $ 23,503 | $ 18,736 |
| Intersegment | **10,278** | 15,142 | 11,625 |
| Total United States | **19,442** | 38,645 | 30,361 |
| International | **13,409** | 19,469 | 15,213 |
| Intersegment | **18,477** | 24,204 | 19,647 |
| Total International | **31,886** | 43,673 | 34,860 |
| **Total Upstream** | **51,328** | 82,318 | 65,221 |
| **Downstream** | | | |
| United States | **57,846** | 87,515 | 70,535 |
| Excise and similar taxes | **4,573** | 4,746 | 4,990 |
| Intersegment | **190** | 447 | 491 |
| Total United States | **62,609** | 92,708 | 76,016 |
| International | **76,668** | 122,064 | 97,178 |
| Excise and similar taxes | **3,471** | 5,044 | 5,042 |
| Intersegment | **106** | 122 | 38 |
| Total International | **80,245** | 127,230 | 102,258 |
| **Total Downstream** | **142,854** | 219,938 | 178,274 |
| **Chemicals** | | | |
| United States | **271** | 305 | 351 |
| Excise and similar taxes | **–** | 2 | 2 |
| Intersegment | **194** | 266 | 235 |
| Total United States | **465** | 573 | 588 |
| International | **1,231** | 1,388 | 1,143 |
| Excise and similar taxes | **65** | 55 | 86 |
| Intersegment | **132** | 154 | 142 |
| Total International | **1,428** | 1,597 | 1,371 |
| **Total Chemicals** | **1,893** | 2,170 | 1,959 |
| **All Other** | | | |
| United States | **665** | 815 | 757 |
| Intersegment | **964** | 917 | 760 |
| Total United States | **1,629** | 1,732 | 1,517 |
| International | **39** | 52 | 58 |
| Intersegment | **33** | 33 | 31 |
| Total International | **72** | 85 | 89 |
| **Total All Other** | **1,701** | 1,817 | 1,606 |
| **Segment Sales and Other Operating Revenues** | | | |
| United States | **84,145** | 133,658 | 108,482 |
| International | **113,631** | 172,585 | 138,578 |
| **Total Segment Sales and Other Operating Revenues** | **197,776** | 306,243 | 247,060 |
| Elimination of intersegment sales | **(30,374)** | (41,285) | (32,969) |
| **Total Sales and Other Operating Revenues** | **$ 167,402** | $ 264,958 | $ 214,091 |

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

| | Year ended December 31 | | |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| **Upstream** | | | |
| United States | **$ 1,225** | $ 3,693 | $ 2,541 |
| International | **7,686** | 15,132 | 11,307 |
| **Total Upstream** | **8,911** | 18,825 | 13,848 |
| **Downstream** | | | |
| United States | **(111)** | 815 | 520 |
| International | **182** | 813 | 400 |
| **Total Downstream** | **71** | 1,628 | 920 |
| **Chemicals** | | | |
| United States | **54** | (22) | 6 |
| International | **46** | 47 | 36 |
| **Total Chemicals** | **100** | 25 | 42 |
| **All Other** | **(1,117)** | (1,452) | (1,331) |
| **Total Income Tax Expense** | **$ 7,965** | $ 19,026 | $ 13,479 |

*Other Segment Information* Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page 50. Information related to properties, plant and equipment by segment is contained in Note 13, on page 52.



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## Note 12

### Investments and Advances

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, is shown in the table below. For certain equity affiliates, Chevron pays its share of some income taxes directly. For such affiliates, the equity in earnings does not include these taxes, which are reported on the Consolidated Statement of Income as "Income tax expense."

| | Investments and Advances At December 31 | | Equity in Earnings Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 | 2007 |
| **Upstream** | | | | | |
| Tengizchevroil | **$ 5,938** | $ 6,290 | **$ 2,216** | $ 3,220 | $ 2,135 |
| Petropiar/Hamaca | **1,139** | 1,130 | **122** | 317 | 327 |
| Petroboscan | **832** | 816 | **171** | 244 | 185 |
| Angola LNG Limited | **1,853** | 1,191 | **(12)** | (8) | 21 |
| Other | **686** | 725 | **118** | 206 | 204 |
| Total Upstream | **10,448** | 10,152 | **2,615** | 3,979 | 2,872 |
| **Downstream** | | | | | |
| GS Caltex Corporation | **2,406** | 2,601 | **(191)** | 444 | 217 |
| Caspian Pipeline Consortium | **852** | 749 | **105** | 103 | 102 |
| Star Petroleum Refining Company Ltd. | **873** | 877 | **(4)** | 22 | 157 |
| Caltex Australia Ltd. | **740** | 723 | **11** | 250 | 129 |
| Colonial Pipeline Company | **514** | 536 | **51** | 32 | 39 |
| Other | **1,773** | 1,664 | **311** | 354 | 318 |
| Total Downstream | **7,158** | 7,150 | **283** | 1,205 | 962 |
| **Chemicals** | | | | | |
| Chevron Phillips Chemical Company LLC | **2,327** | 2,037 | **328** | 158 | 380 |
| Other | **28** | 25 | **7** | 4 | 6 |
| Total Chemicals | **2,355** | 2,062 | **335** | 162 | 386 |
| **All Other** | | | | | |
| Other | **507** | 567 | **83** | 20 | (76) |
| Total equity method | **$ 20,468** | $ 19,931 | **$ 3,316** | $ 5,366 | $ 4,144 |
| Other at or below cost | **690** | 989 | | | |
| Total investments and advances | **$ 21,158** | $ 20,920 | | | |
| Total United States | **$ 4,195** | $ 4,002 | **$ 511** | $ 307 | $ 478 |
| Total International | **$ 16,963** | $ 16,918 | **$ 2,805** | $ 5,059 | $ 3,666 |

Descriptions of major affiliates, including significant differences between the company's carrying value of its investments and its underlying equity in the net assets of the affiliates, are as follows:

*Tengizchevroil* Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude-oil fields in Kazakhstan over a 40-year period. At December 31, 2009, the company's carrying value of its investment in TCO was about $200 higher than the amount of underlying equity in TCO's net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO's net assets. See Note 7, on page 43, for summarized financial information for 100 percent of TCO.

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

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

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

*GS Caltex Corporation* Chevron owns 50 percent of GS Caltex Corporation, a joint venture with GS Holdings. The joint venture imports, refines and markets petroleum products and petrochemicals, predominantly in South Korea.

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

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

*Caltex Australia Ltd.* Chevron has a 50 percent equity ownership interest in Caltex Australia Ltd. (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2009,



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

*Colonial Pipeline Company* Chevron owns an approximate 23 percent equity interest in the Colonial Pipeline Company. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market. At December 31, 2009, the company's carrying value of its investment in Colonial Pipeline was approximately $550 higher than the amount of underlying equity in Colonial Pipeline net assets. This difference primarily relates to purchase price adjustments from the acquisition of Unocal Corporation.

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

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

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

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share, which includes Chevron loans to affiliates of $2,422 at December 31, 2009.

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

## 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] | | |
| | **2009** | 2008 | 2007 | **2009** | 2008 | 2007 | **2009** | 2008 | 2007 | **2009** | 2008 | 2007 |
| **Upstream** | | | | | | | | | | | | |
| United States | **$ 57,645** | $ 54,156 | $ 50,991 | **$ 21,885** | $ 22,294 | $ 19,850 | **$ 3,496** | $ 5,374 | $ 5,725 | **$ 3,963** | $ 2,683 | $ 2,700 |
| International | **93,177** | 84,282 | 71,408 | **54,253** | 51,140 | 43,431 | **9,750** | 13,177 | 10,512 | **6,651** | 5,441 | 4,605 |
| Total Upstream | **150,822** | 138,438 | 122,399 | **76,138** | 73,434 | 63,281 | **13,246** | 18,551 | 16,237 | **10,614** | 8,124 | 7,305 |
| **Downstream** | | | | | | | | | | | | |
| United States | **18,915** | 17,394 | 15,807 | **10,089** | 8,977 | 7,685 | **1,871** | 2,032 | 1,514 | **664** | 629 | 509 |
| International | **12,319** | 11,587 | 10,471 | **6,806** | 6,001 | 4,690 | **1,424** | 2,285 | 519 | **437** | 469 | 633 |
| Total Downstream | **31,234** | 28,981 | 26,278 | **16,895** | 14,978 | 12,375 | **3,295** | 4,317 | 2,033 | **1,101** | 1,098 | 1,142 |
| **Chemicals** | | | | | | | | | | | | |
| United States | **730** | 725 | 678 | **331** | 338 | 308 | **25** | 50 | 40 | **31** | 19 | 19 |
| International | **913** | 828 | 815 | **545** | 496 | 453 | **85** | 72 | 53 | **35** | 33 | 26 |
| Total Chemicals | **1,643** | 1,553 | 1,493 | **876** | 834 | 761 | **110** | 122 | 93 | **66** | 52 | 45 |
| **All Other[4]** | | | | | | | | | | | | |
| United States | **4,569** | 4,310 | 3,873 | **2,548** | 2,523 | 2,179 | **354** | 598 | 680 | **325** | 250 | 215 |
| International | **20** | 17 | 41 | **11** | 11 | 14 | **3** | 5 | 5 | **4** | 4 | 1 |
| Total All Other | **4,589** | 4,327 | 3,914 | **2,559** | 2,534 | 2,193 | **357** | 603 | 685 | **329** | 254 | 216 |
| Total United States | **81,859** | 76,585 | 71,349 | **34,853** | 34,132 | 30,022 | **5,746** | 8,054 | 7,959 | **4,983** | 3,581 | 3,443 |
| Total International | **106,429** | 96,714 | 82,735 | **61,615** | 57,648 | 48,588 | **11,262** | 15,539 | 11,089 | **7,127** | 5,947 | 5,265 |
| **Total** | **$188,288** | $173,299 | $154,084 | **$ 96,468** | $ 91,780 | $ 78,610 | **$17,008** | $23,593 | $19,048 | **$12,110** | $ 9,528 | $ 8,708 |

[1] Other than the United States and Nigeria, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2009 and 2008. Only the United States had more than 10 percent in 2007. Nigeria had net PP&E of $12,463 and $10,730 for 2009 and 2008, respectively.
[2] Net of dry hole expense related to prior years' expenditures of $84, $55 and $89 in 2009, 2008 and 2007, respectively.
[3] Depreciation expense includes accretion expense of $463, $430 and $399 in 2009, 2008 and 2007, respectively.
[4] Primarily mining operations, power generation businesses, real estate assets and management information systems.

