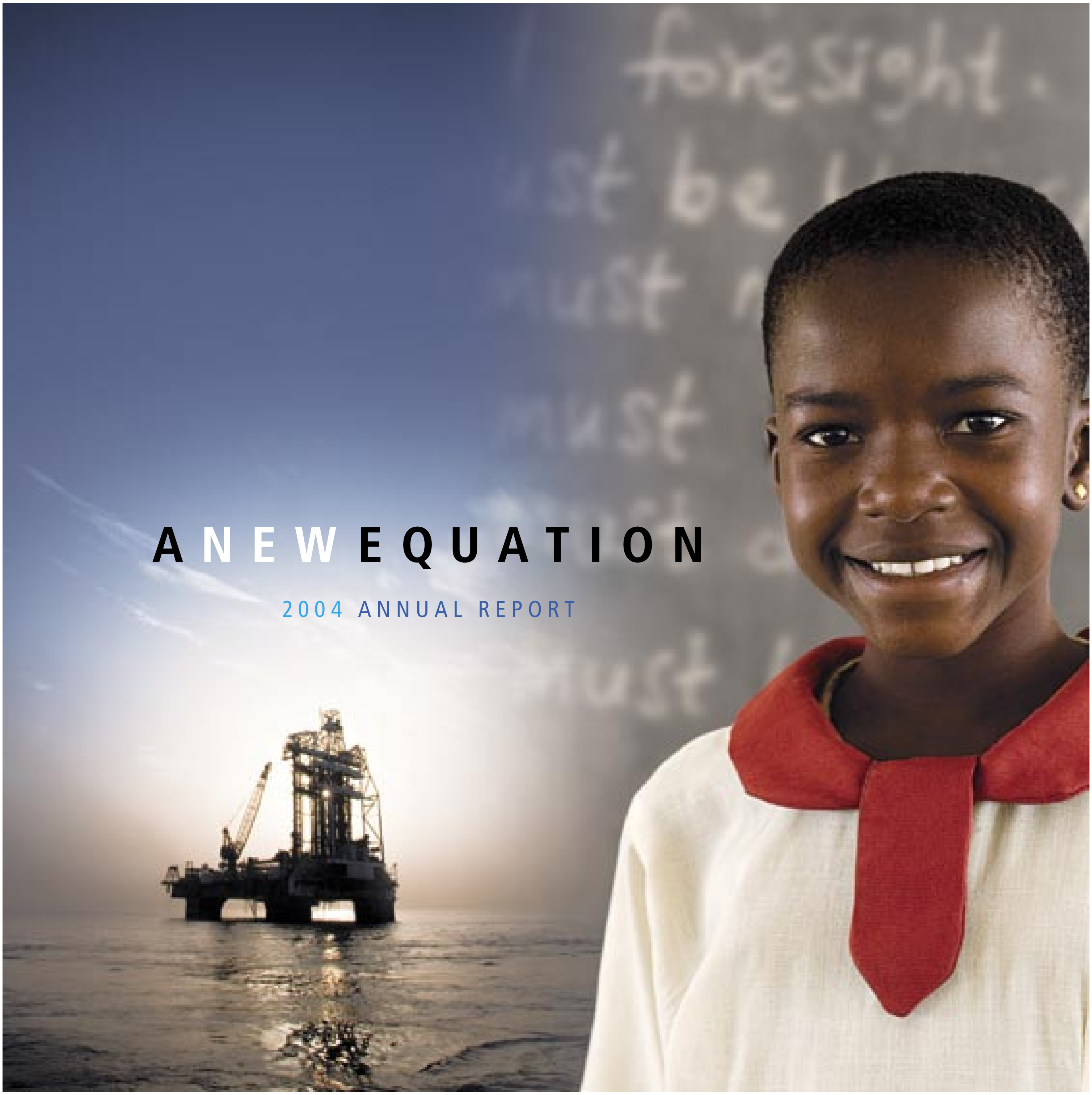
ChevronTexaco



A NEW EQUATION

2004 ANNUAL REPORT

ABOUT THE COVER

Energy is essential to human and economic progress. At ChevronTexaco, we are investing billions of dollars in frontier areas such as the deep water to deliver new energy supplies to meet growing worldwide demand. At the same time, we are investing in local communities where we do business to enhance capacity for education, health care and economic growth.

INSIDE FRONT COVER

Downtown Shanghai at night reflects the growth in global demand for new energy supplies, particularly in China. ChevronTexaco's long-term strategies are focused on growing production to help meet new demand and fuel economic growth and human progress.

A New Equation

In 2004, it became clear that the world was witnessing a new energy equation driven by a number of factors – growing global demand, a more challenging frontier of energy supplies in areas such as the deep water and oil sands, and a complex geopolitical environment. Abundant, reliable energy is critical to healthy economies and healthy communities. Addressing this new equation is one of the greatest challenges facing energy producers and consumers.

ChevronTexaco has a 125-year history of rising to challenges and creating opportunities. Today, we are responding to the new energy equation by leveraging our strengths: a high-impact exploration and development program; a commitment to safe, efficient and environmentally sound operations; the application of technology to maximize the value of our existing assets and develop promising new energy sources; and the creation of partnerships that benefit our company, our communities and, of course, our many customers around the world.

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TO OUR STOCKHOLDERS

In 2004, our company delivered the strongest financial performance in its 125-year history. Net income was $13.3 billion. We outperformed our peers in return on capital employed, a key measure of overall company performance. We strengthened our balance sheet, reducing our debt level by $1.3 billion and ending the year with cash and marketable securities of $10.7 billion. Most significant, we achieved a total stockholder return for the year of 25.5 percent and accomplished our five-year goal to be a leader among our three largest peers in this measure, posting an annualized return of 7.4 percent for 2000 through 2004. This was 9.7 percentage points higher than Standard & Poor's 500 return over the same five-year period.

We increased our annual dividend payments for the 17th consecutive year and returned value to stockholders through the launch of a common stock buyback program of up to $5 billion by 2007. At the end of 2004, we had repurchased shares in the open market totaling more than $2 billion.

We accomplished all of this while having our safest year ever – a core value at ChevronTexaco.

RIGHT STRATEGIES

Our performance was driven by executing well against the right strategies at the right time. In upstream, our strategic focus is on growing profitability in core areas and building new legacy positions. Our natural gas strategy targets the commercialization of our significant international resource base for delivery to North American and Asian markets. In downstream, our strategic priority is to enhance returns by focusing on areas of market and supply strength.

Oil demand has been stronger than predicted, and spare capacity has been reduced. With almost 75 percent of our production in crude oil, we are well positioned to benefit from higher prices. At the same time, refining margins have been particularly strong in Asia and the U.S. West Coast and Sun Belt, where the company has a majority of its refining capacity.

STRONG FOCUS, EXECUTION, GROWTH

While the industry benefited from high commodity prices this past year, ChevronTexaco's performance was enhanced by strong execution against its strategic objectives. Specific achievements included strong exploration results, with potentially significant new crude oil and natural gas discoveries in North America, Europe, Australia, Africa and Latin America. We also continued our portfolio rationalization through the sale of nonstrategic production assets at a time when we could take advantage of high market prices. In 2004, our downstream operations were aligned functionally across the globe. This resulted in operating and efficiency gains and produced significant earnings improvements. We also made solid progress toward commercializing our equity natural gas resource base, most notably by securing long-term regasification capacity in the U.S. Gulf of Mexico and obtaining key permits for a planned Baja California, Mexico, liquefied natural gas import terminal.

We continued to focus on integrating our operations across the enterprise to capture efficiencies and create new value. For example, we modified our Pembroke Refinery in the United Kingdom to process market-disadvantaged equity crude oil from our Chad operations in Africa into high-quality gasoline blendstocks for North America. We have combined separate groups to create a single organization to manage technology for upstream and downstream. This approach, which is unique in the industry, allows us to optimize technology solutions across the enterprise, from the reservoir to the retail pump.

Looking forward, our growth opportunities are excellent. We are aggressively managing production decline rates in mature fields, adding exploration acreage in key areas and building a world-class portfolio of capital projects – Benguela Belize-Lobito Tomboco in Angola, Agbami in Nigeria, Tahiti in the Gulf of Mexico and the Tengizchevroil expansion in Kazakhstan. All of these projects are scheduled to come online over the next four years, contributing to our oil-equivalent production goal of 3 million barrels a day by 2008.

A NEW EQUATION

We are at a strategic inflection point in our industry. The convergence of growing demand, challenging resource locations such as the deep water and oil sands, a need for greater diversity of energy supplies, a complex geopolitical environment, and a shifting competitive landscape have created a fundamentally new energy equation.

ChevronTexaco is strongly positioned to succeed in this new environment. We have robust strategies that have been tested under a variety of market conditions. We are committed to achieving and maintaining world-class levels of operating and capital discipline. We are leveraging technology to create operating efficiencies in the near term and develop promising new energy sources for the long term. We are continuing to build on our efforts to be the partner of choice in strategic energy regions of the world.

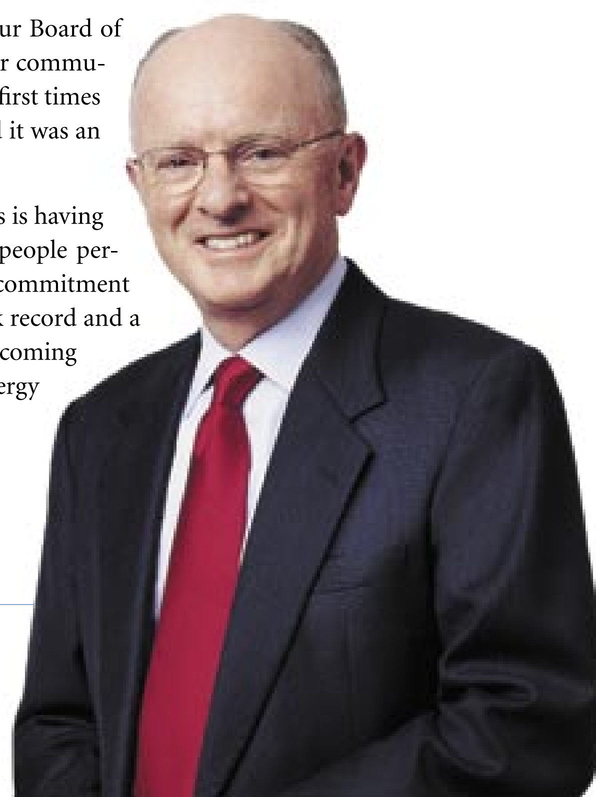
A strong reflection of our commitment to partnership occurred in 2004 when our Board of Directors held a meeting in Angola to review our business operations, witness our community engagement projects and visit with the country's leadership. It was one of the first times a Board from a major multinational company has met in sub-Saharan Africa, and it was an affirmation of our continuing commitment to this continent.

Even with sound strategies and a strong balance sheet, the critical factor for success is having the right people in the right positions doing the right things. ChevronTexaco's people performed superbly in 2004, and we are continuing to enhance the capabilities and commitment of our global work force. We have a strong management team with a proven track record and a dedicated, experienced Board. We look forward to the opportunities we face in the coming year to increase competitive returns and stockholder value and to deliver the energy needed to fuel economic development and growth around the world.

Thank you for your continued support.

Dave O'Reilly

DAVE O'REILLY
CHAIRMAN OF THE BOARD AND CHIEF EXECUTIVE OFFICER
MARCH 2, 2005

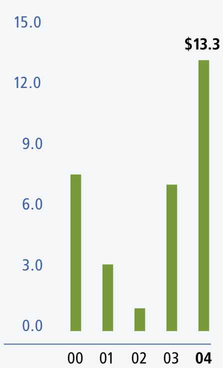


CHEVRONTEXACO FINANCIAL HIGHLIGHTS

Millions of dollars, except per-share amounts	2004	2003	% Change
Net income[1]	$ 13,328	$ 7,230	84 %
Sales and other operating revenues[1]	$ 151,156	$ 120,032	26 %
Capital and exploratory expenditures[2]	$ 8,315	$ 7,363	13 %
Total assets at year-end	$ 93,208	$ 81,470	14 %
Total debt at year-end	$ 11,272	$ 12,597	(11)%
Stockholders' equity at year-end	$ 45,230	$ 36,295	25 %
Cash provided by operating activities	$ 14,690	$ 12,315	19 %
Common shares outstanding at year-end[3] (Thousands)	2,107,120	2,138,295	(1)%
Per-share data[3]			
Net income – diluted[1,4]	$ 6.28	$ 3.48	81 %
Cash dividends	$ 1.53	$ 1.43	7 %
Stockholders' equity	$ 21.47	$ 16.97	27 %
Common stock price at year-end	$ 52.51	$ 43.19	22 %
Total debt to total debt-plus-equity ratio	19.9%	25.8%	
Return on average stockholders' equity	32.7%	21.3%	
Return on capital employed (ROCE)	25.8%	15.7%	

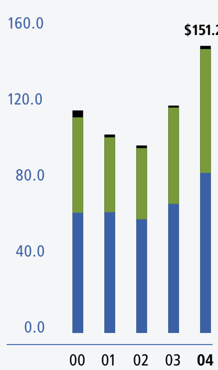
[1] Includes discontinued operations
[2] Includes equity in affiliates
[3] 2003 adjusted for stock split in 2004
[4] 2003 includes $0.08 for a capital stock transaction as described in Note 26 to the Consolidated Financial Statements

NET INCOME
Billions of dollars



Net income rose sharply on the strength of upstream operations and much-improved results from the downstream businesses in 2004. Special-item charges in 2002 reduced earnings more than $3 billion.

SALES & OTHER OPERATING REVENUES*
Billions of dollars

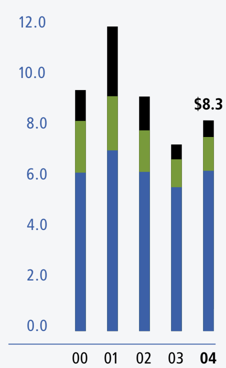


- Chemicals & Other
- Crude Oil & Condensate, Natural Gas & Natural Gas Liquids
- Petroleum Products

Sales and other operating revenues increased 26 percent on higher prices for crude oil, natural gas and refined products.

**Includes discontinued operations*

CAPITAL & EXPLORATORY EXPENDITURES*
Billions of dollars



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

Capital and exploratory expenditures increased about 13 percent from the 2003 level. Years 2000 through 2002 were higher due to additional investments in equity affiliates Tengizchevroil and Dynegy Inc.

**Includes equity in affiliates*

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars

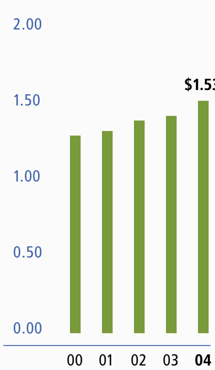
Higher earnings helped boost the company's operating cash flow by 19 percent.

CHEVRONTEXACO OPERATING HIGHLIGHTS[1]

	2004	2003	% Change
Net production of crude oil and natural gas liquids (Thousands of barrels per day)	**1,710**	1,808	(5)%
Net production of natural gas (Millions of cubic feet per day)	**3,958**	4,292	(8)%
Net oil-equivalent production (Thousands of oil-equivalent barrels per day)	**2,509**	2,637	(5)%
Refinery input (Thousands of barrels per day)	**1,958**	1,991	(2)%
Sales of refined products (Thousands of barrels per day)	**3,908**	3,738	5 %
Net proved reserves of crude oil, condensate and natural gas liquids[2] (Millions of barrels)			
– Consolidated companies	**5,511**	6,280	(12)%
– Affiliated companies	**2,462**	2,319	6 %
Net proved reserves of natural gas[2] (Billions of cubic feet)			
– Consolidated companies	**16,128**	17,553	(8)%
– Affiliated companies	**3,547**	2,638	34 %
Net proved oil-equivalent reserves[2] (Millions of barrels)			
– Consolidated companies	**8,199**	9,206	(11)%
– Affiliated companies	**3,053**	2,758	11 %
Number of employees at year-end[3]	**47,265**	50,582	(7)%

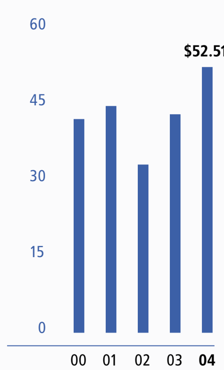
[1] Includes equity in affiliates, except number of employees
[2] At the end of the year
[3] Excludes service station personnel

ANNUAL CASH DIVIDENDS
Dollars per share



The company increased its annual dividend payout for the 17th consecutive year.

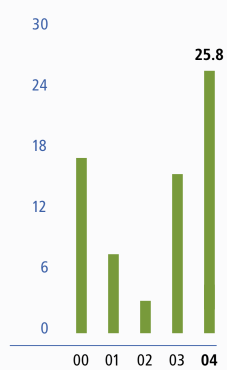
CHEVRONTEXACO YEAR-END COMMON STOCK PRICE*
Dollars per share



The company's stock price rose 22 percent during 2004, outpacing the broader market indexes.

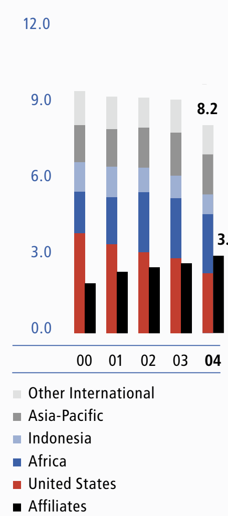
**Adjusted for stock split in 2004*

RETURN ON CAPITAL EMPLOYED
Percentage



Higher net income helped boost ChevronTexaco's return on capital employed to 25.8 percent.

NET PROVED RESERVES
Billions of BOE*



Net proved reserves for consolidated companies declined 11 percent in 2004, while affiliated companies' reserves climbed by 11 percent.

**Barrels of oil-equivalent*

STRATEGY + EXECUTION =

SUSTAINED

CHEVRONTEXACO IS COMMITTED TO CREATING LONG-TERM STOCKHOLDER VALUE WHILE DELIVERING NEW ENERGY SUPPLIES TO MEET GROWING WORLDWIDE DEMAND. IN 2004, WE ACHIEVED MILESTONES IN OUR TWO MAIN BUSINESSES – UPSTREAM AND DOWNSTREAM – THAT ARE DELIVERING STRONG RESULTS NOW AND FOR THE FUTURE.

ChevronTexaco's upstream and downstream operations are large, diversified and competitive. In upstream, we are among the top producers in Asia-Pacific, Indonesia, Kazakhstan, South America, the United States and western Africa. We are the only international oil company producing under a concession from the Kingdom of Saudi Arabia, and we are the largest natural gas resource holder in Australia.

Our downstream is global, with 21 refineries and a marketing network in approximately 170 countries. We have a highly competitive downstream presence in Asia and on the West Coast of North America, areas where energy demand growth is expected to be especially strong. We also have a large downstream presence on the U.S. Gulf Coast, in Latin America and in sub-Saharan Africa. We market products under three of the industry's most respected brands – Chevron, Texaco and Caltex.

▸ Opposite page, left to right: Sanha condensate gas utilization and Bomboco oil project, Angola; Hamaca heavy-oil upgrader, Venezuela; Chevron "TOP TIER" gasoline, Hawaii service station.



2004 KEY RESULTS

UPSTREAM

- Achieved exploration success rate of 57 percent, compared with 10-year industry average of 32 percent
- Brought on new production from Angola, China, U.K. North Sea, Thailand, Venezuela
- Secured access to planned Sabine Pass regasification facility in Louisiana
- Reached agreements to evaluate gas-to-liquids opportunities in Qatar

DOWNSTREAM

- Transformed to a global, functional organization model and achieved significant earnings improvements
- Resumed marketing fuels under Texaco brand in United States; Chevron first U.S. and Canada brand designated "TOP TIER Detergent Gasoline" by four leading auto manufacturers

RESULTS

UPSTREAM Our upstream strategy is to improve profitability in core areas and build new legacy positions. Progress was made on both fronts in 2004.

CORE AREAS During the year, we brought a number of world-class projects onstream and strengthened our position in several core areas. One such project was the Bomboco Field, which began initial production in 2004. Bomboco is part of a $1.9 billion development under way in the deep water of Angola. We also achieved first production from China's Bohai Bay and from an expansion of the Alba Field in the U.K. North Sea. In Venezuela, the Hamaca heavy-oil upgrader project was completed, and the first sales of Hamaca synthetic crude were made.

We have an ongoing effort under way to maximize value from our producing assets. A major focus is on lowering costs while increasing reliability and production volumes. We also continue to upgrade our portfolio of core assets. In 2004, we completed virtually all of our major planned asset sales, taking advantage of favorable market conditions to sell nonstrategic producing properties. ›

THE "BIG 5" We are moving forward on our "Big 5" projects. These are legacy developments that are expected to boost production and reserves over the next five years. Three of the projects are in the deep water: the Agbami Field in Nigeria, the Tahiti Field in the U.S. Gulf of Mexico and the Benguela Belize-Lobito Tomboco development in Angola. Additionally, we are moving forward with a major expansion at the Tengizchevroil joint venture in Kazakhstan. We expect these and other capital projects to add approximately 850,000 net barrels of oil-equivalent production per day by 2009. Also in our "Big 5" lineup is the development of the giant Greater Gorgon Area natural gas fields offshore Western Australia (see Page 9).

EXPLORATION SUCCESSES For the third consecutive year, our exploration efforts achieved excellent results. Major discoveries were made in the U.S. Gulf of Mexico, Western Australia, Venezuela, Nigeria, Thailand, the U.K. North Sea, and the offshore area between Angola and the Republic of Congo. We acquired new acreage in the U.S. Gulf of Mexico, offshore eastern Canada, Nigeria, Venezuela, Norway and the U.K. Atlantic Margin. We also increased our position in the Mackenzie Delta in northern Canada and extended exploration rights in Angola. In an ongoing effort to move more resources into reserves, we are appraising recent high-potential discoveries in the deepwater Gulf of Mexico, Nigeria and Angola.

NEW BUSINESS DEVELOPMENT We intend to build our reputation as a partner of choice to secure major new opportunities in resource-rich areas of the world. In 2004, we announced a Memorandum of Understanding with Russia's Gazprom to begin feasibility studies for oil and natural gas projects in Russia and the United States. We also are pursuing opportunities in northern Africa and the Middle East.

DOWNSTREAM Our downstream strategy is to improve returns by focusing on areas of market and supply strength. In 2004, we completed a reorganization along global, functional lines, which created efficiencies and significant earnings improvements across the organization.

REFINING Our refinery operations are located in strong markets, have the flexibility to exploit market opportunities and can run significant volumes of lower-quality, lower-priced crude oil. Our refinery utilization rate, an industry measure that incorporates the economic value of each refinery process unit, has risen approximately 2 percent since 2003. Improved utilization rates have enabled us to capitalize on high margins, especially in Asia.

A REFINING SYSTEM STRATEGICALLY LOCATED AND CONFIGURED

Our refining portfolio is very competitive. Approximately 60 percent of our refining capacity is located in the Asia-Pacific and on the North American West Coast, where margins have been particularly strong. In 2004, we increased our ownership in the Singapore Refining Company to take advantage of Asia's growing energy demand. Our refineries also are flexible and able to run significant volumes of lower-quality crude oil. Our U.S. West Coast and Gulf Coast refineries are complex and positioned for advantage when light-heavy price differentials are wide. We currently are focused on enhancing our light product conversion and heavy crude capability, with upgrades planned at refineries in Asia, California and Mississippi.

► In response to Asia's growing demand for refined products, we increased our ownership in the Singapore Refining Company from 33 percent to 50 percent.

DEVELOPING THE PROMISE OF NATURAL GAS

► The *Northwest Swan* is the newest liquefied natural gas carrier in Australia's North West Shelf Venture.

Over the next two decades, demand for natural gas is expected to outpace demand for oil. The fastest-growing markets will be Asia and the United States, and ChevronTexaco is positioned to supply both. We have large holdings of natural gas resources in both the Pacific and Atlantic basins. Our strategy is to commercialize them by targeting North American and Asian markets.

In the Pacific Basin, our focus is on the Greater Gorgon Area offshore Western Australia. We plan to deliver liquefied natural gas (LNG) from Gorgon to markets in Asia and on the West Coast of North America. Also in Australia, we are part of the North West Shelf Venture, which supplies LNG to Japan and South Korea. In 2004, a fourth gas-processing train was completed to expand LNG production, and ChevronTexaco began operating the venture's newest LNG carrier. In the Atlantic Basin, our strategy is to deliver natural gas from West Africa and Latin America to markets in North America. We have received key permits for regasification terminals on the West and Gulf coasts of North America and have secured capacity in a planned regasification terminal in Louisiana.

Gas-to-liquids (GTL) is the other important element of our natural gas strategy. Through our Sasol Chevron joint venture, we have a GTL project under way in Nigeria and are evaluating projects in Qatar and Australia.

Our LNG and GTL initiatives benefit from our experience across the natural gas value chain, including our global shipping, power, and North America marketing and pipeline operations.

During the year, we continued to lower refinery operating and maintenance costs. Our turnaround process for refinery maintenance is considered world class by the industry's leading external refining benchmarking firm. We also are driving greater efficiencies through our refinery network. In 2004, our refineries improved energy efficiency by 2.5 percent compared with 2003, an important achievement in a high fuel-price environment.

MARKETING We made significant strides in our marketing initiatives in 2004. In July, we resumed marketing fuels under the Texaco brand in the United States. By the end of the year, we were supplying more than 1,000 Texaco retail sites, primarily in the Southeast, and had plans to supply additional sites in the Southeast and West in 2005. We also received important recognition of our Chevron fuel brand. It was the first in the United States and Canada to be certified by four of the world's top automakers as meeting "TOP TIER" criteria for gasoline detergency levels. We also made progress in selling nonstrategic retail sites. At the end of 2004, we had sold nearly 1,600 sites since a divestiture program began in 2003. At the same time, we maintained sales volumes through our network of approximately 25,700 retail outlets, including affiliates.

PEMBROKE REFINERY

In 2004, we modified the Pembroke Refinery in the United Kingdom to process acidic, high-calcium crude oil from the Doba Field in the Republic of Chad. These modifications enable us to increase the value of the crude oil and turn it into high-value petroleum products.

AT CHEVRONTEXACO, WE ARE BUILDING THE FOUNDATION FOR PROFITABLE GROWTH THROUGH A STRONG UPSTREAM PRESENCE, WHICH INCLUDES OUR LARGE NATURAL GAS RESOURCE BASE, AND THROUGH OUR GLOBAL DOWNSTREAM ORGANIZATION.

AUSTRALIA

ChevronTexaco is part of the North West Shelf Venture, which supplies liquefied natural gas to markets in Japan and South Korea. Here, operator technicians Steve Blasedale (left) and Craig Baker help oversee a fourth gas-processing train, which was completed in 2004. Also in Australia, we are moving to develop the giant natural gas resources in the Greater Gorgon Area, one of our "Big 5" projects.

