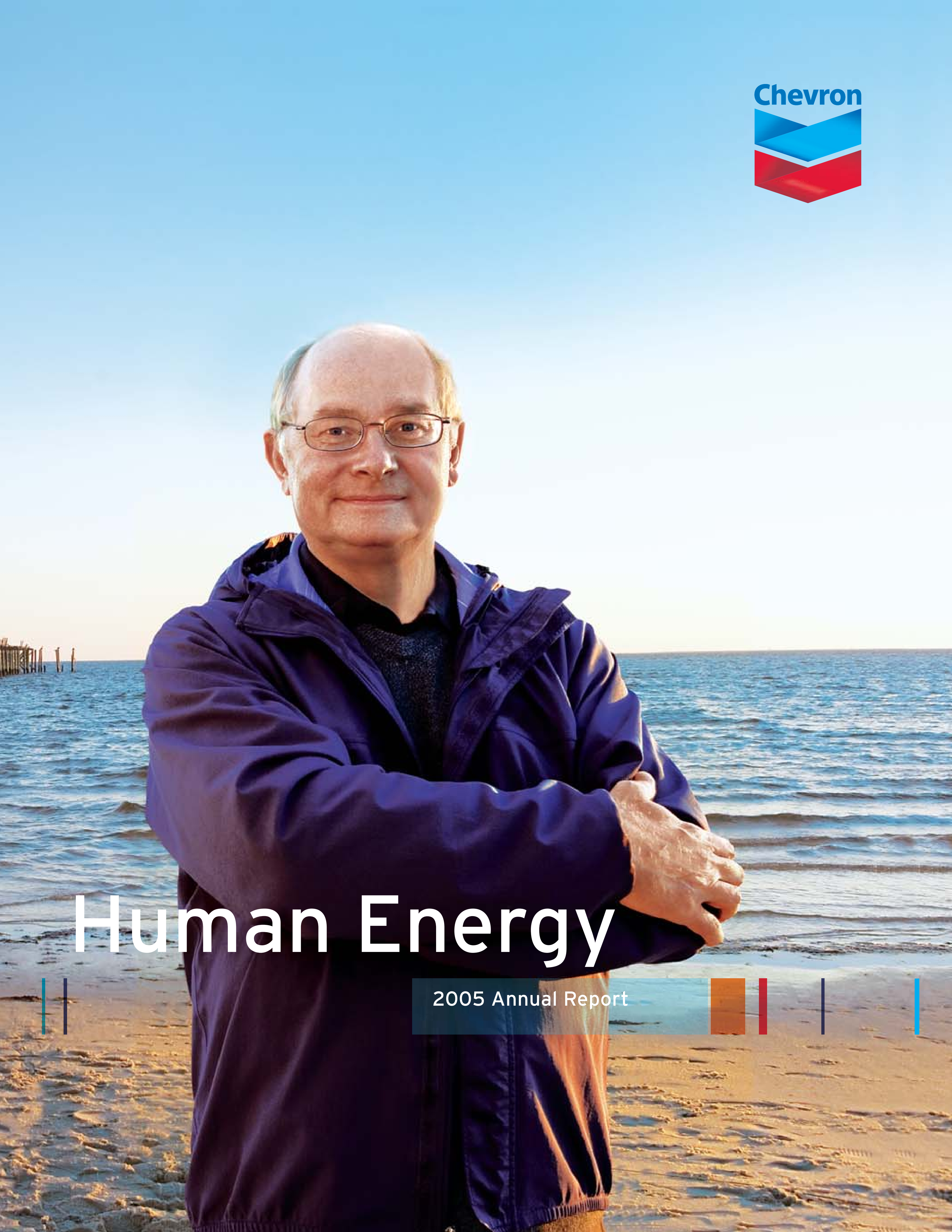
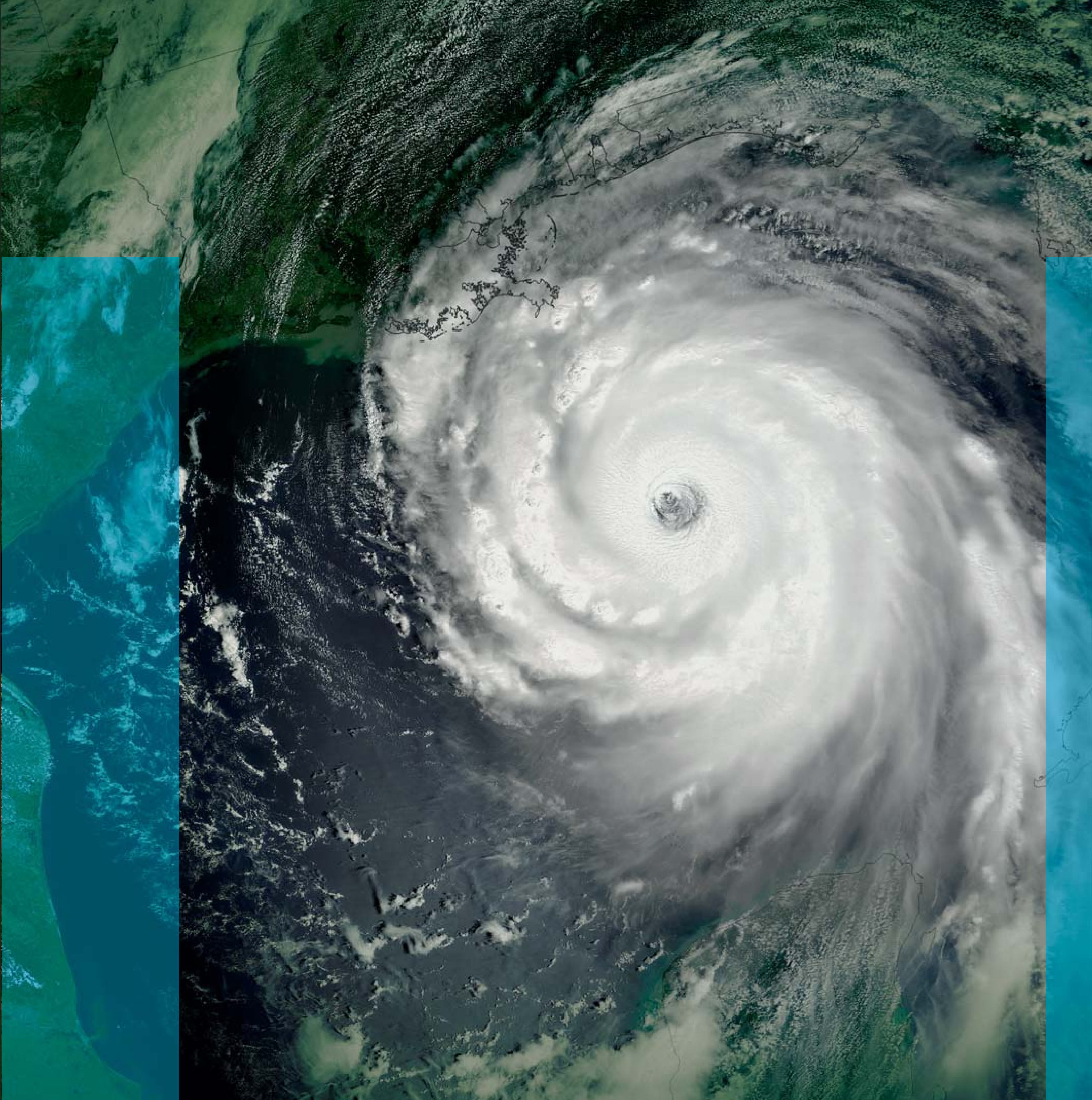


Human Energy

2005 Annual Report



"WHAT WE'RE MADE OF"

Hurricanes Katrina and Rita interrupted crude oil and natural gas production in the U.S. Gulf of Mexico and temporarily shut down one of our largest refineries. Chevron employees throughout the region responded to the storms with exceptional courage, compassion and commitment. They rescued neighbors, located colleagues and provided urgently needed food, water, clothing and medical aid to local communities. At the same time, they launched a massive, around-the-clock effort to restore production, refining, transportation and marketing operations and to deliver critically needed emergency fuel to the region. "There wasn't a barrier we couldn't overcome," says Roland Kell, general manager of the Pascagoula, Mississippi, refinery, which was damaged by the storms. "We truly found out what we're made of."

ON THE COVER: Roland Kell, general manager, Pascagoula Refinery.
ON THE BACK COVER: The employee team who led relief efforts and the safe startup of the refinery: (left to right) Val Vialpando, Darin Matthews, Amy Brandenstein, Amy Jones, Brian Beech, Marisa Jackson, Bob Phillips and Christine Sims.

GROWING ENERGY DEMAND IS ONE OF THE WORLD'S GREAT CHALLENGES. Together, we must continue to find innovative ways to provide the energy that will fuel economic development and improve the quality of life for people everywhere. At Chevron, we are relentlessly focused on producing safe, reliable energy now and for the future. How are we doing it? By applying the energy we have most in abundance: human energy — our own and that of our partners around the world.

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2005 was a year of unprecedented accomplishment and challenge for our company.

We reported record earnings and completed the acquisition and integration of Unocal. We made major new discoveries of crude oil and natural gas and took significant steps to expand our global natural gas business. Although our employees and facilities sustained damage from back-to-back hurricanes in the U.S. Gulf Coast, we are recovering with remarkable resilience and efficiency.

Our financial performance reflects the capital discipline that is necessary to create sustained value and growth. Net income in 2005 was $14.1 billion on sales and other operating revenues of $194 billion – representing record levels in both categories. Return on capital employed for the year was a strong 21.9 percent. We increased our dividend in 2005 for the 18th consecutive year, completed the purchase of $5 billion of the company's shares in the open market under a program started in 2004 and initiated a new program to acquire up to an additional $5 billion of shares over a period of up to three years. A critical measure of our performance, total stockholder return (TSR), was 11.3 percent for 2005. From 2001 through 2005, TSR averaged 9.7 percent, among the highest of our larger peer companies.

MAINTAINING MOMENTUM We executed strongly against our key business strategies in 2005, enhancing our foundation for current and future growth. The successful integration of Unocal's operations strengthened our competitive profile in key markets, particularly in Southeast Asia, where we are in the top tier of natural gas producers. Unocal's world-class assets in Asia, the Caspian and the U.S. Gulf of Mexico are a superb strategic fit with Chevron's portfolio and capabilities. In addition, Unocal provided us with a deep source of talent and leading-edge technology, particularly with the drill bit, that we are integrating throughout our enterprise.

We enhanced our position in the deep water with discoveries at Big Foot and Knotty Head in the U.S. Gulf of Mexico and at Manatee offshore Trinidad and Tobago, among others. Our combination of experience and applied technology resulted in a total of 31 successful exploration wells in 2005 and an exploration success rate of 58 percent, one of the best in the industry.

We reached key milestones in our queue of major capital projects, most notably the Benguela Belize-Lobito Tomboco deepwater project in Angola, which is the first of our "Big 5" projects to begin production. We began construction of production facilities for the Tahiti (U.S.) and Agbami (Nigeria) deepwater projects, as well as the Escravos gas-to-liquids plant in Nigeria. Our global gas business reached key agreements with Japanese utility companies for future sales of liquefied natural gas (LNG) from the Gorgon project in Australia into Japan, the world's largest LNG market.

Refining and marketing operations benefited from strong margins in Asian and U.S. markets, and we moved forward with expansion plans at our largest U.S. refineries. In Asia, we approved a major upgrade of the Yeosu Refinery in South Korea, the world's fourth-largest refinery, to enable heavy oil processing.

Our planned capital and exploratory spending program for 2006 is $14.8 billion, a 34 percent increase over 2005. This level of investment is aligned with our strong queue of growth projects and our commitment to bring new energy supplies to market.

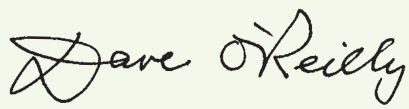
COMPETITIVE ADVANTAGE The operating environment for the energy industry continues to be challenging. With a sustained increase in global demand, tight supplies and a dynamic geopolitical situation, we continue to believe our industry is dealing with a fundamentally new energy equation. To some extent, risk in our industry has shifted from below ground – where Chevron has proved extremely effective at finding and producing hydrocarbons – to above ground, where challenges include access to resources, barriers to the free flow of capital investment to produce those resources and the economic development of infrastructure needed to connect energy supplies to markets.

In this environment, the competitive advantage will go to companies that demonstrate sustained performance and operating excellence, apply new technology in ways that drive results, and create partnerships that enable the efficient execution of complex cross-border projects. These are all core capabilities of Chevron.

HUMAN ENERGY: THE HEART OF CHEVRON Our success in 2005 was defined by a number of factors – robust strategies, consistent execution, a safety record that is among the best in our business, innovative technology and strong commodity prices. But the fundamental contributor to our success is the people of Chevron. Their dedication, resourcefulness and sheer ingenuity were on display throughout the year and were dramatically highlighted in our response to Hurricanes Katrina and Rita. Whether it was Chevron employees helping each other, assisting the community or working to restore energy supplies to the marketplace as quickly as they did, their actions were truly heroic.

It is our people who develop our strategies, build our partnerships, create new technology, ensure that we operate safely and ethically, and manage the great risks that are part of our business. It is this "human energy" that this year's *Annual Report* celebrates. It is at the heart of Chevron. And it will continue to drive our mission to deliver safe, clean and reliable energy to fuel economic growth and human progress.

Thank you for your continued support.



DAVE O'REILLY
CHAIRMAN OF THE BOARD AND
CHIEF EXECUTIVE OFFICER
FEBRUARY 27, 2006

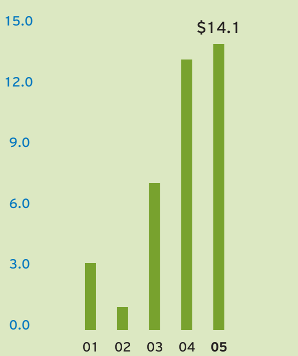
"IT IS OUR PEOPLE WHO DEVELOP OUR STRATEGIES, BUILD OUR PARTNERSHIPS, CREATE NEW TECHNOLOGY, ENSURE THAT WE OPERATE SAFELY AND ETHICALLY, AND MANAGE THE GREAT RISKS THAT ARE PART OF OUR BUSINESS. IT IS THIS 'HUMAN ENERGY' THAT THIS YEAR'S *ANNUAL REPORT* CELEBRATES."

CHEVRON FINANCIAL HIGHLIGHTS

Millions of dollars, except per-share amounts	2005	2004	% Change
Net income	**$ 14,099**	$ 13,328	6 %
Sales and other operating revenues	**$ 193,641**	$ 150,865	28 %
Capital and exploratory expenditures*	**$ 11,063**	$ 8,315	33 %
Total assets at year-end	**$ 125,833**	$ 93,208	35 %
Total debt at year-end	**$ 12,870**	$ 11,272	14 %
Stockholders' equity at year-end	**$ 62,676**	$ 45,230	39 %
Cash provided by operating activities	**$ 20,105**	$ 14,690	37 %
Common shares outstanding at year-end (Thousands)	**2,218,519**	2,092,952	6 %
Per-share data			
Net income – diluted	**$ 6.54**	$ 6.28	4 %
Cash dividends	**$ 1.75**	$ 1.53	14 %
Stockholders' equity	**$ 28.25**	$ 21.61	31 %
Common stock price at year-end	**$ 56.77**	$ 52.51	8 %
Total debt to total debt-plus-equity ratio	**17.0%**	19.9%	
Return on average stockholders' equity	**26.1%**	32.7%	
Return on capital employed (ROCE)	**21.9%**	25.8%	

*Includes equity in affiliates

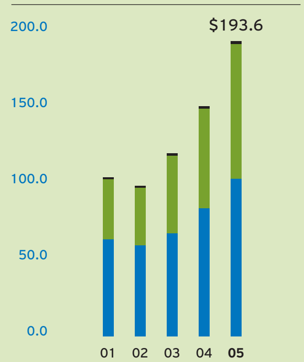
NET INCOME*
Billions of dollars



Net income rose on the continued strength of upstream operations. Special-item charges in 2002 reduced earnings more than $3 billion.

*Includes discontinued operations

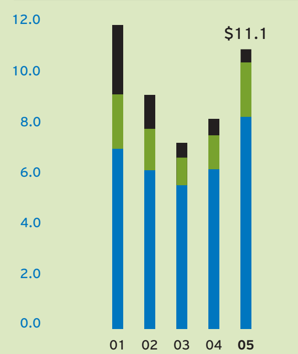
SALES & OTHER OPERATING REVENUES
Billions of dollars



- Chemicals & Other
- Crude Oil & Condensate, Natural Gas & Natural Gas Liquids
- Petroleum Products

Sales and other operating revenues increased 28 percent on higher prices for crude oil, natural gas and refined products, and the inclusion of Unocal for five months post-acquisition.

CAPITAL & EXPLORATORY EXPENDITURES*
Billions of dollars

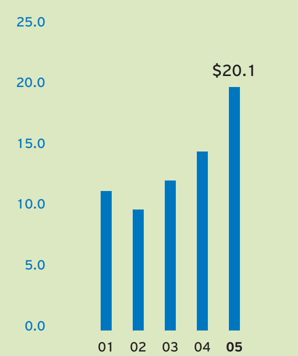


- Chemicals & Other
- Refining, Marketing & Transportation
- Exploration & Production

Capital and exploratory expenditures increased 33 percent from 2004. Years 2001 and 2002 were higher due to additional investments in equity affiliates Tengizchevroil and Dynegy Inc.

*Includes equity in affiliates but excludes cost of Unocal acquisition

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars



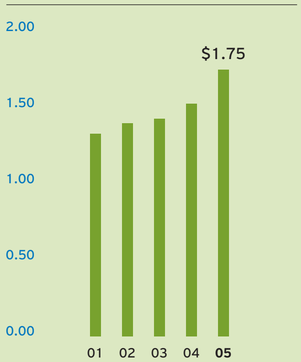
Operating cash flow increased 37 percent mainly due to higher earnings in the upstream segment.

CHEVRON OPERATING HIGHLIGHTS[1]

	2005	2004	% Change
Net production of crude oil and natural gas liquids (Thousands of barrels per day)	**1,669**	1,710	(2)%
Net production of natural gas (Millions of cubic feet per day)	**4,233**	3,958	7 %
Net oil-equivalent production (Thousands of oil-equivalent barrels per day)	**2,517**	2,509	–
Refinery input (Thousands of barrels per day)	**1,883**	1,958	(4)%
Sales of refined products (Thousands of barrels per day)	**3,768**	3,908	(4)%
Net proved reserves of crude oil, condensate and natural gas liquids[2] (Millions of barrels)			
– Consolidated companies	**5,626**	5,511	2 %
– Affiliated companies	**2,374**	2,462	(4)%
Net proved reserves of natural gas[2] (Billions of cubic feet)			
– Consolidated companies	**20,466**	16,128	27 %
– Affiliated companies	**2,968**	3,547	(16)%
Net proved oil-equivalent reserves[2] (Millions of barrels)			
– Consolidated companies	**9,037**	8,199	10 %
– Affiliated companies	**2,869**	3,053	(6)%
Number of employees at year-end[3]	**53,440**	47,265	13 %

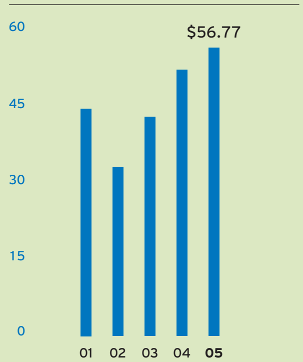
[1] Includes equity in affiliates, except number of employees
[2] At the end of the year
[3] Excludes service station personnel

ANNUAL CASH DIVIDENDS
Dollars per share



The company increased its annual dividend payout for the 18th consecutive year.

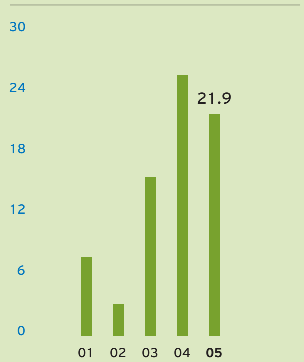
CHEVRON YEAR-END COMMON STOCK PRICE*
Dollars per share



The company's stock price rose 8 percent during 2005, outpacing the broader market indexes.

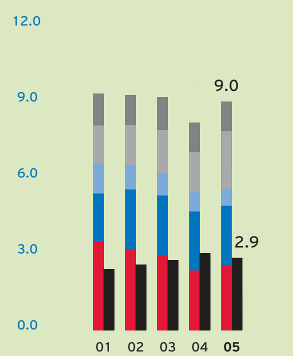
*2001–2003 adjusted for stock split in 2004

RETURN ON CAPITAL EMPLOYED
Percent



Although earnings reached a record level in 2005, return on capital employed declined to 21.9 percent due to the higher capital base resulting from the Unocal acquisition.

NET PROVED RESERVES
Billions of BOE*



- Other International
- Asia-Pacific
- Indonesia
- Africa
- United States
- Affiliates

Net proved reserves for consolidated companies climbed 10 percent in 2005, primarily due to the Unocal acquisition.

*Barrels of oil-equivalent

RHONDA REDWINE

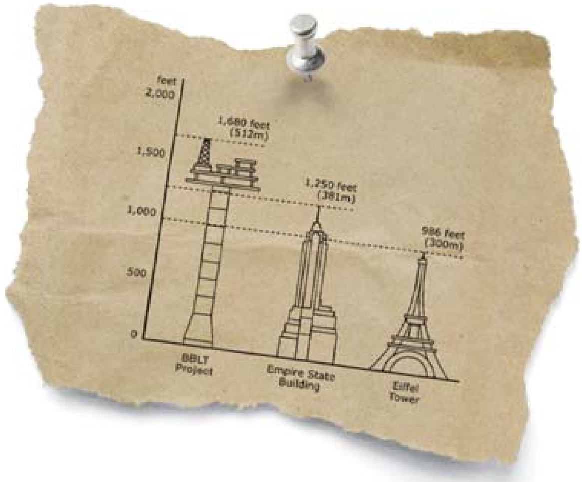
PROJECT MANAGER

BENGUELA BELIZE PROJECT
› ANGOLA

PROFESSIONAL: Mechanical Engineer, Tulane University (New Orleans, Louisiana); 26 years with Chevron.

PERSONAL: Reading novels and travel books.

"In Angola's deep water, which will be a key source of future energy supplies, we safely installed one of the tallest and most complex man-made structures in the world. It is a remarkable achievement and a credit to the team who is developing this giant field."



Skyscraper at Sea

The $2.3 billion Benguela Belize-Lobito Tomboco (BBLT) development is a testament to our ability to manage large and complex projects. In 2005, we completed the first phase of the groundbreaking development ahead of schedule, within budget and, most important, in a safe manner. A major part of the project was installing a drilling and production platform that stands 1,680 feet (512 meters) high, among the tallest man-made structures in the world. The Offshore Energy Association recognized the platform as "Project of the Year." Initial production from the Belize Field began in early 2006. When BBLT is fully onstream, maximum total production is expected to be approximately 200,000 barrels of crude oil per day.

A COMMITMENT TO AFRICA

BBLT is more than one of our "Big 5" capital projects — it demonstrates our ongoing commitment to Africa. We are one of the largest U.S. private investors in sub-Saharan Africa, an area that holds enormous potential for adding to the world's energy supplies. Although it has made significant progress, Africa remains one of the world's most challenging regions in terms of social and economic development. We are partnering with governments and local communities to help the region develop its energy resources in ways that will stimulate economic growth and improve the quality of life.

BILLY VARNADO

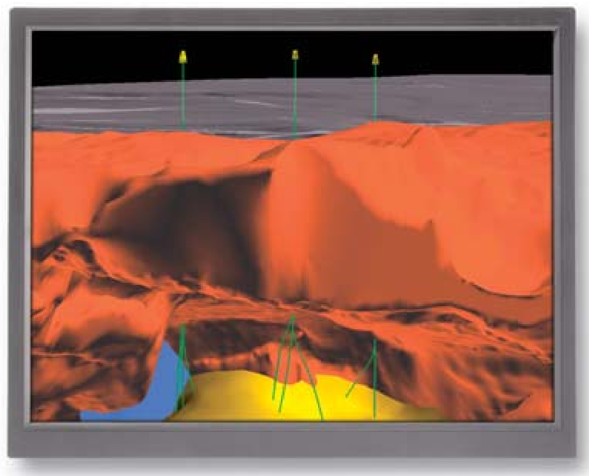
PROJECT MANAGER

TAHITI DEVELOPMENT
> U.S. GULF OF MEXICO

PROFESSIONAL: Petroleum Engineer, Louisiana State University (Baton Rouge); 28 years with Chevron.

PERSONAL: Hunting and fishing.

"We're applying new and extended technology to develop Tahiti. Drilling to depths up to five miles below the rig floor into an extremely high-pressure environment demands it. When it is brought into production, Tahiti will have the deepest producing wells in the Gulf of Mexico."



Exploring for Growth

A string of discoveries in the deepwater U.S. Gulf of Mexico has established Chevron as one of the industry's top explorers. Credit belongs, in large measure, to technical teams who are applying proprietary technology that can map deepwater reservoirs with unprecedented clarity. The image of the Tahiti Field, above, penetrates through thick layers of subsurface salt and other challenges that distort traditional seismic imagery. Chevron has a major position in the deepwater Gulf and is investing heavily to increase energy supplies from the area. A "Big 5" project, Tahiti is one of the largest, deepest and most significant discoveries made to date in the Gulf.

AN EXPLORATION SUCCESS STORY

Since 2002, Chevron has almost doubled its exploration discovery rate. In 2005 alone, the company drilled 31 successful exploration wells, achieving a success rate of 58 percent. Our exploration efforts have added significant new resources to our existing crude oil and natural gas resource base. We are focused on converting those undeveloped resources into proved reserves.

ZHANUZAK URAZOV

FIELD REGULATORY
COMPLIANCE MANAGER

TENGIZCHEVROIL
> KAZAKHSTAN

PROFESSIONAL: Petroleum Engineer, Kazakh National Technical University (Almaty, Kazakhstan); 13 years with Tengizchevroil, 25 years at the Tengiz Field.

PERSONAL: Reading, movies and dining out.

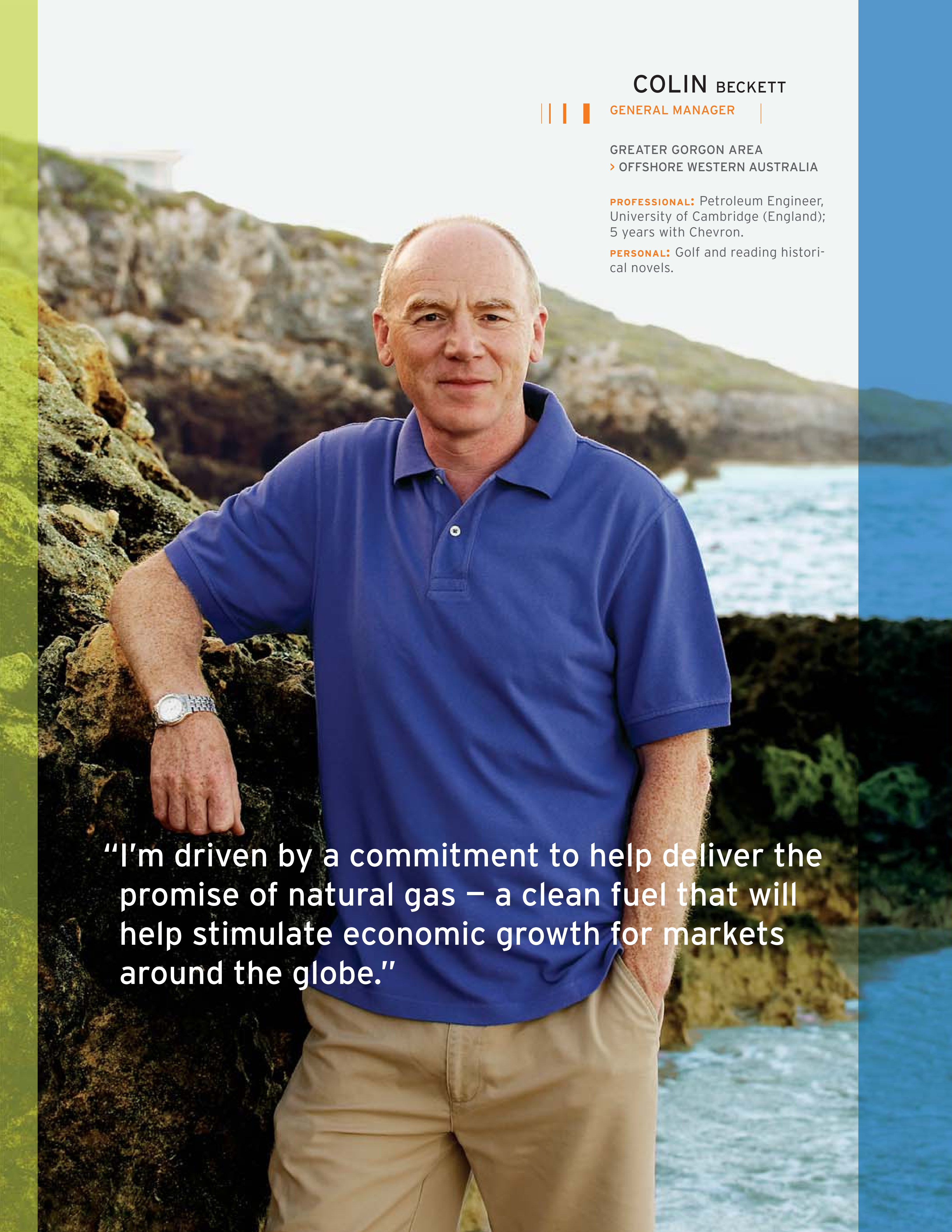
"I have never seen a project with this kind of potential. We are taking technology to new levels of sophistication to produce a long-term increase in oil recovery and make Tengizchevroil even more productive."

Technology That Drives Results

At Kazakhstan's giant Tengiz oil field, state-of-the-art injection technology is being developed that will increase crude oil production capacity from 300,000 barrels per day in 2005 to an estimated 460,000 to 550,000 barrels per day by the third quarter of 2007. Our "Big 5" $5.5 billion Sour Gas Injection/Second Generation Plant project, now under construction, is an example of how Chevron is applying technology in a focused way across the enterprise to enhance performance. The project will include the largest single-train, sour crude oil processing plant in the world. Advanced compression technology will enable sour gas to be reinjected back into the reservoir at up to 10,000 pounds per square inch of pressure.

A UNIQUE APPROACH TO TECHNOLOGY

Chevron has built a technology organization that is unique in the industry. It is the only one that is fully integrated and capable of delivering technology and services throughout the energy value chain. It also is partnership-driven. In addition to developing proprietary technology, the company has forged alliances to share technical risk, cost and talent with external organizations that have complementary capabilities.



COLIN BECKETT

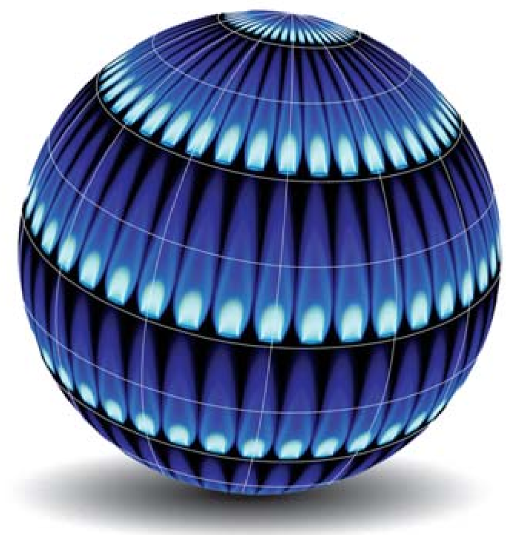
GENERAL MANAGER

GREATER GORGON AREA
› OFFSHORE WESTERN AUSTRALIA

PROFESSIONAL: Petroleum Engineer, University of Cambridge (England); 5 years with Chevron.

PERSONAL: Golf and reading historical novels.

"I'm driven by a commitment to help deliver the promise of natural gas — a clean fuel that will help stimulate economic growth for markets around the globe."



Delivering the Promise of Natural Gas

Chevron is building an integrated global gas business that brings together the key businesses involved in every aspect of natural gas activities — production, liquefaction, shipping, regasification, pipelines, marketing and trading, power generation, and gas-to-liquids technology. A major part of this effort is the development and marketing of the 10 million-metric-ton-per-year Gorgon liquefied natural gas (LNG) project offshore Western Australia. One of our "Big 5" projects, Gorgon is a world-class asset with vast natural gas resources. It is well positioned to supply LNG to customers in Asia and North America, two of the world's fastest-growing markets.

LNG MILESTONES ACHIEVED

Two LNG milestones were reached in 2005. First, the Gorgon joint-venture partners signed a framework agreement that will enable the combined development of Gorgon and nearby natural gas fields as one world-class project. This was followed by Chevron signing Heads of Agreement with three major Japanese utilities as foundation customers for sales of Gorgon LNG. Agreements were signed with Tokyo Gas Co., Ltd.; Chubu Electric Co., Inc.; and Osaka Gas Co., Ltd.

OLUMUYIWA AGBOOLA

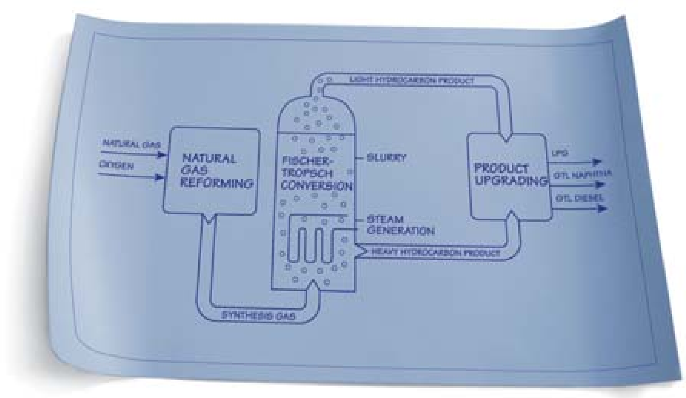
COMMERCIAL MANAGER

CHEVRON NIGERIA LTD.
> NIGERIA

PROFESSIONAL: Chartered Accountant, University of Lagos (Nigeria); 26 years with Chevron.

PERSONAL: Writing and making improvements to his community.