## Note 14

### Litigation

*MTBE* Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 50 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

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

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

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

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

## Note 15

### Taxes

*Income Taxes*

| | Year ended December 31 | | |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| Taxes on income | | | |
| U.S. Federal | | | |
| Current | **$ 128** | $ 2,879 | $ 1,446 |
| Deferred | **(147)** | 274 | 225 |
| State and local | | | |
| Current | **216** | 528 | 356 |
| Deferred | **14** | 141 | (18) |
| Total United States | **211** | 3,822 | 2,009 |
| International | | | |
| Current | **7,154** | 15,021 | 11,416 |
| Deferred | **600** | 183 | 54 |
| Total International | **7,754** | 15,204 | 11,470 |
| Total taxes on income | **$ 7,965** | $ 19,026 | $ 13,479 |

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

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

| | Year ended December 31 | | |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| U.S. statutory federal income tax rate | **35.0%** | 35.0% | 35.0% |
| Effect of income taxes from international operations at rates different from the U.S. statutory rate | **10.4** | 10.1 | 8.2 |
| State and local taxes on income, net of U.S. federal income tax benefit | **0.9** | 1.0 | 0.8 |
| Prior-year tax adjustments | **(0.3)** | (0.1) | 0.3 |
| Tax credits | **(1.1)** | (0.5) | (0.4) |
| Effects of enacted changes in tax laws | **0.1** | (0.6) | (0.3) |
| Other | **(2.0)** | (0.7) | (1.8) |
| Effective tax rate | **43.0%** | 44.2% | 41.8% |

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

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

| | At December 31 | |
|---|---|---|
| | **2009** | 2008 |
| Deferred tax liabilities | | |
| Properties, plant and equipment | **$ 18,545** | $ 18,271 |
| Investments and other | **2,350** | 2,225 |
| Total deferred tax liabilities | **20,895** | 20,496 |
| Deferred tax assets | | |
| Foreign tax credits | **(5,387)** | (4,784) |
| Abandonment/environmental reserves | **(4,424)** | (4,338) |
| Employee benefits | **(3,499)** | (3,488) |
| Deferred credits | **(3,469)** | (3,933) |
| Tax loss carryforwards | **(819)** | (1,139) |
| Other accrued liabilities | **(553)** | (445) |
| Inventory | **(431)** | (260) |
| Miscellaneous | **(1,681)** | (1,732) |
| Total deferred tax assets | **(20,263)** | (20,119) |
| Deferred tax assets valuation allowance | **7,921** | 7,535 |
| Total deferred taxes, net | **$ 8,553** | $ 7,912 |

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

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

The overall valuation allowance relates to deferred tax assets for foreign tax credit carryforwards, tax loss carryforwards and temporary differences. It reduces the deferred tax assets to amounts that are, in management's assessment, more likely than not to be realized. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2010 through 2036. Foreign tax credit carryforwards of $5,387 will expire between 2010 and 2019.

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

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

Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled $20,458 at December 31, 2009. This amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of earnings that are intended to be reinvested indefinitely. At the end of 2009, deferred income taxes were recorded for the undistributed earnings of certain international operations for which the company no longer intends to indefinitely reinvest the earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

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

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

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

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

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

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

*Taxes Other Than on Income*

| | Year ended December 31 | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| United States | | | |
| Excise and similar taxes on products and merchandise | **$ 4,573** | $ 4,748 | $ 4,992 |
| Import duties and other levies | **(4)** | 1 | 12 |
| Property and other miscellaneous taxes | **584** | 588 | 491 |
| Payroll taxes | **223** | 204 | 185 |
| Taxes on production | **135** | 431 | 288 |
| Total United States | **5,511** | 5,972 | 5,968 |
| International | | | |
| Excise and similar taxes on products and merchandise | **3,536** | 5,098 | 5,129 |
| Import duties and other levies | **6,550** | 8,368 | 10,404 |
| Property and other miscellaneous taxes | **1,740** | 1,557 | 528 |
| Payroll taxes | **134** | 106 | 89 |
| Taxes on production | **120** | 202 | 148 |
| Total International | **12,080** | 15,331 | 16,298 |
| Total taxes other than on income | **$ 17,591** | $ 21,303 | $ 22,266 |

## Note 16

### Short-Term Debt

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

*Weighted-average interest rates at December 31, 2009 and 2008, were 0.08 percent and 0.67 percent, respectively.

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

**Note 16** Short-Term Debt – Continued

the balance sheet date. In 2009, $350 of tax-exempt Gulf Opportunity Zone bonds related to projects at the Pascagoula Refinery were issued.

The company periodically enters into interest rate swaps on a portion of its short-term debt. At December 31, 2009, the company had no interest rate swaps on short-term debt. See Note 10, beginning on page 46, for information concerning the company's debt-related derivative activities.

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

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

## Note 17

### Long-Term Debt

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

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

[1] Guarantee of ESOP debt.
[2] Weighted-average interest rate at December 31, 2009.

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

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

## Note 18

### New Accounting Standards

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

*Employer's Disclosures About Postretirement Benefit Plan Assets (FSP FAS 132(R)-1)* In December 2008, the FASB issued FSP FAS 132(R)-1, which was subsequently codified into ASC 715, *Compensation – Retirement Benefits,* and became effective with the company's reporting at December 31, 2009. This standard amended and expanded the disclosure requirements for the plan assets of defined benefit pension and other postretirement plans. Refer to information beginning on page 59 in Note 21, Employee Benefits, for these disclosures.

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

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

*Extractive Industries – Oil and Gas (ASC 932), Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03)* In January 2010, the FASB issued ASU 2010-03, which became effective for the company on December 31, 2009. The standard amends certain sections of ASC 932, *Extractive Industries – Oil and Gas,* to align them with the requirements in the Securities and Exchange Commission's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the final rule). The final rule was issued on December 31, 2008. Refer to Table V – Reserve Quantity Information, beginning on page 76, for additional information on the final rule and the impact of adoption.

## Note 19
### Accounting for Suspended Exploratory Wells

Accounting standards for the costs of exploratory wells (ASC 932) provide that exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. The accounting standards provide a number of indicators that can assist an entity in demonstrating that sufficient progress is being made in assessing the reserves and economic viability of the project.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2009:

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

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

| | At December 31 | | |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| Exploratory well costs capitalized for a period of one year or less | **$ 564** | $ 559 | $ 449 |
| Exploratory well costs capitalized for a period greater than one year | **1,871** | 1,559 | 1,211 |
| Balance at December 31 | **$ 2,435** | $ 2,118 | $ 1,660 |
| Number of projects with exploratory well costs that have been capitalized for a period greater than one year* | **46** | 50 | 54 |

*Certain projects have multiple wells or fields or both.

Of the $1,871 of exploratory well costs capitalized for more than one year at December 31, 2009, $1,143 (28 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $728 balance is related to 18 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.



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The projects for the $728 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $330 (one project) – negotiation of crude-oil and natural-gas transportation contracts and construction agreements; (b) $107 (two projects) – discussion with possible natural-gas purchasers ongoing; (c) $73 (two projects) – continued unitization efforts on adjacent discoveries that span international boundaries while planning on an LNG facility has commenced; (d) $49 (one project) – progression of development concept selection; (e) $47 (one project) – subsurface and facilities engineering studies concluding with front-end engineering and design expected to begin in early 2010; (f) $34 (one project) – reviewing development alternatives; $88 – miscellaneous activities for 10 projects with smaller amounts suspended. While progress was being made on all 46 projects, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations connected with the projects. The majority of these decisions are expected to occur in the next three years.

The $1,871 of suspended well costs capitalized for a period greater than one year as of December 31, 2009, represents 149 exploratory wells in 46 projects. The tables below contain the aging of these costs on a well and project basis:

| *Aging based on drilling completion date of individual wells:* | Amount | Number of wells |
|---|---|---|
| 1992 | $ 8 | 3 |
| 1997–1998 | 15 | 3 |
| 1999–2003 | 271 | 42 |
| 2004–2008 | 1,577 | 101 |
| Total | $ 1,871 | 149 |

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

## Note 20

### Stock Options and Other Share-Based Compensation

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

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

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

*Chevron Long-Term Incentive Plan (LTIP)* Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and nonstock grants. From April 2004 through January 2014, no more than 160 million shares may be issued under the LTIP, and no more than 64 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient.

*Texaco Stock Incentive Plan (Texaco SIP)* On the closing of the acquisition of Texaco in October 2001, outstanding options granted under the Texaco SIP were converted to Chevron options. These options, which have 10-year contractual lives extending into 2011, retained a provision for being restored. This provision enables a participant who exercises a stock option to receive new options equal to the number of shares exchanged or who has shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant, and the exercise price is the market value of the common stock on the day the restored option is granted. Beginning in 2007, restored options were issued under the LTIP. No further awards may be granted under the former Texaco plans.