AGBAMI

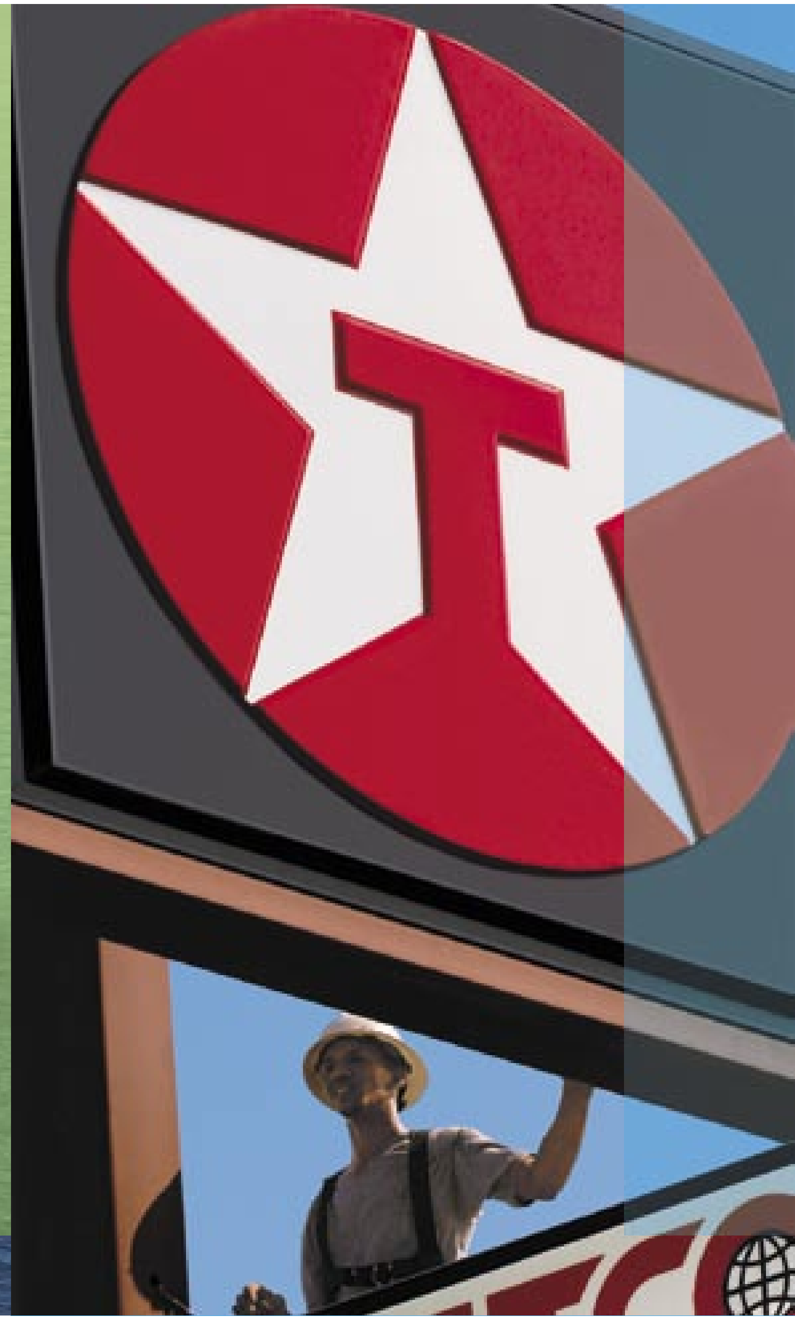
A "Big 5" project, the $4.5 billion Agbami development is located in Nigeria's deep water. It is estimated to contain approximately 800 million barrels of oil-equivalent that are potentially recoverable. Development drilling is under way, and we expect initial production in 2008.

TAHITI

The Tahiti Field in the U.S. Gulf of Mexico is estimated to contain between 400 million and 500 million barrels of oil-equivalent that are potentially recoverable, thereby ensuring its position as one of our "Big 5" projects. In 2004, we completed a successful well test in 4,100 feet (1,215 meters) of water and 25,800 feet (7,870 meters) subsea – the deepest yet in the gulf.

RISING STAR

The Texaco Star is hoisted atop this station in Rockwall, Texas. In 2004, we resumed marketing fuels under the Texaco brand in the United States. By the end of the year, we were supplying more than 1,000 Texaco retail sites, primarily in the Southeast, and had plans to supply additional sites in the Southeast and West in 2005.



VENEZUELA

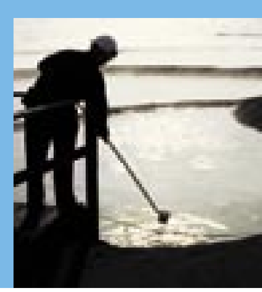
Latin America is an important part of our Atlantic Basin liquefied natural gas strategy. In 2004, we found significant quantities of natural gas in Venezuela's Plataforma Deltana. This confirmed our initial assessment of the region as a potential source of new and significant natural gas resources.

KAZAKHSTAN

A "Big 5" project is the Tengizchevroil second generation/sour gas injection project in Kazakhstan. The project, which uses state-of-the-art injection technology, is expected to increase total crude oil production capacity from 298,000 barrels a day to between 430,000 and 500,000 barrels a day when the project is completed in 2006.

MANAGING A GLOBAL, CAPITAL-INTENSIVE BUSINESS REQUIRES RIGOR AND DISCIPLINE. WE HELP ENSURE BOTH THROUGH A SET OF PRIORITIES WE CALL "4+1." THESE PRIORITIES DRIVE WORLD-CLASS PERFORMANCE IN FOUR AREAS: OPERATIONAL EXCELLENCE, COST REDUCTION, CAPITAL STEWARDSHIP AND PROFITABLE GROWTH. THE "PLUS 1" IS ORGANIZATIONAL CAPABILITY – HOW WE COMBINE THE TALENT OF OUR PEOPLE WITH COMPREHENSIVE MANAGEMENT SYSTEMS TO ACHIEVE SUPERIOR PERFORMANCE IN ALL FOUR AREAS.

4+1= WORLD-CLASS PERFORMANCE



▸ Above: Gulzada Izbasarova, site safety officer, helps ensure a safe workplace for the Tengizchevroil second generation/sour gas injection project in Kazakhstan, a "Big 5" development. ▸ Below: James Farrell, environmental operator, takes a sample from water treatment ponds at ChevronTexaco's Richmond Refinery in California.

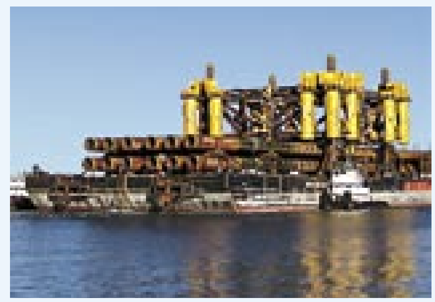
We have designed and implemented comprehensive and disciplined management systems to help us build organizational capability in operational excellence and capital stewardship. These systems are aimed at achieving top operating performance and ensuring that we direct our $10 billion 2005 capital and exploratory budget toward the highest-quality opportunities with the greatest potential to create future growth and stockholder value.

OPERATIONAL EXCELLENCE Operational excellence is a systematic process for managing our businesses at world-class levels. It is not an independent process; rather, it is woven into every aspect of our activities. Through operational excellence, we protect people and the environment and maintain our reputation as a reliable and efficient energy provider.

Our company's highest priority is safety, and 2004 was our safest year ever. Our total recordable incident rate (per 200,000 hours worked) for employees and contractors improved 14 percent from the previous year, and days away from work improved 10 percent. Even so, our goal is zero incidents – no one injured – and we will not be satisfied until we reach it.

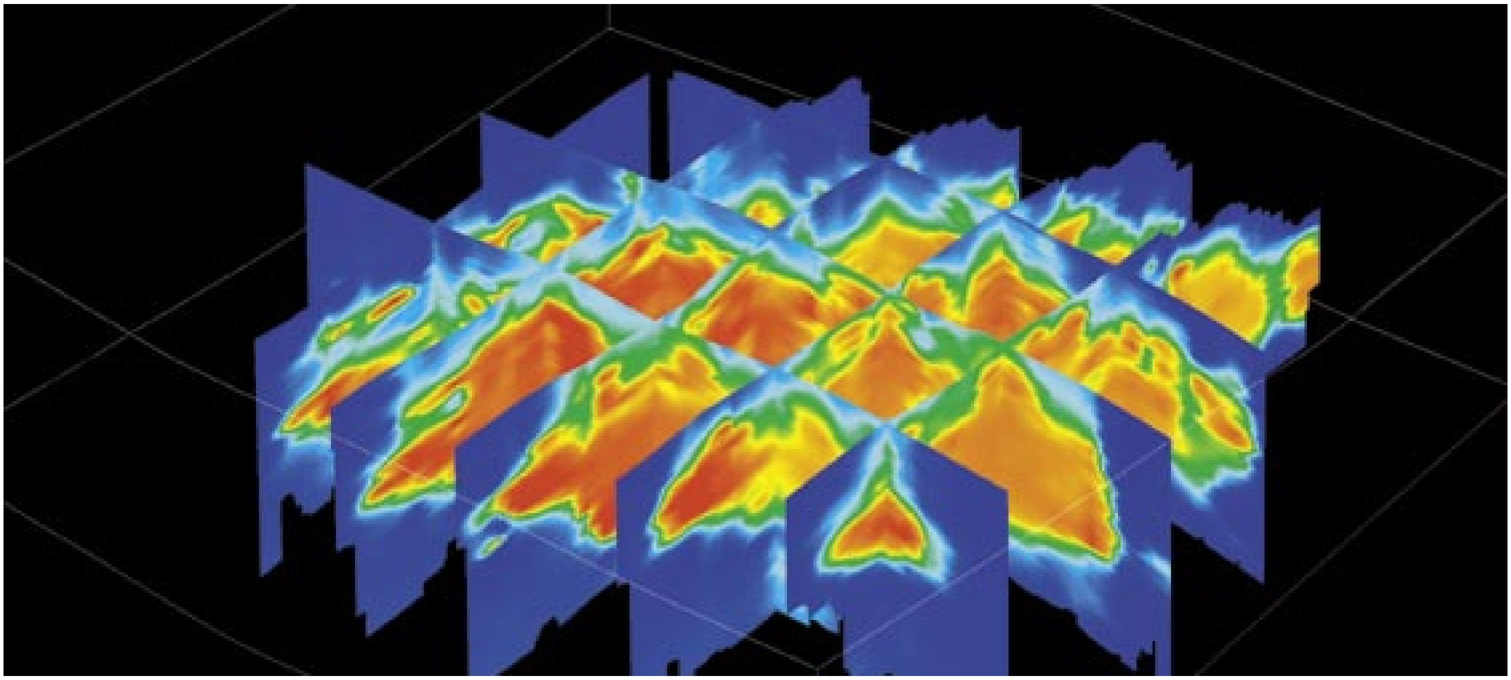
Our environmental performance also continued to improve during the year. Compared with 2003, we reduced the number of oil spills by 14 percent and the volume spilled by 42 percent. We also made strides in energy conservation. In 2004, we consumed 2 percent less energy in our operations than in the previous year, representing savings of $72 million. Since 1992, the year we began tracking, we have reduced companywide energy use by 24 percent. We also are tracking and managing our greenhouse gas emissions. As part of this effort, in 2004 we completed a companywide third-party verification of greenhouse gas emissions.

CHEVRON ENERGY SOLUTIONS (CES) This subsidiary helps external partners and internal business units find ways to save energy. For example, in 2004, the U.S. Postal Service (USPS) asked CES to complete major energy efficiency upgrades and a hybrid renewable power plant – including a fuel cell and two solar electric technologies – at USPS's largest processing and distribution facilities in San Francisco, California. The improvements are expected to lower total annual electricity purchases by $1.2 million and reduce carbon dioxide emissions by approximately 6,600 tons annually, the equivalent of planting 1,860 acres of trees.



BUILDING THE "PLUS 1" FOR CAPITAL STEWARDSHIP

We are committed to being the industry leader in capital stewardship and have a management system in place to help us identify the most promising investments and execute them well. An example is the $2.2 billion Benguela Belize-Lobito Tomboco project offshore Angola, one of our "Big 5" projects. The development calls for the first compliant piled tower (CPT) to be installed outside the U.S. Gulf of Mexico. Fixed to the sea floor, it will support drilling and production facilities and will be the fifth-tallest structure in the world. The tower is being fabricated in numerous countries – on schedule and on budget. Above: The CPT base template and foundation piles are en route from Texas to Angola.



INNOVATION + TECHNOLOGY =

COMPETITIVE EDGE

WE ARE COMBINING THE INNOVATION OF OUR PEOPLE WITH THE LATEST ADVANCEMENTS IN TECHNOLOGY TO CREATE A COMPETITIVE EDGE AND DRIVE FUTURE GROWTH. THE TECHNOLOGIES WE ARE DEPLOYING ARE HELPING US DECREASE COSTS AND GENERATE GREATER EFFICIENCIES. JUST AS IMPORTANT, THEY ARE HELPING US FIND AND DEVELOP NEW ENERGY RESOURCES FOR THE FUTURE.

► Shown above is a 3-D model of well temperature data from the Kern River heavy oil field in Bakersfield, California. ChevronTexaco is a leader in heavy-oil production and processing, and in thermal management.

ChevronTexaco has built a technology organization that is unique in our industry. It is the only one that is fully integrated and capable of delivering technology and services throughout the energy value chain. Our technology strategy also is partner-driven. We have forged alliances to share technical risk, cost and talent with external organizations that have complementary capabilities. Our technology group not only supports the strategies of our core businesses, but also is engaged in developing technology to enable our most promising opportunities.

CORE BUSINESSES In upstream, we are deploying technology to help select exploration prospects with ever-greater precision and drill them with minimum impact on the environment. Our proprietary seismic technology has led to a series of major discoveries in recent years, particularly in deep water. In 2004, our exploratory success rate was 57 percent, well above the 10-year industry average of 32 percent.

Technology also is supporting major petroleum developments. One example is the Tengizchevroil (TCO) sour gas injection project in Kazakhstan. In 2004, TCO completed the design of the world's largest single train sulfur-recovery unit and significantly advanced gas-injection technology. In another effort, we are developing a next-generation reservoir simulator with an industry partner. The simulator will improve the speed and accuracy of modeling large, complex reservoirs and estimating their reserves.

Additionally, technology is playing an important role as we commercialize our large natural gas resources. Efforts are under way to improve the construction of liquefied natural gas (LNG) facilities, reduce LNG storage costs and enhance regasification processes. The Sasol Chevron gas-to-liquids (GTL) joint venture will be applying some of the most advanced GTL technologies to projects in progress in Nigeria and Qatar.

In downstream, we are deploying catalyst technologies and making advanced fuels for our customers. As part of this effort, we continue to improve our ability to convert extra-heavy oil into high-value, light petroleum products. Additionally, we are investing in technology to produce lubricant additives that use sulfur-free GTL base stocks.

PARTNERSHIPS We partner with academic, business and public-sector organizations to create and deploy effective, cost-efficient technologies. In 2004, we established a new Center of Research Excellence at the University of Southern California to develop next-generation digital oil-field technologies. Centers focused on other research have been established at the University of Tulsa and Colorado School of Mines.

► Above: A hydrogen fuel cell unit at our San Ramon, California, headquarters is the primary power source for a data center. Shown here (left to right), ChevronTexaco Technology Ventures' Jeffrey Jacobs and Ed Wisler. ► Below: The first of up to six U.S. hydrogen energy service stations opened in 2005 in Chino, California.

PRACTICAL HYDROGEN – CREATING FUTURE FUEL OPTIONS

As energy demand continues to grow, ChevronTexaco is pursuing next-generation fuels, including hydrogen. In 2004, the U.S. Department of Energy selected ChevronTexaco to lead a consortium that will demonstrate hydrogen infrastructure and fuel-cell vehicles. Over a five-year period, the consortium will build up to six hydrogen energy service stations with fueling facilities for small fleets of fuel-cell vehicles and capacity to generate high-quality electrical power from stationary fuel cells.

ACCESS TO ABUNDANT, RELIABLE ENERGY IS ESSENTIAL TO HEALTHY ECONOMIES AND QUALITY OF LIFE. WE ARE FORMING PARTNERSHIPS TO HELP BUILD ECONOMIC AND HUMAN CAPACITY IN THE COMMUNITIES WHERE WE OPERATE AND TO PROVIDE A PLATFORM FOR SUSTAINABLE BUSINESS DEVELOPMENT.

► An estimated 700,000 Angolans have benefited from a partnership initiative to support the country's agricultural development.

At ChevronTexaco, we believe that how we do business is as important as the business we do. We are committed to corporate responsibility and take special care to ensure that our presence in a community builds not only economic capacity, but also human capacity.

How we operate in Africa is a good example. 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. Despite significant progress, the region remains one of the world's most challenging in terms of social and economic development. By forming public-private partnerships, we are creating sustainable programs to expand the capacity of local communities to become economically self-sufficient and enhance their quality of life.

The largest of these partnerships is a $50 million initiative to help Angola rebuild from its long civil war. Approximately 40 percent of the funds are in support of agricultural development, an area that offers the greatest potential to increase family income. At the end of 2004, an estimated 700,000 Angolans had benefited from seeds, tools, food and technical aid that had been given to assist small farms. Partners include the U.S. Agency for International Development, the United Nations Development Program and other organizations.

Additional efforts are under way to develop small- and medium-sized businesses in Angola. Funding has been committed to support the opening of the country's first micro-credit bank. Partners are European development institutes and the International Finance Corporation, an arm of the World Bank.

HEALTHY COMMUNITIES A number of the company's major operations are in countries threatened by HIV/AIDS. In early 2005, we began implementing a corporatewide policy to provide employees access to care and treatment where available. We also continue to build public-private partnerships to improve overall health care in the communities where we operate. In Latin America, the Trust for the Americas recognized us for our health and dental care efforts as well as educational initiatives, particularly in Venezuela.

DEVELOPING ENERGY AND PEOPLE

Training and developing the local work force is one of our highest priorities and one of the most important ways we contribute to a country's social and economic capacity. One example is the Partitioned Neutral Zone (PNZ) between Saudi Arabia and Kuwait. Over the years, we have prepared Saudi employees to assume professional and managerial positions for the operations there. Today, more than 90 percent of PNZ employees are from the national work force.

▸ Bottom, right: We are partnering with a nonprofit pediatric hospital in Venezuela to provide health and dental care to youngsters, such as Alicia Fernandez, who live in Zulia State.

A NEW EQUATION : MANAGEMENT PERSPECTIVES

SUSTAINED SUCCESS REQUIRES A DEEP UNDERSTANDING OF THE OPERATING ENVIRONMENT, THE DEVELOPMENT OF SOUND STRATEGIES IN THE CONTEXT OF THAT ENVIRONMENT AND DISCIPLINED, FLAWLESS EXECUTION OF THOSE STRATEGIES. CHEVRONTEXACO HAS A BROAD GRASP OF ALL THREE DIMENSIONS OF SUCCESS. HERE, CHAIRMAN AND CEO DAVE O'REILLY AND OTHER COMPANY EXECUTIVES DISCUSS THE NEW ENERGY EQUATION AND CHEVRONTEXACO'S STRATEGIC ROAD MAP.

O'REILLY: When we talk about a new equation in the energy business, we mean that our operating environment is changing in significant ways. Demand continues to rise while supplies are relatively constrained, particularly in OECD (Organization for Economic Cooperation and Development) countries. New resources are located in areas that are increasingly challenging to develop, such as the deep water or oil sands. And the geopolitical environment is becoming more complex. As we move into this new environment, both consuming and producing nations are coming to view energy as a strategic concern. ChevronTexaco is in a strong position to succeed in this environment. We have robust strategies that work well under a wide range of market conditions. We are bringing major new production projects on line in key energy basins around

	PICTURED FROM LEFT:
DAVID J. O'REILLY	Chairman of the Board and Chief Executive Officer
PETER J. ROBERTSON	Vice Chairman of the Board
GEORGE L. KIRKLAND	Executive Vice President, Upstream and Gas
PATRICIA A. WOERTZ	Executive Vice President, Downstream

the world, and we are making focused investments to test the practical applications of alternate energy sources. Finally, we enjoy a strong reputation as a partner of choice, which will increasingly be a competitive advantage in an interdependent, interconnected world.

ROBERTSON: A major factor in today's energy equation is growth in demand. Recent increases have been phenomenal. China, where there is a rapidly growing middle class, has doubled oil imports in the last four years, and economic growth in Asia, as a whole, is forecast to continue at a strong pace. Globally, we anticipate population growth of approximately 1 billion people by 2020, primarily in the developing world. They will aspire to a standard of living that will require access to considerable amounts of energy. Put simply, the world needs all the energy it can get. I am an optimist about meeting this challenge. We use energy much more efficiently than we ever have in the past, and our focus on conservation will continue. We are developing, adapting and applying technology to maximize the value of the resources we have. And we are making investments with the long term in mind, not in response to boom-or-bust cycles.

KIRKLAND: Despite changes in our operating environment, we are continuing to apply the same fundamentals that have driven the success of our business since its inception – discipline, innovation and execution. That being said, we have certain competencies that give us a competitive advantage in today's environment. Our exploration program was very strong in 2004, with a success rate of 57 percent, compared with a 10-year industry average of 32 percent. Our competencies in deepwater development and operations will become increasingly important over the next 10 years as we increase our deepwater portfolio from 3 percent to 20 percent of total production. And we have distinguished ourselves as an effective partner with host governments in developing countries, a strategic focus area for developing new supplies.

WOERTZ: With global refineries running at nearly full capacity, meeting growing demand requires greater levels of ingenuity and efficiency. Our refinery improvements are focused on increasing both productivity and the ability to handle a more diverse and difficult crude slate, an important advantage as demand for light, sweet crude relative to supplies continues to intensify worldwide. Customers around the globe continue to expect new products, including cleaner fuels. We are finding innovative ways to develop technology and deliver it where it is needed. With ingenuity comes flexibility and adaptability, key dynamics for the new equation.

CHEVRONTEXACO AT A GLANCE

ChevronTexaco Corporation celebrated its 125th anniversary in 2004. Since its founding, it has grown to be one of the world's largest integrated energy companies. We have more than 47,000 employees and a presence in approximately 180 countries. We are involved in virtually every aspect of the energy industry – from crude oil and natural gas exploration and production to the refining, marketing and transportation of petroleum products. We also have interests in petrochemicals and power generation assets and are working to develop and commercialize future energy technologies.

At the end of 2004, worldwide net proved oil and natural gas reserves for consolidated operations were 8.2 billion barrels of oil-equivalent and for affiliate operations 3.1 billion barrels of oil-equivalent. For the year, net production averaged 2.5 million barrels per day of oil-equivalent. Major producing areas include Angola, Indonesia, Kazakhstan, Nigeria, the Partitioned Neutral Zone, the United Kingdom and the United States. Major exploration areas include Angola, Nigeria, the U.S. Gulf of Mexico, Venezuela, and the offshore area between Angola and the Republic of Congo.

ChevronTexaco holds vast natural gas resources in some of the world's most prolific basins, including Australia where it is the largest leaseholder of undeveloped natural gas resources. Plans are under way to commercialize these resources through liquefied natural gas (LNG) and gas-to-liquids (GTL) technologies. Major LNG projects are under way to supply markets in North America and Asia. Through our Sasol Chevron joint venture, we are pursuing GTL projects in Nigeria, Qatar and Australia. Our natural gas business also includes pipeline, shipping, natural gas marketing and trading, and power generation.

UPSTREAM

OTHER

▸ Clockwise from top right: Caltex station, Singapore; Hawaii Refinery, Oahu; San Diego, California, terminal; environmental laboratory, Richmond, California, refinery.

▸ Clockwise from top right opposite page: Tengizchevroil second generation/sour gas injection project, Kazakhstan; ChevronTexaco *Colorado Voyager;* Singapore trading floor; North West Shelf Venture, Australia; Bohai Bay, China.

DOWNSTREAM

With 21 wholly owned and affiliated refineries, ChevronTexaco processed approximately 2 million barrels of crude oil per day in 2004 and averaged approximately 4 million barrels per day of refined products sales worldwide. Strategic focus areas are Asia, the U.S. West Coast, U.S. Gulf Coast and Latin America, and sub-Saharan Africa. Worldwide, we have strong recognition through our Chevron, Texaco and Caltex motor fuel brands. Products are sold through a network of approximately 25,700 retail stations, including those of affiliate companies.

BUSINESSES

ChevronTexaco, through its 50-50 joint venture Chevron Phillips Chemical Company LLC (CPChem), is one of the leading manufacturers of commodity petrochemicals. CPChem has 32 manufacturing facilities in eight countries. Chevron Oronite markets more than 500 performance-enhancing products and supplies one-fourth of the world's fuel and lubricant additives. Chevron Energy Solutions develops and constructs energy-saving projects for external and internal customers. Global Power Generation develops and markets commercial power projects worldwide.

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*.

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

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 oils*.

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 royalties. *Net production* is gross production minus royalties paid to landowners. *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*.

Refinery utilization rate Represents average crude oil consumed in fuel and asphalt refineries for the year expressed as a percentage of the refineries' average annual crude unit capacity adjusted for refinery dispositions.

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.

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

Merger-related expenses The incremental expenses incurred to effect the combination of Chevron and Texaco. The amount shown on the Income Statement is before income tax. Examples are employee termination expenses; professional service fees for investment bankers, attorneys and public accountants; employee and office relocation costs; expenses associated with closure of redundant facilities; and reconfiguration of information technology, telecommunications and accounting systems.

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

Return on capital employed (ROCE) ROCE is 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 The return to stockholders from 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

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OTHER INFORMATION

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

CAUTIONARY STATEMENTS 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 ChevronTexaco Corporation contains forward-looking statements relating to ChevronTexaco'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, ChevronTexaco undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the factors that could cause actual results to differ materially are 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; Dynegy Inc.'s ability to successfully complete its recapitalization and restructuring plans; inability or failure of the company's joint-venture partners to fund their share of operations and development activities; potential failure to achieve expected production from existing and future oil and gas development projects; potential delays in the development, construction or start-up of planned projects; potential disruption or interruption of the company's production or manufacturing facilities due to war, accidents, political events, civil unrest or severe weather; potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); potential liability resulting from pending or future litigation; the company's ability to successfully implement the restructuring of its worldwide downstream organization and other business units; the company's ability to sell or dispose of assets or operations as expected; and 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 herein also could have material adverse effects on forward-looking statements.

KEY FINANCIAL RESULTS

Millions of dollars, except per-share amounts	2004	2003	2002
Net Income	$ 13,328	$ 7,230	$ 1,132
Per Share Amounts:*			
Net Income – Basic	$ 6.30	$ 3.48	$ 0.53
– Diluted	$ 6.28	$ 3.48	$ 0.53
Dividends	$ 1.53	$ 1.43	$ 1.40
Sales and Other			
Operating Revenues	$ 150,865	$119,575	$98,340
Return on:			
Average Capital Employed	25.8%	15.7%	3.2%
Average Stockholders' Equity	32.7%	21.3%	3.5%

*2003 and 2002 restated to reflect a two-for-one stock split effected as a 100 percent stock dividend in 2004.

INCOME FROM CONTINUING OPERATIONS BY MAJOR OPERATING AREA

Millions of dollars	2004	2003	2002
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	$ 3,868	$ 3,160	$ 1,703
International	5,622	3,199	2,823
Total Exploration and Production	9,490	6,359	4,526
Downstream – Refining, Marketing and Transportation			
United States	1,261	482	(398)
International	1,989	685	31
Total Refining, Marketing and Transportation	3,250	1,167	(367)
Chemicals	314	69	86
All Other	(20)	(213)	(3,143)
Income From Continuing Operations	$ 13,034	$ 7,382	$ 1,102
Income From Discontinued Operations – Upstream	294	44	30
Income Before Cumulative Effect of Changes in Accounting Principles	$ 13,328	$ 7,426	$ 1,132
Cumulative Effect of Changes in Accounting Principles	–	(196)	–
Net Income*	$ 13,328	$ 7,230	$ 1,132
*Includes Foreign Currency Effects:	$ (81)	$ (404)	$ (43)

In 2003, net income included charges of $200 million for the cumulative effect of changes in accounting principles, related to the adoption of Financial Accounting Standards Board (FASB) Statement No. 143 (FAS 143), "Accounting for Asset Retirement Obligations." Refer to Note 25 of the Consolidated Financial Statements on page 77 for additional discussion.

Net income in each period presented included amounts for matters that management characterized as "special items," as described in the table that follows. These amounts, 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. Special items are discussed in detail for each major operating area in the "Results of Operations" section beginning on page 30. "Restructuring and Reorganizations" is described in detail in Note 12 to the Consolidated Financial Statements on page 63.

SPECIAL ITEMS

Millions of dollars – Gains (charges)	2004	2003	2002
Asset Dispositions			
Continuing Operations	$ 960	$ 122	$ –
Discontinued Operations	257	–	–
Litigation Provisions	(55)	–	(57)
Asset Impairments/Write-offs	–	(340)	(485)
Dynegy-Related	–	325	(2,306)
Tax Adjustments	–	118	60
Restructuring and Reorganizations	–	(146)	–
Environmental Remediation Provisions	–	(132)	(160)
Merger-Related Expenses	–	–	(386)
Total	$ 1,162	$ (53)	$(3,334)

BUSINESS ENVIRONMENT AND OUTLOOK

As shown in the "Special Items" table, net special gains of $1.2 billion, associated mainly with the disposition of non-strategic upstream assets, benefited income in 2004. In 2002, $2.3 billion of the $3.3 billion of net charges related to the company's investment in its Dynegy Inc. affiliate. Refer to page 35 for a discussion of the company's investment in Dynegy.

