



Human Energy™

Energy Ingenuity

2007 Annual Report

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Energy

Demand for energy is growing.

The world is undergoing an economic expansion that is raising the standard of living for millions of people around the globe. Energy is the foundation for this expansion. Access to reliable and abundant energy is essential for human and economic progress. As the world's population continues to grow, so does our need for greater supplies of energy. How we deliver that energy – in ways that sustain and protect our environment – is one of the great challenges of our time.

▶ Ingenuity

Human energy is rising to the challenge.

Chevron is built on the idea that with commitment and ingenuity there is no problem that cannot be solved, no challenge that cannot be overcome. This is how the people of Chevron approach their jobs every day. The world needs energy to power businesses, heat homes, light schools, transport people, deliver products, create jobs and improve the overall quality of life. Energy moves the world forward. Human energy makes it possible.



2007 was a year of significant achievement for our company. We reported record earnings, led our peer group in total stockholder return and advanced our robust queue of major capital projects, which are creating a strong foundation for long-term growth. Most important, the people of Chevron performed superbly, demonstrating the values and ingenuity that distinguish our company.

Net income of \$18.7 billion represented a fourth consecutive year of record earnings. Capital and exploratory expenditures for the year were \$20 billion, and return on capital employed was 23.1 percent. We increased the annual dividend for the 20th consecutive year and achieved a total stockholder return of 30.5 percent, approximately 25 percentage points higher than the return delivered by the S&P 500. We continued to return cash to our stockholders through stock buyback programs, purchasing \$7 billion of our common shares during 2007. In September, we initiated a new program to acquire up to \$15 billion of our common shares over a period of up to three years. We are committed to the capital discipline necessary to create sustainable, long-term value for our stockholders.

Achieving Milestones

In the upstream, we executed our strategy of managing our base business profitably while advancing new projects for future growth and returns. Our base business, which is our daily crude oil and natural gas production activities around the world, generates the cash to fund our long-term growth. We manage these assets with a strong focus on world-class reservoir management, improved recovery rates and continual innovation. Nowhere is this more evident than in California's San Joaquin Valley, where the Kern River Field celebrated its 2 billionth barrel of production in late 2007. Kern River began production in 1899 and through the consistent application of innovative technology continues to be a world-class asset.

Our exploration program, which is centered on high-impact prospects in key basins, had a highly successful year. We posted a 41 percent success rate, adding approximately 1 billion barrels of potentially recoverable oil and natural gas resources.

Major capital projects in the upstream reached several milestones. The Agbami floating production, storage and offloading vessel was completed and was positioned in the deep water off Nigeria in early 2008. In 2007, the Bibiyana gas field in Bangladesh began production, and we launched commercial production from the 110-megawatt Darajat III geothermal plant in Indonesia.

Chevron's track record as a successful partner helped us achieve a 10-year extension for producing natural gas in the Gulf of Thailand, which will help realize our goal of increasing production from this area to more than 1 billion cubic feet per day. Our expertise in producing sour gas at the Tengizchevroil project in Kazakhstan was a key factor in our selection as a partner by the China National Petroleum Corporation for the development of the Chuandongbei natural gas area in central China.

Our global downstream operations continue to focus on increasing refinery flexibility, improving reliability and creating new business opportunities. We completed projects to increase the flexibility and capacity of two major refineries – in El Segundo, California, and at our 50 percent-owned Yeosu refinery complex in South Korea. The downstream business also enhanced its focus on profitable growth through the divestiture of several nonstrategic assets.

Our 2007 safety performance showed significant improvement, but we will never be satisfied until we have reduced the number of safety-related incidents to zero. We are absolutely committed to achieving this goal.

Enhancing Technology and Capability

In the current business environment, companies with superior ability to source and deploy technology will build a sustainable competitive advantage.

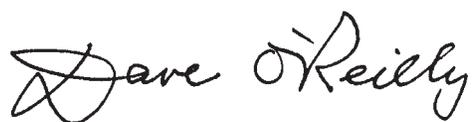
Our technology strategies are centered on delivering superior performance in our core businesses and establishing leading positions in emerging and transformational technologies. To that end, we opened two new Global Technology Centers – in Aberdeen, Scotland, and Perth, Australia – to expand our research and development capability. In addition, we created a number of strategic alliances with universities to conduct advanced research into new energy sources and processes.

To build upon our organizational capability, in 2007 we restructured the upstream business into four operating companies – North America; Asia-Pacific; Africa and Latin America; and Eurasia, Europe and Middle East. This new structure will strengthen our focus on long-term growth, enhance business partnerships, and drive more efficiency, standardization and collaboration across the organization.

Human Energy and Ingenuity

In 2007, we launched a new global advertising campaign, “The Power of Human Energy.” It focuses on the realities of energy today – the challenge of meeting rising demand as the global economy expands, together with the imperative to manage the impact of energy consumption on the environment. These are huge challenges. But as the campaign makes clear, human ingenuity will discover solutions as it has throughout history. The people of Chevron are working every day to apply the kind of ingenuity that will create responsible, practical and sustainable solutions to these challenges.

Thank you for investing in our company. We look forward to another year of achievement as we continue to create value for our stockholders while working to meet the world’s growing demand for safe, reliable energy.



Dave O'Reilly
Chairman of the Board and
Chief Executive Officer
February 28, 2008

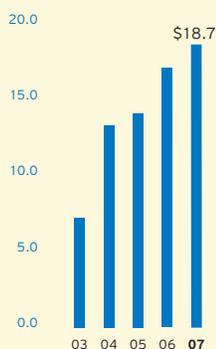


Chevron Financial Highlights

Millions of dollars, except per-share amounts	2007	2006	% Change
Net income	\$ 18,688	\$ 17,138	9.0 %
Sales and other operating revenues	\$ 214,091	\$ 204,892	4.5 %
Minority interests income	\$ 107	\$ 70	52.9 %
Interest expense (after tax)	\$ 107	\$ 312	(65.7)%
Capital and exploratory expenditures*	\$ 20,026	\$ 16,611	20.6 %
Total assets at year-end	\$ 148,786	\$ 132,628	12.2 %
Total debt at year-end	\$ 7,232	\$ 9,838	(26.5)%
Minority interests	\$ 204	\$ 209	(2.4)%
Stockholders' equity at year-end	\$ 77,088	\$ 68,935	11.8 %
Cash provided by operating activities	\$ 24,977	\$ 24,323	2.7 %
Common shares outstanding at year-end (Thousands)	2,076,266	2,150,390	(3.4)%
Per-share data			
Net income - diluted	\$ 8.77	\$ 7.80	12.4 %
Cash dividends	\$ 2.26	\$ 2.01	12.4 %
Stockholders' equity	\$ 37.13	\$ 32.06	15.81 %
Common stock price at year-end	\$ 93.33	\$ 73.53	26.93 %
Total debt to total debt-plus-equity ratio	8.6%	12.5%	
Return on average stockholders' equity	25.6%	26.0%	
Return on capital employed (ROCE)	23.1%	22.6%	

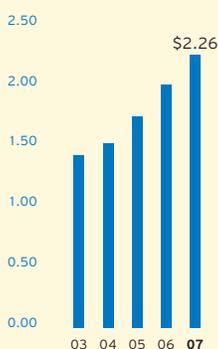
*Includes equity in affiliates

Net Income
Billions of dollars



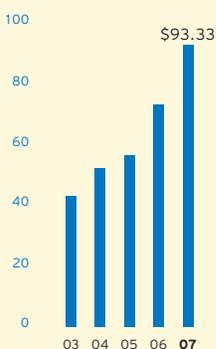
Net income rose in 2007 on improved upstream results and gains on asset sales. Higher crude oil prices squeezed margins and lowered profits in the downstream and chemicals businesses.

Annual Cash Dividends
Dollars per share



The company increased its annual dividend payout for the 20th consecutive year.

Chevron Year-End Common Stock Price*
Dollars per share



The company's stock price rose 27 percent in 2007, outpacing the broader market indexes.

*2003 adjusted for stock split in 2004

Return on Capital Employed
Percent



Record net income helped boost Chevron's return on capital employed to 23.1 percent. The decline from 2004 to 2005 reflected a higher capital base resulting from the Unocal acquisition.

Chevron Operating Highlights¹

	2007	2006	% Change
Net production of crude oil and natural gas liquids (Thousands of barrels per day)	1,756	1,732	1.4 %
Net production of natural gas (Millions of cubic feet per day)	5,019	4,956	1.3 %
Other produced volumes (Thousands of barrels per day)	27	109	(75.2)%
Net oil-equivalent production ² (Thousands of oil-equivalent barrels per day)	2,619	2,667	(1.8)%
Refinery input (Thousands of barrels per day)	1,833	1,989	(7.8)%
Sales of refined products (Thousands of barrels per day)	3,484	3,621	(3.8)%
Net proved reserves of crude oil, condensate and natural gas liquids ³ (Millions of barrels)			
– Consolidated companies	4,665	5,294	(11.9)%
– Affiliated companies	2,422	2,512	(3.6)%
Net proved reserves of natural gas ³ (Billions of cubic feet)			
– Consolidated companies	19,137	19,910	(3.9)%
– Affiliated companies	3,003	2,974	1.0 %
Net proved oil-equivalent reserves ³ (Millions of barrels)			
– Consolidated companies	7,855	8,612	(8.8)%
– Affiliated companies	2,922	3,008	(2.9)%
Number of employees at year-end ⁴	59,162	55,882	5.9 %

¹ Includes equity in affiliates, except number of employees

² Includes "Other produced volumes"

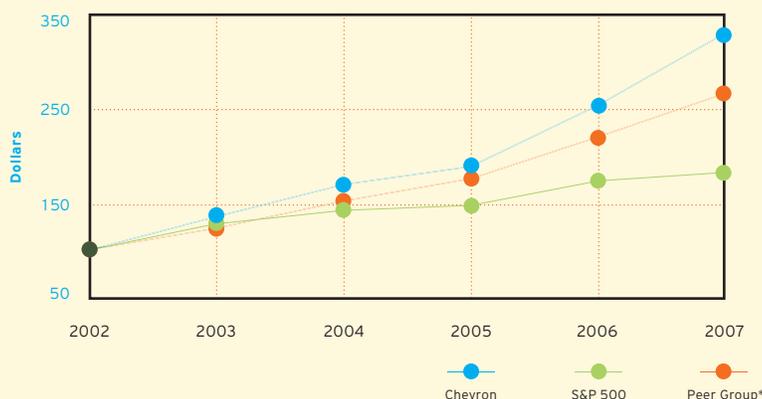
³ At the end of the year

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, 2002, and ending December 31, 2007, and is weighted by market capitalization as of the beginning of each year. It includes the re-investment 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, 2002, as of the end of each year between 2003 and 2007.

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



	2002	2003	2004	2005	2006	2007
Chevron	100	135.18	169.63	188.86	252.74	329.77
S&P 500	100	128.69	142.69	149.69	173.33	182.75
Peer Group*	100	124.15	153.00	174.80	218.81	266.53

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

How do you develop energy safely and securely when it is located almost five miles below sea level?



Chevron is working at the frontier of ultra-deepwater technology and has set world records for test equipment, pressure, depth and duration. This platform is destined for the Blind Faith Field in the U.S. Gulf of Mexico where it will be placed in approximately 6,500 feet (1,981 meters) of water and produce at depths of more than 24,000 feet (7,315 meters). Blind Faith is one of a number of deepwater projects that Chevron and partners are developing. Overall, we have approximately 40 crude oil and natural gas projects planned or in development, each representing a Chevron investment of \$1 billion or more.



Blind Faith Platform, Kiewit Offshore Services fabrication yard, Ingleside, Texas.



How do you make a 100-year-old oil field feel young again?



In California's San Joaquin Valley, Chevron is dramatically extending the producing life of some of the oldest oil fields in the United States. The Kern River Field, for one, is more than a century old. Several decades ago, it was in a steep production decline. With the application of advanced steamflood technologies, Kern River produced its 2 billionth barrel of oil in 2007, making it one of the largest and most prolific fields in the United States. We are exporting best practices learned in the San Joaquin Valley to heavy oil fields in other parts of the world, including Indonesia and the Partitioned Neutral Zone between Kuwait and Saudi Arabia. Technologies such as advanced steamflooding are enabling us to increase the value of existing resources while helping us develop the resources of tomorrow.



How do you make refineries more flexible and productive?



Chevron is investing in new processes and equipment to keep its refining operations running safely and reliably while turning even the lowest-quality crude oils into the clean-burning, high-performing products that customers demand. In 2007, a major upgrade was completed here at our affiliate refinery in Yeosu, South Korea, to process greater quantities of heavy, lower-cost crude oils. Similar upgrades have been made at our refineries in El Segundo, California, and Pascagoula, Mississippi. During the year, we also completed an upgrade at our Pembroke Refinery in the United Kingdom to process greater quantities of light, high-sulfur crude oils from the Caspian Sea region.



View from Mt. Youngchui of the Yeosu Refinery, located on the southern edge, Korean Peninsula.



How do you transport natural gas from Australia to major markets in Asia?



Chevron is Australia's largest holder of natural gas resources and is well positioned to supply three of Asia's leading markets – China, Japan and South Korea. We are transporting natural gas to these markets by cooling it to 260 degrees below zero Fahrenheit (-162 degrees Celsius) and converting it into a liquid that can be shipped in specially designed tankers. Here, the Chevron-operated tanker *Northwest Swan* takes on liquefied natural gas in Western Australia. It will be shipped to China, converted back to gas and delivered to customers through the country's pipeline infrastructure.

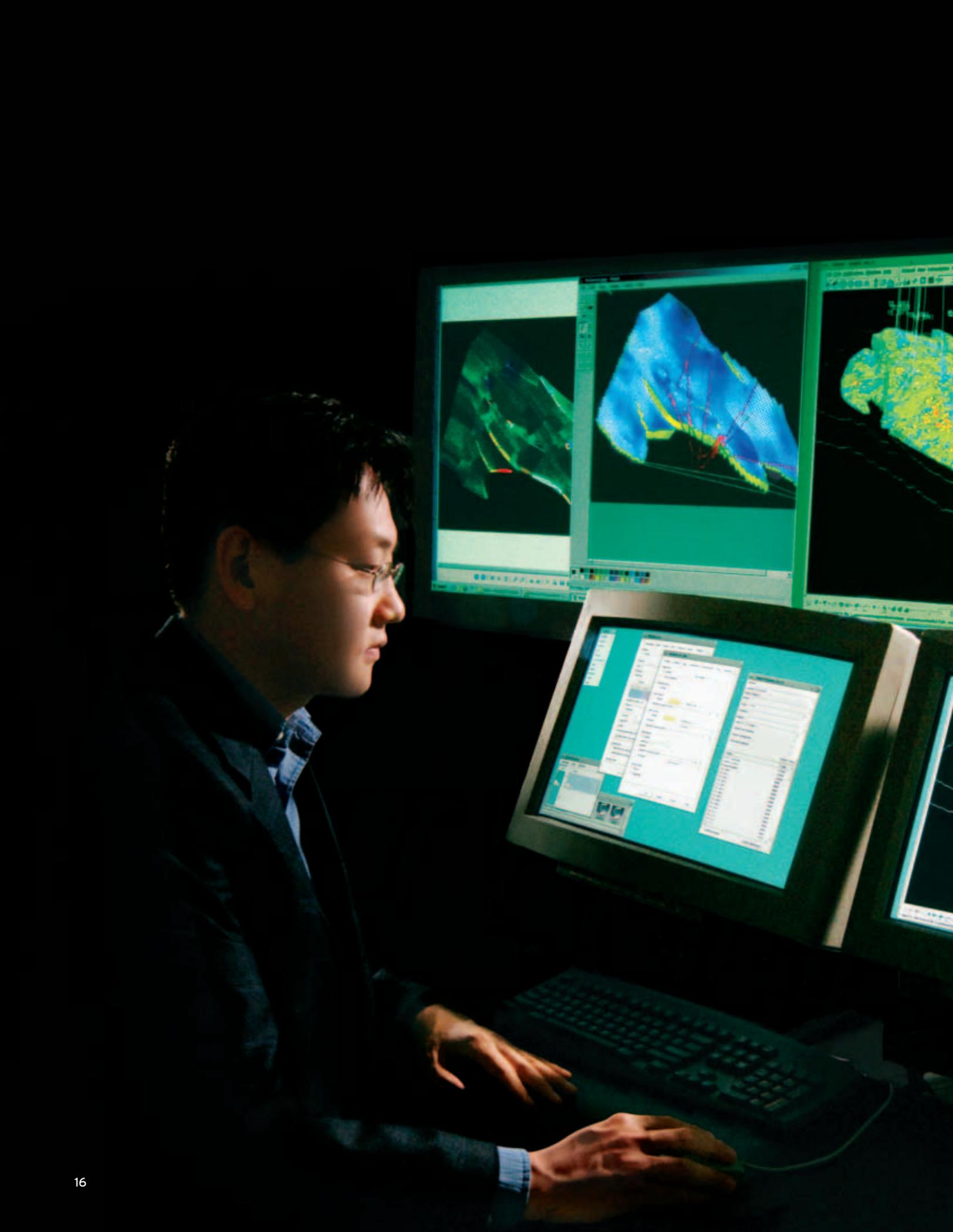


How do you provide 16 million people with energy that is clean, reliable and renewable?

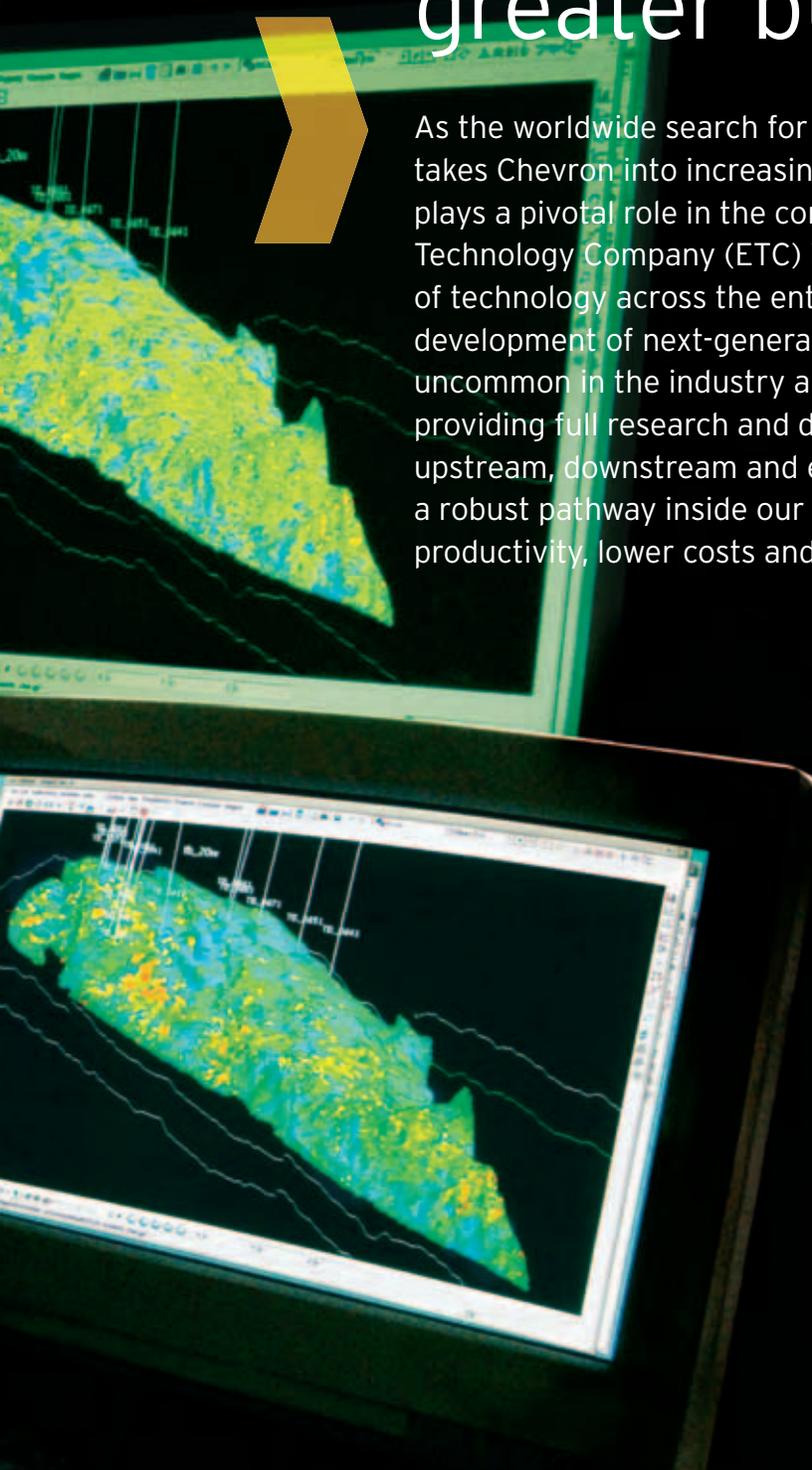


Chevron is the world's largest private producer of geothermal energy. Overall, we produce enough geothermal energy to meet the needs of 16 million people living in Indonesia and the Philippines, where our geothermal operations are located. The advantages of geothermal energy are enormous. It is a reliable energy source and can reduce reliance on fossil fuels. Geothermal power plants emit virtually no greenhouse gases. And geothermal energy is renewable, since it is derived from the natural heat within the Earth.

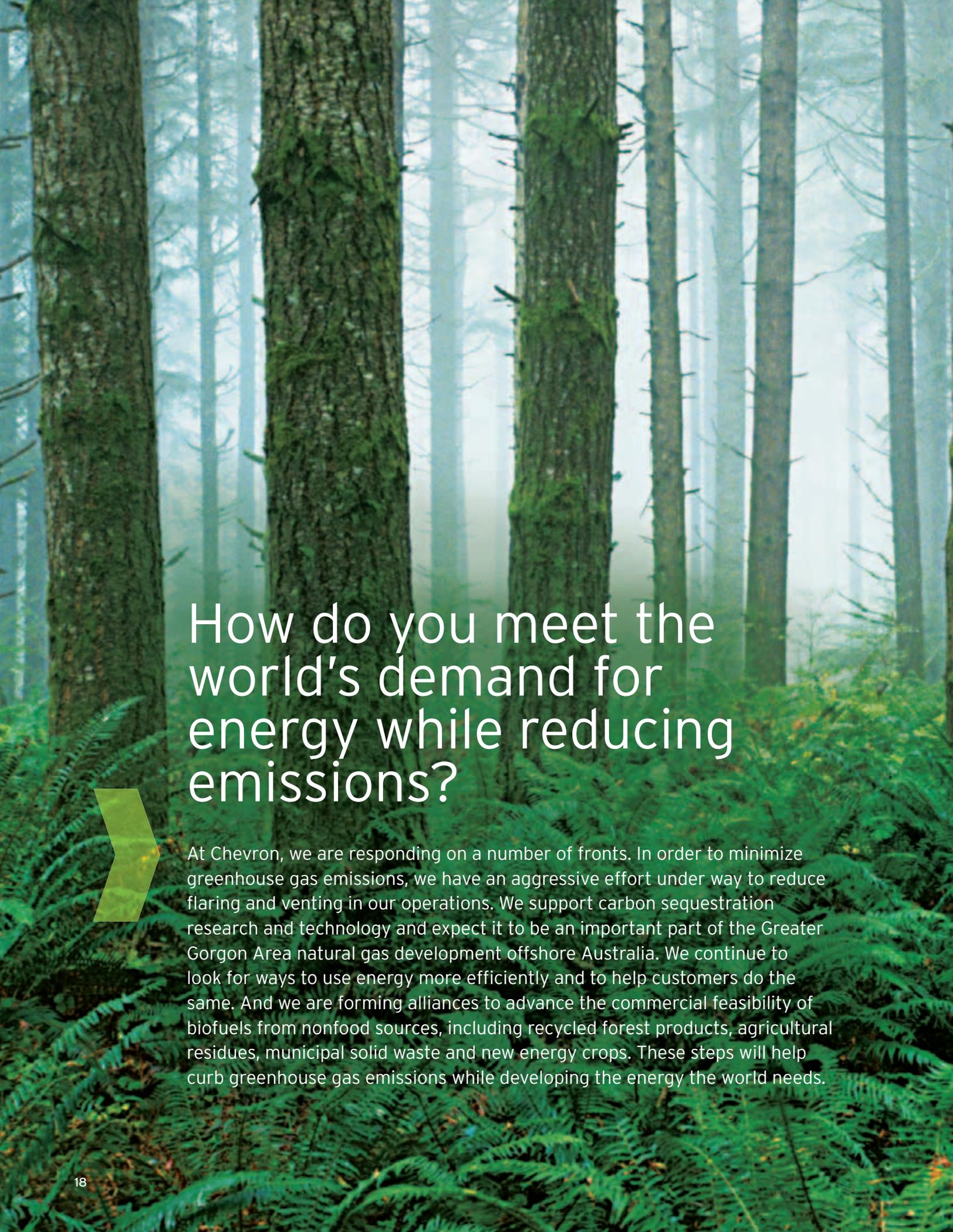




How do you leverage technology to create greater business value?



As the worldwide search for new crude oil and natural gas supplies takes Chevron into increasingly more challenging areas, technology plays a pivotal role in the company's success. Chevron's Energy Technology Company (ETC) integrates the development and deployment of technology across the enterprise, from deepwater oil fields to the development of next-generation energy sources. This integration is uncommon in the industry and delivers a competitive advantage by providing full research and development capabilities to Chevron's upstream, downstream and emerging energy businesses. ETC is creating a robust pathway inside our company to improve efficiency, increase productivity, lower costs and encourage innovation.



How do you meet the world's demand for energy while reducing emissions?



At Chevron, we are responding on a number of fronts. In order to minimize greenhouse gas emissions, we have an aggressive effort under way to reduce flaring and venting in our operations. We support carbon sequestration research and technology and expect it to be an important part of the Greater Gorgon Area natural gas development offshore Australia. We continue to look for ways to use energy more efficiently and to help customers do the same. And we are forming alliances to advance the commercial feasibility of biofuels from nonfood sources, including recycled forest products, agricultural residues, municipal solid waste and new energy crops. These steps will help curb greenhouse gas emissions while developing the energy the world needs.





How do you help build healthy and economically self-sufficient communities?



At Chevron, we are convinced that partnerships based on mutual benefit are the best way to build strong, self-sufficient communities and a stable business environment. Wherever we operate, we invest in and collaborate with governments, local communities, nongovernmental organizations and academic institutions to help contribute to economic and social progress. One recent project is in Bangladesh, where we have established a number of clinics to provide health care to villagers living near the world-class Bibiyana natural gas field, which began production in 2007.





Operating Highlights

Chevron is one of the world's leading integrated energy companies, with subsidiaries that conduct business across the globe. Our success is driven by the ingenuity and commitment of approximately 59,000 employees who operate across the energy spectrum. 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 and commercialize the energy resources of the future, including biofuels and other renewables.



Upstream

At a Glance At the end of 2007, worldwide net proved crude oil and natural gas reserves for consolidated operations were 7.9 billion barrels of oil-equivalent and for affiliated operations were 2.9 billion barrels. Net oil-equivalent production averaged 2.62 million barrels per day, including volumes produced from oil sands in Canada. Major producing areas include Angola, Australia, Azerbaijan, Bangladesh, Denmark, Indonesia, Kazakhstan, Nigeria, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, Thailand, the United Kingdom, the United States and Venezuela. Major exploration areas include western Africa, Australia, Brazil, Canada, the Gulf of Thailand, the Norwegian Barents Sea, the international waters between Trinidad and Tobago and Venezuela, the U.K. Atlantic Margin, and the U.S. Gulf of Mexico.

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

Upstream explores for and produces crude oil and natural gas. Chevron has holdings in some of the world's largest and most prolific basins, and we are one of the top producers wherever we operate. Our queue of new crude oil and natural gas projects is considered one of the best in the industry, and we manage one of the industry's most successful exploration programs.

A Year of Successes: Chevron has a strong crude oil and natural gas position and is a leader in working in extremely difficult environments, including ultra-deep water. During the year, we achieved a number of milestones. At the giant Tengiz Field in Kazakhstan, our 50 percent-owned affiliate Tengizchevroil (TCO) began production from two major expansion projects. When fully operational in 2008, production capacity is expected to increase from 300,000 barrels of crude oil per day to 540,000 barrels per day. In 2007, TCO produced its 1 billionth barrel of crude oil.

We also continued to move forward on major deepwater developments. At the end of the year, one of the world's largest floating production, storage and offloading vessels arrived at the Agbami Field offshore Nigeria. The vessel is capable of processing 250,000 barrels of crude oil and natural gas liquids per day and has a storage capacity of approximately 2.15 million barrels of crude oil. First production is expected by the third quarter of 2008. The Agbami Field is 68 percent-owned and operated by Chevron. In the deepwater U.S. Gulf of Mexico, production is scheduled to begin from the Blind Faith Field by mid-2008 (see Pages 6-7). Although progress continued on the giant Tahiti Field, also in the Gulf, initial production was delayed until the third quarter of 2009 when rigorous testing identified metallurgical problems in part of the facility's mooring system.

In 2007, a milestone agreement was reached with the government of Thailand to extend the production period of four offshore blocks in the Gulf of Thailand to 2022. The extension facilitates Chevron and co-concessionaires' long-term plans to boost production from the blocks from approximately 740 million cubic feet per day of natural gas to 1.2 billion cubic feet per day.