*Unocal Share-Based Plans (Unocal Plans)* When Chevron acquired Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights. These awards retained the same provisions as the original Unocal Plans. If not exercised, these awards will expire between early 2010 and early 2015.



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

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

[1] Expected term is based on historical exercise and postvesting cancellation data.
[2] Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

A summary of option activity during 2009 is presented below:

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

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

As of December 31, 2009, there was $233 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 1.8 years.

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

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

## Note 21

### Employee Benefit Plans

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

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

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

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

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

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

| | Pension Benefits | | | | Other Benefits | |
|---|---|---|---|---|---|---|
| | **2009** | | 2008 | | | |
| | U.S. | Int'l. | U.S. | Int'l. | **2009** | 2008 |
| Deferred charges and other assets | **$ 6** | **$ 37** | $ 6 | $ 31 | **$ –** | $ – |
| Accrued liabilities | **(66)** | **(67)** | (72) | (61) | **(208)** | (209) |
| Reserves for employee benefit plans | **(2,300)** | **(1,450)** | (2,613) | (1,261) | **(2,857)** | (2,722) |
| **Net amount recognized at December 31** | **$(2,360)** | **$(1,480)** | $(2,679) | $(1,291) | **$ (3,065)** | $ (2,931) |

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

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

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

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

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

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

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

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2009, for the company's U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 11, 13 and 10 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2010, the company estimates actuarial losses of $318, $102 and $26 will be amortized from "Accumulated other comprehensive loss" for U.S. pension, international pension and OPEB plans, respectively. In addition, the company estimates an additional $220 will be recognized from "Accumulated other comprehensive loss" during 2010 related to lump-sum settlement costs from U.S. pension plans.

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

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

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

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

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 69 percent of the company's pension plan assets. At December 31, 2009, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

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

*Discount Rate* The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2009, the company selected a 5.3 percent discount rate for the U.S. pension plan and 5.8 percent for the U.S. postretirement benefit plan. This rate was based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2009. The discount rates at the end of 2008 and 2007 were 6.3 percent for the U.S. pension plan and the OPEB plan.

*Other Benefit Assumptions* For the measurement of accumulated postretirement benefit obligation at December 31, 2009, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 7 percent in 2010 and gradually decline to 5 percent for 2018 and beyond. For this measurement at December 31, 2008, the assumed health care cost-trend rates started with 7 percent in 2009 and gradually declined to 5 percent for 2017 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company's medical contributions for the primary U.S. plan. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| Effect on total service and interest cost components | $ 10 | $ (9) |
| Effect on postretirement benefit obligation | $102 | $ (87) |

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

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

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

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

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

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

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

[1] U.S. equities include investments in the company's common stock in the amount of $29 at December 31, 2009.
[2] Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is based on the restriction that advance notification of redemptions, typically two business days, is required.
[3] Mixed funds are composed of funds that invest in both equity and fixed income instruments in order to diversify and lower risk.
[4] The year-end valuations of the U.S. real estate assets are based on internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.
[5] The "Other" asset category includes net payables for securities purchased but not yet settled (Level 1); dividends, interest- and tax-related receivables (Level 2); insurance contracts and investments in private-equity limited partnerships (Level 3).

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

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



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

The company's U.S. and U.K. pension plans comprise 84 percent of the total pension assets. Both the U.S. and U.K. plans have an Investment Committee that regularly meets during the year to review the asset holdings and their returns. To assess the plan's investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income and Cash 20–60 percent, Real Estate 0–15 percent, and Other 0–5 percent. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines, which are reviewed regularly: Equities 60–80 percent and Fixed Income and Cash 20–40 percent. The other significant international pension plans also have established maximum and minimum asset allocation ranges that vary by plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset category risk. There are no significant concentrations of risk in plan assets due to the diversification of investment categories.

The company does not prefund its OPEB obligations.

*Cash Contributions and Benefit Payments* In 2009, the company contributed $1,494 and $245 to its U.S. and international pension plans, respectively. In 2010, the company expects contributions to be approximately $600 and $300 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon plan-investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately $208 in 2010, as compared with $187 paid in 2009.

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

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

*Employee Savings Investment Plan* Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP).

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is described in the section that follows. Total company matching contributions to employee accounts within the ESIP were $257, $231 and $206 in 2009, 2008 and 2007, respectively. This cost was reduced by the value of shares released from the LESOP totaling $184, $40 and $33 in 2009, 2008 and 2007, respectively. The remaining amounts, totaling $73, $191 and $173 in 2009, 2008 and 2007, respectively, represent open market purchases.

*Employee Stock Ownership Plan* Within the Chevron ESIP is an employee stock ownership plan (ESOP). In 1989, Chevron established a LESOP as a constituent part of the ESOP. The LESOP provides partial prefunding of the company's future commitments to the ESIP.

As permitted by accounting standards for share-based compensation (ASC 718), the debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" on the Consolidated Balance Sheet and the Consolidated Statement of Equity.

The company reports compensation expense equal to LESOP debt principal repayments less dividends received and used by the LESOP for debt service. Interest accrued on LESOP debt is recorded as interest expense. Dividends paid on LESOP shares are reflected as a reduction of retained earnings. All LESOP shares are considered outstanding for earnings-per-share computations.

Total credits to expense for the LESOP were $3, $1 and $1 in 2009, 2008 and 2007, respectively. The net credit for the respective years was composed of credits to compensation expense of $15, $15 and $17 and charges to interest expense for LESOP debt of $12, $14 and $16.

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

Shares held in the LESOP are released and allocated to the accounts of plan participants based on debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. LESOP shares as of December 31, 2009 and 2008, were as follows:

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

*Benefit Plan Trusts* Prior to its acquisition by Chevron, Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2009, the trust contained 14.2 million shares of Chevron treasury stock. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The company intends to continue to pay its obligations under the benefit plans. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Prior to its acquisition by Chevron, Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2009 and 2008, trust assets of $57 and $60, respectively, were invested primarily in interest-earning accounts.

*Employee Incentive Plans* Effective January 2008, the company established the Chevron Incentive Plan (CIP), a single annual cash bonus plan for eligible employees that links awards to corporate, unit and individual performance in the prior year. This plan replaced other cash bonus programs, which primarily included the Management Incentive Plan (MIP) and the Chevron Success Sharing program. In 2009 and 2008, charges to expense for cash bonuses were $561 and $757, respectively. In 2007, charges to expense for MIP were $184 and charges for other cash bonus programs were $431. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 20, on page 58.

## Note 22

### Other Contingencies and Commitments

*Income Taxes* The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 15 beginning on page 53 for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

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

*Indemnifications* The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300. Through the end of 2009, the company paid $48 under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. In February 2009, Shell delivered a letter to the company purporting to preserve unmatured claims for certain Equilon indemnities. The letter itself provides no estimate of the ultimate claim amount. Management does not believe this letter or any other information provides a basis to estimate the amount, if any, of a range of loss or potential range of loss with respect to either the Equilon or the Motiva indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

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

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

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

*Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements* The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2010 – $7,500; 2011 – $4,300; 2012 – $1,400; 2013 – $1,400; 2014 – $1,000; 2015 and after – $4,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $8,100 in 2009, $5,100 in 2008 and $3,700 in 2007.

*Environmental* The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude-oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemical companies.

Chevron's environmental reserve as of December 31, 2009, was $1,700. Included in this balance were remediation activities at approximately 250 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation reserve for these sites at year-end 2009 was $185. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2009 environmental reserves balance of $1,515, $820 related to the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), and pipelines. The remaining $695 was associated with various sites in international downstream ($107), upstream ($369), chemicals ($149) and other businesses ($70). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United

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

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

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

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

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

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

## Note 23

### Asset Retirement Obligations

In accordance with accounting standards for asset retirement obligations (ASC 410), the company records the fair value of a liability for an asset retirement obligation (ARO) when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company's control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. The legal obligations associated with the retirement of the tangible long-lived assets require recognition in certain circumstances including: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

Accounting standards for asset retirement obligations primarily affect the company's accounting for crude-oil and natural-gas producing assets. No significant AROs associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets have been recognized, as indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream and chemical long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2009, 2008 and 2007:

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

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

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

## Note 24

### Other Financial Information

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

Other financial information is as follows:

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

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

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

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

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

## Note 25

### Assets Held for Sale

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

## Note 26

### Earnings Per Share

Basic earnings per share (EPS) is based upon Net Income Attributable to Chevron Corporation ("earnings") less preferred stock dividend requirements and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company and the company's share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company's retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (refer to Note 20, "Stock Options and Other Share-Based Compensation," beginning on page 58). The table below sets forth the computation of basic and diluted EPS:

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

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



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## Five-Year Financial Summary