The special items recorded in 2002 through 2004 are not indicative of any future trends of events or their impact on future earnings. Because of the nature of special item-related events, the company may not always be able to anticipate their occurrence or associated effects on income in any period. Apart from the effects of special-item gains and charges, the company's earnings depend largely on the profitability of its upstream – exploration and production – and downstream – refining, marketing and transportation – business segments. The single largest variable that affects the company's results of operations is crude oil prices. Overall earnings trends are typically less affected by results from the company's commodity chemicals segment and other activities and investments.

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, develop and produce hydrocarbons in promising areas, drilling success, the ability to bring long-lead-time capital-intensive projects to completion on budget and schedule, and efficient and profitable operation of mature properties.

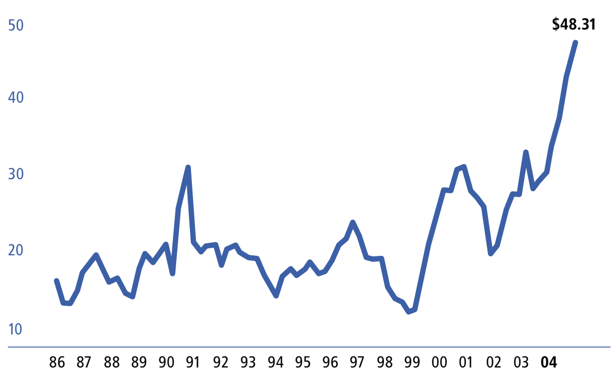
The company also continuously evaluates opportunities to dispose of assets that are not key to providing sufficient long-term value and to acquire assets or operations complementary to its asset base to help sustain the company's growth. In addition to the asset-disposition and restructuring plans announced in 2003, which generated $3.7 billion of sales proceeds in 2004, other such plans may also occur in future periods and result in significant gains or losses. Refer to the "Operating Developments" section on page 28 for a discussion that includes references to the company's asset disposition activities.

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

Upstream Year-to-year changes in exploration and production earnings align most closely 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 damages 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. Longer-term trends in earnings for this 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.

The level of operating expenses associated with the efficient production of oil and 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. Operating expenses can also be affected by uninsured damages to production facilities caused by severe weather or civil unrest.

CRUDE OIL PRICES 1986 THROUGH 2004
Dollars per barrel



The average spot price of West Texas Intermediate, a benchmark crude oil, rose 55 percent from the fourth quarter of 2003 to the fourth quarter of 2004.

Industry price levels for crude oil reached record highs during 2004. For example, the price for West Texas Intermediate (WTI) crude oil, one of the benchmark crudes, reached $55 per barrel in October 2004. WTI prices for the full year averaged $41 per barrel, an increase of approximately $10 per barrel from 2003. The WTI spot price per barrel at the end of February 2005 was approximately $51. These relatively high industry prices reflected, among other things, increased demand from higher economic growth, particularly in Asia and the United States, the heightened level of geopolitical uncertainty in many areas of the world, crude oil supply concerns in the Middle East and other key producing regions, and production shut in for repairs following Hurricane Ivan in the Gulf of Mexico in September 2004.

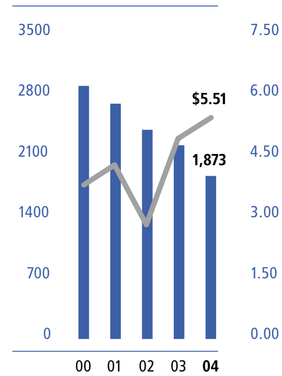
During most of 2004, the differential in prices between high quality, light-sweet crude oils, such as the U.S. benchmark WTI, and the heavier crudes was unusually wide. The upward trend in prices in 2004 for lighter crude oils tracked the increased demand for light products, as all refineries could process these higher quality crudes. However, the demand and price for the heavier crudes were dampened due to the limited number of refineries that are able to process this lower quality feedstock. The company produces heavy crude oil (including volumes under an operating service agreement) in California, Indonesia, the Partitioned Neutral Zone (between Saudi Arabia and Kuwait) and Venezuela.

Natural gas prices, particularly in the United States, were also higher in 2004 than in 2003. Benchmark prices in 2004 for Henry Hub U.S. natural gas peaked in October 2004 above $8.50 per thousand cubic feet (MCF). For the full year, prices averaged nearly $6.00 per MCF, compared with $5.50 in 2003. At the end of February 2005, the Henry Hub spot price was about $6.10 per MCF.

As compared with the supply and demand factors for natural gas in the United States and the resultant trend in the Henry Hub benchmark prices, certain other regions of the world in which the company operates have significantly different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices for the company's production of natural gas. (Refer to the table on page 34 for the company's average natural gas prices for the United States 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 developed 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 gas, ChevronTexaco and other companies in the industry are 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 and additional investment 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,

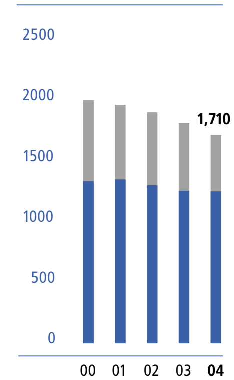
U.S. NATURAL GAS PRICES & NET PRODUCTION



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

Average prices climbed 10 percent during 2004. Production was down 16 percent due to asset sales, the effects of storms in the U.S. Gulf of Mexico and normal field declines.

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



■ United States
■ International

Net liquids production declined about 5 percent in 2004, mainly caused by asset sales and the effects of storms.

**Includes equity in affiliates*

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).

Partially offsetting the benefit of higher crude oil and natural gas prices in 2004 was a 5 percent decline in the company's worldwide oil-equivalent production from the prior year, including volumes produced from oil sands and production under an operating service agreement. The decrease was largely the result of lower production in the United States due to normal field declines, property sales and production curtailments resulting from damages to producing operations caused by Hurricane Ivan. International oil-equivalent production was down marginally between years. Refer also to page 32 for additional discussion and detail of production volumes worldwide.

The level of oil-equivalent production in future periods is uncertain, in part because of OPEC production quotas and the potential for local civil unrest and changing geopolitics that could cause production disruptions. Approximately 25 percent of the company's net oil-equivalent production in 2004, including volumes produced from oil sands and under an operating service agreement, was 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 2004 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 28 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 has been shut in since March 2003 because of civil unrest and damage to production facilities. The company has adopted a phased plan to restore these operations and has begun production-resumption efforts in certain areas.

As a result of Hurricane Ivan in September 2004, production in the fourth quarter was about 60,000 barrels per day lower than it otherwise would have been. Damages to producing facilities are expected to restrict oil-equivalent production in the first quarter 2005 by approximately 35,000 barrels per day. Most of the remaining shut-in production is expected to be restored in the second quarter of 2005.

Downstream Refining, marketing and transportation earnings are closely tied to regional 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.

Specific factors influencing 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 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 tankers. Factors beyond the company's control include the general level of inflation, especially energy costs to operate the refinery network.

Downstream earnings improved in 2004 compared with the prior year, primarily as a result of increased demand and higher margins for the industry's refined products in most of the areas in which the company and its equity affiliates have operations. In 2004, refined-product margins in North America and Asia were at their highest level in recent years. Industry margins may be volatile in the future, depending primarily on price movements for crude oil feedstocks, the demand for refined products, inventory levels, refinery maintenance and mishaps, and other factors.

Chemicals Earnings in the petrochemicals segment are closely tied to global chemical demand, inventory levels and plant capacities. Additionally, feedstock and fuel costs, which tend to follow crude oil and natural gas price movements, influence earnings in this segment.

Earnings improved in 2004 compared with 2003 primarily from the results of the company's 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem) affiliate, which recorded higher margins and sales volumes for commodity chemicals and higher equity affiliate income.

OPERATING DEVELOPMENTS

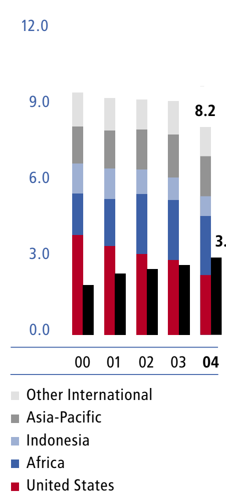
Key operating developments and other events during 2004 and early 2005 included:

Upstream

North America During 2004, the company closed on the sale of more than 300 producing properties and other assets in the United States and Canada, generating proceeds of $2.5 billion. These sales, which accounted for less than 10 percent of the oil-equivalent production and reserves in North America, were part of plans announced in 2003 to dispose of assets that did not provide sufficient long-term value to the company and to improve the overall competitive performance and operating efficiency of the company's exploration and production portfolio.

In the Gulf of Mexico, the company awarded two major engineering contracts for the development of subsea systems and a floating production facility to advance the development of the operated and 58 percent-owned Tahiti prospect, a major deepwater discovery. A successful well test of the original discovery well was also conducted in 2004. Elsewhere in the Gulf of Mexico, a deepwater crude

NET PROVED RESERVES
Billions of BOE*



Net proved reserves for consolidated companies declined 11 percent in 2004, while affiliated companies' reserves climbed by 11 percent.

*Barrels of oil-equivalent

oil discovery was announced at the operated and 50 percent-owned Jack prospect in Walker Ridge Block 759.

Angola In late 2004, first production was achieved at the Block 0 Sanha Bomboco project, which will help reduce natural-gas flaring.

Australia In mid-2004, the company announced a natural gas discovery at the wholly owned Wheatstone-1 well located offshore Western Australia. Production tests were completed in the third quarter 2004, and in early 2005 the company was evaluating development options.

Cambodia In January 2005, the company announced crude oil discoveries at four exploration wells in offshore Block A. ChevronTexaco is the operator of the block and holds a 55 percent interest.

China In August 2004, initial crude oil production occurred at the 16 percent-owned BZ 25-1 Field, located in Bohai Bay. Crude oil production also began late in 2004 at the HZ 19-3 Field, in which the company has a 33 percent working interest.

Faroe Islands In January 2005, the company was awarded five offshore exploration blocks in the Faroe Islands' second offshore licensing round. The blocks are near the earlier Rosebank/Lochnagar discovery in the United Kingdom. The company has a 40 percent interest and will be the operator.

Kazakhstan The company's first crude oil from Karachaganak Field was loaded at Russia's Black Sea port of Novorossiysk in mid-2004. This represented the first shipment of Karachaganak crude oil through the Caspian Pipeline Consortium export pipeline that provides access to world markets.

Construction continued during 2004 by the company's 50 percent-owned Tengizchevroil affiliate on Sour Gas Injection (SGI)/Second Generation Project (SGP), which is expected to increase total production from the current capacity of 298,000 barrels of crude oil per day to between 430,000 and 500,000 barrels per day by the end of 2006, with the expansion dependent upon the success of the SGI.

Libya In early 2005, the company was awarded onshore Block 177 in Libya's first exploration license round under the Exploration and Production Sharing Agreement IV terms. The company was also made operator of the block with 100 percent equity. The events mark the company's return to Libya after a 28-year absence.

Nigeria At the deepwater Agbami project, several milestones were achieved in 2004, including initial development drilling in the third quarter and reaching a unitization agreement with other owners in the area. In early 2005, a contract for the construction of a floating production, storage and offshore loading platform was awarded. The project is being unitized, and the company's equity will be about 68 percent.

The company was awarded a 100 percent contractor interest in the deepwater Nigeria Block OPL-247 in the eastern part of the Niger Delta in the second quarter 2004. Block 247 is adjacent to Block 222, which includes the company's Usan and Ukot discoveries.

In the third quarter 2004, the company announced a crude oil discovery at the Usan 5 well. Additionally, in early 2005, hydrocarbons were encountered at the Usan 6 appraisal well. ChevronTexaco holds a 30 percent interest in the wells, both of which are located in OPL-222.

Nigeria – São Tomé and Príncipe Joint Development Zone (JDZ) The company was awarded the right in early 2004 to conduct exploration activities in deepwater Block 1 in the JDZ, offshore São Tomé and Príncipe and Nigeria. In early 2005, the company signed a production-sharing contract with the Joint Development Authority, under which ChevronTexaco will be the operator with a 51 percent interest in the block.

Southern Africa The company announced a discovery in the deepwater area between Angola and the Republic of Congo at the Lianzi-1 exploration well in the third quarter 2004. The discovery, in the shared 14K/A-IMI Unit, is located in the same area as the previous Block 14 deepwater crude oil discoveries at Landana and Tombua in Angola. ChevronTexaco is the operator of the 14K/A-IMI Unit and holds about a 31 percent interest.

Russia In September 2004, the company and OAO Gazprom signed a six-month memorandum of understanding to jointly undertake feasibility studies for the possible implementation of projects in Russia and the United States. This represents a possible opportunity to participate in the development of the vast natural gas and crude oil resource base in Russia and to develop a close partnership with Russia's largest natural gas producer.

Thailand The company announced successful exploration and appraisal drilling results in mid-2004 at Block G4/43, located in the Gulf of Thailand. Block G4/43 is adjacent to the company's operated and 52 percent-owned Block B8/32.

Trinidad and Tobago In early 2005, the company announced successful exploration drilling results at the offshore Manatee 1 exploration well in Block 6d. ChevronTexaco operates and holds a 50 percent interest in this well.

United Kingdom In the third quarter 2004, production of first crude oil occurred at the 21 percent-owned Alba Extreme South Phase 2 project. Alba Field is located in Block 16/26, northeast of Aberdeen. In the fourth quarter, a crude oil and natural gas discovery was made at the offshore 40 percent-owned Rosebank/Lochnagar well (213/27-1Z) in the Faroe-Shetland Channel.

Venezuela In August 2004, the company was awarded an exploration license and 100 percent interest for Block 3 in Plataforma Deltana, an offshore area on Venezuela's Atlantic continental shelf. The exploration rights added to the company's existing Block 2 license in Venezuela and Block 6d in Trinidad and Tobago, across the border with Venezuela. Two exploration wells were successful during 2004 in the operated and 60 percent-owned Plataforma Deltana Block 2.

The company completed onshore construction of the 30 percent-owned Hamaca Project's crude oil upgrading facility. This facility has the capacity to process 190,000 barrels per day of heavy crude oil and upgrade into 180,000 barrels per day of lighter higher-value crude oil. Upgrading began in October 2004.

Global Natural Gas Projects In Qatar, Sasol Chevron, ChevronTexaco's 50-50 global joint venture with Sasol of South Africa, entered into a memorandum of understanding with Qatar Petroleum to expand the Oryx gas-to-liquids project and a letter of intent to examine GTL base oils opportunities in Qatar. Qatar Petroleum and Sasol Chevron also agreed to pursue an opportunity to develop a 130,000-barrel-per-day integrated gas-to-liquids project.

In Australia, the North West Shelf Venture began commissioning of a fourth LNG train in September 2004. This increased the venture's LNG production capacity by approximately 50 percent during 2004. ChevronTexaco holds a one-sixth interest in the joint venture.

The company announced in the fourth quarter 2004 an agreement with other shareholders of the West African Gas Pipeline Co. Ltd. to move forward with the construction of a pipeline to be used for the transportation of natural gas more than 400 miles from Nigeria to customers in Ghana, Benin and Togo.

In early 2005, the company announced plans to conduct a feasibility study on a potential liquefied natural gas (LNG) project at Olokola in southwest Nigeria. Future decisions to move forward with Olokola LNG will depend on the results of the feasibility study.

In November 2004, ChevronTexaco and its partners in the Brass LNG Project awarded the contract for front-end engineering and design for a world-scale LNG plant to be located in Nigeria. The LNG plant will have two processing trains with potential processing capacity of 5 million metric tons each. ChevronTexaco is expected to supply a major amount of feed gas to the LNG project.

In Angola, front-end engineering and design work is scheduled to begin in the first half of 2005 for the construction of a multibillion dollar LNG processing plant that also will help eliminate natural gas flaring associated with crude oil producing operations. The company has a 36 percent ownership interest in the plant and will co-lead the project with the Angolan government's national oil company.

In September 2004, the company was awarded authorization from the Mexican Environment and Natural Resources Secretariat for its Environmental Impact Assessment and Risk Assessment for a proposed LNG receiving and regasification terminal offshore Baja California, Mexico. In December 2004, the company was awarded a natural gas storage permit from the Mexican Regulatory Energy Commission for a proposed natural gas terminal. The company also received notice from the Mexican Communication and Transport Secretariat, through its Port Authority, that it won the public licensing round for the offshore port terminal.

In November 2004, the company announced it had plans to submit permit applications for a proposed LNG import terminal to be located at the company's Pascagoula Refinery.

In December 2004, the company announced the finalization of a 20-year agreement for regasification capacity at the proposed Sabine Pass LNG terminal in Louisiana.

Downstream

Worldwide Reorganization In early 2004, the company's downstream businesses began operating as global refining, marketing, and supply and trading businesses. Previously, these functions were aligned by the individual geographic areas in which the company operates. This realignment is targeted to improve operating efficiencies and financial performance.

Singapore Joint Venture In July 2004, the company acquired an additional interest in the Singapore Refining Company Pte. Ltd. (SRC), increasing its ownership from 33 percent to 50 percent. This additional interest in SRC is expected to strengthen ChevronTexaco's existing strategic position in the Asia-Pacific area, one of its core markets.

China Joint Venture In January 2005, the company announced a preliminary agreement for a business partner in China to take a majority interest in the company's existing joint venture that operates retail service stations in South China.

Asset Dispositions Throughout 2004, the company continued the marketing and sale of service station sites. Dispositions of about 1,600 sites occurred from the program's inception in early 2003 through the end of 2004. In February 2005, the company announced a memorandum of understanding to negotiate the sale of approximately 140 service stations in the United Kingdom.

Texaco Brand Under terms of an agreement executed at the time of the merger with Texaco, the company regained nonexclusive rights to use the Texaco brand in the United States on July 1, 2004, and resumed marketing gasoline under the Texaco retail brand in the United States in mid-2004. By the end of the year, the company was supplying more than 1,000 Texaco retail sites primarily in the Southeast. The company plans to supply additional sites in the Southeast and West during 2005.

Chemicals

Saudi Arabia The company's 50 percent-owned affiliate, CPChem, began construction of an integrated styrene facility and expansion of an adjacent aromatics plant at Al Jubail, Saudi Arabia, in the fourth quarter 2004. The project is scheduled for completion in the first half of 2008.

Other

Common Stock Dividends and Stock Repurchase Program In September 2004, the company increased its quarterly common stock dividend by 10 percent and immediately followed the dividend increase with a two-for-one stock split in the form of a stock dividend. In connection with a stock repurchase program initiated in April 2004, the company purchased 42,324,000 shares in the open market for $2.1 billion through December. Purchases through the end of February 2005 increased the total shares acquired to 47,969,000 shares for $2.4 billion. The repurchase program is in effect for up to three years from the date initiated for acquisitions of up to $5 billion.

RESULTS OF OPERATIONS

Major Operating Areas The following section presents the results of operations for the company's business segments, as well as for the departments and companies managed at the corporate level. (Refer to Note 9 beginning on page 60 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 segment income between periods, the discussion, when applicable, is in two parts – first, on underlying trends and second, on special-item gains and charges that tended to obscure these trends. In the following discussions, the term "earnings" is defined as net income or segment income before the cumulative effect of changes in accounting principles. This section should also be read in conjunction with the discussion of the company's "Business Environment and Outlook" on pages 26 through 28.

U.S. Upstream – Exploration and Production

Millions of dollars	**2004**	2003	2002
Income From Continuing Operations	**$ 3,868**	$ 3,160	$ 1,703
Income From Discontinued Operations	**70**	23	14
Cumulative Effect of Accounting Change	**–**	(350)	–
Segment Income*	**$ 3,938**	$ 2,833	$ 1,717
*Includes Special-Item Gains (Charges):			
Asset Dispositions			
Continuing Operations	**$ 316**	$ 77	$ –
Discontinued Operations	**50**	–	–
Litigation Provisions	**(55)**	–	–
Asset Impairments/Write-offs	**–**	(103)	(183)
Restructuring and Reorganizations	**–**	(38)	–
Environmental Remediation Provisions	**–**	–	(31)
Total	**$ 311**	$ (64)	$ (214)

Income from continuing operations in 2004 of nearly $3.9 billion was about $700 million higher than in 2003. Nearly $400 million of the increase represented the difference in the effect on earnings in the respective periods from special items, which are discussed below. The remaining $300 million improvement was composed of about a $1 billion benefit from higher crude oil and natural gas prices that was largely offset by the effects of lower production.

Income from continuing operations in 2003 was about $3.2 billion, up approximately $1.5 billion from 2002. The benefit of higher prices between periods was about $1.7 billion and was partially offset by the effect of lower production.

The company's average liquids realization in 2004 was $34.12 per barrel, compared with $26.66 in 2003 and $21.34 in 2002. The average natural gas realization was $5.51 per thousand cubic feet in 2004, compared with $5.01 and $2.89 in 2003 and 2002, respectively.

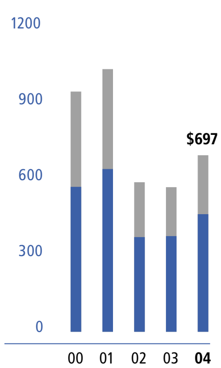
Net oil-equivalent production averaged 817,000 barrels per day in 2004, down 12 percent from 2003 and 19 percent from 2002. The lower production in 2004 included the effects of about 30,000 barrels per day associated with property sales and 21,000 barrels per day of production shut in as a result of damages to facilities from Hurricane Ivan in the third quarter. Adjusting for the effects of property sales and storms in all periods presented, oil-equivalent production in 2004 declined about 7 percent from 2003 and 14 percent from 2002, mainly as a result of normal field declines that do not typically reverse.

The net liquids component of oil-equivalent production for 2004 averaged 505,000 barrels per day, a decline of 10 percent from 2003 and 16 percent from 2002. Excluding the effects of property sales and storms, net liquids production in 2004 declined 5 percent and 11 percent from 2003 and 2002, respectively.

Net natural gas production averaged 1.9 billion cubic feet per day in 2004, 16 percent lower than 2003 and 22 percent lower than 2002. Adjusting for the effects of property sales and storms, 2004 net natural gas production declined 10 percent in 2003 and 17 percent in 2002.

Refer to the "Selected Operating Data" table on page 34 for the three-year comparative production volumes in the United States.

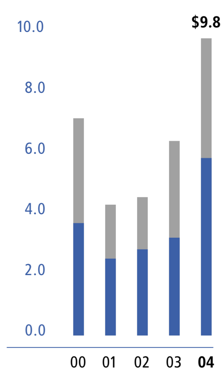
EXPLORATION EXPENSES
Millions of dollars



■ United States
■ International

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

WORLDWIDE EXPLORATION & PRODUCTION EARNINGS*
Billions of dollars



■ United States
■ International

Earnings increased significantly in 2004 on higher prices for crude oil and natural gas. Partially offsetting were the effects of lower production volumes.

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

Segment income in 2004 included special gains of $366 million from property sales, partially offset by special charges of $55 million resulting from 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. Special charges in 2002 totaled $214 million, which included $183 million for the impairment of a number of fields caused by the write-down of proved reserves and $31 million for costs of environmental remediation.

International Upstream – Exploration and Production

Millions of dollars	**2004**	2003	2002
Income From Continuing Operations[1]	**$5,622**	$3,199	$2,823
Income From Discontinued Operations	**224**	21	16
Cumulative Effect of Accounting Change	**–**	145	–
Segment Income[2]	**$5,846**	$3,365	$2,839
[1] Includes Foreign Currency Effects:	**$ (129)**	$ (319)	$ 90
[2] Includes Special-Item Gains (Charges):			
Asset Dispositions			
Continuing Operations	**$ 644**	$ 32	$ –
Discontinued Operations	**207**	–	–
Asset Impairments/Write-offs	**–**	(30)	(100)
Restructuring and Reorganizations	**–**	(22)	–
Tax Adjustments	**–**	118	(37)
Total	**$ 851**	$ 98	$(137)

Income from continuing operations of $5.6 billion in 2004 increased about $2.4 billion from 2003. Approximately $1.1 billion of the increase was associated with higher prices for crude oil and natural gas. Approximately $750 million of the increase was the result of the effects of special items in each period, which are discussed below. 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. Otherwise, the benefit of about $200 million in lower foreign currency losses was largely offset by higher transportation costs.

Income from continuing operations of $3.2 billion in 2003 was nearly $400 million higher than in 2002. Higher crude oil and natural gas prices accounted for an increase of about $900 million, which was partially offset by $400 million from the effect of foreign currency changes and about $100 million of higher income tax-expense.

Net oil-equivalent production of 1.7 million barrels per day in 2004 – including other produced volumes of 140,000 net barrels per day from oil sands and production under an operating service agreement – declined about 1 percent from 2003 and 2 percent from 2002. Excluding the lower production associated with property sales and reduced volumes associated with cost-recovery provisions of certain production-sharing agreements, 2004 net oil-equivalent production increased nearly 3 percent from 2003 and 1 percent from 2002 – primarily from higher oil-equivalent production in Chad, Kazakhstan and Venezuela.

The net liquids component of oil-equivalent production, including volumes produced from oil sands and under an operating service agreement, declined about 1 percent from the production level in 2003 and about 3 percent from 2002. Excluding the effects of property sales and lower cost-recovery volumes under certain production-sharing agreements, 2004 net liquids production increased about 1 percent from 2003 and decreased about 1 percent from 2002.

The net natural gas component of oil-equivalent production was up 1 percent from 2003 and 6 percent from 2002. During 2004, production increases in Angola, Kazakhstan, Denmark and Australia were partially offset by declines associated with asset sales. In 2003, areas with production increases included Australia, Kazakhstan, the Philippines and the United Kingdom.

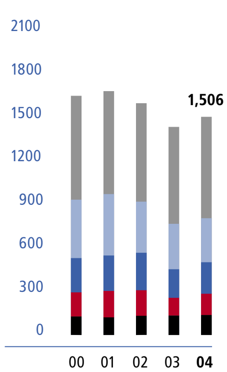
Refer to the "Selected Operating Data" table on page 34 for the three-year comparative of international production volumes.

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 gains of $98 million included benefits of $150 million related to income taxes and property sales, partially offset by asset impairments in advance of sale and charges for employee termination costs. In 2002, special charges of $137 million included $100 million for asset impairments resulting from the write-down of proved reserves for fields in Africa and Canada.

U.S. Downstream – Refining, Marketing and Transportation

Millions of dollars	2004	2003	2002
Segment Income (Loss)*	**$ 1,261**	$ 482	$ (398)
*Includes Special-Item Gains (Charges):			
Asset Dispositions	$ –	$ 37	$ –
Asset Impairments/Write-offs	–	–	(66)
Environmental Remediation Provisions	–	(132)	(92)
Restructuring and Reorganizations	–	(28)	–
Litigation Provisions	–	–	(57)
Total	$ –	$ (123)	$ (215)

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

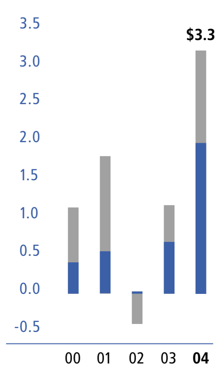


■ Gasoline
■ Jet Fuel
■ Gas Oils & Kerosene
■ Residual Fuel Oil
■ Other

Refined products sales volumes increased about 5 percent from 2003, with higher sales of most products.

Includes equity in affiliates

WORLDWIDE REFINING, MARKETING & TRANSPORTATION EARNINGS
Billions of dollars



■ United States
■ International

Downstream earnings improved significantly due to higher industry demand and improved margins for refined products worldwide.

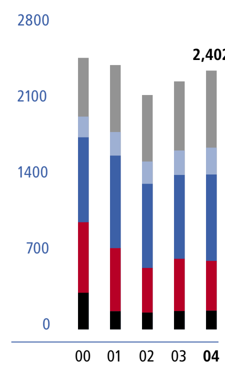
The earnings improvement in 2004 from both 2003 and 2002 was associated mainly with higher margins for refined products. Margins in 2004 were the highest in recent years. Margins in 2002 were very depressed, and at one point hovered near their 12-year lows.