We continue to enhance production from existing fields and are a leader in producing heavy oil from mature fields (see Pages 8-9). We are sharing our expertise with our partners in the Partitioned Neutral Zone between Kuwait and Saudi Arabia, where we are the only international oil company producing under a concession from the Kingdom of Saudi Arabia. In 2007, approximately 30 Saudi Arabian and Kuwaiti employees began an extensive training program at our heavy oil operations in California to prepare them to operate one of the first heavy oil steamfloods in the Middle East.

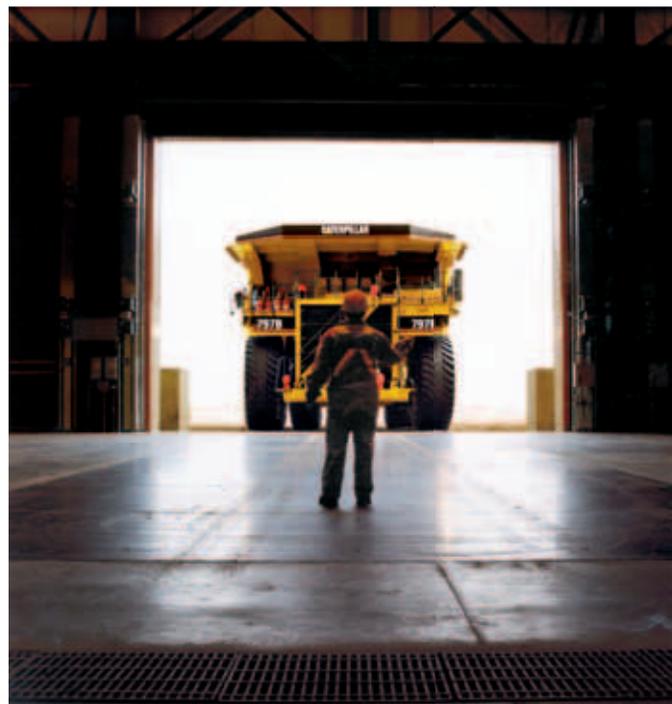
Chevron also operates the world's largest steamflood at the Duri heavy oil field in Indonesia. The field has produced more than 2 billion barrels of crude oil since it was discovered in 1941.

Additionally, we and our partners continue to make progress in developing the Athabasca Oil Sands Project in Canada.

Exploration Success: Chevron's strong exploration program continues to feed the pipeline for future crude oil and natural gas developments. In 2007, we announced two major discoveries in Angola's deep water, where we have a number of developments under way. We also discovered crude oil offshore the Republic of the Congo. Offshore the United Kingdom, west of the Shetland Islands, we tested three appraisal wells for the Rosebank/Lochnagar discovery, a promising frontier area for exploration and development.

To advance our deepwater exploration capabilities, we have commissioned the construction of two state-of-the-art drill ships. Each will be capable of drilling to total depths of up to 40,000 feet (12,192 meters) and in water depths of up to 12,000 feet (3,658 meters). Deliveries of the drill ships are expected in 2008 and 2009.

During the year, we acquired new exploration acreage offshore Western Australia, near our giant Greater Gorgon Area natural gas holdings, and in the Gulf of Thailand.



Gas

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

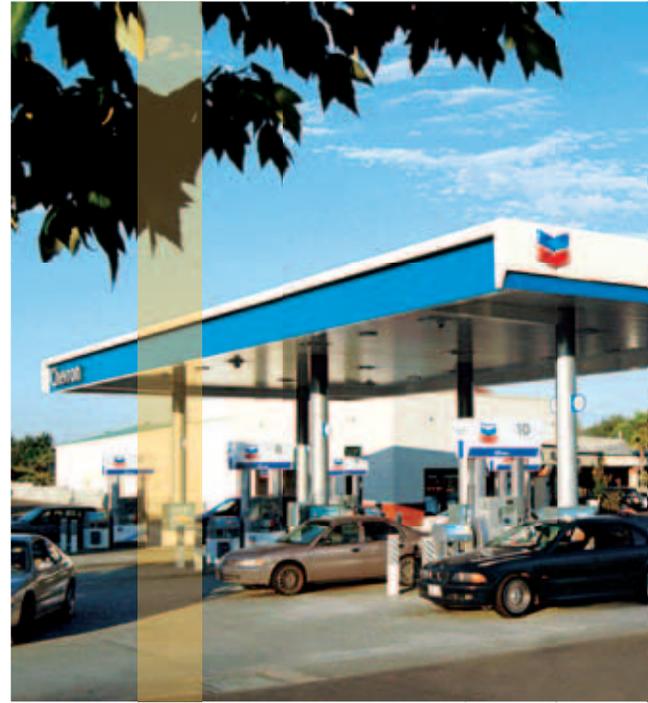
Over the next two decades, growth in demand for natural gas is expected to outpace that for crude oil. Chevron has vast natural gas resources and is well positioned to help meet growing demand (see Pages 12-13). We hold the largest natural gas resource position in Australia and have significant holdings in western Africa, Bangladesh, Indonesia, Kazakhstan, North America, South America, Thailand and the United Kingdom.

A milestone was achieved in 2007 when federal and state governments gave environmental approval to move forward with developing the Greater Gorgon Area offshore Western Australia. Plans call for building a liquefied natural gas (LNG) and domestic natural gas plant on Barrow Island and transporting the LNG to markets in Asia. Another milestone was reached when the government and partners agreed to move an LNG facility in Angola into the construction phase.

We also entered into agreements to supply additional natural gas to Trinidad and Tobago for a term of at least 11 years, to export natural gas from Colombia to Venezuela, and to develop and operate a large natural gas field in central China.

In Bangladesh, production began from the Bibiyana natural gas field, one of the largest producing gas fields in the country. By mid-2008, the first shipments of natural gas are expected to begin from Nigerian operations to the neighboring countries of Benin, Ghana and Togo. The associated 421-mile (678-kilometer) pipeline is the first regional natural gas transmission system to be developed in sub-Saharan Africa.

Chevron also is participating in the development of a gas-to-liquids (GTL) business. Through our GTL joint venture, Sasol Chevron, we are providing management, operating and technical services for an approximately 34,000-barrel-per-day GTL plant under construction in Nigeria.



Downstream

At a Glance In 2007, Chevron processed approximately 1.8 million barrels of crude oil per day and averaged approximately 3.5 million barrels per day of refined product sales worldwide. Downstream's most significant areas of operations are sub-Saharan Africa, Southeast Asia, South Korea, the United Kingdom, the U.S. Gulf Coast extending into Latin America, and the U.S. West Coast. We hold interests in 18 fuel refineries and one asphalt plant and market under the Chevron, Texaco and Caltex motor fuel brands. Products are sold through a network of more than 25,000 retail stations, including those of affiliated companies.

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

Chevron's downstream operations include refining, fuels and lubricants, marketing, supply and trading, and transportation. Our refining operations are strategically located to serve the world's fastest-growing markets, in Asia and North America, and they are configured to refine significant volumes of low-cost crude oils into high-value products. Our three motor fuel brands – Chevron, Texaco and Caltex – are among the most respected in the industry.

Refining: To improve margins, Chevron is selectively investing in its refining system to process greater quantities of low-cost heavy and high-sulfur crude oils. By the end of 2007, major upgrades had been completed at refineries in El Segundo, California; Pembroke, United Kingdom; and at our affiliate refinery in Yeosu, South Korea (see Pages 10-11). After completing an upgrade of our Pascagoula, Mississippi, refinery in 2006, we announced plans to build a unit at the refinery that will increase gasoline production by approximately 10 percent, or about 600,000 gallons per day. Construction is expected to begin in 2008 and be completed by mid-2010.

In an ongoing effort to focus on areas of market strength, we divested our interests in nonstrategic refining and other manufacturing properties in the Netherlands.

Unplanned shutdowns caused our refining utilization rate to decline from the previous year. An aggressive effort is under way to address reliability issues and improve our utilization rate.

Marketing: Chevron's three brands hold top positions in their markets around the world. In 2007, we continued to expand our U.S. Texaco marketing network to more than 2,400 sites and to strengthen our international Caltex and Texaco brands through the phased introduction of our performance-enhancing gasoline additive, Techron.

To improve returns, we continued to divest nonstrategic assets. In 2007, we sold our fuels and marketing businesses in Belgium, Luxembourg and the Netherlands; our retail fuels business in Uruguay; and our North America credit card businesses.



Renewable Energy, Technology and Other Businesses

Renewable Energy

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

In 2007, we forged research alliances with Texas A&M University and the National Renewable Energy Laboratory to develop cellulosic biofuels from nonfood sources. In another collaboration, the Alameda-Contra Costa Transit District in California is testing a biodiesel fuel blend and a gas-to-liquids diesel that Chevron is providing for a fleet of buses operating in the San Francisco Bay Area.

Additionally, Chevron expanded geothermal production in Indonesia with the startup of the 110-megawatt Darajat III geothermal power plant in West Java. Chevron is the world's largest private producer of geothermal energy (see Pages 14-15).

Our Chevron Energy Solutions subsidiary is helping internal and external customers increase their energy efficiency and use renewable sources of energy. One solar project for a California university is expected to supply 20 percent of the school's annual power needs and lower its utility costs.

Technology

Chevron's three technology companies – Energy Technology, Technology Ventures and Information Technology – support our

core businesses and enable our most promising future opportunities (see Pages 16-17). In 2007, we established new technology centers in Australia and Scotland to provide strategic research, development and technical services to our global businesses. We also have centers in California and Texas.

Other Businesses

Our 50-50 joint venture Chevron Phillips Chemical Company LLC is one of the world's leading manufacturers of petrochemicals. Chevron Oronite markets more than 500 performance-enhancing products and supplies one-fourth of the world's fuel and lubricant additives. Other businesses include mining, pipeline, power generation and shipping. For more information, visit our Web site: www.chevron.com.

Operational Excellence

At Chevron, safety is our highest priority. For the sixth consecutive year, we reduced the rate of injuries severe enough to require days away from work by 22 percent, compared with 2006. Although our safety performance is among the top in the industry, we will not be satisfied until we have zero incidents – no one injured.

We also continued efforts to improve the efficiency of our operations. Since 1992, the year we began tracking, we have increased our energy efficiency by 27 percent and lowered our annual energy costs by approximately \$2 billion.

Chevron has integrated systematic processes into all aspects of its operations to protect the safety and health of people and the environment and to ensure reliable and efficient operations. During the year, an outside independent audit determined that the design of our Operational Excellence Management System met, and in some cases exceeded, the requirements of ISO 14001 (environmental management systems) and OHSAS 18001 (health and safety management systems).

Glossary of Energy and Financial Terms

Energy Terms

Additives Chemicals to control engine deposits and improve lubricating performance.

Barrels of oil-equivalent (BOE) A 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 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 the 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.

Liquefied petroleum gas (LPG) Light gases, such as butane and propane, that can be maintained as liquids while under pressure.

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 crude oil*.

Petrochemicals Chemicals derived from petroleum; used principally for the manufacture of chemicals, plastics and resins, synthetic fibers, detergents, adhesives, and synthetic motor oils.

Production *Total production* refers to all the crude 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) where production is shared between the parties in a pre-arranged 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 on 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, and biofuels).

Reserves Crude oil, natural gas liquids and natural gas contained in underground rock formations called reservoirs. *Proved reserves* are the estimated quantities that geologic and engineering data demonstrate can be produced with reasonable certainty from known reservoirs under existing economic and operating conditions. 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 rules of the United States Securities and Exchange Commission (SEC) permit oil and gas companies to disclose in their filings with the SEC only proved reserves. Certain terms, such as "probable" or "possible" reserves, "potentially recoverable" volumes, or "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. We use these other terms, which are not approved for use in SEC filings, because they are commonly used in the industry, are measures considered by management to be important in making capital investment and operating decisions, and provide some indication to our stockholders of the potential ultimate recovery of oil and gas from properties in which we have an interest. In that regard, potentially recoverable volumes are those that can be produced using all known primary and enhanced recovery methods.

Synthetic crude 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.

Cumulative effect of change in accounting principle The effect in the financial statements in the period of change of a retroactive application of a new accounting principle.

Goodwill The excess of the purchase price of an acquired entity over the total fair value assigned to assets acquired and liabilities assumed.

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

Net income The primary earnings measure for a company, as determined under United States Generally Accepted Accounting Principles (GAAP), and detailed on a separate financial statement.

Return on capital employed (ROCE) Ratio calculated by dividing *net income* (adjusted for after-tax interest expense and minority interest) by the average of total debt, minority interest and *stockholders' equity* for the year.

Stockholders' equity The owners' share of the company; the difference between total assets and total liabilities.

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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Other information

The company has submitted to the New York Stock Exchange a certificate of the Chief Executive Officer of the company certifying that he is not aware of any violation by the company of New York Stock Exchange corporate governance listing standards. The 302 certifications have been filed in the Form 10-K.

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 our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are crude oil and natural gas prices; refining margins and marketing margins; chemicals margins; actions of competitors; timing of exploration expenses; the competitiveness of alternate energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affil-

iates; 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 startup 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 OPEC (Organization of Petroleum Exporting Countries); the potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental statutes, regulations and litigation; the potential liability resulting from pending or future litigation; the company's acquisition or disposition of assets; gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, 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.

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

Key Financial Results

<i>Millions of dollars, except per-share amounts</i>	2007	2006	2005
Net Income	\$ 18,688	\$ 17,138	\$ 14,099
Per Share Amounts:			
Net Income – Basic	\$ 8.83	\$ 7.84	\$ 6.58
– Diluted	\$ 8.77	\$ 7.80	\$ 6.54
Dividends	\$ 2.26	\$ 2.01	\$ 1.75
Sales and Other			
Operating Revenues	\$ 214,091	\$ 204,892	\$ 193,641
Return on:			
Average Capital Employed	23.1%	22.6%	21.9%
Average Stockholders' Equity	25.6%	26.0%	26.1%

Income by Major Operating Area

<i>Millions of dollars</i>	2007	2006	2005
Upstream – Exploration and Production			
United States	\$ 4,532	\$ 4,270	\$ 4,168
International	10,284	8,872	7,556
Total Upstream	14,816	13,142	11,724
Downstream – Refining, Marketing and Transportation			
United States	966	1,938	980
International	2,536	2,035	1,786
Total Downstream	3,502	3,973	2,766
Chemicals	396	539	298
All Other	(26)	(516)	(689)
Net Income*	\$ 18,688	\$ 17,138	\$ 14,099

*Includes Foreign Currency Effects: \$ (352) 2007, \$ (219) 2006, \$ (61) 2005

Refer to the “Results of Operations” section beginning on page 34 for a detailed discussion of financial results by major operating area for the three years ending December 31, 2007.

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, France, India, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Neutral Zone between Saudi Arabia and Kuwait, the Philippines, Qatar, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, the United States, Venezuela and Vietnam.

Current and future 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 and/or unusual in nature.

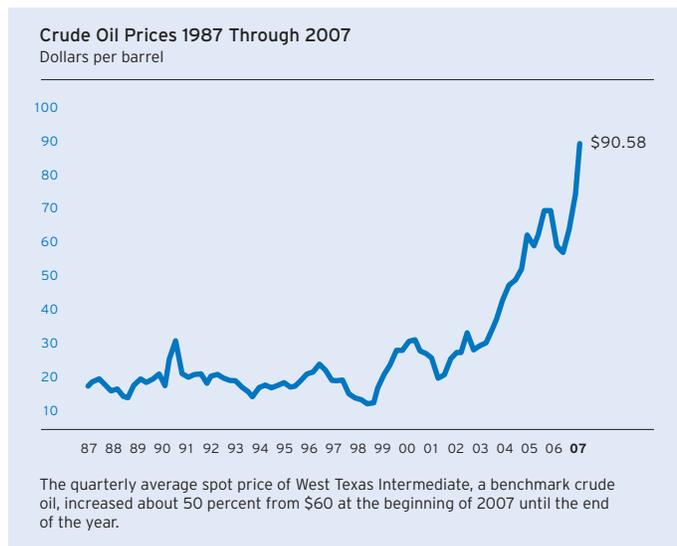
Chevron and the oil and gas industry at large continue to experience an increase in certain costs that exceeds the general trend of inflation in many areas of the world. This increase in costs is affecting the company's operating expenses and capital expenditures, particularly for the upstream business. 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 adequate financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments. In the current environment of higher commodity prices, certain governments have sought to renegotiate contracts or impose additional costs on the company. Other governments may attempt to do so in the future. The company will continue to monitor these developments, take them into account in evaluating future investment opportunities, and otherwise seek to mitigate any risks to the company's current operations or future prospects.

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 growth. Asset sales during 2007 included the company's 31 percent ownership interest in a refinery and related assets in the Netherlands; fuels marketing businesses in Belgium, Luxembourg, the Netherlands and Uruguay; and the investment in common stock of Dynegy Inc. Other asset dispositions and restructurings may occur in future periods and could result in significant gains or losses.

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

Upstream Earnings for the upstream segment are closely aligned with industry price levels for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry inventory levels, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and regional supply interruptions 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 business.

Price levels for capital and exploratory costs and operating expenses associated with the efficient production of crude oil and natural gas can also be subject to external factors beyond the company's control. External factors include not only the general level of inflation but also prices charged by the industry's 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. The oil and gas industry worldwide has experienced significant price increases for these items since 2005, and future price increases may continue to exceed the general level of inflation. Capital and exploratory expenditures and operating expenses also can be affected by damages to production facilities caused by severe weather or civil unrest.

Industry price levels for crude oil increased during 2007. The spot price for West Texas Intermediate (WTI) crude oil, a benchmark crude oil, averaged \$72 per barrel in 2007, up approximately \$6 per barrel from the 2006 average price. The rise in crude oil prices was attributed primarily to increasing demand in growing economies, the heightened level of geopolitical uncertainty in some areas of the world and supply concerns in other key producing regions. As of mid-February 2008, the WTI price was about \$93 per barrel.

As in 2006, a wide differential in prices existed in 2007 between high-quality (i.e., high-gravity, low-sulfur) crude oils

and those of lower quality (i.e., low-gravity, heavier types of crude). The price for the heavier crudes has been dampened because of ample supply and lower relative demand due to the limited number of refineries that are able to process this lower-quality feedstock into light products (i.e., motor gasoline, jet fuel, aviation gasoline and diesel fuel). The price for higher-quality crude oil has remained high, as the demand for light products, which can be more easily manufactured by refineries from high-quality crude oil, has been strong worldwide. Chevron produces or shares in the production of heavy crude oil in California, Chad, Indonesia, the Partitioned Neutral Zone between Saudi Arabia and Kuwait, Venezuela and certain fields in Angola, China and the United Kingdom North Sea. (Refer to page 38 for the company's average U.S. and international crude oil prices.)

In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply and demand conditions in those markets. In the United States during 2007, benchmark prices at Henry Hub averaged about \$7 per thousand cubic feet (MCF), compared with about \$6.50 in 2006. As of mid-February 2008, the Henry Hub price was about \$8 per MCF. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. U.S. natural gas prices are also typically higher during the winter period when demand for heating is greatest.

Certain other regions of the world in which the company operates have different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices for the company's production of natural gas. (Refer to page 38 for the company's average natural gas prices for the U.S. and international regions.) Additionally, excess-supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-price



conditions in the United States and other markets because of the lack of infrastructure to transport and receive liquefied natural gas.

To help address this regional imbalance between supply and demand for natural gas, Chevron is planning increased investments in long-term projects in areas of excess supply to install infrastructure to produce and liquefy natural gas for transport by tanker, along with investments and commitments to regasify the product in markets where demand is strong and supplies are not as plentiful. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices in the areas of excess supply (before the natural gas is transferred to a company-owned or third-party processing facility) are expected to remain well below sales prices for natural gas that is produced much nearer to areas of high demand and can be transported in existing natural gas pipeline networks (as in the United States).

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

Chevron's worldwide net oil-equivalent production in 2007, including volumes produced from oil sands, averaged 2.62 million barrels per day, a decline of about 48,000 barrels per day from 2006, due mainly to the effect of a conversion of operating service agreements in Venezuela to joint-stock companies. (Refer to the table "Selected Operating Data" on page 38 for a listing of production volumes for each of the three years ending December 31, 2007.) The company estimates that oil-equivalent production in 2008 will average approximately 2.65 million barrels per day. This estimate is subject to many uncertainties, including quotas that may be imposed by OPEC, the price effect on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, changes in fiscal terms or restrictions on the scope of company operations, delays in project startups, weather conditions that may shut in production, civil unrest, changing geopolitics or other disruptions to operations. Future production levels also are affected by the size and number of economic investment opportunities and, for new large-scale projects, the time lag between initial exploration and the beginning of production. Most of Chevron's upstream investment is currently being made outside the United States. Investments in upstream projects generally are made well in advance of the start of the associated crude oil and natural gas production.

Approximately 28 percent of the company's net oil-equivalent production in 2007 occurred in the OPEC-member countries of Angola, Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. OPEC quotas did not significantly affect Chevron's

production level in 2007. The impact of OPEC quotas on the company's production in 2008 is uncertain.

In October 2006, Chevron's Boscan and LL-652 operating service agreements in Venezuela were converted to Empresas Mixtas (i.e., joint-stock companies), with Petróleos de Venezuela, S.A. (PDVSA) as majority shareholder. From that time, Chevron reported its equity share of the Boscan and LL-652 production, which was approximately 85,000 barrels per day less than what the company previously reported under the operating service agreements. The change to the Empresa Mixta structure did not have a material effect on the company's results of operations, consolidated financial position or liquidity.

In February 2007, the president of Venezuela issued a decree announcing the government's intention for PDVSA to take over operational control of all Orinoco Heavy Oil Associations effective May 1, 2007, and to increase its ownership in all such associations to a minimum of 60 percent. The decree included Chevron's 30 percent-owned Hamaca project. In April 2007, Chevron signed a memorandum of understanding (MOU) with PDVSA that summarized the ongoing discussions to transfer control of Hamaca operations in accordance with the February decree. As provided in the MOU, a PDVSA-controlled transitory operational committee, on which Chevron had representation, assumed responsibility for daily operations on May 1, 2007. The MOU stipulated that terms of existing contracts were to remain in place during the transition period. In December 2007, Chevron executed a conversion agreement and signed a charter and by-laws with a PDVSA subsidiary that provided for Chevron to retain its 30 percent interest in the Hamaca project. The new entity, Petropiar, commenced activities in January 2008. The conversion agreement did not have a material effect on Chevron's results of operations, consolidated financial position or liquidity.

Refer to pages 34 through 35 for additional discussion of the company's upstream operations.

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, refinery maintenance programs and disruptions at refineries resulting from unplanned outages that may be 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, the effectiveness of

the crude-oil and product-supply functions and the economic returns on invested capital. Profitability can also be affected by the volatility of 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, sub-Saharan Africa and the United Kingdom. Chevron operates or has ownership interests in refineries in each of these areas except Latin America. For the industry, refined-product margins were generally higher in 2007 than in 2006. For the company, U.S. refined-product margins during 2007 were negatively affected by planned and unplanned downtime at its three largest U.S. refineries.

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

Refer to pages 35 through 36 for additional discussion of the company's downstream operations.

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

Refer to page 36 for additional discussion of chemicals earnings.

Operating Developments

Key operating developments and other events during 2007 and early 2008 included the following:

Upstream

Angola Discovered crude oil at the 31 percent-owned and operated Malange-1 well in offshore Block 14. Additional drilling and geologic and engineering studies are planned to appraise the discovery. The company and partners also made the final investment decision to construct a liquefied natural gas (LNG) plant that will be owned 36 percent by Chevron. The plant will be

designed with a capacity to process 1 billion cubic feet of natural gas per day and produce 5.2 million metric tons a year of LNG and related gas liquids products.

Australia Received federal and state environmental approvals for development of the 50 percent-owned and operated Gorgon LNG project located off the northwest coast. The approvals represented a significant milestone toward the development of the company's natural gas resources offshore Australia.

Bangladesh Began production at the 98 percent-owned Bibiyana natural gas field. The field's total production is expected to increase to a maximum of 500 million cubic feet per day by 2010.

China Signed a 30-year production-sharing contract with China National Petroleum Corporation to assume operatorship and hold a 49 percent interest in the development of the Chuandongbei natural gas area in central China. Design input capacity of the proposed gas plants is expected to be 740 million cubic feet of natural gas per day.

Indonesia Began commercial operation of the 110-megawatt Darajat III geothermal power plant in Garut, West Java. The plant increased Darajat's total capacity to 259 megawatts.

Kazakhstan Initiated production from the first phase of the Sour Gas Injection and Second Generation Plant expansion projects at the 50 percent-owned Tengiz Field. This phase increased production capacity by 90,000 barrels of crude oil per day to approximately 400,000. Full facility expansion is expected to occur during the second-half 2008, increasing production capacity to 540,000 barrels per day.

Republic of the Congo Confirmed two crude oil discoveries in the offshore Moho-Bilondo permit. Evaluation and development studies were undertaken to appraise the discoveries, in which Chevron holds a 32 percent nonoperated working interest.

Thailand Signed an agreement to increase sales of natural gas from company-operated Blocks 10, 11, 12 and 13 in the Gulf of Thailand to PTT Public Company Limited. Chevron has ownership interests ranging from 60 percent to 80 percent in the blocks, which received 10-year production-period extensions to 2022. The company was also granted the concession rights for a six-year period to four prospective offshore petroleum blocks, three of which it will operate.

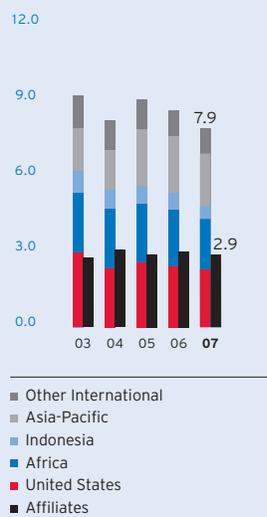
Trinidad and Tobago Signed an agreement to sell natural gas to the National Gas Company of Trinidad and Tobago for 11 years with an option for a four-year extension. The gas is expected to be sourced from Chevron's 50 percent-owned East Coast Marine Area.

United States Announced that first production from the Tahiti project in the deepwater Gulf of Mexico is expected by the third quarter 2009. The startup is approximately one year later than originally planned due to metallurgical problems with the mooring shackles for the floating production facility.

Downstream

Benelux Countries Sold the company's 31 percent interest in the Nerefco Refinery and related assets in the Netherlands, and the company's fuels marketing businesses in Belgium, Luxembourg and the Netherlands, resulting in gains totaling \$960 million.

Net Proved Reserves
Billions of BOE*



Net proved reserves for consolidated companies declined 8 percent in 2007, while affiliated companies' reserves were 3 percent lower.

*Barrels of oil-equivalent; excludes oil sands reserves

South Korea Completed construction and commissioned new facilities associated with a \$1.5 billion upgrade at the 50 percent-owned GS Caltex Yeosu Refinery, enabling the refinery to process heavier and higher-sulfur crude oils and increase the production of gasoline, diesel and other light products.

United States Approved plans at the company's refinery in Pascagoula, Mississippi, for the construction of a Continuous Catalyst Regeneration unit, which is expected to increase gasoline production by 10 percent, or 600,000 gallons per day, by mid-2010. At the refinery in El Segundo, California, modifications were completed to enable the processing of heavier crude oils into light transportation fuels and other refined products.

Other

Common Stock Dividends Increased the company's quarterly common stock dividend by 11.5 percent in April to \$0.58 per share, marking the 20th consecutive year the company has increased its annual dividend payment.

Common Stock Repurchase Program Approved a program in September to acquire up to \$15 billion of the company's common stock over a period of up to three years, which followed three stock repurchase programs of \$5 billion each that were completed in 2005, 2006 and September 2007.

Dynegy Sold the company's common stock investment in Dynegy Inc., resulting in a gain of \$680 million.

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. Income is also presented for the U.S. and international geographic areas of the upstream and downstream business segments. (Refer to Note 8, beginning on page 64, for a discussion of the company's “reportable segments,” as defined in FASB No. 131, Disclosures About Segments of an Enterprise and Related Information.) This section should also be read in conjunction with the discussion in “Business Environment and Outlook” on pages 30 through 33.

U.S. Upstream – Exploration and Production

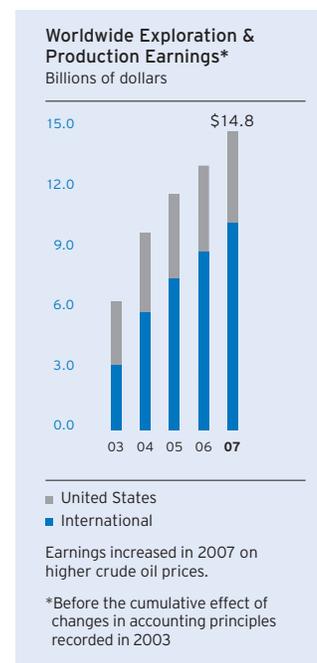
Millions of dollars	2007	2006	2005
Income	\$ 4,532	\$ 4,270	\$ 4,168

U.S. upstream income of \$4.5 billion in 2007 increased approximately \$260 million from 2006. Results in 2007 benefited approximately \$700 million from higher prices for crude oil and natural gas liquids. This benefit to income was

partially offset by the effects of a decline in oil-equivalent production and an increase in depreciation, operating and exploration expenses.