"Imagine ultraclean diesel fuel for markets around the world and a project to produce it that will help bring economic progress to Nigeria. Only it's not imagination – it's reality, and it's happening right now."

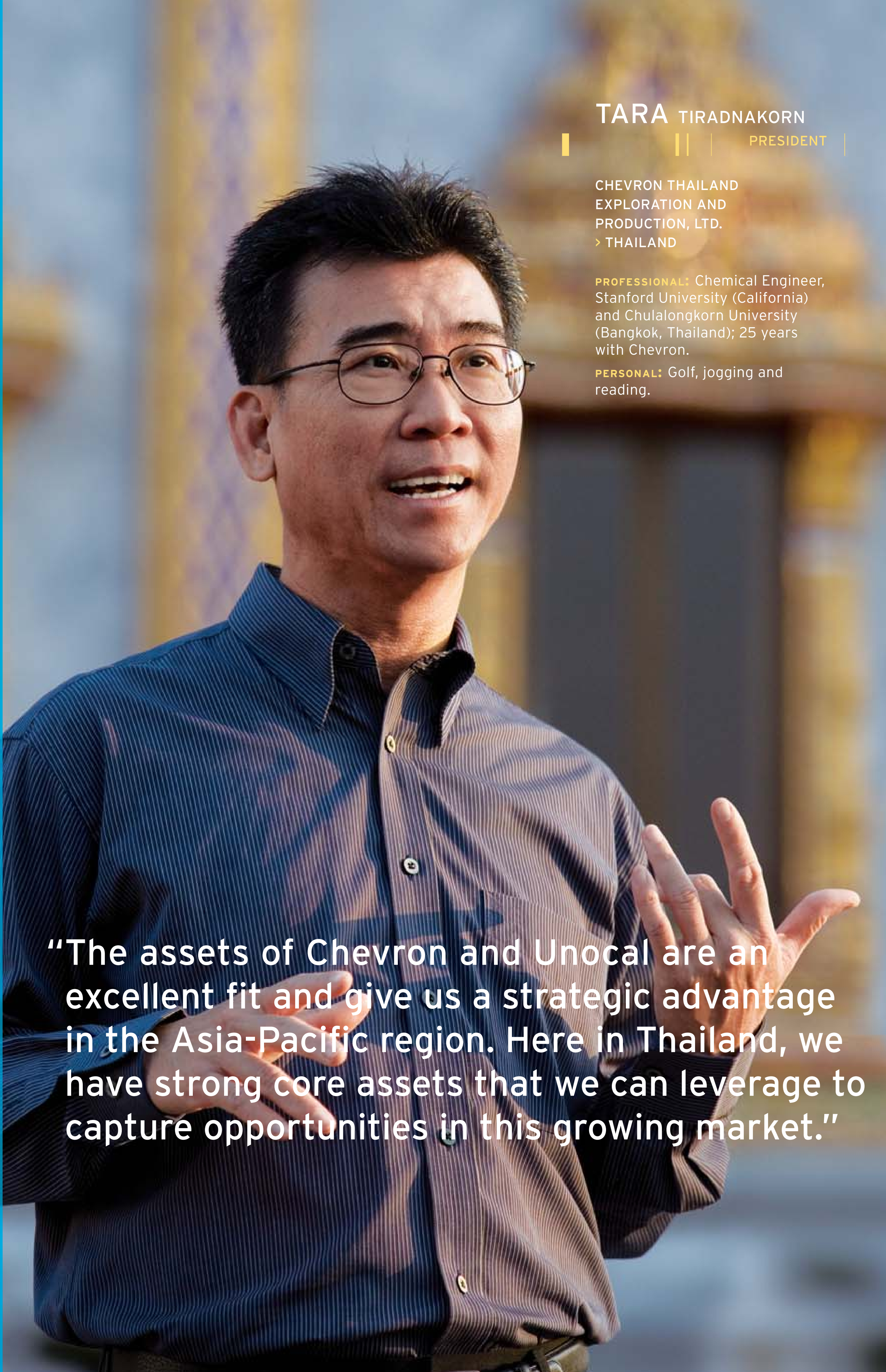


Ultraclean Fuel for the Future

Through our joint venture with Sasol, the South Africa-based pioneer of gas-to-liquids (GTL) technology, we are pursuing projects to turn natural gas into an ultraclean transportation fuel that can improve the performance of conventional diesel engines. In Nigeria, the joint venture is providing management as well as operating and technical services for a 34,000-barrel-per-day plant under construction at Escravos. The project is a significant step toward realizing a cleaner environment for Nigeria, creating employment opportunities and generating revenue for the country, and delivering the promise of natural gas.

A HOST OF OPPORTUNITIES

In 2005, the Escravos GTL project entered a $1.7 billion engineering, procurement and construction phase — a milestone for the year. We expect GTL diesel from Nigeria to be fueling cars and trucks in Europe by the end of the decade. In addition to Escravos, Sasol Chevron is pursuing other GTL opportunities. In Qatar, the company is evaluating a planned $6 billion slate of commercial-scale projects, and it is exploring GTL opportunities in Australia.



TARA TIRADNAKORN

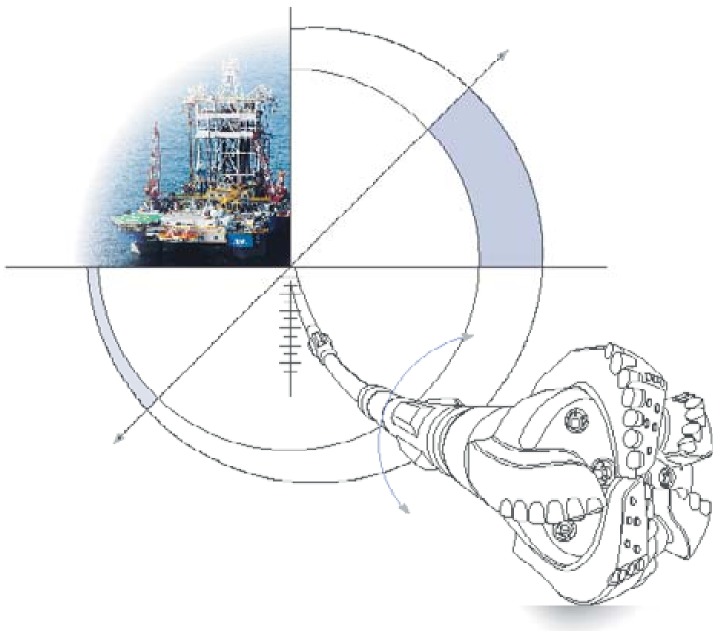
PRESIDENT

CHEVRON THAILAND EXPLORATION AND PRODUCTION, LTD.
> THAILAND

PROFESSIONAL: Chemical Engineer, Stanford University (California) and Chulalongkorn University (Bangkok, Thailand); 25 years with Chevron.

PERSONAL: Golf, jogging and reading.

"The assets of Chevron and Unocal are an excellent fit and give us a strategic advantage in the Asia-Pacific region. Here in Thailand, we have strong core assets that we can leverage to capture opportunities in this growing market."



Drilling for Success

The Unocal acquisition paired Chevron with a unique independent petroleum company with super-major assets. Unocal not only had a portfolio of major upstream assets and prospects, but it also had developed some of the most advanced drilling and completion techniques in the industry. The combination of the two companies enhances Chevron's position in the fast-growing and strategic Asia-Pacific region. It further strengthens our U.S. Gulf of Mexico profile with Unocal's important deepwater discoveries and promising exploration acreage. And it reinforces our standing as a leading oil company in the Caspian region.

COMBINING TECHNOLOGY AND INNOVATION

Unocal brings to Chevron a strong record of applying the innovation of its people with leading-edge technologies. Its technical expertise and capabilities span the range of oil and gas activities — from advanced 3-D seismic imaging to reservoir surveillance to the design of world-class production facilities. Its drilling teams are considered among the best in the industry at working successfully in some of the most difficult environments in the world, including the deepwater U.S. Gulf of Mexico, Indonesia and Thailand.

Human Energy — In Abundance

It is the people of Chevron who drive our company's success and deliver the energy that improves the quality of life for people everywhere. Here you will find examples of employee ingenuity and commitment, as well as tributes from those who have benefited from their work. To read more about these efforts, please visit our Web site: www.chevron.com/humanenergyinabundance/.

Luanda, Angola

TRACKING A GLOBAL KILLER

"Our employees can't contribute their best if the health of their families and communities is threatened by HIV/AIDS. Through treatment, we are improving the lives of those with the disease. Our education programs help employees understand that HIV/AIDS is a preventable disease."

DR. VANDA ANDRADE
Medical Director, Southern Africa Strategic Business Unit

Singapore

FRONTIERS OF EFFICIENCY

"Using a range of ideas and solutions from personnel throughout the Singapore Refinery, along with some very powerful analytical tools, we are working to achieve significant reductions in our energy use — and without compromising the refinery's ability to produce product in a profitable way."

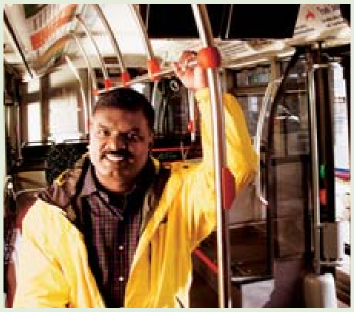
NARAYAN KAMATH
Manager, Planning and Economics (Products)
Singapore Refinery

Lagos, Nigeria

SAVING LIVES THROUGH SAFETY

"Something needed to be done and done fast. We were having too many driving incidents. Chevron's Project Preserve safety team helped us reduce the number and severity of accidents in our Nigerian operations."

TAIYE ORITSEJAFOR
Manager, District Logistics, Southwest Nigeria



San Ramon, California

ACCELERATING NEW FUELS

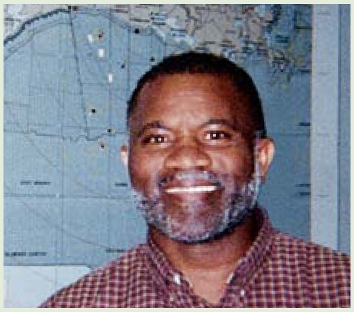
"With a fleet of hydrogen-powered transit buses now operating in the San Francisco Bay Area, we are tackling the challenges of developing hydrogen as a practical new source of energy."

RAJESH PAULOSE
Program Manager, Hydrogen

visit

our Corporate Responsibility Web site in late April for other examples of how Chevron employees are working to improve quality of life:

http://www.chevron.com/cr_report/2005/



Lafayette, Louisiana

SAFELY WEATHERING STORMS AT SEA

"The hurricanes in the U.S. Gulf of Mexico caused very little environmental damage offshore, despite severe damage to rigs and platforms. That's because of advanced technology that can shut off subsea wells remotely in the event of an emergency."

HENRY MOUTON
Supervisor, Supervisory Control and Data Acquisition, Gulf of Mexico Business Unit

Caracas, Venezuela

PROVIDING THE POWER OF EDUCATION

"We are delivering the power of education to Venezuelans who need it most – disadvantaged students seeking hope and opportunity."

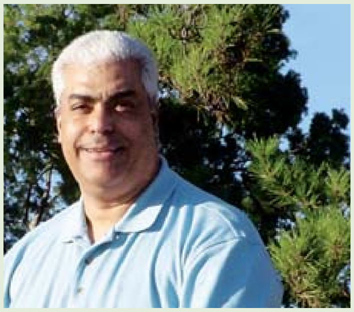
MARGARITA ARANGO
Manager, Policy, Government and Public Affairs
Latin America Upstream

Jakarta, Indonesia

CAPTURING RENEWABLE ENERGY SOURCES

"In Indonesia, we are expanding a geothermal power project that not only will provide additional electrical power but also will help Indonesia avoid more than 400,000 tons per year of carbon dioxide emissions."

REX SOEPARJADI
Manager, Salak Geothermal

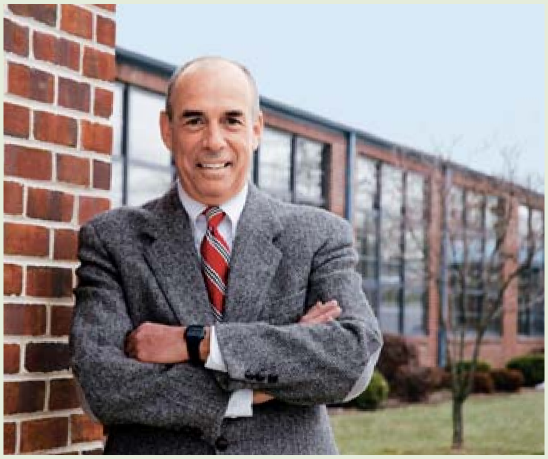


Bakersfield, California

FIELDS OF THE FUTURE

"By applying advances in technology, data interpretation and heat management, we are turning our older heavy oil fields into the fields of the future – fields that are more modern, more efficient and have a longer producing life."

GARY PIRON
Manager, Kern River Area



Chambersburg, Pennsylvania

THE VALUE OF CONSERVATION

"Chevron helped our schools use energy much more efficiently. The company's recommendations have led to a better learning environment for our students and saved us $420,000 a year in energy bills – money we're putting back into education in the classroom."

DR. EDWIN SPONSELLER
Superintendent, Chambersburg Area School District

OPERATING HIGHLIGHTS

Chevron is one of the world's largest integrated energy companies. We have more than 53,000 employees, and our subsidiaries conduct business in approximately 180 countries. We are involved in virtually every aspect of the energy industry — from exploring for, producing, transporting and refining crude oil and natural gas; to marketing petroleum products; to manufacturing and selling petrochemical products; generating power; and developing future energy resources.

UPSTREAM

UPSTREAM AT A GLANCE

At the end of 2005, worldwide net proved crude oil and natural gas reserves for consolidated operations were 9 billion barrels of oil-equivalent and for affiliated operations were 2.9 billion barrels. Production averaged 2.5 million barrels of oil-equivalent per day, including volumes produced from oil sands and production under an operating service agreement. Major producing areas are Angola, Australia, Indonesia, Kazakhstan, Nigeria, the Partitioned Neutral Zone, Thailand, the United Kingdom, the United States and Venezuela. Major exploration areas are Australia, Brazil, Canada, the Norwegian North Sea, Trinidad and Tobago, the U.K. Atlantic Margin, the U.S. Gulf of Mexico, Venezuela and western Africa.

Chevron's upstream business explores for and produces crude oil and natural gas. We hold strategic positions in the world's largest and most prolific regions, and we are typically among the top three producers wherever we operate. During the year, we made significant progress in advancing our upstream strategy – to grow the profitability of our core areas of operation and to build new legacy positions.

CORE AREAS The Unocal acquisition greatly enhanced our position in the Asia-Pacific region, the Caspian and the U.S. Gulf of Mexico, core areas where we already had a significant presence. We also continued to make good progress in maximizing the value of our base business, primarily by lowering costs while increasing reliability and production volumes. In the Gulf of Thailand, for example, we improved production substantially by returning nonproducing wells to production and by removing bottlenecks at several mature fields. Also during the year, we completed the $1.7 billion sale of a wholly owned Canadian subsidiary of Unocal. The disposition was consistent with our recent divestiture of nonstrategic producing properties in western Canada.

"BIG 5" In 2005, we moved forward with a number of major capital investments, including our "Big 5" projects. Initial production began in early 2006 from the Benguela Belize-Lobito Tomboco development offshore Angola. Construction began on production facilities for the giant Agbami Field offshore Nigeria and the Tahiti Field in the U.S. Gulf of Mexico. We made progress on the Tengizchevroil expansion project in Kazakhstan, and we reached milestones in developing our vast natural gas resources in the Greater Gorgon Area offshore Western Australia.

NATURAL GAS Commercializing our natural gas resources is an important part of our upstream strategy. In addition to the Gorgon development, we are a partner in the North West Shelf project offshore Western Australia, where a major expansion is under way to increase liquefied natural gas (LNG) export capacity by approximately one-third. We also are pursuing a number of opportunities to import natural gas into North America. We recently increased our capacity at the Sabine Pass LNG import terminal, under construction in Louisiana, and we have filed an application to build an LNG regasification terminal near our Pascagoula, Mississippi, refinery. Through the Sasol Chevron joint venture, we are developing a global business to produce and market high-performing, ultraclean transportation fuels using gas-to-liquids technology.

2005 MOMENTUM

- Began initial production from developments in Angola, Azerbaijan, Bangladesh, Chad, Indonesia, Thailand, Trinidad and Tobago, and the United Kingdom
- Drilled significant discoveries in Angola, Cambodia, Nigeria, Trinidad and Tobago, the U.S. Gulf of Mexico, and Venezuela
- Acquired promising new offshore acreage in Thailand, the U.K. Atlantic Margin, U.K. North Sea, U.S. Gulf of Mexico, Vietnam, Western Australia and western Venezuela; onshore, the successful bidder on a block in Libya
- Signed framework agreement with joint-venture partners that will enable the combined development of Gorgon and nearby natural gas fields as one world-class project; signed Heads of Agreement with three Japanese utilities for the sale of liquefied natural gas (LNG) from Gorgon
- Moved major projects into engineering and design phase – Gorgon LNG project; Angola LNG project; Usan Field, deepwater Nigeria

› Above, left to right: Steam pipes and expansion joints, McKittrick Field, San Joaquin Valley, California. › Agbami Field, deepwater Nigeria.

DOWNSTREAM

DOWNSTREAM AT A GLANCE

In 2005, Chevron processed approximately 2 million barrels of crude oil per day and averaged approximately 3.8 million barrels per day of refined products sales worldwide. Our major areas of operations are in Asia, on the U.S. West Coast, on the U.S. Gulf Coast extending to Latin America and in sub-Saharan Africa. We market under the Chevron, Texaco and Caltex motor fuel brands. Products are sold through a network of approximately 26,500 retail stations, including those of affiliate companies.

Chevron's downstream comprises refining, fuels and lubricants marketing, supply and trading, and transportation. It is a global and diverse organization with interests in 19 fuel refineries and a marketing presence in approximately 175 countries. Our downstream strategy is to improve returns by focusing on areas of market and supply strength.

REFINING Our refineries are well positioned to meet demand in some of the world's most significant product growth markets – Asia and North America. They have the flexibility to respond to market opportunities when they arise and can run significant volumes of lower-quality, lower-priced crude oil to improve profitability.

During the year, we continued our efforts to lower refinery operating and maintenance costs, primarily by achieving greater energy efficiency and improving maintenance procedures. We also are systematically addressing our reliability performance in order to enhance refinery utilization rates.

MARKETING We market petroleum products under three of the industry's most trusted brands – Chevron, Texaco and Caltex. To offer our customers unsurpassed fuels, we have begun a phased introduction of our gasoline additive, Techron, to international Texaco and Caltex products. We continue to upgrade our marketing portfolio by selling nonstrategic retail sites. Since 2003, we have divested more than 2,300 such sites, many of which continue to market company-branded fuels. We will pursue additional sales and acquisitions based on favorable market opportunities.

2005 MOMENTUM

- Resumed planned levels of operations at the Pascagoula, Mississippi, refinery two weeks earlier than estimated following Hurricanes Katrina and Rita; employees shut down facilities, evacuated, returned and resumed operations – all safely and with no harm to the environment
- Completed expansion at El Segundo, California, refinery to increase production of gasoline and other light products; began similar expansion at the Pascagoula Refinery
- Began phased introduction of our gasoline additive, Techron, to Texaco and Caltex products
- Divested nonstrategic fuel marketing assets and high-graded retail network
- Approved project at our affiliate refinery in Yeosu, South Korea, to add conversion units to run heavy crude oil and improve yield of high-value products

› Above, left to right: Pembroke Refinery, United Kingdom. › Caltex service station, Singapore.

› Opposite page, left to right: Solar electric system, U.S. Postal Service facility, Sacramento, California.
› Hydrogen energy station, Oakland, California.

OTHER BUSINESSES

Chevron, through its 50-50 joint venture Chevron Phillips Chemical Company LLC, is one of the leading manufacturers of petrochemicals. The company has 31 manufacturing facilities in nine countries and markets chemicals products including olefins, polyolefins, aromatics and specialty products.

Chevron Oronite markets more than 500 performance-enhancing products and supplies one-fourth of the world's fuel and lubricant additives. Oronite operates two major global businesses – lubricating oil additives and fuel additives.

Chevron's technology companies work together to deploy technologies that enhance our core businesses. Chevron Energy Solutions delivers energy-efficiency solutions to external and internal clients. Chevron Technology Ventures invests in next-generation technology, including hydrogen for transportation needs. Chevron enhances its technical capabilities through extensive partnerships with technology companies, universities and public agencies throughout the world.

Global Power Generation develops and markets commercial power projects worldwide.

For more information about the businesses of Chevron, visit our Web site: www.chevron.com.

HELPING OTHERS IMPROVE ENERGY EFFICIENCY

Chevron Energy Solutions (CES) helps clients improve their energy efficiency, conserve energy and install alternative power solutions, such as solar and fuel cell generation systems. Some examples include:

- Upgrades to U.S. Postal Service facilities in Northern California are reducing power purchases significantly, resulting in yearly savings of more than $2 million and lower greenhouse gas emissions.
- For a California college district, CES installed solar electric and cogeneration projects that are reducing electricity purchases by 46 percent, or $800,000 a year.
- Electricity generated from restaurant kitchen grease and other organic matter will reduce energy purchases for a water pollution control plant in Millbrae, California.

OPERATIONAL EXCELLENCE

At Chevron, our goal is to be admired for world-class performance in protecting people and the environment. To achieve this, we follow a disciplined operational excellence management system. In 2005, an external audit verified that our system meets international quality assurance standards, including those of the International Standardization Organization and the Occupational Health and Safety Administration System.

Our commitment to operational excellence was demonstrated in a number of ways throughout the year. Despite the effects of storm damage to our operations, we showed improvement in both our safety and environmental performance.

Safety is our No. 1 priority, and 2005 was our safest year ever. The total on-the-job injury rate improved 20 percent from 2004, and the rate of injuries severe enough to require days away from work improved 30 percent. Our safety goal is zero incidents, and we will not be satisfied until we achieve it.

We have a long-term commitment toward reducing the energy we use in our day-to-day operations. By conserving energy, we can produce our products more cost-effectively for our customers and reduce the impact on the environment, including reducing greenhouse gas emissions as well as other air emissions. Since we began tracking our energy use in 1992, we have increased our energy efficiency by 24 percent. In addition to driving greater energy efficiencies through our own organization, we also are helping other businesses and institutions conserve energy in their operations (see sidebar above).

ENERGY TERMS

Additives Chemicals to control engine deposits and improve lubricating performance.

Barrels of oil-equivalent (BOE) A unit of measure to quantify crude oil 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*.

Condensate Liquid hydrocarbons produced with natural gas, separated by cooling and other means.

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

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

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

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

Greenhouse gases Gases that trap heat in the Earth's atmosphere (e.g., 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 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 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 host 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 host 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 A contractual agreement between a company and a host government whereby the company bears all exploration, development and production costs in return for an agreed-upon share of production.

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, biomass fuels, and hydrogen).

Reserves Crude oil or 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 to solid hydrocarbons, such as extra-heavy crude oil or *oil sands*.

GLOSSARY OF ENERGY AND FINANCIAL TERMS

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 programs. Excludes cash flows related to the company's financing and investing activities.

Cumulative effect of change in accounting principle The effect on net income in the period of change of a retroactive calculation and 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.

Special items Amounts that, because of their nature and significance, are identified separately to help explain the changes in net income and segment income between periods and to help distinguish the underlying trends for the company's core businesses.

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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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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" 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. You 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 unknown or unexpected problems in the resumption of operations affected by Hurricanes Katrina and Rita and other severe weather in the Gulf of Mexico; crude oil and natural gas prices; refining margins and marketing margins; chemicals prices and competitive conditions affecting supply and demand for aromatics, olefins and additives products; actions of competitors; the competitiveness of alternate energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; the ability to successfully integrate the operations of Chevron and Unocal Corporation; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's net production or manufacturing facilities due to war, accidents, political events, civil unrest or severe weather; the potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations and litigation (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); the potential liability resulting from pending or future litigation; the company's acquisition or disposition of assets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

KEY FINANCIAL RESULTS

Millions of dollars, except per-share amounts	**2005**	2004	2003
Net Income	**$ 14,099**	$ 13,328	$ 7,230
Per Share Amounts:			
Net Income – Basic	**$ 6.58**	$ 6.30	$ 3.48
– Diluted	**$ 6.54**	$ 6.28	$ 3.48
Dividends	**$ 1.75**	$ 1.53	$ 1.43
Sales and Other			
Operating Revenues	**$ 193,641**	$ 150,865	$ 119,575
Return on:			
Average Capital Employed	**21.9%**	25.8%	15.7%
Average Stockholders' Equity	**26.1%**	32.7%	21.3%

INCOME FROM CONTINUING OPERATIONS BY MAJOR OPERATING AREA

Millions of dollars	**2005**	2004	2003
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	**$ 4,168**	$ 3,868	$ 3,160
International	**7,556**	5,622	3,199
Total Upstream	**11,724**	9,490	6,359
Downstream – Refining, Marketing and Transportation			
United States	**980**	1,261	482
International	**1,786**	1,989	685
Total Downstream	**2,766**	3,250	1,167
Chemicals	**298**	314	69
All Other	**(689)**	(20)	(213)
Income From Continuing Operations	**$ 14,099**	$ 13,034	$ 7,382
Income From Discontinued Operations – Upstream	**–**	294	44
Income Before Cumulative Effect of Changes in Accounting Principles	**$ 14,099**	$ 13,328	$ 7,426
Cumulative Effect of Changes in Accounting Principles	**–**	–	(196)
Net Income*	**$ 14,099**	$ 13,328	$ 7,230
*Includes Foreign Currency Effects:	**$ (61)**	$ (81)	$ (404)

Net income in 2003 included a $196 million charge for the cumulative effect of changes in accounting principle. The primary change related to the company's adoption of Financial Accounting Standards Board Statement No. 143, "Accounting for Asset Retirement Obligations," which is discussed in Note 24 to the Consolidated Financial Statements. Net income in 2004 included gains of approximately $1.2 billion relating to the sale of nonstrategic upstream properties. Refer also to the "Results of Operations" section beginning on page 31 for a detailed discussion of financial results by major operating area for the three years ending December 31, 2005.

BUSINESS ENVIRONMENT AND OUTLOOK

The company's current and future earnings depend largely on the profitability of the 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. Overall earnings trends are typically less affected by results from the company's chemical business and other activities and investments. Earnings for the company in any period may also be affected by events or transactions that are infrequent and/or unusual in nature.

The company's long-term competitive position, particularly given the capital-intensive and commodity-based nature of the industry, is closely associated with the company's ability to invest in projects that provide adequate financial returns and to manage operating expenses effectively. Creating and maintaining an inventory of projects depends on many factors, including obtaining rights to explore for crude oil and natural gas, developing and producing hydrocarbons in promising areas, drilling successfully, bringing long-lead-time capital-intensive projects to completion on budget and on schedule, and operating mature upstream properties efficiently and profitably.

The company also continually evaluates opportunities to dispose of assets that are not key to providing long-term value, or to acquire assets or operations complementary to its asset base to help augment the company's growth. Asset disposition and restructuring may occur in future periods and could result in significant gains or losses.

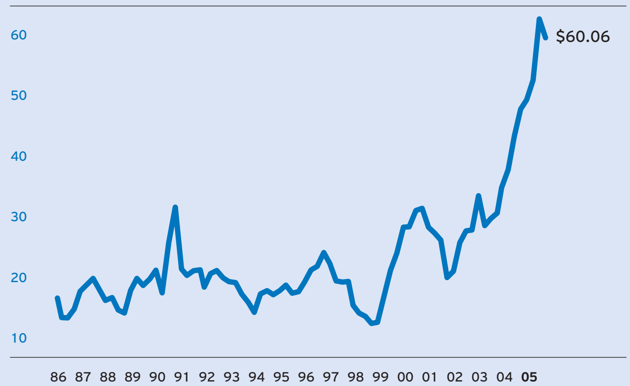
In August 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. The aggregate purchase price was $17.3 billion, which included $7.5 billion cash, approximately 169 million shares of Chevron common stock valued at $9.6 billion, and $0.2 billion for stock options on approximately 5 million shares and merger-related fees. Refer to Note 2, beginning on page 60, for a discussion of the Unocal acquisition.

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 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 capitalized 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 product- and service-providers, which can be affected by the volatility of the industry's own supply and demand conditions for such products and services. The oil and gas industry worldwide experienced significant price increases for these items during 2005 that are expected to continue into 2006. Capitalized costs and operating expenses can also be affected by uninsured damages to production facilities caused by severe weather or civil unrest.

CRUDE OIL PRICES 1986 THROUGH 2005
Dollars per barrel



The average spot price of West Texas Intermediate, a benchmark crude oil, rose 24 percent from the fourth quarter of 2004 to the fourth quarter of 2005.

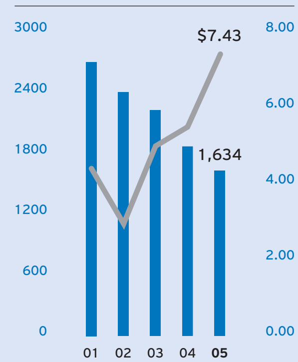
Industry price levels for crude oil continued an upward trend in 2005. The spot price for West Texas Intermediate (WTI) crude oil, one of the benchmark crudes, averaged $57 per barrel in 2005, an increase of approximately $16 per barrel from the 2004 average price. The WTI spot price for the first two months of 2006 averaged about $64 per barrel. The rise in crude oil prices reflects, among other things, 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, including production in the Gulf of Mexico that partially was shut in following the hurricanes.

As was the case in 2004, the differential in prices between high-quality, light-sweet crude oils, such as the U.S. benchmark WTI, and heavier crudes was unusually wide in 2005. Chevron produces heavy crude oil in California, Chad, Indonesia, the Partitioned Neutral Zone (between Saudi Arabia and Kuwait), Venezuela (including volumes produced under an operating service agreement) and certain fields in Angola, China and the United Kingdom North Sea. The price for the heavier crudes has been dampened because of ample supply, together with lower relative demand from the number of refineries that are able to process this lower-quality feedstock into light-product fuels (i.e., motor gasoline, jet fuel, aviation gasoline and diesel fuel). The demand for heavy crude was further reduced in late 2005 as refining capacity along the U.S. Gulf Coast was interrupted by hurricanes. The price for higher-quality light oil, on the other hand, has remained high, as the demand for light products, which can be manufactured by any refinery from light oil, has been robust worldwide.

Natural gas prices, particularly in the United States, also trended upward in 2005. For the full year, U.S. benchmark prices at Henry Hub averaged about $8 per thousand cubic feet (MCF), compared with about $6 in 2004. Henry Hub spot prices peaked in December 2005 above $14, as supplies early in the winter heating season were reduced by production shut in following Hurricanes Katrina and Rita. By mid-February 2006, prices had moved downward to 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 to meet customer demand.

In contrast to the United States, 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 36 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 lack of infrastructure and the difficulties in transporting natural gas. To help address this regional imbalance between supply and demand for natural

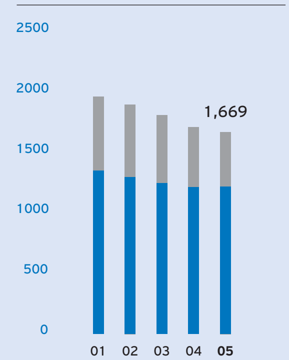
U.S. NATURAL GAS PRICES & NET PRODUCTION



- Prices in Dollars per Thousand Cubic Feet (right scale)
- Production in Millions of Cubic Feet per Day (left scale)

Average prices increased 35 percent during 2005. Production was down 13 percent mainly due to the effects of storms in the U.S. Gulf of Mexico, asset sales and natural field declines partially offset by the addition of Unocal production.

NET CRUDE OIL & NATURAL GAS LIQUIDS PRODUCTION*
Thousands of barrels per day



- United States
- International

Net liquids production declined about 2 percent in 2005, mainly due to the effects of storms, asset sales and natural field declines partially offset by the addition of Unocal production.

*Includes equity in affiliates

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 that can be transported in existing natural gas pipeline networks (as in the United States).

Longer-term trends in earnings for the upstream segment are also a function of other factors besides price fluctuations, including changes in the company's crude oil and natural gas production levels and the company's ability to find or acquire and efficiently produce crude oil and natural gas reserves. Most of the company's overall capital investment is in its upstream businesses, particularly 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.

Chevron's worldwide net oil-equivalent production of approximately 2.5 million barrels per day in 2005, including volumes produced from oil sands and production under an operating service agreement, remained essentially unchanged from 2004. However, production in the fourth quarter 2005 was nearly 2.7 million barrels per day, reflecting the benefit of volumes associated with the properties acquired from Unocal, the effect of which was partially offset by production shut in as a result of the hurricanes in the Gulf of Mexico. Prior to the hurricanes in August and September 2005, oil-equivalent production in the Gulf of Mexico was approximately 300,000 barrels per day. In 2006, production is projected to average approximately 200,000 barrels per day, as normal field declines are expected to exceed the production being restored from wells that were shut in or damaged from the hurricanes and the production that will result from the drilling of new wells in the area. Approximately 20,000 net oil-equivalent barrels of daily production are not expected to be sufficiently economic to restore.

The company estimates that oil-equivalent production in 2006 will average between 2.7 million and 2.8 million barrels per day. However, future estimates are 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, severe weather, and the potential for local civil unrest and changing geopolitics that could cause production disruptions. Approximately 26 percent of the company's net oil-equivalent production in 2005, including net barrels from oil sands and production under an operating service agreement, occurred in the OPEC-member countries of Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. Although the company's production level during 2005 was not constrained in these areas by OPEC quotas, future production could be affected by OPEC-imposed limitations. Future production levels also are affected by the size and number of economic investment opportunities and, for new large-scale projects, the time lag between initial exploration and the beginning of production. Refer to pages 29 through 30 for discussion of the company's major upstream projects.

In certain onshore areas of Nigeria, approximately 45,000 barrels per day of the company's net production capacity was shut in during 2003 because of civil unrest and damage to production facilities. The company has adopted a phased plan to restore these operations, and about one-third of the volumes had been returned to production as of early 2006.

Refer to pages 31 through 33 for additional discussion of the company's upstream operations.