Unaudited

| *Millions of dollars, except per-share amounts* | **2009** | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| **Statement of Income Data** | | | | | |
| **Revenues and Other Income** | | | | | |
| Total sales and other operating revenues[1,2] | **$ 167,402** | $ 264,958 | $ 214,091 | $ 204,892 | $193,641 |
| Income from equity affiliates and other income | **4,234** | 8,047 | 6,813 | 5,226 | 4,559 |
| **Total Revenues and Other Income** | **171,636** | 273,005 | 220,904 | 210,118 | 198,200 |
| **Total Costs and Other Deductions** | **153,108** | 229,948 | 188,630 | 178,072 | 172,907 |
| **Income Before Income Tax Expense** | **18,528** | 43,057 | 32,274 | 32,046 | 25,293 |
| **Income Tax Expense** | **7,965** | 19,026 | 13,479 | 14,838 | 11,098 |
| **Net Income** | **10,563** | 24,031 | 18,795 | 17,208 | 14,195 |
| Less: Net income attributable to noncontrolling interests | **80** | 100 | 107 | 70 | 96 |
| **Net Income Attributable to Chevron Corporation** | **$ 10,483** | $ 23,931 | $ 18,688 | $ 17,138 | $ 14,099 |
| **Per Share of Common Stock** | | | | | |
| **Net Income Attributable to Chevron[2]** | | | | | |
| – Basic | **$ 5.26** | $ 11.74 | $ 8.83 | $ 7.84 | $ 6.58 |
| – Diluted | **$ 5.24** | $ 11.67 | $ 8.77 | $ 7.80 | $ 6.54 |
| **Cash Dividends Per Share** | **$ 2.66** | $ 2.53 | $ 2.26 | $ 2.01 | $ 1.75 |
| **Balance Sheet Data (at December 31)** | | | | | |
| Current assets | **$ 37,216** | $ 36,470 | $ 39,377 | $ 36,304 | $ 34,336 |
| Noncurrent assets | **127,405** | 124,695 | 109,409 | 96,324 | 91,497 |
| **Total Assets** | **164,621** | 161,165 | 148,786 | 132,628 | 125,833 |
| Short-term debt | **384** | 2,818 | 1,162 | 2,159 | 739 |
| Other current liabilities | **25,827** | 29,205 | 32,636 | 26,250 | 24,272 |
| Long-term debt and capital lease obligations | **10,130** | 6,083 | 6,070 | 7,679 | 12,131 |
| Other noncurrent liabilities | **35,719** | 35,942 | 31,626 | 27,396 | 25,815 |
| **Total Liabilities** | **72,060** | 74,048 | 71,494 | 63,484 | 62,957 |
| **Total Chevron Corporation Stockholders' Equity** | **$ 91,914** | $ 86,648 | $ 77,088 | $ 68,935 | $ 62,676 |
| Noncontrolling interests | **647** | 469 | 204 | 209 | 200 |
| **Total Equity** | **$ 92,561** | $ 87,117 | $ 77,292 | $ 69,144 | $ 62,876 |
| [1] Includes excise, value-added and similar taxes: | **$ 8,109** | $ 9,846 | $ 10,121 | $ 9,551 | $ 8,719 |
| [2] Includes amounts in revenues for buy/sell contracts; associated costs are in "Total Costs and Other Deductions." | **$ –** | $ – | $ – | $ 6,725 | $ 23,822 |



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## 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* | **2009** | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| **United States** | | | | | |
| Gross production of crude oil and natural gas liquids[1] | **523** | 459 | 507 | 510 | 499 |
| Net production of crude oil and natural gas liquids[1] | **484** | 421 | 460 | 462 | 455 |
| Gross production of natural gas | **1,611** | 1,740 | 1,983 | 2,115 | 1,860 |
| Net production of natural gas[2] | **1,399** | 1,501 | 1,699 | 1,810 | 1,634 |
| Net oil-equivalent production | **717** | 671 | 743 | 763 | 727 |
| Refinery input | **899** | 891 | 812 | 939 | 845 |
| Sales of refined products[3] | **1,403** | 1,413 | 1,457 | 1,494 | 1,473 |
| Sales of natural gas liquids | **161** | 159 | 160 | 124 | 151 |
| Total sales of petroleum products | **1,564** | 1,572 | 1,617 | 1,618 | 1,624 |
| Sales of natural gas | **5,901** | 7,226 | 7,624 | 7,051 | 5,449 |
| **International** | | | | | |
| Gross production of crude oil and natural gas liquids[1] | **1,857** | 1,751 | 1,751 | 1,739 | 1,676 |
| Net production of crude oil and natural gas liquids[1] | **1,362** | 1,228 | 1,296 | 1,270 | 1,214 |
| Other produced volumes | **26** | 27 | 27 | 109 | 143 |
| Gross production of natural gas | **4,519** | 4,525 | 4,099 | 3,767 | 2,726 |
| Net production of natural gas[2] | **3,590** | 3,624 | 3,320 | 3,146 | 2,599 |
| Net oil-equivalent production | **1,987** | 1,859 | 1,876 | 1,904 | 1,790 |
| Refinery input | **979** | 967 | 1,021 | 1,050 | 1,038 |
| Sales of refined products[3] | **1,851** | 2,016 | 2,027 | 2,127 | 2,252 |
| Sales of natural gas liquids | **111** | 114 | 118 | 102 | 120 |
| Total sales of petroleum products | **1,962** | 2,130 | 2,145 | 2,229 | 2,372 |
| Sales of natural gas | **4,062** | 4,215 | 3,792 | 3,478 | 2,450 |
| **Total Worldwide** | | | | | |
| Gross production of crude oil and natural gas liquids[1] | **2,380** | 2,210 | 2,258 | 2,249 | 2,175 |
| Net production of crude oil and natural gas liquids[1] | **1,846** | 1,649 | 1,756 | 1,732 | 1,669 |
| Other produced volumes | **26** | 27 | 27 | 109 | 143 |
| Gross production of natural gas | **6,130** | 6,265 | 6,082 | 5,882 | 4,586 |
| Net production of natural gas[2] | **4,989** | 5,125 | 5,019 | 4,956 | 4,233 |
| Net oil-equivalent production | **2,704** | 2,530 | 2,619 | 2,667 | 2,517 |
| Refinery input | **1,878** | 1,858 | 1,833 | 1,989 | 1,883 |
| Sales of refined products[3] | **3,254** | 3,429 | 3,484 | 3,621 | 3,725 |
| Sales of natural gas liquids | **272** | 273 | 278 | 226 | 271 |
| Total sales of petroleum products | **3,526** | 3,702 | 3,762 | 3,847 | 3,996 |
| Sales of natural gas | **9,963** | 11,441 | 11,416 | 10,529 | 7,899 |
| Worldwide – Excludes Equity in Affiliates | | | | | |
| Number of wells completed (net)[4] | | | | | |
| Oil and gas | **1,265** | 1,648 | 1,633 | 1,575 | 1,365 |
| Dry | **14** | 12 | 30 | 32 | 26 |
| Productive oil and gas wells (net)[4] | **50,817** | 51,291 | 51,528 | 50,695 | 49,508 |

[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 | **58** | 70 | 65 | 56 | 48 |
| International | **463** | 450 | 433 | 419 | 356 |
| Total | **521** | 520 | 498 | 475 | 404 |

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

| | | | | | |
|---|---|---|---|---|---|
| United States | – | – | – | 26 | 88 |
| International | – | – | – | 24 | 129 |

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



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## Supplemental Information on Oil and Gas Producing Activities

Unaudited

In accordance with FASB and SEC disclosure and reporting requirements for oil and gas producing activities, this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved-reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Angola, Chad, Nigeria, Republic of the Congo and Democratic Republic

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

| | Consolidated Companies | | | | | Affiliated Companies | |
|---|---|---|---|---|---|---|---|
| *Millions of dollars* | U.S. | Africa | Asia | Other | Total | TCO | Other |
| **Year Ended Dec. 31, 2009** | | | | | | | |
| Exploration | | | | | | | |
| Wells | **$ 361** | **$ 140** | **$ 45** | **$ 429** | **$ 975** | **$ –** | **$ –** |
| Geological and geophysical | **62** | **114** | **49** | **103** | **328** | **–** | **–** |
| Rentals and other | **153** | **92** | **60** | **316** | **621** | **–** | **–** |
| Total exploration | **576** | **346** | **154** | **848** | **1,924** | **–** | **–** |
| Property acquisitions[2] | | | | | | | |
| Proved | **3** | **–** | **–** | **–** | **3** | **–** | **–** |
| Unproved | **29** | **–** | **–** | **–** | **29** | **–** | **–** |
| Total property acquisitions | **32** | **–** | **–** | **–** | **32** | **–** | **–** |
| Development[3] | **3,338** | **3,426** | **2,698** | **2,365** | **11,827** | **265** | **69** |
| **Total Costs Incurred[4]** | **$ 3,946** | **$ 3,772** | **$ 2,852** | **$ 3,213** | **$13,783** | **$ 265** | **$ 69** |
| **Year Ended Dec. 31, 2008[5]** | | | | | | | |
| Exploration | | | | | | | |
| Wells | $ 519 | $ 197 | $ 85 | $ 314 | $ 1,115 | $ – | $ – |
| Geological and geophysical | 66 | 90 | 42 | 131 | 329 | – | – |
| Rentals and other | 143 | 60 | 70 | 212 | 485 | – | – |
| Total exploration | 728 | 347 | 197 | 657 | 1,929 | – | – |
| Property acquisitions[2] | | | | | | | |
| Proved | 88 | – | 169 | – | 257 | – | – |
| Unproved | 579 | – | 280 | – | 859 | – | – |
| Total property acquisitions | 667 | – | 449 | – | 1,116 | – | – |
| Development[3] | 4,348 | 3,723 | 4,697 | 2,419 | 15,187 | 643 | 120 |
| **Total Costs Incurred** | $ 5,743 | $ 4,070 | $ 5,343 | $ 3,076 | $18,232 | $ 643 | $ 120 |
| **Year Ended Dec. 31, 2007[5]** | | | | | | | |
| Exploration | | | | | | | |
| Wells | $ 452 | $ 202 | $ 62 | $ 292 | $ 1,008 | $ – | $ 7 |
| Geological and geophysical | 73 | 136 | 24 | 133 | 366 | – | – |
| Rentals and other | 133 | 70 | 101 | 148 | 452 | – | – |
| Total exploration | 658 | 408 | 187 | 573 | 1,826 | – | 7 |
| Property acquisitions[2] | | | | | | | |
| Proved | 243 | 5 | 92 | (2) | 338 | – | – |
| Unproved | 113 | 8 | 35 | 24 | 180 | – | – |
| Total property acquisitions | 356 | 13 | 127 | 22 | 518 | – | – |
| Development[3] | 5,210 | 4,176 | 2,190 | 1,831 | 13,407 | 832 | 64 |
| **Total Costs Incurred** | $ 6,224 | $ 4,597 | $ 2,504 | $ 2,426 | $15,751 | $ 832 | $ 71 |

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 23, "Asset Retirement Obligations," on page 67.
[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired in nonmonetary transactions.
[3] Includes $121, $224 and $99 costs incurred prior to assignment of proved reserves in 2009, 2008 and 2007, respectively. Also includes $104 and $12 in 2009 for consolidated Other and affiliated Other, respectively.
[4] Includes cost incurred for oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries – Oil and Gas* (Topic 932).
[5] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.