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

The company's average realization for crude oil and natural gas liquids in 2007 was \$63.16 per barrel, compared with \$56.66 in 2006 and \$46.97 in 2005. The average natural gas realization was \$6.12 per thousand cubic feet in 2007, compared with \$6.29 and \$7.43 in 2006 and 2005, respectively.



Net oil-equivalent production in 2007 averaged 743,000 barrels per day, down 2.6 percent from 2006 and up 2 percent from 2005, which included only five months of production from the Unocal properties acquired in August of that year. The net liquids component of oil-equivalent production for 2007 averaged 460,000 barrels per day, which was essentially flat compared with 2006, and an increase of 1 percent from 2005. Net natural gas production averaged 1.7 billion cubic feet per day in 2007, down 6 percent from 2006 and up 4 percent from 2005.

Refer to the “Selected Operating Data” table, on page 38, for the three-year comparative production volumes in the United States.

International Upstream – Exploration and Production

Millions of dollars	2007	2006	2005
Income*	\$ 10,284	\$ 8,872	\$ 7,556
*Includes Foreign Currency Effects:	\$ (417)	\$ (371)	\$ 14

International upstream income of \$10.3 billion in 2007 increased \$1.4 billion from 2006. Earnings in 2007 benefited approximately \$1.6 billion from higher prices, primarily for crude oil, and \$300 million from increased liftings. Non-recurring income tax items also benefited earnings between periods. These benefits to income were partially offset by the impact of higher operating and depreciation expenses.

Income in 2006 of approximately \$8.9 billion increased \$1.3 billion from 2005. Earnings in 2006 benefited approximately \$3 billion from higher prices for crude oil and natural gas and an additional seven months of production from the former Unocal properties. About 70 percent of this benefit was associated with the impact of higher prices. Substantially offsetting these benefits were increases in depreciation expense, operating expense and exploration expense. Also adversely affecting 2006 income were higher taxes related to an increase in tax rates in the United Kingdom and Venezuela and settlement of tax claims and other tax items in Venezuela, Angola and Chad. Foreign currency effects reduced earnings by \$371 million in 2006, but increased income \$14 million in 2005.

The company’s average realization for crude oil and natural gas liquids in 2007 was \$65.01 per barrel, compared with \$57.65 in 2006 and \$47.59 in 2005. The average natural gas realization was \$3.90 per thousand cubic feet in 2007, compared with \$3.73 and \$3.19 in 2006 and 2005, respectively.

Net oil-equivalent production of 1.88 million barrels per day in 2007 declined about 2 percent from 2006 and increased 5 percent from 2005. The volumes for each year included production from oil sands in Canada and an operating service agreement in Venezuela until its conversion to a joint-stock company in October 2006. The decline between 2006 and 2007 was associated with the impact of this contract conversion in Venezuela and the price effects on production volumes calculated under production-sharing agreements. Partially offsetting the decline was increased production in Bangladesh, Angola and Azerbaijan. The increase from 2005 was due to that year having included only five months of production from the former Unocal properties.

The net liquids component of oil-equivalent production was 1.3 million barrels per day in 2007, a decrease of approximately 4 percent from 2006 and 3 percent from 2005. Net natural gas production of 3.3 billion cubic feet per day in 2007 was up 5.5 percent and 28 percent from 2006 and 2005, respectively.

Refer to the “Selected Operating Data” table, on page 38, for the three-year comparative of international production volumes.

U.S. Downstream – Refining, Marketing and Transportation

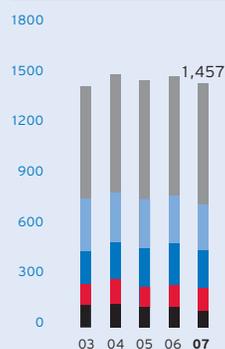
Millions of dollars	2007	2006	2005
Income	\$ 966	\$ 1,938	\$ 980

U.S. downstream earnings of \$966 million in 2007 declined nearly \$1 billion from 2006 and were essentially the same as 2005. The decline in 2007 from 2006 was associated mainly with weaker refined-product margins due to the effects of higher crude oil prices and the negative impacts of higher planned and unplanned downtime on refinery production volumes at the company’s three major refineries. Operating expenses were also higher in 2007. The improvement in 2006 earnings from 2005 was primarily associated with higher average refined-product margins in 2006 and the adverse effect of downtime in 2005 at refining, marketing and pipeline operations that was caused by hurricanes in the Gulf of Mexico.

Sales volumes of refined products were 1.46 million barrels per day in 2007, a decrease of 3 percent and 1 percent from 2006 and 2005, respectively. The reported sales volume for 2007 was on a different basis than 2006 and 2005 due to a change in accounting rules that became effective April 1, 2006, for certain purchase and sale (buy/sell) contracts with the same counterparty. Excluding the impact of this accounting standard, refined-product sales in 2007 decreased 1 percent from 2006 and increased about 5 percent from 2005. Branded gasoline sales volumes of 629,000 barrels per day in 2007 increased about 2 percent from 2006 and 6 percent from 2005, largely due to growth of the Texaco brand.

Refer to the “Selected Operating Data” table on page 38 for a three-year comparative of sales volumes of gasoline and other refined products and refinery-input volumes. Refer also to Note 13, “Accounting for Buy/Sell Contracts,” on page 69

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



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

Refined-product sales volumes decreased about 3 percent from 2006, on lower sales of gas oil. Excluding the effect of an accounting change for buy/sell contracts, sales volumes decreased about 1 percent.

Worldwide Refining, Marketing & Transportation Earnings*
Billions of dollars



■ United States
■ International

Downstream earnings decreased 12 percent, mainly due to lower margins and increased refinery downtime. Gains on asset sales in 2007 totaled \$1.1 billion.

*Includes equity in affiliates

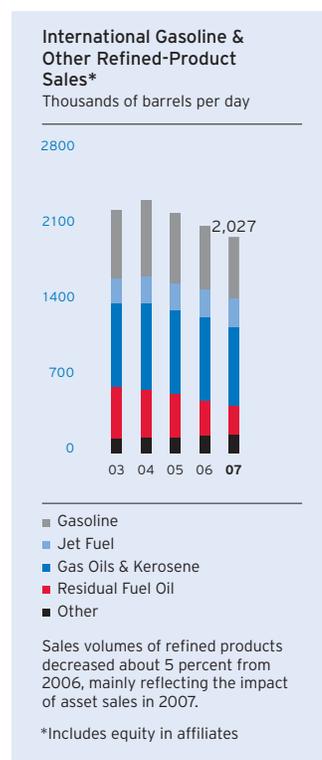
for a discussion of the accounting for purchase and sale contracts with the same counterparty.

International Downstream – Refining, Marketing and Transportation

Millions of dollars	2007	2006	2005
Income*	\$ 2,536	\$ 2,035	\$ 1,786

*Includes Foreign Currency Effects: \$ 62 \$ 98 \$ (24)

International downstream income of \$2.5 billion in 2007 increased about \$500 million from 2006 and \$750 million from 2005. Results for 2007 included gains of approximately \$1 billion on the sale of assets, including an interest in a refinery and marketing assets in the Benelux region of Europe. Margins on the sale of refined products in 2007 were up slightly from the prior year. Operating expenses were higher, and earnings from the company's shipping operations were lower. The increase in earnings in 2006 compared with 2005 was associated mainly with the benefit of higher refined-product sales margins in the Asia-Pacific area and Canada and improved results from crude-oil and refined-product trading activities.



Refined-product sales volumes were 2.03 million barrels per day in 2007, about 5 percent and 10 percent lower than 2006 and 2005, respectively, due largely to the impact of asset sales and the accounting-standard change for buy/sell contracts. Excluding the accounting change, sales decreased about 4 percent and 5 percent from 2006 and 2005, respectively.

Refer to the "Selected Operating Data" table on page 38 for a three-year comparative of sales volumes of gasoline and other refined products and refinery-input volumes. Refer also to Note 13, "Accounting for Buy/Sell Contracts," on page 69 for a discussion of the accounting for purchase and sale contracts with the same counterparty.

Chemicals

Millions of dollars	2007	2006	2005
Income*	\$ 396	\$ 539	\$ 298

*Includes Foreign Currency Effects: \$ (3) \$ (8) \$ -

The chemicals segment includes the company's Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem). In 2007, earnings were \$396 million, compared with \$539 million and \$298 million in 2006 and 2005, respectively. Between 2006 and 2007, the benefit of improved margins on sales of lubricants and fuel additives by Oronite was more than offset by the effect of lower margins on the sale of commodity chemicals by CPChem. In 2006, earnings of \$539 million increased about \$240 million from 2005 due to higher margins for commodity chemicals at CPChem and for fuel and lubricant additives at Oronite.



All Other

Millions of dollars	2007	2006	2005
Net Charges*	\$ (26)	\$ (516)	\$ (689)

*Includes Foreign Currency Effects: \$ 6 \$ 62 \$ (51)

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 prior to its sale in May 2007.

Net charges of \$26 million in 2007 decreased \$490 million from 2006. 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. Excluding these items and the effects of foreign currency, net charges decreased about \$40 million between periods.

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

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

<i>Millions of dollars</i>	2007	2006	2005
Sales and other operating revenues	\$ 214,091	\$204,892	\$193,641

Sales and other operating revenues in 2007 increased over 2006 due primarily to higher prices for crude oil, natural gas, natural gas liquids and refined products, partially offset by lower sales volumes. The increase in 2006 from 2005 was primarily due to higher prices for refined products. The higher revenues in 2006 were net of an impact from a change in the accounting for buy/sell contracts, as described in Note 13 on page 69.

<i>Millions of dollars</i>	2007	2006	2005
Income from equity affiliates	\$ 4,144	\$ 4,255	\$ 3,731

Lower income from equity affiliates in 2007 was mainly due to a decline in earnings from CPChem, Dynegy (sold in May 2007) and downstream affiliates in the Asia-Pacific area. Partially offsetting these declines were improved results for Tengizchevroil (TCO) and income for a full year from Petroboscan, which was converted from an operating service agreement to a joint-stock company in October 2006. The increase between 2005 and 2006 was primarily due to improved results for TCO and CPChem. Refer to Note 11, beginning on page 67, for a discussion of Chevron's investment in affiliated companies.

<i>Millions of dollars</i>	2007	2006	2005
Other income	\$ 2,669	\$ 971	\$ 828

Other income of nearly \$2.7 billion in 2007 included the net of gains totaling \$1.7 billion from the sale of downstream assets in the Benelux countries and the company's investment in Dynegy and a loss of approximately \$245 million on the early redemption of Texaco debt. Interest income was approximately \$600 million, \$600 million and \$400 million in 2007, 2006 and 2005, respectively. Foreign currency losses were \$352 million, \$260 million and \$60 million in the corresponding years.

<i>Millions of dollars</i>	2007	2006	2005
Purchased crude oil and products	\$133,309	\$128,151	\$127,968

Crude oil and product purchases in 2007 increased from 2006 due to higher prices for crude oil, natural gas, natural gas liquids and refined products. Crude oil and product purchases in 2006 increased from 2005 on higher prices for crude oil and refined products and the inclusion of Unocal-related amounts for the full year 2006 versus five months in 2005. The increase was mitigated by the effect of the accounting change in April 2006 for buy/sell contracts.

<i>Millions of dollars</i>	2007	2006	2005
Operating, selling, general and administrative expenses	\$ 22,858	\$ 19,717	\$ 17,019

Operating, selling, general and administrative expenses in 2007 increased 16 percent from a year earlier. Expenses were higher in a number of categories, with the largest increases recorded for the cost of employee payroll and contract labor. Total expenses increased in 2006 from 2005 due mainly to the inclusion of former-Unocal expenses for the full year 2006. Besides this effect, expenses were higher in 2006 for labor, transportation and uninsured costs associated with the hurricanes in 2005.

<i>Millions of dollars</i>	2007	2006	2005
Exploration expense	\$ 1,323	\$ 1,364	\$ 743

Exploration expenses in 2007 declined from 2006 mainly due to lower amounts for well write-offs and geological and geophysical costs for operations outside the United States. Expenses increased in 2006 from 2005 due to higher amounts for well write-offs and geological and geophysical costs for operations outside the United States, as well as the inclusion of Unocal-related amounts for the full year 2006.

<i>Millions of dollars</i>	2007	2006	2005
Depreciation, depletion and amortization	\$ 8,708	\$ 7,506	\$ 5,913

Depreciation, depletion and amortization expenses increased from 2005 through 2007, reflecting an increase in charges related to asset write-downs and higher depreciation rates for certain crude oil and natural gas producing fields worldwide and the inclusion of Unocal-related amounts beginning in August 2005.

<i>Millions of dollars</i>	2007	2006	2005
Taxes other than on income	\$ 22,266	\$ 20,883	\$ 20,782

Taxes other than on income increased in 2007 from a year earlier due to higher duties in the company's U.K. downstream operations. Taxes other than on income were essentially unchanged in 2006 from 2005, with the effect of higher U.S. refined-product sales being offset by lower sales volumes subject to duties in the company's European downstream operations.

<i>Millions of dollars</i>	2007	2006	2005
Interest and debt expense	\$ 166	\$ 451	\$ 482

Interest and debt expense in 2007 decreased from 2006 primarily due to lower average debt balances and higher amounts of interest capitalized. The decrease in 2006 versus 2005 was mainly due to lower average debt balances and an increase in the amount of interest capitalized, partially offset by higher average interest rates on commercial paper and other variable-rate debt.

Millions of dollars	2007	2006	2005
Income tax expense	\$ 13,479	\$ 14,838	\$ 11,098

Effective income tax rates were 42 percent in 2007, 46 percent in 2006 and 44 percent in 2005. Rates were lower in 2007 compared with the prior year due mainly to the impact of nonrecurring items, including asset sales in 2007 and the absence of 2006 charges related to a tax-law change that increased tax rates on upstream operations in the U.K. North Sea and the settlement of a tax claim in Venezuela. The higher tax rate in 2006 compared with 2005 also reflected these nonrecurring charges in 2006. Refer also to the discussion of income taxes in Note 15 beginning on page 70.

Selected Operating Data^{1,2}

	2007	2006	2005
U.S. Upstream³			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	460	462	455
Net Natural Gas Production (MMCFPD) ⁴	1,699	1,810	1,634
Net Oil-Equivalent Production (MBOEPD)	743	763	727
Sales of Natural Gas (MMCFPD)	7,624	7,051	5,449
Sales of Natural Gas Liquids (MBPD)	160	124	151
Revenues From Net Production			
Liquids (\$/Bbl)	\$ 63.16	\$ 56.66	\$ 46.97
Natural Gas (\$/MCF)	\$ 6.12	\$ 6.29	\$ 7.43
International Upstream³			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	1,296	1,270	1,214
Net Natural Gas Production (MMCFPD) ⁴	3,320	3,146	2,599
Net Oil-Equivalent			
Production (MBOEPD) ⁵	1,876	1,904	1,790
Sales Natural Gas (MMCFPD)	3,792	3,478	2,450
Sales Natural Gas Liquids (MBPD)	118	102	120
Revenues From Liftings			
Liquids (\$/Bbl)	\$ 65.01	\$ 57.65	\$ 47.59
Natural Gas (\$/MCF)	\$ 3.90	\$ 3.73	\$ 3.19
U.S. and International Upstream³			
Net Oil-Equivalent Production Including			
Other Produced Volumes (MBOEPD) ^{4,5}			
United States	743	763	727
International	1,876	1,904	1,790
Total	2,619	2,667	2,517
U.S. Downstream			
Gasoline Sales (MBPD) ⁶	728	712	709
Other Refined-Product Sales (MBPD)	729	782	764
Total (MBPD) ⁷	1,457	1,494	1,473
Refinery Input (MBPD)	812	939	845
International Downstream			
Gasoline Sales (MBPD) ⁶	581	595	662
Other Refined-Product Sales (MBPD)	1,446	1,532	1,590
Total (MBPD) ^{7,8}	2,027	2,127	2,252
Refinery Input (MBPD)	1,021	1,050	1,038

¹ Includes equity in affiliates.

² MBPD = Thousands of barrels per day; MMCFPD = Millions of cubic feet per day; MBOEPD = Thousands of barrels of oil-equivalent per day; Bbl = Barrel; MCF = Thousands of cubic feet. Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of gas = 1 barrel of oil.

³ Includes net production beginning August 2005, for properties associated with acquisition of Unocal.

⁴ Includes natural gas consumed in operations (MMCFPD):

United States	65	56	48
International	433	419	356

⁵ Includes other produced volumes (MBPD):

Athabasca Oil Sands – Net	27	27	32
Boscan Operating Service Agreement	–	82	111
Total	27	109	143

⁶ Includes branded and unbranded gasoline.

⁷ Includes volumes for buy/sell contracts (MBPD):

United States	–	26	88
International	–	24	129

⁸ Includes sales of affiliates (MBPD):

Total	492	492	498
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Liquidity and Capital Resources

Cash, cash equivalents and marketable securities Total balances were \$8.1 billion and \$11.4 billion at December 31, 2007 and 2006, respectively. Cash provided by operating activities in 2007 was \$25.0 billion, compared with \$24.3 billion in 2006 and \$20.1 billion in 2005.

Cash provided by operating activities was net of contributions to employee pension plans of \$300 million, \$400 million and \$1.0 billion in 2007, 2006 and 2005, respectively. Cash provided by investing activities included proceeds from asset sales of \$3.3 billion in 2007, \$1.0 billion in 2006 and \$2.7 billion in 2005.

Cash provided by operating activities and asset sales during 2007 was sufficient to fund the company's \$17.7 billion capital and exploratory program, pay \$4.8 billion of dividends to stockholders and repay approximately \$3.7 billion of debt.

Restricted cash of \$799 million associated with capital-investment projects at the company's Pascagoula, Mississippi, refinery and Angola liquefied natural gas project was invested in short-term marketable securities and reclassified from cash equivalents to a long-term asset on the Consolidated Balance Sheet.

Dividends The company paid dividends of approximately \$4.8 billion in 2007, \$4.4 billion in 2006 and \$3.8 billion in 2005. In April 2007, the company increased its quarterly common stock dividend by 11.5 percent to 58 cents per share.

Debt, capital lease and minority interest obligations Total debt and capital lease balances were \$7.2 billion at December 31, 2007, down from \$9.8 billion at year-end 2006. The company also had minority interest obligations of \$204 million, down from \$209 million at December 31, 2006.

The \$2.6 billion reduction in total debt and capital lease obligations during 2007 included the early redemption and maturity of individual debt issues. In February, \$144 million of Texaco Capital Inc. bonds matured. In the second and fourth quarters, the company redeemed approximately \$809 million and \$65 million, respectively, of Texaco Capital Inc.

debt and recognized an after-tax loss of approximately \$175 million. In August, \$2 billion of Chevron Canada Funding Company bonds matured. In December, the company issued a \$650 million tax exempt Mississippi Gulf Opportunity Zone bond to fund an upgrade project at the company's refinery in Pascagoula, Mississippi. Commercial paper balances at the end of 2007 declined approximately \$450 million from \$3.5 billion at year-end 2006. In February 2008, \$750 million of Chevron Canada Funding Company bonds matured.

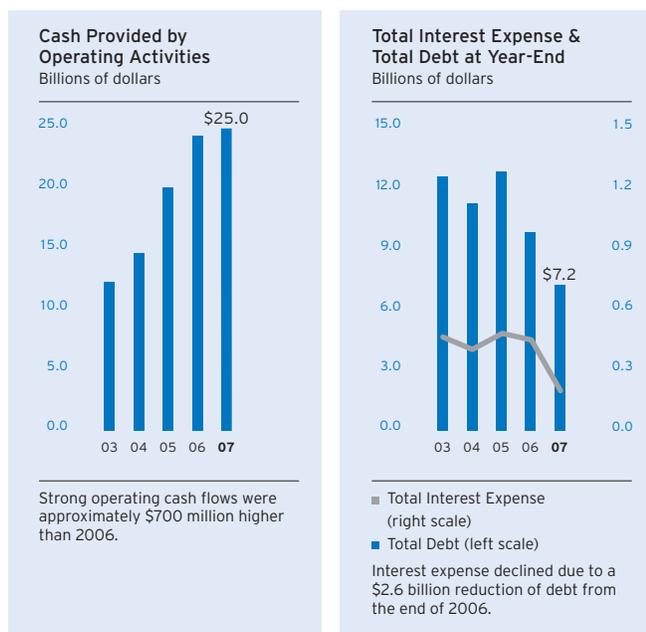
The company's debt and capital lease obligations due within one year, consisting primarily of commercial paper and the current portion of long-term debt, totaled \$5.5 billion at December 31, 2007, down from \$6.6 billion at year-end 2006. Of these amounts, \$4.4 billion and \$4.5 billion were reclassified to long-term at the end of each period, respectively. At year-end 2007, settlement of these obligations was not expected to require the use of working capital within one year, 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 2007, the company had \$5 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, 2007.

In March 2007, the company filed with the Securities and Exchange Commission (SEC) an automatic registration statement that expires in March 2010. This registration statement is for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company. At the same time, the company withdrew three shelf registration statements on file with the SEC that permitted the issuance of up to \$3.8 billion of debt securities.

At December 31, 2007, the company had outstanding public bonds issued by Chevron Corporation Profit Sharing/Savings Plan Trust Fund, Chevron Canada Funding Company (formerly ChevronTexaco Capital Company), Texaco Capital Inc. and Union Oil Company of California. All of these securities are guaranteed by Chevron Corporation and are rated AA by Standard and Poor's Corporation and Aa1 by Moody's Investors Service. The rating by Moody's reflects an upgrade in December from Aa2. 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 A \$5 billion stock repurchase program initiated in December 2006 was completed in September 2007. During 2007, about 61.5 million common shares were acquired under this program at a total cost of \$4.9 billion. Upon completion of this program, the company authorized the acquisition of up to \$15 billion of additional common shares from time to time at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. The program is for a period of up to three years and may be discontinued at any time. As of December 31, 2007, 23.5 million shares had been acquired under the new program for \$2.1 billion. Purchases through mid-February 2008 increased the total shares acquired to 34.2 million at a cost of approximately \$3.0 billion.

Capital and exploratory expenditures Total reported expenditures for 2007 were \$20 billion, including \$2.3 billion for the company's share of affiliates' expenditures, which did not require cash outlays by the company. In 2006 and 2005, expenditures were \$16.6 billion and \$11.1 billion, respectively, including the company's share of affiliates' expenditures of \$1.9 billion and \$1.7 billion in the corresponding periods. The 2005 amount excludes \$17.3 billion for the acquisition of Unocal Corporation.

Of the \$20 billion in expenditures for 2007, about three-fourths, or \$15.5 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2006 and 2005. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the three years, reflecting the company's continuing focus on opportunities that are available outside the United States.

Capital and Exploratory Expenditures

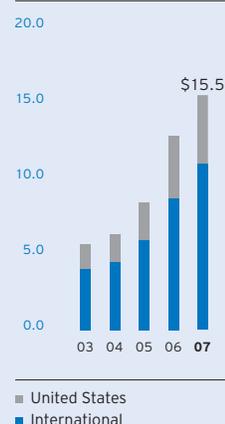
Millions of dollars	2007			2006			2005		
	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream – Exploration and Production	\$ 4,558	\$10,980	\$15,538	\$ 4,123	\$ 8,696	\$12,819	\$ 2,450	\$ 5,939	\$ 8,389
Downstream – Refining, Marketing and Transportation	1,576	1,867	3,443	1,176	1,999	3,175	818	1,332	2,150
Chemicals	218	53	271	146	54	200	108	43	151
All Other	768	6	774	403	14	417	329	44	373
Total	\$ 7,120	\$12,906	\$20,026	\$ 5,848	\$10,763	\$16,611	\$ 3,705	\$ 7,358	\$11,063
Total, Excluding Equity in Affiliates	\$ 6,900	\$10,790	\$17,690	\$ 5,642	\$ 9,050	\$14,692	\$ 3,522	\$ 5,860	\$ 9,382

In 2008, the company estimates capital and exploratory expenditures will be 15 percent higher at \$22.9 billion, including \$2.6 billion of spending by affiliates. About three-fourths of the total, or \$17.5 billion, is budgeted for exploration and production activities, with \$12.7 billion of this amount outside the United States. Spending in 2008 is primarily targeted for exploratory prospects in the deep-water U.S. Gulf of Mexico and western Africa and major development projects in Angola, Australia, Brazil, Indonesia, Kazakhstan, Nigeria, Thailand, the deepwater U.S. Gulf of Mexico, the Piceance Basin in Colorado and an oil sands project in Canada.

Worldwide downstream spending in 2008 is estimated at \$4.1 billion, with about \$2.3 billion for projects in the United States. Capital projects include upgrades to 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 2008 are budgeted at \$1.3 billion. Technology investments include projects related to unconventional hydrocarbon technologies, oil and gas reservoir management and gas-fired and renewable power generation.

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



Exploration and production expenditures increased by \$2.7 billion in 2007. Many significant projects were in their capital-intensive phase.

*Includes equity in affiliates

Pension Obligations In 2007, the company's pension plan contributions were \$317 million (approximately \$78 million to the U.S. plans). The company estimates contributions in 2008 will be approximately \$500 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in "Critical Accounting Estimates and Assumptions," beginning on page 46.

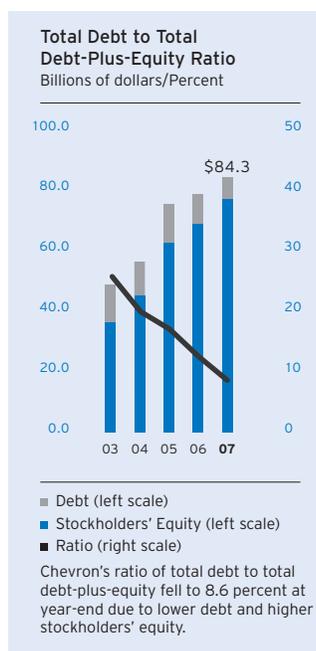
Financial Ratios

Financial Ratios

	At December 31		
	2007	2006	2005
Current Ratio	1.2	1.3	1.4
Interest Coverage Ratio	69.2	53.5	47.5
Total Debt/Total Debt-Plus-Equity	8.6%	12.5%	17.0%

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 2007, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately \$7 billion.

Interest Coverage Ratio – income before income tax expense, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs. The company's interest coverage ratio was higher between 2007 and 2006 and between 2006 and 2005, primarily due to higher before-tax income and lower average debt balances in each of the subsequent years.



Debt Ratio – total debt as a percentage of total debt plus equity. The progressive decrease between 2005 and 2007, was due to lower average debt levels and higher stockholders' equity balances.

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

Direct Guarantee

Millions of dollars	Commitment Expiration by Period				
	Total	2008	2009–2011	2012	After 2012
Guarantee of non-consolidated affiliate or joint-venture obligation	\$ 613	\$ –	\$ –	\$ 38	\$ 575

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 reduce 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 carries 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 2007, 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 must be asserted no later than February 2009 for Equilon indemnities and no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

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

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. Under the indemnification agreement, the company's liability is unlimited until April 2022, when the indemnification expires. The acquirer shares in certain environmental

remediation costs up to a maximum obligation of \$200 million, which had not been reached as of December 31, 2007.

Securitization During 2007, the company completed the sale of its U.S. proprietary consumer credit card business and related receivables. This transaction included terminating the qualifying Special Purpose Entity (SPE) that was used to securitize associated retail accounts receivable.

Through the use of another qualifying SPE, the company had \$675 million of securitized trade accounts receivable related to its downstream business as of December 31, 2007. This arrangement has the effect of accelerating Chevron's collection of the securitized amounts. Chevron's total estimated financial exposure under this securitization at December 31, 2007, was \$65 million. In the event that the SPE experiences major defaults in the collection of receivables, Chevron believes that it would have no additional loss exposure connected with third-party investments in this securitization.

Minority Interests The company has commitments of \$204 million related to minority interests in subsidiary companies.

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: 2008 – \$4.7 billion; 2009 – \$3.3 billion; 2010 – \$3.3 billion; 2011 – \$1.9 billion; 2012 – \$1.3 billion; 2013 and after – \$4.9 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3.7 billion in 2007, \$3.0 billion in 2006 and \$2.1 billion in 2005.

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

Contractual Obligations

<i>Millions of dollars</i>	Payments Due by Period				
	Total	2008	2009–2011	2012	After 2012
On Balance Sheet: ¹					
Short-Term Debt ²	\$ 1,162	\$ 1,162	\$ –	\$ –	\$ –
Long-Term Debt ²	5,664	–	4,926	33	705
Noncancelable Capital					
Lease Obligations	406	–	193	61	152
Interest	3,950	360	899	292	2,399
Off-Balance-Sheet:					
Noncancelable Operating					
Lease Obligations	3,167	513	1,255	293	1,106
Throughput and					
Take-or-Pay Agreements	13,118	3,699	4,783	618	4,018
Other Unconditional					
Purchase Obligations ³	6,300	988	3,779	653	880

¹ 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 due. 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.

² \$4.4 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2009–2011 period.

³ 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 liquefied natural gas and related natural gas liquids per year. Volumes and prices associated with these purchase obligations are neither fixed nor determinable.

Financial and Derivative Instruments

No material change in market risk occurred between 2006 and 2007 for the financial and derivative instruments discussed below. The hypothetical variances used in this section were selected for illustrative purposes only and do not represent the company's estimation of market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2007 Annual Report on Form 10-K.

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

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of this activity were not material to the company's financial position, net income or cash flows in 2007.