Downstream Refining, marketing and transportation earnings are closely tied to global and regional supply and demand for refined products and the associated effects on industry refining and marketing margins. The company's core marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia and sub-Saharan Africa. In 2005, industry refining margins improved over the prior year, reflecting strong demand for refined products; however, marketing margins, which are highly influenced by regional market conditions, were mixed. Many regions experienced stronger marketing margins, but these margins were generally lower in the United States and Europe, as retail prices did not keep pace with rising crude oil and spot product prices. Industry margins in the future may be volatile, due primarily to changes in the price of crude oil used for refinery feedstock, disruptions at refineries resulting from maintenance programs and mishaps and levels of inventory and demand for refined products.

Other influences on the company's profitability in this segment include the operating efficiencies and expenses of the refinery network, including the effects of any downtime due to planned and unplanned maintenance, refinery upgrade projects and operating incidents. The level of operating expenses for the downstream segment can also be affected by the volatility of charter expenses for the company's shipping operations, which are driven by the industry's demand for crude oil and product tankers. Other factors affecting the company's downstream profitability that are beyond the company's control include the general level of inflation and energy costs to operate the refinery network.

Refer to pages 33 through 34 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. Additionally, feedstock and fuel costs, which tend to follow crude oil and natural gas price movements, influence earnings in this segment.

Refer to page 34 for additional discussion of chemical earnings for both the company's Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC.

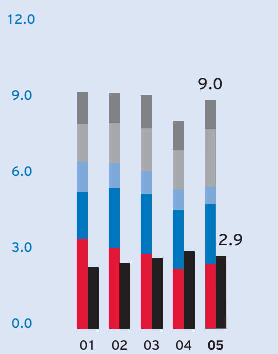
OPERATING DEVELOPMENTS

Key operating developments and other events during 2005 and early 2006 included:

Upstream

Worldwide Proved Reserves As a result of the acquisition of Unocal in August 2005, the company increased its net oil-equivalent proved reserves by approximately 1.5 billion barrels. Significant unproved volumes of oil and gas were also added to the company's resource base. (Refer to pages 94 through 99 for a detailed discussion of proved reserve changes for 2005 and Note 2 beginning on page 60 for a discussion of the Unocal acquisition.)

NET PROVED RESERVES
Billions of BOE*



- Other International
- Asia-Pacific
- Indonesia
- Africa
- United States
- Affiliates

Net proved reserves for consolidated companies climbed 10 percent in 2005, primarily due to the Unocal acquisition.

*Barrels of oil-equivalent

North America In September 2005, the company sold Northrock Resources Limited, a wholly owned Canadian subsidiary of Unocal, for $1.7 billion. The disposition was consistent with Chevron's divestiture in 2004 of its conventional crude oil and natural gas business in western Canada, enabling the company's continued focus on the profitable growth of production of crude oil and natural gas in strategically important core areas of operation.

In late 2005, the company began construction of the floating production facility to be installed in the Tahiti Field, in the deepwater Gulf of Mexico. Tahiti is anticipated to have a maximum total daily production of 125,000 barrels per day of crude oil and 70 million cubic feet of natural gas. Chevron is the operator and holds a 58 percent working interest in the project that is being developed in phases and expected to come onto production in 2008.

In the same period, the decision was made to proceed with the development of the Blind Faith Field, also in the deepwater Gulf of Mexico. First production is expected in 2008, with initial total daily output estimated at 30,000 barrels of crude oil and 30 million cubic feet of natural gas. Chevron is the operator and holds a 62.5 percent working interest in the project.

In late 2005, the company drilled deepwater crude oil discoveries in the Gulf of Mexico at the 60 percent-owned and operated Big Foot prospect in the Walker Ridge Block 29 and the 25 percent-owned, nonoperated Knotty Head prospect located in Green Canyon Block 512. Additional appraisal activity continued into 2006 at both locations.

Angola In early 2006, first oil was produced from the 31 percent-interest deepwater Belize Field in Block 14, offshore Angola. The Benguela, Belize, Lobito and Tomboco fields form a project that is being developed in two phases. The maximum total production from both phases of the project is anticipated to reach 200,000 barrels of crude oil per day in 2008.

Australia In mid-2005, the company won exploration rights to four deepwater blocks in the northern Carnarvon Basin offshore Western Australia. In early 2006, the company was awarded rights to another block in the Carnarvon Basin. The blocks are located in an area of significant natural gas potential and near the Chevron-led Gorgon Project. Chevron holds a 50 percent operated interest in the blocks.

Kazakhstan In late 2005, the company's 50 percent-owned Tengizchevroil (TCO) affiliate awarded commercial contracts to enable increased crude-oil exports through a southern route across the Caspian Sea. The southern route will provide additional export capacity for TCO's increased production until the Caspian Pipeline Consortium pipeline is expanded. The additional crude oil production at TCO will result from major facilities-expansion projects being constructed at a total cost of approximately $5.5 billion. By the third quarter 2007, TCO's crude production capacity is projected to increase from the current capacity of 300,000 barrels per day to between 460,000 and 550,000.

Nigeria In early 2005, a construction contract was awarded for the $1.1 billion floating production, storage and offloading (FPSO) vessel to be used at the Agbami Field. The construction contract was a key milestone in the development of the 68 percent-owned Agbami Field, which is scheduled to come online in 2008 with an estimated maximum total daily production of 250,000 barrels of crude oil.

Nigeria – São Tomé e Príncipe Joint Development Zone (JDZ) In early 2005, the company signed a production-sharing contract for Block 1 in the Nigeria – São Tomé e Príncipe JDZ. Chevron will be the operator and has a 51 percent interest in the block. Drilling of the first exploration well was under way in late-February 2006.

Venezuela In June 2005, the company discovered natural gas in Block 3 of Plataforma Deltana, offshore Venezuela. The site is in the proximity of the Loran natural gas field in Block 2 and provides sufficient resources for a detailed evaluation of Venezuela's first liquefied natural gas (LNG) train.

In the third quarter 2005, the company was awarded an exploration license for the Cardon III Block, offshore western Venezuela. The block is in a region with natural gas potential to the north of the Maracaibo producing area.

In December 2005, Chevron signed a transition agreement with Petróleos de Venezuela, S.A. (PDVSA), the Venezuelan state-owned petroleum company, to convert contracts for the Boscan and LL-652 operating service agreements into an Empresa Mixta (EM). The EM is a joint-stock contractual structure with PDVSA as the majority shareholder. Negotiation of the ownership and format of the final EM structure will be conducted during 2006. Possible financial implications of the EM structure are uncertain, but are not expected to have a material effect on the company's consolidated financial position or liquidity.

Global Natural Gas Projects In Angola, the company awarded contracts in April 2005 for front-end engineering and design studies for a multibillion-dollar onshore LNG project located in northern Angola. This project will be designed to help reduce flaring of natural gas and represents a major step toward the commercialization of some of Angola's vast natural gas resources. The company has a 36 percent ownership interest in the Angola LNG project and will co-lead development with the Angolan government's national oil company. Construction is expected to begin in 2007.

In April 2005, the company reached an agreement with joint-venture participants in the Greater Gorgon Area, offshore Western Australia that will enable the combined development of natural gas at Gorgon and nearby gas fields as one project. The company is a significant holder of gas resources in the area and will have an approximate 50 percent ownership interest across most of the Greater Gorgon Area.

In June 2005, the company announced the decision to move the Australian Greater Gorgon gas development project into the front-end engineering and design phase for a two-train (10 million metric tons per year) LNG facility and a potential domestic gas plant on Barrow Island, targeting initial production by 2010. Chevron is the operator and has a 50 percent ownership interest in the licenses for the Greater Gorgon Area.

In the fourth quarter 2005, the company signed a Heads of Agreement (HOA) for first sale of LNG from the Gorgon Project into Japan, the world's largest LNG market. The preliminary agreement was signed by Chevron Australia Pty Ltd with Tokyo Gas Co., Ltd., a major Japanese utility company, for the purchase of 1.2 million metric tons per year of Gorgon LNG over 25 years. Two additional HOAs were later signed by Chevron Australia Pty Ltd with Chubu Electric Co., Inc. and Osaka Gas Co., Ltd., both companies from Japan. Each preliminary agreement was for the purchase of 1.5 million metric tons per year of Gorgon LNG over 25 years commencing in 2010 and 2011, respectively.

The company and its partners in the North West Shelf (NWS) venture agreed in mid-2005 to expand the project's onshore LNG facilities in Western Australia. Chevron holds a one-sixth interest in the NWS venture. The $1.5 billion project includes adding a fifth train that will increase LNG export capacity by more than 4 million metric tons per year to approximately 16 million metric tons per year, with start-up expected in 2008. In December 2005, the NWS joint venture participants approved development of the Angel natural gas field, which will provide the natural gas supply for the Train 5 expansion.

In Nigeria, the company awarded a $1.7 billion contract in April 2005 for the engineering, procurement and construction of the Escravos gas-to-liquids project. Plant construction began in 2005 including major equipment fabrication and site preparation.

In the third quarter 2005, installation began on a 350-mile main offshore segment of the West African Gas Pipeline that will provide natural gas to markets in Ghana, Togo and Benin by connecting to an existing onshore pipeline in Nigeria. The pipeline will have a capacity of approximately 475 million cubic feet per day and will help in the reduction of the flaring of natural gas in the company's areas of operation.

In Russia, OAO Gazprom has included Chevron on a list of companies that could continue further commercial and technical discussions concerning the development and related commercial activities of the Shtokmanovskoye Field. Discussions were under way in early 2006, but the timing of Gazprom's selection of the company or companies that will participate in the field development was uncertain. Shtokmanovskoye is a very large natural gas field offshore Russia in the Barents Sea. OAO Gazprom is Russia's largest natural gas producer.

In the United States, Chevron completed the acquisition of the remaining 40 percent interest of Bridgeline Holdings, L.P. in August 2005. Bridgeline manages and operates more than 1,000 miles of pipeline and 12 billion cubic feet of natural gas storage capacity in southern Louisiana.

In the third quarter 2005, the company filed an application with the Federal Energy Regulatory Commission to own, construct and operate a natural gas import terminal at the Casotte Landing site adjacent to Chevron's refinery in Pascagoula, Mississippi. The terminal will be designed to initially process 1.3 billion cubic feet of natural gas per day from imported LNG.

In the fourth quarter 2005, the company committed to pipeline and additional LNG terminal capacity in the Sabine Pass area of Louisiana. The first commitment was for 1 billion cubic feet per day of pipeline capacity in a new pipeline and additional interconnect capacity to an existing pipeline. The company also exercised its option to increase capacity at a Sabine Pass LNG terminal from 700 million to 1 billion cubic feet per day.

Downstream

United States The company initiated a project to increase the capacity of the Pascagoula, Mississippi, refinery's fluid catalytic cracking unit by approximately 25 percent, from a current capacity of 63,000 barrels per day. This project is designed to enable the refinery to increase its production of gasoline and other light products and is expected to be completed by late 2006.

South Korea The company's 50 percent-owned GS Caltex affiliate announced a major upgrade project at its 650,000-barrel-per-day Yeosu refining complex. At an estimated total cost of $1.5 billion, the facilities will increase the yield of high-value refined products and reduce feedstock costs through the processing of heavy crude oil. Start-up is expected by the end of 2007.

Chemicals

Qatar The company's 50 percent-owned affiliate, Chevron Phillips Chemical Company LLC (CPChem), has obtained approvals and completed the financial closing for the Q-Chem II complex to be located next to the existing Q-Chem I complex in Mesaieed, Qatar. The Q-Chem II complex will include a 350,000-metric-ton-per-year polyethylene plant and a 345,000-metric-ton-per-year normal alpha olefins plant. The project also includes a separate joint venture to develop a 1,300,000-metric-ton-per-year ethylene cracker at Qatar's Ras Laffan Industrial City. CPChem and its partners expect to start-up the cracker and derivatives plants in late 2008. CPChem owns a 49 percent interest of Q-Chem II.

Other

Common Stock Dividends and Stock Repurchase Program In April 2005, the company increased its quarterly common stock dividend by 12.5 percent to $0.45 per share. The company completed an authorized $5 billion of stock buybacks in November 2005 under a repurchase program initiated in April 2004. Upon completion of this program, the company then authorized the acquisition of up to $5 billion of additional shares over a period of up to three years. Purchases under this authorization totaled $481 million through mid-February 2006.

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 operations of coal and other minerals, power generation businesses, and the various companies and departments that are managed at the corporate level. 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 FAS 131, *"Disclosures About Segments of an Enterprise and Related Information."*)

To aid in the understanding of changes in income between periods, the discussion, when applicable, is in two parts – first on underlying trends, and second on special-item gains and charges. The special items are identified separately because of their nature and amount and also to help discern the underlying trends for the company's businesses. This section should also be read in conjunction with the discussion in "Business Environment and Outlook" on pages 26 through 29.

U.S. Upstream – Exploration and Production

Millions of dollars	**2005**	2004	2003
Income From Continuing Operations	**$ 4,168**	$ 3,868	$ 3,160
Income From Discontinued Operations	**–**	70	23
Cumulative Effect of Accounting Change	**–**	–	(350)
Total Income*	**$ 4,168**	$ 3,938	$ 2,833
*Includes Special-Item Gains (Charges):			
Asset Dispositions			
Continuing Operations	**$ –**	$ 316	$ 77
Discontinued Operations	**–**	50	–
Litigation Provisions	**–**	(55)	–
Asset Impairments/Write-offs	**–**	–	(103)
Restructuring and Reorganizations	**–**	–	(38)
Total	**$ –**	$ 311	$ (64)

U.S. upstream income of nearly $4.2 billion in 2005 increased $230 million. The amount in 2004 included net special-item benefits (discussed below) of more than $300 million. Higher prices for crude oil and natural gas in 2005 and earnings from the former Unocal operations contributed approximately $2 billion to the increase between periods. Approximately 90 percent of this amount related to the effects of higher prices on heritage-Chevron production. These benefits were partially offset by the adverse effects of lower production (discussed below), higher operating expenses and higher depreciation expense associated with heritage-Chevron properties.

Income of $3.9 billion in 2004 was $1.1 billion higher than the $2.8 billion recorded in 2003. Of this increase, $725 million resulted from the difference in the effect on earnings in the respective periods from special items and the cumulative-effect charges recorded in 2003 for the implementation of a new accounting standard. (Refer to Note 24, beginning on page 83, for a discussion of FAS 143, *"Accounting for Asset Retirement Obligations."*) The balance of the increase from 2003 to 2004 was composed of about a $1 billion benefit from higher prices for crude oil and natural gas that was partially offset by the effect of lower production.

The company's average realization for crude oil and natural gas liquids in 2005 was $46.97 per barrel, compared with $34.12 in 2004 and $26.66 in 2003. The average natural gas realization was $7.43 per thousand cubic feet in 2005, compared with $5.51 and $5.01 in 2004 and 2003, respectively.

Net oil-equivalent production in 2005 averaged 727,000 barrels per day, down 11 percent from 2004 and 22 percent from 2003. The decline between 2004 and 2005 was the result of the effects of hurricanes, property sales and normal field declines, which were partially offset by the benefit of five months of production in 2005 from properties acquired from Unocal. The lower production between 2003 and 2004 was associated with property sales, the effects of storms and normal field declines.

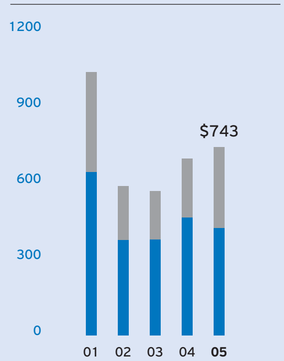
The net liquids component of oil-equivalent production for 2005 averaged 455,000 barrels per day, a decline of 10 percent from 2004 and 19 percent from 2003. Absent the effects of the Unocal volumes in 2005, property sales and storms, net liquids production in 2005 declined 6 percent and 11 percent from 2004 and 2003, respectively.

Net natural gas production averaged 1.6 billion cubic feet per day in 2005, down 13 percent and 27 percent from 2004 and 2003, respectively. Excluding the Unocal volumes in 2005, the effects of property sales and shut-in production related to storms, net natural gas production in 2005 declined 10 percent from 2004 and 20 percent from 2003.

Refer to the "Selected Operating Data" table, on page 36, for the three-year comparative production volumes in the United States.

No special items were recorded in 2005. Special items in 2004 included gains of $366 million from property sales, partially offset by charges of $55 million due to an adverse litigation matter. Net special charges of $64 million in 2003 were composed of charges of $103 million for asset impairments, associated mainly with the write-down of assets in anticipation of sale; charges of $38 million for restructuring and reorganization, mainly for employee severance costs; and gains of $77 million from property sales.

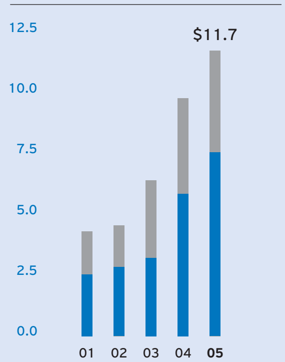
EXPLORATION EXPENSES
Millions of dollars



United States
International

Exploration expenses declined after the October 2001 merger with Texaco, reflecting, in part, the high-grading of the combined exploration portfolio.

WORLDWIDE EXPLORATION & PRODUCTION EARNINGS*
Billions of dollars



United States
International

Earnings increased in 2005 on higher prices for crude oil and natural gas.

*Before the cumulative effect of changes in accounting principles but including discontinued operations

International Upstream – Exploration and Production

Millions of dollars	**2005**	2004	2003
Income From Continuing Operations[1]	**$ 7,556**	$ 5,622	$ 3,199
Income From Discontinued Operations	–	224	21
Cumulative Effect of Accounting Change	–	–	145
Total Income[2]	**$ 7,556**	$ 5,846	$ 3,365
[1] Includes Foreign Currency Effects:	**$ 14**	$ (129)	$ (319)
[2] Includes Special-Item Gains (Charges):			
Asset Dispositions			
Continuing Operations	$ –	$ 644	$ 32
Discontinued Operations	–	207	–
Asset Impairments/Write-offs	–	–	(30)
Restructuring and Reorganizations	–	–	(22)
Tax Adjustments	–	–	118
Total	$ –	$ 851	$ 98

International upstream income of more than $7.5 billion in 2005 increased $1.7 billion from $5.8 billion in 2004. Higher prices for crude oil and natural gas in 2005 and earnings from the former Unocal operations increased earnings approximately $2.9 billion between periods. About 80 percent of this benefit arose from the effect of higher prices on heritage-Chevron production. Partially offsetting these benefits were higher expenses between periods for heritage-Chevron operations for certain income-tax items, including the absence of a $200 million benefit in 2004 relating to changes in income tax laws. The change between years also reflected the impact of $851 million of special-item gains in 2004, while no special items were recorded in 2005. Foreign currency losses in 2004 were $129 million. Gains of $14 million were recorded in 2005.

Income of $5.8 billion in 2004 was nearly $2.5 billion higher than earnings recorded in 2003. Approximately $900 million of the increase was the difference between the effects in each period from special items (discussed below) and foreign currency losses. Approximately $1.1 billion of the increase was associated with higher prices for crude oil and natural gas. Another $400 million resulted from lower income-tax expense between periods, including a benefit of about $200 million in 2004 as a result of changes in income tax laws. Partially offsetting these effects were higher transportation costs in 2006 of about $200 million. The balance of the change between periods was associated with a gain in 2003 from the implementation of a new accounting standard. (Refer to Note 24, beginning on page 83, for a discussion of FAS 143, *"Accounting for Asset Retirement Obligations."*)

Net oil-equivalent production of 1.8 million barrels per day in 2005, including 143,000 net barrels per day from oil sands in Canada and production under an operating service agreement in Venezuela, increased about 6 percent from 2004 and 5 percent from 2003. Absent the net effect of increased volumes in 2005 from five months of production from the former Unocal operations, the effect of property sales and the effect of higher prices on cost-recovery and variable-royalty provisions of certain contracts, oil-equivalent production in 2005 was essentially the same as 2004 and 2003.

The net liquids component of oil-equivalent production was 1.4 million barrels per day in 2005, unchanged from 2004 and 2003. Excluding the effects of Unocal production, property sales and the effect of higher prices on cost-recovery and variable-royalty volumes, 2005 net liquids production was essentially the same as 2004 and decreased 1 percent from 2003.

Net natural gas production of 2.6 billion cubic feet per day in 2005 was up 25 percent and 26 percent from 2004 and 2003, respectively. Excluding the effect of production from the Unocal properties, production increased 2 percent and 3 percent from 2004 and 2003, respectively.

Refer to the "Selected Operating Data" table, on page 36, for the three-year comparative of international production volumes.

No special items were recorded in 2005. Special-item gains in 2004 included $585 million from the sale of producing properties in western Canada and $266 million from the sale of other nonstrategic assets, including the company's operations in the Democratic Republic of the Congo and a Canadian natural-gas processing business. In 2003, net special-item gains of $98 million included benefits of $150 million related to income taxes and property sales, partially offset by asset impairments and charges for employee termination costs.

U.S. Downstream – Refining, Marketing and Transportation

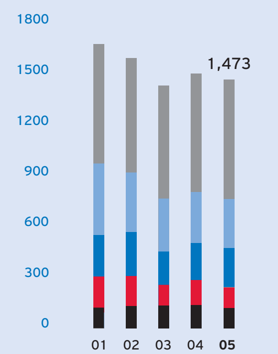
Millions of dollars	**2005**	2004	2003
Income*	**$ 980**	$ 1,261	$ 482
*Includes Special-Item Gains (Charges):			
Asset Dispositions	**$ –**	$ –	$ 37
Environmental Remediation Provisions	**–**	–	(132)
Restructuring and Reorganizations	**–**	–	(28)
Total	**$ –**	$ –	$ (123)

U.S. downstream earnings of nearly $1 billion in 2005 decreased about $300 million from 2004 and were up $500 million from 2003. Results in 2003 included net special-item charges (discussed below) of $123 million. Average refined-product margins in 2005 were higher than in 2004, and margins in 2004 were significantly higher than in 2003. However, the effects of increased downtime at refineries and other facilities and higher fuel costs dampened earnings in 2005. A portion of the downtime in 2005 was associated with hurricanes in the Gulf of Mexico. As a result of the storms, the company's refinery in Pascagoula, Mississippi, was shut down for more than a month, and the company's marketing and pipeline operations along the Gulf Coast were also disrupted for an extended period.

Sales volumes of refined products in 2005 were approximately 1.5 million barrels per day, or about 2 percent lower than in 2004. Branded gasoline sales volumes of approximately 600,000 barrels per day increased about 4 percent from the 2004 period. In 2004, refined-product sales volumes increased about 5 percent from 2003, primarily due to higher sales of gasoline, diesel fuel and fuel oil. Refer to the "Selected Operating Data" table, on page 36, for the three-year comparative refined-product sales volumes in the United States.

In 2003, net special-item charges of $123 million included $132 million for environmental remediation and $28 million for employee severance costs associated with the global downstream restructuring and reorganization. These charges were partially offset by net gains of $37 million from asset sales.

U.S. GASOLINE & OTHER REFINED PRODUCTS SALES*
Thousands of barrels per day

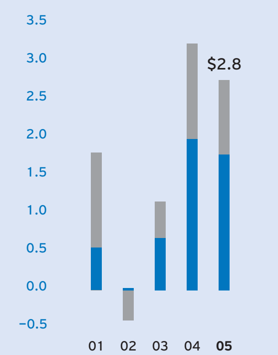


■ Gasoline
■ Jet Fuel
■ Gas Oils & Kerosene
■ Residual Fuel Oil
■ Other

Refined products sales volumes declined about 2 percent from 2004, with lower sales of fuel oils and other products.

*Includes equity in affiliates

WORLDWIDE REFINING, MARKETING & TRANSPORTATION EARNINGS
Billions of dollars



■ United States
■ International

Downstream earnings declined due to lower international margins for refined products and U.S. refinery downtime.

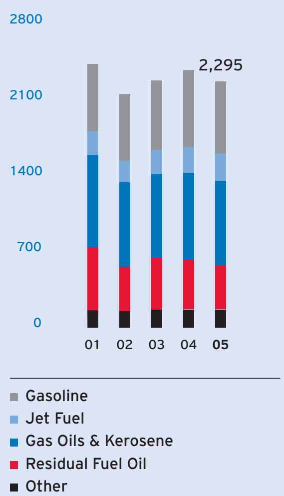
International Downstream – Refining, Marketing and Transportation

Millions of dollars	**2005**	2004	2003
Income[1,2]	**$ 1,786**	$ 1,989	$ 685
[1] Includes Foreign Currency Effects:	**$ (24)**	$ 7	$ (141)
[2] Includes Special-Item Charges:			
Asset Dispositions	**$ –**	$ –	$ (24)
Asset Impairments/Write-offs	**–**	–	(123)
Restructuring and Reorganizations	**–**	–	(42)
Total	**$ –**	$ –	$ (189)

The international downstream includes the company's consolidated refining and marketing businesses, non-U.S. shipping operations, non-U.S. supply and trading activities, and equity earnings of affiliates, primarily in the Asia-Pacific region.

Income of nearly $1.8 billion in 2005 decreased 10 percent from $2 billion in 2004 but was up about $1.1 billion from 2003. The decrease from the 2004 period was due mainly to lower sales volumes, higher costs for fuel and transportation, expenses associated with an explosion and fire at a 40 percent-owned, nonoperated terminal in the United Kingdom, and tax adjustments in various countries. These items more than offset an improvement in average refined-product margins between periods. The $1.3 billion increase

INTERNATIONAL GASOLINE & OTHER REFINED PRODUCTS SALES*
Thousands of barrels per day



Refined products sales volumes decreased about 4 percent from 2004.

*Includes equity in affiliates

in income from 2003 to 2004 reflected significantly higher average refined-product margins in most of the company's operating areas and higher earnings from international shipping operations. Earnings in 2003 also included special-item charges (discussed below) and foreign currency losses that totaled more than $300 million.

Total international refined products sales volumes were 2.3 million barrels per day in 2005, about 4 percent lower than 2004. The sales decline was primarily the result of lower gasoline trading activity and lower fuel-oil sales. Refined product sales volume of 2.4 million barrels per day in 2004 was about 4 percent higher than 2.3 million in 2003. Refer to the "Selected Operating Data" table, on page 36, for the three-year comparative refined-product sales volumes in the international areas.

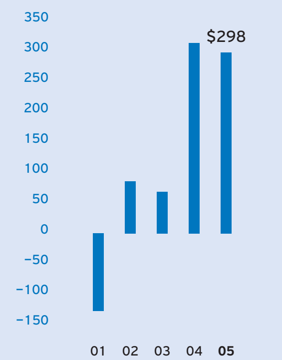
The special-item charges of $189 million in 2003 included the write-down of the Batangas Refinery in the Philippines in advance of its conversion to a product terminal facility, employee severance costs associated with the global downstream restructuring and reorganization, the recognition of the impairment of certain assets in anticipation of their sale and the company's share of losses from an asset sale and asset impairment by an equity affiliate.

Chemicals

Millions of dollars	**2005**	2004	2003
Segment Income*	**$ 298**	$ 314	$ 69
*Includes Foreign Currency Effects:	**$ –**	$ (3)	$ 13

The chemicals segment includes the company's Oronite subsidiary and the company's 50 percent share of its equity investment in Chevron Phillips Chemical Company LLC (CPChem). In 2005, results for the company's Oronite subsidiary were down due to significantly higher costs for feedstocks and adverse effects from the shut-down of operations in the U.S. Gulf Coast due to hurricanes. Earnings in 2005 for CPChem were higher than 2004 on improved margins for commodity chemicals. Results for both businesses in 2005 were dampened by the effects of the U.S. hurricanes. Significantly lower earnings in 2003 reflected weak demand for commodity chemicals and industry oversupply conditions in the period.

WORLDWIDE CHEMICALS EARNINGS*
Millions of dollars



Chemicals earnings declined about 5 percent from 2004 mainly due to the effects of storms.

*Includes equity in affiliates

All Other

Millions of dollars	**2005**	2004	2003
Charges Before Cumulative Effect of Changes in Accounting Principles	**$ (689)**	$ (20)	$ (213)
Cumulative Effect of Accounting Changes	**–**	–	9
Net Charges[1,2]	**$ (689)**	$ (20)	$ (204)
[1] Includes Foreign Currency Effects:	**$ (51)**	$ 44	$ 43
[2] Includes Special-Item Gains (Charges):			
Dynegy-Related	**$ –**	$ –	$ 325
Asset Impairments/Write-offs	**–**	–	(84)
Restructuring and Reorganizations	**–**	–	(16)
Total	**$ –**	$ –	$ 225

All Other consists of the company's interest in Dynegy, mining operations of coal and other minerals, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities and technology companies.

The net charges of $689 million in 2005 increased significantly from $20 million in 2004. Approximately $400 million of the change related to larger benefits in 2004 from corporate-level tax adjustments. Higher charges in 2005 were associated with environmental remediation of properties that had been sold or idled and ongoing Unocal corporate-level activities. Interest expense also was higher in 2005 due to an increase in interest rates and the debt assumed with the Unocal acquisition.

The improvement between 2003 and 2004 was primarily associated with the company's investment in Dynegy, including gains from the redemption of certain Dynegy securities, higher interest income, lower interest expense and the favorable corporate-level tax adjustments.

Net special-item gains in 2003 included a Dynegy-related net benefit of $325 million, which was composed of a gain of $365 million from the exchange of the company's investment in Dynegy securities that was partially offset by a $40 million charge for Chevron's share of an asset impairment by Dynegy. Other special-item charges were for asset write-downs of $84 million, primarily in Chevron's gasification business, and employee severance costs of $16 million.

CONSOLIDATED STATEMENT OF INCOME

Comparative amounts for certain income statement categories are shown below. Amounts associated with special items in the comparative periods are also indicated to assist in the explanation of the period-to-period changes. Besides the information in this section, separately disclosed on the face of the Consolidated Statement of Income are a gain from the exchange of Dynegy securities and the cumulative effect of changes in accounting principles. These matters are discussed elsewhere in Management's Discussion and Analysis and in Note 27 to the Consolidated Financial Statements, on page 86. Refer to the Results of Operations section, beginning of page 31, for additional information relating to special-item gains and charges.

Millions of dollars	**2005**	2004	2003
Sales and other operating revenues	**$ 193,641**	$ 150,865	$ 119,575

Sales and other operating revenues in 2005 increased over 2004 and 2003 due primarily to higher prices for crude oil, natural gas and refined products worldwide. The amount in 2005 also included revenues for five months from former Unocal operations.

Millions of dollars	**2005**	2004	2003
Income from equity affiliates	**$ 3,731**	$ 2,582	$ 1,029
Memo: Special-item gains, before tax	**$ –**	$ –	$ 179

Improved results for Tengizchevroil and Hamaca (Venezuela) accounted for nearly three-fourths of the increased income from equity affiliates in 2005. Profits in 2005 also increased at the company's CPChem and Dynegy affiliates. The improvement in 2004 from 2003 was the result of higher earnings from the company's downstream affiliates in the Asia-Pacific area, Tengizchevroil, CPChem, Dynegy and the Caspian Pipeline Consortium. Refer to Note 13, beginning on page 68, for a discussion of Chevron's investment in affiliated companies.

Millions of dollars	**2005**	2004	2003
Other income	**$ 828**	$ 1,853	$ 308
Memo: Special-item gains, before tax	**$ –**	$ 1,281	$ 217

Other income in 2005 included no special-item gains or losses; however, net special-item gains relating to upstream property sales were nearly $1.3 billion in 2004 and more than $200 million in 2003. The increase from 2003 through 2005 was otherwise partly due to higher interest income in each period – $400 million in 2005, $200 million in 2004 and $120 million in 2003 – on higher average interest rates and balances of cash and marketable securities. Foreign currency losses were $60 million in both 2005 and 2004 and about $200 million in 2003.

Millions of dollars	**2005**	2004	2003
Purchased crude oil and products	**$ 127,968**	$ 94,419	$ 71,310

Crude oil and product purchases in 2005 increased approximately 35 percent from 2004, due mainly to higher prices for crude oil, natural gas and refined products as well as to the inclusion in 2005 of Unocal-related amounts for five months. Crude oil and product purchase costs increased 32 percent in 2004 from the prior year as a result of higher prices and increased purchased volumes of crude oil and products.

Millions of dollars	**2005**	2004	2003
Operating, selling, general and administrative expenses	**$ 17,019**	$ 14,389	$ 12,940
Memo: Special-item charges, before tax	**$ –**	$ 85	$ 475

Operating, selling, general and administrative expenses in 2005 increased 18 percent from a year earlier. Higher amounts in 2005 included former-Unocal expenses for five months, and for heritage-Chevron operations, higher costs for labor and transportation, uninsured costs associated with storms in the Gulf of Mexico, asset write-offs, repair and maintenance services, fuel costs for plant operations and a number of corporate items that individually were not significant. Total expenses increased from 2003 to 2004 due mainly to costs for chartering crude oil tankers and other transportation expenses.

Millions of dollars	**2005**	2004	2003
Exploration expense	**$ 743**	$ 697	$ 570

Exploration expenses in 2005 increased mainly due to the inclusion of Unocal amounts for five months. In 2004, amounts were higher than in 2003 for international operations, primarily for seismic costs and expenses associated with evaluating the feasibility of different project alternatives.

Millions of dollars	2005	2004	2003
Depreciation, depletion and amortization	**$ 5,913**	$ 4,935	$ 5,326
Memo: Special-item charges, before tax	**$ –**	$ –	$ 286

Depreciation, depletion and amortization expenses in 2005 increased mainly as a result of five months of depreciation and depletion expense for the former Unocal assets and higher depreciation rates for certain heritage-Chevron crude oil and natural gas producing fields worldwide. Between 2003 and 2004, expenses did not change materially, after consideration of the effects of special-item charges for asset impairments in 2003.

Millions of dollars	2005	2004	2003
Interest and debt expense	**$ 482**	$ 406	$ 474

Interest and debt expense in 2005 increased mainly due to the inclusion of debt assumed with the Unocal acquisition and higher average interest rates for commercial paper borrowings. The decline between 2003 and 2004 reflected lower average debt balances.

Millions of dollars	2005	2004	2003
Taxes other than on income	**$ 20,782**	$ 19,818	$ 17,901

Taxes other than on income in 2005 increased as a result of higher international taxes assessed on product values, higher duty rates in the areas of the company's European downstream operations and higher U.S. federal excise taxes on jet fuel resulting from a change in tax law that became effective in 2005. The increase in 2004 from 2003 primarily reflected the weakening U.S. dollar on foreign currency-denominated duties in the company's European downstream operations.