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of the Congo. The Asia geographic area includes activities principally in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, Myanmar, the Partitioned Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The Other geographic regions include activities in Argentina, Australia, Brazil, Canada, Colombia, Denmark, the Netherlands, Norway, Trinidad and Tobago, the United Kingdom, Venezuela and other countries. Amounts for TCO represent Chevron's 50 percent equity share of Tengizchevroil, an exploration and production partnership in the Republic of Kazakhstan. The affiliated companies Other amounts are composed of the company's equity interests in Venezuela and Angola. Refer to Note 12, beginning on page 50, 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. | Africa | Asia | Other | Total | TCO | Other |
| **At Dec. 31, 2009** | | | | | | | |
| Unproved properties | **$ 2,320** | **$ 321** | **$ 3,355** | **$ 963** | **$ 6,959** | **$ 113** | **$ –** |
| Proved properties and related producing assets | **51,582** | **20,967** | **29,637** | **17,267** | **119,453** | **6,404** | **1,759** |
| Support equipment | **810** | **1,012** | **1,383** | **648** | **3,853** | **947** | **–** |
| Deferred exploratory wells | **762** | **603** | **209** | **861** | **2,435** | **–** | **–** |
| Other uncompleted projects | **2,384** | **3,960** | **2,936** | **5,572** | **14,852** | **284** | **58** |
| Gross Capitalized Costs | **57,858** | **26,863** | **37,520** | **25,311** | **147,552** | **7,748** | **1,817** |
| Unproved properties valuation | **915** | **163** | **170** | **390** | **1,638** | **32** | **–** |
| Proved producing properties – | | | | | | | |
| Depreciation and depletion | **34,574** | **8,823** | **15,783** | **11,243** | **70,423** | **1,150** | **282** |
| Support equipment depreciation | **424** | **526** | **773** | **357** | **2,080** | **356** | **–** |
| Accumulated provisions | **35,913** | **9,512** | **16,726** | **11,990** | **74,141** | **1,538** | **282** |
| Net Capitalized Costs[1] | **$21,945** | **$17,351** | **$20,794** | **$13,321** | **$73,411** | **$ 6,210** | **$ 1,535** |
| **At Dec. 31, 2008[2,3]** | | | | | | | |
| Unproved properties | $ 2,495 | $ 294 | $ 3,300 | $ 1,051 | $ 7,140 | $ 113 | $ – |
| Proved properties and related producing assets | 46,280 | 17,495 | 27,607 | 15,277 | 106,659 | 5,991 | 837 |
| Support equipment | 717 | 967 | 1,321 | 570 | 3,575 | 888 | – |
| Deferred exploratory wells | 602 | 499 | 198 | 819 | 2,118 | – | – |
| Other uncompleted projects | 4,275 | 4,226 | 2,461 | 2,643 | 13,605 | 501 | 101 |
| Gross Capitalized Costs | 54,369 | 23,481 | 34,887 | 20,360 | 133,097 | 7,493 | 938 |
| Unproved properties valuation | 845 | 202 | 150 | 576 | 1,773 | 29 | – |
| Proved producing properties – | | | | | | | |
| Depreciation and depletion | 30,780 | 6,602 | 13,617 | 9,649 | 60,648 | 831 | 163 |
| Support equipment depreciation | 382 | 523 | 690 | 356 | 1,951 | 307 | – |
| Accumulated provisions | 32,007 | 7,327 | 14,457 | 10,581 | 64,372 | 1,167 | 163 |
| Net Capitalized Costs | $ 22,362 | $ 16,154 | $ 20,430 | $ 9,779 | $ 68,725 | $ 6,326 | $ 775 |

[1] Includes net capitalized cost for oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries – Oil and Gas* (Topic 932).
[2] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.
[3] Amounts for Affiliated Companies – Other conformed to agreements entered in 2007 and 2008 for Venezuelan affiliates.

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

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

[2] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.
[3] Amounts for Affiliated Companies – Other conformed to agreements entered in 2007 and 2008 for Venezuelan affiliates.



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

The company's results of operations from oil and gas producing activities for the years 2009, 2008 and 2007 are shown in the following table. Net income from exploration and production activities as reported on page 48 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 48.

| | Consolidated Companies | | | | | Affiliated Companies | |
|---|---|---|---|---|---|---|---|
| *Millions of dollars* | U.S. | Africa | Asia | Other | Total | TCO | Other |
| **Year Ended Dec. 31, 2009[2]** | | | | | | | |
| Revenues from net production | | | | | | | |
| Sales | **$ 2,278** | **$ 1,767** | **$ 5,648** | **$ 3,173** | **$12,866** | **$ 4,043** | **$ 938** |
| Transfers | **9,133** | **7,304** | **4,926** | **3,866** | **25,229** | **–** | **–** |
| Total | **11,411** | **9,071** | **10,574** | **7,039** | **38,095** | **4,043** | **938** |
| Production expenses excluding taxes | **(3,281)** | **(1,345)** | **(2,208)** | **(1,390)** | **(8,224)** | **(363)** | **(240)** |
| Taxes other than on income | **(367)** | **(132)** | **(53)** | **(284)** | **(836)** | **(50)** | **(96)** |
| Proved producing properties: | | | | | | | |
| Depreciation and depletion | **(3,493)** | **(2,175)** | **(2,279)** | **(1,598)** | **(9,545)** | **(381)** | **(88)** |
| Accretion expense[3] | **(194)** | **(66)** | **(70)** | **(79)** | **(409)** | **(7)** | **(3)** |
| Exploration expenses | **(451)** | **(236)** | **(113)** | **(542)** | **(1,342)** | **–** | **–** |
| Unproved properties valuation | **(228)** | **(11)** | **(44)** | **(28)** | **(311)** | **–** | **–** |
| Other income (expense)[4] | **156** | **98** | **(327)** | **(340)** | **(413)** | **(131)** | **9** |
| Results before income taxes | **3,553** | **5,204** | **5,480** | **2,778** | **17,015** | **3,111** | **520** |
| Income tax expense | **(1,258)** | **(3,214)** | **(2,921)** | **(1,360)** | **(8,753)** | **(935)** | **(258)** |
| **Results of Producing Operations** | **$ 2,295** | **$ 1,990** | **$ 2,559** | **$ 1,418** | **$ 8,262** | **$ 2,176** | **$ 262** |
| **Year Ended Dec. 31, 2008[5]** | | | | | | | |
| Revenues from net production | | | | | | | |
| Sales | $ 4,882 | $ 2,578 | $ 7,969 | $ 4,534 | $19,963 | $ 4,971 | $ 1,599 |
| Transfers | 12,868 | 8,373 | 7,179 | 5,150 | 33,570 | – | – |
| Total | 17,750 | 10,951 | 15,148 | 9,684 | 53,533 | 4,971 | 1,599 |
| Production expenses excluding taxes | (3,822) | (1,228) | (2,096) | (969) | (8,115) | (376) | (125) |
| Taxes other than on income | (716) | (163) | (263) | (370) | (1,512) | (41) | (278) |
| Proved producing properties: | | | | | | | |
| Depreciation and depletion | (2,286) | (1,176) | (2,299) | (1,452) | (7,213) | (237) | (77) |
| Accretion expense[3] | (242) | (60) | (48) | (59) | (409) | (2) | (1) |
| Exploration expenses | (370) | (223) | (178) | (398) | (1,169) | – | – |
| Unproved properties valuation | (114) | (13) | (36) | (8) | (171) | – | – |
| Other income (expense)[4] | 707 | (350) | 198 | 318 | 873 | 184 | 105 |
| Results before income taxes | 10,907 | 7,738 | 10,426 | 6,746 | 35,817 | 4,499 | 1,223 |
| Income tax expense | (3,856) | (6,051) | (5,697) | (3,441) | (19,045) | (1,357) | (612) |
| **Results of Producing Operations** | $ 7,051 | $ 1,687 | $ 4,729 | $ 3,305 | $16,772 | $ 3,142 | $ 611 |

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Includes results of producing operations for oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries – Oil and Gas* (Topic 932).
[3] Represents accretion of ARO liability. Refer to Note 23, "Asset Retirement Obligations," on page 67.
[4] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.
[5] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.