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

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

Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes.

Effective with 2007 year-end reporting, the company changed the model used to quantify information about market risk for its commodity derivatives from a "sensitivity analysis" approach to Value-at-Risk (VaR). The major reason for the change is that VaR allows estimation of a portfolio's aggregate market risk exposure and takes into account correlations between trading assets. Therefore, it reflects risk reduction due to diversification or hedging activities. Most of the company's market positions are time and commodity spreads, and the company believes that VaR is a more accurate tool to measure this type of exposure than the sensitivity analysis model. The company fully developed and tested its VaR model during 2007.

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 potential portfolio's values.

The VaR model utilizes an exponentially weighted moving average for computing historical volatilities and correlations, a 95 percent confidence level, and 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 nonexchange-traded swaps, most of which can be liquidated or hedged effectively within one day. The table below presents 95 percent/one-day VaR for each of the company's primary risk exposures in the area of commodity derivative instruments at December 31, 2007:

Millions of dollars	2007
Crude Oil	\$ 29
Natural Gas	3
Refined Products	23

Sensitivity analysis for the company's open commodity derivative instruments at December 31, 2007, and December 31, 2006, based on a hypothetical 10 percent increase in commodity prices, is provided in the following table:

Incremental Increase (Decrease) in Fair Value of Open Commodity Derivative Contracts Assuming a Hypothetical Increase in Year-End Commodity Prices of 10 Percent

Millions of dollars	2007	2006
Crude Oil	\$ (113)	\$ 4
Natural Gas	14	10
Refined Products	(96)	(30)

The same hypothetical decrease in prices of these commodities would result in approximately the same opposite effects on the fair values of the contracts. The hypothetical effect on these contracts was estimated by calculating the fair value of the contracts as the difference between the hypothetical and current market prices multiplied by the contract amounts.

The change in the amounts between years in the table above for crude oil and refined products is associated with an increase in commodity prices, volumes hedged and the use of longer-term contracts.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The aggregate effect of a hypothetical 10 percent increase in the value of the U.S. dollar at year-end 2007 would be a reduction in the fair value of the foreign exchange contracts of approximately \$75 million. The effect would be the opposite for a hypothetical 10 percent decrease in the value of the U.S. dollar at year-end 2007.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company's fixed-rate debt are accounted for as fair value hedges. Interest rate swaps related to floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2007, the company had no interest-rate swaps on floating-rate debt. At year-end 2007, the weighted average maturity of "receive fixed" interest rate swaps was less than one year. A hypothetical increase or decrease of 10 basis points in fixed interest rates would have a *de minimis* impact on the fair value of the "receive fixed" swaps.

Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements. Long-term purchase agreements are in place with the

company's refining affiliate in Thailand. Refer to page 33 for further discussion. Management believes the foregoing agreements and others have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

Litigation and Other Contingencies

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. The company is a party to 88 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepages of MTBE into groundwater. Chevron has agreed in principle to a tentative settlement of 60 pending lawsuits and claims. The terms of this agreement, which must be approved by a number of parties, including the court, are confidential and not material to the company's results of operations, liquidity or financial position.

Resolution of remaining 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 tentative settlement of the referenced 60 lawsuits did not set any precedents related to standards of liability to be used to judge the merits of the claims, corrective measures required or monetary damages to be assessed for the remaining lawsuits and claims or future lawsuits and claims. As a result, the company's ultimate exposure related to pending lawsuits and claims is not currently 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.

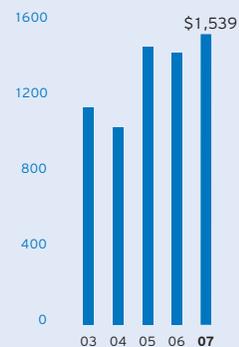
RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal's undisclosed and pending patents. Eleven lawsuits were consolidated in U.S. District Court for the Central District of California, where a class action has been certified, and three were consolidated in a state court action. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys' fees, and interest on behalf of an alleged class of consumers

who purchased "summertime" RFG in California from January 1995 through August 2005. The parties have reached a tentative agreement to resolve all of the above matters in an amount that is not material to the company's results of operations, liquidity or financial position. The terms of this agreement are confidential and subject to further negotiation and approval, including by the courts.

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

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

Year-End Environmental
Remediation Reserves
Millions of dollars



Reserves for environmental remediation at the end of 2007 were up 7 percent from the prior year. Reserves increased in 2005 due to the assumption of Unocal environmental liabilities.

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.

<i>Millions of dollars</i>	2007	2006	2005
Balance at January 1	\$ 1,441	\$ 1,469	\$ 1,047
Net Additions	562	366	731
Expenditures	(464)	(394)	(309)
Balance at December 31	\$ 1,539	\$ 1,441	\$ 1,469

Included in the \$1,539 million year-end 2007 reserve balance were remediation activities of 240 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 2007 was \$123 million. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's consolidated financial position or liquidity.

Of the remaining year-end 2007 environmental reserves balance of \$1,416 million, \$864 million related to approximately 2,000 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining \$552 million was associated with various sites in international downstream (\$146 million), upstream (\$267 million), chemicals (\$105 million) and other (\$34 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2007 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

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

The company accounts for asset retirement obligations in accordance with Financial Accounting Standards Board Statement (FASB) No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). Under FAS 143, the fair value of a liability for an asset retirement obligation is recorded when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. The liability balance of approximately \$8.3 billion for asset retirement obligations at year-end 2007 related primarily to upstream and mining 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, beginning on page 84, related to FAS 143 and the company's adoption in 2005 of FASB Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143* (FIN 47), and the discussion of "Environmental Matters" on page 46.

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 70 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, 2007, the company had approximately \$1.7 billion of suspended exploratory wells included in properties, plant and equipment, an increase of \$421 million from 2006 and an increase of \$551 million from 2005.

The future trend of the company's exploration expenses can be affected by amounts associated with well write-offs, including wells that had been previously suspended pending determination as to whether the well had found reserves that could be classified as proved. The effect on exploration expenses in future periods of the \$1.7 billion of suspended wells at year-end 2007 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page 74, 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 2007 at approximately \$2.7 billion for its consolidated companies. Included in these expenditures were approximately \$900 million 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 2008, total worldwide environmental capital expenditures are estimated at \$1.9 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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

Critical Accounting Estimates and Assumptions

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

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

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

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

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be “more likely than not.” Another example is the estimation of crude oil and natural gas reserves under SEC rules that require “... geological and engineering data (that) demonstrate with reasonable certainty (reserves) to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.” Refer to Table V, “Reserve Quantity Information,” beginning on page 93, for the changes in these estimates for the three years ending December 31, 2007, and to Table VII, “Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves” on page 101 for estimates of proved-reserve values for each of the three years ending December 31, 2007, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements, beginning on page 59, 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 48, 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 59. 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 20, beginning on page 75, includes information on the funded status of the company’s pension and OPEB plans

at the end of 2007 and 2006; the components of pension and OPEB expense for the three years ending December 31, 2007; and the underlying assumptions for those periods.

Pension and OPEB expense is recorded on the Consolidated Statement of Income in “Operating expenses” or “Selling, general and administrative expenses” and applies to all business segments. The year-end 2007 and 2006 funded status, measured as the difference between plan assets and obligations, of each of the company’s pension and OPEB plans is recognized on the Consolidated Balance Sheet. The funded status of overfunded pension plans is recorded as a long-term asset in “Deferred charges and other assets.” The funded status of underfunded or unfunded pension and OPEB plans is recorded in “Accrued liabilities” or “Reserves for employee benefit plans.” Amounts yet to be recognized as components of pension or OPEB expense are recorded in “Accumulated other comprehensive income.”

To estimate the long-term rate of return on pension assets, the company uses a process that incorporates actual historical asset-class returns and an assessment of expected future performance and takes into consideration external actuarial advice and asset-class factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company’s estimates of long-term rates of return are consistent with these studies. The expected long-term rate of return on U.S. pension plan assets, which account for 67 percent of the company’s pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2007, actual asset returns averaged 8.7 percent for this plan.

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

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2007, the company selected a 6.3 percent discount rate for the major U.S. pension and postretirement plans. This rate was selected based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2007. The discount rates at the end of 2006 and 2005 were 5.8 percent and 5.5 percent, respectively.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2007 was \$620 million. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the company’s primary U.S. pension plan would have reduced total pension plan expense for 2007 by approximately \$70

million. A 1 percent increase in the discount rate for this same plan, which accounted for about 60 percent of the company-wide pension obligation, would have reduced total pension plan expense for 2007 by approximately \$155 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan recorded on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2007, for underfunded plans was approximately \$1.7 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan would have reduced the plan obligation by approximately \$250 million, which would have increased the plan's overfunded status from approximately \$160 million to \$410 million. Other plans would be less underfunded as discount rates increase. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

In 2007, the company's pension plan contributions were \$317 million (including \$78 million to the U.S. plans). In 2008, the company estimates contributions will be approximately \$500 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

For the company's OPEB plans, expense for 2007 was \$233 million and the total liability, which reflected the underfunded status of the plans at the end of 2007, was \$2.9 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2007, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 75 percent of the company-wide OPEB expense, would have decreased OPEB expense by approximately \$20 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 87 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2007 by approximately \$60 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. The cap becomes effective in the year of retirement for pre-Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre-Medicare-eligible employees retiring before that date and all Medicare-eligible retirees. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 8 percent in 2008 and gradually drop to 5 percent for 2014 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB

expense in 2007, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for about 87 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 20, beginning on page 75, for information on the \$3.3 billion of before-tax actuarial losses recorded by the company as of December 31, 2007; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2008.

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 were recorded for the three years ending December 31, 2007. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for

impairment when the fair value of the investment falls below the company's carrying value. When such a decline is deemed to be other than temporary, an impairment charge is recorded to the income statement for the difference between the investment's carrying value and its estimated fair value at the time. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. Differing assumptions could affect whether an investment is impaired in any period or the amount of the impairment and are not subject to sensitivity analysis.

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

Business Combinations – Purchase-Price Allocation Accounting for business combinations requires the allocation of the company's purchase price to the various assets and liabilities of the acquired business at their respective fair values. The company uses all available information to make these fair value determinations, and for major acquisitions, may hire an independent appraisal firm to assist in making fair value estimates. In some instances, assumptions with respect to the timing and amount of future revenues and expenses associated with an asset might have to be used in determining its fair value. Actual timing and amount of net cash flows from revenues and expenses related to that asset over time may differ materially from those initial estimates, and if the timing is delayed significantly or if the net cash flows decline significantly, the asset could become impaired.

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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 records 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 70. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, and environmental remediation and tax matters for the three years ended December 31, 2007.

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

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which became effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 does not require any new fair value measurements but applies to assets and liabilities that are required to be recorded at fair value under other accounting standards. The implementation of FAS 157 did not have a material effect on the company's results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Its Related Interpretive Accounting Pronouncements That Address Leasing Transactions (FSP 157-1) In February 2008, the FASB issued FSP 157-1, which became effective for the company on January 1, 2008. This FSP excludes FASB Statement No. 13, *Accounting for Leases*, and its related interpretive accounting pronouncements from the provisions of FAS 157. Implementation of this standard did not have a material effect on the company's results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-2, Effective Date of FASB Statement No. 157 (FSP 157-2) In February 2008, the FASB issued FSP 157-2, which delays the company's January 1, 2008, effective date of FAS 157 for all nonfinancial assets

and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. Implementation of this standard did not have a material effect on the company's results of operations or consolidated financial position.

FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 (FAS 159) In February 2007, the FASB issued FAS 159, which became effective for the company on January 1, 2008. This standard permits companies to choose to measure many financial instruments and certain other items at fair value and report unrealized gains and losses in earnings. Such accounting is optional and is generally to be applied instrument by instrument. The implementation of FAS 159 did not have a material effect on the company's results of operations or consolidated financial position.

FASB Statement No. 141 (revised 2007), Business Combinations (FAS 141-R) In December 2007, the FASB issued FAS 141-R, which will become effective for business combination transactions having an acquisition date on or after January 1, 2009. This standard requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date to be measured at their respective fair values. The Statement requires acquisition-related costs, as well as restructuring costs the acquirer expects to incur for which

it is not obligated at acquisition date, to be recorded against income rather than included in purchase-price determination. It also requires recognition of contingent arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in income.

FASB Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (FAS 160) The FASB issued FAS 160 in December 2007, which will become effective for the company January 1, 2009, with retroactive adoption of the Statement's presentation and disclosure requirements for existing minority interests. This standard will require ownership interests in subsidiaries held by parties other than the parent to be presented within the equity section of the consolidated statement of financial position but separate from the parent's equity. It will also require the amount of consolidated net income attributable to the parent and the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement. Certain changes in a parent's ownership interest are to be accounted for as equity transactions and when a subsidiary is deconsolidated, any noncontrolling equity investment in the former subsidiary is to be initially measured at fair value. The company does not anticipate the implementation of FAS 160 will significantly change the presentation of its consolidated income statement or consolidated balance sheet.

Quarterly Results and Stock Market Data

Unaudited

<i>Millions of dollars, except per-share amounts</i>	2007				2006			
	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q
Revenues and Other Income								
Sales and other operating revenues ^{1,2}	\$ 59,900	\$ 53,545	\$ 54,344	\$ 46,302	\$ 46,238	\$ 52,977	\$ 52,153	\$ 53,524
Income from equity affiliates	1,153	1,160	894	937	1,079	1,080	1,113	983
Other income	357	468	856	988	429	155	270	117
Total Revenues and Other Income	61,410	55,173	56,094	48,227	47,746	54,212	53,536	54,624
Costs and Other Deductions								
Purchased crude oil and products ²	38,056	33,988	33,138	28,127	27,658	32,076	32,747	35,670
Operating expenses	4,798	4,397	4,124	3,613	4,092	3,650	3,835	3,047
Selling, general and administrative expenses	1,833	1,446	1,516	1,131	1,203	1,428	1,207	1,255
Exploration expenses	449	295	273	306	547	284	265	268
Depreciation, depletion and amortization	2,094	2,495	2,156	1,963	1,988	1,923	1,807	1,788
Taxes other than on income ¹	5,560	5,538	5,743	5,425	5,533	5,403	5,153	4,794
Interest and debt expense	7	22	63	74	92	104	121	134
Minority interests	35	25	19	28	2	20	22	26
Total Costs and Other Deductions	52,832	48,206	47,032	40,667	41,115	44,888	45,157	46,982
Income Before Income Tax Expense	8,578	6,967	9,062	7,560	6,631	9,324	8,379	7,642
Income Tax Expense	3,703	3,249	3,682	2,845	2,859	4,307	4,026	3,646
Net Income	\$ 4,875	\$ 3,718	\$ 5,380	\$ 4,715	\$ 3,772	\$ 5,017	\$ 4,353	\$ 3,996
Per-Share of Common Stock								
Net Income								
– Basic	\$ 2.34	\$ 1.77	\$ 2.52	\$ 2.20	\$ 1.75	\$ 2.30	\$ 1.98	\$ 1.81
– Diluted	\$ 2.32	\$ 1.75	\$ 2.52	\$ 2.18	\$ 1.74	\$ 2.29	\$ 1.97	\$ 1.80
Dividends	\$ 0.58	\$ 0.58	\$ 0.58	\$ 0.52	\$ 0.52	\$ 0.52	\$ 0.52	\$ 0.45
Common Stock Price Range – High³	\$ 94.86	\$ 94.84	\$ 84.24	\$ 74.95	\$ 75.97	\$ 67.85	\$ 62.88	\$ 62.21
– Low³	\$ 83.79	\$ 80.76	\$ 74.83	\$ 66.43	\$ 62.94	\$ 60.88	\$ 56.78	\$ 54.08
¹ Includes excise, value-added and similar taxes:	\$ 2,548	\$ 2,550	\$ 2,609	\$ 2,414	\$ 2,498	\$ 2,522	\$ 2,416	\$ 2,115
² Includes amounts for buy/sell contracts:	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$ 6,725
³ End of day price.								

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 22, 2008, stockholders of record numbered approximately 214,000. There are no restrictions on the company's ability to pay dividends.

Management's Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

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

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

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

Management's Report on Internal Control Over Financial Reporting

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company's internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the company's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.



David J. O'Reilly
Chairman of the Board
and Chief Executive Officer

February 28, 2008



Stephen J. Crowe
Vice President
and Chief Financial Officer



Mark A. Humphrey
Vice President
and Comptroller

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, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2007, and December 31, 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, 2007, 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 Controls 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.

As discussed in Note 13 to the Consolidated Financial Statements, the Company changed its method of accounting for buy/sell contracts on April 1, 2006.

As discussed in Note 15 to the Consolidated Financial Statements, the Company changed its method of accounting for uncertain income tax positions on January 1, 2007.

As discussed in Note 20 to the Consolidated Financial Statements, the Company changed its method of accounting for defined benefit pension and other postretirement plans on December 31, 2006.

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 28, 2008*

Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2007	2006	2005
Revenues and Other Income			
Sales and other operating revenues ^{1,2}	\$ 214,091	\$ 204,892	\$ 193,641
Income from equity affiliates	4,144	4,255	3,731
Other income	2,669	971	828
Total Revenues and Other Income	220,904	210,118	198,200
Costs and Other Deductions			
Purchased crude oil and products ²	133,309	128,151	127,968
Operating expenses	16,932	14,624	12,191
Selling, general and administrative expenses	5,926	5,093	4,828
Exploration expenses	1,323	1,364	743
Depreciation, depletion and amortization	8,708	7,506	5,913
Taxes other than on income ¹	22,266	20,883	20,782
Interest and debt expense	166	451	482
Minority interests	107	70	96
Total Costs and Other Deductions	188,737	178,142	173,003
Income Before Income Tax Expense	32,167	31,976	25,197
Income Tax Expense	13,479	14,838	11,098
Net Income	\$ 18,688	\$ 17,138	\$ 14,099
Per-Share of Common Stock			
Net Income			
– Basic	\$ 8.83	\$ 7.84	\$ 6.58
– Diluted	\$ 8.77	\$ 7.80	\$ 6.54
¹ Includes excise, value-added and similar taxes.	\$ 10,121	\$ 9,551	\$ 8,719
² Includes amounts in revenues for buy/sell contracts; associated costs are in "Purchased crude oil and products." Refer also to Note 13, on page 69.	\$ –	\$ 6,725	\$ 23,822

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2007	2006	2005
Net Income	\$ 18,688	\$ 17,138	\$ 14,099
Currency translation adjustment			
Unrealized net change arising during period	31	55	(5)
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	17	(88)	(32)
Reclassification to net income of net realized loss	2	–	–
Total	19	(88)	(32)
Derivatives			
Net derivatives (loss) gain on hedge transactions	(10)	2	(242)
Reclassification to net income of net realized loss	7	95	34
Income taxes on derivatives transactions	(3)	(30)	77
Total	(6)	67	(131)
Defined benefit plans			
Minimum pension liability adjustment	–	(88)	89
Actuarial loss			
Amortization to net income of net actuarial loss	356	–	–
Actuarial gain arising during period	530	–	–
Prior service cost			
Amortization to net income of net prior service credits	(15)	–	–
Prior service cost arising during period	204	–	–
Nonsponsored defined benefit plans	19	–	–
Income taxes on defined benefit plans	(409)	50	(31)
Total	685	(38)	58
Other Comprehensive Gain (Loss), Net of Tax	729	(4)	(110)
Comprehensive Income	\$ 19,417	\$ 17,134	\$ 13,989

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amounts

	At December 31	
	2007	2006
Assets		
Cash and cash equivalents	\$ 7,362	\$ 10,493
Marketable securities	732	953
Accounts and notes receivable (less allowance: 2007 – \$165; 2006 – \$175)	22,446	17,628
Inventories:		
Crude oil and petroleum products	4,003	3,586
Chemicals	290	258
Materials, supplies and other	1,017	812
Total inventories	5,310	4,656
Prepaid expenses and other current assets	3,527	2,574
Total Current Assets	39,377	36,304
Long-term receivables, net	2,194	2,203
Investments and advances	20,477	18,552
Properties, plant and equipment, at cost	154,084	137,747
Less: Accumulated depreciation, depletion and amortization	75,474	68,889
Properties, plant and equipment, net	78,610	68,858
Deferred charges and other assets	3,491	2,088
Goodwill	4,637	4,623
Total Assets	\$ 148,786	\$ 132,628
Liabilities and Stockholders' Equity		
Short-term debt	\$ 1,162	\$ 2,159
Accounts payable	21,756	16,675
Accrued liabilities	5,275	4,546
Federal and other taxes on income	3,972	3,626
Other taxes payable	1,633	1,403
Total Current Liabilities	33,798	28,409
Long-term debt	5,664	7,405
Capital lease obligations	406	274
Deferred credits and other noncurrent obligations	15,007	11,000
Noncurrent deferred income taxes	12,170	11,647
Reserves for employee benefit plans	4,449	4,749
Minority interests	204	209
Total Liabilities	71,698	63,693
Preferred stock (authorized 100,000,000 shares, \$1.00 par value; none issued)	–	–
Common stock (authorized 4,000,000,000 shares, \$0.75 par value; 2,442,676,580 shares issued at December 31, 2007 and 2006)	1,832	1,832
Capital in excess of par value	14,289	14,126
Retained earnings	82,329	68,464
Notes receivable – key employees	(1)	(2)
Accumulated other comprehensive loss	(2,015)	(2,636)
Deferred compensation and benefit plan trust	(454)	(454)
Treasury stock, at cost (2007 – 352,242,618 shares; 2006 – 278,118,341 shares)	(18,892)	(12,395)
Total Stockholders' Equity	77,088	68,935
Total Liabilities and Stockholders' Equity	\$ 148,786	\$ 132,628

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Millions of dollars

	Year ended December 31		
	2007	2006	2005
Operating Activities			
Net income	\$ 18,688	\$ 17,138	\$ 14,099
Adjustments			
Depreciation, depletion and amortization	8,708	7,506	5,913
Dry hole expense	507	520	226
Distributions less than income from equity affiliates	(1,439)	(979)	(1,304)
Net before-tax gains on asset retirements and sales	(2,315)	(229)	(134)
Net foreign currency effects	378	259	62
Deferred income tax provision	261	614	1,393
Net decrease (increase) in operating working capital	685	1,044	(54)
Minority interest in net income	107	70	96
(Increase) in long-term receivables	(82)	(900)	(191)
(Increase) decrease in other deferred charges	(530)	232	668
Cash contributions to employee pension plans	(317)	(449)	(1,022)
Other	326	(503)	353
Net Cash Provided by Operating Activities	24,977	24,323	20,105
Investing Activities			
Cash portion of Unocal acquisition, net of Unocal cash received	–	–	(5,934)
Capital expenditures	(16,678)	(13,813)	(8,701)
Repayment of loans by equity affiliates	21	463	57
Proceeds from asset sales	3,338	989	2,681
Net sales of marketable securities	185	142	336
Net purchases of other short-term investments	(799)	–	–
Net Cash Used for Investing Activities	(13,933)	(12,219)	(11,561)
Financing Activities			
Net payments of short-term obligations	(345)	(677)	(109)
Repayments of long-term debt and other financing obligations	(3,343)	(2,224)	(966)
Proceeds from issuances of long-term debt	650	–	20
Cash dividends – common stock	(4,791)	(4,396)	(3,778)
Dividends paid to minority interests	(77)	(60)	(98)
Net purchases of treasury shares	(6,389)	(4,491)	(2,597)
Redemption of preferred stock of subsidiaries	–	–	(140)
Net Cash Used for Financing Activities	(14,295)	(11,848)	(7,668)
Effect of Exchange Rate Changes			
On Cash and Cash Equivalents	120	194	(124)
Net Change in Cash and Cash Equivalents	(3,131)	450	752
Cash and Cash Equivalents at January 1	10,493	10,043	9,291
Cash and Cash Equivalents at December 31	\$ 7,362	\$ 10,493	\$ 10,043

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Stockholders' Equity

Shares in thousands; amounts in millions of dollars

	2007		2006		2005	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred Stock	–	\$ –	–	\$ –	–	\$ –
Common Stock						
Balance at January 1	2,442,677	\$ 1,832	2,442,677	\$ 1,832	2,274,032	\$ 1,706
Shares issued for Unocal acquisition	–	–	–	–	168,645	126
Balance at December 31	2,442,677	\$ 1,832	2,442,677	\$ 1,832	2,442,677	\$ 1,832
Capital in Excess of Par						
Balance at January 1		\$ 14,126		\$ 13,894		\$ 4,160
Shares issued for Unocal acquisition		–		–		9,585
Treasury stock transactions		163		232		149
Balance at December 31		\$ 14,289		\$ 14,126		\$ 13,894
Retained Earnings						
Balance at January 1		\$ 68,464		\$ 55,738		\$ 45,414
Net income		18,688		17,138		14,099
Cash dividends on common stock		(4,791)		(4,396)		(3,778)
Adoption of EITF 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry"		–		(19)		–
Adoption of FIN 48, "Accounting for Uncertainty in Income Taxes"		(35)		–		–
Tax benefit from dividends paid on unallocated ESOP shares and other		3		3		3
Balance at December 31		\$ 82,329		\$ 68,464		\$ 55,738
Notes Receivable – Key Employees		\$ (1)		\$ (2)		\$ (3)
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		\$ (90)		\$ (145)		\$ (140)
Change during year		31		55		(5)
Balance at December 31		\$ (59)		\$ (90)		\$ (145)
Pension and other postretirement benefit plans						
Balance at January 1		\$ (2,585)		\$ (344)		\$ (402)
Change to defined benefit plans during year		685		(38)		58
Adoption of FAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"		(108)		(2,203)		–
Balance at December 31		\$ (2,008)		\$ (2,585)		\$ (344)
Unrealized net holding gain on securities						
Balance at January 1		\$ –		\$ 88		\$ 120
Change during year		19		(88)		(32)
Balance at December 31		\$ 19		\$ –		\$ 88
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		\$ 39		\$ (28)		\$ 103
Change during year		(6)		67		(131)
Balance at December 31		\$ 33		\$ 39		\$ (28)
Balance at December 31		\$ (2,015)		\$ (2,636)		\$ (429)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		\$ (214)		\$ (246)		\$ (367)
Net reduction of ESOP debt and other		–		32		121
Balance at December 31		(214)		(214)		(246)
Benefit Plan Trust (Common Stock)	14,168	(240)	14,168	(240)	14,168	(240)
Balance at December 31	14,168	\$ (454)	14,168	\$ (454)	14,168	\$ (486)
Treasury Stock at Cost						
Balance at January 1	278,118	\$ (12,395)	209,990	\$ (7,870)	166,912	\$ (5,124)
Purchases	85,429	(7,036)	80,369	(5,033)	52,013	(3,029)
Issuances – mainly employee benefit plans	(11,304)	539	(12,241)	508	(8,935)	283
Balance at December 31	352,243	\$ (18,892)	278,118	\$ (12,395)	209,990	\$ (7,870)
Total Stockholders' Equity at December 31		\$ 77,088		\$ 68,935		\$ 62,676

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. Subsequent recoveries in the carrying value of other investments are reported in "Other comprehensive income."

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

Derivatives The majority of the company's activity in commodity derivative instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's commodity trading activity, gains and losses from the derivative instruments are reported in current income. For derivative instruments relating to foreign currency exposures, gains and losses are reported in current income. Interest rate swaps – hedging a portion of the company's fixed-rate debt – are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the Consolidated Balance Sheet, with resulting gains and losses reflected in income. 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 are marked-to-market, with any unrealized gains or losses included in "Other comprehensive income."

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

Note 1 Summary of Significant Accounting Policies – Continued

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs 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 74, for additional discussion of accounting for suspended exploratory well costs.

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

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

As required under Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143), the fair value of a liability for an ARO is recorded as an asset and a liability when there is a

legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 23, beginning on page 84, relating to AROs.

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

Depreciation and depletion expenses for mining assets are determined using the unit-of-production method as the 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 FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company’s U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and

mineral producing properties, a liability for an asset retirement obligation is made, following FAS 143. Refer to Note 23, beginning on page 84, for a discussion of FAS 143.

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

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

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

Revenue Recognition Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized on the basis of the company's net working interest (entitlement method). Excise, value-added and 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 54. Refer to Note 13, on page 69, for a discussion of the accounting for buy/sell arrangements.

Stock Options and Other Share-Based Compensation Effective July 1, 2005, the company adopted the provisions of FASB Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

Refer to Note 21, beginning on page 80, for a description of the company's share-based compensation plans, information related to awards granted under those plans and additional information on the company's adoption of FAS 123R.

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123R to stock options, stock appreciation rights, performance units and restricted stock units for the full year 2005.

	Year ended December 31
	2005
Net income, as reported	\$ 14,099
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	81
Deduct: Total stock-based employee compensation expense determined under fair-valued-based method for awards, net of related tax effects*	(108)
Pro forma net income	\$ 14,072
Net income per share:	
Basic – as reported	\$ 6.58
Basic – pro forma	\$ 6.56
Diluted – as reported	\$ 6.54
Diluted – pro forma	\$ 6.53

*Fair value determined using the Black-Scholes option-pricing model.

Note 2

Acquisition of Unocal Corporation

In August 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. The aggregate purchase price of Unocal was \$17,288. The final purchase-price allocation to the assets and liabilities acquired was completed as of June 30, 2006.