Millions of dollars	2005	2004	2003
Income tax expense	**$ 11,098**	$ 7,517	$ 5,294
Memo: Special-item charges (benefits)	**$ –**	$ 291	$ (312)

Effective income tax rates were 44 percent in 2005, 37 percent in 2004 and 43 percent in 2003, after excluding the effect of net special items. Rates were higher in 2005 compared with the prior year due to the absence of benefits in 2004 from changes in the income tax laws for certain international operations and an increase in earnings in countries with higher tax rates. As compared with the effective tax rate in 2003, the effective tax rate in 2004 benefited from changes in the income tax laws for certain international operations, a change in the mix of international upstream earnings occurring in countries with different tax rates and favorable corporate consolidated tax effects. Refer also to the discussion of income taxes in Note 16 to the Consolidated Financial Statements, beginning on page 71.

SELECTED OPERATING DATA[1,2]

	2005	2004	2003
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)[3]	**455**	505	562
Net Natural Gas Production (MMCFPD)[3,4]	**1,634**	1,873	2,228
Net Oil-Equivalent Production (MBOEPD)[3]	**727**	817	933
Sales of Natural Gas (MMCFPD)	**5,449**	4,518	4,304
Sales of Natural Gas Liquids (MBPD)	**151**	177	194
Revenues From Net Production			
Liquids ($/Bbl)	**$ 46.97**	$ 34.12	$ 26.66
Natural Gas ($/MCF)	**$ 7.43**	$ 5.51	$ 5.01
International Upstream			
Net Crude and Natural Gas Liquids Production (MBPD)[3]	**1,214**	1,205	1,246
Net Natural Gas Production (MMCFPD)[3,4]	**2,599**	2,085	2,064
Net Oil-Equivalent Production (MBOEPD)[3,5]	**1,790**	1,692	1,704
Sales Natural Gas (MMCFPD)	**2,289**	1,885	1,951
Sales Natural Gas Liquids (MBPD)	**108**	105	107
Revenues From Liftings			
Liquids ($/Bbl)	**$ 47.59**	$ 34.17	$ 26.79
Natural Gas ($/MCF)	**$ 3.19**	$ 2.68	$ 2.64
U.S. and International Upstream			
Net Oil-Equivalent Production Including Other Produced Volumes (MBOEPD)[4,5]			
United States	**727**	817	933
International	**1,790**	1,692	1,704
Total	**2,517**	2,509	2,637
U.S. Downstream – Refining, Marketing and Transportation			
Gasoline Sales (MBPD)[6]	**709**	701	669
Other Refined Products Sales (MBPD)	**764**	805	767
Total (MBPD)[7]	**1,473**	1,506	1,436
Refinery Input (MBPD)[8]	**845**	914	951
International Downstream – Refining, Marketing and Transportation			
Gasoline Sales (MBPD)[6]	**669**	717	643
Other Refined Products Sales (MBPD)	**1,626**	1,685	1,659
Total (MBPD)[7,9]	**2,295**	2,402	2,302
Refinery Input (MBPD)	**1,038**	1,044	1,040

[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 equivalents 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 from August 1, 2005, related to former Unocal properties.

[4] Includes natural gas consumed on lease (MMCFPD):			
United States	**48**	50	65
International	**332**	293	268
[5] Includes other produced volumes (MBPD):			
Athabasca Oil Sands – Net	**32**	27	15
Boscan Operating Service Agreement	**111**	113	99
	143	140	114
[6] Includes branded and unbranded gasoline			
[7] Includes volumes for buy/sell contracts (MBPD):			
United States	**82**	84	90
International	**129**	96	104
[8] The company sold its interest in the El Paso Refinery in August 2003.			
[9] Includes sales of affiliates (MBPD):	**540**	536	525

INFORMATION RELATED TO INVESTMENT IN DYNEGY INC.

At year-end 2005, Chevron owned an approximate 24 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States. The company also held an investment in Dynegy preferred stock.

Investment in Dynegy Common Stock At December 31, 2005, the carrying value of the company's investment in Dynegy common stock was approximately $300 million. This amount was about $200 million below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. The difference had been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors associated with the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate to recognize a portion of the difference between these allocated values and Dynegy's historical book values. The market value of the company's investment in Dynegy's common stock at the end of 2005 was approximately $470 million.

Investments in Dynegy Preferred Stock At the end of 2005, the company held $400 million face value of Dynegy Series C Convertible Preferred Stock with a stated maturity of 2033. The stock is accounted for at its fair value, which was estimated to be $360 million at year-end 2005. Temporary changes in the estimated fair value of the preferred stock are reported in "Other Comprehensive Income." However, if in any future period a decline in fair value is deemed to be other than temporary, a charge against income in the period would be recorded. Dividends received from the preferred stock are recorded to income in the period received.

LIQUIDITY AND CAPITAL RESOURCES

Cash, cash equivalents and marketable securities Total balances were $11.1 billion and $10.7 billion at December 31, 2005 and 2004, respectively. Cash provided by operating activities in 2005 was $20.1 billion, compared with $14.7 billion in 2004 and $12.3 billion in 2003.

The 2005 increase in cash provided by operating activities mainly reflected higher earnings in the upstream segment, including earnings from the former-Unocal operations. Cash provided by operating activities was net of contributions to employee pension plans of $1.0 billion, $1.6 billion and $1.4 billion in 2005, 2004 and 2003, respectively. Cash provided by investing activities included proceeds from asset sales of $2.7 billion in 2005, $3.7 billion in 2004 and $1.1 billion in 2003.

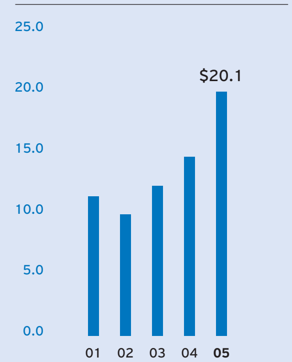
Cash provided by operating activities and asset sales during 2005 was sufficient to fund the company's $8.7 billion capital and exploratory program, pay $3.8 billion of dividends to stockholders, repay approximately $970 million in long-term debt, and repurchase $3 billion of common stock. Partial consideration for the acquisition of Unocal in August 2005 also included $7.5 billion in cash. Unocal balances of cash, cash equivalents and marketable securities at the acquisition date totaled $1.6 billion.

Dividends The company paid dividends of approximately $3.8 billion in 2005, $3.2 billion in 2004 and $3 billion in 2003. In April 2005, the company increased its quarterly common stock dividend by 12.5 percent to 45 cents per share.

Debt, capital lease and minority interest obligations Total debt and capital lease balances were $12.9 billion at December 31, 2005, up from $11.3 billion at year-end 2004. The 2005 year-end balance included approximately $2.2 billion of debt and capital lease obligations assumed with the acquisition of Unocal. The company also had minority interest obligations of $200 million, up from $172 million at December 31, 2004.

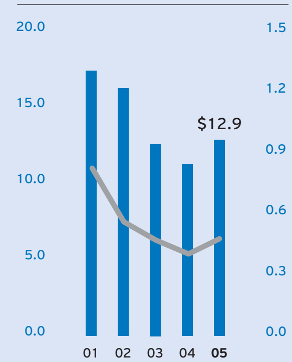
The company's debt and capital lease obligations due within one year, consisting primarily of commercial paper and the current portion of long-term debt, totaled $5.6 billion at December 31, 2005, unchanged from December 31, 2004. Of these amounts, $4.9 billion and $4.7 billion were reclassified to long-term at the end of each period, respectively. At year-end 2005, settlement of these obligations was not expected to require the use of working capital in 2006, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis. The company's practice has been to continually refinance its commercial paper, maintaining levels it believes appropriate and economic.

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars



Operating cash flow increased 37 percent mainly due to higher earnings in the upstream segment.

TOTAL INTEREST EXPENSE & TOTAL DEBT AT YEAR-END
Billions of dollars



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

Interest expense rose mainly due to debt assumptions from the Unocal acquisition.

At year-end 2005, the company had $4.9 billion in committed credit facilities with various major banks, which permitted the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowings 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 the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company's strong credit rating. No borrowings were outstanding under these facilities at December 31, 2005. In addition, the company has three existing effective "shelf" registration statements on file with the Securities and Exchange Commission that together would permit additional registered debt offerings up to an aggregate $3.8 billion of debt securities. Following the acquisition of Unocal, the company withdrew Unocal's "shelf" registration statements.

In October 2005, the company fully redeemed the Unocal subsidiary Pure Resources' 7.125 percent Senior Notes due 2011 for $395 million. The company's $150 million of Texaco Brasil zero coupon notes were paid at maturity in November 2005. In December 2005, the company exercised a par-call redemption of $200 million in Texaco Capital Inc. 5.7 percent Notes due 2008.

In February 2006, the company retired Union Oil bonds at maturity for approximately $185 million.

Texaco Capital LLC, a wholly owned finance subsidiary, issued Deferred Preferred Shares Series C (Series C) in December 1995. In February 2005, the company redeemed the Series C shares and paid accumulated dividends of approximately $140 million.

In January 2005, the company contributed $98 million to its Employee Stock Ownership Plan (ESOP) to permit the ESOP to make a $144 million debt service payment, which included a principal payment of $113 million.

In the second quarter 2004, Chevron entered into $1 billion of interest rate fixed-to-floating swap transactions, in which the company receives a fixed interest rate and pays a floating rate, based on the notional principal amounts. Under the terms of the swap agreements, of which $250 million and $750 million will terminate in September 2007 and February 2008, respectively, the net cash settlement will be based on the difference between fixed-rate and floating-rate interest amounts.

Chevron's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investors Service. The company's senior debt of Texaco Capital Inc. is rated Aa3, and Union Oil Company of California bonds are rated A1 by Moody's. These companies are wholly owned subsidiaries of Chevron. The company's U.S. commercial paper is rated A-1+ by Standard and Poor's and P-1 by Moody's, and the company's Canadian commercial paper is rated R-1 (middle) by Dominion Bond Rating Service. 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. Further reductions from debt balances at December 31, 2005, are dependent upon many factors, including management's continuous assessment of debt as an appropriate component of the company's overall capital structure. The company believes it has substantial borrowing capacity to meet unanticipated cash requirements, and during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, the company believes that it has the flexibility to increase borrowings and/or modify capital-spending plans to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

Common Stock Repurchase Program In connection with a $5 billion stock repurchase program initiated in April 2004, the company acquired 92.1 million of its common shares for $5 billion through November 2005. During 2005, about 49.8 million of common shares were repurchased under this program for a total cost of $2.9 billion.

In December 2005, the company authorized the acquisition of up to an additional $5 billion of its 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. Under this program, the company acquired approximately 1.7 million shares in the open market for $100 million during December 2005. Purchases through mid-February 2006 increased the total shares acquired to 8.3 million at a cost of $481 million.

Capital and exploratory expenditures Excluding the $17.3 billion acquisition of Unocal Corporation, total reported expenditures for 2005 were $11.1 billion, including $1.7 billion for the company's share of affiliates' expenditures, which did not require cash outlays by the company. In 2004

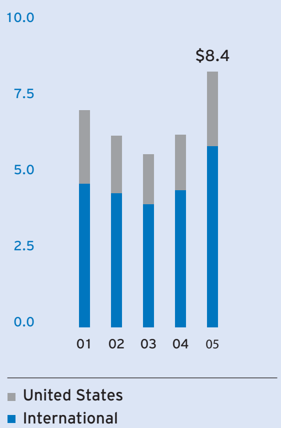
Capital and Exploratory Expenditures

	2005			2004			2003		
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream – Exploration and Production	**$ 2,450**	**$ 5,939**	**$ 8,389**	$ 1,820	$ 4,501	$ 6,321	$ 1,641	$ 4,034	$ 5,675
Downstream – Refining, Marketing and Transportation	**818**	**1,332**	**2,150**	497	832	1,329	403	697	1,100
Chemicals	**108**	**43**	**151**	123	27	150	173	24	197
All Other	**329**	**44**	**373**	512	3	515	371	20	391
Total	**$ 3,705**	**$ 7,358**	**$ 11,063**	$ 2,952	$ 5,363	$ 8,315	$ 2,588	$ 4,775	$ 7,363
Total, Excluding Equity in Affiliates	**$ 3,522**	**$ 5,860**	**$ 9,382**	$ 2,729	$ 4,024	$ 6,753	$ 2,306	$ 3,920	$ 6,226

and 2003, expenditures were $8.3 billion and $7.4 billion, respectively, including the company's share of affiliates' expenditures of $1.6 billion and $1.1 billion in the corresponding periods.

Of the $11.1 billion in expenditures for 2005, about three-fourths, or $8.4 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2004 and 2003. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the years, reflecting the company's continuing focus on opportunities that are available outside the United States.

EXPLORATION & PRODUCTION – CAPITAL & EXPLORATORY EXPENDITURES*
Billions of dollars



Exploration and production projects accounted for 76 percent of total capital and exploratory expenditures in 2005.

*Includes equity in affiliates

In 2006, the company estimates capital and exploratory expenditures will be 33 percent higher at $14.8 billion, including spending by affiliates. About three-fourths, or $11.3 billion, is again for exploration and production activities, with $8 billion of that amount outside the United States. Spending is primarily targeted for exploratory prospects in the deepwater Gulf of Mexico and western Africa and major development projects in Angola, Nigeria, Kazakhstan and the deepwater Gulf of Mexico. Included in the upstream expenditures is about $1 billion to develop the company's international natural gas resource base.

Worldwide downstream spending in 2006 is estimated at $2.8 billion, with about $1.9 billion for refining and marketing and $900 million for supply and transportation projects, including pipelines to support expanded upstream production. Approximately two-thirds of the total projected spending is outside the United States.

Investments in chemicals businesses in 2006 are budgeted at $250 million. Estimates for energy technology, information technology and facilities, real estate activities, power-related businesses, and other businesses total approximately $460 million.

Pension Obligations In 2005, the company's pension plan contributions totaled approximately $1 billion, including nearly $200 million to the Unocal plans. Approximately $800 million of the total was contributed to U.S. plans. In 2006, the company estimates contributions will be $500 million. Actual amounts are dependent upon plan-investment results, changes in pension obligations, regulatory environments 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

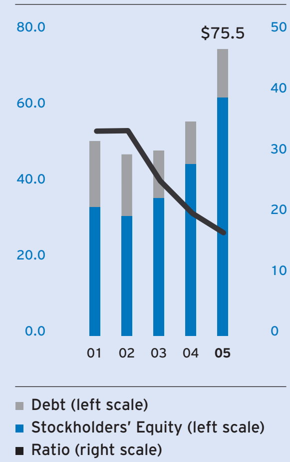
	At December 31		
	2005	2004	2003
Current Ratio	**1.4**	1.5	1.2
Interest Coverage Ratio	**47.5**	47.6	24.3
Total Debt/Total Debt-Plus-Equity	**17.0%**	19.9%	25.8%

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 LIFO basis. At year-end 2005, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $4.8 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 essentially unchanged between 2004 and 2005. The interest coverage ratio was higher in 2004 compared with 2003, primarily due to higher before-tax income and lower average debt balances.

Debt Ratio – total debt as a percentage of total debt plus equity. Although total debt was higher at the end of 2005 than a year earlier, the debt ratio declined as a result of higher stockholders' equity balances for retained earnings and the capital stock that was issued in connection with the Unocal acquisition. The decline in the debt ratio between 2003 and 2004 was primarily due to lower debt levels and higher retained earnings.

TOTAL DEBT TO TOTAL DEBT-PLUS-EQUITY RATIO
Billions of dollars/Percent



Chevron's ratio of total debt to total debt-plus-equity fell to 17 percent at year-end as the company's stockholders' equity climbed.

GUARANTEES, OFF-BALANCE-SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS, AND OTHER CONTINGENCIES

*Direct or Indirect Guarantees**

Millions of dollars	Commitment Expiration by Period				
	Total	2006	2007–2009	2010	After 2010
Guarantees of non-consolidated affiliates or joint venture obligations	$ 985	$ 454	$ 426	$ 35	$ 70
Guarantees of obligations of third parties	294	113	136	8	37
Guarantees of Equilon debt and leases	193	24	55	19	95

*The amounts exclude indemnifications of contingencies associated with the sale of the company's interest in Equilon and Motiva in 2002, as discussed in the "Indemnifications" section on pages 40 through 41.

At December 31, 2005, the company and its subsidiaries provided guarantees, either directly or indirectly, of $985 million in guarantees for notes and other contractual obligations of affiliated companies and $294 million for third parties as described by major category below. There are no material amounts being carried as liabilities for the company's obligations under these guarantees.

Of the $985 million in guarantees provided to affiliates, $806 million relate to borrowings for capital projects or general corporate purposes. These guarantees were undertaken to achieve lower interest rates and generally cover the construction period of the capital projects. Included in these amounts are Unocal-related guarantees of $230 million associated with a construction completion guarantee for the debt financing of Unocal's equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Approximately 95 percent of the amounts guaranteed will expire between 2006 and 2010 with the remaining guarantees expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed. There are no recourse provisions, and no assets are held as collateral for these guarantees. The remaining balance of $179 million represents obligations in connection with pricing of power-purchase agreements for certain of the company's cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliates do not perform under the agreements. There are no recourse provisions to third parties, and no assets are held as collateral for these pricing guarantees.

Guarantees of $294 million have been provided to third parties, including guarantees of approximately $150 million related to construction loans to host governments in the company's international upstream operations. The remaining guarantees of $144 million were provided principally as conditions of sale of the company's interest in certain operations, to provide a source of liquidity to the guaranteed parties and in connection with company marketing programs. No amounts of the company's obligations under these guarantees are recorded as liabilities. About 85 percent of the total amounts guaranteed will expire in 2010, with the remainder expiring after 2010. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed. Approximately $85 million of the guarantees have recourse provisions, which enable the company to recover any payments made under the terms of the guarantees from securities held over the guaranteed parties' assets.

At December 31, 2005, Chevron also had outstanding guarantees for about $190 million of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell Oil Company (Shell) for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2006 through 2010 period, with the guarantees of the remaining amounts expiring by 2019.

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 indemnities cover certain contingent liabilities. The company would be required to perform should the indemnified liabilities become actual losses. Should that occur, the company could be required to make future payments up to $300 million. Through the end of 2005, the company paid approximately $38 million under these indemnities. The company expects to receive additional requests for 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 periods of Texaco's ownership interests 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 relating to Equilon indemnities must be asserted as early as February 2007, or no later than February 2009, and claims relating to Motiva must be asserted no later than February 2012. Under the terms of the 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 of Unocal's 76 Products Company business that existed prior to its sale in 1997. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments by the company; however, the purchaser shares certain costs under this indemnity up to an aggregate cap of $200 million. Claims relating to these indemnities must be asserted by April 2022. Through the end of 2005, approximately $113 million had been applied to the cap, which includes payments made by either Unocal or Chevron totaling $80 million.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying special purpose entities (SPEs). At December 31, 2005, approximately $1.2 billion, representing about 7 percent of Chevron's total current accounts receivable balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2005, was approximately $60 million. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event of the SPEs experiencing major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Throughput Agreements and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements, and take-or-pay agreements, some of which relate to supplier's financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, 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: 2006 – $2.2 billion; 2007– $1.9 billion; 2008 – $1.8 billion; 2009 – $1.8 billion; 2010 – $0.5 billion; 2011 and after – $3.8 billion. Total payments under the agreements were approximately $2.1 billion in 2005, $1.6 billion in 2004, and $1.4 billion in 2003. The most significant take-or-pay agreement calls for the company to purchase approximately 55,000 barrels per day of refined products from an equity affiliate refiner in Thailand. This purchase agreement is in conjunction with the financing of a refinery owned by the affiliate and expires in 2009. The future estimated commitments under this contract are: 2006 – $1.3 billion; 2007 – $1.3 billion; 2008 – $1.3 billion; and 2009 – $1.3 billion. In 2005, under the terms of an agreement entered in 2004, the company exercised its option to acquire additional regasification capacity at the Sabine Pass Liquefied Natural Gas Terminal. Payments of $2.5 billion over the 20-year period are expected to commence in 2009.

Minority Interests The company has commitments of approximately $200 million related to minority interests in subsidiary companies.

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

Contractual Obligations

Millions of dollars		Payments Due by Period			
	Total	2006	2007–2009	2010	After 2010
On Balance Sheet:					
Short-Term Debt[1]	$ 739	$ 739	$ –	$ –	$ –
Long-Term Debt[1,2]	11,807	–	8,775	176	2,856
Noncancelable Capital Lease Obligations	324	–	154	36	134
Interest Expense	5,600	500	1,100	300	3,700
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	2,917	507	1,194	284	932
Unconditional Purchase Obligations	1,200	500	600	100	–
Throughput and Take-or-Pay Agreements	10,800	1,700	4,900	400	3,800

[1] $4.9 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 2007–2009 period.
[2] Includes guarantees of $247 of LESOP (leveraged employee stock ownership plan) debt, $14 due in 2006 and $233 due after 2006.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to the price volatility of crude oil, refined products, natural gas, natural gas liquids and refinery feedstock. 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 or sale of crude oil; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids.

Chevron also uses derivative commodity instruments for trading purposes. The results of this activity were not material to the company's financial position, net income or cash flows in 2005.

The company's positions are monitored and managed on a daily basis by an internal risk control group to ensure compliance with the company's risk management policy that has 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 New York Mercantile Exchange and the International Petroleum 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 market quotes and other independent third-party quotes.

Each hypothetical 10 percent increase in the price of natural gas and crude oil would increase the fair value of the natural gas purchase derivative contracts by approximately $33 million and reduce the fair value of the crude oil sale derivative contracts by about $11 million. The same hypothetical decrease in the prices of these commodities would result in the same opposite effects on the fair values of the contracts.

The hypothetical effect on these contracts was estimated by calculating the cash value of the contracts as the difference between the hypothetical and contract delivery prices multiplied by the contract amounts.

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 2005 would be a reduction in the fair value of the foreign exchange contracts of approximately $70 million. The effect would be the opposite for a hypothetical 10 percent decrease in the year-end value of the U.S. dollar.

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, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

At year-end 2005, the weighted average maturity of "receive fixed" interest rate swaps was approximately 2 years. There were no "receive floating" swaps outstanding at year end. A hypothetical increase of 10 basis points in fixed interest rates would reduce the fair value of the "receive fixed" swaps by approximately $3 million.

For the financial and derivative instruments discussed above, there was not a material change in market risk between 2005 and 2004.

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 2005 Annual Report on Form 10-K.

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 41 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.

Chevron is a party to more than 70 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 seepage of MTBE into groundwater. Resolution of these actions may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future.

The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. The company does not use MTBE in the manufacture of gasoline in the United States.

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, and land development areas, whether operating, closed or divested.

The following table displays the annual changes to the company's before-tax environmental remediation reserves, including those for federal Superfund sites and analogous sites under state laws.

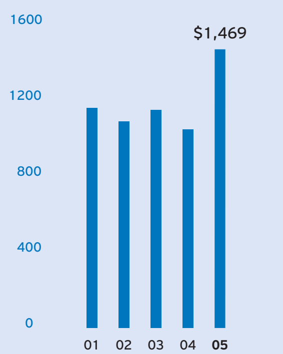
Millions of dollars	**2005**	2004	2003
Balance at January 1	**$ 1,047**	$ 1,149	$ 1,090
Net Additions	**731**	155	296
Expenditures	**(309)**	(257)	(237)
Balance at December 31	**$ 1,469**	$ 1,047	$ 1,149

Included in the additions for 2005 were liabilities assumed in connection with the acquisition of Unocal. These liabilities relate primarily to sites that had been divested or closed by Unocal prior to its acquisition by Chevron, including but were not limited to, former refineries, transportation and distribution facilities and service stations, former crude oil and natural gas fields and mining operations, as well as active mining operations. Other liability additions during 2005 for heritage-Chevron related primarily to refined-product marketing sites and various operating, closed or divested facilities in the United States.

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 2005 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

As of December 31, 2005, Chevron was involved with the remediation activities of 221 sites for which it had been identified as a potentially responsible party or otherwise 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 2005 was $139 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.

YEAR-END ENVIRONMENTAL REMEDIATION RESERVES
Millions of dollars



Reserves for environmental remediation increased 40 percent from 2004, mainly due to the assumption of Unocal environmental liabilities.

Of the remaining year-end 2005 environmental reserves balance of $1,330 million, $855 million related to approximately 2,250 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 $475 million was associated with various sites in the international downstream ($101 million), upstream ($257 million), chemicals ($50 million) and other ($67 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil and/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.

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. Although the amount of future costs may be material to the company's results of operations in the period in which they are recognized, the company does not expect these costs will have a material adverse 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.

Effective January 1, 2003, the company implemented Financial Accounting Standards Board Statement 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 $4.3 billion for asset retirement obligations at year-end 2005 related primarily to upstream and coal 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 24, beginning on page 83, related to FAS 143 and the company's adoption in 2005 of FIN 47, FASB Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143"* (FIN 47), and the discussion of "Environmental Matters" on page 45.

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally 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. The U.S. federal income tax liabilities have been settled through 1996 for Chevron Corporation (formerly ChevronTexaco Corporation) and 1997 for Chevron Global Energy Inc. (formerly Caltex Corporation), Unocal Corporation (Unocal), and Texaco Inc. (Texaco). The company's California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal and through 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Areas in which the company and its affiliates have significant operations or ownership interests include the United States, Canada, Australia, the United Kingdom, Norway, Denmark, France, the Netherlands, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of the Congo, Angola, Nigeria, Chad, South Africa, the Democratic Republic of the Congo, Indonesia, Bangladesh, the Philippines, Myanmar, Singapore, China, Thailand, Vietnam, Cambodia, Azerbaijan, Kazakhstan, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago and South Korea. The company's Caspian Pipeline Consortium (CPC) affiliate operates in Russia and Kazakhstan. The company's Tengizchevroil affiliate operates in Kazakhstan. Through an affiliate, the company participates in the development of the Baku-Tbilisi-Ceyhan (BTC) pipeline through Azerbaijan, Georgia and Turkey. Also through an affiliate, the company has an interest in the Chad/Cameroon pipeline. The company's Petrolera Ameriven affiliate operates the Hamaca project in Venezuela. The company's Chevron Phillips Chemical Company LLC (CPChem) affiliate manufactures and markets a wide range of petrochemicals on a worldwide basis, with manufacturing facilities in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially or wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest, acts of violence or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries. Refer to page 30 for a discussion of the company's transition agreement with Petróleos de Venezuela, S.A. (PDVSA), the Venezuelan state-owned petroleum company, to convert contracts for the Boscan and LL-652 operating service agreements into an Empresa Mixta.

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. If the company decides not to continue development, the costs of these wells are expensed. At December 31, 2005, the company had approximately $1.1 billion of suspended exploratory wells included in properties, plant and equipment, an increase of more than $400 million from 2004 and an increase of less than $600 million from 2003. Of the increase in 2005, about $300 million was the year-end suspended well balance for the former-Unocal operations. The year-end 2005 balance primarily reflects drilling activities in the United States, Nigeria and Indonesia.

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 $1.1 billion of suspended wells at year-end 2005 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 20, beginning on page 73, for additional discussion of suspended wells.

Equity Redetermination For crude oil and natural gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. Chevron currently estimates its maximum possible net before-tax liability at approximately $200 million. At the same time, a possible maximum net amount that could be owed to Chevron was estimated at about $50 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Accounting for Buy/Sell Contracts In the first quarter 2005, the Securities and Exchange Commission (SEC) issued comment letters to Chevron and other companies in the oil and gas industry requesting disclosure of information related to the accounting for buy/sell contracts. Under a buy/sell contract, a company agrees to buy a specific quantity and quality of a commodity to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of a commodity at a different location to the same counterparty. Physical delivery occurs for each side of the transaction, and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and risk of nonperformance by the counterparty. Both parties settle each side of the buy/sell through separate invoicing.

The company routinely enters into buy/sell contracts, primarily in the United States downstream business, associated with crude oil and refined products. For crude oil, these contracts are used to facilitate the company's crude oil marketing activity, which includes the purchase and sale of crude oil production, fulfillment of the company's supply arrangements as to physical delivery location and crude oil specifications, and purchase of crude oil to supply the company's refining system. For refined products, buy/sell arrangements are used to help fulfill the company's supply agreements to customer locations and specifications.

The company has historically accounted for buy/sell transactions in the Consolidated Statement of Income the same as for a monetary transaction – purchases are reported as "Purchased crude oil and products;" sales are reported as "Sales and other operating revenues." The SEC raised the issue as to whether the accounting for buy/sell contracts should be shown net on the income statement and accounted for under the provisions of Accounting Principles Board (APB) Opinion No. 29, *"Accounting for Nonmonetary Transactions"* (APB 29). The company understands that others in the oil and gas industry may report buy/sell transactions on a net basis in the income statement rather than gross.

The Emerging Issues Task Force (EITF) of the FASB deliberated this topic as Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty"* (EITF 04-13). At its September 2005 meeting, the EITF reached consensus that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, should be combined and considered as a single arrangement for purposes of applying APB 29 when the transactions were entered into "in contemplation" of one another. EITF 04-13 was ratified by the FASB in September 2005 and is effective for new arrangements, or modifications or renewals of existing arrangements, entered into beginning on or after April 1, 2006, which will be the effective date for the company's adoption of this standard. Upon adoption, the company will report the net effect of buy/sell transactions on its Consolidated Statement of Income as "Purchased crude oil and products" instead of reporting the revenues associated with these arrangements as "Sales and other operating revenues" and the costs as "Purchased crude oil and products."

While this issue was under deliberation by the EITF, the SEC staff directed Chevron and other companies to disclose on the face of the income statement the amounts associated with buy/sell contracts and to discuss in a footnote to the financial statements the basis for the underlying accounting. The amounts for buy/sell contracts shown on the company's Consolidated Statement of Income "Sales and other operating revenues" for the three years ending December 31, 2005, were $23,822, $18,650 and $14,246, respectively. These revenue amounts associated with buy/sell contracts represented 12 percent of total "Sales and other operating revenues" in 2005, 2004 and 2003. Nearly all of these revenue amounts in each period associated with buy/sell contracts pertain to the company's downstream segment. The costs associated with these buy/sell revenue amounts are included in "Purchased crude oil and products" on the Consolidated Statement of Income in each period.

Other Contingencies Chevron receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and may 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 2005 at approximately $1.3 billion for its consolidated companies. Included in these expenditures were $341 million of environmental capital expenditures and $979 million 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, which includes $14 million and $66 million, respectively, for Unocal activities for the last five months of 2005.

For 2006, total worldwide environmental capital expenditures are estimated at $1.1 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

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

The discussion in this section of "critical" accounting estimates 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;
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 oil and 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 94, for the changes in these estimates for the three years ending December 31, 2005, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 102 for estimates of proved-reserve values for each of the three years ending December 31, 2003 through 2005, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements, beginning on page 58, 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 Property, Plant and Equipment and Investments in Affiliates," on page 47, 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 58. 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 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 employee 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 expense are the discount rate applied to benefit obligations and the assumed health care cost-trend rates used in the calculation of benefit obligations.

Note 21, beginning on page 74, includes information for the three years ending December 31, 2005, on the components of pension and OPEB expense and on the underlying assumptions as well as on the funded status for the company's pension plans at the end of 2005 and 2004.

To estimate the long-term rate of return on pension assets, the company employs a rigorous 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 United States pension plan assets, which account for 72 percent of the company's pension plan assets, has remained at 7.8 percent since 2002.

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, 2005, the company selected a 5.5 percent discount rate based on Moody's Aa Corporate Bond Index and a cash flow analysis using the Citigroup Pension Discount Curve for the major U.S. pension and postretirement benefit plans. The discount rates at the end of 2004 and 2003 were 5.8 percent and 6 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 2005 was approximately $600 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, which accounted for about 53 percent of the companywide pension obligation, would have reduced total pension plan expense for 2005 by approximately $50 million. A 1 percent increase in the discount rate for this same plan would have reduced total benefit plan expense for 2005 by approximately $130 million. 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 2005, the company's pension plan contributions were approximately $1 billion (nearly $800 million to the U.S. plans). In 2006, the company expects contributions to be approximately $500 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory environments and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

Pension expense is recorded on the Consolidated Statement of Income in "Operating expenses" or "Selling, general and administrative expenses" and applies to all business segments. Depending upon the funding status of the different plans, either a long-term prepaid asset or a long-term liability is recorded. Any unfunded accumulated benefit obligation in excess of recorded liabilities is recorded in "Other comprehensive income." See Note 21 to the Consolidated Financial Statements, beginning on page 74, for the pension-related balance sheet effects at the end of 2005 and 2004.

For the company's OPEB plans, expense for 2005 was about $200 million and was also recorded as "Operating expenses" or "Selling, general and administrative expenses" in all business segments.

Effective January 1, 2005, the company amended its main U.S. postretirement medical plan to limit future increases in the company contribution. For current retirees, the increase in company contribution is capped at 4 percent each year. For future retirees, the 4 percent cap will be effective at retirement. For active employees and retirees below age 65 whose claims experiences are combined for rating purposes, the assumed health care cost trend rates start with 10 percent in 2006 and gradually drop to 5 percent for 2011 and beyond.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2005, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 80 percent of the companywide OPEB obligation, would have decreased OPEB expense by approximately $20 million.

Impairment of Property, Plant and Equipment and Investments in Affiliates The company assesses its property, 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 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.

The amount and income statement classification of major impairments of PP&E for the three years ending December 31, 2005, are included in the commentary on the business segments elsewhere in this discussion. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in the 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 was made to sell such assets, that is, the asset is held for sale, and the estimated proceeds less costs to sell were less than the 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 When acquired as part of a business combination, goodwill is not subject to amortization. As required by Financial Accounting Standards Board (FASB) Statement No. 142, *"Goodwill and Other Intangible Assets,"* the company will test 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. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page 60.

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 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. Refer to the business segment discussions elsewhere in this discussion for the effect on earnings from losses associated with certain litigation and environmental remediation and tax matters for the three years ended December 31, 2005.

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. 151, "Inventory Costs, an Amendment of ARB No. 43, Chapter 4" (FAS 151) In November 2004, the FASB issued FAS 151, which became effective for the company on January 1, 2006. The standard amends the guidance in Accounting Research Bulletin (ARB) No. 43, Chapter 4, "Inventory Pricing" to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. In addition, the standard requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. The adoption of this standard will not have an impact on the company's results of operations, financial position or liquidity.

EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry" (Issue 04-6) In March 2005, the FASB ratified the earlier EITF consensus on Issue 04-6, which became effective for the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to ARB No. 43, "Restatement and Revision of Accounting Research Bulletins." Adoption of this accounting for its coal, oil sands and other mining operations will not have a significant effect on the company's results of operations, financial position or liquidity.

QUARTERLY RESULTS AND STOCK MARKET DATA

Unaudited

Millions of dollars, except per-share amounts	2005 4TH Q	2005 3RD Q	2005 2ND Q	2005 1ST Q	2004 4TH Q	2004 3RD Q	2004 2ND Q	2004 1ST Q
REVENUES AND OTHER INCOME								
Sales and other operating revenues[1,2]	**$ 52,457**	**$ 53,429**	**$ 47,265**	**$ 40,490**	$ 41,612	$ 39,611	$ 36,579	$ 33,063
Income from equity affiliates	**1,110**	**871**	**861**	**889**	785	613	740	444
Other income	**227**	**156**	**217**	**228**	295	496	924	138
TOTAL REVENUES AND OTHER INCOME	**53,794**	**54,456**	**48,343**	**41,607**	42,692	40,720	38,243	33,645
COSTS AND OTHER DEDUCTIONS								
Purchased crude oil and products	**34,246**	**36,101**	**31,130**	**26,491**	26,290	25,650	22,452	20,027
Operating expenses	**3,819**	**3,190**	**2,713**	**2,469**	2,874	2,557	2,234	2,167
Selling, general and administrative expenses	**1,340**	**1,337**	**1,152**	**999**	1,319	1,231	986	1,021
Exploration expenses	**274**	**177**	**139**	**153**	274	173	165	85
Depreciation, depletion and amortization	**1,725**	**1,534**	**1,320**	**1,334**	1,283	1,219	1,243	1,190
Taxes other than on income[1]	**5,063**	**5,282**	**5,311**	**5,126**	5,216	4,948	4,889	4,765
Interest and debt expense	**135**	**136**	**104**	**107**	112	107	94	93
Minority interests	**33**	**24**	**18**	**21**	22	23	18	22
TOTAL COSTS AND OTHER DEDUCTIONS	**46,635**	**47,781**	**41,887**	**36,700**	37,390	35,908	32,081	29,370
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	**7,159**	**6,675**	**6,456**	**4,907**	5,302	4,812	6,162	4,275
INCOME TAX EXPENSE	**3,015**	**3,081**	**2,772**	**2,230**	1,862	1,875	2,056	1,724
INCOME FROM CONTINUING OPERATIONS	**4,144**	**3,594**	**3,684**	**2,677**	3,440	2,937	4,106	2,551
INCOME FROM DISCONTINUED OPERATIONS	**–**	**–**	**–**	**–**	–	264	19	11
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**$ 4,144**	**$ 3,594**	**$ 3,684**	**$ 2,677**	$ 3,440	$ 3,201	$ 4,125	$ 2,562
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, NET OF TAX	**–**	**–**	**–**	**–**	–	–	–	–
NET INCOME[3]	**$ 4,144**	**$ 3,594**	**$ 3,684**	**$ 2,677**	$ 3,440	$ 3,201	$ 4,125	$ 2,562
PER-SHARE OF COMMON STOCK[4]								
INCOME FROM CONTINUING OPERATIONS								
– BASIC	**$ 1.88**	**$ 1.65**	**$ 1.77**	**$ 1.28**	$ 1.64	$ 1.38	$ 1.93	$ 1.21
– DILUTED	**$ 1.86**	**$ 1.64**	**$ 1.76**	**$ 1.28**	$ 1.63	$ 1.38	$ 1.93	$ 1.20
INCOME FROM DISCONTINUED OPERATIONS								
– BASIC	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ 0.13	$ 0.01	$ –
– DILUTED	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ 0.13	$ 0.01	$ –
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES								
– BASIC	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ –	$ –	$ –
– DILUTED	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ –	$ –	$ –
NET INCOME								
– BASIC	**$ 1.88**	**$ 1.65**	**$ 1.77**	**$ 1.28**	$ 1.64	$ 1.51	$ 1.94	$ 1.21
– DILUTED	**$ 1.86**	**$ 1.64**	**$ 1.76**	**$ 1.28**	$ 1.63	$ 1.51	$ 1.94	$ 1.20
DIVIDENDS	**$ 0.45**	**$ 0.45**	**$ 0.45**	**$ 0.40**	$ 0.40	$ 0.40	$ 0.37	$ 0.36
COMMON STOCK PRICE RANGE – HIGH	**$ 64.45**	**$ 65.77**	**$ 59.34**	**$ 62.08**	$ 56.07	$ 54.49	$ 47.50	$ 45.71
– LOW	**$ 55.75**	**$ 56.36**	**$ 50.51**	**$ 50.55**	$ 50.99	$ 46.21	$ 43.95	$ 41.99

[1] Includes consumer excise taxes:	**$ 2,173**	**$ 2,268**	**$ 2,162**	**$ 2,116**	$ 2,150	$ 2,040	$ 1,921	$ 1,857
[2] Includes amounts for buy/sell contracts:	**$ 5,897**	**$ 6,588**	**$ 5,962**	**$ 5,375**	$ 5,117	$ 4,640	$ 4,637	$ 4,256
[3] Net benefits (charges) for special items included in "Net Income":	**$ –**	**$ –**	**$ –**	**$ –**	$ 146	$ 486	$ 585	$ (55)

[4] The amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX) and on the Pacific Exchange. As of February 23, 2006, stockholders of record numbered approximately 230,000. 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 its 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 its internal control over financial reporting was effective as of December 31, 2005.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2005, 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

STEPHEN J. CROWE
Vice President
and Chief Financial Officer

MARK A. HUMPHREY
Vice President
and Comptroller

February 27, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Chevron Corporation's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

In our opinion, the accompanying consolidated balance sheets and the related statements of income, comprehensive income, stockholders' equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 24 to the Consolidated Financial Statements, beginning on page 83, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

San Francisco, California
February 27, 2006

CONSOLIDATED STATEMENT OF INCOME

Millions of dollars, except per-share amounts

	Year ended December 31		
	2005	2004	2003
REVENUES AND OTHER INCOME			
Sales and other operating revenues[1,2]	**$ 193,641**	$ 150,865	$ 119,575
Income from equity affiliates	**3,731**	2,582	1,029
Other income	**828**	1,853	308
Gain from exchange of Dynegy preferred stock	**–**	–	365
TOTAL REVENUES AND OTHER INCOME	**198,200**	155,300	121,277
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products[2]	**127,968**	94,419	71,310
Operating expenses	**12,191**	9,832	8,500
Selling, general and administrative expenses	**4,828**	4,557	4,440
Exploration expenses	**743**	697	570
Depreciation, depletion and amortization	**5,913**	4,935	5,326
Taxes other than on income[1]	**20,782**	19,818	17,901
Interest and debt expense	**482**	406	474
Minority interests	**96**	85	80
TOTAL COSTS AND OTHER DEDUCTIONS	**173,003**	134,749	108,601
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	**25,197**	20,551	12,676
INCOME TAX EXPENSE	**11,098**	7,517	5,294
INCOME FROM CONTINUING OPERATIONS	**14,099**	13,034	7,382
INCOME FROM DISCONTINUED OPERATIONS	**–**	294	44
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**$ 14,099**	$ 13,328	$ 7,426
Cumulative effect of changes in accounting principles	**–**	–	(196)
NET INCOME	**$ 14,099**	$ 13,328	$ 7,230
PER-SHARE OF COMMON STOCK[3]			
INCOME FROM CONTINUING OPERATIONS			
– BASIC	**$ 6.58**	$ 6.16	$ 3.55
– DILUTED	**$ 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 INCOME			
– BASIC	**$ 6.58**	$ 6.30	$ 3.48
– DILUTED	**$ 6.54**	$ 6.28	$ 3.48
[1] Includes consumer excise taxes:	**$ 8,719**	$ 7,968	$ 7,095
[2] Includes amounts in revenues for buy/sell contracts associated costs are in "Purchased crude oil and products." See Note 15, on page 70:	**$ 23,822**	$ 18,650	$ 14,246

[3] All periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Millions of dollars

	Year ended December 31		
	2005	2004	2003
NET INCOME	**$ 14,099**	$ 13,328	$ 7,230
Currency translation adjustment			
Unrealized net change arising during period	**(5)**	36	32
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(32)**	35	445
Reclassification to net income of net realized (gain)	**–**	(44)	(365)
Total	**(32)**	(9)	80
Net derivatives (loss) gain on hedge transactions			
Net (loss) gain arising during period			
Before income taxes	**(242)**	(8)	115
Income taxes	**89**	(1)	(40)
Reclassification to net income of net realized loss			
Before income taxes	**34**	–	–
Income taxes	**(12)**	–	–
Total	**(131)**	(9)	75
Minimum pension liability adjustment			
Before income taxes	**89**	719	12
Income taxes	**(31)**	(247)	(10)
Total	**58**	472	2
OTHER COMPREHENSIVE (LOSS) GAIN, NET OF TAX	**(110)**	490	189
COMPREHENSIVE INCOME	**$ 13,989**	$ 13,818	$ 7,419

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

Millions of dollars, except per-share amounts

	At December 31 2005	2004
ASSETS		
Cash and cash equivalents	**$ 10,043**	$ 9,291
Marketable securities	**1,101**	1,451
Accounts and notes receivable (less allowance: 2005 – $156; 2004 – $174)	**17,184**	12,429
Inventories:		
Crude oil and petroleum products	**3,182**	2,324
Chemicals	**245**	173
Materials, supplies and other	**694**	486
Total inventories	**4,121**	2,983
Prepaid expenses and other current assets	**1,887**	2,349
TOTAL CURRENT ASSETS	**34,336**	28,503
Long-term receivables, net	**1,686**	1,419
Investments and advances	**17,057**	14,389
Properties, plant and equipment, at cost	**127,446**	103,954
Less: Accumulated depreciation, depletion and amortization	**63,756**	59,496
Properties, plant and equipment, net	**63,690**	44,458
Deferred charges and other assets	**4,428**	4,277
Goodwill	**4,636**	–
Assets held for sale	**–**	162
TOTAL ASSETS	**$ 125,833**	$ 93,208
LIABILITIES AND STOCKHOLDERS' EQUITY		
Short-term debt	**$ 739**	$ 816
Accounts payable	**16,074**	10,747
Accrued liabilities	**3,690**	3,410
Federal and other taxes on income	**3,127**	2,502
Other taxes payable	**1,381**	1,320
TOTAL CURRENT LIABILITIES	**25,011**	18,795
Long-term debt	**11,807**	10,217
Capital lease obligations	**324**	239
Deferred credits and other noncurrent obligations	**10,507**	7,942
Noncurrent deferred income taxes	**11,262**	7,268
Reserves for employee benefit plans	**4,046**	3,345
Minority interests	**200**	172
TOTAL LIABILITIES	**63,157**	47,978
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	**–**	–
Common stock (authorized 4,000,000,000 shares, $0.75 par value; 2,442,676,580 and 2,274,032,014 shares issued at December 31, 2005 and 2004, respectively)	**1,832**	1,706
Capital in excess of par value	**13,894**	4,160
Retained earnings	**55,738**	45,414
Notes receivable – key employees	**(3)**	–
Accumulated other comprehensive loss	**(429)**	(319)
Deferred compensation and benefit plan trust	**(486)**	(607)
Treasury stock, at cost (2005 – 209,989,910 shares; 2004 – 166,911,890 shares)	**(7,870)**	(5,124)
TOTAL STOCKHOLDERS' EQUITY	**62,676**	45,230
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 125,833**	$ 93,208

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

Millions of dollars

	Year ended December 31		
	2005	2004	2003
OPERATING ACTIVITIES			
Net income	**$ 14,099**	$ 13,328	$ 7,230
Adjustments			
Depreciation, depletion and amortization	**5,913**	4,935	5,326
Dry hole expense	**226**	286	256
Distributions less than income from equity affiliates	**(1,304)**	(1,422)	(383)
Net before-tax gains on asset retirements and sales	**(134)**	(1,882)	(194)
Net foreign currency effects	**62**	60	199
Deferred income tax provision	**1,393**	(224)	164
Net (increase) decrease in operating working capital	**(54)**	430	162
Minority interest in net income	**96**	85	80
(Increase) decrease in long-term receivables	**(191)**	(60)	12
Decrease (increase) in other deferred charges	**668**	(69)	1,646
Cumulative effect of changes in accounting principles	**–**	–	196
Gain from exchange of Dynegy preferred stock	**–**	–	(365)
Cash contributions to employee pension plans	**(1,022)**	(1,643)	(1,417)
Other	**353**	866	(597)
NET CASH PROVIDED BY OPERATING ACTIVITIES	**20,105**	14,690	12,315
INVESTING ACTIVITIES			
Cash portion of Unocal acquisition, net of Unocal cash received	**(5,934)**	–	–
Capital expenditures	**(8,701)**	(6,310)	(5,625)
Advances to equity affiliate	**–**	(2,200)	–
Repayment of loans by equity affiliates	**57**	1,790	293
Proceeds from asset sales	**2,681**	3,671	1,107
Net sales (purchases) of marketable securities	**336**	(450)	153
NET CASH USED FOR INVESTING ACTIVITIES	**(11,561)**	(3,499)	(4,072)
FINANCING ACTIVITIES			
Net (payments) borrowings of short-term obligations	**(109)**	114	(3,628)
Proceeds from issuances of long-term debt	**20**	–	1,034
Repayments of long-term debt and other financing obligations	**(966)**	(1,398)	(1,347)
Cash dividends – common stock	**(3,778)**	(3,236)	(3,033)
Dividends paid to minority interests	**(98)**	(41)	(37)
Net (purchases) sales of treasury shares	**(2,597)**	(1,645)	57
Redemption of preferred stock of subsidiaries	**(140)**	(18)	(75)
NET CASH USED FOR FINANCING ACTIVITIES	**(7,668)**	(6,224)	(7,029)
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	**(124)**	58	95
NET CHANGE IN CASH AND CASH EQUIVALENTS	**752**	5,025	1,309
CASH AND CASH EQUIVALENTS AT JANUARY 1	**9,291**	4,266	2,957
CASH AND CASH EQUIVALENTS AT DECEMBER 31	**$ 10,043**	$ 9,291	$ 4,266

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

Shares in thousands; amounts in millions of dollars

	2005		2004		2003	
	Shares	Amount	Shares	Amount	Shares	Amount
PREFERRED STOCK	**–**	**$ –**	–	$ –	–	$ –
COMMON STOCK[1]						
Balance at January 1	**2,274,032**	**$ 1,706**	2,274,042	$ 1,706	2,274,042	$ 1,706
Shares issued for Unocal acquisition	**168,645**	**126**		–		–
Conversion of Texaco Inc. acquisition	**–**	**–**	(10)	–	–	–
BALANCE AT DECEMBER 31	**2,442,677**	**$ 1,832**	2,274,032	$ 1,706	2,274,042	$ 1,706
CAPITAL IN EXCESS OF PAR[1]						
Balance at January 1		**$ 4,160**		$ 4,002		$ 3,980
Shares issued for Unocal acquisition		**9,585**		–		–
Stock options and restricted stock units		**67**		–		–
Treasury stock transactions		**82**		158		22
BALANCE AT DECEMBER 31		**$ 13,894**		$ 4,160		$ 4,002
RETAINED EARNINGS						
Balance at January 1		**$ 45,414**		$ 35,315		$ 30,942
Net income		**14,099**		13,328		7,230
Cash dividends on common stock		**(3,778)**		(3,236)		(3,033)
Tax benefit from dividends paid on unallocated ESOP shares and other		**3**		7		6
Exchange of Dynegy securities		**–**		–		170
BALANCE AT DECEMBER 31		**$ 55,738**		$ 45,414		$ 35,315
NOTES RECEIVABLE – KEY EMPLOYEES		**$ (3)**		$ –		$ –
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		**$ (140)**		$ (176)		$ (208)
Change during year[2]		**(5)**		36		32
Balance at December 31		**$ (145)**		$ (140)		$ (176)
Minimum pension liability adjustment						
Balance at January 1		**$ (402)**		$ (874)		$ (876)
Change during year		**58**		472		2
Balance at December 31		**$ (344)**		$ (402)		$ (874)
Unrealized net holding gain on securities						
Balance at January 1		**$ 120**		$ 129		$ 49
Change during year		**(32)**		(9)		80
Balance at December 31		**$ 88**		$ 120		$ 129
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 103**		$ 112		$ 37
Change during year[2]		**(131)**		(9)		75
Balance at December 31		**$ (28)**		$ 103		$ 112
BALANCE AT DECEMBER 31		**$ (429)**		$ (319)		$ (809)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST						
DEFERRED COMPENSATION						
Balance at January 1		**$ (367)**		$ (362)		$ (412)
Net reduction of ESOP debt and other		**121**		(5)		50
BALANCE AT DECEMBER 31		**(246)**		(367)		(362)
BENEFIT PLAN TRUST (COMMON STOCK)[1]	**14,168**	**(240)**	14,168	(240)	14,168	(240)
BALANCE AT DECEMBER 31	**14,168**	**$ (486)**	14,168	$ (607)	14,168	$ (602)
TREASURY STOCK AT COST[1]						
Balance at January 1	**166,912**	**$ (5,124)**	135,747	$ (3,317)	137,769	$ (3,374)
Purchases	**52,013**	**(3,029)**	42,607	(2,122)	81	(3)
Issuances – mainly employee benefit plans	**(8,935)**	**283**	(11,442)	315	(2,103)	60
BALANCE AT DECEMBER 31	**209,990**	**$ (7,870)**	166,912	$ (5,124)	135,747	$ (3,317)
TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31		**$ 62,676**		$ 45,230		$ 36,295

[1] 2003 restated to reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.
[2] Includes Unocal balances at December 31, 2005.

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Chevron manages its investments in and provides administrative, financial and management support to U.S. and foreign subsidiaries and affiliates that engage in fully integrated petroleum and chemicals operations. In addition, Chevron holds investments in businesses involving power generation, geothermal production, and the mining of coal and other minerals. Collectively, these companies conduct business activities in approximately 180 countries. Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and also marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil, natural gas 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. Deferred income taxes are provided for these gains and losses.

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 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.

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.

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 are also 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 20, beginning on page 73, 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 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.

Effective January 1, 2003, the company implemented Financial Accounting Standards Board Statement No. 143, *"Accounting for Asset Retirement Obligations (FAS 143),"* in which the fair value of a liability for an asset retirement obligation 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 24, beginning on page 83, relating to asset retirement obligations, which includes additional information on the company's adoption of FAS 143.

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 coal 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, repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill acquired in a business combination is not subject to amortization. As required by Financial Accounting Standards Board (FASB) Statement No. 142, *"Goodwill and Other Intangible Assets,"* the company will test 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. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page 60.

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.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – Continued

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 coal producing properties, a liability for an asset retirement obligation is made, following FAS 143. Refer to Note 24, beginning on page 83, 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). Refer to Note 15, beginning on page 70, 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 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 (APB) Opinion No. 25, *"Accounting for Stock Issued to Employees,"* (APB 25) and related interpretations and disclosure requirements established by FAS 123, *"Accounting for Stock-Based Compensation."*

Refer to Note 22, beginning on page 78, 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 123 to stock options, stock appreciation rights, performance units and restricted stock units for periods prior to adoption of FAS 123R, and the actual effect on net income and earnings per share for periods after adoption of FAS 123R.

	Year ended December 31		
	2005	2004	2003
Net income, as reported	**$ 14,099**	$ 13,328	$ 7,230
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects[1]	**$ 81**	$ 42	$ 16
Deduct: Total stock-based employee compensation expense determined under fair-valued-based method for awards, net of related tax effects[1,2]	**$ (108)**	$ (84)	$ (41)
Pro forma net income	**$ 14,072**	$ 13,286	$ 7,205
Net income per share:[3,4]			
Basic – as reported	**$ 6.58**	$ 6.30	$ 3.48
Basic – pro forma	**$ 6.56**	$ 6.28	$ 3.47
Diluted – as reported	**$ 6.54**	$ 6.28	$ 3.48
Diluted – pro forma	**$ 6.53**	$ 6.26	$ 3.47

[1] Periods prior to 2005 conformed to the 2005 presentation.
[2] Fair value determined using the Black-Scholes option-pricing model.
[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 amounts in 2003 include a benefit of $0.08 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which under the applicable accounting rules was recorded directly to the company's retained earnings and not included in net income for the period.

NOTE 2.

ACQUISITION OF UNOCAL CORPORATION

On August 10, 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. Unocal's principal upstream operations are in North America and Asia, including the Caspian region. Also located in Asia are Unocal's geothermal energy and electrical power businesses. Other activities include ownership interests in proprietary and common carrier pipelines, natural gas storage facilities and mining operations.

The aggregate purchase price of Unocal was approximately $17,300, which included approximately $7,500 cash, 169 million shares of Chevron common stock valued at or about $9,600, and $200 for stock options on approximately 5 million shares and merger-related fees. The value of the common shares was based on the average market price for a 5-day period beginning two days before the terms of the acquisition were finalized and announced on July 19, 2005. The issued shares represented approximately 7.5 percent of the number of shares outstanding immediately after the August 10 close. The value of the stock options at the acquisition date was determined using the Black-Scholes option-pricing model.

A third-party appraisal firm has been engaged to assist the company in the process of determining the fair values of Unocal's tangible and intangible assets. Initial fair-value estimates were made in the third quarter 2005, and adjustments to those initial estimates were made in the fourth quarter. The company expects the valuation process will be finalized in the first half of 2006. Once completed, the associated deferred tax liabilities will also be adjusted. No significant intangible assets other than goodwill are included in the preliminary allocation of the purchase price in the table below. No in-process research and development assets were acquired.

The acquisition was accounted for under the rules of Financial Accounting Standards Board (FASB) Statement No. 141, *"Business Combinations."* The following table summarizes the preliminary allocation of the purchase price to Unocal's assets and liabilities:

	At August 1, 2005
Current assets	$ 3,531
Investments and long-term receivables	1,647
Properties	17,288
Goodwill	4,700
Other assets	2,055
Total assets acquired	29,221
Current liabilities	(2,365)
Long-term debt and capital leases	(2,392)
Deferred income taxes	(3,743)
Other liabilities	(3,435)
Total liabilities assumed	(11,935)
Net assets acquired	$ 17,286

The $4,700 of goodwill is assigned to the upstream segment. None of the goodwill is deductible for tax purposes. The goodwill represents benefits of the acquisition that are additional to the fair values of the other net assets acquired. The primary reasons for the acquisition and the principal factors that contributed to a Unocal purchase price that resulted in the recognition of goodwill were as follows:

- The "going concern" element of the Unocal businesses, which presents the opportunity to earn a higher rate of return on the assembled collection of net assets than would be expected if those assets were acquired separately. These benefits include upstream growth opportunities in the Asia-Pacific, Gulf of Mexico and Caspian regions. Some of these areas contain operations that are complementary to Chevron's, and the acquisition is consistent with Chevron's long-term strategies to grow profitability in its core upstream areas, build new legacy positions and commercialize the company's large undeveloped natural gas resource base.
- Cost savings that can be obtained through the capture of operational synergies. The opportunities for cost savings include the elimination of duplicate facilities and services, high-grading of investment opportunities in the combined portfolio and the sharing of best practices of the two companies.

Goodwill recorded in the acquisition is not subject to amortization, but will be tested periodically for impairment as required by FASB Statement No. 142, *"Goodwill and Other Intangible Assets."*

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

	Year ended December 31	
	2005	2004
Sales and other operating revenues	**$ 198,762**	$ 158,471
Net income	**14,967**	14,164
Net income per share of common stock		
Basic	**$ 6.68**	$ 6.22
Diluted	**$ 6.64**	$ 6.19

The pro forma summary uses estimates and assumptions based on information available at the time. Management believes the estimates and assumptions to be reasonable; however, actual results may differ significantly from this pro forma financial information. The pro forma information does not reflect any synergistic savings that might be achieved from combining the operations and is not intended to reflect the actual results that would have occurred had the companies actually been combined during the periods presented.

NOTE 3.

INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

	Year ended December 31		
	2005	2004	2003
Net (increase) decrease in operating working capital was composed of the following:			
Increase in accounts and notes receivable	**$ (3,164)**	$ (2,515)	$ (265)
(Increase) decrease in inventories	**(968)**	(298)	115
(Increase) decrease in prepaid expenses and other current assets	**(54)**	(76)	261
Increase in accounts payable and accrued liabilities	**3,851**	2,175	242
Increase (decrease) in income and other taxes payable	**281**	1,144	(191)
Net (increase) decrease in operating working capital	**$ (54)**	$ 430	$ 162
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$ 455**	$ 422	$ 467
Income taxes	**$ 8,875**	$ 6,679	$ 5,316
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (918)**	$ (1,951)	$ (3,563)
Marketable securities sold	**1,254**	1,501	3,716
Net sales (purchases) of marketable securities	**$ 336**	$ (450)	$ 153

The 2005 "Net increase in operating working capital" included a reduction of $20 for excess income tax benefits associated with stock options exercised since July 1, 2005, in accordance with the cash-flows classification requirements of

NOTE 3. INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS– Continued

FAS 123R, *"Share-Based Payment."* This amount was offset by an equal amount in "Net purchases of treasury shares." Refer to Note 22, beginning on page 78, for additional information related to the company's adoption of FAS 123R.

The "Net (purchases) sales of treasury shares" in 2005 and 2004 included purchases of $3,029 and $2,122, respectively, related to the company's common stock repurchase programs and share-based compensation plans, which were partially offset by the issuance of shares for the exercise of stock options.

The 2003 "Net cash provided by operating activities" included an $890 "Decrease in other deferred charges" and a decrease of the same amount in "Other" related to balance sheet netting of certain pension-related asset and liability accounts, in accordance with the requirements of Financial Accounting Standards Board (FASB) Statement No. 87, *"Employers' Accounting for Pensions."*

The "cash portion of Unocal acquisition, net of Unocal cash received" represents the purchase price, net of $1,600 of cash received. The aggregate purchase price of Unocal was $17,300. Refer to Note 2 starting on page 60 for additional discussion of the Unocal acquisition.

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 38, are presented in the following table:

	Year ended December 31		
	2005	2004	2003
Additions to properties, plant and equipment[1]	**$ 8,154**	$ 5,798	$ 4,953
Additions to investments	**459**	303	687
Current-year dry hole expenditures	**198**	228	132
Payments for other liabilities and assets, net	**(110)**	(19)	(147)
Capital expenditures	**8,701**	6,310	5,625
Expensed exploration expenditures	**517**	412	315
Assets acquired through capital lease obligations and other financing obligations	**164**	31	286[2]
Capital and exploratory expenditures, excluding equity affiliates	**9,382**	6,753	6,226
Equity in affiliates' expenditures	**1,681**	1,562	1,137
Capital and exploratory expenditures, including equity affiliates	**$ 11,063**	$ 8,315	$ 7,363

[1] Net of noncash additions of $435 in 2005, $212 in 2004 and $1,183 in 2003.
[2] Includes deferred payment of $210 related to the 1993 acquisition of the company's interest in the Tengizchevroil joint venture.

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 investments in the Chevron Phillips Chemical Company LLC (CPChem) joint venture and Dynegy Inc. (Dynegy), which are accounted for using the equity method.

During 2003, Chevron implemented legal reorganizations in which certain Chevron subsidiaries transferred assets to or under CUSA and other Chevron companies were merged with and into CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the following table gives retroactive effect to the reorganizations, with all periods presented as if the companies had always been combined and the reorganizations had occurred on January 1, 2003. However, the financial information included in this table may not reflect the financial position and operating results in the future or the historical results in the periods presented had the reorganizations actually occurred on January 1, 2003.

	Year ended December 31		
	2005	2004	2003
Sales and other operating revenues	**$ 138,296**	$ 108,351	$ 82,760
Total costs and other deductions	**132,180**	102,180	78,399
Net income*	**4,693**	4,773	3,083

*2003 net income includes a charge of $323 for the cumulative effect of changes in accounting principles.

	At December 31	
	2005	2004
Current assets	**$ 27,878**	$ 23,147
Other assets	**20,611**	19,961
Current liabilities	**20,286**	17,044
Other liabilities	**12,897**	12,533
Net equity	**15,306**	13,531
Memo: Total debt	**$ 8,353**	$ 8,349

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 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		
	2005	2004	2003
Sales and other operating revenues	**$ 640**	$ 660	$ 601
Total costs and other deductions	**509**	495	535
Net income	**113**	160	50

	At December 31	
	2005	2004
Current assets	**$ 358**	$ 292
Other assets	**283**	219
Current liabilities	**119**	67
Other liabilities	**243**	278
Net equity	**279**	166

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2005.

NOTE 6.

STOCKHOLDERS' EQUITY

Retained earnings at December 31, 2005 and 2004, included approximately $5,000 and $3,950, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2005, about 142 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), as amended and restated, which was approved by the stockholders in 2004. In addition, approximately 561 thousand shares remain available for issuance from the 800 thousand 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), which was approved by stockholders in 2003. Refer to Note 26, on page 86, for a discussion of the company's common stock split in 2004.

NOTE 7.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to price volatility of crude oil, refined products, natural gas, natural gas liquids 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 or sale of crude oil; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids. The company also uses derivative commodity instruments for limited trading purposes.

The company uses International Swaps Dealers 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." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

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 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." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

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, whereas interest rate swaps related to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as "Accounts and notes receivable" or "Accounts payable," with gains and losses reported directly in income as part of "Interest and debt expense." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

Fair Value Fair values are derived either from quoted market prices 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.

NOTE 7. FINANCIAL AND DERIVATIVE INSTRUMENTS – Continued

Long-term debt of $7,424 and $5,815 had estimated fair values of $7,945 and $6,444 at December 31, 2005 and 2004, respectively.

For interest rate swaps, the notional principal amounts of $1,400 and $1,665 had estimated fair values of $(10) and $36 at December 31, 2005 and 2004, respectively.

The company holds cash equivalents and U.S. dollar marketable securities in domestic and offshore portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had fair values of $8,995 and $8,789 at December 31, 2005 and 2004, respectively. Of these balances, $7,894 and $7,338 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 2 years.

For the financial and derivative instruments discussed above, there was not a material change in market risk from that presented in 2004.

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, 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.

Investment in Dynegy Preferred Stock At December 31, 2005, the company held an investment in $400 face value of Dynegy Series C Convertible Preferred Stock, with a stated maturity date of 2033. The stock was recorded at its fair value, which was estimated to be $360 at the end of 2005.

Temporary changes in the estimated fair value of the preferred stock are reported in "Other comprehensive income." However, if any future decline in fair value is deemed to be other than temporary, a charge against income in the period would be recorded. Dividends payable on the preferred stock are recognized in income each period.

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 FAS 131, *"Disclosures About Segments of an Enterprise and Related Information."*

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

"All Other" activities include the company's interest in Dynegy, mining operations of coal and other minerals, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, 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 (loss) from continuing operations is presented in the following table:

	Year ended December 31		
	2005	2004	2003
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	**$ 4,168**	$ 3,868	$ 3,160
International	**7,556**	5,622	3,199
Total Upstream	**11,724**	9,490	6,359
Downstream – Refining, Marketing and Transportation			
United States	**980**	1,261	482
International	**1,786**	1,989	685
Total Downstream	**2,766**	3,250	1,167
Chemicals			
United States	**240**	251	5
International	**58**	63	64
Total Chemicals	**298**	314	69
Total Segment Income	**14,788**	13,054	7,595
All Other			
Interest expense	**(337)**	(257)	(352)
Interest income	**266**	129	75
Other	**(618)**	108	64
Income From Continuing Operations	**14,099**	13,034	7,382
Income From Discontinued Operations	**–**	294	44
Cumulative effect of changes in accounting principles	**–**	–	(196)
Net Income	**$ 14,099**	$ 13,328	$ 7,230

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2005 and 2004 follow:

	At December 31	
	2005	2004
Upstream – Exploration and Production		
United States	**$ 19,006**	$ 11,869
International	**46,501**	31,239
Goodwill	**4,636**	–
Total Upstream	**70,143**	43,108
Downstream – Refining, Marketing and Transportation		
United States	**12,273**	10,091
International	**22,294**	19,415
Total Downstream	**34,567**	29,506
Chemicals		
United States	**2,452**	2,316
International	**727**	667
Total Chemicals	**3,179**	2,983
Total Segment Assets	**107,889**	75,597
All Other*		
United States	**9,234**	11,746
International	**8,710**	5,865
Total All Other	**17,944**	17,611
Total Assets – United States	**42,965**	36,022
Total Assets – International	**78,232**	57,186
Goodwill	**4,636**	–
Total Assets	**$ 125,833**	$ 93,208

* All Other assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company's investment in Dynegy, mining operations of coal and other minerals, 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 2005, 2004 and 2003 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, the only country in which Chevron recorded significant revenues was the United Kingdom, with revenues of $15,296, $13,985 and $12,121 in 2005, 2004 and 2003, respectively.

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA – Continued

	Year ended December 31		
	2005	2004	2003
Upstream – Exploration and Production			
United States	**$ 16,044**	$ 8,242	$ 6,842
Intersegment	**8,651**	8,121	6,295
Total United States	**24,695**	16,363	13,137
International	**10,190**	7,246	7,013
Intersegment	**13,652**	10,184	8,142
Total International	**23,842**	17,430	15,155
Total Upstream	**48,537**	33,793	28,292
Downstream – Refining, Marketing and Transportation			
United States	**73,721**	57,723	44,701
Excise taxes	**4,521**	4,147	3,744
Intersegment	**535**	179	225
Total United States	**78,777**	62,049	48,670
International	**83,223**	67,944	52,486
Excise taxes	**4,184**	3,810	3,342
Intersegment	**14**	87	46
Total International	**87,421**	71,841	55,874
Total Downstream	**166,198**	133,890	104,544
Chemicals			
United States	**343**	347	323
Intersegment	**241**	188	129
Total United States	**584**	535	452
International	**760**	747	677
Excise taxes	**14**	11	9
Intersegment	**131**	107	83
Total International	**905**	865	769
Total Chemicals	**1,489**	1,400	1,221
All Other			
United States	**597**	551	338
Intersegment	**514**	431	121
Total United States	**1,111**	982	459
International	**44**	97	100
Intersegment	**26**	16	4
Total International	**70**	113	104
Total All Other	**1,181**	1,095	563
Segment Sales and Other Operating Revenues			
United States	**105,167**	79,929	62,718
International	**112,238**	90,249	71,902
Total Segment Sales and Other Operating Revenues	**217,405**	170,178	134,620
Elimination of intersegment sales	**(23,764)**	(19,313)	(15,045)
Total Sales and Other Operating Revenues*	**$ 193,641**	$ 150,865	$ 119,575

*Includes buy/sell contracts of $23,822 in 2005, $18,650 in 2004 and $14,246 in 2003. Substantially all of the amounts in each period relates to the downstream segment. Refer to Note 15, beginning on page 70, for a discussion of the company's accounting for buy/sell contracts.