Sales volumes for refined products of approximately 1.5 million barrels per day in 2004 increased about 5 percent from 2003. The increase between periods was primarily from higher sales of gasoline, diesel fuel and fuel oil. Branded gasoline sales volumes of 567,000 barrels per day increased 2 percent from 2003. The sales improvement partially reflected the reintroduction of the Texaco brand in the Southeast. In 2003, sales volumes for refined products declined about 10 percent from the prior year. Industry demand in 2003 was weaker for branded gasoline, diesel and jet fuels and sales were lower under certain supply contracts.

Refer to the "Selected Operating Data" table on page 34 for the three-year comparative refined-product sales volumes in the United States.

In 2003, net special charges of $123 million included $160 million for environmental remediation and employee severance costs associated with the global downstream restructuring and reorganization. These charges were partially offset by gains on asset sales. In 2002, special charges of $215 million included amounts for environmental remediation, the write-down of the El Paso refinery in advance of sale and a litigation matter.

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



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

Refined products sales volumes increased about 4 percent from 2003.

Includes equity in affiliates

International Downstream – Refining, Marketing and Transportation

Millions of dollars	2004	2003	2002
Segment Income[1,2]	**$ 1,989**	$ 685	$ 31
[1] Includes Foreign Currency Effects:	**$ 7**	$ (141)	$ (176)
[2] Includes Special-Item Gains (Charges):			
Asset Dispositions	$ –	$ (24)	$ –
Asset Impairments/Write-offs	–	(123)	(136)
Restructuring and Reorganizations	–	(42)	–
Total	$ –	$ (189)	$ (136)

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

Earnings of nearly $2 billion in 2004 improved significantly from 2003 and 2002, mainly the result of higher average margins for refined products for both company and affiliate operations and higher earnings from international shipping operations. Margins in

2004 were the highest in recent years. Earnings in 2004 also included a benefit of $40 million related to changes in income tax laws.

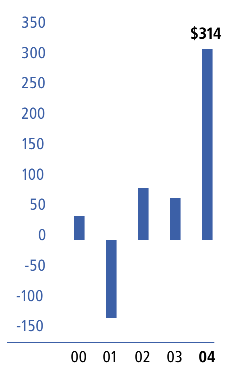
Total international refined products sales volumes were 2.4 million barrels per day in 2004, more than 4 percent higher than 2.3 million in 2003 and about 10 percent higher than 2.2 million in 2002. Weak economic conditions dampened industry demand in 2002. Refer to the "Selected Operating Data" table on page 34 for the three-year comparative refined-product sales volumes in the international areas.

Special 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 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. The special charge in 2002 was for a write-down of the company's investment in its publicly traded Caltex Australia Limited affiliate to its estimated fair value.

Chemicals

Millions of dollars	2004	2003	2002
Segment Income*	**$ 314**	$ 69	$ 86
*Includes Foreign Currency Effects:	**$ (3)**	$ 13	$ 3

WORLDWIDE CHEMICALS EARNINGS*
Millions of dollars



Chemicals earnings improved significantly on higher margins for commodity chemicals and higher affiliate income.

**Includes equity in affiliates*

The chemicals segment includes the company's Oronite division and the company's 50 percent share of its equity investment in Chevron Phillips Chemical Company LLC (CPChem). In 2004, results for the company's Oronite subsidiary improved on higher sales volumes. Earnings in 2004 for CPChem increased as the result of increased chemical commodity margins and sales volumes and higher equity affiliate income. Protracted weak demand for commodity chemicals and industry oversupply conditions suppressed earnings for this segment in 2003 and 2002.

All Other

Millions of dollars	2004	2003	2002
Charges Before Cumulative Effect of Changes in Accounting Principles	**$ (20)**	$ (213)	$ (3,143)
Cumulative Effect of Accounting Changes	**–**	9	–
Net Charges[1,2]	**$ (20)**	$ (204)	$ (3,143)
[1] Includes Foreign Currency Effects:	**$ 44**	$ 43	$ 40
[2] Includes Special-Item Gains (Charges):			
Dynegy-Related	**$ –**	$ 325	$ (2,306)
Asset Impairments/Write-offs	**–**	(84)	–
Restructuring and Reorganizations	**–**	(16)	–
Tax Adjustments	**–**	–	97
Environmental Remediation Provisions	**–**	–	(37)
Merger-Related Expenses	**–**	–	(386)
Total	**$ –**	$ 225	$ (2,632)

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

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 favorable corporate-level tax adjustments. The net change between 2002 and 2003 was largely attributable to the differences in the effect of net special charges. The 2003 period also included lower interest expense and other corporate charges compared with 2002.

Net special gains in 2003 included a benefit of $365 million from the exchange of the company's investment in Dynegy preferred stock for cash and other Dynegy securities. This benefit was partially offset by charges for asset write-downs of $84 million, primarily in the gasification business, which was later sold; $40 million for the company's share of an asset impairment by Dynegy; and employee severance costs of $16 million.

Special charges in 2002 included $2.3 billion related to Dynegy, composed of $1.6 billion for the write-down of the company's investment in Dynegy common and preferred stock to its estimated fair value and $680 million for the company's share of Dynegy's own special items for asset write-downs and revaluations, and a loss on an asset sale. Refer also to page 35 for "Information Relating to the Company's Investment in Dynegy."

CONSOLIDATED STATEMENT OF INCOME

Comparative amounts for certain income statement categories are shown in the following table. For each category, the 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, merger-related expenses, write-down of investments in Dynegy and the cumulative effect of changes in accounting principles. These matters are discussed elsewhere in MD&A and in Note 14 to the Consolidated Financial Statements on page 63.

Millions of dollars	2004	2003	2002
Income (loss) from equity affiliates	**$ 2,582**	$ 1,029	$ (25)
Memo: Special gains (charges), before tax	**–**	179	(829)
Other income	**$ 1,853**	$ 308	$ 222
Memo: Special gains, before tax	**1,281**	217	–
Operating expenses	**$ 9,832**	$ 8,500	$ 7,795
Memo: Special charges, before tax	**85**	329	259
Selling, general and administrative expenses	**$ 4,557**	$ 4,440	$ 4,155
Memo: Special charges, before tax	**–**	146	180
Depreciation, depletion and amortization	**$ 4,935**	$ 5,326	$ 5,169
Memo: Special charges, before tax	**–**	286	298
Interest and debt expense	**$ 406**	$ 474	$ 565
Memo: Special charges, before tax	**–**	–	–
Taxes other than on income	**$ 19,818**	$ 17,901	$ 16,682
Memo: Special charges, before tax	**–**	–	–
Income tax expense	**$ 7,517**	$ 5,294	$ 2,998
Memo: Special charges (benefits)	**291**	(312)	(604)

Explanations follow for variations between years for the amounts in the table above – after consideration of the effects of special gains and charges – as well as for other income statement categories. Refer to the preceding segment discussions in this section for information relating to special gains and charges.

Sales and other operating revenues were $151 billion in 2004, compared with $120 billion in 2003 and $98 billion in 2002. Revenues increased in 2004 and 2003 primarily from higher prices for crude oil, natural gas and refined products worldwide.

Income (loss) from equity affiliates increased in 2004 and 2003, as earnings improved for a number of affiliates, including downstream affiliates in the Asia-Pacific area, Tengizchevroil, CPChem, Dynegy and the Caspian Pipeline Consortium.

Other income in 2004 included net gains of $1.6 billion, primarily from upstream property sales, compared with gains of $286 million and $94 million in 2003 and 2002, respectively. Interest income increased to $199 million in 2004, compared with about $120 million in 2003 and 2002, as a result of higher balances of cash and marketable securities. Foreign currency losses were $60 million, $199 million and $5 million in 2004, 2003 and 2002, respectively.

Purchased crude oil and products were $94 billion in 2004, an increase of 32 percent from 2003, due mainly to higher prices and increased purchases of crude oil and products. Crude oil and product purchases increased about 25 percent in 2003, primarily due to significantly higher prices for crude oil, natural gas and refined products.

Operating, selling, general and administrative expenses of $14 billion increased from $13 billion in 2003. The increases in 2004 included costs for chartering of crude oil tankers and other transportation expenses. During 2003, operating, selling, general and administrative expenses increased nearly $1 billion, primarily from higher freight rates for international shipping operations and higher costs associated with employee pension plans and other employee-benefit expenses.

Exploration expenses were $697 million in 2004, $570 million in 2003 and $591 million in 2002. In 2004, amounts were higher for international operations, primarily for seismic costs and expenses associated with evaluating the feasibility of different project alternatives.

Depreciation, depletion and amortization expenses did not change materially between years after consideration of the effects of special-item charges.

Interest and debt expense was $406 million in 2004, compared with $474 million in 2003 and $565 million in 2002. The lower amount in 2004 reflected lower average debt balances. The decline between 2003 and 2002 reflected lower average interest rates on commercial paper and other variable-rate debt and lower average debt levels.

Taxes other than on income were $19.8 billion, $17.9 billion and $16.7 billion in 2004, 2003 and 2002, respectively. The increase in 2004 and 2003 primarily reflected the weakening U.S. dollar on foreign currency-denominated duties in the company's European downstream operations.

Income tax expense corresponded to effective tax rates of 37 percent in 2004, 43 percent in 2003 and 45 percent in 2002 after taking into account the effect of net special items. Refer also to Note 17 on page 66 to the Consolidated Financial Statements.

Merger-related expenses were $576 million in 2002. No merger-related expenses were reported in 2004 or 2003, reflecting the completion of merger integration activities in 2002.

SELECTED OPERATING DATA[1,2]

	2004	2003	2002
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**505**	562	602
Net Natural Gas Production (MMCFPD)[3]	**1,873**	2,228	2,405
Net Oil-Equivalent Production (MBOEPD)	**817**	933	1,003
Natural Gas Sales (MMCFPD)	**4,518**	4,304	5,891
Natural Gas Liquids Sales (MBPD)	**177**	194	241
Revenues From Net Production			
Liquids ($/Bbl)	**$ 34.12**	$ 26.66	$ 21.34
Natural Gas ($/MCF)	**$ 5.51**	$ 5.01	$ 2.89
International Upstream			
Net Crude and Natural Gas Liquids Production (MBPD)	**1,205**	1,246	1,295
Net Natural Gas Production (MMCFPD)[3]	**2,085**	2,064	1,971
Net Oil-Equivalent Production (MBOEPD)[4]	**1,692**	1,704	1,720
Natural Gas Sales (MMCFPD)	**1,885**	1,951	3,131
Natural Gas Liquids Sales (MBPD)	**105**	107	131
Revenues From Liftings			
Liquids ($/Bbl)	**$ 34.17**	$ 26.79	$ 23.06
Natural Gas ($/MCF)	**$ 2.68**	$ 2.64	$ 2.14
Net Oil-Equivalent Production Including Other Produced Volumes (MBPD)[3,4]			
U.S.	**817**	933	1,003
International	**1,692**	1,704	1,720
Total	**2,509**	2,637	2,723
U.S. Downstream – Refining, Marketing and Transportation			
Gasoline Sales (MBPD)	**701**	669	680
Other Refined Products Sales (MBPD)	**805**	767	920
Total[5]	**1,506**	1,436	1,600
Refinery Input (MBPD)[6]	**914**	951	979
International Downstream – Refining Marketing and Transportation			
Gasoline Sales (MBPD)	**717**	643	620
Other Refined Products Sales (MBPD)	**1,685**	1,659	1,555
Total[7]	**2,402**	2,302	2,175
Refinery Input (MBPD)	**1,044**	1,040	1,100

[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.

	2004	2003	2002
[3] Includes natural gas consumed on lease:			
United States	**50**	65	64
International	**293**	268	256
[4] Other produced volumes include:			
Athabasca Oil Sands – Net	**27**	15	–
Boscan Operating Service Agreement	**113**	99	97
	140	114	97
[5] Includes volume for buy/sell contracts:	**84**	90	101
[6] The company sold its interest in the El Paso Refinery in August 2003.			
[7] Includes volume for buy/sell contracts:	**96**	104	96

INFORMATION RELATED TO INVESTMENT IN DYNEGY INC.

At year-end 2004, ChevronTexaco owned an approximate 25 percent equity interest in the common stock of Dynegy – an energy provider engaged in power generation, gathering and processing of natural gas, and the fractionation, storage, transportation and marketing of natural gas liquids. The company also held an investment in Dynegy preferred stock.

Investment in Dynegy Common Stock At December 31, 2004, the carrying value of the company's investment in Dynegy common stock was approximately $150 million. This amount was about $365 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 has been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors giving rise 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 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 December 31, 2004, was approximately $450 million.

Investments in Dynegy Notes and Preferred Stock At the beginning of 2004, the company held $223 million face value of Dynegy Junior Unsecured Subordinated Notes due 2016 and $400 million face value of Dynegy Series C Convertible Preferred Stock with a stated maturity of 2033.

The Junior Notes were redeemed at face value during 2004, and gains of $54 million were recorded for the difference between the face amounts and the carrying values at the time of redemption. The face value of the company's investment in the Series C preferred stock at December 31, 2004, was $400 million. The stock is recorded at its fair value, which was estimated to be $370 million at December 31, 2004. Future temporary changes in the estimated fair value of the preferred stock will be 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 received from the preferred stock are recognized in income each period.

LIQUIDITY AND CAPITAL RESOURCES

Cash, Cash Equivalents and Marketable Securities Total balances were $10.7 billion and $5.3 billion at December 31, 2004 and 2003, respectively. Cash provided by operating activities in 2004 was $14.7 billion, compared with $12.3 billion in 2003 and $9.9 billion in 2002. These amounts were net of contributions to employee pension plans of $1.6 billion, $1.4 billion and $246 million in 2004, 2003 and 2002, respectively. The 2004 increase in cash provided by operating activities mainly reflected higher earnings in the worldwide upstream and downstream businesses. Cash provided by investing activities included proceeds from asset sales of $3.7 billion in 2004, $1.1 billion in 2003 and $2.3 billion in 2002.

Cash provided by operating activities and asset sales during 2004 was sufficient to fund the company's capital and exploratory program, pay $3.2 billion of dividends to stockholders, reduce total debt by $1.3 billion, repurchase $2.1 billion of common stock, and increase the balance of cash, cash equivalents and marketable securities by $5.5 billion.

Dividends Payments of approximately $3.2 billion in 2004 and $3 billion in 2003 and 2002 were made for dividends. In September 2004, the company increased its quarterly common stock dividend by 10 percent to 40 cents per share, on a post-stock split basis.

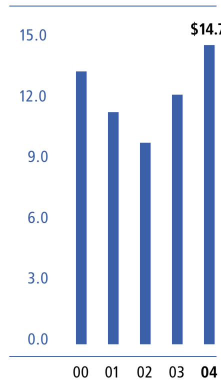
Debt, Capital Lease and Minority Interest Obligations Total debt and capital lease balances were $11.3 billion at December 31, 2004, down from $12.6 billion at year-end 2003. The company also had minority interest obligations of $172 million, down from $268 million at December 31, 2003.

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, 2004, down from $6.0 billion at December 31, 2003. Of these amounts, $4.7 billion and $4.3 billion were reclassified to long-term at the end of each period, respectively. At year-end 2004, settlement of these obligations was not expected to require the use of working capital in 2005, 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.

At year-end 2004, ChevronTexaco had $4.7 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, 2004. In addition, the company had three existing effective "shelf" registrations on file with the Securities and Exchange Commission (SEC) that together would permit additional registered debt offerings up to an aggregate of $3.8 billion of debt securities.

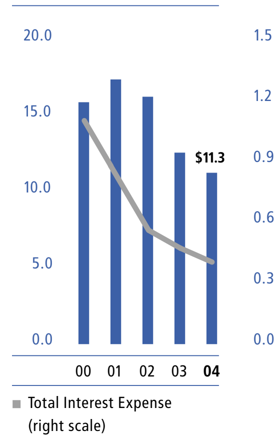
In 2004, repayments of long-term debt at maturity included $500 million of 6.625 percent ChevronTexaco Corporation bonds, an aggregate $265 million of various Philippine debt and $240 million of ChevronTexaco Corporation 8.11 percent notes.

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars



Higher earnings helped boost the company's operating cash flow by 19 percent.

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



Interest expense continued to fall on significantly lower debt levels.

In the third quarter 2004, $300 million of 6 percent Texaco Capital Inc. debt, due June 2005, also was retired.

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 and accumulated dividends at a cost of approximately $140 million.

In January 2005, the company contributed $98 million 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, ChevronTexaco entered into $1 billion of interest rate fixed-to-floating swap transactions. Under the terms of the swap agreements, of which $250 million and $750 million 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.

ChevronTexaco's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investor Service, except for senior debt of Texaco Capital Inc., which is rated Aa3. ChevronTexaco's U.S. commercial paper is rated A-1+ by Standard and Poor's and Prime 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, 2004, 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 or modify capital-spending plans or both to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

Tengizchevroil Funding As part of the funding of the expansion of Tengizchevroil's (TCO) production facilities, in the fourth quarter 2004 ChevronTexaco purchased from TCO $2.2 billion of 6.124 percent Series B Notes (Series B), due 2014. Interest on the notes is payable semiannually, and principal is to be repaid semiannually in equal installments beginning in February 2008.

Immediately following the purchase of the Series B, ChevronTexaco received from TCO approximately $1.8 billion, representing a repayment of subordinated loans from the company, interest and dividends. The $2.2 billion investment in the Series B Notes, which the company intends to hold until maturity, and the $1.8 billion distribution were recorded on the Consolidated Balance Sheet to "Investments and Advances."

Common Stock Repurchase Program The company announced a stock repurchase program on March 31, 2004. Acquisitions of up to $5 billion may be made 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. The company purchased 42,324,000 shares in the open market for $2.1 billion through December 2004. Purchases through February 2005 increased the total shares acquired to 47,969,000 for $2.4 billion.

Capital and Exploratory Expenditures Total reported expenditures for 2004 were $8.3 billion, including $1.56 billion for the company's share of affiliates' expenditures, which did not require cash outlays by the company. In 2003 and 2002, expenditures were $7.4 billion and $9.3 billion, respectively, including the company's share of affiliates' expenditures of $1.1 billion and $1.4 billion in the corresponding periods. Of the total 2004 reported expenditures, $6.3 billion, or 76 percent, was for upstream activities, compared with 77 percent in 2003 and 68 percent in 2002. International upstream accounted for 71 percent of the worldwide upstream total in 2004 and 2003 and 70 percent in 2002, reflecting the company's continuing focus on international exploration and production activities.

Expenditures in 2004 increased 13 percent compared with 2003, primarily driven by higher upstream expenditures. Downstream spending increased 21 percent from 2003. Expenditures were higher in 2002 than in 2003, due in part to large lease acquisitions in the North Sea and the Gulf of Mexico, spending for the Athabasca Oil Sands Project in western Canada, and additional common stock investments in Dynegy.

Including its share of spending by affiliates, the company estimates 2005 capital and exploratory expenditures at $10 billion, which is about 20 percent higher than 2004. About $7.4 billion, or 74 percent of the total, is targeted for exploration and production activities, with $4.9 billion of that amount targeted for outside the United States. The upstream spending is targeted for the most promising exploratory prospects in the deepwater Gulf of Mexico and West Africa and major development projects in Angola, Nigeria, Kazakhstan and the deepwater Gulf of Mexico. Included in the upstream expenditures is about $400 million to develop the company's international natural gas resource base.

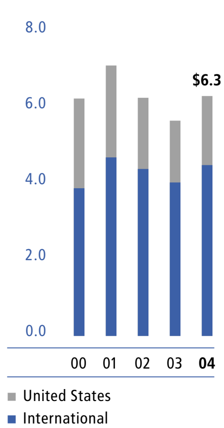
Worldwide downstream spending in 2005 is estimated at $1.9 billion, with about $1.5 billion for refining and marketing

Capital and Exploratory Expenditures

	2004			2003			2002		
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Exploration and Production	**$ 1,820**	**$ 4,501**	**$ 6,321**	$ 1,641	$ 4,034	$ 5,675	$ 1,888	$ 4,395	$ 6,283
Refining, Marketing and Transportation	**497**	**832**	**1,329**	403	697	1,100	750	882	1,632
Chemicals	**123**	**27**	**150**	173	24	197	272	37	309
All Other	**512**	**3**	**515**	371	20	391	855*	176*	1,031
Total	**$ 2,952**	**$ 5,363**	**$ 8,315**	$ 2,588	$ 4,775	$ 7,363	$ 3,765	$ 5,490	$ 9,255
Total, Excluding Equity in Affiliates	**$ 2,729**	**$ 4,024**	**$ 6,753**	$ 2,306	$ 3,920	$ 6,226	$ 3,312	$ 4,590	$ 7,902

*2002 conformed to 2004 presentation.

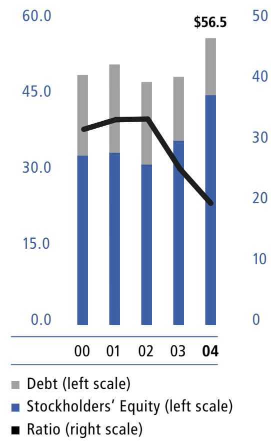
EXPLORATION & PRODUCTION – CAPITAL & EXPLORATORY EXPENDITURES*
Billions of dollars



Exploration and production projects accounted for 76 percent of total capital and exploratory expenditures in 2004.

**Includes equity in affiliates*

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



ChevronTexaco's ratio of total debt to total debt-plus-equity fell to 20 percent at year-end as the company's stockholders' equity climbed.

and $400 million for supply and transportation projects, including pipelines to support expanded upstream production.

Investments in chemicals businesses in 2005 are budgeted at $200 million. Estimates for energy technology, information technology and facilities, and power-related businesses total approximately $500 million.

Pension Obligations In 2004, the company's pension plan contributions totaled $1.6 billion (approximately $1.3 billion to the U.S. plans). In 2005, the company expects contributions to be approximately $400 million. Actual amounts are dependent upon 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 43.

FINANCIAL RATIOS

Current Ratio – current assets divided by current liabilities. The current ratio is adversely affected by the fact that ChevronTexaco's inventories are valued on a Last-In, First-Out (LIFO) basis. At year-end 2004, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $3.0 billion.

Interest Coverage Ratio – income before income tax expense, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs. The company's interest coverage ratio was higher in 2004, primarily due to higher before-tax income and lower average debt balances.

Debt Ratio – total debt as a percentage of total debt plus equity. The decrease between the comparable periods was due to lower average debt levels and higher retained earnings.

Financial Ratios

	At December 31		
	2004	2003	2002
Current Ratio	**1.5**	1.2	0.9
Interest Coverage Ratio	**47.6**	24.3	7.6
Total Debt/Total Debt Plus Equity	**19.9%**	25.8%	34.0%

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

*Direct or Indirect Guarantees**

Millions of dollars		Commitment Expiration by Period			
	Total	2005	2006–2008	2009	After 2009
Guarantees of Non-consolidated Affiliates or Joint Venture Obligations	$ 963	$ 515	$ 210	$ 135	$ 103
Guarantees of Obligations of Third Parties	130	70	16	4	40
Guarantees of Equilon Debt and Leases	215	18	61	18	118

*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 page 38.

At December 31, 2004, the company and its subsidiaries provided guarantees, either directly or indirectly, of $963 million for notes and other contractual obligations of affiliated companies and $130 million for third parties as described by major category below. There are no amounts being carried as liabilities for the company's obligations under these guarantees.

Of the $963 million in guarantees provided to affiliates, $774 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. Approximately 90 percent of the amounts guaranteed will expire by 2009, 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 $189 million balance of the $963 million represents obligations in connection with pricing of power purchase agreements for certain of its cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliate does 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 $130 million have been provided to third parties, including guarantees of approximately $40 million of construction loans to host governments in the company's international upstream operations. The remaining guarantees of $90 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 70 percent of the total amounts guaranteed will expire in 2009, with the remainder expiring after 2009. 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 $70 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, 2004, ChevronTexaco also had outstanding guarantees for approximately $215 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 45 percent of the amounts guaranteed will expire within the 2005 through 2009 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, including those associated with the Unocal patent litigation. 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 2004, the company paid approximately $28 million under these contingencies and had agreed to pay approximately $10 million additional under an award of arbitration, subject to minor adjustments yet to be resolved. The company may 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 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.

Securitization In other off-balance-sheet arrangements, 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, 2004, approximately $1.2 billion, representing about 10 percent of ChevronTexaco's total current accounts receivable balance, were securitized. ChevronTexaco's total estimated financial exposure under these securitizations at December 31, 2004, was approximately $50 million. These arrangements have the effect of accelerating ChevronTexaco's collection of the securitized amounts. In the event of the SPEs experiencing major defaults in the collection of receivables, ChevronTexaco 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 2005 – $1.6 billion; 2006 – $1.7 billion; 2007 – $1.6 billion; 2008 – $1.5 billion; 2009 – $1.5 billion; 2010 and after – $2.3 billion. Total payments under the agreements were approximately $1.6 billion in 2004, $1.4 billion in 2003 and $1.2 billion in 2002. 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: 2005 – $1.2 billion; 2006 – $1.2 billion; 2007 – $1.3 billion; 2008 – $1.3 billion; and 2009 – $1.3 billion. Additionally, in 2004 the company entered into a 20-year agreement to acquire regasification capacity at the Sabine Pass LNG terminal. Payments of $1.2 billion over the 20-year period are expected to commence in 2010.

Minority Interests The company has commitments of approximately $172 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	2005	2006 – 2008	2009	After 2009
On Balance Sheet:					
Short-Term Debt	$ 816	$ 816	$ –	$ –	$ –
Long-Term Debt[1, 2]	10,217	–	8,123	455	1,639
Noncancelable Capital Lease Obligations	239	–	110	29	100
Interest Expense	4,830	465	1,120	270	2,975
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,232	390	857	236	749
Unconditional Purchase Obligations	1,000	300	600	100	–
Through-Put and Take-or-Pay Agreements	9,400	1,350	4,250	1,450	2,350

[1] $4.7 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the repayment of the entire amount in the 2006 through 2008 period.
[2] Includes guarantees of $360 of LESOP (leverage employee stock ownership plan) debt, $127 due in 2005 and $233 due after 2006.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments ChevronTexaco is exposed to market risks related to the volatility of crude oil, refined products, electricity, natural gas and refinery feedstock prices. The company uses financial derivative commodity instruments to manage its exposure to price volatility on a small portion of its activity, including firm commitments and anticipated transactions for the purchase or sale of crude oil and refined products; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids.

ChevronTexaco also uses financial derivative commodity instruments for trading purposes, and the results of this activity were not material to the company's financial position, net income or cash flows in 2004.

The company's positions are monitored and reported 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 financial 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 options 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 derivative contracts by approximately $40 million and reduce the fair value of the crude oil derivative contracts by about $15 million. The same hypothetical decreases 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 on foreign exchange contracts of a hypothetical 10 percent change to year-end exchange rates would be approximately $50 million.

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.

During 2004, four new swaps were initiated to hedge a portion of the company's fixed-rate debt. At year-end 2004, the weighted average maturity of "receive fixed" interest rate swaps was approximately three years. There were no "receive floating" swaps outstanding at year end.

A hypothetical increase of 10 basis points in market-fixed interest rates would reduce the fair value of the "receive fixed" swaps by approximately $4 million.

For the financial and derivative instruments discussed above, there was not a material change in market risk from that presented in 2003.

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.

TRANSACTIONS WITH RELATED PARTIES

ChevronTexaco enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply and offtake agreements. Internationally, there are long-term purchase agreements in place with the company's refining affiliate in Thailand. Refer to page 38 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 The company and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive.

The company is a party to 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.

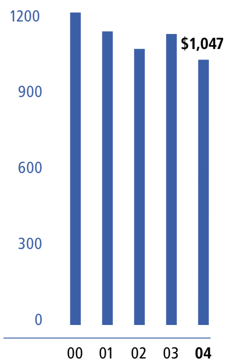
The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. The company does not use MTBE in the manufacture of gasoline in the United States and there are no detectable levels of MTBE in that gasoline.

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, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. 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. In 2004, the company recorded additional provisions for estimated remediation costs primarily at refined products marketing sites and various operating, closed or divested facilities in the United States.