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

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

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.
[3] Includes $10 costs incurred prior to assignment of proved reserves in 2007.
[4] Represents accretion of ARO liability. Refer to Note 23, "Asset Retirement Obligations," on page 67.
[5] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

**Table IV** Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs[1,2]

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

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.
[3] I ncludes oil sands in consolidated Other and heavy oil in affiliated Other as a result of the update to *Extractive Industries – Oil and Gas* (Topic 932).
[4] Geographic presentation conformed to 2009 consistent with the presentation of the oil and gas reserve tables.

**Table V** Reserve Quantity Information

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

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

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

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

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the 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 has more than 30 years experience working in the oil and gas industry and a Master's of Science in Petroleum Engineering. All RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC manages its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

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

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

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

**Summary of Net Oil and Gas Reserves**

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

[1] Based on 12-month average price.
[2] Based on year-end prices.

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

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

*Effect of New Rules* The most significant effect of the company's adopting the new guidance was the inclusion of Canadian oil sands as synthetic oil in the consolidated companies reserves. As indicated in Table V, on page 79, an additional 460 million BOE were included at year-end 2009. The synthetic oil reported for affiliated companies represents volumes reclassified from heavy crude oil to synthetic oil, and does not represent additional reserves. It was impracticable to estimate the remaining impact of the new rules because of the cost and resources required to prepare detailed field-level calculations. However, the use of the 12-month average price had an upward effect on reserves related to production-sharing and variable-royalty contracts as the 12-month average price for crude oil and

**Table V** Reserve Quantity Information – Continued

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

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

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

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

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

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

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

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

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

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

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

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

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

*Proved Reserve Quantities* At December 31, 2009, oil-equivalent reserves for the company's consolidated operations were 8.3 billion barrels. (Refer to the term "Reserves" on page 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, oil-equivalent reserves were 3.0 billion barrels, 80 percent of which were associated with the company's 50 percent ownership in TCO.

Aside from the Tengiz Field in the TCO affiliate, no single property accounted for more than 5 percent of the company's total oil-equivalent proved reserves. About 25 other individual properties in the company's portfolio of assets each contained between 1 percent and 5 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for approximately 48 percent of the company's total proved reserves. These properties were geographically dispersed, located in the United States, Canada, South America, West Africa, the Middle East, Southeast Asia, and Australia.

In the United States, total oil-equivalent reserves at year-end 2009 were 1.8 billion barrels. California properties accounted for approximately 44 percent of the U.S. reserves, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company's heavy-oil fields in California employ a continuous steamflooding process. The Gulf of Mexico region contains about 22 percent of the U.S. reserves, with liquids representing about 15 percent of reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Other U.S. areas represent the remaining 34 percent of U.S. reserves, which are about evenly split between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and $CO_2$ injection.

For the three years ending December 31, 2009, the pattern of net reserve changes shown in the following tables are not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties and civil unrest.

The company's estimated net proved oil and natural gas reserves and changes thereto for the years 2007, 2008 and 2009 are shown in the following table and on page 81.

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

| | Consolidated Companies | | | | | | Affiliated Companies | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| *Millions of barrels* | U.S. | Africa | Asia | Synthetic Oil[1,2] | Other | Total | TCO | Synthetic Oil[1,3] | Other | Consolidated and Affiliated Companies |
| **Reserves at Jan. 1, 2007** | 1,751 | 1,698 | 1,259 | | 586 | 5,294 | 1,950 | | 562 | 7,806 |
| Changes attributable to: | | | | | | | | | | |
| Revisions | (5) | (89) | (54) | | 2 | (146) | 92 | | 11 | (43) |
| Improved recovery | 9 | 7 | 4 | | – | 20 | – | | – | 20 |
| Extensions and discoveries | 36 | 6 | – | | 18 | 60 | – | | – | 60 |
| Purchases[5] | 10 | – | – | | – | 10 | – | | 316 | 326 |
| Sales[6] | (9) | – | – | | – | (9) | – | | (432) | (441) |
| Production | (168) | (122) | (186) | | (88) | (564) | (53) | | (24) | (641) |
| **Reserves at Dec. 31, 2007**[4] | 1,624 | 1,500 | 1,023 | | 518 | 4,665 | 1,989 | | 433 | 7,087 |
| Changes attributable to: | | | | | | | | | | |
| Revisions | (16) | 2 | 574 | | (24) | 536 | 249 | | 18 | 803 |
| Improved recovery | 5 | 1 | 18 | | 3 | 27 | – | | 10 | 37 |
| Extensions and discoveries | 17 | 3 | 5 | | 8 | 33 | – | | – | 33 |
| Purchases | 1 | – | – | | – | 1 | – | | – | 1 |
| Sales[6] | (7) | – | – | | – | (7) | – | | – | (7) |
| Production | (154) | (121) | (164) | | (81) | (520) | (62) | | (22) | (604) |
| **Reserves at Dec. 31, 2008**[4] | 1,470 | 1,385 | 1,456 | – | 424 | 4,735 | 2,176 | – | 439 | 7,350 |
| Changes attributable to: | | | | | | | | | | |
| Revisions | 63 | (46) | (121) | 460 | (1) | 355 | (184) | 266 | (269) | 168 |
| Improved recovery | 2 | 48 | – | – | – | 50 | 36 | – | – | 86 |
| Extensions and discoveries | 6 | 10 | 3 | – | 33 | 52 | – | – | – | 52 |
| Purchases | – | – | – | – | – | – | – | – | – | – |
| Sales[6] | (3) | – | – | – | (6) | (9) | – | – | – | (9) |
| Production | (177) | (151) | (167) | – | (78) | (573) | (82) | – | (19) | (674) |
| **Reserves at Dec. 31, 2009**[4] | **1,361** | **1,246** | **1,171** | **460** | **372** | **4,610** | **1,946** | **266** | **151** | **6,973** |

[1] Prospective reporting effective December 31, 2009.
[2] Reserves associated with Canada.
[3] Reserves associated with Venezuela that were reported in other as heavy oil in 2008 and 2007.
[4] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 8 for the definition of a PSC). PSC-related reserve quantities are 26 percent, 32 percent and 26 percent for consolidated companies for 2009, 2008 and 2007, respectively.
[5] Includes reserves acquired through nonmonetary transactions.
[6] Includes reserves disposed of through nonmonetary transactions.

**Table V** Reserve Quantity Information – Continued

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

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

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

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

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

*Improved Recovery* In 2007, improved recovery increased liquids volumes by 20 million barrels worldwide. No addition was individually significant.

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

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

*Extensions and Discoveries* In 2007, extensions and discoveries increased liquids volumes by 60 million barrels worldwide. The largest additions were 36 million barrels in the United States, mainly for the deepwater Tahiti and Mad Dog fields in the Gulf of Mexico.

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

In 2009, extensions and discoveries increased liquids volumes by 52 million barrels worldwide. The largest additions were 33 million barrels in Other regions related to the Gorgon Project in Australia and delineation drilling in Argentina. Africa and the United States accounted for 10 million barrels and 6 million barrels, respectively.

*Purchases* In 2007, acquisitions of 316 million barrels for equity affiliates related to the formation of a new Hamaca equity affiliate in Venezuela.

*Sales* In 2007, affiliated company sales of 432 million barrels related to the dissolution of a Hamaca equity affiliate in Venezuela.

**Table V** Reserve Quantity Information – Continued

Net Proved Reserves of Natural Gas

| *Billions of cubic feet* | Consolidated Companies U.S. | Africa | Asia | Other | Total | Affiliated Companies TCO | Other | Total Consolidated and Affiliated Companies |
|---|---|---|---|---|---|---|---|---|
| **Reserves at Jan 1, 2007** | 4,028 | 3,206 | 7,102 | 5,574 | 19,910 | 2,743 | 231 | 22,884 |
| Changes attributable to: | | | | | | | | |
| Revisions | 209 | (141) | 346 | (19) | 395 | 75 | (2) | 468 |
| Improved recovery | – | – | – | 1 | 1 | – | – | 1 |
| Extensions and discoveries | 86 | 11 | 358 | 63 | 518 | – | – | 518 |
| Purchases[1] | 50 | – | 91 | – | 141 | – | 211 | 352 |
| Sales[3] | (76) | – | – | – | (76) | – | (175) | (251) |
| Production | (620) | (27) | (690) | (415) | (1,752) | (70) | (10) | (1,832) |
| **Reserves at Dec. 31, 2007[2]** | 3,677 | 3,049 | 7,207 | 5,204 | 19,137 | 2,748 | 255 | 22,140 |
| Changes attributable to: | | | | | | | | |
| Revisions | (28) | 60 | 1,073 | 61 | 1,166 | 498 | 632 | 2,296 |
| Improved recovery | – | – | – | – | – | – | – | – |
| Extensions and discoveries | 108 | – | 23 | 1 | 132 | – | – | 132 |
| Purchases | 66 | – | 441 | – | 507 | – | – | 507 |
| Sales[3] | (124) | – | – | – | (124) | – | – | (124) |
| Production | (549) | (53) | (748) | (446) | (1,796) | (71) | (9) | (1,876) |
| **Reserves at Dec. 31, 2008[2]** | 3,150 | 3,056 | 7,996 | 4,820 | 19,022 | 3,175 | 878 | 23,075 |
| Changes attributable to: | | | | | | | | |
| Revisions | 39 | 4 | 493 | 33 | 569 | (237) | 193 | 525 |
| Improved recovery | – | – | – | – | – | – | – | – |
| Extensions and discoveries | 53 | 3 | 54 | 4,277 | 4,387 | – | – | 4,387 |
| Purchases | – | – | – | – | – | – | – | – |
| Sales | (33) | – | – | (84) | (117) | – | – | (117) |
| Production | (511) | (42) | (683) | (472) | (1,708) | (105) | (8) | (1,821) |
| **Reserves at Dec. 31, 2009[2,4]** | **2,698** | **3,021** | **7,860** | **8,574** | **22,153** | **2,833** | **1,063** | **26,049** |

[1] Includes reserves acquired through nonmonetary transactions.
[2] Includes year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 8 for the definition of a PSC). PSC-related reserve quantities are 31 percent, 40 percent and 37 percent for consolidated companies for 2009, 2008 and 2007, respectively.
[3] Includes reserves disposed of through nonmonetary transactions.