Segment Income Taxes Segment income tax expenses for the years 2005, 2004 and 2003 are as follows:

	Year ended December 31		
	2005	2004	2003[1]
Upstream – Exploration and Production			
United States	**$ 2,330**	$ 2,308	$ 1,853
International	**8,440**	5,041	3,831
Total Upstream	**10,770**	7,349	5,684
Downstream – Refining, Marketing and Transportation			
United States	**575**	739	300
International	**576**	442	275
Total Downstream	**1,151**	1,181	575
Chemicals			
United States	**99**	47	(25)
International	**25**	17	6
Total Chemicals	**124**	64	(19)
All Other	**(947)**	(1,077)	(946)
Income Tax Expense From Continuing Operations[2]	**$ 11,098**	$ 7,517	$ 5,294

[1] See Note 24, beginning on page 83, for information concerning the cumulative effect of changes in accounting principles due to the adoption of FAS 143, *"Accounting for Asset Retirement Obligations."*
[2] Income tax expense of $100 and $50 related to discontinued operations for 2004 and 2003, respectively, is not included.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 13, beginning on page 68. Information related to properties, plant and equipment by segment is contained in Note 14, on page 70.

NOTE 9.

LITIGATION

Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to more than 70 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 seepage of MTBE into groundwater. Resolution of these actions may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future.

The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. The company does not use MTBE in the manufacture of gasoline in the United States.

NOTE 10.

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, 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	
	2005	2004
Exploration and Production	**$ 442**	$ 277
Refining, Marketing and Transportation	**837**	842
Total	**1,279**	1,119
Less: Accumulated amortization	**745**	690
Net capitalized leased assets	**$ 534**	$ 429

Rental expenses incurred for operating leases during 2005, 2004 and 2003 were as follows:

	Year ended December 31		
	2005	2004	2003
Minimum rentals	**$ 2,102**	$ 2,093	$ 1,567
Contingent rentals	**6**	7	3
Total	**2,108**	2,100	1,570
Less: Sublease rental income	**43**	40	48
Net rental expense	**$ 2,065**	$ 2,060	$ 1,522

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, 2005, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2006	$ 507	$ 106
2007	444	87
2008	401	76
2009	349	77
2010	284	58
Thereafter	932	564
Total	$ 2,917	$ 968
Less: Amounts representing interest and executory costs		(277)
Net present values		691
Less: Capital lease obligations included in short-term debt		(367)
Long-term capital lease obligations		$ 324

NOTE 11.

RESTRUCTURING AND REORGANIZATION COSTS

In connection with the Unocal acquisition, the company implemented a restructuring and reorganization program as part of the effort to capture the synergies of the combined companies. The program is expected to be substantially completed by the end of 2006 and is aimed at eliminating redundant operations, consolidating offices and facilities, and sharing common services and functions.

As part of the restructuring and reorganization, approximately 700 positions have been preliminarily identified for elimination. Most of the positions are in the United States and relate primarily to corporate and upstream executive and administrative functions. By year-end 2005, approximately 250 of these employees had been terminated.

An accrual of $106 was established as part of the purchase-price allocation for Unocal. Payments against the accrual in 2005 were $62. The balance at year-end 2005 was classified as a current liability on the Consolidated Balance Sheet. Adjustments to the accrual may occur in future periods as the implementation plans are finalized and estimates are refined.

Amounts before tax	**2005**
Balance at August 1	**$ 106**
Payments	**(62)**
Balance at December 31	**$ 44**

As a result of various other reorganizations and restructurings across several businesses and corporate departments, the company recorded before-tax charges of $258 ($146 after tax) during 2003 for estimated termination benefits for approximately 4,500 employees. Nearly half of the liability related to the global downstream segment. Substantially all of the employee reductions had occurred by early 2006.

Activity for the company's liability related to these other reorganizations and restructurings is summarized in the following table:

Amounts before tax	**2005**	2004
Balance at January 1	**$ 119**	$ 240
Additions/adjustments	**(10)**	27
Payments	**(62)**	(148)
Balance at December 31	**$ 47**	$ 119

At December 31, 2005, the amount was classified as a current liability on the Consolidated Balance Sheet and the associated charges or credits during the period were categorized as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income.

NOTE 12.

ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

At December 31, 2004, the company classified $162 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. Assets in this category related to a group of service stations outside the United States.

Summarized income statement information relating to discontinued operations is as follows:

	Year ended December 31		
	2005	2004	2003
Revenues and other income	**$ –**	$ 635	$ 485
Income from discontinued operations before income tax expense	**–**	394	94
Income from discontinued operations, net of tax	**–**	294	44

Not all assets sold or to be disposed of are classified as discontinued operations, mainly because the cash flows from the assets were not, or will not be, eliminated from the ongoing operations of the company.

NOTE 13.

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, are as follows:

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2005	2004	**2005**	2004	2003
Upstream – Exploration and Production					
Tengizchevroil	**$ 5,007**	$ 4,725	**$ 1,514**	$ 950	$ 611
Hamaca	**1,189**	836	**390**	98	45
Other	**679**	341	**139**	148	155
Total Upstream	**6,875**	5,902	**2,043**	1,196	811
Downstream – Refining, Marketing and Transportation					
GS Caltex Corporation	**1,984**	1,820	**320**	296	107
Caspian Pipeline Consortium	**1,014**	1,039	**101**	140	52
Star Petroleum Refining Company Ltd.	**709**	663	**81**	207	8
Caltex Australia Ltd.	**435**	263	**214**	173	13
Colonial Pipeline Company	**565**	–	**13**	–	–
Other	**1,562**	1,125	**273**	143	100
Total Downstream	**6,269**	4,910	**1,002**	959	280
Chemicals					
Chevron Phillips Chemical Company LLC	**1,908**	1,896	**449**	334	24
Other	**20**	19	**3**	2	1
Total Chemicals	**1,928**	1,915	**452**	336	25
All Other					
Dynegy Inc.	**682**	525	**189**	86	(56)
Other	**740**	601	**45**	5	(31)
Total equity method	**$ 16,494**	$ 13,853	**$ 3,731**	$ 2,582	$ 1,029
Other at or below cost	**563**	536			
Total investments and advances	**$ 17,057**	$ 14,389			
Total United States	**$ 4,624**	$ 3,788	**$ 833**	$ 588	$ 175
Total International	**$ 12,433**	$ 10,601	**$ 2,898**	$ 1,994	$ 854

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.

Hamaca Chevron has a 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex (formerly LG Caltex Oil Corporation), 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 in South Korea.

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

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 at Map Ta Phut, Thailand. The Petroleum Authority of Thailand owns the remaining 36 percent of SPRC.

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2005, the fair value of Chevron's share of CAL common stock was approximately $1,900. The aggregate carrying value of the company's investment in CAL was approximately $70 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest as a result of the Unocal acquisition. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of CPChem, formed in 2000 when Chevron merged most of its petrochemicals businesses with those of Phillips Petroleum Company (now ConocoPhillips Corporation). At December 31, 2005, the company's carrying value of its investment in CPChem was approximately $100 lower than the amount of underlying equity in CPChem's net assets.

Dynegy Inc. Chevron owns an approximate 24 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States. The company also holds investments in Dynegy preferred stock.

Investment in Dynegy Common Stock At December 31, 2005, the carrying value of the company's investment in Dynegy common stock was approximately $300. This amount was about $200 below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. This difference has been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors contributing to the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate to reflect the difference between these allocated values and Dynegy's historical book values. The market value of the company's investment in Dynegy's common stock at December 31, 2005, was approximately $470.

Investment in Dynegy Preferred Stock Refer to Note 7, beginning on page 63, for a discussion of this investment.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $8,824, $7,933 and $6,308 with affiliated companies for 2005, 2004 and 2003, respectively. "Purchased crude oil and products" includes $3,219, $2,548 and $1,740 with affiliated companies for 2005, 2004 and 2003, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,729 and $1,188 due from affiliated companies at December 31, 2005 and 2004, respectively. "Accounts payable" includes $249 and $192 due to affiliated companies at December 31, 2005 and 2004, respectively.

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share.

	Affiliates			Chevron Share		
Year ended December 31	**2005**	2004	2003	**2005**	2004	2003
Total revenues	**$ 64,642**	$ 55,152	$ 42,323	**$ 31,252**	$ 25,916	$ 19,467
Income before income tax expense	**7,883**	5,309	1,657	**4,165**	3,015	1,211
Net income	**6,645**	4,441	1,508	**3,534**	2,582	1,029
At December 31						
Current assets	**$ 19,903**	$ 16,506	$ 12,204	**$ 8,537**	$ 7,540	$ 5,180
Noncurrent assets	**46,925**	38,104	39,422	**17,747**	15,567	15,765
Current liabilities	**13,427**	10,949	9,642	**6,034**	4,962	4,132
Noncurrent liabilities	**26,579**	22,261	22,738	**4,906**	4,520	5,002
Net equity	**$ 26,822**	$ 21,400	$ 19,246	**$ 15,344**	$ 13,625	$ 11,811

NOTE 14.

PROPERTIES, PLANT AND EQUIPMENT[1,2]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[3]			Depreciation Expense[4,5]		
	2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Upstream												
United States	**$ 43,390**	$ 37,329	$ 34,798	**$ 15,327**	$ 10,047	$ 9,953	**$ 2,160**	$ 1,584	$ 1,776	**$ 1,869**	$ 1,508	$ 1,815
International	**54,497**	38,721	37,402	**34,311**	21,192	20,572	**4,897**	3,090	3,246	**2,804**	2,180	2,227
Total Upstream	**97,887**	76,050	72,200	**49,638**	31,239	30,525	**7,057**	4,674	5,022	**4,673**	3,688	4,042
Downstream												
United States	**13,832**	12,826	12,959	**6,169**	5,611	5,881	**793**	482	389	**461**	490	493
International	**11,235**	10,843	11,174	**5,529**	5,443	5,944	**453**	441	388	**550**	572	655
Total Downstream	**25,067**	23,669	24,133	**11,698**	11,054	11,825	**1,246**	923	777	**1,011**	1,062	1,148
Chemicals												
United States	**624**	615	613	**282**	292	303	**12**	12	12	**19**	20	21
International	**721**	725	719	**402**	392	404	**43**	27	24	**23**	26	38
Total Chemicals	**1,345**	1,340	1,332	**684**	684	707	**55**	39	36	**42**	46	59
All Other[6]												
United States	**3,127**	2,877	2,772	**1,655**	1,466	1,393	**199**	314	169	**186**	158	109
International	**20**	18	119	**15**	15	88	**4**	2	8	**1**	3	26
Total All Other	**3,147**	2,895	2,891	**1,670**	1,481	1,481	**203**	316	177	**187**	161	135
Total United States	**60,973**	53,647	51,142	**23,433**	17,416	17,530	**3,164**	2,392	2,346	**2,535**	2,176	2,438
Total International	**66,473**	50,307	49,414	**40,257**	27,042	27,008	**5,397**	3,560	3,666	**3,378**	2,781	2,946
Total	**$ 127,446**	$ 103,954	$ 100,556	**$ 63,690**	$ 44,458	$ 44,538	**$ 8,561**	$ 5,952	$ 6,012	**$ 5,913**	$ 4,957	$ 5,384

[1] Refer to Note 24, beginning on page 83, for a discussion of the effect on 2003 PP&E balances and depreciation expenses related to the adoption of FAS 143, *"Accounting for Asset Retirement Obligations."*
[2] 2005 balances include assets acquired in connection with the acquisition of Unocal Corporation. Refer to Note 2, beginning on page 60, for additional information.
[3] Net of dry hole expense related to prior years' expenditures of $28, $58 and $124 in 2005, 2004 and 2003, respectively.
[4] Depreciation expense includes accretion expense of $187, $93 and $132 in 2005, 2004 and 2003, respectively.
[5] Depreciation expense includes discontinued operations of $22 and $58 in 2004 and 2003, respectively.
[6] Primarily mining operations of coal and other minerals, power generation businesses, real estate assets and management information systems.

NOTE 15.

ACCOUNTING FOR BUY/SELL CONTRACTS

In the first quarter 2005, the Securities and Exchange Commission (SEC) issued comment letters to Chevron and other companies in the oil and gas industry requesting disclosure of information related to the accounting for buy/sell contracts. Under a buy/sell contract, a company agrees to buy a specific quantity and quality of a commodity to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of a commodity at a different location to the same counterparty. Physical delivery occurs for each side of the transaction, and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and risk of nonperformance by the counterparty. Both parties settle each side of the buy/sell through separate invoicing.

The company routinely enters into buy/sell contracts, primarily in the United States downstream business, associated with crude oil and refined products. For crude oil, these contracts are used to facilitate the company's crude oil marketing activity, which includes the purchase and sale of crude oil production, fulfillment of the company's supply arrangements as to physical delivery location and crude oil specifications, and purchase of crude oil to supply the company's refining system. For refined products, buy/sell arrangements are used to help fulfill the company's supply agreements to customer locations and specifications.

The company has historically accounted for buy/sell transactions in the Consolidated Statement of Income the same as for a monetary transaction – purchases are reported as "Purchased crude oil and products"; sales are reported as "Sales and other operating revenues." The SEC raised the issue as to whether the accounting for buy/sell contracts should be shown net on the income statement and accounted for under the provisions of Accounting Principles Board (APB) Opinion No. 29, *"Accounting for Nonmonetary Transactions"* (APB 29). The company understands that others in the oil and gas industry may report buy/sell transactions on a net basis in the income statement rather than gross.

The Emerging Issues Task Force (EITF) of the FASB deliberated this topic as Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty."* At its September 2005 meeting, the EITF reached consensus that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, should be combined and considered as a single arrangement for purposes of applying APB 29 when the transactions were entered into "in contemplation" of one another. EITF 04-13 was ratified by the FASB in September 2005 and is effective for new arrangements, or modifications or renewals of existing arrangements, entered into beginning on or after April 1, 2006, which will be the effective date for the company's adoption of this standard. Upon adoption, the company will report the net effect of buy/sell transactions on its Consolidated Statement of Income as "Purchased crude oil and products" instead of reporting the revenues associated with these arrangements as "Sales and other operating revenues" and the costs as "Purchased crude oil and products."

While this issue was under deliberation by the EITF, the SEC staff directed Chevron and other companies to disclose on the face of the income statement the amounts associated with buy/sell contracts and to discuss in a footnote to the financial statements the basis for the underlying accounting. The amounts for buy/sell contracts shown on the company's Consolidated Statement of Income "Sales and other operating revenues" for the three years ending December 31, 2005, were $23,822, $18,650 and $14,246, respectively. These revenue amounts associated with buy/sell contracts represented 12 percent of total "Sales and other operating revenues" in 2005, 2004 and 2003. Nearly all of these revenue amounts in each period associated with buy/sell contracts pertain to the company's downstream segment. The costs associated with these buy/sell revenue amounts are included in "Purchased crude oil and products" on the Consolidated Statement of Income in each period.

NOTE 16.

TAXES

	Year ended December 31		
	2005	2004	2003
Taxes on income[1]			
U.S. federal			
Current	**$ 1,459**	$ 2,246	$ 1,133
Deferred[2]	**567**	(290)	121
State and local	**409**	345	133
Total United States	**2,435**	2,301	1,387
International			
Current	**7,837**	5,150	3,864
Deferred[2]	**826**	66	43
Total International	**8,663**	5,216	3,907
Total taxes on income	**$ 11,098**	$ 7,517	$ 5,294

[1] Excludes income tax expense of $100 and $50 related to discontinued operations for 2004 and 2003, respectively.
[2] Excludes a U.S. deferred tax benefit of $191 and a foreign deferred tax expense of $170 associated with the adoption of FAS 143 in 2003 and the related cumulative effect of changes in accounting method in 2003.

In 2005, the before-tax income for U.S. operations, including related corporate and other charges, was $6,733, compared with a before-tax income of $7,776 and $5,664 in 2004 and 2003, respectively. For international operations, before-tax income was $18,464, $12,775 and $7,012 in 2005, 2004 and 2003, respectively. U.S. federal income tax expense was reduced by $289, $176 and $196 in 2005, 2004 and 2003, 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		
	2005	2004	2003
U.S. statutory federal income tax rate	**35.0%**	35.0%	35.0%
Effect of income taxes from international operations in excess of taxes at the U.S. statutory rate	**9.2**	5.3	12.8
State and local taxes on income, net of U.S. federal income tax benefit	**1.0**	0.9	0.5
Prior-year tax adjustments	**0.1**	(1.0)	(1.6)
Tax credits	**(1.1)**	(0.9)	(1.5)
Effects of enacted changes in tax laws	**–**	(0.6)	0.3
Capital loss tax benefit	**(0.1)**	(2.1)	(0.8)
Other	**0.2**	–	(1.9)
Consolidated companies	**44.3**	36.6	42.8
Effect of recording income from equity affiliates on an after-tax basis	**(0.2)**	–	(1.0)
Effective tax rate	**44.1%**	36.6%	41.8%

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	
	2005	2004
Deferred tax liabilities		
Properties, plant and equipment	**$ 14,220**	$ 8,889
Investments and other	**1,469**	931
Total deferred tax liabilities	**15,689**	9,820
Deferred tax assets		
Abandonment/environmental reserves	**(2,083)**	(1,495)
Employee benefits	**(1,250)**	(965)
Tax loss carryforwards	**(1,113)**	(1,155)
Capital losses	**(246)**	(687)
Deferred credits	**(1,618)**	(838)
Foreign tax credits	**(1,145)**	(93)
Inventory	**(182)**	(99)
Other accrued liabilities	**(240)**	(300)
Miscellaneous	**(1,237)**	(876)
Total deferred tax assets	**(9,114)**	(6,508)
Deferred tax assets valuation allowance	**3,249**	1,661
Total deferred taxes, net	**$ 9,824**	$ 4,973

In 2005, the reported amount of net total deferred taxes increased by approximately $5,000 from the amount reported in 2004. The increase was largely attributable to net deferred taxes arising through the Unocal acquisition.

Deferred tax assets related to foreign tax credits increased approximately $1,000 between 2004 and 2005. The associated valuation allowance also increased approximately the same amount. The change in both categories reflected the addition of Unocal amounts as well as the effect of the company's tax election in 2005 for certain heritage-Chevron international upstream operations.

NOTE 16. TAXES – Continued

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 foreign jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2006 through 2013. Foreign tax credit carryforwards of $1,145 will expire in 2015.

At December 31, 2005 and 2004, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2005	2004
Prepaid expenses and other current assets	**$ (892)**	$ (1,532)
Deferred charges and other assets	**(547)**	(769)
Federal and other taxes on income	**1**	6
Noncurrent deferred income taxes	**11,262**	7,268
Total deferred income taxes, net	**$ 9,824**	$ 4,973

It is the company's policy for subsidiaries that are included in the U.S. consolidated tax return to record income tax expense as though they file separately, with the parent recording the adjustment to income tax expense for the effects of consolidation.

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 $14,317 at December 31, 2005. A significant majority of 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 such earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

American Jobs Creation Act of 2004 In October 2004, the American Jobs Creation Act of 2004 was passed into law. The Act provides a deduction for income from qualified domestic refining and upstream production activities, which will be phased in from 2005 through 2010. For that income, the company expects the net effect of this provision of the Act to result in a decrease in the federal effective tax rate for 2006 to approximately 34 percent, based on current earnings levels. In the long term, the company expects that the new deduction will result in a decrease of the annual effective tax rate to about 32 percent for that category of income, based on current earnings levels.

Taxes other than on income were as follows:

	Year ended December 31		
	2005	2004	2003
United States			
Excise taxes on products and merchandise	**$ 4,521**	$ 4,147	$ 3,744
Import duties and other levies	**8**	5	11
Property and other miscellaneous taxes	**392**	359	309
Payroll taxes	**149**	137	138
Taxes on production	**323**	257	244
Total United States	**5,393**	4,905	4,446
International			
Excise taxes on products and merchandise	**4,198**	3,821	3,351
Import duties and other levies	**10,466**	10,542	9,652
Property and other miscellaneous taxes	**535**	415	320
Payroll taxes	**52**	52	54
Taxes on production	**138**	86	83
Total International	**15,389**	14,916	13,460
Total taxes other than on income*	**$ 20,782**	$ 19,821	$ 17,906

*Includes taxes on discontinued operations of $3 and $5 in 2004 and 2003, respectively.

NOTE 17.
SHORT-TERM DEBT

	At December 31	
	2005	2004
Commercial paper*	**$ 4,098**	$ 4,068
Notes payable to banks and others with originating terms of one year or less	**170**	310
Current maturities of long-term debt	**467**	333
Current maturities of long-term capital leases	**70**	55
Redeemable long-term obligations		
Long-term debt	**487**	487
Capital leases	**297**	298
Subtotal	**5,589**	5,551
Reclassified to long-term debt	**(4,850)**	(4,735)
Total short-term debt	**$ 739**	$ 816

*Weighted-average interest rates at December 31, 2005 and 2004, were 4.18 percent and 1.98 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, 2005, the company had $4,850 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company's commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2005 or at year-end.

At December 31, 2005 and 2004, the company classified $4,850 and $ 4,735, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2006, as the company has both the intent and the ability to refinance this debt on a long-term basis.

NOTE 18.

LONG-TERM DEBT

Chevron has three "shelf" registration statements on file with the SEC that together would permit the issuance of $3,800 of debt securities pursuant to Rule 415 of the Securities Act of 1933. Total long-term debt, excluding capital leases, at December 31, 2005, was $11,807, which included $1,861 assumed in connection with the acquisition of Unocal. The company's long-term debt outstanding at year-end 2005 and 2004 was as follows:

	At December 31	
	2005	2004
3.5% notes due 2007	**$ 1,992**	$ 1,995
3.375% notes due 2008	**736**	754
7.5% debentures due 2029[1]	**475**	–
5.05% debentures due 2012[1]	**412**	–
5.5% notes due 2009	**406**	422
7.35% debentures due 2009[1]	**347**	–
7% debentures due 2028[1]	**259**	–
9.75% debentures due 2020	**250**	250
7.327% amortizing notes due 2014[2]	**247**	360
Fixed interest rate notes, maturing from 2006 to 2015 (8.1%)[1,3]	**241**	–
8.625% debentures due 2031	**199**	199
8.625% debentures due 2032	**199**	199
7.5% debentures due 2043	**198**	198
Fixed and floating interest rate loans due 2007 to 2009 (4.4%)[1,3]	**194**	–
9.125% debentures due 2006[1]	**167**	–
8.625% debentures due 2010	**150**	150
8.875% debentures due 2021	**150**	150
8% debentures due 2032	**148**	148
7.09% notes due 2007	**144**	144
8.25% debentures due 2006	**129**	129
Medium-term notes, maturing from 2017 to 2043 (7.5%)[3]	**210**	210
Other foreign currency obligations (3.2%)[3]	**30**	39
5.7% notes due 2008	**–**	206
Other long-term debt (6.4%)[3]	**141**	262
Total including debt due within one year	**7,424**	5,815
Debt due within one year	**(467)**	(333)
Reclassified from short-term debt	**4,850**	4,735
Total long-term debt	**$ 11,807**	$ 10,217

[1] Debt assumed with acquisition of Unocal in 2005.
[2] Guarantee of ESOP debt.
[3] Less than $100 individually; weighted-average interest rate at December 31, 2005.

Consolidated long-term debt maturing after December 31, 2005, is as follows: 2006 – $467; 2007 – $2,287; 2008 – $856; 2009 – $782; and 2010 – $176; after 2010 – $2,856.

In October 2005, the company fully redeemed Pure Resources 7.125 percent Senior Notes due 2011 for $395. The company's $150 of Texaco Brasil zero coupon notes were paid at maturity in November 2005. In December 2005, the company exercised a par call redemption of $200 for Texaco Capital Inc. 5.7 percent Notes due 2008.

In January 2005, the company contributed $98 to permit the ESOP to make a principal payment of $113.

NOTE 19.

NEW ACCOUNTING STANDARDS

FASB Statement No. 151, "Inventory Costs, an Amendment of ARB No. 43, Chapter 4" (FAS 151) In November 2004, the FASB issued FAS 151, which became effective for the company on January 1, 2006. The standard amends the guidance in Accounting Research Bulletin (ARB) No. 43, Chapter 4, *"Inventory Pricing,"* to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. In addition, the standard requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. The adoption of this standard will not have an impact on the company's results of operations, financial position or liquidity.

EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" (Issue 04-6) In March 2005, the FASB ratified the earlier EITF consensus on Issue 04-6, which became effective for the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to ARB No. 43, *"Restatement and Revision of Accounting Research Bulletins."* Adoption of this accounting for its coal, oil sands and other mining operations will not have a significant effect on the company's results of operations, financial position or liquidity.

NOTE 20.

ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS

Refer to Note 1, beginning on page 58, in the section "Properties, Plant and Equipment" for a discussion of the company's accounting policy for the cost of exploratory wells. The company's suspended wells are reviewed in this context on a quarterly basis.

In April 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1, *"Accounting for Suspended Well Costs,"* which amended FAS 19, *"Financial Accounting and Reporting by Oil and Gas Producing Companies."* The company elected early application of this guidance with the first quarter 2005 financial statements.

Under the provisions of FSP FAS 19-1, 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.

NOTE 20. ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS – Continued

If either condition is not met, or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. The FSP 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, 2005. No capitalized exploratory well costs were charged to expense upon the adoption of FSP FAS 19-1. Amounts may differ from those previously disclosed due to the requirements of FSP FAS 19-1 to exclude costs suspended and expensed in the same annual period.

	Year ended December 31		
	2005	2004	2003
Beginning balance at January 1	**$ 671**	$ 549	$ 478
Additions associated with the acquisition of Unocal	**317**	–	–
Additions to capitalized exploratory well costs pending the determination of proved reserves	**290**	252	344
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(140)**	(64)	(145)
Capitalized exploratory well costs charged to expense	**(6)**	(66)	(126)
Other reductions*	**(23)**	–	(2)
Ending balance at December 31	**$ 1,109**	$ 671	$ 549

*Represent property sales and an exchange.

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 Chevron's August 2005 acquisition of Unocal.

	Year ended December 31		
	2005	2004	2003
Exploratory well costs capitalized for a period of one year or less	**$ 259**	$ 222	$ 181
Exploratory well costs capitalized for a period greater than one year	**850**	449	368
Balance at December 31	**$ 1,109**	$ 671	$ 549
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**40**	22	22

*Certain projects have multiple wells or fields or both.

Of the $850 of exploratory well costs capitalized for a period greater than one year at December 31, 2005, approximately $313 (20 projects) related to projects that had drilling activities under way or firmly planned for the near future. An additional $63 (four projects) had drilling activity during 2005. The $474 balance related to 16 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 $474 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $141 – additional seismic interpretation planned, with front-end engineering and design (FEED) expected to commence in 2007 (two projects); (b) $82 – evaluation of drilling results and pre-FEED studies ongoing with FEED expected to commence in 2006 (one project); (c) $74 – finalization of pre-unit agreement with operator of adjacent field and the progression of joint subsurface and joint concept selection studies, with FEED expected to begin in 2006 (one project); (d) $63 – FEED contracts executed in 2005 and continued marketing of equity natural gas (two projects); (e) $114 – miscellaneous activities for 10 projects with smaller amounts suspended. While progress was being made on all the projects in this category, 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 $850 of suspended well costs capitalized for a period greater than one year as of December 31, 2005, represents 105 exploratory wells in 40 projects. The tables below contain the aging of these costs on a well and project basis:

Exploratory wells costs greater than one year:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1994–2000	$ 147	28
2001–2004	703	77
Total	$ 850	105

Aging based on drilling completion date of last well in project:	Amount	Number of projects
1998–2000	$ 91	4
2001–2005	759	36
Total	$ 850	40

NOTE 21.

EMPLOYEE BENEFIT PLANS

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

The company also sponsors other postretirement 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 the retirees share the costs. For retiree medical coverage in the company's main U.S. plan, the increase to the company contributions for retiree medical coverage is limited to no more than 4 percent each year, effective at retirement, beginning in 2005. Certain life insurance benefits are paid by the company and annual contributions are based on actual plan experience.

The company uses a measurement date of December 31 to value its pension and other postretirement benefit plan obligations.

The status of the company's pension and other postretirement benefit plans for 2005 and 2004 is as follows:

	Pension Benefits				Other Benefits	
	2005		2004			
	U.S.	Int'l.	U.S.	Int'l.	**2005**	2004
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	**$ 6,587**	**$ 3,144**	$ 5,819	$ 2,708	**$ 2,820**	$ 3,135
Assumption of Unocal benefit obligations	**1,437**	**169**	–	–	**277**	–
Service cost	**208**	**84**	170	70	**30**	26
Interest cost	**395**	**199**	326	180	**164**	164
Plan participants' contributions	**1**	**6**	1	6	**–**	–
Plan amendments	**42**	**7**	–	26	**–**	(811)
Actuarial loss	**593**	**476**	861	165	**189**	497
Foreign currency exchange rate changes	**–**	**(293)**	–	207	**(2)**	8
Benefits paid	**(669)**	**(181)**	(590)	(213)	**(226)**	(199)
Curtailment	**–**	**–**	–	(6)	**–**	–
Special termination benefits	**–**	**–**	–	1	**–**	–
Benefit obligation at December 31	**8,594**	**3,611**	6,587	3,144	**3,252**	2,820
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	**5,776**	**2,634**	4,444	2,129	**–**	–
Acquisition of Unocal plan assets	**1,034**	**65**	–	–	**–**	–
Actual return on plan assets	**527**	**441**	589	229	**–**	–
Foreign currency exchange rate changes	**–**	**(303)**	–	172	**–**	–
Employer contributions	**794**	**228**	1,332	311	**226**	199
Plan participants' contributions	**1**	**6**	1	6	**–**	–
Benefits paid	**(669)**	**(181)**	(590)	(213)	**(226)**	(199)
Fair value of plan assets at December 31	**7,463**	**2,890**	5,776	2,634	**–**	–
FUNDED STATUS	**(1,131)**	**(721)**	(811)	(510)	**(3,252)**	(2,820)
Unrecognized net actuarial loss	**2,332**	**1,108**	2,080	939	**1,167**	1,071
Unrecognized prior-service cost	**305**	**89**	308	104	**(679)**	(771)
Unrecognized net transitional assets	**–**	**5**	–	7	**–**	–
Total recognized at December 31	**$ 1,506**	**$ 481**	$ 1,577	$ 540	**$ (2,764)**	$ (2,520)
AMOUNTS RECOGNIZED IN THE CONSOLIDATED BALANCE SHEET AT DECEMBER 31						
Prepaid benefit cost	**$ 1,961**	**$ 960**	$ 1,759	$ 933	**$ –**	$ –
Accrued benefit liability[1]	**(890)**	**(545)**	(712)	(458)	**(2,764)**	(2,520)
Intangible asset	**12**	**2**	14	5	**–**	–
Accumulated other comprehensive income[2]	**423**	**64**	516	60	**–**	–
Net amount recognized	**$ 1,506**	**$ 481**	$ 1,577	$ 540	**$ (2,764)**	$ (2,520)

[1] The company recorded additional minimum liabilities of $435 and $66 in 2005 for U.S. and international plans, respectively, and $530 and $64 in 2004 for U.S. and international plans, respectively, to reflect the amount of unfunded accumulated benefit obligations. The long-term portion of accrued benefits liability is recorded in "Reserves for employee benefit plans," and the short-term portion is reflected in "Accrued liabilities."

[2] "Accumulated other comprehensive income" includes deferred income taxes of $148 and $22 in 2005 for U.S. and international plans, respectively, and $181 and $21 in 2004 for U.S. and international plans, respectively. This item is presented net of these taxes in the Consolidated Statement of Stockholders' Equity.

NOTE 21. EMPLOYEE BENEFIT PLANS – Continued

The accumulated benefit obligations for all U.S. and international pension plans were $7,931 and $3,080, respectively, at December 31, 2005, and $6,117 and $2,734, respectively, at December 31, 2004.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2005 and 2004, was:

	At December 31	
	2005	2004
Projected benefit obligations	**$ 2,950**	$ 1,449
Accumulated benefit obligations	**2,625**	1,360
Fair value of plan assets	**1,359**	282

The components of net periodic benefit cost for 2005, 2004 and 2003 were:

	Pension Benefits						Other Benefits		
	2005		2004		2003				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2005**	2004	2003
Service cost	**$ 208**	**$ 84**	$ 170	$ 70	$ 144	$ 54	**$ 30**	$ 26	$ 28
Interest cost	**395**	**199**	326	180	334	151	**164**	164	191
Expected return on plan assets	**(449)**	**(208)**	(358)	(169)	(224)	(132)	**–**	–	–
Amortization of transitional assets	**–**	**2**	–	1	–	(3)	**–**	–	–
Amortization of prior-service costs	**45**	**16**	42	16	45	14	**(91)**	(47)	(3)
Recognized actuarial losses	**177**	**51**	114	69	133	42	**93**	54	12
Settlement losses	**86**	**–**	96	4	132	1	**–**	–	–
Curtailment losses	**–**	**–**	–	2	–	6	**–**	–	–
Special termination benefits recognition	**–**	**–**	–	1	–	–	**–**	–	–
Net periodic benefit cost	**$ 462**	**$ 144**	$ 390	$ 174	$ 564	$133	**$ 196**	$ 197	$ 228

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

	Pension Benefits						Other Benefits		
	2005		2004		2003				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2005**	2004	2003
Assumptions used to determine benefit obligations									
Discount rate	**5.5%**	**5.9%**	5.8%	6.4%	6.0%	6.8%	**5.6%**	5.8%	6.1%
Rate of compensation increase	**4.0%**	**5.1%**	4.0%	4.9%	4.0%	4.9%	**4.0%**	4.1%	4.1%
Assumptions used to determine net periodic benefit cost									
Discount rate[1,2]	**5.5%**	**6.4%**	5.9%	6.8%	6.3%	7.1%	**5.8%**	6.1%	6.8%
Expected return on plan assets[1,2]	**7.8%**	**7.9%**	7.8%	8.3%	7.8%	8.3%	**N/A**	N/A	N/A
Rate of compensation increase[2]	**4.0%**	**5.0%**	4.0%	4.9%	4.0%	5.1%	**4.0%**	4.1%	4.1%

[1] Discount rate and expected rate of return on plan assets were reviewed and updated as needed on a quarterly basis for the main U.S. pension plan.
[2] The 2005 discount rate, expected return on plan assets and rate of compensation increase reflect the remeasurement of the Unocal benefit plans at July 31, 2005, due to the acquisition of Unocal.