Millions of dollars	**2004**	2003	2002
Balance at January 1	**$ 1,149**	$ 1,090	$ 1,160
Net Additions	**155**	296	229
Expenditures	**(257)**	(237)	(299)
Balance at December 31	**$ 1,047**	$ 1,149	$ 1,090

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

YEAR-END ENVIRONMENTAL REMEDIATION RESERVES
Millions of dollars



Reserves for environmental remediation declined 9 percent from 2003. Expenditures for remediation efforts outpaced new liabilities.

2004 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

As of December 31, 2004, ChevronTexaco was involved with the remediation activities of 210 sites at 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 2004 was $107 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 ChevronTexaco to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's consolidated financial position or liquidity.

Of the remaining year-end 2004 environmental reserves balance of $940 million, $712 million related to more than 2,000 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), and pipelines. The remaining $228 million was associated with various sites in the international downstream ($111 million), upstream ($69 million) and chemicals ($48 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

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.

Prior to January 1, 2003, additional reserves for dismantlement, abandonment and restoration of its worldwide oil and gas and coal properties at the end of their productive lives, which included costs related to environmental issues, were recognized on a unit-of-production basis as accumulated depreciation, depletion and amortization. Effective January 1, 2003, the company implemented FAS 143, *"Accounting for Asset Retirement Obligations."* 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 for asset retirement obligations at year-end 2004 was $2.9 billion. Refer also to Note 25 on page 77 related to FAS 143.

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 prevents estimation of the fair value of the asset retirement obligation.

Refer to "Environmental Matters" on page 42 for additional information related to environmental matters.

Income Taxes The company estimates 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 estimated. The U.S. federal income tax liabilities have been settled through 1996 for ChevronTexaco (formerly Chevron), 1997 for ChevronTexaco Global Energy Inc. (formerly Caltex), and 1991 for Texaco. California franchise tax liabilities have been settled through 1991 for Chevron 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 ChevronTexaco and its affiliates have operations 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 Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of Congo, Angola, Nigeria, Chad, South Africa, Indonesia, the Philippines, Singapore, China, Thailand, 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. 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 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 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 ChevronTexaco'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. ChevronTexaco 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 ChevronTexaco is estimated at about $50 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

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, 2004, the company had $671 million of suspended exploratory wells included in properties, plant and equipment, an increase of $122 million from 2003 and an increase of $193 million from 2002. The balance at year-end 2004 primarily reflects drilling activities in the United States and Nigeria.

The SEC has issued several comment letters to companies in the oil and gas industry related to the accounting for suspended exploratory wells, particularly for those suspended under certain circumstances for more than one year.

The company's accounting policy in this regard is to capitalize the cost of exploratory wells pending determination of whether the wells found proved reserves. Costs of wells that find proved reserves remain capitalized. Costs also are capitalized for wells that find commercially producible reserves that cannot be classified as proved, pending one or more of the following: (1) decisions on additional major capital expenditures, (2) the results of additional exploratory wells that are under way or firmly planned, and (3) securing final regulatory approvals for development. Otherwise, well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year following completion of drilling. All other exploratory well costs are expensed.

This topic was discussed at the September 2004 meeting of the Emerging Issues Task Force (EITF) as Issue 04-9, *"Accounting for Suspended Well Costs"* (EITF 04-9). The discussion centered on whether certain circumstances would permit the continued capitalization of the costs for an exploratory well beyond one year in the absence of plans for another exploratory well. The outcome of the September 2004 EITF meeting was agreement between the EITF and the FASB that the circumstances outlined were inconsistent with the provisions in FASB Statement No. 19, *"Financial Accounting and Reporting by Oil and Gas Producing Companies"* (FAS 19), and an amendment of FAS 19 would be required to formally adopt this view. In February 2005, the FASB issued a proposed FASB Staff Position (FSP) to amend FAS 19. Refer to Note 21 on page 69 to the Consolidated Financial Statements for a discussion of this FSP, the SEC's comment letters and the company's costs associated with suspended exploratory wells.

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 for the $671 million of suspended wells at year-end 2004 is uncertain, given the referenced deliberations by the SEC and FASB, as is the effect on the normal project-evaluation and future drilling activities for all of the wells that have been suspended.

Accounting for Buy/Sell Contracts In January and February 2005, the Securities and Exchange Commission (SEC) issued comment letters to ChevronTexaco 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 has 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 accounts for buy/sell transactions in the Consolidated Statement of Income the same as any other monetary transaction for which title passes, and the risk and reward of ownership are assumed by the counterparties. At issue with the SEC is whether the industry's accounting for buy/sell contracts instead 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 topic is under deliberation by the Emerging Issues Task Force (EITF) of the FASB as Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty."* The EITF first discussed this issue in November 2004. Additional research is being performed by the FASB staff, and the topic will be discussed again at a future EITF meeting. While this issue is under deliberation, the SEC staff directed ChevronTexaco and other companies in its January and February 2005 comment letters 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.

With regard to the latter, the company's accounting treatment for buy/sell contracts is based on the view that such transactions are monetary in nature. Monetary transactions are outside the scope of APB 29. The company believes its accounting is also supported by the indicators of gross reporting of purchases and sales in paragraph 3 of EITF Issue No. 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Additionally, FASB Interpretation No. 39, *"Offsetting of Amounts Related to Certain Contracts"* (FIN 39), prohibits a receivable from being netted against a payable when the receivable is subject to credit risk unless a right of offset exists that is enforceable by law. The company also views netting the separate components of buy/sell contracts in the income statement to be inconsistent with the gross presentation that FIN 39 requires for the resulting receivable and payable on the balance sheet.

The company's buy/sell transactions are also similar to the "barrel back" example used in other accounting literature, including EITF Issue No. 03-11, *"Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-3"* (which indicates a company's decision to show buy/sell-types of transactions gross on the income statement as being a matter of judgment of the relevant facts and circumstances of the company's activities) and Derivatives Implementation Group (DIG) Issue No. K1, *"Miscellaneous: Determining Whether Separate Transactions Should be Viewed as a Unit."*

The company further notes that the accounting for buy/sell contracts as separate purchases and sales is in contrast to the accounting for other types of contracts typically described by the industry as exchange contracts, which are considered non-monetary in nature and appropriately shown net on the income statement. Under an exchange contract, for example, one company agrees to exchange refined products in one location for another company's same quantity of refined products in another location. Upon transfer, the only amounts that may be invoiced are for transportation and quality differentials. Among other things, unlike buy/sell contracts, the obligations of each party to perform under the contract are not independent and the risks and rewards of ownership are not separately transferred.

As shown on the company's Consolidated Statement of Income, "Sales and other operating revenues" for the three years ending December 31, 2004, included $18,650 million, $14,246 million and $7,963 million, respectively, for buy/sell contracts. These revenue amounts associated with buy/sell contracts represented 12 percent of total "Sales and other operating revenues" in 2004 and 2003 and 8 percent in 2002. 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 ChevronTexaco 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-ChevronTexaco 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, ChevronTexaco estimated its worldwide environmental spending in 2004 at approximately $1.1 billion for its consolidated companies. Included in these expenditures were $285 million of environmental capital expenditures and approximately $810 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.

For 2005, total worldwide environmental capital expenditures are estimated at $710 million. 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 and 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 87 for the changes in these estimates for the three years ending December 31, 2004, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves," on page 92 for estimates of proved-reserve values for each year-end 2002 through 2004, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements 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 44 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 on page 54. 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 22 to the Consolidated Financial Statements, beginning on page 70, includes information for the three years ending December 31, 2004, on the components of pension and OPEB expense and the underlying assumptions as well as on the funded status for the company's pension plans at the end of 2004 and 2003.

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 regularly 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. For example, the expected long-term rate of return on United States pension plan assets, which account for about 70 percent of the company's pension plan assets, has remained at 7.8 percent since 2002.

The year-end market-related value of U.S. pension plan assets 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 plans outside the United States, market value of assets as of the measurement date is used in calculating the pension expense.

The discount rate assumptions used to determine pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2004, the company calculated the U.S. pension obligation using a 5.8 percent discount rate. The discount rates used at the end of 2003 and 2002 were 6 percent and 6.8 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 2004 was $564 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 60 percent of the company-wide pension obligation, would have reduced total pension plan expense for 2004 by approximately $45 million. A 1 percent increase in the discount rate for this same plan would have reduced total benefit plan expense for 2004 by approximately $115 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 2004, the company's pension plan contributions totaled $1.6 billion (approximately $1.3 billion to the U.S. plans). In

2005, the company expects contributions to be approximately $400 million. Actual contribution amounts are dependent upon 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 22 to the Consolidated Financial Statements beginning on page 70 for the pension-related balance sheet effects at the end of 2004 and 2003.

For the company's OPEB plans, expense for 2004 was $197 million and was also recorded as "Operating expenses" or "Selling, general and administrative expenses" in all business segments. At December 31, 2004, the discount rate applied to the company's OPEB obligations was 5.8 percent – the same discount rate used for U.S. pension obligations. 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. Before retirement, the assumed health care cost trend rates start with 10.6 percent in 2004 and gradually drop to 4.8 percent for 2010 and beyond. Once the employee elects to retire, the trend rates are capped at 4 percent.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2004, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 90 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, 2004, are included in the commentary on the business segments elsewhere in this discussion, as well as in Note 2 to the Consolidated Financial Statements beginning on page 56. 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 and 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.

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 and in Note 2 to the Consolidated Financial Statements on page 56 for the effect on earnings from losses associated with certain litigation and environmental remediation and tax matters for the three years ended December 31, 2004.

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.

American Jobs Creation Act of 2004 In October 2004, the American Jobs Creations Act of 2004 (the Act) was passed into law. The Act provides deduction from income for qualified domestic refining and upstream production activities, which will be phased in from 2005 through 2010. For that specific category of 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 2005 and 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 federal effective tax rate to about 32 percent for that category of income, based on current earnings levels.

Under the guidance in FASB Staff Position No. FAS 109-1, *"Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004,"* the tax deduction on qualified production activities provided by the American Jobs Creation Act of 2004 will be treated as a "special deduction," as described in FAS 109. As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction will be reported in the period in which the deduction is claimed on the company's tax return.

The Act also provides for a limited opportunity to repatriate earnings from outside the United States at a special reduced tax rate that can be as low as 5.25 percent. In early 2005, the company was in the process of reviewing the guidance that the IRS issued on January 13, 2005, regarding this provision and also considering other relevant information. The company does not anticipate a major change in its plans for repatriating earnings from international operations under the provisions of the Act.

NEW ACCOUNTING STANDARDS

FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46) In January 2003, FIN 46 was issued and established standards for determining under what circumstances a variable interest entity (VIE) should be consolidated by its primary beneficiary. FIN 46 also requires disclosures about VIEs that the company is not required to consolidate but in which it has a significant variable interest. In December 2003, the FASB issued FIN 46-R, which not only includes amendments to FIN 46, but also requires application of the interpretation to all affected entities no later than March 31, 2004, for calendar year-reporting companies. Prior to this requirement, companies were required to apply the interpretation to special-purpose entities by December 31, 2003. The full adoption of the interpretation as of March 31, 2004, including the requirement relating to special-purpose entities, did not have a material impact on the company's results of operations, financial position or liquidity.

FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP FAS 106-2) In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") became law. The Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued FSP FAS 106-2. One U.S. subsidiary was deemed at least actuarially equivalent and eligible for the federal subsidy. The effect on the company's postretirement benefit obligation and the associated annual expense was *de minimis.*

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 is 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 company is currently evaluating the impact of this standard.

FASB Statement No. 123R, "Share-Based Payment" (FAS 123R) In December 2004, the FASB issued FAS 123R, which requires that compensation cost relating to share-based payments be recognized in the company's financial statements. The company currently accounts for those payments under the recognition and measurement principles of *Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees,"* and related interpretations. The company is preparing to implement this standard effective July 1, 2005. Although the transition method to be used to adopt the standard has not been selected, the impact of adoption is expected to have a minimal impact on the company's results of operations, financial position and liquidity. Refer to Note 1, beginning on page 54, for the company's calculation of the pro forma impact on net income of FAS 123, which would be similar to that under FAS 123R.

FASB Statement No. 153, "Exchanges of Nonmonetary Assets – An Amendment of APB Opinion No. 29" (FAS 153) In December 2004, the FASB issued FAS 153, which is effective for the company for asset-exchange transactions beginning July 1, 2005. Under APB No. 29, assets received in certain types of nonmonetary exchanges were permitted to be recorded at the carrying value of the assets that were exchanged (i.e., recorded on a carryover basis). As amended by FAS 153, assets received in some circumstances will have to be recorded instead at their fair values. In the past, ChevronTexaco has not engaged in a large number of nonmonetary asset exchanges for significant amounts.

Unaudited

	2004				2003[1]			
Millions of dollars, except per-share amount	4TH Q	3RD Q	2ND Q	1ST Q	4TH Q	3RD Q	2ND Q	1ST Q
REVENUES AND OTHER INCOME								
Sales and other operating revenues[2,3]	**$ 41,612**	**$ 39,611**	**$ 36,579**	**$ 33,063**	$ 30,018	$ 30,058	$ 28,982	$ 30,517
Income from equity affiliates	**785**	**613**	**740**	**444**	262	287	216	264
Other income	**295**	**496**	**924**	**138**	67	147	52	42
Gain from exchange of Dynegy securities	**–**	**–**	**–**	**–**	–	365	–	–
TOTAL REVENUES AND OTHER INCOME	**42,692**	**40,720**	**38,243**	**33,645**	30,347	30,857	29,250	30,823
COSTS AND OTHER DEDUCTIONS								
Purchased crude oil and products	**26,290**	**25,650**	**22,452**	**20,027**	17,907	18,024	17,187	18,192
Operating expenses	**2,874**	**2,557**	**2,234**	**2,167**	2,488	2,227	1,853	1,932
Selling, general and administrative expenses	**1,319**	**1,231**	**986**	**1,021**	1,172	1,198	1,061	1,009
Exploration expenses	**274**	**173**	**165**	**85**	138	130	147	155
Depreciation, depletion and amortization	**1,283**	**1,219**	**1,243**	**1,190**	1,309	1,394	1,400	1,223
Taxes other than on income[2]	**5,216**	**4,948**	**4,889**	**4,765**	4,643	4,417	4,511	4,330
Interest and debt expense	**112**	**107**	**94**	**93**	111	115	118	130
Minority interests	**22**	**23**	**18**	**22**	14	24	20	22
TOTAL COSTS AND OTHER DEDUCTIONS	**37,390**	**35,908**	**32,081**	**29,370**	27,782	27,529	26,297	26,993
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	**5,302**	**4,812**	**6,162**	**4,275**	2,565	3,328	2,953	3,830
INCOME TAX EXPENSE	**1,862**	**1,875**	**2,056**	**1,724**	837	1,363	1,363	1,731
INCOME FROM CONTINUING OPERATIONS	**3,440**	**2,937**	**4,106**	**2,551**	1,728	1,965	1,590	2,099
INCOME FROM DISCONTINUED OPERATIONS	**–**	**264**	**19**	**11**	7	10	10	17
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**$ 3,440**	**$ 3,201**	**$ 4,125**	**$ 2,562**	$ 1,735	$ 1,975	$ 1,600	$ 2,116
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, NET OF TAX	**–**	**–**	**–**	**–**	–	–	–	(196)
NET INCOME[4]	**$ 3,440**	**$ 3,201**	**$ 4,125**	**$ 2,562**	$ 1,735	$ 1,975	$ 1,600	$ 1,920
PER-SHARE OF COMMON STOCK[5]								
INCOME FROM CONTINUING OPERATIONS								
– BASIC	**$ 1.64**	**$ 1.38**	**$ 1.93**	**$ 1.21**	$ 0.82	$ 1.00[6]	$ 0.75	$ 0.98
– DILUTED	**$ 1.63**	**$ 1.38**	**$ 1.93**	**$ 1.20**	$ 0.82	$ 1.00[6]	$ 0.75	$ 0.98
INCOME FROM DISCONTINUED OPERATIONS								
– BASIC	**$ –**	**$ 0.13**	**$ 0.01**	**$ –**	$ –	$ 0.01	$ –	$ 0.01
– DILUTED	**$ –**	**$ 0.13**	**$ 0.01**	**$ –**	$ –	$ 0.01	$ –	$ 0.01
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES								
– BASIC	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ –	$ –	$ (0.09)
– DILUTED	**$ –**	**$ –**	**$ –**	**$ –**	$ –	$ –	$ –	$ (0.09)
NET INCOME								
– BASIC	**$ 1.64**	**$ 1.51**	**$ 1.94**	**$ 1.21**	$ 0.82	$ 1.01[6]	$ 0.75	$ 0.90
– DILUTED	**$ 1.63**	**$ 1.51**	**$ 1.94**	**$ 1.20**	$ 0.82	$ 1.01[6]	$ 0.75	$ 0.90
DIVIDENDS	**$ 0.40**	**$ 0.40**	**$ 0.37**	**$ 0.36**	$ 0.37	$ 0.36	$ 0.35	$ 0.35
COMMON STOCK PRICE RANGE – HIGH	**$ 56.07**	**$ 54.49**	**$ 47.50**	**$ 45.71**	$ 43.49	$ 37.28	$ 38.11	$ 35.20
– LOW	**$ 50.99**	**$ 46.21**	**$ 43.95**	**$ 41.99**	$ 35.57	$ 35.02	$ 31.06	$ 30.65

[1] 2003 conformed to the 2004 presentation for discontinued operations.								
[2] Includes consumer excise taxes:	$ 2,150	$ 2,040	$ 1,921	$ 1,857	$ 1,825	$ 1,814	$ 1,765	$ 1,691
[3] Includes amounts for buy/sell contracts:	$ 5,117	$4,640	$4,637	$4,256	$ 3,538	$ 3,734	$ 3,751	$ 3,223
[4] Net benefits (charges) for special items included in "Net Income":	$ 146	$ 486	$ 585	$ (55)	$ 89	$ 14	$ (117)	$ (39)

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

[6] 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 the net income for the period.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX) and on the Pacific Exchange. As of February 25, 2005, stockholders of record numbered approximately 227,000. There are no restrictions on the company's ability to pay dividends.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

To the Stockholders of ChevronTexaco Corporation

Management of ChevronTexaco 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.

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

The Board of Directors of ChevronTexaco 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, 2004.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which is 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

March 2, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of ChevronTexaco Corporation:
We have completed an integrated audit of ChevronTexaco Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004, and audits of its 2003 and 2002 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 consolidated statements of income, comprehensive income, stockholders' equity and cash flows present fairly, in all material respects, the financial position of ChevronTexaco Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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.

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, 2004, 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, 2004, 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.

As discussed in Note 25 on page 77 to the financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003.

PricewaterhouseCoopers LLP

San Francisco, California
March 2, 2005

Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2004	2003	2002
REVENUES AND OTHER INCOME			
Sales and other operating revenues[1,2]	**$ 150,865**	$ 119,575	$ 98,340
Income (loss) from equity affiliates	**2,582**	1,029	(25)
Other income	**1,853**	308	222
Gain from exchange of Dynegy preferred stock	**–**	365	–
TOTAL REVENUES AND OTHER INCOME	**155,300**	121,277	98,537
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products[2]	**94,419**	71,310	57,051
Operating expenses	**9,832**	8,500	7,795
Selling, general and administrative expenses	**4,557**	4,440	4,155
Exploration expenses	**697**	570	591
Depreciation, depletion and amortization	**4,935**	5,326	5,169
Taxes other than on income[1]	**19,818**	17,901	16,682
Interest and debt expense	**406**	474	565
Minority interests	**85**	80	57
Write-down of investments in Dynegy Inc.	**–**	–	1,796
Merger-related expenses	**–**	–	576
TOTAL COSTS AND OTHER DEDUCTIONS	**134,749**	108,601	94,437
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	**20,551**	12,676	4,100
INCOME TAX EXPENSE	**7,517**	5,294	2,998
INCOME FROM CONTINUING OPERATIONS	**13,034**	7,382	1,102
INCOME FROM DISCONTINUED OPERATIONS	**294**	44	30
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**$ 13,328**	$ 7,426	$ 1,132
Cumulative effect of changes in accounting principles	**–**	(196)	–
NET INCOME	**$ 13,328**	$ 7,230	$ 1,132
PER-SHARE OF COMMON STOCK[3]			
INCOME FROM CONTINUING OPERATIONS			
– BASIC	**$ 6.16**	$ 3.55	$ 0.52
– DILUTED	**$ 6.14**	$ 3.55	$ 0.52
INCOME FROM DISCONTINUED OPERATIONS			
– BASIC	**$ 0.14**	$ 0.02	$ 0.01
– DILUTED	**$ 0.14**	$ 0.02	$ 0.01
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES			
– BASIC	**$ –**	$ (0.09)	$ –
– DILUTED	**$ –**	$ (0.09)	$ –
NET INCOME			
– BASIC	**$ 6.30**	$ 3.48	$ 0.53
– DILUTED	**$ 6.28**	$ 3.48	$ 0.53
[1] Includes consumer excise taxes:	**$ 7,968**	$ 7,095	$ 7,006
[2] Includes amounts in revenues for buy/sell contracts (associated costs are in "Purchased crude oil and products") See Note 16 on page 65:	**$ 18,650**	$ 14,246	$ 7,963

[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		
	2004	2003	2002
NET INCOME	**$ 13,328**	$ 7,230	$ 1,132
Currency translation adjustment			
Unrealized net change arising during period	**36**	32	15
Unrealized holding (loss) gain on securities			
Net gain (loss) arising during period			
Before income taxes	**35**	445	(149)
Income taxes	**–**	–	52
Reclassification to net income of net realized (gain) loss			
Before income taxes	**(44)**	(365)	217
Income taxes	**–**	–	(76)
Total	**(9)**	80	44
Net derivatives (loss) gain on hedge transactions			
Before income taxes	**(8)**	115	52
Income taxes	**(1)**	(40)	(18)
Total	**(9)**	75	34
Minimum pension liability adjustment			
Before income taxes	**719**	12	(1,208)
Income taxes	**(247)**	(10)	423
Total	**472**	2	(785)
OTHER COMPREHENSIVE GAIN (LOSS), NET OF TAX	**490**	189	(692)
COMPREHENSIVE INCOME	**$ 13,818**	$ 7,419	$ 440

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amounts

	At December 31	
	2004	2003
ASSETS		
Cash and cash equivalents	**$ 9,291**	$ 4,266
Marketable securities	**1,451**	1,001
Accounts and notes receivable (less allowance: 2004 – $174; 2003 – $179)	**12,429**	9,722
Inventories:		
Crude oil and petroleum products	**2,324**	2,003
Chemicals	**173**	173
Materials, supplies and other	**486**	472
	2,983	2,648
Prepaid expenses and other current assets	**2,349**	1,789
TOTAL CURRENT ASSETS	**28,503**	19,426
Long-term receivables, net	**1,419**	1,493
Investments and advances	**14,389**	12,319
Properties, plant and equipment, at cost	**103,954**	100,556
Less: Accumulated depreciation, depletion and amortization	**59,496**	56,018
	44,458	44,538
Deferred charges and other assets	**4,277**	2,594
Assets held for sale	**162**	1,100
TOTAL ASSETS	**$ 93,208**	$ 81,470
LIABILITIES AND STOCKHOLDERS' EQUITY		
Short-term debt	**$ 816**	$ 1,703
Accounts payable	**10,747**	8,675
Accrued liabilities	**3,410**	3,172
Federal and other taxes on income	**2,502**	1,392
Other taxes payable	**1,320**	1,169
TOTAL CURRENT LIABILITIES	**18,795**	16,111
Long-term debt	**10,217**	10,651
Capital lease obligations	**239**	243
Deferred credits and other noncurrent obligations	**7,942**	7,758
Noncurrent deferred income taxes	**7,268**	6,417
Reserves for employee benefit plans	**3,345**	3,727
Minority interests	**172**	268
TOTAL LIABILITIES	**47,978**	45,175
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	**–**	–
Common stock (authorized 4,000,000,000 shares, $0.75 par value; 2,274,032,014 and 2,274,042,114 shares issued at December 31, 2004 and 2003, respectively*)	**1,706**	1,706
Capital in excess of par value*	**4,160**	4,002
Retained earnings	**45,414**	35,315
Accumulated other comprehensive loss	**(319)**	(809)
Deferred compensation and benefit plan trust	**(607)**	(602)
Treasury stock, at cost (2004 – 166,911,890 shares; 2003 – 135,746,674 shares*)	**(5,124)**	(3,317)
TOTAL STOCKHOLDERS' EQUITY	**45,230**	36,295
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 93,208**	$ 81,470

*2003 restated to 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 Cash Flows

Millions of dollars

	Year ended December 31		
	2004	2003	2002
OPERATING ACTIVITIES			
Net income	**$ 13,328**	$ 7,230	$ 1,132
Adjustments			
Depreciation, depletion and amortization	**4,935**	5,326	5,169
Dry hole expense	**286**	256	288
Distributions (less) more than income from equity affiliates	**(1,422)**	(383)	510
Net before-tax gains on asset retirements and sales	**(1,882)**	(194)	(33)
Net foreign currency effects	**60**	199	5
Deferred income tax provision	**(224)**	164	(81)
Net decrease in operating working capital	**430**	162	1,125
Minority interest in net income	**85**	80	57
Cumulative effect of changes in accounting principles	**–**	196	–
Gain from exchange of Dynegy preferred stock	**–**	(365)	–
Write-down of investments in Dynegy, before tax	**–**	–	1,796
(Increase) decrease in long-term receivables	**(60)**	12	(39)
(Increase) decrease in other deferred charges	**(69)**	1,646	428
Cash contributions to employee pension plans	**(1,643)**	(1,417)	(246)
Other	**866**	(597)	(168)
NET CASH PROVIDED BY OPERATING ACTIVITIES	**14,690**	12,315	9,943
INVESTING ACTIVITIES			
Capital expenditures	**(6,310)**	(5,625)	(7,597)
Advances to equity affiliate	**(2,200)**	–	–
Repayment of loans by equity affiliates	**1,790**	293	–
Proceeds from asset sales	**3,671**	1,107	2,341
Net (purchases) sales of marketable securities	**(450)**	153	209
NET CASH USED FOR INVESTING ACTIVITIES	**(3,499)**	(4,072)	(5,047)
FINANCING ACTIVITIES			
Net borrowings (payments) of short-term obligations	**114**	(3,628)	(1,810)
Proceeds from issuances of long-term debt	**–**	1,034	2,045
Repayments of long-term debt and other financing obligations	**(1,398)**	(1,347)	(1,356)
Cash dividends – common stock	**(3,236)**	(3,033)	(2,965)
Dividends paid to minority interests	**(41)**	(37)	(26)
Net (purchases) sales of treasury shares	**(1,645)**	57	41
Redemption of preferred stock of subsidiaries	**(18)**	(75)	–
NET CASH USED FOR FINANCING ACTIVITIES	**(6,224)**	(7,029)	(4,071)
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	**58**	95	15
NET CHANGE IN CASH AND CASH EQUIVALENTS	**5,025**	1,309	840
CASH AND CASH EQUIVALENTS AT JANUARY 1	**4,266**	2,957	2,117
CASH AND CASH EQUIVALENTS AT DECEMBER 31	**$ 9,291**	$ 4,266	$ 2,957

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Stockholders' Equity

Shares in thousands; amounts in millions of dollars

	2004		2003		2002	
	Shares	Amount	Shares	Amount	Shares	Amount
PREFERRED STOCK	–	$ –	–	$ –	–	$ –
COMMON STOCK*						
Balance at January 1	**2,274,042**	**$ 1,706**	2,274,042	$ 1,706	2,274,042	$ 1,706
Conversion of Texaco Inc. shares	**(10)**	**–**	–	–	–	–
BALANCE AT DECEMBER 31	**2,274,032**	**$ 1,706**	2,274,042	$ 1,706	2,274,042	$ 1,706
CAPITAL IN EXCESS OF PAR*						
Balance at January 1		**$ 4,002**		$ 3,980		$ 3,958
Treasury stock transactions		**158**		22		22
BALANCE AT DECEMBER 31		**$ 4,160**		$ 4,002		$ 3,980
RETAINED EARNINGS						
Balance at January 1		**$ 35,315**		$ 30,942		$ 32,767
Net income		**13,328**		7,230		1,132
Cash dividends						
Common stock		**(3,236)**		(3,033)		(2,965)
Tax benefit from dividends paid on unallocated ESOP shares and other		**7**		6		8
Exchange of Dynegy securities		**–**		170		–
BALANCE AT DECEMBER 31		**$ 45,414**		$ 35,315		$ 30,942
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		**$ (176)**		$ (208)		$ (223)
Change during year		**36**		32		15
Balance at December 31		**$ (140)**		$ (176)		$ (208)
Minimum pension liability adjustment						
Balance at January 1		**$ (874)**		$ (876)		$ (91)
Change during year		**472**		2		(785)
Balance at December 31		**$ (402)**		$ (874)		$ (876)
Unrealized net holding gain on securities						
Balance at January 1		**$ 129**		$ 49		$ 5
Change during year		**(9)**		80		44
Balance at December 31		**$ 120**		$ 129		$ 49
Net derivatives gain on hedge transactions						
Balance at January 1		**$ 112**		$ 37		$ 3
Change during year		**(9)**		75		34
Balance at December 31		**$ 103**		$ 112		$ 37
BALANCE AT DECEMBER 31		**$ (319)**		$ (809)		$ (998)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST						
DEFERRED COMPENSATION						
Balance at January 1		**$ (362)**		$ (412)		$ (512)
Net reduction of ESOP debt and other		**(5)**		50		100
BALANCE AT DECEMBER 31		**(367)**		(362)		(412)
BENEFIT PLAN TRUST (COMMON STOCK)*	**14,168**	**(240)**	14,168	(240)	14,168	(240)
BALANCE AT DECEMBER 31	**14,168**	**$ (607)**	14,168	$ (602)	14,168	$ (652)
TREASURY STOCK AT COST*						
Balance at January 1	**135,747**	**$ (3,317)**	137,769	$ (3,374)	139,601	$ (3,415)
Purchases	**42,607**	**(2,122)**	81	(3)	76	(3)
Issuances – mainly employee benefit plans	**(11,442)**	**315**	(2,103)	60	(1,908)	44
BALANCE AT DECEMBER 31	**166,912**	**$ (5,124)**	135,747	$ (3,317)	137,769	$ (3,374)
TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31		**$ 45,230**		$ 36,295		$ 31,604

*2003 and 2002 restated to 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.