The following unaudited pro forma summary presents the results of operations as if the acquisition of Unocal had occurred at the beginning of 2005:

	Year ended December 31
	2005
Sales and other operating revenues	\$ 198,762
Net income	14,967
Net income per share of common stock	
Basic	\$ 6.68
Diluted	\$ 6.64

The pro forma summary used estimates and assumptions based on information available at the time. Management believes the estimates and assumptions to be reasonable; however, actual results may have differed significantly from this pro forma financial information.

Note 3

Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2007	2006	2005
Net decrease (increase) in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	\$ (3,867)	\$ 17	\$ (3,164)
Increase in inventories	(749)	(536)	(968)
Increase in prepaid expenses and other current assets	(370)	(31)	(54)
Increase in accounts payable and accrued liabilities	4,930	1,246	3,851
Increase in income and other taxes payable	741	348	281
Net decrease (increase) in operating working capital	\$ 685	\$ 1,044	\$ (54)
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	\$ 470	\$ 455
Income taxes	\$ 12,340	\$ 13,806	\$ 8,875
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	\$ (1,975)	\$ (1,271)	\$ (918)
Marketable securities sold	2,160	1,413	1,254
Net sales (purchases) of marketable securities	\$ 185	\$ 142	\$ 336

The Consolidated Statement of Cash Flows does not include noncash financing and investing activities. Refer to Note 23, starting on page 84, for a discussion of revisions to the company's asset retirement obligations that did not involve cash receipts or payments in 2007.

In accordance with the cash-flow classification requirements of FAS 123R, *Share-Based Payment*, the "Net decrease (increase) in operating working capital" includes reductions of \$96 and \$94 for excess income tax benefits associated with stock options exercised during 2007 and 2006, respectively. These amounts are offset by "Net purchases of treasury shares."

The 2007 "Net purchases of other short-term investments" consist of \$799 in restricted cash associated with capital-investment projects at the company's Pascagoula, Mississippi, refinery and Angola liquefied natural gas project that was invested in short-term marketable securities and reclassified from cash equivalents to a long-term deferred asset on the Consolidated Balance Sheet. In December 2007, the company issued a \$650 tax exempt Mississippi Gulf Opportunity Zone Bond as a source of funds for the Pascagoula Refinery project.

The "Net purchases of treasury shares" represents the cost of common shares acquired in the open market less the cost of shares issued for share-based compensation plans. Open-

market purchases totaled \$7,036, \$5,033 and \$3,029 in 2007, 2006 and 2005, respectively.

The major components of "Capital expenditures" and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, presented in Management's Discussion and Analysis, beginning on page 30, are presented in the following table:

	Year ended December 31		
	2007	2006	2005
Additions to properties, plant and equipment*	\$ 16,127	\$ 12,800	\$ 8,154
Additions to investments	881	880	459
Current-year dry hole expenditures	418	400	198
Payments for other liabilities and assets, net	(748)	(267)	(110)
Capital expenditures	16,678	13,813	8,701
Expensed exploration expenditures	816	844	517
Assets acquired through capital lease obligations and other financing obligations	196	35	164
Capital and exploratory expenditures, excluding equity affiliates	17,690	14,692	9,382
Equity in affiliates' expenditures	2,336	1,919	1,681
Capital and exploratory expenditures, including equity affiliates	\$ 20,026	\$ 16,611	\$ 11,063

*Net of noncash additions of \$3,560 in 2007, \$440 in 2006 and \$435 in 2005.

Note 4

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

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

During 2007, 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 on the following page gives retroactive effect to the reorganizations as if they had occurred on January 1, 2005. However, the financial information on the following page may not reflect the financial position and operating results in the periods presented if the reorganization actually had occurred on that date.

NOTE 4 Summarized Financial Data - Chevron U.S.A. Inc. - Continued

	Year ended December 31		
	2007	2006	2005
Sales and other operating revenues	\$ 153,574	\$ 145,774	\$ 137,866
Total costs and other deductions	147,510	137,765	131,809
Net income	5,203	5,668	4,775

	At December 31	
	2007	2006
Current assets	\$ 32,803	\$ 26,066
Other assets	27,401	23,538
Current liabilities	20,050	16,917
Other liabilities	11,447	9,037
Net equity	28,707	23,650

Memo: Total debt \$ 4,433 \$ 3,465

Note 5**Summarized Financial Data – Chevron Transport Corporation Ltd.**

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

	Year ended December 31		
	2007	2006	2005
Sales and other operating revenues	\$ 667	\$ 692	\$ 640
Total costs and other deductions	713	602	509
Net income	(39)	119	113

	At December 31	
	2007	2006
Current assets	\$ 335	\$ 413
Other assets	337	345
Current liabilities	107	92
Other liabilities	188	250
Net equity	377	416

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2007.

Note 6**Stockholders' Equity**

Retained earnings at December 31, 2007 and 2006, included approximately \$7,284 and \$5,580, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2007, about 120 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 454,000 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 7**Financial and Derivative Instruments**

For the financial and derivative instruments discussed below, no material change in market risk occurred relative to the information presented in 2006.

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

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

The company uses International Swaps 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 marked-to-market exposure represents the netting of the positive and negative exposures with that counterparty and is a reasonable measure of the company's credit risk exposure. The company also uses other netting agreements with certain counterparties with which it conducts significant transactions to mitigate credit risk.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as "Accounts and notes receivable," "Accounts payable," "Long-term receivables – net" and "Deferred credits and other noncurrent obligations." Gains and losses on the company's risk management activities are reported as either "Sales and other operating revenues" or "Purchased crude oil and products," whereas trading gains and losses are reported as "Other income."

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

Note 7 Financial and Derivative Instruments - Continued

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as “Accounts and notes receivable” or “Accounts payable,” with gains and losses reported as “Other income.”

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company’s fixed-rate debt are accounted for as fair value hedges.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as “Accounts and notes receivable” or “Accounts payable.”

Fair Value Fair values are derived from quoted market prices, other independent third-party quotes or, if not available, the present value of the expected cash flows. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end.

Long-term debt of \$2,132 and \$5,131 had estimated fair values of \$2,325 and \$5,621 at December 31, 2007 and 2006, respectively.

The company holds cash equivalents and marketable securities in U.S. and non-U.S. portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had carrying/fair values of \$5,427 and \$9,200 at December 31, 2007 and 2006, respectively. Of these balances, \$4,695 and \$8,247 at the respective year-ends were classified as cash equivalents that had average maturities under 90 days. The remainder, classified as marketable securities, had average maturities of approximately one year. At December 31, 2007, restricted cash with a carrying/fair value of \$799 that is related to capital-investment projects at the company’s Pascagoula, Mississippi, refinery and Angola liquefied natural gas project was reclassified from cash equivalents to a long-term deferred asset on the Consolidated Balance Sheet. This restricted cash was invested in short-term marketable securities.

Fair values of other financial and derivative instruments at the end of 2007 and 2006 were not material.

Concentrations of Credit Risk The company’s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, marketable securities, derivative financial instruments and trade receivables. The company’s short-term investments are placed with a wide array of 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 consequence, the company believes concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, requiring Letters of Credit is a principal method used to support sales to customers.

Note 8

Operating Segments and Geographic Data

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. For this purpose, the investments are grouped as follows: upstream – exploration and production; downstream – refining, marketing and transportation; chemicals; and all other. The first three of these groupings represent the company’s “reportable segments” and “operating segments” as defined in Financial Accounting Standards Board (FASB) Statement No. 131, *Disclosures About Segments of an Enterprise and Related Information* (FAS 131).

The segments are separately managed for investment purposes under a structure that includes “segment managers” who report to the company’s “chief operating decision maker” (CODM) (terms as defined in FAS 131). The CODM is the company’s Executive Committee, a committee of senior officers that includes the Chief Executive Officer and that, in turn, reports to the Board of Directors of Chevron Corporation.

The operating segments represent components of the company as described in FAS 131 terms that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and to assess their performance; and (c) for which discrete financial information is available.

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

“All Other” activities include the company’s interest in Dynege (through May 2007, when Chevron sold its interest), mining operations, power generation businesses, worldwide

Note 8 Operating Segments and Geographic Data - Continued

cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels, and technology companies.

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

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

	Year ended December 31		
	2007	2006	2005
Income by Major Operating Area			
Upstream			
United States	\$ 4,532	\$ 4,270	\$ 4,168
International	10,284	8,872	7,556
Total Upstream	14,816	13,142	11,724
Downstream			
United States	966	1,938	980
International	2,536	2,035	1,786
Total Downstream	3,502	3,973	2,766
Chemicals			
United States	253	430	240
International	143	109	58
Total Chemicals	396	539	298
Total Segment Income	18,714	17,654	14,788
All Other			
Interest expense	(107)	(312)	(337)
Interest income	385	380	266
Other	(304)	(584)	(618)
Net Income	\$ 18,688	\$ 17,138	\$ 14,099

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2007 and 2006 are as follows:

	At December 31	
	2007	2006
Upstream		
United States	\$ 23,535	\$ 20,727
International	61,049	51,844
Goodwill	4,637	4,623
Total Upstream	89,221	77,194
Downstream		
United States	16,790	13,482
International	26,075	22,892
Total Downstream	42,865	36,374
Chemicals		
United States	2,484	2,568
International	870	832
Total Chemicals	3,354	3,400
Total Segment Assets	135,440	116,968
All Other*		
United States	6,847	8,481
International	6,499	7,179
Total All Other	13,346	15,660
Total Assets – United States	49,656	45,258
Total Assets – International	94,493	82,747
Goodwill	4,637	4,623
Total Assets	\$ 148,786	\$ 132,628

*"All Other" assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company's investment in Dynege prior to its disposition in 2007, mining operations, power generation businesses, technology companies, and assets of the corporate administrative functions.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2007, 2006 and 2005 are presented in the following table. Products are transferred between operating segments at internal product values that approximate market prices.

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

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

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

Note 8 Operating Segments and Geographic Data - Continued

	Year ended December 31		
	2007	2006	2005
Upstream			
United States	\$ 18,736	\$ 18,061	\$ 16,044
Intersegment	11,625	10,069	8,651
Total United States	30,361	28,130	24,695
International	15,213	14,560	10,190
Intersegment	19,647	17,139	13,652
Total International	34,860	31,699	23,842
Total Upstream	65,221	59,829	48,537
Downstream			
United States	70,535	69,367	73,721
Excise and similar taxes	4,990	4,829	4,521
Intersegment	491	533	535
Total United States	76,016	74,729	78,777
International	97,178	91,325	83,223
Excise and similar taxes	5,042	4,657	4,184
Intersegment	38	37	14
Total International	102,258	96,019	87,421
Total Downstream	178,274	170,748	166,198
Chemicals			
United States	351	372	343
Excise and similar taxes	2	2	-
Intersegment	235	243	241
Total United States	588	617	584
International	1,143	959	760
Excise and similar taxes	86	63	14
Intersegment	142	160	131
Total International	1,371	1,182	905
Total Chemicals	1,959	1,799	1,489
All Other			
United States	757	653	597
Intersegment	760	584	514
Total United States	1,517	1,237	1,111
International	58	44	44
Intersegment	31	23	26
Total International	89	67	70
Total All Other	1,606	1,304	1,181
Segment Sales and Other			
Operating Revenues			
United States	108,482	104,713	105,167
International	138,578	128,967	112,238
Total Segment Sales and Other			
Operating Revenues	247,060	233,680	217,405
Elimination of intersegment sales	(32,969)	(28,788)	(23,764)
Total Sales and Other			
Operating Revenues*	\$ 214,091	\$ 204,892	\$ 193,641

*Includes buy/sell contracts of \$6,725 in 2006 and \$23,822 in 2005. Substantially all of the amounts in each period relate to the downstream segment. Refer to Note 13, on page 69, for a discussion of the company's accounting for buy/sell contracts.

Segment Income Taxes Segment income tax expense for the years 2007, 2006 and 2005 are as follows:

	Year ended December 31		
	2007	2006	2005
Upstream			
United States	\$ 2,541	\$ 2,668	\$ 2,330
International	11,307	10,987	8,440
Total Upstream	13,848	13,655	10,770
Downstream			
United States	520	1,162	575
International	400	586	576
Total Downstream	920	1,748	1,151
Chemicals			
United States	6	213	99
International	36	30	25
Total Chemicals	42	243	124
All Other	(1,331)	(808)	(947)
Total Income Tax Expense	\$ 13,479	\$ 14,838	\$ 11,098

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 11, beginning on page 67. Information related to properties, plant and equipment by segment is contained in Note 12, on page 69.

Note 9

Lease Commitments

Certain noncancelable leases are classified as capital leases, and the leased assets are included as part of "Properties, plant and equipment, at cost." Such leasing arrangements involve tanker charters, crude oil production and processing equipment, service stations, 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	
	2007	2006*
Upstream	\$ 482	\$ 461
Downstream	\$ 551	\$ 550
Chemical and all other	171	2
Total	1,204	1,013
Less: Accumulated amortization	628	548
Net capitalized leased assets	\$ 576	\$ 465

*2006 conformed to 2007 presentation.

Rental expenses incurred for operating leases during 2007, 2006 and 2005 were as follows:

	Year ended December 31		
	2007	2006	2005
Minimum rentals	\$ 2,419	\$ 2,326	\$ 2,102
Contingent rentals	6	6	6
Total	2,425	2,332	2,108
Less: Sublease rental income	30	33	43
Net rental expense	\$ 2,395	\$ 2,299	\$ 2,065

Note 9 Lease Commitments - Continued

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

At December 31, 2007, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a non-cancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2008	\$ 513	\$ 103
2009	478	106
2010	430	83
2011	347	85
2012	293	91
Thereafter	1,106	347
Total	\$ 3,167	\$ 815
Less: Amounts representing interest and executory costs		(315)
Net present values		500
Less: Capital lease obligations included in short-term debt		(94)
Long-term capital lease obligations		\$ 406

Note 10

Restructuring and Reorganization Costs

In 2007, the company implemented a restructuring and reorganization program in its downstream operations. Approximately 1,000 employees were eligible for severance payments. Most of the associated positions are located outside the United States. The majority of the terminations are expected to occur in 2008, and the program is expected to be complete by the end of 2009.

Shown in the table below is the activity for the company's liability related to the downstream reorganization. The associated charges against income were categorized as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income.

Amounts before tax	2007
Balance at January 1	\$ -
Additions	85
Payments	-
Balance at December 31	\$ 85

Note 11

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		Equity in Earnings		
	At December 31		Year ended December 31		
	2007	2006	2007	2006	2005
Upstream					
Tengizchevroil	\$ 6,321	\$ 5,507	\$ 2,135	\$ 1,817	\$ 1,514
Hamaca	1,168	928	327	319	390
Petroboscan	762	712	185	31	-
Angola LNG Limited	574	-	21	-	-
Other	765	682	204	123	139
Total Upstream	9,590	7,829	2,872	2,290	2,043
Downstream					
GS Caltex Corporation	2,276	2,176	217	316	320
Caspian Pipeline Consortium	951	990	102	117	101
Star Petroleum Refining Company Ltd.	944	787	157	116	81
Escravos Gas-to-Liquids	628	432	103	146	95
Caltex Australia Ltd.	580	559	129	186	214
Colonial Pipeline Company	546	555	39	34	13
Other	1,501	1,407	215	212	178
Total Downstream	7,426	6,906	962	1,127	1,002
Chemicals					
Chevron Phillips Chemical Company LLC	2,024	2,044	380	697	449
Other	24	22	6	5	3
Total Chemicals	2,048	2,066	386	702	452
All Other					
Dynegy Inc.	-	254	8	68	189
Other	449	586	(84)	68	45
Total equity method	\$ 19,513	\$ 17,641	\$ 4,144	\$ 4,255	\$ 3,731
Other at or below cost	964	911			
Total investments and advances	\$ 20,477	\$ 18,552			
Total United States	\$ 3,889	\$ 4,191	\$ 478	\$ 955	\$ 833
Total International	\$ 16,588	\$ 14,361	\$ 3,666	\$ 3,300	\$ 2,898

Descriptions of major affiliates are as follows:

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude oil fields in Kazakhstan over a 40-year period. At December 31, 2007, the company's carrying value of its investment in TCO was about \$210 higher than the amount of underlying equity in TCO net assets.

Hamaca Chevron's 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt was converted to a 30 percent share-holding in a joint stock company in January 2008, with a 25-year contract term.

Note 11 Investments and Advances - Continued

Petroboscan Chevron has a 39 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela until 2026. Chevron previously operated the field under an operating service agreement. At December 31, 2007, the company's carrying value of its investment in Petroboscan was approximately \$310 higher than the amount of underlying equity in Petroboscan net assets.

Angola LNG Ltd. Chevron has a 36 percent interest in Angola LNG, 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, a joint venture with GS Holdings. The joint venture, originally formed in 1967 between the LG Group and Caltex, imports, refines and markets petroleum products and petrochemicals predominantly in South Korea.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC), which provides the critical export route for crude oil from both TCO and Karachaganak. At December 31, 2007, the company's carrying value of its investment in CPC was about \$50 higher than the amount of underlying equity in CPC net assets.

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

Escravos Gas-to-Liquids Chevron Nigeria Limited (CNL) has a 75 percent interest in Escravos Gas-to-Liquids (EGTL) with the other 25 percent of the joint venture owned by Nigeria National Petroleum Company. Sasol Ltd provides 50 percent of the venture capital required by CNL as risk-based financing (returns are based on project performance). This venture was formed to convert natural gas produced from Chevron's Nigerian operations into liquid products for sale in international markets. At December 31, 2007, the company's carrying value of its investment in EGTL was about \$25 lower than the amount of underlying equity in EGTL net assets.

Caltex Australia Ltd Chevron has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2007, the fair value of Chevron's share of CAL common stock was approximately \$2,294. The aggregate carrying value of the company's investment in CAL was approximately \$50 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest in the Colonial Pipeline Company. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market. At December 31, 2007, the company's carrying value of its investment in Colonial Pipeline was approximately \$580 higher than the amount of underlying equity in Colonial Pipeline net assets.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC (CPChem), with the other half owned by ConocoPhillips Corporation. At December 31, 2007, the company's carrying value of its investment in CPChem was approximately \$60 lower than the amount of underlying equity in CPChem net assets.

Dynege Inc. In May 2007, Chevron sold its 19 percent common stock investment in Dynege Inc., a provider of electricity to markets and customers throughout the United States, for approximately \$940, resulting in a gain of \$680.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes \$11,555, \$9,582 and \$8,824 with affiliated companies for 2007, 2006 and 2005, respectively. "Purchased crude oil and products" includes \$5,464, \$4,222 and \$3,219 with affiliated companies for 2007, 2006 and 2005, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes \$1,722 and \$1,297 due from affiliated companies at December 31, 2007 and 2006, respectively. "Accounts payable" includes \$374 and \$262 due to affiliated companies at December 31, 2007 and 2006, respectively.

Note 11 Investments and Advances - Continued

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share, which includes Chevron loans to affiliates of \$4,124 at December 31, 2007.

Year ended December 31	Affiliates			Chevron Share		
	2007	2006	2005	2007	2006	2005
Total revenues	\$ 94,864	\$ 73,746	\$ 64,642	\$ 46,579	\$ 35,695	\$ 31,252
Income before income tax expense	12,510	10,973	7,883	5,836	5,295	4,165
Net income	9,743	7,905	6,645	4,550	4,072	3,534
At December 31						
Current assets	\$ 26,360	\$ 19,769	\$ 19,903	\$ 11,914	\$ 8,944	\$ 8,537
Noncurrent assets	48,440	49,896	46,925	19,045	18,575	17,747
Current liabilities	19,033	15,254	13,427	9,009	6,818	6,034
Noncurrent liabilities	22,757	24,059	26,579	3,745	3,902	4,906
Net equity	\$ 33,010	\$ 30,352	\$ 26,822	\$ 18,205	\$ 16,799	\$ 15,344

Note 12

Properties, Plant and Equipment

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost ¹			Depreciation Expense ²		
	2007	2006	2005	2007	2006	2005	2007	2006	2005	2007	2006	2005
Upstream												
United States	\$ 50,991	\$ 46,191	\$ 43,390	\$ 19,850	\$ 16,706	\$ 15,327	\$ 5,725	\$ 3,739	\$ 2,160	\$ 2,700	\$ 2,374	\$ 1,869
International	71,408	61,281	54,497	43,431	37,730	34,311	10,512	7,290	4,897	4,605	3,888	2,804
Total Upstream	122,399	107,472	97,887	63,281	54,436	49,638	16,237	11,029	7,057	7,305	6,262	4,673
Downstream												
United States	15,807	14,553	13,832	7,685	6,741	6,169	1,514	1,109	793	509	474	461
International	10,471	11,036	11,235	4,690	5,233	5,529	519	532	453	633	551	550
Total Downstream	26,278	25,589	25,067	12,375	11,974	11,698	2,033	1,641	1,246	1,142	1,025	1,011
Chemicals												
United States	678	645	624	308	289	282	40	25	12	19	19	19
International	815	771	721	453	431	402	53	54	43	26	24	23
Total Chemicals	1,493	1,416	1,345	761	720	684	93	79	55	45	43	42
All Other³												
United States	3,873	3,243	3,127	2,179	1,709	1,655	680	270	199	215	171	186
International	41	27	20	14	19	15	5	8	4	1	5	1
Total All Other	3,914	3,270	3,147	2,193	1,728	1,670	685	278	203	216	176	187
Total United States	71,349	64,632	60,973	30,022	25,445	23,433	7,959	5,143	3,164	3,443	3,038	2,535
Total International	82,735	73,115	66,473	48,588	43,413	40,257	11,089	7,884	5,397	5,265	4,468	3,378
Total	\$ 154,084	\$ 137,747	\$ 127,446	\$ 78,610	\$ 68,858	\$ 63,690	\$ 19,048	\$ 13,027	\$ 8,561	\$ 8,708	\$ 7,506	\$ 5,913

¹ Net of dry hole expense related to prior years' expenditures of \$89, \$120 and \$28 in 2007, 2006 and 2005, respectively.

² Depreciation expense includes accretion expense of \$399, \$275 and \$187 in 2007, 2006 and 2005, respectively.

³ Primarily mining operations, power generation businesses, real estate assets and management information systems.

Note 13

Accounting for Buy/Sell Contracts

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

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

With the company's adoption of Issue 04-13, buy/sell transactions beginning in the second quarter 2006 are netted against each other on the Consolidated Statement of Income, with no effect on net income. Amounts associated with buy/sell transactions in periods prior to the second quarter 2006 are shown as a footnote to the Consolidated Statement of Income on page 54.

Note 14

Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. The company is a party to 88 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepages of MTBE into groundwater. Chevron has agreed in principle to a tentative settlement of 60 pending lawsuits and claims. The terms of this agreement, which must be approved by a number of parties, including the court, are confidential and not material to the company's results of operations, liquidity or financial position.

Resolution of remaining 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 tentative settlement of the referenced 60 lawsuits did not set any precedents related to standards of liability to be used to judge the merits of the claims, corrective measures required or monetary damages to be assessed for the remaining lawsuits and claims or future lawsuits and claims. As a result, the company's ultimate exposure related to pending lawsuits and claims is not currently 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.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal's undisclosed and pending patents. Eleven lawsuits were consolidated in U.S. District Court for the Central District of California, where a class action has been certified, and three were consolidated in a state court action. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys' fees, and interest on behalf of an alleged class of consumers who purchased "summertime" RFG in California from January 1995 through August 2005. The parties have reached a tentative agreement to resolve all of the above matters in an amount that is not material to the company's results of operations,

liquidity or financial position. The terms of this agreement are confidential, and subject to further negotiation and approval, including by the courts.

Note 15

Taxes

Income Taxes

	Year ended December 31		
	2007	2006	2005
Taxes on income			
U.S. Federal			
Current	\$ 1,446	\$ 2,828	\$ 1,459
Deferred	225	200	567
State and local	338	581	409
Total United States	2,009	3,609	2,435
International			
Current	11,416	11,030	7,837
Deferred	54	199	826
Total International	11,470	11,229	8,663
Total taxes on income	\$ 13,479	\$ 14,838	\$ 11,098

In 2007, before-tax income for U.S. operations, including related corporate and other charges, was \$7,794, compared with before-tax income of \$9,131 and \$6,733 in 2006 and 2005, respectively. For international operations, before-tax income was \$24,373, \$22,845 and \$18,464 in 2007, 2006 and 2005, respectively. U.S. federal income tax expense was reduced by \$132, \$116 and \$289 in 2007, 2006 and 2005, respectively, for business tax credits.

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

	Year ended December 31		
	2007	2006	2005
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	8.3	10.3	9.2
State and local taxes on income, net of U.S. federal income tax benefit	0.8	1.0	1.0
Prior-year tax adjustments	0.3	0.9	0.1
Tax credits	(0.4)	(0.4)	(1.1)
Effects of enacted changes in tax laws	(0.3)	0.3	—
Other	(1.8)	(0.7)	(0.1)
Effective tax rate	41.9%	46.4%	44.1%

The company's effective tax rate decreased by 4.5 percent in 2007 from the prior year. The 2 percent decrease pertaining to the "Effect of income taxes from international

Note 15 Taxes - Continued

operations ...” was primarily due to the impact of asset sales and to lower effective tax rates in certain non-U.S. operations. The 1 percent decrease in “Other” primarily relates to the effects of asset sales in 2007.

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	
	2007	2006
Deferred tax liabilities		
Properties, plant and equipment	\$ 17,310	\$ 16,054
Investments and other	1,837	2,137
Total deferred tax liabilities	19,147	18,191
Deferred tax assets		
Abandonment/environmental reserves	(3,587)	(2,925)
Employee benefits	(2,148)	(2,707)
Tax loss carryforwards	(1,603)	(1,509)
Capital losses	–	(246)
Deferred credits	(1,689)	(1,670)
Foreign tax credits	(3,138)	(1,916)
Inventory	(608)	(378)
Other accrued liabilities	(477)	(375)
Miscellaneous	(1,528)	(1,144)
Total deferred tax assets	(14,778)	(12,870)
Deferred tax assets valuation allowance	5,949	4,391
Total deferred taxes, net	\$ 10,318	\$ 9,712

In 2007, deferred tax liabilities increased by approximately \$1,000 from the amount reported in 2006. The increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets increased by approximately \$1,900 in 2007. The increase related primarily to additional foreign tax credits arising from earnings in high-tax-rate international jurisdictions. This increase was substantially offset by valuation allowances.

The overall valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences for which no benefit is expected to be realized. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2008 through 2029. Foreign tax credit carryforwards of \$3,138 will expire between 2008 and 2017.

At December 31, 2007 and 2006, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2007	2006
Prepaid expenses and other current assets	\$ (1,234)	\$ (1,167)
Deferred charges and other assets	(812)	(844)
Federal and other taxes on income	194	76
Noncurrent deferred income taxes	12,170	11,647
Total deferred income taxes, net	\$ 10,318	\$ 9,712

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 \$20,557 at December 31, 2007. 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 2007, 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 Effective January 1, 2007, the company implemented Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109* (FIN 48), which clarifies the accounting for income tax benefits that are uncertain in nature. This interpretation was intended by the standard-setters to address the diversity in practice that existed in this area of accounting for income taxes.

Under FIN 48, 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 FIN 48 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 accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, recognition of interest and penalties, and accounting for the cumulative-effect adjustment at the date of adoption. Upon adoption of FIN 48 on January 1, 2007, the company recorded a cumulative-effect adjustment that reduced retained earnings by \$35.

Note 15 Taxes - Continued

The following table indicates the changes to the company's unrecognized tax benefits for the year ended December 31, 2007. The term "unrecognized tax benefits" in FIN 48 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 in accordance with the guidelines of FIN 48. Interest and penalties are not included.

Balance at January 1, 2007 (date of FIN 48 adoption)	\$ 2,296
Foreign currency effects	19
Additions based on tax positions taken in 2007	418
Additions for tax positions taken in prior years	120
Reductions for tax positions taken in prior years	(225)
Settlements with taxing authorities in 2007	(255)
Reductions due to tax positions previously expected to be taken but subsequently not taken on 2006 tax returns	(174)
Balance at December 31, 2007	<u>\$ 2,199</u>

The only individually significant change for 2007 was a reduction in an unrecognized tax benefit for a position previously expected to be taken but subsequently not taken on a 2006 tax return. Although unrecognized tax benefits for individual tax positions may increase or decrease during 2008, the company believes that no change will be individually significant during 2008. Approximately 80 percent of the \$2,199 of unrecognized tax benefits at December 31, 2007, would have an impact on the overall 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, 2007. In this regard, the company received a final U.S. federal income tax audit report for years 2002 and 2003 in March 2007. In early 2008, the company's 2004 and 2005 tax returns were under examination by the Internal Revenue Service. For other major tax jurisdictions, the latest years for which income tax examinations had been finalized were as follows: 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, 2007, accruals of \$198 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet. For the year 2007, income tax expense associated with interest and penalties was not material.