Expected Return on Plan Assets The company employs a rigorous process to determine estimates of the long-term rate of return on pension assets. These estimates are primarily driven 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 determination of the company's estimates of 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 72 percent of the company's pension plan assets. At December 31, 2005, 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, 2005, the company selected a

5.5 percent discount rate (shown in the table on page 76) based on Moody's Aa Corporate Bond Index and a cash flow analysis using the Citigroup Pension Discount Curve. The discount rates at the end of 2004 and 2003 were 5.8 percent and 6 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2005, for the main U.S. postretirement medical plan, the assumed health care cost trend rates start with 10 percent in 2006 and gradually decline to 5 percent for 2011 and beyond. For this measurement at December 31, 2004, the assumed health care cost trend rates started with 9.5 percent in 2005 and gradually declined to 4.8 percent for 2010 and beyond. In both measurements, increases in the company's contributions are capped at 4 percent effective at retirement.

Assumed health care cost-trend rates have a significant effect on the amounts reported for retiree health care costs. 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	$ 8	$ (9)
Effect on postretirement benefit obligation	$ 126	$ (184)

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

	U.S.		International	
Asset Category	**2005**	2004	**2005**	2004
Equities	**69%**	70%	**60%**	57%
Fixed Income	**21%**	21%	**39%**	42%
Real Estate	**9%**	9%	**1%**	1%
Other	**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 established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income 20–60 percent, Real Estate 0–15 percent and Other 0–5 percent. 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 $13 and $8 at December 31, 2005 and 2004, respectively. The "Other" asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments In 2005, the company contributed $794 and $228 to its U.S. and international pension plans, respectively. In 2006, 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 $220 in 2006, as compared with $226 paid in 2005.

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

	Pension Benefits		Other
	U.S.	Int'l.	Benefits
2006	$ 788	$ 177	$ 220
2007	$ 639	$ 185	$ 218
2008	$ 674	$ 195	$ 224
2009	$ 714	$ 202	$ 231
2010	$ 729	$ 212	$ 237
2011–2015	$ 3,803	$ 1,240	$ 1,238

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

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is discussed below. Total company matching contributions to employee accounts within the ESIP were $145, $139 and $136 in 2005, 2004 and 2003, respectively. This cost was reduced by the value of shares released from the LESOP totaling $(4), $(138) and $(23) in 2005, 2004 and 2003, respectively. The remaining amounts, totaling $141, $1 and $113 in 2005, 2004 and 2003, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron Employee Savings Investment Plan (ESIP) is an employee stock ownership plan (ESOP). In 1989, Chevron established a leveraged employee stock ownership plan (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

NOTE 21. EMPLOYEE BENEFIT PLANS – Continued

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 expenses (credits) recorded for the LESOP were $94, $(29) and $24 in 2005, 2004 and 2003, respectively, including $18, $23 and $28 of interest expense related to LESOP debt and a charge (credit) to compensation expense of $76, $(52) and $(4).

Of the dividends paid on the LESOP shares, $55, $52 and $61 were used in 2005, 2004 and 2003, respectively, to service LESOP debt. Included in the 2004 amount was a repayment of debt entered into in 1999 to pay interest on the ESOP debt. Interest expense on this debt was recognized and reported as LESOP interest expense in 1999. In addition, the company made contributions in 2005 and 2003 of $98 and $26, respectively, to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2004 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, 2005 and 2004, were as follows:

Thousands	**2005**	2004
Allocated shares	**23,928**	24,832
Unallocated shares	**9,163**	9,940
Total LESOP shares	**33,091**	34,772

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2005, 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, 2005, trust assets totaled $130 and were invested primarily in interest-earning accounts.

Management 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. The 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 $155, $147 and $125 in 2005, 2004 and 2003, respectively. Awards under the LTIP consist of stock options and other share-based compensation that are described more fully in Note 22 below.

Other Incentive Plans The company has a program that provides eligible employees, other than those covered by MIP and LTIP, with an annual cash bonus if the company achieves certain financial and safety goals. Additionally, in August 2005, the company assumed responsibility for the remaining pro-rated cash bonuses under the Unocal Annual Incentive Plan. Charges for the programs were $324, $339 and $151 in 2005, 2004 and 2003, respectively.

NOTE 22.

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 (APB) Opinion No. 25, *"Accounting for Stock Issued to Employees,"* (APB 25) and related interpretations and disclosure requirements established by FAS 123, *"Accounting for Stock-Based Compensation."*

The company adopted FAS 123R using the modified prospective method and, accordingly, results for prior periods have not been restated. Refer to Note 1, beginning on page 58, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition of FAS 123 for periods prior to adoption of FAS 123R and the actual effect on net income and earnings per share for periods after adoption of FAS 123R.

For 2005, compensation expense charged against income for the first time for stock options was $65 ($42 after tax). In addition, compensation expense charged against income for stock appreciation rights, performance units and restricted stock units was $59 ($39 after tax), $65 ($42 after tax) and $25 ($16 after tax) for 2005, 2004 and 2003, respectively. There were no significant capitalized stock-based compensation costs at December 31, 2005.

Cash received from option exercises under all share-based payment arrangements for 2005, 2004 and 2003 was $297, $385 and $32, respectively. Actual tax benefits realized for the tax deductions from option exercises was $71, $49 and $6 for 2005, 2004 and 2003, respectively.

Cash paid to settle performance units and stock appreciation rights was $110, $23 and $11 for 2005, 2004 and 2003, respectively. Cash paid in 2005 included $73 million for Unocal awards paid under change-in-control plan provisions.

At adoption of FAS 123R, the impact of measuring stock appreciation rights at fair value instead of intrinsic value resulted in an insignificant charge against income in the third quarter 2005. For restricted stock units, FAS 123R required that unrecognized compensation amounts presented in "Deferred compensation and benefit plan trust" on the Consolidated Balance Sheet be reclassified against the appropriate equity accounts. This resulted in a reclassification of $7 to "Capital in excess of par value."

Prior to the adoption of FAS 123R, the company presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in the Consolidated Statement of Cash Flows. FAS 123R requires the cash flow resulting from the tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. Refer to Note 3, beginning on page 61, for information on excess tax benefits.

In November 2005, the FASB issued a Staff Position FAS 123R-3 (FSP FAS 123R-3), *"Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards,"* which provides a one-time transition election for companies to follow in calculating the beginning balance of the pool of excess tax benefits related to employee compensation and a simplified method to determine the subsequent impact on the pool of employee awards that are fully vested and outstanding upon the adoption of FAS 123R. Under the FSP, the company must decide by November 2006 whether to make this one-time transition election, which may provide some administrative relief in calculating the future tax effects of stock option issuances. Whether or not the one-time election is made, the company anticipates no significant difference in the amount of tax expense recorded in future periods.

In the discussion below, the references to share price and number of shares have been adjusted for the two-for-one stock split in September 2004.

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 non-stock grants. For a 10-year period after April 2004, 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 granted by Chevron vested one year after the date of grant. Performance units granted under the LTIP extend for 3 years from grant date and are settled in cash at the end of the 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 retained a provision for being restored, which 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. Apart from the restored options, no further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) On the closing of the acquisition of Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options at a conversion ratio of 1.07 Chevron shares for each Unocal share. These awards retained the same provisions as the original Unocal Plans. Awards issued prior to 2004 generally may be exercised for up to 3 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 remain exercisable until the end of the normal option term if termination of employment occurs 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.

NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION – Continued

The fair market values of stock options and stock appreciation rights granted in 2005, 2004 and 2003 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2005	2004	2003
Chevron LTIP:			
Expected term in years[1]	**6.4**	7.0	7.0
Volatility[2]	**24.5%**	16.5%	19.3%
Risk-free interest rate based on zero coupon U.S. treasury note	**3.8%**	4.4%	3.1%
Dividend yield	**3.4%**	3.7%	3.5%
Weighted-average fair value per option granted	**$ 11.66**	$ 7.14	$ 5.51
Texaco SIP:			
Expected term in years[1]	**2.1**	2.0	2.0
Volatility[2]	**18.6%**	17.8%	22.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**3.8%**	2.5%	1.7%
Dividend yield	**3.4%**	3.8%	3.9%
Weighted-average fair value per option granted	**$ 6.09**	$ 4.00	$ 4.03
Unocal Plans:[3]			
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] Represents options converted at the acquisition date.

A summary of option activity under the LTIP as well as former Texaco and Unocal plans is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2005	54,440	$ 42.89		
Granted	8,718	$ 56.76		
Granted in Unocal acquisition	5,313	$ 35.02		
Exercised*	(13,946)	$ 44.19		
Restored	5,596	$ 58.41		
Forfeited*	(597)	$ 49.19		
Outstanding at December 31, 2005	59,524	$ 45.32	6.1 yrs.	$ 694
Exercisable at December 31, 2005	40,033	$ 42.18	5.2 yrs.	$ 586

*Includes fully vested Chevron options exchanged for outstanding Unocal options.

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2005, 2004 and 2003 was $258, $129 and $17, respectively.

At 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 vesting provisions of the company's share-based compensation programs for awards issued after adoption of FAS 123R. As of December 31, 2005, there was $89 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 2.3 years.

At January 1, 2005, the number of LTIP performance units outstanding was equivalent to 2,673,482 shares. During 2005, 709,900 units were granted, 1,012,932 units vested with cash proceeds distributed to recipients, and 24,434 units were forfeited. At December 31, 2005, units outstanding were 2,346,016, and the value of the liability recorded for these instruments was $83. In addition, outstanding stock appreciation rights that were awarded under various LTIP and former Texaco and Unocal programs totaled approximately 800,000 equivalent shares as of December 31, 2005. A liability of $16 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 after two years, in February 2000, and expire after 10 years, in February 2008. A total of 9,641,000 options were awarded with an exercise price of $38.15625 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 7 years and a volatility of 24.7 percent.

At January 1, 2005, the number of broad-based employee stock options outstanding was 2,109,504. During 2005, exercises of 397,500 shares and forfeitures of 29,100 shares reduced outstanding options to 1,682,904. As of December 31, 2005, these instruments had an aggregate intrinsic value of $31 and the remaining contractual term of these options was 2.1 years. The total intrinsic value of these options exercised during 2005 and 2004 was $9 and $16, respectively. Exercises in 2003 were insignificant.

NOTE 23.

OTHER CONTINGENCIES AND COMMITMENTS

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally 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. The U.S. federal income tax liabilities have been settled through 1996 for Chevron (formerly ChevronTexaco Corporation) and 1997 for Chevron Global

Energy Inc. (formerly Caltex Corporation), Unocal Corporation (Unocal) and Texaco Inc. (Texaco). California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal and through 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company, and in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees At December 31, 2005, the company and its subsidiaries provided, either directly or indirectly, guarantees of $985 for notes and other contractual obligations of affiliated companies and $294 for third parties, as described by major category below. There are no material amounts being carried as liabilities for the company's obligations under these guarantees.

Of the $985 guarantees provided to affiliates, $806 related to borrowings for capital projects or general corporate purposes. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are Unocal-related guarantees of approximately $230 associated with a construction completion guarantee for the debt financing of Unocal's equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Approximately 95 percent of the $806 guaranteed will expire between 2006 and 2010, with the remaining guarantees expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed. There are no recourse provisions, and no assets are held as collateral for these guarantees. The other guarantees of $179 represent obligations in connection with pricing of power-purchase agreements for certain of the company's cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliates do not perform under the agreements. There are no provisions for recourse to third parties, and no assets are held as collateral for these pricing guarantees.

Of the $294 in guarantees provided to third parties, approximately $150 related to construction loans to host governments of certain of the company's international upstream operations. The remaining guarantees of $144 were provided principally as conditions of sale of the company's interest in certain operations, to provide a source of liquidity to the guaranteed parties and in connection with company marketing programs. No amounts of the company's obligations under these guarantees are recorded as liabilities. About 85 percent of the $294 in guarantees expire by 2010, with the remainder expiring after 2010. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed. Approximately $85 of the guarantees have recourse provisions, which enable the company to recover any payments made under the terms of the guarantees from securities held over the guaranteed parties' assets.

At December 31, 2005, Chevron also had outstanding guarantees for about $190 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell Oil Company (Shell) for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2006 through 2010 period, with the guarantees of the remaining amounts expiring by 2019.

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 2005, the company paid approximately $38 under these indemnities. The company expects to receive additional requests for 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 periods 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 relating to Equilon indemnities must be asserted either as early as February 2007, or no later than February 2009, and claims relating to Motiva must be asserted no later than February 2012. Under the terms of the 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 of Unocal's 76 Products Company business that existed prior to its sale in 1997. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments by the company; however, the purchaser shares certain costs under this indemnity up to an aggregate cap of $200. Claims relating to these indemnities must be asserted by April 2022. Through the end of 2005,

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS – Continued

approximately $113 had been applied to the cap, which includes payments made by either Unocal or Chevron totaling $80.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying Special Purpose Entities (SPEs). At December 31, 2005, approximately $1,200, representing about 7 percent of Chevron's total current accounts receivables balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2005, was approximately $60. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event that the SPEs experience major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Throughput Agreements, and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements, 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, 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: 2006 – $2,200; 2007 – $1,900; 2008 – $1,800; 2009 – $1,800; 2010 – $500; 2011 and after – $3,800. Total payments under the agreements were approximately $2,100 in 2005, $1,600 in 2004 and $1,400 in 2003.

The most significant take-or-pay agreement calls for the company to purchase approximately 55,000 barrels per day of refined products from an equity affiliate refiner in Thailand. This purchase agreement is in conjunction with the financing of a refinery owned by the affiliate and expires in 2009. The future estimated commitments under this contract are: 2006 – $1,300; 2007 – $1,300; 2008 – $1,300; and 2009 – $1,300. Under the terms of a 2004 agreement, the company exercised its option in 2005 to acquire additional regasification capacity at the Sabine Pass Liquefied Natural Gas Terminal. Payments of $2.5 billion over the 20-year period are expected to commence in 2009.

Minority Interests The company has commitments of approximately $200 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 chemical 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, and land development areas, 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, 2005, was $1,469. Included in this balance were liabilities assumed in connection with the acquisition of Unocal, which relate primarily to sites that had been previously divested or closed by Unocal. The sites included, but were not limited to, former refineries, transportation and distribution facilities and service stations, crude oil and natural gas fields and mining operations, as well as active mining operations.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state and local regulations. No single remediation site at year-end 2005 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

Included in the year-end 2005 balance was $139 related to sites for which Chevron had been identified by the U.S. Environmental Protection Agency or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws as a "potentially responsible party" or otherwise involved in the remediation.

Of the remaining year-end 2005 environmental reserves balance of $1,330, $855 related to approximately 2,250 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 $475 was associated with various sites in the international downstream ($101), upstream ($257), chemicals ($50) and other ($67). 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.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Areas in which the company and its affiliates have significant operations include the United States, Canada, Australia, the United Kingdom, Norway, Denmark, France, the Netherlands, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of the Congo, Angola, Nigeria, Chad, South Africa, the Democratic Republic of the Congo, Indonesia, Bangladesh, the Philippines, Myanmar, Singapore, China, Thailand, Vietnam, Cambodia, Azerbaijan, Kazakhstan, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago, and South Korea. The company's Caspian Pipeline Consortium (CPC) affiliate operates in Russia and Kazakhstan. The company's Tengizchevroil (TCO) affiliate operates in Kazakhstan. Through an affiliate, the company participates in the development of the Baku-Tbilisi-Ceyhan (BTC) pipeline through Azerbaijan, Georgia and Turkey. Also through an affiliate, the company has an interest in the Chad/Cameroon pipeline. The company's Petrolera Ameriven affiliate operates the Hamaca project in Venezuela. The company's CPChem affiliate manufactures and markets a wide range of petrochemicals on a worldwide basis, with manufacturing facilities in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially or wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest, acts of violence or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have at times significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

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. Chevron estimates its maximum possible net before-tax liability at approximately $200. At the same time, a possible maximum net amount that could be owed to Chevron is estimated at about $50. 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, host 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 24.

ASSET RETIREMENT OBLIGATIONS

The company adopted Financial Accounting Standards Board Statement (FASB) No. 143, *"Accounting for Asset Retirement Obligations,"* (FAS 143), effective January 1, 2003. This accounting standard applies to the fair value of a liability for an asset retirement obligation (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. FAS 143 primarily affects the company's accounting for crude oil and natural gas producing assets and differs in several respects from previous accounting under FAS 19, *"Financial Accounting and Reporting by Oil and Gas Producing Companies."*

In the first quarter 2003, the company recorded a net after-tax charge of $200 for the cumulative effect of the adoption of FAS 143, including the company's share of amounts attributable to equity affiliates. The cumulative-effect adjustment also increased the following balance sheet categories: "Properties, plant and equipment," $2,568; "Accrued liabilities," $115; and "Deferred credits and other noncurrent

NOTE 24. ASSET RETIREMENT OBLIGATIONS – Continued

obligations," $2,674. "Noncurrent deferred income taxes" decreased by $21.

Upon adoption, no significant asset retirement obligations associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets generally were recognized, as indeterminate settlement dates for the asset retirements prevented 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.

Other than the cumulative-effect net charge, the effect of the new accounting standard on net income in 2003 was not materially different from what the result would have been under FAS 19 accounting. Included in "Depreciation, depletion and amortization" were $52 related to the depreciation of the ARO asset and $132 related to the accretion of the ARO liability.

In March 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 an 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 asset retirement obligation 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 asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. In adopting FIN 47, the company did not recognize any additional liabilities for conditional retirement obligations due to an inability to reasonably estimate the fair value of those obligations because of their indeterminate settlement dates.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2005, 2004 and 2003:

	2005	2004	2003
Balance at January 1	**$ 2,878**	$ 2,856	$ 2,797*
Liabilities assumed in the Unocal acquisition	**1,216**	–	–
Liabilities incurred	**90**	37	14
Liabilities settled	**(172)**	(426)	(128)
Accretion expense	**187**	93	132
Revisions in estimated cash flows	**105**	318	41
Balance at December 31	**$ 4,304**	$ 2,878	$ 2,856

*Includes the cumulative effect of the accounting change.

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 (see Note 22, "Stock Options and Other Share-Based Compensation" beginning on page 78). The following table sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2005	2004	2003
BASIC EPS CALCULATION			
Income from continuing operations	**$ 14,099**	$ 13,034	$ 7,382
Add: Dividend equivalents paid on stock units	**2**	3	2
Add: Affiliated stock transaction recorded to retained earnings[1]	**–**	–	170
Income from continuing operations available to common stockholders	**$ 14,101**	$ 13,037	$ 7,554
Income from discontinued operations	**–**	294	44
Cumulative effect of changes in accounting principle[2]	**–**	–	(196)
Net income available to common stockholders – Basic	**$ 14,101**	$ 13,331	$ 7,402
Weighted-average number of common shares outstanding[3]	**2,143**	2,114	2,123
Add: Deferred awards held as stock units	**1**	2	2
Total weighted-average number of common shares outstanding	**2,144**	2,116	2,125
Per-Share of Common Stock			
Income from continuing operations available to common stockholders	**$ 6.58**	$ 6.16	$ 3.55
Income from discontinued operations	**–**	0.14	0.02
Cumulative effect of changes in accounting principle	**–**	–	(0.09)
Net income – Basic	**$ 6.58**	$ 6.30	$ 3.48
DILUTED EPS CALCULATION			
Income from continuing operations	**$ 14,099**	$ 13,034	$ 7,382
Add: Dividend equivalents paid on stock units	**2**	3	2
Add: Affiliated stock transaction recorded to retained earnings[1]	**–**	–	170
Add: Dilutive effects of employee stock-based awards	**2**	1	2
Income from continuing operations available to common stockholders	**$ 14,103**	$ 13,038	$ 7,556
Income from discontinued operations	**–**	294	44
Cumulative effect of changes in accounting principle[2]	**–**	–	(196)
Net income available to common stockholders – Diluted	**$ 14,103**	$ 13,332	$ 7,404
Weighted-average number of common shares outstanding[3]	**2,143**	2,114	2,123
Add: Deferred awards held as stock units	**1**	2	2
Add: Dilutive effect of employee stock-based awards	**11**	6	2
Total weighted-average number of common shares outstanding	**2,155**	2,122	2,127
Per-Share of Common Stock			
Income from continuing operations available to common stockholders	**$ 6.54**	$ 6.14	$ 3.55
Income from discontinued operations	**–**	0.14	0.02
Cumulative effect of changes in accounting principle	**–**	–	(0.09)
Net income – Diluted	**$ 6.54**	$ 6.28	$ 3.48

[1] 2003 amount is 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.
[2] Includes a net loss of $200 for the adoption of FAS 143 and a net gain of $4 for the company's share of Dynegy's cumulative effect of adoption of EITF 02-3.
[3] Share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

NOTE 26.

COMMON STOCK SPLIT

On July 28, 2004, the company's Board of Directors approved a two-for-one stock split in the form of a stock dividend to the company's stockholders of record on August 19, 2004, with distribution of shares on September 10, 2004. The total number of authorized common stock shares and associated par value were unchanged by this action. All per-share amounts in the financial statements reflect the stock split for all periods presented. The effect of the common stock split is reflected on the Consolidated Balance Sheet in "Common stock" and "Capital in excess of par value."

NOTE 27.

OTHER FINANCIAL INFORMATION

Net income in 2004 included gains of approximately $1.2 billion relating to the sale of nonstrategic upstream properties.

Other financial information is as follows:

	Year ended December 31		
	2005	2004	2003
Total financing interest and debt costs	**$ 542**	$ 450	$ 549
Less: Capitalized interest	**60**	44	75
Interest and debt expense	**$ 482**	$ 406	$ 474
Research and development expenses	**$ 316**	$ 242	$ 228
Foreign currency effects*	**$ (61)**	$ (81)	$ (404)

*Includes $(2), $(13) and $(96) in 2005, 2004 and 2003, respectively, for the company's share of equity affiliates' foreign currency effects.

The excess of market value over the carrying value of inventories for which the LIFO method is used was $4,846, $3,036 and $2,106 at December 31, 2005, 2004 and 2003, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of $34, $36 and $82 were included in net income for the years 2005, 2004 and 2003, respectively.

FIVE-YEAR OPERATING SUMMARY[1]

Unaudited

Worldwide – Includes Equity in Affiliates

Thousands of barrels per day, except natural gas data, which is millions of cubic feet per day	**2005**	2004	2003	2002	2001
UNITED STATES					
Gross production of crude oil and natural gas liquids	**499**	555	619	665	670
Net production of crude oil and natural gas liquids	**455**	505	562	602	614
Gross production of natural gas	**1,860**	2,191	2,619	2,945	3,167
Net production of natural gas[2]	**1,634**	1,873	2,228	2,405	2,706
Net production of oil equivalents	**727**	817	933	1,003	1,065
Refinery input[3]	**846**	914	951	979	1,336
Sales of refined products[3]	**1,473**	1,506	1,436	1,600	2,500
Sales of natural gas liquids	**151**	177	194	241	185
Total sales of petroleum products	**1,624**	1,683	1,630	1,841	2,685
Sales of natural gas	**5,449**	4,518	4,304	5,891	8,191
INTERNATIONAL					
Gross production of crude oil and natural gas liquids	**1,676**	1,645	1,681	1,765	1,852
Net production of crude oil and natural gas liquids	**1,214**	1,205	1,246	1,295	1,345
Other produced volumes	**143**	140	114	97	105
Gross production of natural gas	**2,726**	2,203	2,203	2,120	1,949
Net production of natural gas[2]	**2,599**	2,085	2,064	1,971	1,711
Net production of oil equivalents	**1,790**	1,692	1,704	1,720	1,735
Refinery input	**1,038**	1,044	1,040	1,100	1,136
Sales of refined products	**2,295**	2,402	2,302	2,175	2,454
Sales of natural gas liquids	**108**	105	107	131	115
Total sales of petroleum products	**2,403**	2,507	2,409	2,306	2,569
Sales of natural gas	**2,289**	1,885	1,951	3,131	2,675
TOTAL WORLDWIDE					
Gross production of crude oil and natural gas liquids	**2,175**	2,200	2,300	2,430	2,522
Net production of crude oil and natural gas liquids	**1,669**	1,710	1,808	1,897	1,959
Other produced volumes	**143**	140	114	97	105
Gross production of natural gas	**4,586**	4,394	4,822	5,065	5,116
Net production of natural gas[2]	**4,233**	3,958	4,292	4,376	4,417
Net production of oil equivalents	**2,517**	2,509	2,637	2,723	2,800
Refinery input[3]	**1,884**	1,958	1,991	2,079	2,472
Sales of refined products[3]	**3,768**	3,908	3,738	3,775	4,954
Sales of natural gas liquids	**259**	282	301	372	300
Total sales of petroleum products	**4,027**	4,190	4,039	4,147	5,254
Sales of natural gas	**7,738**	6,403	6,255	9,022	10,866
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net)[4]					
Oil and gas	**1,396**	1,307	1,472	1,349	1,698
Dry	**26**	24	36	49	75
Productive oil and gas wells (net)[4]	**52,733**	44,707	48,155	50,320	47,388

[1] Gross production represents the company's share of total production before deducting lessors' royalties. Net production is gross production minus royalties paid to lessors.

[2] Includes natural gas consumed on lease:

United States	**48**	50	65	64	64
International	**332**	293	268	256	262
Total	**380**	343	333	320	326

[3] 2001 includes sales volumes and refinery inputs of units sold as a condition of the Texaco merger.

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

FIVE-YEAR FINANCIAL SUMMARY
Unaudited

Millions of dollars, except per-share amounts	**2005**	2004	2003	2002	2001
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	**$ 193,641**	$ 150,865	$ 119,575	$ 98,340	$ 103,951
Income from equity affiliates and other income	**4,559**	4,435	1,702	197	1,751
TOTAL REVENUES AND OTHER INCOME	**198,200**	155,300	121,277	98,537	105,702
TOTAL COSTS AND OTHER DEDUCTIONS	**173,003**	134,749	108,601	94,437	97,517
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**25,197**	20,551	12,676	4,100	8,185
INCOME TAX EXPENSE	**11,098**	7,517	5,294	2,998	4,310
INCOME FROM CONTINUING OPERATIONS	**14,099**	13,034	7,382	1,102	3,875
INCOME FROM DISCONTINUED OPERATIONS	**–**	294	44	30	56
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**14,099**	13,328	7,426	1,132	3,931
Extraordinary loss, net of tax	**–**	–	–	–	(643)
Cumulative effect of changes in accounting principles	**–**	–	(196)	–	–
NET INCOME	**$ 14,099**	$ 13,328	$ 7,230	$ 1,132	$ 3,288
PER SHARE OF COMMON STOCK[1]					
INCOME FROM CONTINUING OPERATIONS[2]					
– Basic	**$ 6.58**	$ 6.16	$ 3.55	$ 0.52	$ 1.82
– Diluted	**$ 6.54**	$ 6.14	$ 3.55	$ 0.52	$ 1.82
INCOME FROM DISCONTINUED OPERATIONS					
– Basic	**$ –**	$ 0.14	$ 0.02	$ 0.01	$ 0.03
– Diluted	**$ –**	$ 0.14	$ 0.02	$ 0.01	$ 0.03
EXTRAORDINARY ITEM					
– Basic	**$ –**	$ –	$ –	$ –	$ (0.30)
– Diluted	**$ –**	$ –	$ –	$ –	$ (0.30)
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES					
– Basic	**$ –**	$ –	$ (0.09)	$ –	$ –
– Diluted	**$ –**	$ –	$ (0.09)	$ –	$ –
NET INCOME[2]					
– Basic	**$ 6.58**	$ 6.30	$ 3.48	$ 0.53	$ 1.55
– Diluted	**$ 6.54**	$ 6.28	$ 3.48	$ 0.53	$ 1.55
CASH DIVIDENDS PER SHARE	**$ 1.75**	$ 1.53	$ 1.43	$ 1.40	$ 1.33
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	**$ 34,336**	$ 28,503	$ 19,426	$ 17,776	$ 18,327
Noncurrent assets	**91,497**	64,705	62,044	59,583	59,245
TOTAL ASSETS	**125,833**	93,208	81,470	77,359	77,572
Short-term debt	**739**	816	1,703	5,358	8,429
Other current liabilities	**24,272**	17,979	14,408	14,518	12,225
Long-term debt and capital lease obligations	**12,131**	10,456	10,894	10,911	8,989
Other noncurrent liabilities	**26,015**	18,727	18,170	14,968	13,971
TOTAL LIABILITIES	**63,157**	47,978	45,175	45,755	43,614
STOCKHOLDERS' EQUITY	**$ 62,676**	$ 45,230	$ 36,295	$ 31,604	$ 33,958

[1] Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.
[2] The amount in 2003 includes a benefit of $0.08 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

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 the Democratic Republic of the Congo. The Asia-Pacific geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the

TABLE I – COSTS INCURRED IN EXPLORATION, PROPERTY ACQUISITIONS AND DEVELOPMENT[1]

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
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												
Proved – Unocal[2,3]	**–**	**1,608**	**2,388**	**3,996**	**30**	**6,609**	**637**	**1,790**	**9,066**	**13,062**	**–**	**–**
Proved – Other[2]	**–**	**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[4]	**494**	**639**	**596**	**1,729**	**1,871**	**1,026**	**325**	**713**	**3,935**	**5,664**	**767**	**43**
ARO asset	**13**	**41**	**5**	**59**	**21**	**62**	**57**	**13**	**153**	**212**	**–**	**–**
TOTAL COSTS INCURRED	**$ 507**	**$ 3,742**	**$ 3,332**	**$ 7,581**	**$ 2,227**	**$ 10,032**	**$ 1,871**	**$ 2,935**	**$ 17,065**	**$ 24,646**	**$ 767**	**$ 43**
YEAR ENDED DEC. 31, 2004												
Exploration												
Wells	$ –	$ 388	$ –	$ 388	$ 116	$ 25	$ 2	$ 127	$ 270	$ 658	$ –	$ –
Geological and geophysical	–	47	2	49	103	10	12	46	171	220	–	–
Rentals and other	–	43	3	46	52	47	1	53	153	199	–	–
Total exploration	–	478	5	483	271	82	15	226	594	1,077	–	–
Property acquisitions												
Proved[2]	–	6	1	7	111	16	–	4	131	138	–	–
Unproved	–	29	–	29	82	–	–	5	87	116	–	–
Total property acquisitions	–	35	1	36	193	16	–	9	218	254	–	–
Development[4]	412	457	372	1,241	1,047	567	245	542	2,401	3,642	896	208
ARO asset	1	9	3	13	10	53	158	85	306	319	–	–
TOTAL COSTS INCURRED	$ 413	$ 979	$ 381	$ 1,773	$ 1,521	$ 718	$ 418	$ 862	$ 3,519	$ 5,292	$ 896	$ 208
YEAR ENDED DEC. 31, 2003												
Exploration												
Wells	$ –	$ 415	$ 9	$ 424	$ 116	$ 43	$ 2	$ 72	$ 233	$ 657	$ –	$ –
Geological and geophysical	–	16	23	39	75	9	5	30	119	158	–	–
Rentals and other	–	64	(20)	44	12	58	–	46	116	160	–	–
Total exploration	–	495	12	507	203	110	7	148	468	975	–	–
Property acquisitions												
Proved[2]	–	15	3	18	–	20	–	7	27	45	–	–
Unproved	–	30	3	33	51	6	–	14	71	104	–	–
Total property acquisitions	–	45	6	51	51	26	–	21	98	149	–	–
Development	264	434	350	1,048	974	605	363	461	2,403	3,451	551	199
TOTAL COSTS INCURRED	$ 264	$ 974	$ 368	$ 1,606	$ 1,228	$ 741	$ 370	$ 630	$ 2,969	$ 4,575	$ 551	$ 199

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 24, "Asset Retirement Obligations," beginning on page 83.
[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.
[3] Included in proved property acquisitions for Unocal are $845 of ARO assets, composed of: Gulf of Mexico $115; Other U.S. $271; Africa $9; Asia-Pacific $366; Indonesia $25; Other International $59.
[4] Includes $160 and $63 costs incurred prior to assignment of proved reserves in 2005 and 2004, respectively.

Partitioned Neutral Zone between Kuwait and Saudi Arabia, Papua New Guinea (sold in 2003), the Philippines, and Thailand. The international "Other" geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, Germany, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and other countries. Amounts shown for affiliated companies are Chevron's 50 percent equity share of TCO, an exploration and production partnership operating in the Republic of Kazakhstan, and a 30 percent equity share of Hamaca, an exploration and production partnership operating in Venezuela.

Amounts in the tables exclude the cumulative effect adjustment for the adoption of FAS 143, *"Asset Retirement Obligations,"* discussed in Note 24, beginning on page 83.