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

*Revisions* In 2007, net revisions increased reserves for consolidated companies by 395 BCF and increased reserves for affiliated companies by 73 BCF. For consolidated companies, net increases of 346 BCF in Asia and 209 BCF in the United States were partially offset by downward revisions of 160 BCF in Africa and Other regions. In the Asia region, drilling activities in Thailand added 360 BCF, which were partially offset by downward revisions in Azerbaijan and Kazakhstan due to the impact of higher prices. In the United States, improved reservoir performance for many fields contributed to the increase with the largest portion in the mid-continent areas. Decreases in Africa were primarily due to a 136 BCF downward revision in Nigeria resulting from field performance. The Other regions had net downward revisions of 19 BCF. A 185 BCF downward revision in Australia due to drilling results and other smaller declines were mostly offset by improved reservoir performance in Trinidad and Tobago which added 188 BCF.

TCO had an upward revision of 75 BCF associated with improved reservoir performance and development activities. This upward revision was net of a negative impact due to higher year-end prices on royalty determination.

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

For the TCO affiliate in Kazakhstan, an increase of 498 BCF reflected the impacts of lower year-end prices on royalty determination and facility optimization. Reserves associated



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with the Angola LNG project accounted for a majority of the 632 BCF increase in Other affiliated companies.

In 2009, net revisions increased reserves by 569 BCF for consolidated companies and decreased reserves by 44 BCF for affiliated companies. For consolidated companies, net increases were 493 BCF in Asia primarily as a result of reservoir studies in Bangladesh and development drilling in Thailand. These results were partially offset by a downward revision due to the impact of higher prices on production-sharing contracts in Myanmar. The United States and Other regions increased reserves 39 BCF and 33 BCF, respectively. In the United States, development drilling in the Gulf of Mexico was partially offset by performance revisions in the California and mid-continent areas. In Other regions, improved reservoir performance and compression in Australia was partially offset by the effect of higher prices on production-sharing contracts in Trinidad.

For equity affiliates, a downward revision of 237 BCF at TCO was due to the effect of higher prices on royalty determination and an increase in gas injection for SGI/SGP facilities. This decline was partially offset by performance and drilling opportunities related to the Angola LNG project.

*Extensions and Discoveries* In 2007, extensions and discoveries accounted for an increase of 518 BCF worldwide. The largest addition was 330 BCF in Bangladesh, the result of drilling activities. Other additions were not individually significant.

In 2009, worldwide extensions and discoveries of 4,387 BCF were attributed to consolidated companies. The Gorgon Project in Australia accounted for essentially all of the 4,277 BCF additions in the Other regions. In Asia, development drilling in Thailand accounted for the majority of the increase. In the United States, delineation drilling in California accounted for the majority of the increase.

*Purchases* In 2007, purchases of natural gas reserves were 141 BCF for consolidated companies, which include the acquisition of an additional interest in the Bibiyana Field in Bangladesh. Affiliated company purchases of 211 BCF related to the formation of a new Hamaca equity affiliate in Venezuela and an initial booking related to the Angola LNG project.

*Sales* In 2007, sales were 76 BCF and 175 BCF for consolidated companies and equity affiliates, respectively. The affiliated company sales related to the dissolution of a Hamaca equity affiliate in Venezuela.

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

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

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

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed by the FASB requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves. In the following table, "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

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

| | Consolidated Companies | | | | | Affiliated Companies | | Total Consolidated and Affiliated |
|---|---|---|---|---|---|---|---|---|
| *Millions of dollars* | U.S. | Africa | Asia | Other | Total | TCO | Other | Companies |
| **At December 31, 2009** | | | | | | | | |
| Future cash inflows from production[1] | **$ 81,332** | **$ 75,338** | **$ 91,993** | **$ 101,114** | **$ 349,777** | **$ 97,793** | **$ 23,825** | **$ 471,395** |
| Future production costs | **(35,295)** | **(22,459)** | **(31,843)** | **(42,206)** | **(131,803)** | **(6,923)** | **(4,765)** | **(143,491)** |
| Future development costs | **(7,027)** | **(14,715)** | **(12,884)** | **(16,643)** | **(51,269)** | **(8,190)** | **(3,986)** | **(63,445)** |
| Future income taxes | **(13,662)** | **(22,503)** | **(18,905)** | **(17,427)** | **(72,497)** | **(23,357)** | **(7,774)** | **(103,628)** |
| Undiscounted future net cash flows | **25,348** | **15,661** | **28,361** | **24,838** | **94,208** | **59,323** | **7,300** | **160,831** |
| 10 percent midyear annual discount for timing of estimated cash flows | **(8,822)** | **(5,882)** | **(11,722)** | **(17,506)** | **(43,932)** | **(34,937)** | **(4,450)** | **(83,319)** |
| **Standardized Measure Net Cash Flows** | **$ 16,526** | **$ 9,779** | **$ 16,639** | **$ 7,332** | **$ 50,276** | **$ 24,386** | **$ 2,850** | **$ 77,512** |
| **At December 31, 2008** | | | | | | | | |
| Future cash inflows from production[2] | $ 66,174 | $ 52,344 | $ 75,855 | $ 37,408 | $ 231,781 | $ 51,252 | $ 13,968 | $ 297,001 |
| Future production costs | (45,738) | (20,302) | (33,817) | (15,363) | (115,220) | (14,502) | (2,319) | (132,041) |
| Future development costs | (6,099) | (19,001) | (15,298) | (3,408) | (43,806) | (10,140) | (1,551) | (55,497) |
| Future income taxes | (5,091) | (9,581) | (10,278) | (7,593) | (32,543) | (7,517) | (5,223) | (45,283) |
| Undiscounted future net cash flows | 9,246 | 3,460 | 16,462 | 11,044 | 40,212 | 19,093 | 4,875 | 64,180 |
| 10 percent midyear annual discount for timing of estimated cash flows | (2,318) | (1,139) | (7,042) | (4,052) | (14,551) | (11,261) | (2,966) | (28,778) |
| **Standardized Measure Net Cash Flows** | $ 6,928 | $ 2,321 | $ 9,420 | $ 6,992 | $ 25,661 | $ 7,832 | $ 1,909 | $ 35,402 |
| **At December 31, 2007** | | | | | | | | |
| Future cash inflows from production[2] | $162,138 | $132,450 | $110,749 | $ 62,883 | $ 468,220 | $ 159,078 | $ 29,845 | $ 657,143 |
| Future production costs | (41,861) | (15,707) | (29,150) | (17,132) | (103,850) | (10,408) | (1,529) | (115,787) |
| Future development costs | (8,080) | (11,516) | (10,989) | (4,754) | (35,339) | (8,580) | (1,175) | (45,094) |
| Future income taxes | (39,840) | (74,172) | (29,367) | (18,791) | (162,170) | (39,575) | (13,600) | (215,345) |
| Undiscounted future net cash flows | 72,357 | 31,055 | 41,243 | 22,206 | 166,861 | 100,515 | 13,541 | 280,917 |
| 10 percent midyear annual discount for timing of estimated cash flows | (31,133) | (14,171) | (16,091) | (8,417) | (69,812) | (64,519) | (7,779) | (142,110) |
| **Standardized Measure Net Cash Flows** | $ 41,224 | $ 16,884 | $ 25,152 | $ 13,789 | $ 97,049 | $ 35,996 | $ 5,762 | $ 138,807 |

[1] Based on 12-month average price.
[2] Based on year-end prices.



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**Table VII** Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves

The changes in present values between years, which can be significant, reflect changes in estimated proved-reserve quantities and prices and assumptions used in forecasting production volumes and costs. Changes in the timing of production are included with "Revisions of previous quantity estimates."