NOTE 1.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General ChevronTexaco 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, chemicals and coal mining operations. In addition, ChevronTexaco holds investments in the power generation business. Collectively, these companies conduct business activities in more than 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 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 which 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 price 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." Short-term investments 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 wells that find commercially producible reserves that cannot be classified as proved, pending one or more of the following: (1) decisions on additional major capital expenditures, (2) the results of additional exploratory wells that are under way or firmly planned, and (3) securing final regulatory approvals for development. Otherwise, well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year following completion of drilling. All other exploratory wells and costs are expensed. Refer to Note 21 on page 69 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. Globally in the refining, marketing, transportation and chemical areas, impairment reviews are generally done on a refinery, plant, marketing area or marketing assets by country basis. 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 25 on page 77 relating to asset retirement obligations, which includes additional information on the company's adoption of FAS 143. Previously, for crude oil, natural gas and coal producing properties, a provision was made through depreciation expense for anticipated abandonment and restoration costs at the end of the property's useful life.

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.

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

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company's U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For oil, gas and coal producing properties, a liability for an asset retirement obligation is made, following FAS 143. Refer to "Properties, Plant and Equipment" in this note 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 ChevronTexaco has an interest with other producers are generally recognized on the basis of the company's net working interest (entitlement method). Refer to Note 16 on page 65 for a discussion of the accounting for buy/sell arrangements.

Stock Compensation At December 31, 2004, the company had stock-based employee compensation plans, which are described

▸ **NOTE 1.** SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – Continued

more fully in Note 22 beginning on page 70. The company accounts for those plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *"Accounting for Stock Issued to Employees,"* and related interpretations. The following table illustrates the effect on net income and earnings per share if the company had applied the fair-value-recognition provisions of Financial Accounting Standards Board (FASB) Statement No. 123, *"Accounting for Stock-Based Compensation,"* to stock-based employee compensation:

	Year ended December 31		
	2004	2003	2002
Net income, as reported	**$ 13,328**	$ 7,230	$ 1,132
Add: Stock-based employee compensation expense included in reported net income determined under APB No. 25, net of related tax effects[1]	**10**	1	(1)
Deduct: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects[1,2]	**(52)**	(26)	(47)
Pro forma net income	**$ 13,286**	$ 7,205	$ 1,084
Earnings per share[3,4]			
Basic – as reported	**$ 6.30**	$ 3.48	$ 0.53
Basic – pro forma	**$ 6.28**	$ 3.47	$ 0.51
Diluted – as reported	**$ 6.28**	$ 3.48	$ 0.53
Diluted – pro forma	**$ 6.26**	$ 3.47	$ 0.51

[1] Costs of stock appreciation rights reported in net income and included in the fair-value method for these rights were $10, $1 and $(1) for 2004, 2003 and 2002, respectively.
[2] The fair value is estimated using the Black-Scholes option-pricing model for stock options. Stock appreciation rights are estimated based on the method outlined in SFAS 123 for these instruments.
[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.

Refer to Note 20 beginning on page 68 for a discussion of the company's plan to implement FASB statement No. 123R, *"Share-Based Payment,"* effective July 1, 2005.

NOTE 2.

SPECIAL ITEMS AND OTHER FINANCIAL INFORMATION

Net income for each period presented includes amounts categorized by the company as "special items," to assist in the explanation of the trend of results.

Listed in the following table are categories of these items and their net increase (decrease) to net income, after related tax effects.

In 2004, the company recorded special gains of $1,217 from the sale of nonstrategic crude oil and natural gas assets, primarily in the United States and Canada, and a special charge of $55 for a litigation matter.

In 2003, impairments of $103 and $30, respectively, were recorded for various U.S. and international oil and gas producing properties, reflecting lower expected recovery of proved reserves or a write-down to market value for assets in anticipation of sale. Impairments of $123 on downstream assets were for the conversion of a refinery to a products terminal and a write-down to market value for assets in anticipation of sale. Also in 2003, ChevronTexaco exchanged its Dynegy Series B Preferred Stock for cash, notes and Series C Preferred Stock. The $365 difference between the fair value of these items and the company's carrying value was included in net income.

In 2002, the company recorded write-downs of $1,626 of its investment in Dynegy common and preferred stock and $136 of its investment in its publicly traded Caltex Australia affiliate to their respective estimated fair values. The write-downs were required because the declines in the fair values of the investments below their carrying values were deemed to be other than temporary. Refer to Note 14 beginning on page 63 for additional information on the company's investment in Dynegy and Caltex Australia.

Also in 2002, impairments of $183 were recorded for various U.S. exploration and production properties and $100 for international projects.

	Year ended December 31		
	2004	2003	2002
Special Items			
Asset dispositions			
Exploration and Production			
Continuing operations			
United States	**$ 316**	$ 77	$ –
International	**644**	32	–
Discontinued operations			
United States	**50**	–	–
International	**207**	–	–
Refining, Marketing and Transportation			
United States	**–**	37	–
International	**–**	(24)	–
	1,217	122	–
Asset impairments/write-offs			
Exploration and Production			
Continuing operations			
United States	**–**	(103)	(183)
International	**–**	(30)	(100)
Refining, Marketing and Transportation			
United States	**–**	–	(66)
International	**–**	(123)	(136)
All Other			
Other asset write-offs	**–**	(84)	–
	–	(340)	(485)
Tax adjustments	**–**	118	60
Environmental remediation provisions	**–**	(132)	(160)
Restructuring and reorganizations	**–**	(146)	–
Merger-related expenses	**–**	–	(386)
Litigation provisions	**(55)**	–	(57)
Dynegy-related			
Impairments – equity share	**–**	(40)	(531)
Asset dispositions – equity share	**–**	–	(149)
Other	**–**	365	(1,626)
	–	325	(2,306)
Total Special Items	**$ 1,162**	$ (53)	$ (3,334)

The aggregate effects on income statement categories from special items, including ChevronTexaco's proportionate share of special items related to equity affiliates, are reflected in the following table.

	Year ended December 31		
	2004	2003	2002
Revenues and other income			
Income (loss) from equity affiliates	$ –	$ 179	$ (829)
Other income	1,281	(148)	–
Gain from exchange of Dynegy preferred stock	–	365	–
Total revenues and other income	1,281	396	(829)
Costs and other deductions			
Operating expenses	85	329	259
Selling, general and administrative expenses	–	146	180
Depreciation, depletion and amortization	–	286	298
Write-down of investments in Dynegy Inc.	–	–	1,796
Merger-related expenses	–	–	576
Total costs and other deductions	85	761	3,109
Income from continuing operations before income tax expense	1,196	(365)	(3,938)
Income tax expense (benefit)	291	(312)	(604)
Income from continuing operations	905	(53)	(3,334)
Income from discontinued operations	257	–	–
Net income	$ 1,162	$ (53)	$ (3,334)

Other financial information is as follows:

	Year ended December 31		
	2004	2003	2002
Total financing interest and debt costs	$ 450	$ 549	$ 632
Less: Capitalized interest	44	75	67
Interest and debt expense	$ 406	$ 474	$ 565
Research and development expenses	$ 242	$ 228	$ 221
Foreign currency effects*	$ (81)	$ (404)	$ (43)

*Includes $(13), $(96) and $(66) in 2004, 2003 and 2002, 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 $3,036, $2,106 and $1,571 at December 31, 2004, 2003 and 2002, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of $36, $82 and $13 were included in net income for the years 2004, 2003 and 2002, respectively.

NOTE 3.

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 was 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 4.

INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

"Net decrease in operating working capital" is composed of the following:

	Year ended December 31		
	2004	2003	2002
Increase in accounts and notes receivable	$ (2,515)	$ (265)	$ (1,135)
(Increase) decrease in inventories	(298)	115	185
(Increase) decrease in prepaid expenses and other current assets	(76)	261	92
Increase in accounts payable and accrued liabilities	2,175	242	1,845
Increase (decrease) in income and other taxes payable	1,144	(191)	138
Net decrease in operating working capital	$ 430	$ 162	$ 1,125
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	$ 422	$ 467	$ 533
Income taxes	$ 6,679	$ 5,316	$ 2,916
Net (purchases) sales of marketable securities consist of the following gross amounts:			
Marketable securities purchased	$ (1,951)	$ (3,563)	$ (5,789)
Marketable securities sold	1,501	3,716	5,998
Net (purchases) sales of marketable securities	$ (450)	$ 153	$ 209

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 "Net (purchases) sales of treasury shares" in 2004 included share repurchases of $2.1 billion related to the company's common stock repurchase program, which were partially offset by the issuance of shares for the exercise of stock options.

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

▸ **NOTE 4.** INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS – Continued

	Year ended December 31		
	2004	2003	2002
Additions to properties, plant and equipment[1]	**$ 5,798**	$ 4,953	$ 6,262
Additions to investments	**303**	687	1,138
Current-year dry hole expenditures	**228**	132	252
Payments for other liabilities and assets, net	**(19)**	(147)	(55)
Capital expenditures	**6,310**	5,625	7,597
Expensed exploration expenditures	**412**	315	303
Payments of long-term debt and other financing obligations, net	**31**	286[2]	2
Capital and exploratory expenditures, excluding equity affiliates	**6,753**	6,226	7,902
Equity in affiliates' expenditures	**1,562**	1,137	1,353
Capital and exploratory expenditures, including equity affiliates	**$ 8,315**	$ 7,363	$ 9,255

[1] Net of noncash additions of $212 in 2004, $1,183 in 2003 and $195 in 2002.
[2] Includes deferred payment of $210 related to the 1993 acquisition of the company's interest in the Tengizchevroil joint venture.

NOTE 5.

SUMMARIZED FINANCIAL DATA – CHEVRON U.S.A. INC.

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of ChevronTexaco Corporation. CUSA and its subsidiaries manage and operate most of ChevronTexaco'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 ChevronTexaco. CUSA also holds ChevronTexaco'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 and 2002, ChevronTexaco implemented legal reorganizations in which certain ChevronTexaco subsidiaries transferred assets to or under CUSA and other ChevronTexaco 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 reorganization in a manner similar to a pooling of interests, with all periods presented as if the companies had always been combined and the reorganization had occurred on January 1, 2002. 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 reorganization actually occurred on January 1, 2002.

	Year ended December 31		
	2004	2003	2002
Sales and other operating revenues	**$ 108,351**	$ 82,760	$ 66,835
Total costs and other deductions	**102,180**	78,399	68,526
Net income (loss)*	**4,773**	3,083	(1,895)

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

	At December 31	
	2004	2003
Current assets	**$ 23,147**	$ 15,539
Other assets*	**19,961**	21,348
Current liabilities	**17,044**	13,122
Other liabilities	**12,533**	14,136
Net equity	**13,531**	9,629
Memo: Total debt	**$ 8,349**	$ 9,091

*Includes assets held for sale of $1,052 at December 31, 2003.

CUSA's net loss of $1,895 for 2002 included net charges of $2,555 for asset write-downs and dispositions, of which $2,306 was related to Dynegy.

NOTE 6.

SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of ChevronTexaco Corporation. CTC is the principal operator of ChevronTexaco'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 ChevronTexaco companies. ChevronTexaco 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		
	2004	2003	2002
Sales and other operating revenues	**$ 660**	$ 601	$ 850
Total costs and other deductions	**495**	535	922
Net income (loss)	**160**	50	(79)

	At December 31	
	2004	2003
Current assets	**$ 292**	$ 116
Other assets	**219**	312
Current liabilities	**67**	96
Other liabilities	**278**	243
Net equity	**166**	89

During 2004, CTC's paid-in capital decreased by $85 from capital settlements.

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2004.

NOTE 7.

STOCKHOLDERS' EQUITY

Retained earnings at December 31, 2004 and 2003, included approximately $3,950 and $1,300, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2004, about 151 million shares of ChevronTexaco's common stock remain available for issuance from the

160 million shares that were reserved for issuance under the ChevronTexaco Corporation Long-Term Incentive Plan (LTIP), as amended and restated, which was approved by the stockholders in 2004. In addition, approximately 622,000 shares remain available for issuance from the 800,000 shares of the company's common stock that were reserved for awards under the ChevronTexaco Corporation Non-Employee Directors' Equity Compensation and Deferral Plan (Non-Employee Directors' Plan), which was approved by stockholders in 2003. Refer to Note 3 on page 57 for a discussion of the company's common stock split.

NOTE 8.
FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments ChevronTexaco is exposed to market risks related to price volatility of crude oil, refined products, electricity, natural gas and refinery feedstock.

The company uses financial derivative commodity instruments to manage this exposure on a small 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 financial derivative commodity instruments for limited trading purposes.

The company maintains a policy of requiring that an International Swaps and Derivatives Association Agreement govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transaction, 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 a reasonable measure of the company's credit risk. It is the company's policy to use other netting agreements with certain counterparties with which it conducts significant transactions.

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.

During 2004, four new swaps relating to a portion of the company's fixed-rate debt were initiated. At year-end 2004, the interest rate swaps outstanding related to fixed-rate debt, and their weighted average maturity was approximately three years.

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.

Long-term debt of $5,815 and $7,229 had estimated fair values of $6,444 and $7,709 at December 31, 2004 and 2003, respectively.

For interest rate swaps, the notional principal amounts of $1,665 and $665 had estimated fair values of $36 and $65 at December 31, 2004 and 2003, 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 $8,789 and $3,803 at December 31, 2004 and 2003, respectively. Of these balances, $7,338 and $2,803 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 2.3 years.

For the financial and derivative instruments discussed above, there was not a material change in market risk from that presented in 2003.

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, Letters of Credit are the principal security obtained to support lines of credit.

Investment in Dynegy Notes and Preferred Stock At the beginning of 2004, the company held investments in $223 face value of Dynegy Junior Unsecured Subordinated Notes due 2016 and $400 face value of Dynegy Series C Convertible Preferred Stock with a stated maturity date of 2033.

The Junior Notes were redeemed at face value during 2004, and gains of $54 were recorded for the difference between the face amounts and the carrying values at the time of redemption. The face value of the company's investment in the Series C preferred stock at December 31, 2004, was $400. The stock is recorded at its fair value, which was estimated to be $370 at December 31, 2004. Future temporary changes in the estimated fair value of the preferred stock will be 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 9.
OPERATING SEGMENTS AND GEOGRAPHIC DATA

Although each subsidiary of ChevronTexaco is responsible for its own affairs, ChevronTexaco 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 ChevronTexaco 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 and also approves capital and exploratory funding for major projects and 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, coal mining operations, 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." Merger-related expenses in 2002 were also included in "All Other." After-tax segment income (loss) from continuing operations is presented in the following table:

	Year ended December 31		
	2004	2003	2002
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	**$ 3,868**	$ 3,160	$ 1,703
International	**5,622**	3,199	2,823
Total Exploration and Production	**9,490**	6,359	4,526
Downstream – Refining, Marketing and Transportation			
United States	**1,261**	482	(398)
International	**1,989**	685	31
Total Refining, Marketing and Transportation	**3,250**	1,167	(367)
Chemicals			
United States	**251**	5	13
International	**63**	64	73
Total Chemicals	**314**	69	86
Total Segment Income	**13,054**	7,595	4,245
All Other			
Interest expense	**(257)**	(352)	(406)
Interest income	**129**	75	72
Other	**108**	64	(2,423)
Merger-related expenses	**–**	–	(386)
Income From Continuing Operations	**13,034**	7,382	1,102
Income From Discontinued Operations	**294**	44	30
Cumulative effect of changes in accounting principles	**–**	(196)	–
Net Income	**$ 13,328**	$ 7,230	$ 1,132

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2004 and 2003 follow:

	At December 31	
	2004	2003
Upstream – Exploration and Production		
United States	**$ 11,869**	$ 12,501
International	**31,239**	28,520
Total Exploration and Production	**43,108**	41,021
Downstream – Refining, Marketing and Transportation		
United States	**10,091**	9,354
International	**19,415**	17,627
Total Refining, Marketing and Transportation	**29,506**	26,981
Chemicals		
United States	**2,316**	2,165
International	**667**	662
Total Chemicals	**2,983**	2,827
Total Segment Assets	**75,597**	70,829
All Other*		
United States	**11,746**	6,644
International	**5,865**	3,997
Total All Other	**17,611**	10,641
Total Assets – United States	**36,022**	30,664
Total Assets – International	**57,186**	50,806
Total Assets	**$ 93,208**	$ 81,470

* All Other assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company's investment in Dynegy, coal mining operations, power generation businesses, technology companies, and assets of the corporate administrative functions.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2004, 2003 and 2002 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 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 coal mining operations, power generation businesses, insurance operations, real estate activities and technology companies.

Other than the United States, the only country where ChevronTexaco generates significant revenues is the United Kingdom, where revenues amounted to $13,985, $12,121 and $10,816 in 2004, 2003 and 2002, respectively.

	Year ended December 31		
	2004	2003	2002
Upstream – Exploration and Production			
United States	**$ 8,242**	$ 6,842	$ 4,923
Intersegment	**8,121**	6,295	4,217
Total United States	**16,363**	13,137	9,140
International	**7,246**	7,013	5,360
Intersegment	**10,184**	8,142	8,301
Total International	**17,430**	15,155	13,661
Total Exploration and Production	**33,793**	28,292	22,801
Downstream – Refining, Marketing and Transportation			
United States	**57,723**	44,701	33,881
Excise taxes	**4,147**	3,744	3,990
Intersegment	**179**	225	163
Total United States	**62,049**	48,670	38,034
International	**67,944**	52,486	45,759
Excise taxes	**3,810**	3,342	3,006
Intersegment	**87**	46	38
Total International	**71,841**	55,874	48,803
Total Refining, Marketing and Transportation	**133,890**	104,544	86,837
Chemicals			
United States	**347**	323	323
Intersegment	**188**	129	109
Total United States	**535**	452	432
International	**747**	677	638
Excise taxes	**11**	9	10
Intersegment	**107**	83	68
Total International	**865**	769	716
Total Chemicals	**1,400**	1,221	1,148
All Other			
United States	**551**	338	413
Intersegment	**431**	121	105
Total United States	**982**	459	518
International	**97**	100	37
Intersegment	**82**	4	–
Total International	**179**	104	37
Total All Other	**1,161**	563	555
Segment Sales and Other Operating Revenues			
United States	**79,929**	62,718	48,124
International	**90,315**	71,902	63,217
Total Segment Sales and Other Operating Revenues	**170,244**	134,620	111,341
Elimination of intersegment sales	**(19,379)**	(15,045)	(13,001)
Total Sales and Other Operating Revenues	**$ 150,865**	$119,575	$ 98,340

▸ **NOTE 9.** OPERATING SEGMENTS AND GEOGRAPHIC DATA – Continued

Segment Income Taxes Segment income tax expenses for the years 2004, 2003 and 2002 are as follows:

	Year ended December 31		
	2004	2003[1]	2002
Upstream – Exploration and Production			
United States	**$ 2,308**	$ 1,853	$ 854
International	**5,041**	3,831	3,415
Total Exploration and Production	**7,349**	5,684	4,269
Downstream – Refining, Marketing and Transportation			
United States	**739**	300	(254)
International	**442**	275	138
Total Refining, Marketing and Transportation	**1,181**	575	(116)
Chemicals			
United States	**47**	(25)	(17)
International	**17**	6	17
Total Chemicals	**64**	(19)	–
All Other	**(1,077)**	(946)	(1,155)
Income Tax Expense From Continuing Operations[2]	**$ 7,517**	$ 5,294	$ 2,998

[1] See Note 25 on page 77 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, $50 and $26 related to discontinued operations for 2004, 2003 and 2002, respectively, is not included.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 14 beginning on page 63. Information related to properties, plant and equipment by segment is contained in Note 15 on page 65.

NOTE 10.
LITIGATION

The company and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive.

The company is a party to more than 70 lawsuits and claims, the majority of which involves 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, and there are no detectable levels of MTBE in that gasoline.

NOTE 11.
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	
	2004	2003
Exploration and Production	**$ 277**	$ 246
Refining, Marketing and Transportation	**842**	842
Total	**1,119**	1,088
Less: Accumulated amortization	**690**	642
Net capitalized leased assets	**$ 429**	$ 446

Rental expenses incurred for operating leases during 2004, 2003 and 2002 were as follows:

	Year ended December 31		
	2004	2003	2002
Minimum rentals	**$ 2,093**	$ 1,567	$ 1,270
Contingent rentals	**7**	3	4
Total	**2,100**	1,570	1,274
Less: Sublease rental income	**40**	48	53
Net rental expense	**$ 2,060**	$ 1,522	$ 1,221

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, 2004, 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: 2005	$ 390	$ 83
2006	338	74
2007	280	62
2008	239	51
2009	236	52
Thereafter	749	562
Total	$ 2,232	$ 884
Less: Amounts representing interest and executory costs		(292)
Net present values		592
Less: Capital lease obligations included in short-term debt		(353)
Long-term capital lease obligations		$ 239

NOTE 12.

RESTRUCTURING AND REORGANIZATION COSTS

In connection with various 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 are expected to occur by the end of 2005.

At the beginning of 2004, a $100 liability remained for employee severance charges recorded in 2002 and 2001 associated with the merger between Chevron Corporation and Texaco Inc. The balance related primarily to deferred payment options elected by certain employees who were terminated before the end of 2003. Approximately $80 of the liability was paid during 2004 and the remainder in January 2005.

Activity for the company's liability related to reorganizations and restructurings in 2004 is summarized in the following table:

Amounts before tax	**2004**	2003
Balance at January 1	**$ 240**	$ 6
Additions	**27**	258
Payments	**(148)**	(24)
Balance at December 31	**$ 119**	$ 240

Substantially all of the balance at December 31, 2004, related to employee severance costs that were part of a presumed ongoing benefit arrangement under applicable accounting rules in FAS 146, *"Accounting for Costs Associated with Exit or Disposal Activities,"* paragraph 8, footnote 7. Therefore, the company accounts for severance costs in accordance with FAS 88, *"Employers' Accounting for Settlements and Curtailments of Defined Pension Plans and for Termination Benefits."* At December 31, 2004, the amount was categorized as a current accrued liability on the Consolidated Balance Sheet and the associated charges during the period were categorized as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income.

NOTE 13.

ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

At December 31, 2004, and December 31, 2003, the company classified $162 and $1,100, respectively, of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. Assets in this category at the end of 2004 related to a group of service stations. These assets are expected to be disposed of in 2005.

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

	Year ended December 31		
	2004	2003	2002
Revenues and other income	**$ 635**	$ 485	$ 376
Income from discontinued operations before income tax expense	**394**	94	56
Income from discontinued operations, net of tax	**294**	44	30

Included in the 2004 after-tax amount were gains totaling $257 related to the sale of a Canadian natural-gas processing business, a wholly owned subsidiary in the Democratic Republic of the Congo and certain producing properties in the Gulf of Mexico.

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

NOTE 14.

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		
	2004	2003	**2004**	2003	2002
Upstream – Exploration and Production					
Tengizchevroil	**$ 4,725**	$ 3,363	**$ 950**	$ 611	$ 490
Other	**1,177**	991	**246**	200	116
Total Exploration and Production	**5,902**	4,354	**1,196**	811	606
Downstream – Refining, Marketing and Transportation					
LG-Caltex Oil Corporation	**1,820**	1,561	**296**	107	46
Caspian Pipeline Consortium	**1,039**	1,026	**140**	52	66
Star Petroleum Refining Company Ltd.	**663**	457	**207**	8	(25)
Caltex Australia Ltd.	**263**	118	**173**	13	(156)
Other	**1,125**	1,069	**143**	100	110
Total Refining, Marketing and Transportation	**4,910**	4,231	**959**	280	41
Chemicals					
Chevron Phillips Chemical Company LLC	**1,896**	1,747	**334**	24	2
Other	**19**	20	**2**	1	4
Total Chemicals	**1,915**	1,767	**336**	25	6
All Other					
Dynegy Inc.	**525**	698	**86**	(56)	(679)
Other	**601**	761	**5**	(31)	1
Total equity method	**$ 13,853**	$ 11,811	**$ 2,582**	$ 1,029	$ (25)
Other at or below cost	**536**	508			
Total investments and advances	**$ 14,389**	$ 12,319			
Total U.S.	**$ 3,788**	$ 3,905	**$ 588**	$ 175	$ (559)
Total International	**$ 10,601**	$ 8,414	**$ 1,994**	$ 854	$ 534

Descriptions of major affiliates are as follows:

Tengizchevroil ChevronTexaco has a 50 percent equity ownership interest in TCO, a joint venture formed in 1993 to develop the Tengiz and Korolev oil fields in Kazakhstan over a 40-year period.

In 2004, as part of the funding of the expansion of TCO's production facilities, ChevronTexaco purchased from TCO $2,200 of 6.124 percent Series B Notes, due 2014, guaranteed by TCO. Interest on the notes is payable semiannually, and principal is to be repaid semiannually in equal installments beginning in February 2008. Immediately following the purchase of the Series B Notes, ChevronTexaco received from TCO approximately $1,800 representing a repayment of subordinated loans from the company, interest and dividends. The $2,200 investment in the Series B Notes, which the company intends to hold to their

▸ **NOTE 14.** INVESTMENTS AND ADVANCES – Continued

maturity, and the $1,800 distribution were recorded to "Investments and Advances."

LG-Caltex Oil Corporation ChevronTexaco owns 50 percent of LG-Caltex, a joint venture formed in 1967 between the LG Group and Caltex to engage in importing, refining and marketing of petroleum products and petrochemicals in South Korea.

Star Petroleum Refining Company Ltd. ChevronTexaco 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. ChevronTexaco has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. During 2002, the company wrote down its investment in CAL by $136 to its estimated fair value at September 30, 2002. At December 31, 2004, the fair value of ChevronTexaco's share of CAL common stock was $1,130. The aggregate carrying value of the company's investment in CAL was approximately $80 lower than the amount of underlying equity in CAL net assets.

Chevron Phillips Chemical Company LLC ChevronTexaco owns 50 percent of CPChem, formed in 2000 when Chevron merged most of its petrochemicals businesses with those of Phillips Petroleum Company. At December 31, 2004, the company's carrying value of its investment in CPChem was approximately $130 lower than the amount of underlying equity in CPChem's net assets.