TABLE II – CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES[1]

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
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	**9,530**	**17,871**	**11,103**	**38,504**	**8,169**	**14,308**	**4,441**	**9,259**	**36,177**	**74,681**	**2,259**	**1,212**
Support equipment	**204**	**193**	**230**	**627**	**715**	**426**	**3,124**	**356**	**4,621**	**5,248**	**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**	**–**
ARO asset[2]	**16**	**412**	**364**	**792**	**235**	**620**	**265**	**368**	**1,488**	**2,280**	**5**	**1**
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	**6,813**	**13,866**	**5,943**	**26,622**	**4,132**	**3,915**	**2,895**	**5,533**	**16,475**	**43,097**	**455**	**90**
Support equipment depreciation	**140**	**119**	**149**	**408**	**317**	**88**	**1,824**	**222**	**2,451**	**2,859**	**213**	**–**
ARO asset depreciation[2]	**5**	**201**	**106**	**312**	**134**	**101**	**66**	**187**	**488**	**800**	**5**	**–**
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**
AT DEC. 31, 2004												
Unproved properties	$ 769	$ 380	$ 109	$ 1,258	$ 322	$ 211	$ –	$ 970	$ 1,503	$ 2,761	$ 108	$ –
Proved properties and related producing assets	9,170	16,610	8,660	34,440	7,188	7,485	3,643	8,961	27,277	61,717	2,163	963
Support equipment	211	175	208	594	513	127	3,030	361	4,031	4,625	496	–
Deferred exploratory wells	–	225	–	225	213	81	–	152	446	671	–	–
Other uncompleted projects	91	400	169	660	2,050	605	351	391	3,397	4,057	1,749	149
ARO asset[2]	28	204	70	302	206	113	181	292	792	1,094	20	–
GROSS CAP. COSTS	10,269	17,994	9,216	37,479	10,492	8,622	7,205	11,127	37,446	74,925	4,536	1,112
Unproved properties valuation	734	111	27	872	118	67	–	294	479	1,351	15	–
Proved producing properties – Depreciation and depletion	6,694	13,562	5,617	25,873	3,753	3,122	2,396	4,933	14,204	40,077	423	43
Support equipment depreciation	148	107	139	394	268	60	1,802	206	2,336	2,730	190	–
ARO asset depreciation[2]	24	174	64	262	128	49	36	148	361	623	5	–
Accumulated provisions	7,600	13,954	5,847	27,401	4,267	3,298	4,234	5,581	17,380	44,781	633	43
NET CAPITALIZED COSTS	$ 2,669	$ 4,040	$ 3,369	$ 10,078	$ 6,225	$ 5,324	$ 2,971	$ 5,546	$ 20,066	$ 30,144	$ 3,903	$ 1,069

[1] Includes assets held for sale.
[2] See Note 24, "Asset Retirement Obligations," beginning on page 83.

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
AT DEC. 31, 2003[2]												
Unproved properties	$ 769	$ 416	$ 131	$ 1,316	$ 290	$ 214	$ –	$ 1,048	$ 1,552	$ 2,868	$ 108	$ –
Proved properties and related producing assets	8,785	18,069	10,749	37,603	6,474	6,288	3,097	10,469	26,328	63,931	2,091	356
Support equipment	200	200	277	677	519	100	3,016	374	4,009	4,686	425	–
Deferred exploratory wells	–	126	1	127	233	67	2	120	422	549	–	–
Other uncompleted projects	76	280	152	508	1,894	1,502	715	334	4,445	4,953	1,011	661
ARO asset[3]	25	227	83	335	207	60	23	236	526	861	20	1
GROSS CAP. COSTS	9,855	19,318	11,393	40,566	9,617	8,231	6,853	12,581	37,282	77,848	3,655	1,018
Unproved properties valuation	731	138	43	912	101	59	1	310	471	1,383	12	–
Proved producing properties – Depreciation and depletion	6,473	14,450	6,894	27,817	3,656	2,793	2,022	6,015	14,486	42,303	354	24
Future equipment depreciation	141	133	180	454	237	68	1,784	200	2,289	2,743	160	–
ARO asset depreciation[3]	23	186	79	288	133	36	19	148	336	624	4	–
Accumulated provisions	7,368	14,907	7,196	29,471	4,127	2,956	3,826	6,673	17,582	47,053	530	24
NET CAPITALIZED COSTS	$ 2,487	$ 4,411	$ 4,197	$ 11,095	$ 5,490	$ 5,275	$ 3,027	$ 5,908	$ 19,700	$ 30,795	$ 3,125	$ 994

[1] Includes assets held for sale.
[2] 2003 reclassified to conform to 2005 presentation.
[3] See Note 24, "Asset Retirement Obligations," beginning on page 83.

TABLE III – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES[1]

The company's results of operations from oil and gas producing activities for the years 2005, 2004 and 2003 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.

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
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**
YEAR ENDED DEC. 31, 2004												
Revenues from net production												
Sales	$ 251	$ 1,925	$ 2,163	$ 4,339	$ 1,321	$ 1,191	$ 256	$ 2,481	$ 5,249	$ 9,588	$ 1,619	$ 205
Transfers	2,651	1,768	1,224	5,643	2,645	2,265	1,613	1,903	8,426	14,069	–	–
Total	2,902	3,693	3,387	9,982	3,966	3,456	1,869	4,384	13,675	23,657	1,619	205
Production expenses excluding taxes	(710)	(547)	(697)	(1,954)	(574)	(431)	(591)	(544)	(2,140)	(4,094)	(143)	(53)
Taxes other than on income	(57)	(45)	(321)	(423)	(24)	(138)	(1)	(134)	(297)	(720)	(26)	–
Proved producing properties: Depreciation and depletion	(232)	(774)	(384)	(1,390)	(367)	(401)	(393)	(798)	(1,959)	(3,349)	(104)	(4)
Accretion expense[2]	(12)	(25)	(19)	(56)	(22)	(8)	(13)	11	(32)	(88)	(2)	–
Exploration expenses	–	(227)	(6)	(233)	(235)	(69)	(17)	(144)	(465)	(698)	–	–
Unproved properties valuation	(3)	(29)	(4)	(36)	(23)	(8)	–	(25)	(56)	(92)	–	–
Other income (expense)[3]	14	24	474	512	49	10	12	1,028	1,099	1,611	(7)	(58)
Results before income taxes	1,902	2,070	2,430	6,402	2,770	2,411	866	3,778	9,825	16,227	1,337	90
Income tax expense	(703)	(765)	(898)	(2,366)	(2,036)	(1,395)	(371)	(1,759)	(5,561)	(7,927)	(401)	–
RESULTS OF PRODUCING OPERATIONS	$ 1,199	$ 1,305	$ 1,532	$ 4,036	$ 734	$ 1,016	$ 495	$ 2,019	$ 4,264	$ 8,300	$ 936	$ 90

[1] The value of owned production consumed on lease 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 24, "Asset Retirement Obligations," beginning on page 83.
[3] Includes net sulfur income, foreign currency transaction gains and losses, certain significant impairment write-downs in 2004 and 2003, miscellaneous expenses, etc. Also includes net income from related oil and gas activities that do not have oil and gas reserves attributed to them (for example, net income from technical and operating service agreements) and items identified in the Management's Discussion and Analysis on pages 31 through 35. Does not include results for LNG-related activities.

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
YEAR ENDED DEC. 31, 2003[2]												
Revenues from net production												
Sales	$ 261	$ 2,197	$ 2,049	$ 4,507	$ 1,339	$ 1,442	$ 55	$ 2,556	$ 5,392	$ 9,899	$ 1,116	$ 104
Transfers	2,085	1,740	1,096	4,921	1,835	1,738	1,566	1,356	6,495	11,416	–	–
Total	2,346	3,937	3,145	9,428	3,174	3,180	1,621	3,912	11,887	21,315	1,116	104
Production expenses excluding taxes	(631)	(578)	(750)	(1,959)	(505)	(331)	(616)	(669)	(2,121)	(4,080)	(117)	(20)
Taxes other than on income	(28)	(48)	(280)	(356)	(22)	(126)	(1)	(100)	(249)	(605)	(29)	–
Proved producing properties:												
Depreciation and depletion	(224)	(878)	(430)	(1,532)	(327)	(398)	(314)	(846)	(1,885)	(3,417)	(97)	(4)
Accretion expense[3]	(12)	(37)	(20)	(69)	(20)	(5)	(8)	(26)	(59)	(128)	(2)	–
Exploration expenses	(2)	(168)	(23)	(193)	(123)	(130)	(8)	(117)	(378)	(571)	–	–
Unproved properties valuation	–	(16)	(4)	(20)	(20)	(9)	–	(41)	(70)	(90)	–	–
Other (expense) income[4]	(18)	(104)	(51)	(173)	(173)	(342)	2	(175)	(688)	(861)	(4)	(35)
Results before income taxes	1,431	2,108	1,587	5,126	1,984	1,839	676	1,938	6,437	11,563	867	45
Income tax expense	(528)	(777)	(585)	(1,890)	(1,410)	(1,158)	(289)	(831)	(3,688)	(5,578)	(260)	–
RESULTS OF PRODUCING OPERATIONS	$ 903	$ 1,331	$ 1,002	$ 3,236	$ 574	$ 681	$ 387	$ 1,107	$ 2,749	$ 5,985	$ 607	$ 45

[1] The value of owned production consumed on lease 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] 2003 includes certain reclassifications to conform to 2005 presentation.
[3] Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," beginning on page 83.
[4] Includes net sulfur income, foreign currency transaction gains and losses, certain significant impairment write-downs, miscellaneous expenses, etc. Also includes net income from related oil and gas activities that do not have oil and gas reserves attributed to them (for example, net income from technical and operating service agreements) and items identified in the Management's Discussion and Analysis on pages 31 through 35.

TABLE IV – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES – UNIT PRICES AND COSTS[1,2]

	Consolidated Companies										Affiliated Companies	
	United States				International							
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
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**
YEAR ENDED DEC. 31, 2004												
Average sales prices												
Liquids, per barrel	$ 33.43	$ 34.69	$ 34.61	$ 34.12	$ 34.85	$ 31.34	$ 31.12	$ 34.58	$ 33.33	$ 33.60	$ 30.23	$ 23.32
Natural gas, per thousand cubic feet	5.18	6.08	5.07	5.51	0.04	3.41	3.88	2.68	2.90	4.27	0.65	0.27
Average production costs, per barrel	8.14	5.26	6.65	6.60	4.89	3.50	9.69	3.47	4.67	5.43	2.31	6.10
YEAR ENDED DEC. 31, 2003												
Average sales prices												
Liquids, per barrel	$ 25.77	$ 27.89	$ 26.48	$ 26.66	$ 28.54	$ 24.66	$ 25.10	$ 27.56	$ 26.70	$ 26.69	$ 22.07	$ 17.06
Natural gas, per thousand cubic feet	5.04	5.56	4.51	5.01	0.04	3.64	2.26	2.58	2.87	4.08	0.68	0.33
Average production costs, per barrel[3]	7.01	4.47	6.40	5.82	4.42	2.49	9.30	3.99	4.41	4.99	2.04	3.24

[1] The value of owned production consumed on lease as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.
[3] Conformed to 2005 presentation to exclude taxes.

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 underground 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.

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, 2005, oil-equivalent reserves for the company's consolidated operations totaled 9.0 billion barrels. (Refer to page 24 for the definition of oil-equivalent reserves.) Nearly 22 percent of the total was in the United States. Year-end reserves of approximately 1.4 billion barrels were associated with the properties obtained as part of the August 2005 acquisition of Unocal. For the company's interests in equity affiliates, oil-equivalent reserves totaled 2.9 billion barrels, 84 percent of which was 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 individual properties each contained between 1 percent and 5 percent of the total. In the aggregate, these properties accounted for 35 percent of the company's total proved oil-equivalent reserves. These other properties were geographically dispersed, located in the United States, South America, Europe, West Africa, the Middle East and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2005 were 2.6 billion barrels. Of this amount, 39 percent, 21 percent and 40 percent were located in California, the Gulf of Mexico and other U.S. areas, respectively.

In California, liquids reserves represented 95 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 63 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 CO_2 injection.

The pattern of net reserve changes shown in the following tables for the three years ending December 31, 2005, is not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, matters that are outside the company's control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties and civil unrest.

The company's estimated net proved underground oil and natural gas reserves and changes thereto for the years 2003, 2004 and 2005 are shown in the tables on pages 96 and 98.

TABLE V – RESERVE QUANTITY INFORMATION – Continued

NET PROVED RESERVES OF CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS

	Consolidated Companies											
	United States				International						Affiliated Companies	
Millions of barrels	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
RESERVES AT JAN. 1, 2003	1,102	389	626	2,117	1,976	815	889	697	4,377	6,494	1,689	485
Changes attributable to:												
Revisions	(4)	(5)	–	(9)	(1)	105	(57)	19	66	57	200	–
Improved recovery	38	8	7	53	36	–	54	52	142	195	–	–
Extensions and discoveries	2	113	9	124	24	15	3	26	68	192	–	–
Purchases[1]	–	1	–	1	–	–	–	12	12	13	–	–
Sales[2]	(3)	(2)	(18)	(23)	–	(42)	–	(1)	(43)	(66)	–	–
Production	(84)	(69)	(52)	(205)	(112)	(97)	(82)	(109)	(400)	(605)	(49)	(6)
RESERVES AT DEC. 31, 2003	1,051	435	572	2,058	1,923	796	807	696	4,222	6,280	1,840	479
Changes attributable to:												
Revisions	13	(68)	(2)	(57)	(70)	(43)	(36)	(12)	(161)	(218)	206	(2)
Improved recovery	28	–	6	34	34	–	6	–	40	74	–	–
Extensions and discoveries	–	8	6	14	77	9	–	17	103	117	–	–
Purchases[1]	–	2	–	2	–	–	–	–	–	2	–	–
Sales[2]	–	(27)	(103)	(130)	(16)	–	–	(33)	(49)	(179)	–	–
Production	(81)	(56)	(47)	(184)	(115)	(86)	(79)	(101)	(381)	(565)	(52)	(9)
RESERVES AT DEC. 31, 2004	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, 2005[3]	**965**	**333**	**533**	**1,831**	**1,814**	**829**	**579**	**573**	**3,795**	**5,626**	**1,939**	**435**
DEVELOPED RESERVES[4]												
At Jan. 1, 2003	867	335	564	1,766	1,042	642	655	529	2,868	4,634	99	63
At Dec. 31, 2003	832	304	515	1,651	1,059	641	588	522	2,810	4,461	1,304	140
At Dec. 31, 2004	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**

[1] Includes reserves acquired through property exchanges.
[2] Includes reserves disposed of through property exchanges.
[3] Net reserve changes (excluding production) in 2005 consist of 490 million barrels of developed reserves and (170) million barrels of undeveloped reserves for consolidated companies and (178) million barrels of developed reserves and (154) million barrels of undeveloped reserves for affiliated companies.
[4] During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 11 percent and 20 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 146 million barrels as of December 31, 2005. 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 101.

Noteworthy amounts in the categories of proved-reserve changes for 2003 through 2005 in the table above are discussed below:

Revisions In 2003, net revisions increased reserves by 57 million barrels for consolidated companies. Whereas net U.S. reserve changes were minimal, international volumes increased 66 million barrels. The largest increase was in Kazakhstan in the Asia-Pacific area based on an updated geologic model for one field. The 200 million-barrel increase for TCO was based on an updated model of reservoir and well performance.

In 2004, net revisions decreased reserves 218 million barrels for consolidated companies and increased reserves for affiliates by 204 million barrels. For consolidated companies, the decrease was composed of 161 million barrels for international areas and 57 million barrels for the United States. The largest downward revision internationally was 70 million barrels in Africa. One field in Angola accounted for the majority of the net decline as changes were made to oil-in-place estimates based on reservoir performance data. One field in the Asia-Pacific area essentially accounted for the 43 million-barrel downward revision for that region. The revision was associated with reduced well performance. Part of the 36 million-barrel net downward revision for Indonesia was associated with the effect of higher year-end prices on the calculation of reserves for cost-oil recovery under a production-sharing contract. In the United States, the 68 million-barrel net downward revision in the Gulf of Mexico area was across several fields and based mainly on reservoir analyses and assessments of well performance. For affiliated companies, the 206 million-barrel increase for TCO was based on an updated assessment of reservoir performance for the Tengiz Field. Partially offsetting this increase was a downward effect of higher year-end prices on the variable royalty-rate calculation. Downward revisions also occurred in other geographic areas because of the effect of higher year-end prices on various production-sharing terms and variable royalty calculations.

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.

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.

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.

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.

Sales In 2004, sales of liquids volumes reduced reserves of consolidated companies by 179 million barrels. Sales totaled 130 million barrels in the United States and 33 million barrels in the "Other" international region. Sales in the "Other" region of the United States totaled 103 million barrels, with two fields accounting for approximately one-half of the volume. The 27 million barrels sold in the Gulf of Mexico reflect the sale of a number of Shelf properties. The "Other" international sales include the disposal of western Canada properties and several fields in the United Kingdom. All the sales were associated with the company's program to dispose of assets deemed nonstrategic to the portfolio of producing properties.

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

TABLE V – RESERVE QUANTITY INFORMATION – Continued

NET PROVED RESERVES OF NATURAL GAS

	Consolidated Companies										Affiliated Companies	
	United States				International							
Billions of cubic feet	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
RESERVES AT JAN. 1, 2003	325	2,052	4,040	6,417	2,298	4,646	518	2,924	10,386	16,803	2,489	43
Changes attributable to:												
Revisions	25	(106)	(525)	(606)	342	879	36	976	2,233	1,627	109	70
Improved recovery	15	7	1	23	17	–	15	35	67	90	–	–
Extensions and discoveries	–	270	118	388	3	76	12	47	138	526	–	–
Purchases[1]	–	8	–	8	–	7	–	55	62	70	–	–
Sales[2]	(1)	(12)	(51)	(64)	–	–	–	(6)	(6)	(70)	–	–
Production	(41)	(378)	(394)	(813)	(18)	(235)	(61)	(366)	(680)	(1,493)	(72)	(1)
RESERVES AT DEC. 31, 2003	323	1,841	3,189	5,353	2,642	5,373	520	3,665	12,200	17,553	2,526	112
Changes attributable to:												
Revisions	27	(391)	(316)	(680)	346	236	21	325	928	248	963	23
Improved recovery	2	–	1	3	7	–	13	–	20	23	–	–
Extensions and discoveries	1	54	89	144	16	39	2	13	70	214	–	–
Purchases[1]	–	5	–	5	–	4	–	–	4	9	–	–
Sales[2]	–	(147)	(289)	(436)	–	–	–	(111)	(111)	(547)	–	–
Production	(39)	(298)	(348)	(685)	(32)	(247)	(54)	(354)	(687)	(1,372)	(76)	(1)
RESERVES AT DEC. 31, 2004	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, 2005[3]	**304**	**1,171**	**2,953**	**4,428**	**3,191**	**8,623**	**646**	**3,578**	**16,038**	**20,466**	**2,787**	**181**
DEVELOPED RESERVES[4]												
At Jan. 1, 2003	266	1,770	3,600	5,636	582	2,934	262	2,157	5,935	11,571	1,474	6
At Dec. 31, 2003	265	1,572	2,964	4,801	954	3,627	223	3,043	7,847	12,648	1,789	52
At Dec. 31, 2004	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**

1 Includes reserves acquired through property exchanges.
2 Includes reserves disposed of through property exchanges.
3 Net reserve changes (excluding production) in 2005 consist of 5,141 billion cubic feet of developed reserves and 669 billion cubic feet of undeveloped reserves for consolidated companies and (672) billion cubic feet of developed reserves and 174 billion cubic feet of undeveloped reserves for affiliated companies.
4 During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 12 percent and 19 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of proved-reserve changes for 2003 through 2005 in the table above are discussed below:

Revisions In 2003, revisions accounted for a net increase of 1,627 billion cubic feet (BCF) for consolidated companies, as net increases of 2,233 BCF internationally were partially offset by net downward revisions of 606 BCF in the United States. Internationally, the net 879 BCF increase in the Asia-Pacific region related primarily to Australia and Kazakhstan. In Australia, the increase was associated mainly with a change to the probabilistic method of aggregating the reserves for multiple fields produced through common offshore infrastructure into a single LNG plant. The increase in Kazakhstan related to an updated geologic model for one field and higher gas sales to a third-party processing plant. The net 976 BCF increase in the "Other" international area was mainly the result of operating contract extensions for two fields in South America. In the United States, about one-third of the net 606 BCF negative revision related to two coal bed methane fields in the Mid-Continent region, based on performance data for producing wells. Downward revisions for the balance of the write-down were associated with several fields, based on assessments of well performance and other data.

In 2004, revisions increased reserves for consolidated companies by a net 248 BCF, composed of increases of 928 BCF internationally and decreases of 680 BCF in the United States. Internationally, about half of the 346 BCF increase in Africa related to properties in Nigeria, for which changes were associated with well performance reviews, development drilling and lease fuel calculations. The 236 BCF addition in the Asia-Pacific region was related primarily to reservoir analysis for a single field. Most of the 325 BCF in the "Other" international area is related to a new gas sales contract in Trinidad and Tobago. In the United States, the net 391 BCF downward revision in the Gulf of Mexico was related to well-performance reviews and technical analyses in several fields. Most of the net 316 BCF negative revision in the "Other" U.S. area related to two coal bed methane fields in the Mid-Continent region and their associated wells' performance. The 963 BCF increase for TCO was connected with updated analyses of reservoir performance and processing plant yields.

In 2005, reserves were revised downward by 14 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.

Extensions and Discoveries In 2003, extensions and discoveries accounted for an increase of 526 BCF for consolidated companies, reflecting a 388 BCF increase in the United States, with 270 BCF added in the Gulf of Mexico and 118 BCF in the "Other" region. The Gulf of Mexico increase includes discoveries in several offshore Louisiana fields, with a large number of fields in Texas, Louisiana and other states accounting for the increase in "Other."

In 2004, extensions and discoveries accounted for an increase of 214 BCF, reflecting an increase in the United States of 144 BCF, with 89 BCF added in the "Other" region and 54 BCF added in the Gulf of Mexico through drilling activities in a large number of fields.

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.

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.

Sales In 2004, sales for consolidated companies totaled 547 BCF. Of this total, 436 BCF was in the United States and 111 BCF in the "Other" international region. In the United States, "Other" region sales accounted for 289 BCF, reflecting the disposal of a large number of smaller properties, including a coal bed methane field. Gulf of Mexico sales of 147 BCF reflected the sale of Shelf properties, with four fields accounting for more than one-third of the total sales. Sales in the "Other" international region reflected the disposition of the properties in western Canada and the United Kingdom.

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

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.

	Consolidated Companies											
	United States				International						Affiliated Companies	
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Hamaca
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**
AT DECEMBER 31, 2004												
Future cash inflows from production	$ 32,793	$ 19,043	$ 28,676	$ 80,512	$ 64,628	$ 35,960	$ 25,313	$ 30,061	$ 155,962	$ 236,474	$ 61,875	$ 12,769
Future production costs	(11,245)	(3,840)	(7,343)	(22,428)	(10,662)	(8,604)	(12,830)	(7,884)	(39,980)	(62,408)	(7,322)	(3,734)
Future devel. costs	(1,731)	(2,389)	(667)	(4,787)	(6,355)	(2,531)	(717)	(1,593)	(11,196)	(15,983)	(5,366)	(407)
Future income taxes	(6,706)	(4,336)	(6,991)	(18,033)	(29,519)	(9,731)	(5,354)	(9,914)	(54,518)	(72,551)	(13,895)	(2,934)
Undiscounted future net cash flows	13,111	8,478	13,675	35,264	18,092	15,094	6,412	10,670	50,268	85,532	35,292	5,694
10 percent midyear annual discount for timing of estimated cash flows	(6,656)	(2,715)	(6,110)	(15,481)	(9,035)	(6,966)	(2,465)	(3,451)	(21,917)	(37,398)	(22,249)	(3,817)
STANDARDIZED MEASURE NET CASH FLOWS	$ 6,455	$ 5,763	$ 7,565	$ 19,783	$ 9,057	$ 8,128	$ 3,947	$ 7,219	$ 28,351	$ 48,134	$ 13,043	$ 1,877
AT DECEMBER 31, 2003												
Future cash inflows from production	$ 30,307	$ 23,521	$ 33,251	$ 87,079	$ 55,532	$ 33,031	$ 26,288	$ 29,987	$ 144,838	$ 231,917	$ 56,485	$ 9,018
Future production costs	(10,692)	(5,003)	(9,354)	(25,049)	(8,237)	(6,389)	(11,387)	(6,334)	(32,347)	(57,396)	(6,099)	(1,878)
Future devel. costs	(1,668)	(1,550)	(990)	(4,208)	(4,524)	(2,432)	(1,729)	(1,971)	(10,656)	(14,864)	(6,066)	(463)
Future income taxes	(6,073)	(5,742)	(7,752)	(19,567)	(25,369)	(9,932)	(5,993)	(7,888)	(49,182)	(68,749)	(12,520)	(2,270)
Undiscounted future net cash flows	11,874	11,226	15,155	38,255	17,402	14,278	7,179	13,794	52,653	90,908	31,800	4,407
10 percent midyear annual discount for timing of estimated cash flows	(6,050)	(3,666)	(7,461)	(17,177)	(8,482)	(6,392)	(3,013)	(5,039)	(22,926)	(40,103)	(20,140)	(2,949)
STANDARDIZED MEASURE NET CASH FLOWS	$ 5,824	$ 7,560	$ 7,694	$ 21,078	$ 8,920	$ 7,886	$ 4,166	$ 8,755	$ 29,727	$ 50,805	$ 11,660	$ 1,458

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."

	Consolidated Companies*			Affiliated Companies		
Millions of dollars	**2005**	2004	2003	**2005**	2004	2003
PRESENT VALUE AT JANUARY 1	**$ 48,134**	$ 50,805	$ 48,585	**$ 14,920**	$ 13,118	$ 12,606
Sales and transfers of oil and gas produced net of production costs	**(26,145)**	(18,843)	(16,630)	**(2,712)**	(1,602)	(1,054)
Development costs incurred	**5,504**	3,579	3,451	**810**	1,104	750
Purchases of reserves	**25,307**	58	97	**–**	–	–
Sales of reserves	**(2,006)**	(3,734)	(839)	**–**	–	–
Extensions, discoveries and improved recovery less related costs	**7,446**	2,678	5,445	**–**	–	–
Revisions of previous quantity estimates	**(13,564)**	1,611	1,200	**(2,598)**	970	653
Net changes in prices, development and production costs	**61,370**	6,173	1,857	**19,205**	266	(1,187)
Accretion of discount	**8,160**	8,139	7,903	**2,055**	1,818	1,709
Net change in income tax	**(29,919)**	(2,332)	(264)	**(4,911)**	(754)	(359)
Net change for the year	**36,153**	(2,671)	2,220	**11,849**	1,802	512
PRESENT VALUE AT DECEMBER 31	**$ 84,287**	$ 48,134	$ 50,805	**$ 26,769**	$ 14,920	$ 13,118

*2003 conformed to 2004 and 2005 presentation.

David J. O'Reilly, 59
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 of the American Petroleum Institute, the Institute for International Economics and the Eisenhower Fellowships Board of Trustees. He joined Chevron in 1968.

Peter J. Robertson, 59
Vice Chairman of the Board since 2002. In addition to a broad sharing of the CEO's responsibilities, he is directly responsible for Strategic Planning; Policy, Government and Public Affairs; and Human Resources. Previously he was responsible for worldwide upstream and gas operations. He is a Director of the American Petroleum Institute, the U.S.-Saudi Arabian Business Council and the U.S.-Russian Business Council. He joined Chevron in 1973.

Samuel H. Armacost, 66
Director since 1982. He is Chairman of the Board of SRI International. Previously he was a Managing Director of Weiss, Peck & Greer LLC. He also is a Director of Del Monte Foods Company; Callaway Golf Company; Franklin Resources, Inc.; and Exponent, Inc. (3, 4)

Linnet F. Deily, 60
Director since January 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 Lucent Technologies Inc. (1)

Robert E. Denham, 60
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 Lucent Technologies Inc.; Wesco Financial Corporation; and Fomento Económico Mexicano, S.A. de C.V. (1)

Robert J. Eaton, 66
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, 68
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 The Business Council, Yosemite Fund, Templeton Emerging Markets Investment Trust PLC and the Hoover Institute Board of Overseers. (2, 3)

Franklyn G. Jenifer, 68
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. He is a Member of the Monitoring Committee for the Louisiana Desegregation Settlement Agreement. (1)

Sam Nunn, 67
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.; Internet Security Systems, Inc.; Scientific-Atlanta, Inc.; and General Electric Company. (2, 3)

Donald B. Rice, 66
Director since September 2005. He is Chairman of the Board and Chief Executive Officer of Agensys, Inc., a private biotechnology company. Previously he was President and Chief Operating Officer of Teledyne, Inc. He is a Director of Amgen, Inc.; Vulcan Materials Company; and Wells Fargo & Company. (2, 3)

Charles R. Shoemate, 66
Director since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods. (1)

Ronald D. Sugar, 57
Director since April 2005. He is Chairman of the Board, Chief Executive Officer and President of Northrop Grumman Corporation. Previously he was President and Chief Operating Officer of Northrop Grumman. He is Governor of the Aerospace Industries Association and a Member of the National Academy of Engineering. (2, 4)

Carl Ware, 62
Director since 2001. He is Senior Adviser to the Chief Executive Officer of The Coca-Cola Company and retired 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)

Retiring Director
Carla A. Hills, 72, Lead Director since 2004 and a Director since 1993, has reached the mandatory retirement age for nonemployee directors and will not stand for reelection at the Annual Meeting in April. She is Chairman and Chief Executive Officer of Hills & Company, International Consultants. Hills served as U.S. Trade Representative from 1989 to 1993 and Secretary of the U.S. Department of Housing and Urban Development from 1975 to 1977. She also was a Chevron Director from 1977 through 1988. She is a Director of American International Group, Inc.; Lucent Technologies Inc.; and Time Warner Inc.

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

Lydia I. Beebe, 53
Corporate Secretary since 1995. Responsible for providing corporate governance counsel to the Board of Directors and senior management, and managing stockholder relations and subsidiary governance. Previously Senior Manager, Chevron Tax Department; Manager, Federal Tax Legislation; and Chevron Legal Representative in Washington, D.C. Joined Chevron in 1977.

John E. Bethancourt, 54
Executive Vice President, Technology and Services, since 2003. Responsible also for health, environment and safety as well as project resources, procurement, additives and coal 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, 58
Vice President and Chief Financial Officer since 2005. Responsible for comptroller, audit, treasury, tax and investor relations activities corporatewide. Previously Chevron Vice President and Comptroller; Vice President, Finance, Chevron Products Company; and Assistant Comptroller, Chevron Corporation. Joined Chevron in 1972.

John D. Gass, 53
Corporate Vice President and President, Chevron Global Gas, since 2003. Responsible for the company's natural gas and power generation businesses, shipping company, and pipeline operations. Director of Sasol Chevron and GS Caltex Corporation. Previously Managing Director, Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined the company in 1974.

Mark A. Humphrey, 54
Vice President and Comptroller since 2005. Responsible for 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, 51
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, 55
Executive Vice President, 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.

David M. Krattebol, 61
Vice President and Treasurer since 2000. Previously President, Chevron San Jorge; Vice President, Logistics and Trading, Chevron Products Company; Vice President, Finance, Chevron Products Company; and Vice President, Finance, Chevron Overseas Petroleum Inc. Joined Chevron in 1971.

Sam Laidlaw, 50
Executive Vice President, Business Development, since 2003. Responsible for identifying and developing new, large-scale business opportunities worldwide. Previously Chief Executive Officer of Enterprise Oil PLC, at the time Europe's largest independent oil and gas company. Prior to that President of Amerada Hess Corporation. Non-Executive Director of Hanson PLC. Joined Chevron in 2003.

Gary P. Luquette, 50
Corporate Vice President and President, Chevron North America Exploration and Production Company, since April 2006. Previously Managing Director, European Strategic Business Unit, Chevron International Exploration and Production Company, and Vice President, San Joaquin Valley Business Unit, Chevron North America Exploration and Production Company. Joined Chevron in 1978.

John W. McDonald, 54
Vice President, Strategic Planning, since 2002. Responsible for advising senior management in setting the company's strategic direction. Previously President and Managing Director, Chevron Upstream Europe, Chevron Overseas Petroleum Inc., and Vice President, Gulf of Mexico Offshore Division, Texaco Exploration and Production Inc. Joined the company in 1975.

Donald L. Paul, 59
Vice President and Chief Technology Officer since 2001. Responsible for Chevron's three technology companies: Energy Technology, Information Technology and Technology Ventures. Previously Chevron Vice President, Technology and Environmental Affairs; President, Chevron Canada Resources; and President, Chevron Petroleum Technology Company. Joined Chevron in 1975.

Alan R. Preston, 54
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.

Thomas R. Schuttish, 58
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.

John S. Watson, 49
Corporate Vice President and President, Chevron International Exploration and Production Company, since 2005. Responsible for exploration and production activities outside North America. Previously Chevron Vice President and Chief Financial Officer; Chevron Vice President, Strategic Planning; and Director, Caltex Petroleum Corporation. Joined Chevron in 1980.

Michael K. Wirth, 45
Executive Vice President, Downstream, since March 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, 49
Vice President, Policy, Government and Public Affairs, since 2002. Responsible for government relations, community relations and communications. Director of Chevron Phillips Chemical Company LLC. Previously Chevron Vice President, Strategic Planning; President, Chevron Canada Limited; and Comptroller, Chevron Products Company. Joined Chevron in 1980.

Rhonda I. Zygocki, 48
Vice President, Health, Environment and Safety, since 2003. Responsible for HES strategic planning and issues management, compliance and auditing, and emergency response. Previously Managing Director, Chevron Australia Pty Ltd; Adviser to the Chairman of the Board, Chevron Corporation; and Manager, Strategic Planning, 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, Sam Laidlaw and Michael K. Wirth. Lydia I. Beebe, Secretary.

STOCKHOLDER AND INVESTOR INFORMATION

STOCK EXCHANGE LISTING
Chevron common stock is listed on the New York and Pacific stock exchanges. 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:
Mellon Investor Services LLC
480 Washington Boulevard
27th Floor
Jersey City, NJ 07130-2098
800 368 8357
www.melloninvestor.com

The Mellon Investor Services Program (800 842 7629, same address as above) features dividend reinvestment, optional cash investments of $50 to $100,000 a year, automatic stock purchase and safekeeping of stock certificates.

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 Mellon Investor Services. (See *Stockholder Information.*)

ANNUAL MEETING
The Annual Meeting of stockholders will be held at 8:00 a.m., Wednesday, April 26, 2006, at:
Chevron Corporation
1500 Louisiana Street
Houston, TX 77002-7308

Meeting notice and proxy materials are mailed in advance to stockholders, who are urged to review the materials and to vote their shares. Generally, stockholders may vote by telephone, on the Internet, by mail or by attending the meeting.

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 ADP 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
Bldg. A
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.

For facts and figures 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.*

The *Form 10-K,* prepared annually for the Securities and Exchange Commission, is available after March 1. The *Supplement to the Annual Report,* containing additional financial and operating data, is available after April 15. Please request by writing to:
Comptroller's Department
Chevron Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2005 are available by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2108
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.

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 25 FOR A DISCUSSION OF SOME OF THE FACTORS THAT COULD CAUSE ACTUAL RESULTS TO DIFFER MATERIALLY.

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