Taxes Other Than on Income

	Year ended December 31		
	2007	2006	2005
United States			
Excise and similar taxes on products and merchandise	\$ 4,992	\$ 4,831	\$ 4,521
Import duties and other levies	12	32	8
Property and other miscellaneous taxes	491	475	392
Payroll taxes	185	155	149
Taxes on production	288	360	323
Total United States	5,968	5,853	5,393
International			
Excise and similar taxes on products and merchandise	5,129	4,720	4,198
Import duties and other levies	10,404	9,618	10,466
Property and other miscellaneous taxes	528	491	535
Payroll taxes	89	75	52
Taxes on production	148	126	138
Total International	16,298	15,030	15,389
Total taxes other than on income	\$ 22,266	\$ 20,883	\$ 20,782

Note 16

Short-Term Debt

	At December 31	
	2007	2006
Commercial paper*	\$ 3,030	\$ 3,472
Notes payable to banks and others with originating terms of one year or less	219	122
Current maturities of long-term debt	850	2,176
Current maturities of long-term capital leases	73	57
Redeemable long-term obligations		
Long-term debt	1,351	487
Capital leases	21	295
Subtotal	5,544	6,609
Reclassified to long-term debt	(4,382)	(4,450)
Total short-term debt	\$ 1,162	\$ 2,159

*Weighted-average interest rates at December 31, 2007 and 2006, were 4.35 percent and 5.25 percent, respectively.

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

The company periodically enters into interest rate swaps on a portion of its short-term debt. See Note 7, beginning on page 63, for information concerning the company's debt-related derivative activities.

At December 31, 2007, the company had \$4,950 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company's commercial paper borrowings. Interest on borrowings under the terms of

Note 16 Short-Term Debt - Continued

specific agreements may be based on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2007 or at year-end.

At December 31, 2007 and 2006, the company classified \$4,382 and \$4,450, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2008, 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, 2007, was \$5,664. The company's long-term debt outstanding at year-end 2007 and 2006 was as follows:

	At December 31	
	2007	2006
3.375% notes due 2008	\$ 749	\$ 738
5.5% notes due 2009	405	401
7.327% amortizing notes due 2014 ¹	213	213
8.625% debentures due 2032	161	199
8.625% debentures due 2031	108	199
7.5% debentures due 2043	85	198
8% debentures due 2032	81	148
9.75% debentures due 2020	57	250
8.875% debentures due 2021	46	150
8.625% debentures due 2010	30	150
3.85% notes due 2008	30	–
3.5% notes due 2007	–	1,996
7.09% notes due 2007	–	144
Medium-term notes, maturing from 2021 to 2038 (6.2%) ²	64	210
Fixed interest rate notes, maturing from 2008 to 2011 (8.2%) ²	27	46
Other foreign currency obligations (0.5%) ²	17	23
Other long-term debt (7.4%) ²	59	66
Total including debt due within one year	2,132	5,131
Debt due within one year	(850)	(2,176)
Reclassified from short-term debt	4,382	4,450
Total long-term debt	\$ 5,664	\$ 7,405

¹ Guarantee of ESOP debt.

² Weighted-average interest rate at December 31, 2007.

Long-term debt of \$2,132 matures as follows: 2008 – \$850; 2009 – \$431; 2010 – \$65; 2011 – \$48; 2012 – \$33; and after 2012 – \$705.

In 2007, \$2,000 of Chevron Canada Funding Company bonds matured. The company also redeemed early \$874 of Texaco Capital Inc. bonds, at an after-tax loss of approximately \$175. In 2006, \$510 in bonds were retired at maturity and \$1,700 of Unocal debt was redeemed early at a \$92 before-tax gain.

Note 18

New Accounting Standards

FASB Statement No. 157, Fair Value Measurements (FAS 157)

In September 2006, the FASB issued FAS 157, which became effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 does not require any new fair value measurements but applies to assets and liabilities that are required to be recorded at fair value under other accounting standards. The implementation of FAS 157 did not have a material effect on the company's results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Its Related Interpretive Accounting Pronouncements That Address Leasing Transactions (FSP 157-1)

In February 2008, the FASB issued FSP 157-1, which became effective for the company on January 1, 2008. This FSP excludes FASB Statement No. 13, Accounting for Leases, and its related interpretive accounting pronouncements from the provisions of FAS 157. Implementation of this standard did not have a material effect on the company's results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-2, Effective Date of FASB Statement No. 157 (FSP 157-2)

In February 2008, the FASB issued FSP 157-2, which delays the company's January 1, 2008, effective date of FAS 157 for all nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. Implementation of this standard did not have a material effect on the company's results of operations or consolidated financial position.

FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 (FAS 159)

In February 2007, the FASB issued FAS 159, which became effective for the company on January 1, 2008. This standard permits companies to choose to measure many financial instruments and certain other items at fair value and report unrealized gains and losses in earnings. Such accounting is optional and is generally to be applied instrument by instrument. The implementation of FAS 159 did not have a material effect on the company's results of operations or consolidated financial position.

FASB Statement No. 141 (revised 2007), Business Combinations (FAS 141-R)

In December 2007, the FASB issued FAS 141-R, which will become effective for business combination transactions having an acquisition date on or after January 1, 2009. This standard requires the acquiring entity in a business

Note 18 New Accounting Standards - Continued

combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date to be measured at their respective fair values. The Statement requires acquisition-related costs, as well as restructuring costs the acquirer expects to incur for which it is not obligated at acquisition date, to be recorded against income rather than included in purchase-price determination. It also requires recognition of contingent arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in income.

FASB Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (FAS 160) The FASB issued FAS 160 in December 2007, which will become effective for the company January 1, 2009, with retroactive adoption of the Statement's presentation and disclosure requirements for existing minority interests. This standard will require ownership interests in subsidiaries held by parties other than the parent to be presented within the equity section of the consolidated statement of financial position but separate from the parent's equity. It will also require the amount of consolidated net income attributable to the parent and the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement. Certain changes in a parent's ownership interest are to be accounted for as equity transactions and when a subsidiary is deconsolidated, any noncontrolling equity investment in the former subsidiary is to be initially measured at fair value. The company does not anticipate the implementation of FAS 160 will significantly change the presentation of its consolidated income statement or consolidated balance sheet.

Note 19

Accounting for Suspended Exploratory Wells

The company accounts for the cost of exploratory wells in accordance with FASB Statement No. 19, *Financial and Reporting by Oil and Gas Producing Companies* (FAS 19), as amended by FASB Staff Position (FSP) FAS 19-1, *Accounting for Suspended Well Costs*, which provides that exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FAS 19 provides a number of indicators that can assist an entity to demonstrate sufficient progress is being made in assessing the reserves and economic viability of the project.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2007. No capitalized exploratory well costs were charged to expense upon the 2005 adoption of FSP FAS 19-1.

	2007	2006	2005
Beginning balance at January 1	\$ 1,239	\$ 1,109	\$ 671
Additions associated with the acquisition of Unocal	—	—	317
Additions to capitalized exploratory well costs pending the determination of proved reserves	486	446	290
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(23)	(171)	(140)
Capitalized exploratory well costs charged to expense	(42)	(121)	(6)
Other reductions*	—	(24)	(23)
Ending balance at December 31	\$ 1,660	\$ 1,239	\$ 1,109

*Represent property sales and exchanges.

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling. The aging of the former Unocal wells is based on the date the drilling was completed, rather than the date of Chevron's acquisition of Unocal in 2005.

	At December 31		
	2007	2006	2005
Exploratory well costs capitalized for a period of one year or less	\$ 449	\$ 332	\$ 259
Exploratory well costs capitalized for a period greater than one year	1,211	907	850
Balance at December 31	\$ 1,660	\$ 1,239	\$ 1,109
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	54	44	40

*Certain projects have multiple wells or fields or both.

Of the \$1,211 of exploratory well costs capitalized for more than one year at December 31, 2007, \$750 (32 projects) is related to projects that had drilling activities under way or firmly planned for the near future. An additional \$8 (three projects) is related to projects that had drilling activity during 2007. The \$453 balance related to 19 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the \$453 referenced above had the following activities associated with assessing the reserves and the

projects' economic viability: (a) \$99 (one project) – combined two projects into a single development project and submitted plans to government in 2007; (b) \$74 (three projects) – continued unitization efforts on adjacent discoveries that span international boundaries; (c) \$74 (one project) – finalizing field development evaluation; (d) \$74 (one project) – field rework continues to accommodate larger design capacity and finalize sales agreements; (e) \$42 (one project) – finalizing development concept; (f) \$90 – miscellaneous activities for 12 projects with smaller amounts suspended. While progress was being made on all 54 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 \$1,211 of suspended well costs capitalized for a period greater than one year as of December 31, 2007, represents 127 exploratory wells in 54 projects. The tables below contain the aging of these costs on a well and project basis:

<i>Aging based on drilling completion date of individual wells:</i>	Amount	Number of wells
1994–1996	\$ 27	3
1997–2001	128	32
2002–2006	1,056	92
Total	\$ 1,211	127

<i>Aging based on drilling completion date of last suspended well in project:</i>	Amount	Number of projects
1999	\$ 8	1
2003–2007	1,203	53
Total	\$ 1,211	54

Note 20

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 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 provisions of the Pension Protection Act of 2006 (PPA) became effective for the company in 2008. These provisions change, among other things, the methodology for determining the interest rate to be used in calculating lump-sum benefits. This change in methodology increased the lump-sum interest rate and lowered the company's pension benefit obligations by about \$300 at December 31, 2007. The effect of the interest rate change on pension plan contributions during 2008 is expected to be *de minimis*, as the company's funded pension plans are considered "well-funded" under PPA provisions.

The company also sponsors other postretirement plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and 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.

Effective December 31, 2006, the company implemented the recognition and measurement provisions of Financial Accounting Standards Board Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)*, which requires the recognition of the overfunded or underfunded status of each of its defined benefit pension and other postretirement benefit plans as an asset or liability, with the offset to "Accumulated other comprehensive loss."

The company uses a measurement date of December 31 to value its benefit plan assets and obligations. The funded status of the company's pension and other postretirement benefit plans for 2007 and 2006 is as follows:

Notes to the Consolidated Financial Statements

Millions of dollars, except per-share amounts

Note 20 Employee Benefit Plans - Continued

	Pension Benefits				Other Benefits	
	2007		2006		2007	2006
	U.S.	Int'l.	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	\$ 8,792	\$ 4,207	\$ 8,594	\$ 3,611	\$ 3,257	\$ 3,252
Service cost	260	125	234	98	49	35
Interest cost	483	255	468	214	184	181
Plan participants' contributions	–	7	–	7	122	134
Plan amendments	(301)	97	14	37	–	107
Curtailments	–	(12)	–	–	–	–
Actuarial (gain) loss	(131)	(40)	297	97	(413)	(102)
Foreign currency exchange rate changes	–	219	–	355	12	(5)
Benefits paid	(708)	(225)	(815)	(212)	(272)	(345)
Benefit obligation at December 31	8,395	4,633	8,792	4,207	2,939	3,257
Change in Plan Assets						
Fair value of plan assets at January 1	7,941	3,456	7,463	2,890	–	–
Actual return on plan assets	607	232	1,069	225	–	–
Foreign currency exchange rate changes	–	183	–	321	–	–
Employer contributions	78	239	224	225	150	211
Plan participants' contributions	–	7	–	7	122	134
Benefits paid	(708)	(225)	(815)	(212)	(272)	(345)
Fair value of plan assets at December 31	7,918	3,892	7,941	3,456	–	–
Funded Status at December 31	\$ (477)	\$ (741)	\$ (851)	\$ (751)	\$ (2,939)	\$ (3,257)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2007 and 2006, include:

	Pension Benefits				Other Benefits	
	2007		2006		2007	2006
	U.S.	Int'l.	U.S.	Int'l.		
Deferred charges and other assets	\$ 181	\$ 279	\$ 18	\$ 96	\$ –	\$ –
Accrued liabilities	(68)	(55)	(53)	(47)	(207)	(223)
Reserves for employee benefit plans	(590)	(965)	(816)	(800)	(2,732)	(3,034)
Net amount recognized at December 31	\$ (477)	\$ (741)	\$ (851)	\$ (751)	\$ (2,939)	\$ (3,257)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and other postretirement plans were \$2,990 and \$4,065 at the end of 2007 and 2006. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2007		2006		2007	2006
	U.S.	Int'l.	U.S.	Int'l.		
Net actuarial loss	\$ 1,539	\$ 1,237	\$ 1,892	\$ 1,288	\$ 490	\$ 972
Prior-service costs (credit)	(75)	203	272	126	(404)	(485)
Total recognized at December 31	\$ 1,464	\$ 1,440	\$ 2,164	\$ 1,414	\$ 86	\$ 487

The accumulated benefit obligations for all U.S. and international pension plans were \$7,712 and \$4,000, respectively, at December 31, 2007, and \$7,987 and \$3,669, respectively, at December 31, 2006.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2007 and 2006, was:

	Pension Benefits			
	2007		2006	
	U.S.	Int'l.	U.S.	Int'l.
Projected benefit obligations	\$ 678	\$ 1,089	\$ 848	\$ 849
Accumulated benefit obligations	638	926	806	741
Fair value of plan assets	20	271	12	172

Note 20 Employee Benefit Plans - Continued

The components of net periodic benefit cost for 2007, 2006 and 2005 and amounts recognized in other comprehensive income for 2007 are shown in the table below. For 2007, changes in pension plan assets and benefit obligations were recognized as changes in other comprehensive income.

	2007		2006		2005		Other Benefits		
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	2007	2006	2005
Net Periodic Benefit Cost									
Service cost	\$ 260	\$ 125	\$ 234	\$ 98	\$ 208	\$ 84	\$ 49	\$ 35	\$ 30
Interest cost	483	255	468	214	395	199	184	181	164
Expected return on plan assets	(578)	(266)	(550)	(227)	(449)	(208)	-	-	-
Amortization of transitional assets	-	-	-	1	-	2	-	-	-
Amortization of prior-service costs (credits)	46	17	46	14	45	16	(81)	(86)	(91)
Recognized actuarial losses	128	82	149	69	177	51	81	97	93
Settlement losses	65	-	70	-	86	-	-	-	-
Curtailement losses	-	3	-	-	-	-	-	-	-
Net periodic benefit cost	404	216	417	169	462	144	233	227	196
Changes Recognized in Other Comprehensive Income									
Net actuarial (gain) loss during period	(160)	31	-	-	-	-	(401)	-	-
Amortization of actuarial (loss)	(193)	(82)	-	-	-	-	(81)	-	-
Prior service (credit) cost during period	(301)	97	-	-	-	-	-	-	-
Amortization of prior-service (costs) credits	(46)	(20)	-	-	-	-	81	-	-
Total changes recognized in other comprehensive income	(700)	26	-	-	-	-	(401)	-	-
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	\$ (296)	\$ 242	\$ 417	\$ 169	\$ 462	\$ 144	\$ (168)	\$ 227	\$ 196

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2007, for the company's U.S. pension, international pension and other postretirement benefit plans are being amortized on a straight-line basis over approximately 10, 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 2008, the company estimates actuarial losses of \$59, \$80 and \$39 will be amortized from "Accumulated other comprehensive loss" for U.S. pension, international pension and other postretirement benefit plans,

respectively. In addition, the company estimates an additional \$78 will be recognized from "Accumulated other comprehensive loss" during 2008 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, 2007, was approximately nine and 11 years for U.S. and international pension plans, respectively, and six years for other postretirement benefit plans. During 2008, the company estimates prior service (credits) costs of \$(7), \$25 and \$(81) will be amortized from "Accumulated other comprehensive loss" for U.S. pension, international pension and other postretirement benefit plans, respectively.

Notes to the Consolidated Financial Statements

Millions of dollars, except per-share amounts

Note 20 Employee Benefit Plans - Continued

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

	Pension Benefits						Other Benefits		
	2007		2006		2005		2007	2006	2005
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Assumptions used to determine benefit obligations									
Discount rate	6.3%	6.7%	5.8%	6.0%	5.5%	5.9%	6.3%	5.8%	5.6%
Rate of compensation increase	4.5%	6.4%	4.5%	6.1%	4.0%	5.1%	4.5%	4.5%	4.0%
Assumptions used to determine net periodic benefit cost									
Discount rate ^{1,2}	5.8%	6.0%	5.8%	5.9%	5.5%	6.4%	5.8%	5.9%	5.8%
Expected return on plan assets ¹	7.8%	7.5%	7.8%	7.4%	7.8%	7.9%	N/A	N/A	N/A
Rate of compensation increase ¹	4.5%	6.1%	4.2%	5.1%	4.0%	5.0%	4.5%	4.2%	4.0%

¹ The 2005 discount rate, expected return on plan assets and rate of compensation increase reflect the remeasurement of the acquired Unocal benefit plans at July 31, 2005.

² The 2006 U.S. discount rate reflects remeasurement on July 1, 2006, due to plan combinations and changes, primarily several Unocal plans into related Chevron plans.

Expected Return on Plan Assets The company's estimated long-term rate of return on pension assets is driven primarily by actual historical asset-class returns, an assessment of expected future performance, advice from external actuarial firms and the incorporation of specific asset-class risk factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the 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 67 percent of the company's pension plan assets. At December 31, 2007, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

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

Discount Rate The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2007, the company selected a 6.3 percent discount rate for the major U.S. pension and postretirement plans. 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 2007. The discount rates at the end of 2006 and 2005 were 5.8 percent and 5.5 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2007, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 8 percent in 2008 and gradually decline to 5 percent for 2014 and beyond. For this measurement at December 31, 2006, the assumed health care cost-trend rates started with 9 percent in 2007 and gradually declined to 5 percent for 2011 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

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

	1 Percent Increase	1 Percent Decrease
Effect on total service and interest cost components	\$ 9	\$ (8)
Effect on postretirement benefit obligation	\$ 86	\$ (75)

Plan Assets and Investment Strategy The company's pension plan weighted-average asset allocations at December 31 by asset category are as follows:

Asset Category	U.S.		International	
	2007	2006	2007	2006
Equities	64%	68%	56%	62%
Fixed Income	23%	21%	43%	37%
Real Estate	12%	10%	1%	1%
Other	1%	1%	-	-
Total	100%	100%	100%	100%

The pension plans invest primarily in asset categories with sufficient size, liquidity and cost efficiency to permit investments of reasonable size. The pension plans invest in asset

categories that provide diversification benefits and are easily measured. To assess the plans' investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has approved the following percentage asset-allocation ranges: equities 40–70, fixed income/cash 20–60, real estate 0–15 and other 0–5. The significant international pension plans also have established maximum and minimum asset allocation ranges that vary by each plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset category risk.

Equities include investments in the company's common stock in the amount of \$36 and \$17 at December 31, 2007 and 2006, respectively. The "Other" asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments In 2007, the company contributed \$78 and \$239 to its U.S. and international pension plans, respectively. In 2008, the company expects contributions to be approximately \$300 and \$200 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon plan-investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately \$207 in 2008, as compared with \$150 paid in 2007.

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

	Pension Benefits		Other Benefits
	U.S.	Int'l.	
2008	\$ 832	\$ 238	\$ 207
2009	\$ 841	\$ 272	\$ 213
2010	\$ 849	\$ 282	\$ 219
2011	\$ 856	\$ 279	\$ 225
2012	\$ 863	\$ 296	\$ 228
2013–2017	\$ 4,338	\$ 1,819	\$ 1,195

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 follows. Total company matching contributions to employee accounts within the ESIP were \$206, \$169 and \$145 in 2007, 2006 and 2005, respectively. This cost was reduced by the value of

shares released from the LESOP totaling \$33, \$6 and \$4 in 2007, 2006 and 2005, respectively. The remaining amounts, totaling \$173, \$163 and \$141 in 2007, 2006 and 2005, respectively, represent open market purchases.

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

As permitted by American Institute of Certified Public Accountants (AICPA) Statement of Position 93-6, *Employers' Accounting for Employee Stock Ownership Plans*, the company has elected to continue its practices, which are based on AICPA Statement of Position 76-3, *Accounting Practices for Certain Employee Stock Ownership Plans*, and subsequent consensus of the EITF of the FASB. The debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" on the Consolidated Balance Sheet and the Consolidated Statement of Stockholders' Equity.

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

Total (credits) expenses recorded for the LESOP were \$(1), \$(1) and \$94 in 2007, 2006 and 2005, respectively, including \$16, \$17 and \$18 of interest expense related to LESOP debt and a (credit) charge to compensation expense of \$(17), \$(18) and \$76.

Of the dividends paid on the LESOP shares, \$8, \$59 and \$55 were used in 2007, 2006 and 2005, respectively, to service LESOP debt. The amount in 2006 included \$28 of LESOP debt service that was scheduled for payment on the first business day of January 2007 and was paid in late December 2006. In addition, the company made contributions in 2005 of \$98 to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2007 or 2006 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, 2007 and 2006, were as follows:

Thousands	2007	2006
Allocated shares	20,506	21,827
Unallocated shares	7,365	8,316
Total LESOP shares	27,871	30,143

Note 20 Employee Benefit Plans - Continued

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2007, the trust contained 14.2 million shares of Chevron treasury stock. The company intends to continue to pay its obligations under the benefit plans. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2007 and 2006, trust assets of \$69 and \$98, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans Chevron has two incentive plans, the Management Incentive Plan (MIP) and the Long-Term Incentive Plan (LTIP), for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by the recipients by conversion to stock units or other investment fund alternatives. Aggregate charges to expense for MIP were \$184, \$180 and \$155 in 2007, 2006 and 2005, respectively. Awards under LTIP consist of stock options and other share-based compensation that are described in Note 21 below.

Through 2007 the company had a program that provided eligible employees, other than those covered by MIP and LTIP, with an annual cash bonus if the company achieves certain financial and safety goals. Charges for the program were \$431, \$329 and \$324 in 2007, 2006 and 2005, respectively. Effective in 2008, this program was modified to mirror the design of MIP and both were combined into a single plan named the Chevron Incentive Plan (CIP).

Note 21

Stock Options and Other Share-Based Compensation

Effective July 1, 2005, the company adopted the provisions of Financial Accounting Standards Board (FASB) Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation*.

The company adopted FAS 123R using the modified prospective method, and accordingly, results for prior periods were

not restated. Refer to Note 1, beginning on page 59, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123R for the full year 2005.

For 2007, 2006 and 2005, compensation expense for stock options was \$146 (\$95 after tax), \$125 (\$81 after tax) and \$65 (\$42 after tax), respectively. In addition, compensation expense for stock appreciation rights, performance units and restricted stock units was \$205 (\$133 after tax), \$113 (\$73 after tax) and \$59 (\$39 after tax) for 2007, 2006 and 2005, respectively. There were no significant stock-based compensation costs that were capitalized at December 31, 2007 and 2006.

Cash received in payment for option exercises under all share-based payment arrangements for 2007, 2006 and 2005 was \$445, \$444 and \$297, respectively. Actual tax benefits realized for the tax deductions from option exercises were \$94, \$91 and \$71 for 2007, 2006 and 2005, respectively.

Cash paid to settle performance units and stock appreciation rights was \$88, \$68 and \$110 for 2007, 2006 and 2005, respectively. Cash paid in 2005 included \$73 for Unocal awards paid under change-in-control plan provisions.

The company presents the tax benefits of deductions from the exercise of stock options as financing cash inflows in the Consolidated Statement of Cash Flows. In 2006, the company implemented the transition method of FASB Staff Position FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, for calculating the beginning balance of the pool of excess tax benefits related to employee compensation and determining the subsequent impact on the pool of employee awards that were fully vested and outstanding upon the adoption of FAS 123R. The company's reported tax expense for the period subsequent to the implementation of FAS 123R was not affected by this election. Refer to Note 3, on page 62, for information on excess tax benefits reported on the company's Statement of Cash Flows.

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.

Stock options and stock appreciation rights granted under the LTIP extend for 10 years from grant date. Effective with options granted in June 2002, one-third of each award vests on the first, second and third anniversaries of the date of grant. Prior to this change, options vested one year after

Note 21 Stock Options and Other Share-Based Compensation - Continued

the date of grant. Performance units granted under the LTIP settle in cash at the end of a three-year performance period. Settlement amounts are based on achievement of performance targets relative to major competitors over the period, and payments are indexed to the company's stock price.

Texaco Stock Incentive Plan (Texaco SIP) On the closing of the acquisition of Texaco in October 2001, outstanding options granted under the Texaco SIP were converted to Chevron options. These options, 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 granted 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. Awards issued prior to 2004 generally may be exercised for up to three years after termination of employment (depending upon the terms of the individual award agreements) or the original expiration date, whichever is earlier. Awards issued since 2004 generally remained exercisable until the end of the normal option term if termination of employment occurred prior to August 10, 2007. Other awards issued under the Unocal Plans, including restricted stock, stock units, restricted stock units and performance shares, became vested at the acquisition date, and shares or cash were issued to recipients in accordance with change-in-control provisions of the plans.

The fair market values of stock options and stock appreciation rights granted in 2007, 2006 and 2005 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2007	2006	2005
Stock Options			
Expected term in years ¹	6.3	6.4	6.4
Volatility ²	22.0%	23.7%	24.5%
Risk-free interest rate based on zero coupon U.S. treasury note	4.5%	4.7%	3.8%
Dividend yield	3.2%	3.1%	3.4%
Weighted-average fair value per option granted	\$ 15.27	\$ 12.74	\$ 11.66
Restored Options			
Expected term in years ¹	1.6	2.2	2.1
Volatility ²	21.2%	19.6%	18.6%
Risk-free interest rate based on zero coupon U.S. treasury note	4.5%	4.8%	3.8%
Dividend yield	3.2%	3.3%	3.4%
Weighted-average fair value per option granted	\$ 8.61	\$ 7.72	\$ 6.09
Unocal Plans³			
Expected term in years ¹	—	—	4.2
Volatility ²	—	—	21.6%
Risk-free interest rate based on zero coupon U.S. treasury note	—	—	3.9%
Dividend yield	—	—	3.4%
Weighted-average fair value per option granted	—	—	\$ 21.48

¹ Expected term is based on historical exercise and post-vesting cancellation data.

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

³ Represent options converted at the acquisition date.

A summary of option activity during 2007 is presented below:

	Shares (Thousands)	Weighted- Average Exercise Price	Weighted- Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at				
January 1, 2007	55,945	\$ 47.91		
Granted	12,848	\$ 74.08		
Exercised	(14,340)	\$ 51.92		
Restored	3,458	\$ 80.45		
Forfeited	(554)	\$ 72.36		
Outstanding at				
December 31, 2007	57,357	\$ 54.50	6.3 yrs.	\$ 2,227
Exercisable at				
December 31, 2007	35,540	\$ 45.93	5.1 yrs.	\$ 1,685

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2007, 2006 and 2005 was \$423, \$281 and \$258, respectively.

Upon adoption of FAS 123R, the company elected to amortize newly issued graded awards on a straight-line basis over the requisite service period. In accordance with FAS 123R implementation guidance issued by the staff of the Securities and Exchange Commission, the company accelerates the vesting period for retirement-eligible employees in accordance with

Note 21 Stock Options and Other Share-Based Compensation - Continued

vesting provisions of the company's share-based compensation programs for awards issued after adoption of FAS 123R. As of December 31, 2007, there was \$160 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 two years.

At January 1, 2007, the number of LTIP performance units outstanding was equivalent to 2,110,196 shares. During 2007, 931,200 units were granted, 784,364 units vested with cash proceeds distributed to recipients and 32,017 units were forfeited. At December 31, 2007, units outstanding were 2,225,015, and the fair value of the liability recorded for these instruments was \$205. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 1 million equivalent shares as of December 31, 2007. A liability of \$38 was recorded for these awards.

Broad-Based Employee Stock Options In addition to the plans described above, Chevron granted all eligible employees stock options or equivalents in 1998. The options vested in February 2000 and expired in February 2008. A total of 9,641,600 options were awarded with an exercise price of \$38.16 per share.

The fair value of each option on the date of grant was estimated at \$9.54 using the Black-Scholes model for the preceding 10 years. The assumptions used in the model, based on a 10-year average, were: a risk-free interest rate of 7 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

At January 1, 2007, the number of broad-based employee stock options outstanding was 1,306,059. During 2007, exercises of 637,044 shares and forfeitures of 16,300 shares reduced outstanding options to 652,715. As of December 31, 2007, these instruments had an aggregate intrinsic value of \$36 and the remaining contractual term of these options was 0.1 year. The total intrinsic value of these options exercised during 2007, 2006 and 2005 was \$30, \$10 and \$9, respectively.

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 70 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 reduce 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 carries 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 2007, 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 must be asserted no later than February 2009 for Equilon indemnities and no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

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

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. Under the indemnification agreement, the company's liability is unlimited until April 2022, when the indemnification expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of \$200, which had not been reached as of December 31, 2007.

Securitization During 2007, the company completed the sale of its U.S. proprietary consumer credit card business and related receivables. This transaction included terminating the qualifying Special Purpose Entity (SPE) that was used to securitize associated retail accounts receivable.

Through the use of another qualifying SPE, the company had \$675 of securitized trade accounts receivable related to its downstream business as of December 31, 2007. This arrangement has the effect of accelerating Chevron's collection of the securitized amounts. Chevron's total estimated financial exposure under this securitization at December 31, 2007, was \$65. In the event that the SPE experiences major defaults in the collection of receivables, Chevron believes that it would have no additional loss exposure connected with third-party investments in this securitization.

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: 2008 - \$4,700; 2009 - \$3,300; 2010 - \$3,300; 2011 - \$1,900; 2012 - \$1,300; 2013 and after - \$4,900. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3,700 in 2007, \$3,000 in 2006 and \$2,100 in 2005.

Minority Interests The company has commitments of \$204 related to minority interests in subsidiary companies.