Dynegy Inc. ChevronTexaco owns an approximate 25 percent equity interest in the common stock of Dynegy, an energy provider engaged in power generation, the gathering and processing of natural gas, and the fractionation, storage, transportation and marketing of natural gas liquids. The company also holds investments in Dynegy preferred stock.

Investment in Dynegy Common Stock At December 31, 2004, the carrying value of the company's investment in Dynegy common stock was approximately $150. This amount was about $365 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, 2004, was approximately $450.

Investments in Dynegy Notes and Preferred Stock Refer to Note 8, page 60, for a discussion of these investments.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $7,933, $6,308 and $6,522 with affiliated companies for 2004, 2003 and 2002, respectively. "Purchased crude oil and products" includes $2,548, $1,740 and $1,839 with affiliated companies for 2004, 2003 and 2002, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,188 and $827 due from affiliated companies at December 31, 2004 and 2003, respectively. "Accounts payable" includes $192 and $118 due to affiliated companies at December 31, 2004 and 2003, respectively.

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

	Affiliates			ChevronTexaco Share*		
Year ended December 31	**2004**	2003	2002	**2004**	2003	2002
Total revenues	**$ 55,152**	$ 42,323	$ 31,877	**$ 25,916**	$ 19,467	$ 15,049
Income (loss) before income tax expense	**5,309**	1,657	(1,517)	**3,015**	1,211	70
Net income (loss)	**4,441**	1,508	(1,540)	**2,582**	1,029	(25)
At December 31						
Current assets	**$ 16,506**	$ 12,204	$ 16,808	**$ 7,540**	$ 5,180	$ 6,270
Noncurrent assets	**38,104**	39,422	40,884	**15,567**	15,765	15,219
Current liabilities	**10,949**	9,642	14,414	**4,962**	4,132	5,158
Noncurrent liabilities	**22,261**	22,738	24,129	**4,520**	5,002	5,668
Net equity	**$ 21,400**	$ 19,246	$ 19,149	**$ 13,625**	$ 11,811	$ 10,663

*The company's share of income and underlying equity in the net assets of its investments includes the effects of write-downs of certain investments, largely related to Dynegy Inc. and Caltex Australia Limited, as described in the preceding section.

NOTE 15.
PROPERTIES, PLANT AND EQUIPMENT[1]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment[2]			Additions at Cost[3]			Depreciation Expense[4,5]		
	2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003	2002
Exploration and Production												
United States	**$ 37,329**	$ 34,798	$ 39,986	**$ 10,047**	$ 9,953	$10,457	**$ 1,584**	$1,776	$1,658	**$ 1,508**	$ 1,815	$ 1,806
International	**38,721**	37,402	36,382	**21,192**	20,572	18,908	**3,090**	3,246	3,343	**2,180**	2,227	2,132
Total Exploration and Production	**76,050**	72,200	76,368	**31,239**	30,525	29,365	**4,674**	5,022	5,001	**3,688**	4,042	3,938
Refining, Marketing and Transportation												
United States	**12,826**	12,959	13,423	**5,611**	5,881	6,296	**482**	389	671	**490**	493	570
International	**10,843**	11,174	11,194	**5,443**	5,944	6,310	**441**	388	411	**572**	655	530
Total Refining, Marketing and Transportation	**23,669**	24,133	24,617	**11,054**	11,825	12,606	**923**	777	1,082	**1,062**	1,148	1,100
Chemicals												
United States	**615**	613	614	**292**	303	317	**12**	12	16	**20**	21	21
International	**725**	719	731	**392**	404	420	**27**	24	37	**26**	38	21
Total Chemicals	**1,340**	1,332	1,345	**684**	707	737	**39**	36	53	**46**	59	42
All Other[6]												
United States	**2,877**	2,772	2,783	**1,466**	1,393	1,334	**314**	169	230	**158**	109	149
International	**18**	119	118	**15**	88	113	**2**	8	55	**3**	26	2
Total All Other	**2,895**	2,891	2,901	**1,481**	1,481	1,447	**316**	177	285	**161**	135	151
Total United States	**53,647**	51,142	56,806	**17,416**	17,530	18,404	**2,392**	2,346	2,575	**2,176**	2,438	2,546
Total International	**50,307**	49,414	48,425	**27,042**	27,008	25,751	**3,560**	3,666	3,846	**2,781**	2,946	2,685
Total	**$ 103,954**	$100,556	$105,231	**$ 44,458**	$44,538	$44,155	**$ 5,952**	$6,012	$6,421	**$ 4,957**	$ 5,384	$ 5,231

[1] Refer to Note 25 on page 77 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] Net of accumulated abandonment and restoration costs of $2,263 at December 31, 2002.
[3] Net of dry hole expense related to prior years' expenditures of $58, $124 and $36 in 2004, 2003 and 2002, respectively.
[4] Depreciation expense includes accretion expense of $93 and $132 in 2004 and 2003, respectively.
[5] Depreciation expense includes discontinued operations of $22, $58 and $62 in 2004, 2003 and 2002, respectively.
[6] Primarily coal, real estate assets and management information systems.

NOTE 16.
ACCOUNTING FOR BUY/SELL CONTRACTS

In January and February 2005, the SEC issued comment letters to ChevronTexaco 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 has 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 accounts for buy/sell transactions in the Consolidated Statement of Income the same as any other monetary transaction for which title passes, and the risk and reward of ownership are assumed by the counterparties. At issue with the SEC is whether the industry's accounting for buy/sell contracts instead 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 topic is under deliberation by the Emerging Issues Task Force (EITF) of the FASB as Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty."* The EITF first discussed this issue in November 2004. Additional research is being performed by the FASB staff, and the topic will be discussed again at a future EITF meeting. While this issue is under deliberation, the SEC staff directed ChevronTexaco and other companies in its January and February 2005 comment letters 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.

With regard to the latter, the company's accounting treatment for buy/sell contracts is based on the view that such transactions are monetary in nature. Monetary transactions are outside the scope of APB 29. The company believes its accounting is also supported by the indicators of gross reporting of purchases and sales in paragraph 3 of EITF Issue No. 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Additionally, FASB Interpretation No. 39, *"Offsetting of Amounts Related to Certain Contracts"* (FIN 39), prohibits a receivable from being netted against a payable when the receivable is subject to credit risk unless a right of offset exists that is enforceable by law. The

▸ **NOTE 16.** ACCOUNTING FOR BUY/SELL CONTRACTS – Continued

company also views netting the separate components of buy/sell contracts in the income statement to be inconsistent with the gross presentation that FIN 39 requires for the resulting receivable and payable on the balance sheet.

The company's buy/sell transactions are also similar to the "barrel back" example used in other accounting literature, including EITF Issue No. 03-11, *"Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-3"* (which indicates a company's decision to show buy/sell-types of transactions gross on the income statement as being a matter of judgment of the relevant facts and circumstances of the company's activities) and Derivatives Implementation Group (DIG) Issue No. K1, *"Miscellaneous: Determining Whether Separate Transactions Should be Viewed as a Unit."*

The company further notes that the accounting for buy/sell contracts as separate purchases and sales is in contrast to the accounting for other types of contracts typically described by the industry as exchange contracts, which are considered nonmonetary in nature and appropriately shown net on the income statement. Under an exchange contract, for example, one company agrees to exchange refined products in one location for another company's same quantity of refined products in another location. Upon transfer, the only amounts that may be invoiced are for transportation and quality differentials. Among other things, unlike buy/sell contracts, the obligations of each party to perform under the contract are not independent and the risks and rewards of ownership are not separately transferred.

As shown on the company's Consolidated Statement of Income, "Sales and other operating revenues" for the three years ending December 31, 2004, included $18,650, $14,246 and $7,963, respectively, for buy/sell contracts. 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 17.
TAXES

	Year ended December 31		
	2004	2003	2002
Taxes on income[1]			
U.S. federal			
Current	**$ 2,246**	$ 1,133	$ (80)
Deferred[2]	**(290)**	121	(414)
State and local	**345**	133	21
Total United States	**2,301**	1,387	(473)
International			
Current	**5,150**	3,864	3,138
Deferred[2]	**66**	43	333
Total International	**5,216**	3,907	3,471
Total taxes on income	**$ 7,517**	$ 5,294	$ 2,998

[1] Excludes income tax expense of $100, $50 and $26 related to discontinued operations for 2004, 2003 and 2002, 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 2004, the before-tax income for U.S. operations, including related corporate and other charges, was $7,776, compared with a before-tax income of $5,664 in 2003 and a before-tax loss of $2,162 in 2002. For international operations, before-tax income was $12,775, $7,012 and $6,262 in 2004, 2003 and 2002, respectively. U.S. federal income tax expense was reduced by $176, $196 and $208 in 2004, 2003 and 2002, respectively, for business tax credits.

The company's effective income tax rate varied from the U.S. statutory federal income tax rate because of the following:

	Year ended December 31		
	2004	2003	2002
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	**5.3**	12.8	29.9
State and local taxes on income, net of U.S. federal income tax benefit	**0.9**	0.5	1.1
Prior-year tax adjustments	**(1.0)**	(1.6)	(7.1)
Tax credits	**(0.9)**	(1.5)	(5.1)
Effects of enacted changes in tax laws	**(0.6)**	0.3	2.0
Impairment of investments in equity affiliates	**–**	–	12.6
Capital loss tax benefit	**(2.1)**	(0.8)	–
Other	**–**	(1.9)	–
Consolidated companies	**36.6**	42.8	68.4
Effect of recording income from certain equity affiliates on an after-tax basis	**–**	(1.0)	4.7
Effective tax rate	**36.6%**	41.8%	73.1%

International taxes in 2004 were reduced by approximately $129 related to changes in income tax laws. 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	
	2004	2003*
Deferred tax liabilities		
Properties, plant and equipment	**$ 8,889**	$ 8,539
Investments and other	**931**	602
Total deferred tax liabilities	**9,820**	9,141
Deferred tax assets		
Abandonment/environmental reserves	**(1,495)**	(1,221)
Employee benefits	**(965)**	(1,272)
Tax loss carryforwards	**(1,155)**	(956)
Capital losses	**(687)**	(264)
Deferred credits	**(838)**	(578)
Foreign tax credits	**(93)**	(352)
Inventory	**(99)**	(57)
Other accrued liabilities	**(300)**	(199)
Miscellaneous	**(876)**	(935)
Total deferred tax assets	**(6,508)**	(5,834)
Deferred tax assets valuation allowance	**1,661**	1,553
Total deferred taxes, net	**$ 4,973**	$ 4,860

*2003 conformed to 2004 presentation.

The 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 2005 through 2011. Foreign tax credit carryforwards of $93 will expire in 2014.

At December 31, 2004 and 2003, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2004	2003
Prepaid expenses and other current assets	**$ (1,532)**	$ (940)
Deferred charges and other assets	**(769)**	(641)
Federal and other taxes on income	**6**	24
Noncurrent deferred income taxes	**7,268**	6,417
Total deferred income taxes, net	**$ 4,973**	$ 4,860

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 approximately $10,000 at December 31, 2004. 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 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 specific category of 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 2005 and 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 federal effective tax rate to about 32 percent for that category of income, based on current earnings levels.

Under the guidance in FASB Staff Position No. FAS 109-1, *"Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004,"* the tax deduction on qualified production activities provided by the American Jobs Creation Act of 2004 will be treated as a "special deduction," as described in FAS 109. As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction will be reported in the period in which the deduction is claimed on the company's tax return.

The Act also provides for a limited opportunity to repatriate earnings from outside the United States at a special reduced tax rate that can be as low as 5.25 percent. In early 2005, the company was in the process of reviewing the guidance that the IRS issued on January 13, 2005, regarding this provision and also considering other relevant information. The company does not anticipate a major change in its plans for repatriating earnings from international operations under the provisions of the Act.

Taxes other than on income were as follows:

	Year ended December 31		
	2004	2003	2002
United States			
Excise taxes on products and merchandise	**$ 4,147**	$ 3,744	$ 3,990
Import duties and other levies	**5**	11	12
Property and other miscellaneous taxes	**359**	309	348
Payroll taxes	**137**	138	141
Taxes on production	**257**	244	179
Total United States	**4,905**	4,446	4,670
International			
Excise taxes on products and merchandise	**3,821**	3,351	3,016
Import duties and other levies	**10,542**	9,652	8,587
Property and other miscellaneous taxes	**415**	320	291
Payroll taxes	**52**	54	46
Taxes on production	**86**	83	79
Total International	**14,916**	13,460	12,019
Total taxes other than on income*	**$ 19,821**	$ 17,906	$ 16,689

*Includes taxes on discontinued operations of $3, $5 and $7 in 2004, 2003 and 2002, respectively.

NOTE 18.
SHORT-TERM DEBT

	At December 31 2004	2003
Commercial paper*	**$ 4,068**	$ 4,078
Notes payable to banks and others with originating terms of one year or less	**310**	190
Current maturities of long-term debt	**333**	863
Current maturities of long-term capital leases	**55**	71
Redeemable long-term obligations		
Long-term debt	**487**	487
Capital leases	**298**	299
Subtotal	**5,551**	5,988
Reclassified to long-term debt	**(4,735)**	(4,285)
Total short-term debt	**$ 816**	$ 1,703

*Weighted-average interest rates at December 31, 2004 and 2003, were 1.98 percent and 1.01 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 8 beginning on page 59 for information concerning the company's debt-related derivative activities.

At December 31, 2004, the company had $4,735 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 2004 or at year-end.

At December 31, 2004 and 2003, the company classified $4,735 and $ 4,285, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2005, as the company has both the intent and the ability to refinance this debt on a long-term basis.

NOTE 19.
LONG-TERM DEBT

ChevronTexaco has three "shelf" registrations 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. The company's long-term debt outstanding at year-end 2004 and 2003 was as follows:

	At December 31 2004	2003
3.5% notes due 2007	**$ 1,995**	$ 1,993
3.375% notes due 2008	**754**	749
5.5% note due 2009	**422**	431
7.327% amortizing notes due 2014[1]	**360**	360
9.75% debentures due 2020	**250**	250
5.7% notes due 2008	**206**	220
8.625% debentures due 2031	**199**	199
8.625% debentures due 2032	**199**	199
7.5% debentures due 2043	**198**	198
8.625% debentures due 2010	**150**	150
8.875% debentures due 2021	**150**	150
7.09% notes due 2007	**144**	150
8.25% debentures due 2006	**129**	150
6.625% notes due 2004	**–**	499
8.11% amortizing notes due 2004[2]	**–**	240
6.0% notes due 2005	**–**	299
Medium-term notes, maturing from 2017 to 2043 (7.1%)[3]	**210**	210
Other foreign currency obligations (4.0%)[3]	**39**	52
Other long-term debt (4.3%)[3]	**410**	730
Total including debt due within one year	**5,815**	7,229
Debt due within one year	**(333)**	(863)
Reclassified from short-term debt	**4,735**	4,285
Total long-term debt	**$ 10,217**	$ 10,651

[1] Guarantee of ESOP debt.
[2] Debt assumed from ESOP in 1999.
[3] Less than $150 individually; weighted-average interest rates at December 31, 2004.

Consolidated long-term debt maturing after December 31, 2004, is as follows: 2005 – $333; 2006 – $149; 2007 – $2,178; 2008 – $1,061; and 2009 – $455; after 2009 – $1,639.

In 2004, the company repaid $500 of 6.625 percent notes and $240 of 8.11 percent notes that matured during the year. Other repayments during 2004 include $300 of 6 percent notes due June 2005 and $265 in various Philippine debt.

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

NOTE 20.
NEW ACCOUNTING STANDARDS

FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46) FIN 46 was issued in January 2003 and established standards for determining under what circumstances a variable interest entity (VIE) should be consolidated by its primary beneficiary. FIN 46 also requires disclosures about VIEs that the company is not required to consolidate but in which it has a significant variable interest. In December 2003, the FASB issued FIN 46-R, which not only included amendments to FIN 46, but also required application of the interpretation to all affected entities no later than March 31, 2004, for calendar year reporting companies. Prior to this requirement, companies were required to apply the interpretation to special-purpose entities by December 31, 2003. The full adoption of the interpretation as of March 31, 2004, including the requirement relating to special-purpose entities, did not have an impact on the company's results of operations, financial position or liquidity.

FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP FAS 106-2) In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (The Act) became law. The Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued FSP FAS 106-2. One U.S. subsidiary was deemed at least actuarially equivalent and eligible for the federal subsidy. The effect on the company's postretirement benefit obligation and the associated annual expense was *de minimis.*

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 is 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 company is currently evaluating the impact of this standard.

FASB Statement No. 123R, "Share-Based Payment" (FAS 123R) In December 2004, the FASB issued FAS 123R, which requires that compensation costs relating to share-based payments be recognized in the company's financial statements. The company currently accounts for those payments under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *"Accounting for Stock Issued to Employees,"* and related interpretations. The company is preparing to implement this standard effective July 1, 2005. Although the transition method to be used to adopt the standard has not been selected, the impact of adoption is expected to have a minimal impact on the company's results of operations, financial position and liquidity. Refer to Note 1, beginning on page 54, for the company's calculation of the pro forma impact on net income of FAS 123, which would be similar to that under FAS 123R.

FASB Statement No. 153, "Exchanges of Nonmonetary Assets, – an Amendment of APB Opinion No. 29" (FAS 153) In December 2004, the FASB issued FAS 153, which is effective for the company for asset-exchange transactions beginning July 1, 2005. Under APB 29, assets received in certain types of nonmonetary exchanges were permitted to be recorded at the carrying value of the assets that were exchanged (i.e., recorded on a carryover basis). As amended by FAS 153, assets received in some circumstances will have to be recorded instead at their fair values. In the past, ChevronTexaco has not engaged in a large number of nonmonetary asset exchanges for significant amounts.

NOTE 21.
ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS

Refer to Note 1 on page 54 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.

The SEC issued comment letters during 2004 and in February 2005 to a number of companies in the oil and gas industry related to the accounting for suspended exploratory wells, particularly for those suspended under certain circumstances for more than one year. In February 2005, the FASB issued a proposed FSP to amend FAS 19, *"Financial Accounting and Reporting by Oil and Gas Producing Companies."* Under the provisions of the draft FSP, exploratory well costs would continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. The FSP provided a number of indicators needing to be present to demonstrate sufficient progress was being made in assessing the reserves and economic viability of the project.

The company will monitor the continuing deliberations of the FASB on this matter and the possible implications, if any, to the company's accounting policy and the amounts capitalized for suspended-well costs. The disclosures and discussion below address those suggested in the draft FSP and in the additional guidance issued by the SEC in its February 2005 comment letter to companies in the oil and gas industry.

The following table indicates the changes to the company's suspended exploratory-well costs for the three years ended December 31, 2004:

	Year ended December 31		
	2004	2003	2002
Beginning balance at January 1	**$ 549**	$ 478	$ 655
Additions to capitalized exploratory well costs pending the determination of proved reserves	**262**	346	209
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(64)**	(145)	(310)
Capitalized exploratory well costs charged to expense	**(76)**	(128)	(46)
Other reductions*	**–**	(2)	(30)
Ending balance at December 31	**$ 671**	$ 549	$ 478

*Represents a property sale in 2003 and a retirement due to a legal settlement in 2002.

The following table provides an aging of capitalized well costs, based on the date the drilling was completed, 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:

	Year ended December 31		
	2004	2003	2002
Exploratory well costs capitalized for a period of one year or less	**$ 222**	$ 181	$ 170
Exploratory well costs capitalized for a period greater than one year	**449**	368	308
Balance at December 31	**$ 671**	$ 549	$ 478
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**22**	22	27

*Certain projects have multiple wells or fields or both.

Of the $671 of suspended costs at December 31, 2004, approximately $290 related to 30 wells in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned

▸ **NOTE 21.** ACCOUNTING FOR EXPLORATORY WELLS – Continued

for the near future because the presence of hydrocarbons had already been established and other activities were in process to enable a future decision on project development. The balance related to wells in areas for which drilling was under way or firmly planned for the near future.

Of the $290, approximately $50 related to the well costs suspended one year or less since drilling was completed, and $240 related to costs suspended for more than one year since the completion of drilling. Of the $240 for 11 projects suspended for more than one year since the completion of drilling, activities associated with assessing the reserves and the projects' economic viability included: (a) $75 – discussions of joint development with an operator in an adjacent field and selection of subsurface and development plans, with front-end-engineering and design (FEED) expected to begin in 2005 (one project); (b) $63 – negotiations with contractors for FEED and negotiations with potential customers for natural gas (two projects); (c) $42 – award of contracts for FEED and finalization of fiscal issues with the host country (one project); (d) $20 – finalization of commercial terms with partners with award of detailed engineering and design contracts expected by the end of 2005 (one project); and (e) $40 – miscellaneous activities for projects with smaller amounts suspended. Progress is being made on all projects in this category; and 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.

Included in the $449 in the table on the preceding page for year-end 2004 well costs were $42 for four projects and $50 for one project that related to costs suspended in 2000 and 1998, respectively, when drilling in the associated project areas was completed. Certain wells in the project areas may have been suspended prior to these years of last drilling. Other well costs in the $449 total were associated with projects for which drilling was completed since 2000.

If an FSP is implemented similar to the draft issued in February 2005, the company does not believe it would result in the immediate expensing of a significant amount of suspended-well costs. However, the SEC staff has indicated that it generally would not view conducting environmental and engineering design studies as reasonable support for the suspending of costs beyond one year after drilling is complete. If such restrictions are included in the final FSP, the company may be required to expense a significant amount for wells that had found sufficient hydrocarbons to justify their completion as producing wells and for projects the company continued to consider economically and operationally viable. If a final rule required the company to expense the entire $240 before-tax carrying value for the 11 projects referenced above that were suspended as of December 31, 2004, for more than one year after the completion of drilling, the after-tax charge to earnings would be $150.

NOTE 22.

EMPLOYEE BENEFIT PLANS

The company has defined-benefit pension plans for many employees. The company typically funds only those defined-benefit plans for which funding is required under laws and regulations. In the United States, this includes all qualified tax-exempt plans subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company typically does not 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. In June 2004, the company announced changes to its primary U.S. postretirement benefit plan, which include a limit on future increases in the company contribution, an increase in service points (combination of age and years of company service) required to receive full coverage, and the plan's prescription drug coverage for retirees becoming secondary to Medicare Part D. 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 2004 and 2003 is as follows:

	Pension Benefits				Other Benefits	
	2004		2003			
	U.S.	Int'l.	U.S.	Int'l.	2004	2003
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	**$ 5,819**	**$2,708**	$ 5,308	$ 2,163	**$ 3,135**	$ 2,865
Service cost	**170**	**70**	144	54	**26**	28
Interest cost	**326**	**180**	334	151	**164**	191
Plan participants' contributions	**1**	**6**	1	1	**–**	–
Plan amendments	**–**	**26**	–	25	**(811)**	–
Actuarial loss[1]	**861**	**165**	708	223	**497**	244
Foreign currency exchange rate changes	**–**	**207**	–	257	**8**	7
Benefits paid	**(590)**	**(213)**	(676)	(162)	**(199)**	(200)
Curtailment	**–**	**(6)**	–	(4)	**–**	–
Special termination benefits	**–**	**1**	–	–	**–**	–
Benefit obligation at December 31	**6,587**	**3,144**	5,819	2,708	**2,820**	3,135
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	**4,444**	**2,129**	3,190	1,645	**–**	–
Actual return on plan assets	**589**	**229**	726	203	**–**	–
Foreign currency exchange rate changes	**–**	**172**	–	228	**–**	–
Employer contributions	**1,332**	**311**	1,203	214	**199**	200
Plan participants' contributions	**1**	**6**	1	1	**–**	–
Benefits paid	**(590)**	**(213)**	(676)	(162)	**(199)**	(200)
Fair value of plan assets at December 31	**5,776**	**2,634**	4,444	2,129	**–**	–
FUNDED STATUS	**(811)**	**(510)**	(1,375)	(579)	**(2,820)**	(3,135)
Unrecognized net actuarial loss[1]	**2,080**	**939**	1,598	918	**1,071**	646
Unrecognized prior-service cost	**308**	**104**	350	92	**(771)**	(19)
Unrecognized net transitional assets	**–**	**7**	–	8	**–**	–
Total recognized at December 31	**$ 1,577**	**$ 540**	$ 573	$ 439	**$ (2,520)**	$ (2,508)
AMOUNTS RECOGNIZED IN THE CONSOLIDATED BALANCE SHEET AT DECEMBER 31						
Prepaid benefit cost	**$ 1,759**	**$ 933**	$ 10	$ 679	**$ –**	$ –
Accrued benefit liability[2]	**(712)**	**(458)**	(970)	(392)	**(2,520)**	(2,508)
Intangible asset	**14**	**5**	349	18	**–**	–
Accumulated other comprehensive income[3]	**516**	**60**	1,184	134	**–**	–
Net amount recognized	**$ 1,577**	**$ 540**	$ 573	$ 439	**$ (2,520)**	$ (2,508)

[1] Other Benefits in 2003 include a $10 gain for the Medicare Part D federal subsidy for a small subsidiary plan.
[2] The company recorded additional minimum liabilities of $530 and $64 in 2004 for U.S. and international plans, respectively, and $1,533 and $152 in 2003 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."
[3] "Accumulated other comprehensive income" includes deferred income taxes of $181 and $21 in 2004 for U.S. and international plans, respectively, and $415 and $47 in 2003 for U.S. and international plans, respectively. This item is presented net of these taxes in the Consolidated Statement of Stockholders' Equity.

The accumulated benefit obligations for all U.S. and international pension plans were $ 6,117 and $2,734, respectively, at December 31, 2004, and $5,374 and $2,372, respectively, at December 31, 2003.

Information for pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2004 and 2003, was:

	At December 31	
	2004	2003
Projected benefit obligations	**$ 1,449**	$ 6,637
Accumulated benefit obligations	**1,360**	6,067
Fair value of plan assets	**282**	4,791

▸ **NOTE 22.** EMPLOYEE BENEFIT PLANS – Continued

The components of net periodic benefit cost for 2004, 2003 and 2002 were:

	Pension Benefits						Other Benefits		
	2004		2003		2002				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2004**	2003	2002
Service cost	**$ 170**	**$ 70**	$ 144	$ 54	$ 112	$ 47	**$ 26**	$ 28	$ 25
Interest cost	**326**	**180**	334	151	334	143	**164**	191	178
Expected return on plan assets	**(358)**	**(169)**	(224)	(132)	(288)	(138)	**–**	–	–
Amortization of transitional assets	**–**	**1**	–	(3)	–	(3)	**–**	–	–
Amortization of prior-service costs	**42**	**16**	45	14	32	12	**(47)**	(3)	(3)
Recognized actuarial losses (gains)	**114**	**69**	133	42	32	27	**54**	12	(1)
Settlement losses	**96**	**4**	132	1	146	1	**–**	–	–
Curtailment losses	**–**	**2**	–	6	–	–	**–**	–	–
Special termination benefits recognition	**–**	**1**	–	–	–	–	**–**	–	–
Net periodic benefit cost	**$ 390**	**$ 174**	$ 564	$ 133	$ 368	$ 89	**$ 197**	$ 228	$ 199

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		
	2004		2003		2002				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2004**	2003	2002
Assumptions used to determine benefit obligations									
Discount rate	**5.8%**	**6.4%**	6.0%	6.8%	6.8%	7.1%	**5.8%**	6.1%	6.8%
Rate of compensation increase	**4.0%**	**4.9%**	4.0%	4.9%	4.0%	5.5%	**4.1%**	4.1%	4.1%
Assumptions used to determine net periodic benefit cost									
Discount rate*	**5.9%**	**6.8%**	6.3%	7.1%	7.4%	7.7%	**6.1%**	6.8%	7.3%
Expected return on plan assets*	**7.8%**	**8.3%**	7.8%	8.3%	8.3%	8.9%	**N/A**	N/A	N/A
Rate of compensation increase	**4.0%**	**4.9%**	4.0%	5.1%	4.0%	5.4%	**4.1%**	4.1%	4.1%

*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.