| *Millions of dollars* | Consolidated Companies | Affiliated Companies | Total Consolidated and Affiliated Companies |
|---|---|---|---|
| **Present Value at January 1, 2007** | $ 65,820 | $ 26,535 | $ 92,355 |
| Sales and transfers of oil and gas produced net of production costs | (34,957) | (4,084) | (39,041) |
| Development costs incurred | 10,468 | 889 | 11,357 |
| Purchases of reserves | 780 | 7,711 | 8,491 |
| Sales of reserves | (425) | (7,767) | (8,192) |
| Extensions, discoveries and improved recovery less related costs | 3,664 | – | 3,664 |
| Revisions of previous quantity estimates | (7,801) | (1,333) | (9,134) |
| Net changes in prices, development and production costs | 74,900 | 23,616 | 98,516 |
| Accretion of discount | 12,196 | 3,745 | 15,941 |
| Net change in income tax | (27,596) | (7,554) | (35,150) |
| Net change for the year | 31,229 | 15,223 | 46,452 |
| **Present Value at December 31, 2007** | $ 97,049 | $ 41,758 | $ 138,807 |
| Sales and transfers of oil and gas produced net of production costs | (43,906) | (5,750) | (49,656) |
| Development costs incurred | 13,682 | 763 | 14,445 |
| Purchases of reserves | 233 | – | 233 |
| Sales of reserves | (542) | – | (542) |
| Extensions, discoveries and improved recovery less related costs | 646 | 83 | 729 |
| Revisions of previous quantity estimates | 37,853 | 3,718 | 41,571 |
| Net changes in prices, development and production costs | (169,046) | (51,696) | (220,742) |
| Accretion of discount | 17,458 | 5,976 | 23,434 |
| Net change in income tax | 72,234 | 14,889 | 87,123 |
| Net change for 2008 | (71,388) | (32,017) | (103,405) |
| **Present Value at December 31, 2008** | $ 25,661 | $ 9,741 | $ 35,402 |
| Sales and transfers of oil and gas produced net of production costs | **(27,559)** | **(4,209)** | **(31,768)** |
| Development costs incurred | **10,791** | **335** | **11,126** |
| Purchases of reserves | **–** | **–** | **–** |
| Sales of reserves | **(285)** | **–** | **(285)** |
| Extensions, discoveries and improved recovery less related costs | **3,438** | **697** | **4,135** |
| Revisions of previous quantity estimates | **3,230** | **(4,343)** | **(1,113)** |
| Net changes in prices, development and production costs | **51,528** | **30,915** | **82,443** |
| Accretion of discount | **4,282** | **1,412** | **5,694** |
| Net change in income tax | **(20,810)** | **(7,312)** | **(28,122)** |
| Net change for 2009 | **24,615** | **17,495** | **42,110** |
| **Present Value at December 31, 2009** | **$ 50,276** | **$ 27,236** | **$ 77,512** |

# 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. |

# Board of Directors

**John S. Watson, 53**
**Chairman of the Board and Chief Executive Officer** since January 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 a Director and a Member of the Executive Committee of the American Petroleum Institute. Joined Chevron in 1980.

**George L. Kirkland, 59**
**Vice Chairman of the Board** since January 2010 and **Executive Vice President, Global 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.

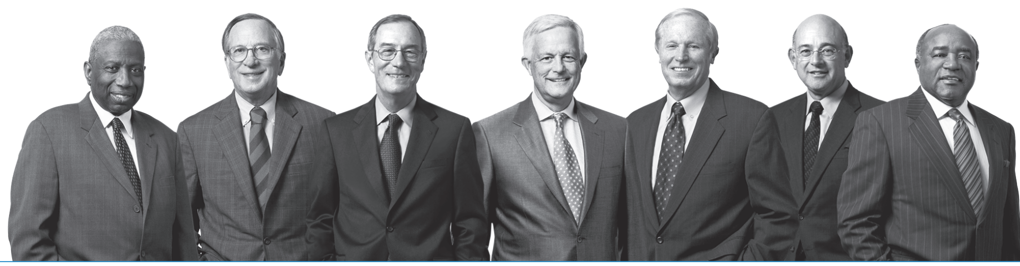
**Samuel H. Armacost, 71**
**Lead Director** since 2006 and a Director since 1982. He is Chairman of the Board of SRI International, an independent research, technology development and commercialization organization. Previously he was a Managing Director of Weiss, Peck & Greer LLC. He also is a Director of Del Monte Foods Company; Callaway Golf Company; Franklin Resources, Inc.; and Exponent, Inc. (2, 3)

**Linnet F. Deily, 64**
**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. (1)

**Robert E. Denham, 64**
**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. (1)

**Robert J. Eaton, 70**
**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)

**Enrique Hernandez Jr., 54**
**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)



**Franklyn G. Jenifer, 71**
**Director** since 1993. He is President Emeritus of The University of Texas at Dallas. Previously he was President of Howard University and Chancellor of the Massachusetts Board of Regents of Higher Education. (2, 3)

**Sam Nunn, 71**
**Director** since 1997. He is Co-Chairman and Chief Executive Officer of the Nuclear Threat Initiative, a charitable organization. He also is Distinguished Professor at the Sam Nunn School of International Affairs, Georgia Institute of Technology. He served as a U.S. Senator from Georgia for 24 years. He is a Director of The Coca-Cola Company, Dell Inc. and the General Electric Company. (2, 3)

**Donald B. Rice, 70**
**Director** since 2005. Former Chairman of the Board and current President and Chief Executive Officer of Agensys, Inc., an operating subsidiary of Astellas Pharma Inc. Previously he was President and Chief Operating Officer of Teledyne, Inc. He is a Director of Vulcan Materials Company and Wells Fargo & Company. (3, 4)

**Kevin W. Sharer, 62**
**Director** since 2007. He is Chairman of the Board, Chief Executive Officer and President of Amgen, Inc., a biotechnology 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, 70**
**Director** since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods, a manufacturer of food products. (1)

**Ronald D. Sugar, 61**
**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. (2, 4)

**Carl Ware, 66**
**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 Coca-Cola Bottling Co. Consolidated and 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 Director**

**David J. O'Reilly, 63,** elected to retire December 31, 2009, after a 41-year career with Chevron. He had been Chairman of the Board and Chief Executive Officer since 2000 and a Director and Vice Chairman since 1998. O'Reilly graduated from University College – Dublin, Ireland, with a degree in chemical engineering, and also received an honorary doctor of science degree from University College in 2002. He joined the corporation in 1968 and was elected a Vice President in 1991. He was responsible for implementing the mergers with Texaco Inc. in 2001 and Unocal Corporation in 2005.

# Corporate Officers

**Lydia I. Beebe,** 57
**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,** 58
**Executive Vice President, Technology and Services,** since 2003. Responsible also for the Project Resource Company; procurement; health, environment and safety; business and real estate services; and mining operations. Previously the company's Vice President, Human Resources, and Texaco Corporate Vice President and President, Production Operations. Joined the company in 1974.

**Pierre R. Breber,** 45
**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,** 52
**Vice President and Comptroller** since April 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,** 58
**Corporate Vice President and President, Chevron Global Gas,** since 2003. Responsible for the company's natural gas business, shipping company, power and pipeline operations. Director of Sasol Chevron. Previously Managing Director, Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined the company in 1974.

**Charles A. James,** 55*
**Executive Vice President** since 2009. Previously Chevron Vice President and General Counsel; Assistant Attorney General, Antitrust Division, U.S. Department of Justice; and Chair, Antitrust and Trade Regulation Practice – Jones, Day, Reavis & Pogue, Washington, D.C. Joined Chevron in 2002.
*Retiring effective May 2010.

**Joe W. Laymon,** 57
**Vice President, Human Resources,** since 2008. Responsible for the company's global human resources and medical services function. Previously Group Vice President, Corporate Human Resources and Labor Affairs, Ford Motor Company. Joined the company in 2008.

**John W. McDonald,** 58
**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,** 47
**Vice President and General Counsel** since August 2009. Responsible for 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,** 52
**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.

**Thomas R. Schuttish,** 62
**General Tax Counsel** since 2002. Responsible for guiding and directing corporatewide tax activities and managing Chevron's Tax department. Previously the company's Assistant General Tax Counsel. Joined Chevron in 1980.

**Paul K. Siegele,** 51
**Vice President, Strategic Planning,** since 2008. Responsible for advising senior management in setting the company's strategic direction, allocating capital and other resources, and determining operating unit performance measures and targets. Previously Vice President, Deepwater Exploration and Projects, Chevron North America Exploration and Production Company. Joined the company in 1980.

**Charles A. Taylor,** 52
**Vice President, Health, Environment and Safety (HES),** since 2007. Responsible for HES strategic planning and issues management, compliance assurance, and emergency response. Previously General Manager, Chevron Nigeria Limited/Nigerian National Petroleum Company joint venture. Joined the company in 1980.

**Michael K. Wirth,** 49
**Executive Vice President, Global Downstream,** since 2006. Responsible for worldwide manufacturing, marketing, lubricants, supply and trading, 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,** 54
**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,** 52
**Vice President, Policy, Government and Public Affairs,** since 2007. Oversees U.S. and international government relations, all aspects of communications, and the company's worldwide efforts to protect and enhance its reputation. Previously Corporate Vice President, Health, Environment and Safety; Managing Director, Chevron Australia Pty Ltd; and Adviser to the Chairman of the Board, Chevron Corporation. Joined Chevron in 1980.

**Executive Committee**
John S. Watson, George L. Kirkland, John E. Bethancourt, Charles A. James, R. Hewitt Pate, Michael K. Wirth and Patricia E. Yarrington. Lydia I. Beebe, Secretary.



010378

## 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

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.*)

### Annual Meeting
The Annual Meeting of stockholders will be held at 8:00 a.m., Wednesday, May 26, 2010, at:
Chevron Corporation
1500 Louisiana Street
Houston, TX 77002-7308

### 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 Web site, 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 Web site, 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 Web site, Chevron.com, or a copy may be requested by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2177
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2009 are available on the company's Web site, Chevron.com, or by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2114
San Ramon, CA 94583-2324

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

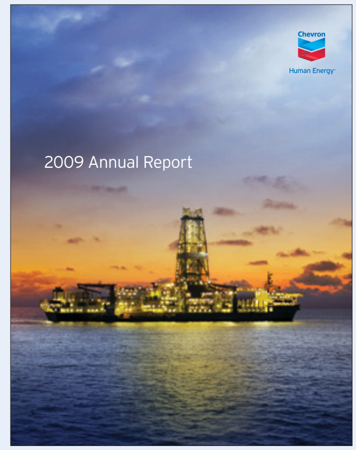
For additional information about the company and the energy industry, visit Chevron's Web site, Chevron.com. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

## 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



*2009 Annual Report*

*2009 Supplement to the Annual Report*

*2009 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.

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