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

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

Chevron's environmental reserve as of December 31, 2007, was \$1,539. Included in this balance were remediation activities of 240 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 2007 was \$123. 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 2007 environmental reserves balance of \$1,416, \$864 related to approximately 2,000 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining \$552 was associated with various sites in the international downstream (\$146), upstream (\$267), chemicals (\$105) and other (\$34). 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 2007 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

Note 22 Other Contingencies and Commitments – Continued

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 below 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

The company accounts for asset retirement obligations (ARO) in accordance with Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). This accounting standard applies to the fair value of a liability for an ARO that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition in certain circumstances: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability

and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates. In 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143* (FIN 47), which was effective for the company on December 31, 2005. FIN 47 clarifies that the phrase “conditional asset retirement obligation,” as used in FAS 143, refers to a legal obligation to perform asset retirement activity for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the company. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Uncertainty about the timing and/or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an ARO. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. In adopting FIN 47, the company did not recognize any additional liabilities for conditional AROs due to an inability to reasonably estimate the fair value of those obligations because of their indeterminate settlement dates.

FAS 143 and FIN 47 primarily affect the company's accounting for crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets have been recognized, as indeterminate settlement dates for the asset retirements 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 2007, 2006 and 2005:

	2007	2006	2005
Balance at January 1	\$ 5,773	\$ 4,304	\$ 2,878
Liabilities assumed in the			
Unocal acquisition	–	–	1,216
Liabilities incurred	178	153	90
Liabilities settled	(818)	(387)	(172)
Accretion expense	399*	275	187
Revisions in estimated cash flows	2,721	1,428	105
Balance at December 31	\$ 8,253	\$ 5,773	\$ 4,304

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

In the table above, the amounts for 2007 and 2006 associated with “Revisions in estimated cash flows” reflect increasing costs to abandon onshore and offshore wells,

Note 23 Asset Retirement Obligations - Continued

equipment and facilities, including \$1,128 in 2006 for the estimated costs to dismantle and abandon wells and facilities damaged by 2005 hurricanes in the U.S. Gulf of Mexico. The long-term portion of the \$8,253 balance at the end of 2007 was \$7,555.

Note 24

Other Financial Information

Net income 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		
	2007	2006	2005
Total financing interest and debt costs	\$ 468	\$ 608	\$ 542
Less: Capitalized interest	302	157	60
Interest and debt expense	\$ 166	\$ 451	\$ 482
Research and development expenses	\$ 562	\$ 468	\$ 316
Foreign currency effects*	\$ (352)	\$ (219)	\$ (61)

*Includes \$18, \$15 and \$(2) in 2007, 2006 and 2005, respectively, for the company's share of equity affiliates' foreign currency effects.

The excess of replacement cost over the carrying value of inventories for which the Last-In, First-Out (LIFO) method is used was \$6,958 and \$6,010 at December 31, 2007 and 2006, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO profits of \$113, \$82 and \$34 were included in net income for the years 2007, 2006 and 2005, respectively.

Note 25

Earnings Per Share

Basic earnings per share (EPS) is based upon net income less preferred stock dividend requirements and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company and the company's share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company's retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (refer to Note 21, "Stock Options and Other Share-Based Compensation" beginning on page 80). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2007	2006	2005
Basic EPS Calculation			
Income from operations	\$ 18,688	\$ 17,138	\$ 14,099
Add: Dividend equivalents paid on stock units	–	1	2
Net income available to common stockholders – Basic	\$ 18,688	\$ 17,139	\$ 14,101
Weighted-average number of common shares outstanding	2,117	2,185	2,143
Add: Deferred awards held as stock units	1	1	1
Total weighted-average number of common shares outstanding	2,118	2,186	2,144
Per share of common stock			
Net income – Basic	\$ 8.83	\$ 7.84	\$ 6.58
Diluted EPS Calculation			
Income from operations	\$ 18,688	\$ 17,138	\$ 14,099
Add: Dividend equivalents paid on stock units	–	1	2
Add: Dilutive effects of employee stock-based awards	–	–	2
Net income available to common stockholders – Diluted	\$ 18,688	\$ 17,139	\$ 14,103
Weighted-average number of common shares outstanding	2,117	2,185	2,143
Add: Deferred awards held as stock units	1	1	1
Add: Dilutive effect of employee stock-based awards	14	11	11
Total weighted-average number of common shares outstanding	2,132	2,197	2,155
Per share of common stock			
Net income – Diluted	\$ 8.77	\$ 7.80	\$ 6.54

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

	2007	2006	2005	2004	2003
United States					
Gross production of crude oil and natural gas liquids ¹	507	510	499	555	619
Net production of crude oil and natural gas liquids ¹	460	462	455	505	562
Gross production of natural gas	1,983	2,115	1,860	2,191	2,619
Net production of natural gas ²	1,699	1,810	1,634	1,873	2,228
Net oil-equivalent production	743	763	727	817	933
Refinery input	812	939	845	914	951
Sales of refined products ³	1,457	1,494	1,473	1,506	1,436
Sales of natural gas liquids	160	124	151	177	194
Total sales of petroleum products	1,617	1,618	1,624	1,683	1,630
Sales of natural gas	7,624	7,051	5,449	4,518	4,304
International					
Gross production of crude oil and natural gas liquids ¹	1,751	1,739	1,676	1,645	1,681
Net production of crude oil and natural gas liquids ¹	1,296	1,270	1,214	1,205	1,246
Other produced volumes	27	109	143	140	114
Gross production of natural gas	4,099	3,767	2,726	2,203	2,203
Net production of natural gas ²	3,320	3,146	2,599	2,085	2,064
Net oil-equivalent production	1,876	1,904	1,790	1,692	1,704
Refinery input	1,021	1,050	1,038	1,044	1,040
Sales of refined products ³	2,027	2,127	2,252	2,368	2,274
Sales of natural gas liquids	118	102	120	118	118
Total sales of petroleum products	2,145	2,229	2,372	2,486	2,392
Sales of natural gas	3,792	3,478	2,450	2,040	2,106
Total Worldwide					
Gross production of crude oil and natural gas liquids ¹	2,258	2,249	2,175	2,200	2,300
Net production of crude oil and natural gas liquids ¹	1,756	1,732	1,669	1,710	1,808
Other produced volumes	27	109	143	140	114
Gross production of natural gas	6,082	5,882	4,586	4,394	4,822
Net production of natural gas ²	5,019	4,956	4,233	3,958	4,292
Net oil-equivalent production	2,619	2,667	2,517	2,509	2,637
Refinery input	1,833	1,989	1,883	1,958	1,991
Sales of refined products ³	3,484	3,621	3,725	3,874	3,710
Sales of natural gas liquids	278	226	271	295	312
Total sales of petroleum products	3,762	3,847	3,996	4,169	4,022
Sales of natural gas	11,416	10,529	7,899	6,558	6,410
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net) ⁴					
Oil and gas	1,597	1,575	1,365	1,307	1,472
Dry	27	32	26	24	36
Productive oil and gas wells (net) ⁴	51,528	50,695	49,508	44,707	48,155

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	65	56	48	50	65
International	433	419	356	293	268
Total	498	475	404	343	333

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

United States	–	26	88	84	90
International	–	24	129	96	104

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

Five-Year Financial Summary

Unaudited

<i>Millions of dollars, except per-share amounts</i>	2007	2006	2005	2004	2003
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues ^{1,2}	\$ 214,091	\$ 204,892	\$ 193,641	\$ 150,865	\$ 119,575
Income from equity affiliates and other income	6,813	5,226	4,559	4,435	1,702
Total Revenues and Other Income	220,904	210,118	198,200	155,300	121,277
Total Costs and Other Deductions					
	188,737	178,142	173,003	134,749	108,601
Income From Continuing Operations Before Income Taxes	32,167	31,976	25,197	20,551	12,676
Income Tax Expense	13,479	14,838	11,098	7,517	5,294
Income From Continuing Operations	18,688	17,138	14,099	13,034	7,382
Income From Discontinued Operations					
	–	–	–	294	44
Income Before					
Cumulative Effect of Changes in Accounting Principles	18,688	17,138	14,099	13,328	7,426
Cumulative effect of changes in accounting principles	–	–	–	–	(196)
Net Income	\$ 18,688	\$ 17,138	\$ 14,099	\$ 13,328	\$ 7,230
Per Share of Common Stock³					
Income From Continuing Operations⁴					
– Basic	\$ 8.83	\$ 7.84	\$ 6.58	\$ 6.16	\$ 3.55
– Diluted	\$ 8.77	\$ 7.80	\$ 6.54	\$ 6.14	\$ 3.55
Income From Discontinued Operations					
– Basic	\$ –	\$ –	\$ –	\$ 0.14	\$ 0.02
– Diluted	\$ –	\$ –	\$ –	\$ 0.14	\$ 0.02
Cumulative Effect of Changes in Accounting Principles					
– Basic	\$ –	\$ –	\$ –	\$ –	\$ (0.09)
– Diluted	\$ –	\$ –	\$ –	\$ –	\$ (0.09)
Net Income²					
– Basic	\$ 8.83	\$ 7.84	\$ 6.58	\$ 6.30	\$ 3.48
– Diluted	\$ 8.77	\$ 7.80	\$ 6.54	\$ 6.28	\$ 3.48
Cash Dividends Per Share	\$ 2.26	\$ 2.01	\$ 1.75	\$ 1.53	\$ 1.43
Balance Sheet Data (at December 31)					
Current assets	\$ 39,377	\$ 36,304	\$ 34,336	\$ 28,503	\$ 19,426
Noncurrent assets	109,409	96,324	91,497	64,705	62,044
Total Assets	148,786	132,628	125,833	93,208	81,470
Short-term debt	1,162	2,159	739	816	1,703
Other current liabilities	32,636	26,250	24,272	17,979	14,408
Long-term debt and capital lease obligations	6,070	7,679	12,131	10,456	10,894
Other noncurrent liabilities	31,830	27,605	26,015	18,727	18,170
Total Liabilities	71,698	63,693	63,157	47,978	45,175
Stockholders' Equity	\$ 77,088	\$ 68,935	\$ 62,676	\$ 45,230	\$ 36,295

¹ Includes excise, value-added and similar taxes:

\$ 10,121 \$ 9,551 \$ 8,719 \$ 7,968 \$ 7,095

² Includes amounts in revenues for buy/sell contracts; associated costs are in "Total Costs and Other Deductions." Refer also to Note 13, on page 69.

\$ – \$ 6,725 \$ 23,822 \$ 18,650 \$ 14,246

³ Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

⁴ The amount in 2003 includes a benefit of \$0.08 for the company's share of a capital stock transaction of its Dynegy affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

Supplemental Information on Oil and Gas Producing Activities

Unaudited

In accordance with Statement of FAS 69, *Disclosures About Oil and Gas Producing Activities*, this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations.

Tables V through VII present information on the company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Republic of the Congo and Democratic Republic of the Congo. The Asia-Pacific

Table I - Costs Incurred in Exploration, Property Acquisitions and Development¹

Millions of dollars	Consolidated Companies											
	United States				International				Affiliated Companies			
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Year Ended Dec. 31, 2007												
Exploration												
Wells	\$ 4	\$ 430	\$ 18	\$ 452	\$ 202	\$ 156	\$ 3	\$ 195	\$ 556	\$ 1,008	\$ -	\$ 7
Geological and geophysical	-	59	14	73	136	48	11	98	293	366	-	-
Rentals and other	-	128	5	133	70	120	50	79	319	452	-	-
Total exploration	4	617	37	658	408	324	64	372	1,168	1,826	-	7
Property acquisitions ²												
Proved	10	220	13	243	5	92	-	(2)	95	338	-	-
Unproved	35	75	3	113	8	35	-	24	67	180	-	-
Total property acquisitions	45	295	16	356	13	127	-	22	162	518	-	-
Development ³	1,198	2,237	1,775	5,210	4,176	1,897	620	1,504	8,197	13,407	832	64
Total Costs Incurred	\$ 1,247	\$ 3,149	\$ 1,828	\$ 6,224	\$ 4,597	\$ 2,348	\$ 684	\$ 1,898	\$ 9,527	\$ 15,751	\$ 832	\$ 71
Year Ended Dec. 31, 2006												
Exploration												
Wells	\$ -	\$ 493	\$ 22	\$ 515	\$ 151	\$ 121	\$ 20	\$ 246	\$ 538	\$ 1,053	\$ 25	\$ -
Geological and geophysical	-	96	8	104	180	53	12	92	337	441	-	-
Rentals and other	-	116	16	132	48	140	58	50	296	428	-	-
Total exploration	-	705	46	751	379	314	90	388	1,171	1,922	25	-
Property acquisitions ²												
Proved	6	152	-	158	1	10	-	15	26	184	-	581
Unproved	1	47	10	58	-	1	-	135	136	194	-	-
Total property acquisitions	7	199	10	216	1	11	-	150	162	378	-	581
Development ³	686	1,632	868	3,186	2,890	1,788	460	1,019	6,157	9,343	671	25
Total Costs Incurred	\$ 693	\$ 2,536	\$ 924	\$ 4,153	\$ 3,270	\$ 2,113	\$ 550	\$ 1,557	\$ 7,490	\$ 11,643	\$ 696	\$ 606
Year Ended Dec. 31, 2005												
Exploration												
Wells	\$ -	\$ 452	\$ 24	\$ 476	\$ 105	\$ 38	\$ 9	\$ 201	\$ 353	\$ 829	\$ -	\$ -
Geological and geophysical	-	67	-	67	96	28	10	68	202	269	-	-
Rentals and other	-	93	8	101	24	58	12	72	166	267	-	-
Total exploration	-	612	32	644	225	124	31	341	721	1,365	-	-
Property acquisitions ²												
Proved - Unocal	-	1,608	2,388	3,996	30	6,609	637	1,790	9,066	13,062	-	-
Proved - Other	-	6	10	16	2	2	-	12	16	32	-	-
Unproved - Unocal	-	819	295	1,114	11	2,209	821	38	3,079	4,193	-	-
Unproved - Other	-	17	6	23	67	-	-	28	95	118	-	-
Total property acquisitions	-	2,450	2,699	5,149	110	8,820	1,458	1,868	12,256	17,405	-	-
Development ³	507	680	601	1,788	1,892	1,088	382	726	4,088	5,876	767	43
Total Costs Incurred	\$ 507	\$ 3,742	\$ 3,332	\$ 7,581	\$ 2,227	\$ 10,032	\$ 1,871	\$ 2,935	\$ 17,065	\$ 24,646	\$ 767	\$ 43

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," beginning on page 84.

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

³ Includes \$99, \$160 and \$160 costs incurred prior to assignment of proved reserves in 2007, 2006 and 2005, respectively.

geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The international "Other" geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and

other countries. Amounts for TCO represent Chevron's 50 percent equity share of Tengizchevroil, an exploration and production partnership in the Republic of Kazakhstan. The affiliated companies "Other" amounts are composed of the company's equity interests in Venezuela, Angola and Russia. Refer to Note 11 beginning on page 67 for a discussion of the company's major equity affiliates.

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

Millions of dollars	Consolidated Companies											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
At Dec. 31, 2007												
Unproved properties	\$ 805	\$ 892	\$ 353	\$ 2,050	\$ 314	\$ 2,639	\$ 630	\$ 1,015	\$ 4,598	\$ 6,648	\$ 112	\$ -
Proved properties and related producing assets	11,260	19,110	13,718	44,088	11,894	17,321	7,705	11,360	48,280	92,368	4,247	858
Support equipment	201	206	230	637	850	284	1,123	439	2,696	3,333	758	-
Deferred exploratory wells	-	406	7	413	368	293	148	438	1,247	1,660	-	-
Other uncompleted projects	308	3,128	573	4,009	6,430	2,049	593	1,421	10,493	14,502	1,633	55
Gross Cap. Costs	12,574	23,742	14,881	51,197	19,856	22,586	10,199	14,673	67,314	118,511	6,750	913
Unproved properties valuation	741	57	35	833	201	221	39	427	888	1,721	23	-
Proved producing properties – Depreciation and depletion	7,383	15,074	7,640	30,097	5,427	6,912	5,592	7,062	24,993	55,090	644	167
Support equipment depreciation	133	92	124	349	464	144	571	261	1,440	1,789	267	-
Accumulated provisions	8,257	15,223	7,799	31,279	6,092	7,277	6,202	7,750	27,321	58,600	934	167
Net Capitalized Costs	\$ 4,317	\$ 8,519	\$ 7,082	\$ 19,918	\$ 13,764	\$ 15,309	\$ 3,997	\$ 6,923	\$ 39,993	\$ 59,911	\$ 5,816	\$ 746
At Dec. 31, 2006												
Unproved properties	\$ 770	\$ 1,007	\$ 370	\$ 2,147	\$ 342	\$ 2,373	\$ 707	\$ 1,082	\$ 4,504	\$ 6,651	\$ 112	\$ -
Proved properties and related producing assets	9,960	18,464	12,284	40,708	9,943	15,486	7,110	10,461	43,000	83,708	2,701	1,096
Support equipment	189	212	226	627	745	240	1,093	364	2,442	3,069	611	-
Deferred exploratory wells	-	343	7	350	231	217	149	292	889	1,239	-	-
Other uncompleted projects	370	2,188	-	2,558	4,299	1,546	493	917	7,255	9,813	2,493	40
Gross Cap. Costs	11,289	22,214	12,887	46,390	15,560	19,862	9,552	13,116	58,090	104,480	5,917	1,136
Unproved properties valuation	738	52	29	819	189	74	14	337	614	1,433	22	-
Proved producing properties – Depreciation and depletion	7,082	14,468	6,880	28,430	4,794	5,273	4,971	6,087	21,125	49,555	541	109
Support equipment depreciation	125	111	130	366	400	102	522	238	1,262	1,628	242	-
Accumulated provisions	7,945	14,631	7,039	29,615	5,383	5,449	5,507	6,662	23,001	52,616	805	109
Net Capitalized Costs	\$ 3,344	\$ 7,583	\$ 5,848	\$ 16,775	\$ 10,177	\$ 14,413	\$ 4,045	\$ 6,454	\$ 35,089	\$ 51,864	\$ 5,112	\$ 1,027

Supplemental Information on Oil and Gas Producing Activities

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

<i>Millions of dollars</i>	Consolidated Companies										Affiliated Companies		
	United States				International						TCO	Other	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total			
At Dec. 31, 2005													
Unproved properties	\$ 769	\$ 1,077	\$ 397	\$ 2,243	\$ 407	\$ 2,287	\$ 645	\$ 983	\$ 4,322	\$ 6,565	\$ 108	\$ –	
Proved properties and related producing assets	9,546	18,283	11,467	39,296	8,404	14,928	6,613	9,627	39,572	78,868	2,264	1,213	
Support equipment	204	193	230	627	715	426	1,217	356	2,714	3,341	549	–	
Deferred exploratory wells	–	284	5	289	245	154	173	248	820	1,109	–	–	
Other uncompleted projects	149	782	209	1,140	2,878	790	427	946	5,041	6,181	2,332	–	
Gross Cap. Costs	10,668	20,619	12,308	43,595	12,649	18,585	9,075	12,160	52,469	96,064	5,253	1,213	
Unproved properties valuation	736	90	22	848	162	69	–	318	549	1,397	17	–	
Proved producing properties – Depreciation and depletion	6,818	14,067	6,049	26,934	4,266	4,016	4,105	5,720	18,107	45,041	460	90	
Support equipment depreciation	140	119	149	408	317	88	680	222	1,307	1,715	213	–	
Accumulated provisions	7,694	14,276	6,220	28,190	4,745	4,173	4,785	6,260	19,963	48,153	690	90	
Net Capitalized Costs	\$ 2,974	\$ 6,343	\$ 6,088	\$ 15,405	\$ 7,904	\$ 14,412	\$ 4,290	\$ 5,900	\$ 32,506	\$ 47,911	\$ 4,563	\$ 1,123	

Table III Results of Operations for Oil and Gas Producing Activities¹

The company's results of operations from oil and gas producing activities for the years 2007, 2006 and 2005 are shown in the following table. Net income from exploration and production activities as reported on page 65 reflects income taxes computed on an effective rate basis.

In accordance with FAS 69, income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page 65.

Millions of dollars	Consolidated Companies											Affiliated Companies	
	United States				International						TCO	Other	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total			
Year Ended Dec. 31, 2007													
Revenues from net production													
Sales	\$ 202	\$ 1,555	\$ 2,476	\$ 4,233	\$ 1,810	\$ 6,192	\$ 1,045	\$ 3,012	\$ 12,059	\$ 16,292	\$ 3,327	\$ 1,290	
Transfers	4,671	2,630	2,707	10,008	6,778	4,440	2,590	2,744	16,552	26,560	–	–	
Total	4,873	4,185	5,183	14,241	8,588	10,632	3,635	5,756	28,611	42,852	3,327	1,290	
Production expenses excluding taxes ²	(1,063)	(936)	(1,400)	(3,399)	(892)	(953)	(892)	(828)	(3,565)	(6,964)	(248)	(92)	
Taxes other than on income	(91)	(53)	(378)	(522)	(49)	(292)	(2)	(58)	(401)	(923)	(31)	(163)	
Proved producing properties: Depreciation and depletion	(300)	(1,143)	(833)	(2,276)	(646)	(1,668)	(623)	(980)	(3,917)	(6,193)	(127)	(94)	
Accretion expense ³	(92)	1	(167)	(258)	(33)	(36)	(21)	(27)	(117)	(375)	(1)	(2)	
Exploration expenses	–	(486)	(25)	(511)	(267)	(225)	(61)	(259)	(812)	(1,323)	–	–	
Unproved properties valuation	(3)	(102)	(27)	(132)	(12)	(150)	(30)	(120)	(312)	(444)	–	–	
Other income (expense) ⁴	3	2	31	36	(447)	(302)	(197)	(722)	(1,668)	(1,632)	18	7	
Results before income taxes	3,327	1,468	2,384	7,179	6,242	7,006	1,809	2,762	17,819	24,998	2,938	946	
Income tax expense	(1,204)	(531)	(864)	(2,599)	(4,907)	(3,456)	(841)	(1,624)	(10,828)	(13,427)	(887)	(462)	
Results of Producing Operations	\$ 2,123	\$ 937	\$ 1,520	\$ 4,580	\$ 1,335	\$ 3,550	\$ 968	\$ 1,138	\$ 6,991	\$ 11,571	\$ 2,051	\$ 484	
Year Ended Dec. 31, 2006													
Revenues from net production													
Sales	\$ 308	\$ 1,845	\$ 2,976	\$ 5,129	\$ 2,377	\$ 4,938	\$ 1,001	\$ 2,814	\$ 11,130	\$ 16,259	\$ 2,861	\$ 598	
Transfers	4,072	2,317	2,046	8,435	5,264	4,084	2,211	2,848	14,407	22,842	–	–	
Total	4,380	4,162	5,022	13,564	7,641	9,022	3,212	5,662	25,537	39,101	2,861	598	
Production expenses excluding taxes	(889)	(765)	(1,057)	(2,711)	(640)	(740)	(728)	(664)	(2,772)	(5,483)	(202)	(42)	
Taxes other than on income	(84)	(57)	(442)	(583)	(57)	(231)	(1)	(60)	(349)	(932)	(28)	(6)	
Proved producing properties: Depreciation and depletion	(275)	(1,096)	(763)	(2,134)	(579)	(1,475)	(666)	(703)	(3,423)	(5,557)	(114)	(33)	
Accretion expense ³	(11)	(80)	(39)	(130)	(26)	(30)	(23)	(49)	(128)	(258)	(1)	–	
Exploration expenses	–	(407)	(24)	(431)	(296)	(209)	(110)	(318)	(933)	(1,364)	(25)	–	
Unproved properties valuation	(3)	(73)	(8)	(84)	(28)	(15)	(14)	(27)	(84)	(168)	–	–	
Other income (expense) ⁴	1	(732)	254	(477)	(435)	(475)	50	385	(475)	(952)	8	(50)	
Results before income taxes	3,119	952	2,943	7,014	5,580	5,847	1,720	4,226	17,373	24,387	2,499	467	
Income tax expense	(1,169)	(357)	(1,103)	(2,629)	(4,740)	(3,224)	(793)	(2,151)	(10,908)	(13,537)	(750)	(174)	
Results of Producing Operations	\$ 1,950	\$ 595	\$ 1,840	\$ 4,385	\$ 840	\$ 2,623	\$ 927	\$ 2,075	\$ 6,465	\$ 10,850	\$ 1,749	\$ 293	

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 \$10 costs incurred prior to assignment of proved reserves in 2007.

³ Represents accretion of ARO liability. Refer to Note 23, "Asset Retirement Obligations," beginning on page 84.

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

Supplemental Information on Oil and Gas Producing Activities

Table III Results of Operations for Oil and Gas Producing Activities¹ - Continued

Millions of dollars	Consolidated Companies										Affiliated Companies		
	United States				International						TCO	Other	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total			
Year Ended Dec. 31, 2005													
Revenues from net production													
Sales	\$ 337	\$ 1,576	\$ 3,174	\$ 5,087	\$ 2,142	\$ 2,941	\$ 539	\$ 2,668	\$ 8,290	\$ 13,377	\$ 2,307	\$ 666	
Transfers	3,497	2,127	1,395	7,019	3,615	3,179	1,986	2,607	11,387	18,406	–	–	
Total	3,834	3,703	4,569	12,106	5,757	6,120	2,525	5,275	19,677	31,783	2,307	666	
Production expenses excluding taxes	(916)	(638)	(777)	(2,331)	(558)	(570)	(660)	(596)	(2,384)	(4,715)	(152)	(82)	
Taxes other than on income	(65)	(41)	(384)	(490)	(48)	(189)	(1)	(195)	(433)	(923)	(27)	–	
Proved producing properties:													
Depreciation and depletion	(253)	(936)	(520)	(1,709)	(414)	(852)	(550)	(672)	(2,488)	(4,197)	(83)	(46)	
Accretion expense ²	(13)	(35)	(46)	(94)	(22)	(20)	(15)	(25)	(82)	(176)	(1)	–	
Exploration expenses	–	(307)	(13)	(320)	(117)	(90)	(26)	(190)	(423)	(743)	–	–	
Unproved properties valuation	(3)	(32)	(4)	(39)	(50)	(8)	–	(24)	(82)	(121)	–	–	
Other income (expense) ³	2	(354)	(140)	(492)	(243)	(182)	182	280	37	(455)	(9)	8	
Results before income taxes	2,586	1,360	2,685	6,631	4,305	4,209	1,455	3,853	13,822	20,453	2,035	546	
Income tax expense	(913)	(482)	(953)	(2,348)	(3,430)	(2,264)	(644)	(1,938)	(8,276)	(10,624)	(611)	(186)	
Results of Producing Operations	\$ 1,673	\$ 878	\$ 1,732	\$ 4,283	\$ 875	\$ 1,945	\$ 811	\$ 1,915	\$ 5,546	\$ 9,829	\$ 1,424	\$ 360	

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

² Represents accretion of ARO liability. Refer to Note 23, "Asset Retirement Obligations," beginning on page 84.

³ 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											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Year Ended Dec. 31, 2007												
Average sales prices												
Liquids, per barrel	\$ 62.61	\$ 65.07	\$ 62.35	\$ 63.16	\$ 69.90	\$ 64.20	\$ 61.05	\$ 62.97	\$ 65.40	\$ 64.71	\$ 62.47	\$ 51.98
Natural gas, per thousand cubic feet	5.77	7.01	5.65	6.12	–	3.60	7.61	4.13	4.02	4.79	0.89	0.44
Average production costs, per barrel	13.23	12.32	12.62	12.72	7.26	3.96	14.28	6.96	6.54	8.58	3.98	3.56
Year Ended Dec. 31, 2006												
Average sales prices												
Liquids, per barrel	\$ 55.20	\$ 60.35	\$ 55.80	\$ 56.66	\$ 61.53	\$ 57.05	\$ 52.23	\$ 57.31	\$ 57.92	\$ 57.53	\$ 56.80	\$ 37.26
Natural gas, per thousand cubic feet	6.08	7.20	5.73	6.29	0.06	3.44	7.12	4.03	3.88	4.85	0.77	0.36
Average production costs, per barrel	10.94	9.59	9.26	9.85	5.13	3.36	11.44	5.23	5.17	6.76	3.31	2.51
Year Ended Dec. 31, 2005												
Average sales prices												
Liquids, per barrel	\$ 45.24	\$ 48.80	\$ 48.29	\$ 46.97	\$ 50.54	\$ 45.88	\$ 44.40	\$ 48.61	\$ 47.83	\$ 47.56	\$ 45.59	\$ 45.89
Natural gas, per thousand cubic feet	6.94	8.43	6.90	7.43	0.04	3.59	5.74	3.31	3.48	5.18	0.61	0.26
Average production costs, per barrel	10.74	8.55	7.57	8.88	4.72	3.38	11.28	4.32	4.93	6.32	2.45	5.53

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

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

Table V - Reserve Quantity Information

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

Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

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

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

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the executive vice president responsible for the company's worldwide exploration and production activities. All of the RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC coordinates its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

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

Table V Reserve Quantity Information - Continued

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

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

Reserve Quantities At December 31, 2007, oil-equivalent reserves for the company's consolidated operations were 7.9 billion barrels. (Refer to the term "Reserves" on page 28 for the definition of oil-equivalent reserves.) Approximately 28 percent of the total reserves were in the United States. For the company's interests in equity affiliates, oil-equivalent reserves were 2.9 billion barrels, 84 percent of which were associated with the company's 50 percent ownership in TCO.

Aside from the TCO operations, no single property accounted for more than 5 percent of the company's total oil-equivalent proved reserves. Fewer than 20 other individual properties in the company's portfolio of assets each contained between 1 percent and 5 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for about 37 percent of the company's proved reserves total. These properties were geographically dispersed, located in the United States, South America, West Africa and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2007 were 2.2 billion barrels. Of this amount, 41 percent, 21 percent and 38 percent were located in California, the Gulf of Mexico and other U.S. areas, respectively.

In California, liquids reserves represented 94 percent of the total, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company's heavy-oil fields in California employ a continuous steamflooding process.

In the Gulf of Mexico region, liquids represented approximately 66 percent of total oil-equivalent reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Costs include investments in wells, production platforms and other facilities, such as gathering lines and storage facilities.

In other U.S. areas, the reserves were split about equally between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO₂ injection.

The pattern of net reserve changes shown in the following tables, for the three years ending December 31, 2007, is not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, changes 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 2005, 2006 and 2007 are shown in the tables on pages 95 and 97.

Table V Reserve Quantity Information - Continued

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

Millions of barrels	Consolidated Companies											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Reserves at Jan. 1, 2005	1,011	294	432	1,737	1,833	676	698	567	3,774	5,511	1,994	468
Changes attributable to:												
Revisions	(23)	(6)	(11)	(40)	(29)	(56)	(108)	(6)	(199)	(239)	(5)	(19)
Improved recovery	57	–	4	61	67	4	42	29	142	203	–	–
Extensions and discoveries	–	37	7	44	53	21	1	65	140	184	–	–
Purchases ¹	–	49	147	196	4	287	20	65	376	572	–	–
Sales ²	(1)	–	(1)	(2)	–	–	–	(58)	(58)	(60)	–	–
Production	(79)	(41)	(45)	(165)	(114)	(103)	(74)	(89)	(380)	(545)	(50)	(14)
Reserves at Dec. 31, 2005³	965	333	533	1,831	1,814	829	579	573	3,795	5,626	1,939	435
Changes attributable to:												
Revisions	(14)	7	7	–	(49)	72	61	(45)	39	39	60	24
Improved recovery	49	–	3	52	13	1	6	11	31	83	–	–
Extensions and discoveries	–	25	8	33	30	6	2	36	74	107	–	–
Purchases ¹	2	2	–	4	15	–	–	2	17	21	–	119
Sales ²	–	–	–	–	–	–	–	(15)	(15)	(15)	–	–
Production	(76)	(42)	(51)	(169)	(125)	(123)	(72)	(78)	(398)	(567)	(49)	(16)
Reserves at Dec. 31, 2006^{3,4}	926	325	500	1,751	1,698	785	576	484	3,543	5,294	1,950	562
Changes attributable to:												
Revisions	1	(1)	(5)	(5)	(89)	7	(66)	7	(141)	(146)	92	11
Improved recovery	6	–	3	9	7	3	1	–	11	20	–	–
Extensions and discoveries	1	25	10	36	6	1	–	17	24	60	–	–
Purchases ¹	1	9	–	10	–	–	–	–	–	10	–	316
Sales ²	–	(8)	(1)	(9)	–	–	–	–	–	(9)	–	(432)
Production	(75)	(43)	(50)	(168)	(122)	(128)	(72)	(74)	(396)	(564)	(53)	(24)
Reserves at Dec. 31, 2007^{3,4}	860	307	457	1,624	1,500	668	439	434	3,041	4,665	1,989	433
Developed Reserves⁵												
At Jan. 1, 2005	832	192	386	1,410	990	543	490	469	2,492	3,902	1,510	188
At Dec. 31, 2005	809	177	474	1,460	945	534	439	416	2,334	3,794	1,611	196
At Dec. 31, 2006	749	163	443	1,355	893	530	426	349	2,198	3,553	1,003	311
At Dec. 31, 2007	701	136	401	1,238	758	422	363	305	1,848	3,086	1,273	263

¹ Includes reserves acquired through nonmonetary transactions.

² Includes reserves disposed of through nonmonetary transactions.

³ Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 28 for the definition of a PSC). PSC-related reserve quantities are 26 percent, 30 percent and 29 percent for consolidated companies for 2007, 2006 and 2005, respectively.

⁴ Net reserve changes (excluding production) in 2007 consist of 97 million barrels of developed reserves and (162) million barrels of undeveloped reserves for consolidated companies and 299 million barrels of developed reserves and (312) million barrels of undeveloped reserves for affiliated companies.

⁵ During 2007, the percentages of undeveloped reserves at December 31, 2006, transferred to developed reserves were 8 percent and 24 percent for consolidated companies and affiliated companies, respectively.

Information on Canadian Oil Sands Net Proved Reserves Not Included Above:

In addition to conventional liquids and natural gas proved reserves, Chevron has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, Chevron views these reserves and their development as an integral part of total upstream operations. However, SEC regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 436 million barrels as of December 31, 2007. The oil sands reserves are not considered in the standardized measure of discounted future net cash flows for conventional oil and gas reserves, which is found on page 100.

Noteworthy amounts in the categories of liquids proved-reserve changes for 2005 through 2007 are discussed below:

Revisions In 2005, net revisions reduced reserves by 239 million and 24 million barrels for worldwide consolidated companies and equity affiliates, respectively. For consolidated companies, the net decrease was 199 million barrels in the international areas and 40 million barrels in the United States. The largest downward net revisions internationally were 108 million barrels in Indonesia and 53 million barrels

in Kazakhstan, due primarily to the effect of higher year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. In the United States, the 40 million-barrel reduction was across many fields in each of the geographic sections. Most of the downward revision for affiliated companies was a 19 million-barrel reduction in Hamaca, attributable to revised government royalty provisions. For TCO, the downward effect of higher year-end prices was partially offset by increased reservoir performance.

Table V Reserve Quantity Information - Continued

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

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 66 million barrels in Indonesia. In Africa, the decrease was mainly based on field performance data for fields in Nigeria and the effect of higher year-end prices in Angola and the Republic of the Congo. In Indonesia, the decline also reflected the impact of higher year-end prices. Higher prices also resulted in downward revisions in Karachaganak and Azerbaijan. For equity affiliates, most of the upward revision was related to a 92 million-barrel increase for the Tengiz Field in TCO and an 11 million-barrel increase for Petrosocan in Venezuela, both as a result of improved reservoir performance. At TCO, the upward revision was tempered by the negative impact of higher year-end prices.

Improved Recovery In 2005, improved recovery increased liquids volumes worldwide by 203 million barrels for consolidated companies. International areas accounted for 142 million barrels of the increase. Indonesia added 42 million barrels due to improved performance. Reserve additions of 67 million barrels in Africa occurred primarily in Angola and resulted from infill drilling, wells workovers and secondary recovery from gas injection. Additions of 29 million barrels in the "Other" international area were mainly attributable to improved waterflood performance offshore eastern Canada. An increase of 61 million barrels occurred in the United States, primarily in California due to improved performance on a large heavy oil field under thermal recovery.

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

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

Extensions and Discoveries In 2005, extensions and discoveries increased liquids volumes worldwide by 184 million barrels for consolidated companies. The largest increase was 49 million barrels in Nigeria, reflecting new development drilling, including in the Agbami Field, among others. New field developments in Brazil contributed another 41 million barrels of discoveries. In the United States, the 44 million-barrel addition was associated mainly with the initial booking of reserves for the Blind Faith Field in the deepwater Gulf of Mexico.

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

In 2007, extensions and discoveries increased liquids volumes by 60 million barrels worldwide. The largest additions were 25 million barrels in the U.S. Gulf of Mexico, mainly for the deepwater Tahiti and Mad Dog fields.

Purchases In 2005, the acquisition of 572 million barrels of liquids related solely to the acquisition of Unocal in August. About three-fourths of the 376 million barrels acquired in the international areas were represented by volumes in Azerbaijan and Thailand. Most volumes acquired in the United States were in Texas and Alaska.

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

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

Sales In 2005, sales of 58 million barrels in the "Other" international area related to the disposition of the former Unocal operations onshore in Canada.

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

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											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Reserves at Jan. 1, 2005	314	1,064	2,326	3,704	2,979	5,405	502	3,538	12,424	16,128	3,413	134
Changes attributable to:												
Revisions	21	(15)	(15)	(9)	211	(428)	(31)	243	(5)	(14)	(547)	49
Improved recovery	8	–	–	8	13	–	–	31	44	52	–	–
Extensions and discoveries	–	68	99	167	25	118	5	55	203	370	–	–
Purchases ¹	–	269	899	1,168	5	3,962	247	274	4,488	5,656	–	–
Sales ²	–	–	(6)	(6)	–	–	–	(248)	(248)	(254)	–	–
Production	(39)	(215)	(350)	(604)	(42)	(434)	(77)	(315)	(868)	(1,472)	(79)	(2)
Reserves at Dec. 31, 2005³	304	1,171	2,953	4,428	3,191	8,623	646	3,578	16,038	20,466	2,787	181
Changes attributable to:												
Revisions	32	40	(102)	(30)	34	400	38	39	511	481	26	–
Improved recovery	5	–	–	5	3	–	–	5	8	13	–	–
Extensions and discoveries	–	111	157	268	11	510	–	10	531	799	–	–
Purchases ¹	6	13	–	19	–	16	–	–	16	35	–	54
Sales ²	–	–	(1)	(1)	–	–	–	(148)	(148)	(149)	–	–
Production	(37)	(241)	(383)	(661)	(33)	(629)	(110)	(302)	(1,074)	(1,735)	(70)	(4)
Reserves at Dec. 31, 2006³	310	1,094	2,624	4,028	3,206	8,920	574	3,182	15,882	19,910	2,743	231
Changes attributable to:												
Revisions	40	39	130	209	(141)	149	12	166	186	395	75	(2)
Improved recovery	–	–	–	–	–	–	–	1	1	1	–	–
Extensions and discoveries	–	40	46	86	11	392	–	29	432	518	–	–
Purchases ¹	2	19	29	50	–	91	–	–	91	141	–	211
Sales ²	–	(39)	(37)	(76)	–	–	–	–	–	(76)	–	(175)
Production	(35)	(210)	(375)	(620)	(27)	(725)	(101)	(279)	(1,132)	(1,752)	(70)	(10)
Reserves at Dec. 31, 2007^{3,4}	317	943	2,417	3,677	3,049	8,827	485	3,099	15,460	19,137	2,748	255
Developed Reserves⁵												
At Jan. 1, 2005	252	937	2,191	3,380	1,108	3,701	271	2,273	7,353	10,733	2,584	63
At Dec. 31, 2005	251	977	2,794	4,022	1,346	4,819	449	2,453	9,067	13,089	2,314	85
At Dec. 31, 2006	250	873	2,434	3,557	1,306	4,751	377	1,912	8,346	11,903	1,412	144
At Dec. 31, 2007	261	727	2,238	3,226	1,151	5,081	326	1,915	8,473	11,699	1,762	117

¹ Includes reserves acquired through nonmonetary transactions.

² Includes reserves disposed of through nonmonetary transactions.

³ Includes year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 28 for the definition of a PSC). PSC-related reserve quantities are 37 percent, 47 percent and 44 percent for consolidated companies for 2007, 2006 and 2005, respectively.

⁴ Net reserve changes (excluding production) in 2007 consist of 1,548 billion cubic feet of developed reserves and (569) billion cubic feet of undeveloped reserves for consolidated companies and 403 billion cubic feet of developed reserves and (294) billion cubic feet of undeveloped reserves for affiliated companies.

⁵ During 2007, the percentages of undeveloped reserves at December 31, 2006, transferred to developed reserves were 10 percent and 27 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2005 through 2007 are discussed below:

Revisions In 2005, reserves were revised downward by 14 billion cubic feet (BCF) for consolidated companies and 498 BCF for equity affiliates. For consolidated companies, negative revisions were 428 BCF in the Asia-Pacific region. Most of the decrease was attributable to one field in Kazakhstan, due mainly to the effects of higher year-end prices on variable-royalty provisions of the production-sharing contract. Reserves additions for consolidated companies totaled 211 BCF and 243 BCF in Africa and “Other,” respectively. The

majority of the African region changes were in Angola, due to a revised forecast of fuel gas usage, and in Nigeria, from improved reservoir performance. The availability of third-party compression in Colombia accounted for most of the increase in the “Other” region. Revisions in the United States decreased reserves by 9 BCF, as nominal increases in the San Joaquin Valley were more than offset by decreases in the Gulf of Mexico and “Other” region. For the TCO affiliate in Kazakhstan, a reduction of 547 BCF reflects the updated forecast of future royalties payable and year-end price effects, partially offset by volumes added as a result of an updated assessment of reservoir performance.

Table V Reserve Quantity Information - Continued

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

In 2007, revisions increased reserves for consolidated companies by a net 395 BCF and increased reserves for affiliated companies by a net 73 BCF. For consolidated companies, net increases were 209 BCF in the United States and 186 BCF internationally. Improved reservoir performance for many fields in the United States contributed 130 BCF in the "Other" region, 40 BCF in California and 39 BCF in the Gulf of Mexico. Drilling activities added 360 BCF in Thailand and improved reservoir performance added 188 BCF in Trinidad and Tobago. These additions were partially offset by downward revisions of 185 BCF in Australia due to drilling results and 136 BCF in Nigeria due to field performance. Negative revisions due to the impact of higher prices were recorded in Azerbaijan and Kazakhstan. 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.

Extensions and Discoveries In 2005, consolidated companies increased reserves by 370 BCF, including 167 BCF in the United States and 118 BCF in the Asia-Pacific region. In the United States, 99 BCF was added in the "Other" region and 68 BCF in the Gulf of Mexico, primarily due to drilling activities. The addition in Asia-Pacific resulted primarily from increased drilling in Kazakhstan.

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

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.

Purchases In 2005, all except 7 BCF of the 5,656 BCF total purchases were associated with the Unocal acquisition. International reserve acquisitions were 4,488 BCF, with Thailand accounting for about half the volumes. Other significant volumes were added in Bangladesh and Myanmar.

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

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 2005, sales of 248 BCF in the "Other" international region related to the disposition of former-Unocal's onshore properties in Canada.

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

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.

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

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of FAS 69. Estimated future cash inflows from production are computed by applying year-end prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated

using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed under FAS 69 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves. In the following table, "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

Supplemental Information on Oil and Gas Producing Activities

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

Millions of dollars	Consolidated Companies											
	United States				International				Affiliated Companies			
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
At December 31, 2007												
Future cash inflows												
from production	\$ 75,201	\$ 34,162	\$ 52,775	\$ 162,138	\$ 132,450	\$ 93,046	\$ 35,020	\$ 45,566	\$ 306,082	\$ 468,220	\$ 159,078	\$ 29,845
Future production costs	(17,888)	(7,193)	(16,780)	(41,861)	(15,707)	(16,022)	(18,270)	(11,990)	(61,989)	(103,850)	(10,408)	(1,529)
Future devel. costs	(3,491)	(3,011)	(1,578)	(8,080)	(11,516)	(8,263)	(4,012)	(3,468)	(27,259)	(35,339)	(8,580)	(1,175)
Future income taxes	(19,112)	(8,507)	(12,221)	(39,840)	(74,172)	(26,838)	(5,796)	(15,524)	(122,330)	(162,170)	(39,575)	(13,600)
Undiscounted future net cash flows	34,710	15,451	22,196	72,357	31,055	41,923	6,942	14,584	94,504	166,861	100,515	13,541
10 percent midyear annual discount for timing of estimated cash flows	(17,204)	(4,438)	(9,491)	(31,133)	(14,171)	(17,117)	(2,702)	(4,689)	(38,679)	(69,812)	(64,519)	(7,779)
Standardized Measure												
Net Cash Flows	\$ 17,506	\$ 11,013	\$ 12,705	\$ 41,224	\$ 16,884	\$ 24,806	\$ 4,240	\$ 9,895	\$ 55,825	\$ 97,049	\$ 35,996	\$ 5,762
At December 31, 2006												
Future cash inflows												
from production	\$ 48,828	\$ 23,768	\$ 38,727	\$ 111,323	\$ 97,571	\$ 70,288	\$ 30,538	\$ 36,272	\$ 234,669	\$ 345,992	\$ 104,069	\$ 20,644
Future production costs	(14,791)	(6,750)	(12,845)	(34,386)	(12,523)	(13,398)	(16,281)	(10,777)	(52,979)	(87,365)	(7,796)	(2,348)
Future devel. costs	(3,999)	(2,947)	(1,399)	(8,345)	(9,648)	(6,963)	(2,284)	(3,082)	(21,977)	(30,322)	(7,026)	(1,732)
Future income taxes	(10,171)	(4,764)	(8,290)	(23,225)	(53,214)	(20,633)	(5,448)	(11,164)	(90,459)	(113,684)	(25,212)	(8,282)
Undiscounted future net cash flows	19,867	9,307	16,193	45,367	22,186	29,294	6,525	11,249	69,254	114,621	64,035	8,282
10 percent midyear annual discount for timing of estimated cash flows	(9,779)	(3,256)	(7,210)	(20,245)	(10,065)	(12,457)	(2,426)	(3,608)	(28,556)	(48,801)	(40,597)	(5,185)
Standardized Measure												
Net Cash Flows	\$ 10,088	\$ 6,051	\$ 8,983	\$ 25,122	\$ 12,121	\$ 16,837	\$ 4,099	\$ 7,641	\$ 40,698	\$ 65,820	\$ 23,438	\$ 3,097
At December 31, 2005												
Future cash inflows												
from production	\$ 50,771	\$ 29,422	\$ 50,039	\$ 130,232	\$ 101,912	\$ 73,612	\$ 32,538	\$ 44,680	\$ 252,742	\$ 382,974	\$ 97,707	\$ 20,616
Future production costs	(15,719)	(5,758)	(12,767)	(34,244)	(11,366)	(12,459)	(18,260)	(11,908)	(53,993)	(88,237)	(7,399)	(2,101)
Future devel. costs	(2,274)	(2,467)	(873)	(5,614)	(8,197)	(5,840)	(1,730)	(2,439)	(18,206)	(23,820)	(5,996)	(762)
Future income taxes	(11,092)	(7,173)	(12,317)	(30,582)	(50,894)	(21,509)	(5,709)	(13,917)	(92,029)	(122,611)	(23,818)	(6,036)
Undiscounted future net cash flows	21,686	14,024	24,082	59,792	31,455	33,804	6,839	16,416	88,514	148,306	60,494	11,717
10 percent midyear annual discount for timing of estimated cash flows	(10,947)	(4,520)	(10,838)	(26,305)	(14,881)	(14,929)	(2,269)	(5,635)	(37,714)	(64,019)	(37,674)	(7,768)
Standardized Measure												
Net Cash Flows	\$ 10,739	\$ 9,504	\$ 13,244	\$ 33,487	\$ 16,574	\$ 18,875	\$ 4,570	\$ 10,781	\$ 50,800	\$ 84,287	\$ 22,820	\$ 3,949

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.”

<i>Millions of dollars</i>	Consolidated Companies			Affiliated Companies		
	2007	2006	2005	2007	2006	2005
Present Value at January 1	\$ 65,820	\$ 84,287	\$ 48,134	\$ 26,535	\$ 26,769	\$ 14,920
Sales and transfers of oil and gas produced net of production costs	(34,957)	(32,690)	(26,145)	(4,084)	(3,180)	(2,712)
Development costs incurred	10,468	8,875	5,504	889	721	810
Purchases of reserves	780	580	25,307	7,711	1,767	–
Sales of reserves	(425)	(306)	(2,006)	(7,767)	–	–
Extensions, discoveries and improved recovery less related costs	3,664	4,067	7,446	–	–	–
Revisions of previous quantity estimates	(7,801)	7,277	(13,564)	(1,333)	(967)	(2,598)
Net changes in prices, development and production costs	74,900	(24,725)	61,370	23,616	(837)	19,205
Accretion of discount	12,196	14,218	8,160	3,745	3,673	2,055
Net change in income tax	(27,596)	4,237	(29,919)	(7,554)	(1,411)	(4,911)
Net change for the year	31,229	(18,467)	36,153	15,223	(234)	11,849
Present Value at December 31	\$ 97,049	\$ 65,820	\$ 84,287	\$ 41,758	\$ 26,535	\$ 26,769

Board of Directors



David J. O'Reilly, 61

Chairman of the Board and Chief Executive Officer since 2000. Previously he was elected a Director and Vice Chairman in 1998, President of Chevron Products Company in 1994, and a Vice President in 1991. He is a Director and a Member of the Executive and Policy Committees of the American Petroleum Institute. He also is a Director of the Peterson Institute for International Economics and the Eisenhower Fellowships Board of Trustees. He joined Chevron in 1968.

Peter J. Robertson, 61

Vice Chairman of the Board since 2002. In addition to a broad sharing of the CEO's responsibilities, he is directly responsible for Policy, Government and Public Affairs; Human Resources; Security; and Compliance. Previously he was responsible for worldwide upstream and gas operations. He is a Director of the U.S.-Russia Business Council, the U.S.-Saudi Arabian Business Council, Resources for the Future and the Global Business Coalition Against HIV/AIDS, and is Chairman of the U.S. Energy Association. He joined Chevron in 1973.

Samuel H. Armacost, 69

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 President, Chief Executive Officer and a Director of BankAmerica Corporation. He also is a Director of Del Monte Foods Company; Callaway Golf Company; Franklin Resources, Inc.; and Exponent, Inc. (3, 4)



Linnet F. Deily, 62

Director since 2006. She served as a Deputy U.S. Trade Representative and 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 Alcatel-Lucent and Honeywell International Inc. (1)

Robert E. Denham, 62

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 Alcatel-Lucent; Wesco Financial Corporation; and Fomento Económico Mexicano, S.A. de C.V. (1)

Robert J. Eaton, 68

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

Sam Ginn, 71

Director since 1989. He is a private investor and the retired Chairman of Vodafone AirTouch, Plc. Previously he was Chairman of the Board and Chief Executive Officer of AirTouch Communications, Inc., and Chairman of the Board, President and Chief Executive Officer of Pacific Telesis Group. He is a Director of ICO Global Communications (Holdings) Limited. (2, 3)



Franklyn G. Jenifer, 69

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. (1)

Sam Nunn, 69

Director since 1997. He is Co-Chairman and Chief Executive Officer of the Nuclear Threat Initiative, a charitable organization. He also is a Distinguished Professor at the Sam Nunn School of International Affairs, Georgia Tech. 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, 68

Director since 2005. Former Chairman of the Board, President and Chief Executive Officer of Agensys, Inc., now 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. (2, 3)



Kevin W. Sharer, 60

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, 68

Director since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods. (1)

Ronald D. Sugar, 59

Director since 2005. He is Chairman of the Board and Chief Executive Officer of Northrop Grumman Corporation. Previously he was President and Chief Operating Officer of Northrop Grumman. He is a Governor of the Aerospace Industries Association and a Member of the National Academy of Engineering. (2, 4)

Carl Ware, 64

Director since 2001. He was Senior Adviser to the Chief Executive Officer of The Coca-Cola Company after retiring as Executive Vice President of Global Public Affairs and Administration for The Coca-Cola Company. Previously he was 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

Corporate Officers



Lydia I. Beebe, 55

Corporate Secretary and Chief Governance Officer since 1995. Responsible for providing corporate governance counsel to the Board of Directors, senior management, operating units and subsidiaries; overseeing stockholder services for Chevron; and providing governance-related services and support throughout the corporation and subsidiaries. Previously Senior Manager, Chevron Tax Department. Joined Chevron in 1977.

John E. Bethancourt, 56

Executive Vice President, Technology and Services, since 2003. Responsible also for health, environment and safety as well as chemical additives and mining operations. Previously the company's Vice President, Human Resources, and Texaco Corporate Vice President and President, Production Operations, Texaco Worldwide Exploration and Production. Joined the company in 1974.

Stephen J. Crowe, 60

Vice President and Chief Financial Officer since 2005. Responsible for comptroller, audit, treasury, tax and investor relations activities corporatewide. Previously Corporate Vice President and Comptroller; Vice President, Finance, Chevron Products Company; and Assistant Comptroller, Chevron Corporation. Joined Chevron in 1972.

John D. Gass, 56

Corporate Vice President and President, Chevron Global Gas, since 2003. Responsible for the company's natural gas business, shipping company, power and pipeline operations, and the Sasol Chevron gas-to-liquids joint venture. Director of Sasol Chevron. Previously Managing Director, Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined the company in 1974.

Mark A. Humphrey, 56

Vice President and Comptroller since 2005. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, funded benefits investments, actuarial functions, and Finance Shared Services. Previously the company's General Manager, Finance Shared Services, and Vice President, Finance, Chevron Products Company. Joined Chevron in 1976.

Charles A. James, 53

Vice President and General Counsel since 2002. Previously Assistant Attorney General, Antitrust Division, U.S. Department of Justice, in President George W. Bush's administration, and Chair, Antitrust and Trade Regulation Practice – Jones, Day, Reavis & Pogue, Washington, D.C. Joined Chevron in 2002.

George L. Kirkland, 57

Executive Vice President, Global Upstream and Gas, since 2005. Responsible for global exploration, production and gas activities. Previously Corporate Vice President and President, Chevron Overseas Petroleum Inc.; President, Chevron Exploration and Production Company; and President, Chevron U.S.A. Production Company. Joined Chevron in 1974.

John W. McDonald, 56

Vice President and Chief Technology Officer since January 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.

Alan R. Preston, 56

Vice President, Human Resources, since 2003. Previously the company's General Manager, Global Remuneration; General Manager, Organization/Compensation, Chevron Corporation; and General Manager, Human Resources, Chevron Products Company. Joined Chevron in 1973.



Jay R. Pryor, 50

Vice President, Corporate Business Development, since 2006. Responsible for identifying and developing new, large-scale business opportunities worldwide. 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, 60

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, 48

Vice President, Strategic Planning, since January 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, 50

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

John S. Watson, 51

Executive Vice President, Strategy and Development, since January 2008. Responsible for business development, mergers and acquisitions, strategic planning, procurement, and the Project Resources Company. Previously Corporate Vice President and President, Chevron International Exploration and Production Company; Corporate Vice President and Chief Financial Officer; and Corporate Vice President, Strategic Planning. Joined Chevron in 1980.

Michael K. Wirth, 47

Executive Vice President, Global Downstream, since 2006. Responsible for worldwide refining, marketing, lubricants, and supply and trading. 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, 52

Vice President and Treasurer since May 2007. Director of Chevron Phillips Chemical Company LLC and serves on the 12th District Federal Reserve Economic Advisory Council. Previously 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, 50

Vice President, Policy, Government and Public Affairs, since May 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

David J. O'Reilly, Peter J. Robertson, John E. Bethancourt, Stephen J. Crowe, Charles A. James, George L. Kirkland, John S. Watson and Michael K. Wirth. Lydia I. Beebe, Secretary.

Stockholder and Investor Information

Stock Exchange Listing

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

Stockholder Information

Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to Chevron's transfer agent and registrar:

BNY Mellon Shareowner Services
480 Washington Boulevard
27th Floor
Jersey City, NJ 07130-2098
800 368 8357
www.melloninvestor.com

The BNY Mellon Shareowner Services Program (866 353 7849, same address as above) 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 28, 2008, at: Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

Electronic Access

Rather than receiving mailed copies, stockholders of record may sign up on our Web site, www.icsdelivery.com/cvx/index.html, for electronic access to future *Annual Reports* and proxy materials. 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*, published in March, summarizes the company's financial performance in the preceding year and provides an outlook for the future.

Chevron's Annual Report on Securities and Exchange Commission Form 10-K and the *Supplement to the Annual Report*, containing additional financial and operating data, are available on the company's Web site, www.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, www.chevron.com, or a copy may be requested by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2181
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2007 are available on the company's Web site, www.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 and educational contributions* is available in the second half of the year on Chevron's Web site, www.chevron.com.

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

Legal 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

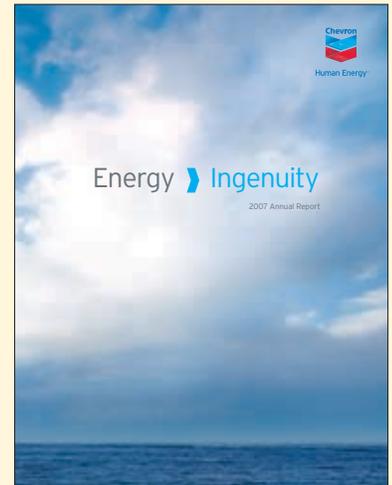
This *Annual Report* contains forward-looking statements – identified by words such as "expects," "intends," "projects," etc. – that reflect management's current estimates and beliefs, but are not guarantees of future results. Please see "Cautionary Statement Relevant to Forward-Looking Information for the Purpose of 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" on Page 29 for a discussion of some of the factors that could cause actual results to differ materially.

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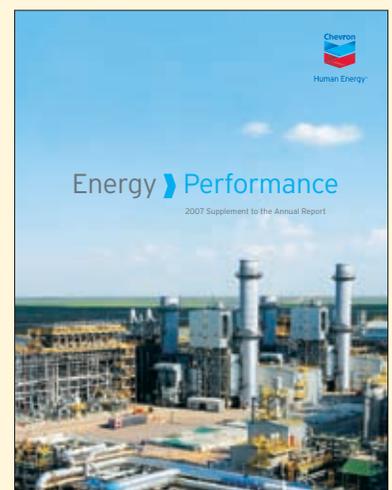
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2007 Annual Report



2007 Supplement to the Annual Report



2007 Corporate Responsibility Report



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