Expected Return on Plan Assets The company employs a rigorous process to determine the estimates of 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 and advice from external actuarial firms while incorporating specific asset-class risk factors. Asset allocations are regularly 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 about 70 percent of the company's pension plan assets. At December 31, 2004, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

The year-end market-related value of U.S. pension plan assets used in the determination of pension expense was based on the market values 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 time period long enough to minimize the effects of distortions from day-to-day market volatility and yet still be contemporaneous to the end of the year. For plans outside the U.S., market value of assets as of the measurement date is used in calculating the pension expense.

Other Benefit Assumptions 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. Before retirement, the assumed health care cost trend rates start with 10.6 percent in 2004 and gradually drop to 4.8 percent for 2010 and beyond. Once the employee elects to retire, the trend rates are capped at 4 percent.

For the measurement of accumulated postretirement benefit obligation at December 31, 2003, the assumed heath care cost trend rates start with 8.4 percent in 2003 and gradually decline to 4.5 percent for 2007 and beyond.

Assumed health care cost-trend rates have a significant effect on the amounts reported for retiree health care costs. A change of one percentage point 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	$ 18	$ (15)
Effect on postretirement benefit obligation	$ 86	$ (98)

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

	U.S.		International	
Asset Category	**2004**	2003	**2004**	2003
Equities	**70%**	70%	**57%**	55%
Fixed Income	**21%**	21%	**42%**	43%
Real Estate	**9%**	8%	**1%**	2%
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 ChevronTexaco Board of Directors has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income 20–65 percent, Real Estate 0–15 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 $8 and $6 at December 31, 2004 and 2003, respectively. The "Other" asset category includes investments in private equity limited partnerships.

Cash Contributions and Benefit Payments In 2004, the company contributed $1,332 and $311 to its U.S. and international pension plans, respectively. In 2005, the company expects contributions to be approximately $250 and $150 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately $220 in 2005, as compared with $199 in 2004.

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

	Pension Benefits		Other
	U.S.	Int'l.	Benefits
2005	$ 489	$ 144	$ 217
2006	$ 507	$ 150	$ 186
2007	$ 524	$ 160	$ 190
2008	$ 540	$ 171	$ 193
2009	$ 553	$ 180	$ 197
2010–2014	$ 2,912	$ 1,038	$ 1,028

Employee Savings Investment Plan Eligible employees of ChevronTexaco and certain of its subsidiaries participate in the ChevronTexaco Employee Savings Investment Plan (ESIP). In 2002, the Employees Thrift Plan of Texaco Inc., Employees Savings Plan of ChevronTexaco Global Energy Inc. (formerly Caltex Corporation), Stock Plan of ChevronTexaco Global Energy, Inc., and Employees Thrift Plan of Fuel and Marine Marketing LLC were merged into the ChevronTexaco 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 $139, $136 and $136 in 2004, 2003 and 2002, respectively. This cost was reduced by the value of shares released from the LESOP totaling $(138), $(23) and $(73) in 2004, 2003 and 2002, respectively. The remaining amounts, totaling $1, $113 and $63 in 2004, 2003 and 2002, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the ChevronTexaco 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 76-3, *"Accounting Practices for Certain Employee Stock Ownership Plans,"* and subsequent consensus of the EITF of the FASB. The debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" in 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 the LESOP debt is recorded as interest expense. Dividends paid on LESOP shares are reflected as a reduction of retained earnings. All LESOP shares are considered outstanding for earnings-per-share computations.

Total (credits) expenses recorded for the LESOP were $(29), $24 and $98 in 2004, 2003 and 2002, respectively, including $23, $28 and $32 of interest expense related to LESOP debt and a (credit) charge to compensation expense of $(52), $(4) and $66.

Of the dividends paid on the LESOP shares, $52, $61 and $49 were used in 2004, 2003 and 2002, 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 no contributions in 2004 and contributions of $26 and $102 in 2003 and 2002, respectively, to satisfy LESOP debt service in excess of dividends received by the LESOP.

In January 2005, the company contributed $98 to permit the LESOP to make a $144 debt service payment, which included a principal payment of $113.

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, 2004 and 2003, were as follows:

Thousands	2004	2003
Allocated shares*	**24,832**	24,198
Unallocated shares	**9,940**	13,634
Total LESOP shares	**34,772**	37,832

*2003 share amounts restated to reflect a two-for-one stock split effected as a 100 percent stock dividend in 2004.

Benefit Plan Trust Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2004, the trust contained 14.2 million shares of ChevronTexaco 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.

Management Incentive Plans ChevronTexaco 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 plans were expanded in 2002 to include former employees of Texaco and Caltex. 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. Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, stock units and nonstock grants. Texaco also had a cash incentive program and a Stock Incentive Plan (SIP) that included stock options, restricted stock and other incentive awards for executives, directors and key employees. Awards under the Caltex LTIP were in the form of performance units and stock appreciation rights. Aggregate charges to expense for these management incentive plans, excluding expense related to LTIP and SIP stock options and restricted stock awards that are discussed in Note 23 that follows, were $214, $148 and $48 in 2004, 2003 and 2002, respectively. Included in this amount for 2004 was $14 related to stock appreciation rights.

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. Charges for the program were $339, $151 and $158 in 2004, 2003 and 2002, respectively.

NOTE 23.
STOCK OPTIONS

The company applies APB Opinion No. 25 and related interpretations in accounting for its stock-based compensation programs. Stock-based compensation expense (credit) recognized in connection with these programs and the stock appreciation rights discussed previously was $16, $2 and $(2) in 2004, 2003 and 2002, respectively.

Refer to Note 1 on page 54 for the pro forma effects on net income and earnings per share had the company applied the fair-value-recognition provisions of FAS No. 123.

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, which is discussed in Note 3 on page 57.

Broad-Based Employee Stock Options In 1998, Chevron granted to all eligible employees options that varied from 200 to 600 shares of stock or equivalents, dependent on the employee's salary or job grade. These options vested after two years in February 2000 and expire in February 2008. Options for 9,641,600 shares were awarded at an exercise price of $38.15625 per share. Outstanding option shares were 4,018,350 at the end of 2002. In 2003, exercises of 23,260 and forfeitures of 122,100 reduced the outstanding option shares to 3,872,990 at the end of the year. In 2004, exercises of 1,720,946 and forfeitures of 42,540 reduced the outstanding option shares to 2,109,504 at the end of the year. The company recorded expense (credit) of $2, $2 and $(2) for these options in 2004, 2003 and 2002, respectively.

The fair value of each option share on the date of grant under FAS No. 123 was estimated at $9.54 using the average results of Black-Scholes models for the preceding 10 years. The 10-year averages of each assumption used by the Black-Scholes models were: a risk-free interest rate of 7.0 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

Long-Term Incentive Plan Stock options granted under the LTIP extend for 10 years from the date of grant. Effective with options granted in June 2002, one-third of the options vest on each of 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, whereas options granted by Texaco under its SIP vested over a two-year period at a rate of 50 percent each year. For a 10-year period after April 2004, no more than 160 million shares may be issued under the Plan, 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. This provision replaced a formula that restricted annual awards to no more than 1 percent of shares outstanding at the beginning of each year. Not counted against the 160 million-share maximum are shares issued as a result of the exercise of options that were granted before the change in formula in 2004.

On the closing of the merger in October 2001, outstanding options granted under the Texaco SIP were converted to ChevronTexaco options at the merger exchange rate of 0.77. These options retained a provision for restored options. This feature enables a participant who exercises a stock option by exchanging previously acquired common stock 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 fair market value of the common stock on the day the restored option is granted. Restricted shares granted under the former Texaco plan contained a performance element that had to be satisfied in order for all or a specified portion of the shares to vest. Upon the merger, all restricted shares became vested and converted to ChevronTexaco shares at the merger exchange ratio of 0.77. Apart from the restored options, no further awards may be granted under the former Texaco plans. No amount for these plans was charged to compensation expense in 2004, 2003 or 2002.

The fair market value of each stock option granted is estimated on the date of grant under FAS No. 123 using the Black-Scholes option-pricing model with the following weighted-average assumptions:

	2004	2003	2002
ChevronTexaco plans:			
Expected life in years	**7**	7	7
Risk-free interest rate	**4.4%**	3.1%	4.6%
Volatility	**16.5%**	19.3%	21.6%
Dividend yield	**3.7%**	3.5%	3.0%
Texaco plans:			
Expected life in years	**2**	2	2
Risk-free interest rate	**2.5%**	1.7%	1.6%
Volatility	**17.8%**	22.0%	24.1%
Dividend yield	**3.8%**	3.9%	3.1%

The Black-Scholes weighted-average fair value of the ChevronTexaco options granted during 2004, 2003 and 2002 was $7.14, $5.51 and $9.30 per share, respectively, and the weighted-average fair value of the SIP restored options granted during 2004, 2003 and 2002 was $4.00, $4.03 and $5.15 per share, respectively.

A summary of the status of stock options awarded under the company's LTIP, as well as the former Texaco plans, for 2004, 2003 and 2002 follows:

	Options (thousands)	Weighted-Average Exercise Price
Outstanding at December 31, 2001	45,240	$ 40.57
Granted	6,582	43.07
Exercised	(3,636)	36.51
Restored	2,548	44.69
Forfeited	(1,490)	44.05
Outstanding at December 31, 2002	49,244	$ 41.33
Granted	9,320	36.70
Exercised	(1,458)	25.07
Restored	120	41.35
Forfeited	(1,966)	42.70
Outstanding at December 31, 2003	55,260	$ 40.93
Granted	9,164	47.06
Exercised	(14,308)	39.87
Restored	4,814	48.84
Forfeited	(578)	43.94
Outstanding at December 31, 2004	54,352	$ 42.90
Exercisable at December 31		
2002	42,890	$ 41.07
2003	42,554	$ 41.62
2004	35,547	$ 42.15

The following table summarizes information about stock options outstanding, including those from former Texaco plans, at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price	Number Exercisable (thousands)	Weighted-Average Exercise Price
$ 15 to $ 25	513	0.55	$ 24.09	513	$ 24.09
25 to 35	875	1.86	32.94	875	32.94
35 to 45	33,061	6.13	40.97	26,031	41.71
45 to 55	19,846	6.54	47.02	8,128	45.69
55 to 65	57	2.41	55.21	–	–
$ 15 to $ 65	54,352	6.15	$ 42.90	35,547	$ 42.15

NOTE 24.

OTHER CONTINGENCIES AND COMMITMENTS

Income Taxes The company estimates its income tax expense and liabilities annually. 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 estimated. The U.S. federal income tax liabilities have been settled through 1996 for ChevronTexaco (formerly Chevron Corporation), 1997 for ChevronTexaco Global Energy Inc. (formerly Caltex) and 1991 for Texaco Inc. California franchise tax liabilities have been settled through 1991 for Chevron and 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, 2004, the company and its subsidiaries provided, either directly or indirectly, guarantees of $963 for notes and other contractual obligations of affiliated companies and $130 for third parties, as described by major category below. There are no amounts being carried as liabilities for the company's obligations under these guarantees.

Of the $963 guarantees provided to affiliates, $774 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. Approximately 90 percent of the amounts guaranteed will expire by 2009, 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 $189 balance of the $963 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 provisions for recourse to third parties, and no assets are held as collateral for these pricing guarantees.

Guarantees of $130 have been provided to third parties, including approximately $40 of construction loans to host governments of certain of the company's international upstream operations. The remaining guarantees of $90 were provided

NOTE 24. OTHER CONTINGENCIES AND COMMITMENTS – Continued

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 70 percent of the total amounts guaranteed will expire by 2009. 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 $70 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, 2004, ChevronTexaco also had outstanding guarantees for approximately $215 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell Oil Company for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 45 percent of the amounts guaranteed will expire by 2009, 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 Oil Company (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, including those associated with the Unocal patent litigation. 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. Through the end of 2004, the company paid approximately $28 under these contingencies and had agreed to pay approximately $10 additional under an award of arbitration, subject to minor adjustments yet to be resolved. The company may 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 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.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying SPEs. At December 31, 2004, approximately $1,200, representing about 10 percent of ChevronTexaco's total current accounts receivables balance, were securitized. ChevronTexaco's total estimated financial exposure under these securitizations at December 31, 2004, was approximately $50. These arrangements have the effect of accelerating ChevronTexaco's collection of the securitized amounts. In the event that the SPEs experience major defaults in the collection of receivables, ChevronTexaco 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 2005 – $1,600; 2006 – $1,700; 2007 – $1,600; 2008 – $1,500; 2009 – $1,500; 2010 and after – $2,300. Total payments under the agreements were approximately $1,600 in 2004, $1,400 in 2003 and $1,200 in 2002.

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: 2005 – $1,200; 2006 – $1,200; 2007 – $1,300; 2008 – $1,300; and 2009 – $1,300. Additionally, in 2004 the company entered into a 20-year agreement to acquire regasification capacity at the Sabine Pass LNG terminal. Payments of $1,200 over the 20-year period are expected to commence in 2010.

Minority Interests The company has commitments of approximately $172 related to minority interests in subsidiary companies.

Texaco Capital LLC, a wholly owned financial subsidiary, issued Deferred Preferred Shares, Series C, in December 1995. In February 2005, the company redeemed current obligations related to minority interests of approximately $140.

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, 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.

ChevronTexaco's environmental reserve as of December 31, 2004, was $1,047. 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 2004 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

Included in the year-end 2004 balance was $107 related to sites for which ChevronTexaco 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 2004 environmental reserves balance of $940, $712 related to more than 2,000 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining $228 was associated with various sites in the international downstream ($111), upstream ($69) and chemicals ($48). 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 ChevronTexaco 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 Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of Congo, Angola, Nigeria, Chad, South Africa, Indonesia, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago, and South Korea. The company's CPC affiliate operates in Russia and Kazakhstan. The company's TCO affiliate operates in Kazakhstan. 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 ChevronTexaco'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. ChevronTexaco currently 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 ChevronTexaco is estimated at about $50. The timing of the settlement and the exact amount within this range of estimates were uncertain.

Other Contingencies ChevronTexaco 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 25.

FAS 143 – ASSET RETIREMENT OBLIGATIONS

The company adopted Financial Accounting Standards Board Statement 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 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.*"

▸ **NOTE 25.** FAS 143 – ASSET RETIREMENT OBLIGATIONS – Continued

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 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.

The following table illustrates what the company's net income before extraordinary items, net income and related per-share amounts would have been if the provisions of FAS 143 had been applied retroactively:

	Year Ended December 31	
	2003	2002
Pro forma net income before extraordinary items	$ 7,430[1]	$ 1,137[2]
Earnings per share – basic[3]	$ 3.57	$ 0.53
Earnings per share – diluted[3]	$ 3.57	$ 0.53
Pro forma net income	$ 7,430[1]	$ 1,137[2]
Earnings per share – basic[4]	$ 3.57	$ 0.53
Earnings per share – diluted[4]	$ 3.57	$ 0.53

[1] Excludes cumulative-effect charge of $200 ($0.09 per basic and diluted share) for the adoption of FAS 143.
[2] Includes benefit of $5 that represents the reversal of FAS 19 depreciation related to abandonment offset partially by pro forma expenses for the depreciation and accretion of the ARO asset and liability, net of tax. There is a *de minimis* effect to net income per basic or diluted share.
[3] Reported net income before extraordinary items was also $3.57 per basic and diluted shares for 2003 and $0.53 per basic and diluted shares for 2002.
[4] Reported net income was $3.48 per basic and diluted shares for 2003 and $0.53 per basic and diluted shares for 2002.

Prior to the implementation of FAS 143, the company had recorded a provision for abandonment that was part of "Accumulated depreciation, depletion and amortization." Upon implementation of FAS 143, the provision for abandonment was reversed, and ARO liability was recorded. The amount of the abandonment reserve at the end of 2002 was $2,263. The 2002 pro-forma ARO liability at January 1 and December 31 was $2,792 and $2,797, respectively.

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

	2004	2003
Balance at January 1	**$ 2,856**	$ 2,797*
Liabilities incurred	**37**	14
Liabilities settled	**(426)**	(128)
Accretion expense	**93**	132
Revisions in estimated cash flows	**318**	41
Balance at December 31	**$ 2,878**	$ 2,856

*Includes the cumulative effect of the accounting change.

NOTE 26.

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 ChevronTexaco 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 23, "Stock Options," beginning on page 74). The following table sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2004	2003	2002
BASIC EPS CALCULATION			
Income from continuing operations	**$ 13,034**	$ 7,382	$ 1,102
Add: Dividend equivalents paid on stock units	**3**	2	3
Add: Affiliated stock transaction recorded to retained earnings[1]	**–**	170	–
Income from continuing operations available to common stockholders	**$ 13,037**	$ 7,554	$ 1,105
Income from discontinued operations	**294**	44	30
Cumulative effect of changes in accounting principle[2]	**–**	(196)	–
Net income available to common stockholders – Basic	**$ 13,331**	$ 7,402	$ 1,135
Weighted average number of common shares outstanding[3]	**2,114**	2,123	2,121
Add: Deferred awards held as stock units	**2**	2	2
Total weighted average number of common share outstanding	**2,116**	2,125	2,123
Per-Share of Common Stock			
Income from continuing operations available to common stockholders	**$ 6.16**	$ 3.55	$ 0.52
Income from discontinued operations	**0.14**	0.02	0.01
Cumulative effect of changes in accounting principle	**–**	(0.09)	–
Net income – Basic	**$ 6.30**	$ 3.48	$ 0.53
DILUTED EPS CALCULATION			
Income from continuing operations	**$ 13,034**	$ 7,382	$ 1,102
Add: Dividend equivalents paid on stock units	**3**	2	3
Add: Affiliated stock transaction recorded to retained earnings[1]	**–**	170	–
Add: Dilutive effects of employee stock-based awards	**1**	2	2
Income from continuing operations available to common stockholders	**$ 13,038**	$ 7,556	$ 1,107
Income from discontinued operations	**294**	44	30
Cumulative effect of changes in accounting principle[2]	**–**	(196)	–
Net income available to common stockholders – Diluted	**$ 13,332**	$ 7,404	$ 1,137
Weighted average number of common shares outstanding[3]	**2,114**	2,123	2,121
Add: Deferred awards held as stock units	**2**	2	2
Add: Dilutive effect of employee stock-based awards	**6**	2	3
Total weighted average number of common share outstanding	**2,122**	2,127	2,126
Per-Share of Common Stock			
Income from continuing operations available to common stockholders	**$ 6.14**	$ 3.55	$ 0.52
Income from discontinued operations	**0.14**	0.02	0.01
Cumulative effect of changes in accounting principle	**–**	(0.09)	–
Net income – Diluted	**$ 6.28**	$ 3.48	$ 0.53

[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 period reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

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	**2004**	2003	2002	2001	2000
UNITED STATES					
Gross production of crude oil and natural gas liquids	**555**	619	665	670	730
Net production of crude oil and natural gas liquids	**505**	562	602	614	667
Gross production of natural gas	**2,191**	2,619	2,945	3,167	3,485
Net production of natural gas[2]	**1,873**	2,228	2,405	2,706	2,910
Net production of oil equivalents	**817**	933	1,003	1,065	1,152
Refinery input[3]	**914**	951	979	1,336	1,390
Sales of refined products[3]	**1,506**	1,436	1,600	2,500	2,667
Sales of natural gas liquids	**177**	194	241	185	170
Total sales of petroleum products	**1,683**	1,630	1,841	2,685	2,837
Sales of natural gas	**4,518**	4,304	5,891	8,191	7,664
INTERNATIONAL					
Gross production of crude oil and natural gas liquids	**1,645**	1,681	1,765	1,852	1,911
Net production of crude oil and natural gas liquids	**1,205**	1,246	1,295	1,345	1,330
Other produced volumes	**140**	114	97	105	123
Gross production of natural gas	**2,203**	2,203	2,120	1,949	1,847
Net production of natural gas[2]	**2,085**	2,064	1,971	1,711	1,556
Net production of oil equivalents	**1,692**	1,704	1,720	1,735	1,712
Refinery input	**1,044**	1,040	1,100	1,136	1,150
Sales of refined products	**2,402**	2,302	2,175	2,454	2,521
Sales of natural gas liquids	**105**	107	131	115	67
Total sales of petroleum products	**2,507**	2,409	2,306	2,569	2,588
Sales of natural gas	**1,885**	1,951	3,131	2,675	2,398
TOTAL WORLDWIDE					
Gross production of crude oil and natural gas liquids	**2,200**	2,300	2,430	2,522	2,641
Net production of crude oil and natural gas liquids	**1,710**	1,808	1,897	1,959	1,997
Other produced volumes	**140**	114	97	105	123
Gross production of natural gas	**4,394**	4,822	5,065	5,116	5,332
Net production of natural gas[2]	**3,958**	4,292	4,376	4,417	4,466
Net production of oil equivalents	**2,509**	2,637	2,723	2,800	2,864
Refinery input[3]	**1,958**	1,991	2,079	2,472	2,540
Sales of refined products[3]	**3,908**	3,738	3,775	4,954	5,188
Sales of natural gas liquids	**282**	301	372	300	237
Total sales of petroleum products	**4,190**	4,039	4,147	5,254	5,425
Sales of natural gas	**6,403**	6,255	9,022	10,866	10,062
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net)[4]					
Oil and gas	**1,282**	1,472	1,349	1,698	1,665
Dry	**24**	36	49	75	67
Productive oil and gas wells (net)[4]	**44,707**	48,155	50,320	47,388	N/A

[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 gas consumed on lease:

United States	**50**	65	64	64	79
International	**293**	268	256	262	244
Total	**343**	333	320	326	323

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

[4] Net wells include wholly owned and the sum of fractional interests in partially owned wells. Also includes wells temporarily shut in that are capable of producing.

Five-Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts	2004	2003	2002	2001	2000
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	**$ 150,865**	$ 119,575	$ 98,340	$ 103,951	$ 116,619
Income from equity affiliates and other income	**4,435**	1,702	197	1,751	1,917
TOTAL REVENUES AND OTHER INCOME	**155,300**	121,277	98,537	105,702	118,536
TOTAL COSTS AND OTHER DEDUCTIONS	**134,749**	108,601	94,437	97,517	104,661
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**20,551**	12,676	4,100	8,185	13,875
INCOME TAX EXPENSE	**7,517**	5,294	2,998	4,310	6,237
NET INCOME FROM CONTINUING OPERATIONS	**13,034**	7,382	1,102	3,875	7,638
NET INCOME FROM DISCONTINUED OPERATIONS	**294**	44	30	56	89
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	**13,328**	7,426	1,132	3,931	7,727
Extraordinary loss, net of tax	**–**	–	–	(643)	–
Cumulative effect of changes in accounting principles	**–**	(196)	–	–	–
NET INCOME	**$ 13,328**	$ 7,230	$ 1,132	$ 3,288	$ 7,727
PER SHARE OF COMMON STOCK[1]					
INCOME FROM CONTINUING OPERATIONS[2]					
– Basic	**$ 6.16**	$ 3.55	$ 0.52	$ 1.82	$ 3.58
– Diluted	**$ 6.14**	$ 3.55	$ 0.52	$ 1.82	$ 3.57
INCOME FROM DISCONTINUED OPERATIONS					
– Basic	**$ 0.14**	$ 0.02	$ 0.01	$ 0.03	$ 0.04
– Diluted	**$ 0.14**	$ 0.02	$ 0.01	$ 0.03	$ 0.04
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	**$ 6.30**	$ 3.48	$ 0.53	$ 1.55	$ 3.62
– Diluted	**$ 6.28**	$ 3.48	$ 0.53	$ 1.55	$ 3.61
CASH DIVIDENDS PER SHARE[3]	**$ 1.53**	$ 1.43	$ 1.40	$ 1.33	$ 1.30
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	**$ 28,503**	$ 19,426	$ 17,776	$ 18,327	$ 17,913
Noncurrent assets	**64,705**	62,044	59,583	59,245	59,708
TOTAL ASSETS	**93,208**	81,470	77,359	77,572	77,621
Short-term debt	**816**	1,703	5,358	8,429	3,094
Other current liabilities	**17,979**	14,408	14,518	12,225	13,567
Long-term debt and capital lease obligations	**10,456**	10,894	10,911	8,989	12,821
Other noncurrent liabilities	**18,727**	18,170	14,968	13,971	14,770
TOTAL LIABILITIES	**47,978**	45,175	45,755	43,614	44,252
STOCKHOLDERS' EQUITY	**$ 45,230**	$ 36,295	$ 31,604	$ 33,958	$ 33,369

[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.
[3] Chevron Corporation dividend pre-merger.

Supplemental Information on Oil and Gas Producing Activities

Unaudited

In accordance with Statement of FAS 69, "Disclosures About Oil and Gas Producing Activities," this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved reserve quantities; standardized measure of estimated discounted future net cash flows related to proved reserves;

and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Republic of Congo and the Democratic Republic of the Congo (sold in 2004). The Asia-Pacific geographic area includes activities principally in Australia, China, Kazakhstan, the 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 the United Kingdom, Canada, Denmark, the Netherlands, Norway, Trinidad and Tobago, Colombia, Venezuela, Brazil, Argentina, and other countries. Amounts shown for affiliated companies are ChevronTexaco'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." Refer to Note 25 on page 77.

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, 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[3]	**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
YEAR ENDED DEC. 31, 2002												
Exploration												
Wells	$ 25	$ 413	$ 39	$ 477	$ 131	$ 32	$ 16	$ 92	$ 271	$ 748	$ –	$ –
Geological and geophysical	–	86	9	95	69	30	13	53	165	260	–	–
Rentals and other	–	30	5	35	29	37	1	43	110	145	–	–
Total exploration	25	529	53	607	229	99	30	188	546	1,153	–	–
Property acquisitions												
Proved[2]	–	96	10	106	–	–	–	–	–	106	–	–
Unproved	–	48	3	51	6	2	–	1	9	60	–	–
Total property acquisitions	–	144	13	157	6	2	–	1	9	166	–	–
Development	221	475	395	1,091	661	593	424	926	2,604	3,695	447	353
TOTAL COSTS INCURRED	$ 246	$ 1,148	$ 461	$ 1,855	$ 896	$ 694	$ 454	$ 1,115	$ 3,159	$ 5,014	$ 447	$ 353

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 25, FAS 143, *"Asset Retirement Obligations,"* on page 77.
[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.
[3] Includes $63 costs incurred prior to assignment of proved reserves.

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, 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**
AT DEC. 31, 2003[3]												
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[2]	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
Support equipment depreciation	141	133	180	454	237	68	1,784	200	2,289	2,743	160	–
ARO asset depreciation[2]	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] See Note 25, FAS 143, *"Asset Retirement Obligations,"* on page 77.
[3] 2003 and 2002 reclassified to conform to 2004 presentation.

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

	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, 2002[2]												
Unproved properties	$ 770	$ 421	$ 171	$ 1,362	$ 330	$ 237	$ 22	$ 1,134	$ 1,723	$ 3,085	$ 108	$ –
Proved properties and related producing assets	8,584	17,657	11,200	37,441	6,037	6,356	3,432	10,185	26,010	63,451	1,975	147
Support equipment	187	189	398	774	447	190	3,004	377	4,018	4,792	338	–
Deferred exploratory wells	–	101	1	102	167	103	–	106	376	478	–	–
Other uncompleted projects	97	209	200	506	1,380	1,179	474	264	3,297	3,803	676	693
GROSS CAP. COSTS	9,638	18,577	11,970	40,185	8,361	8,065	6,932	12,066	35,424	75,609	3,097	840
Unproved properties valuation	732	154	75	961	80	67	23	277	447	1,408	9	–
Proved producing properties – depreciation and depletion	6,295	13,722	7,098	27,115	3,275	2,608	2,143	5,358	13,384	40,499	285	9
Future abandonment and restoration	150	363	486	999	508	147	157	392	1,204	2,203	24	–
Support equipment depreciation	130	123	304	557	289	100	1,764	223	2,376	2,933	138	–
Accumulated provisions	7,307	14,362	7,963	29,632	4,152	2,922	4,087	6,250	17,411	47,043	456	9
NET CAPITALIZED COSTS	$ 2,331	$ 4,215	$ 4,007	$ 10,553	$ 4,209	$ 5,143	$ 2,845	$ 5,816	$18,013	$ 28,566	$ 2,641	$ 831

[1] Includes assets held for sale.
[2] 2003 and 2002 reclassified to conform to 2004 presentation.

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 2004, 2003 and 2002 are shown in the following table. Net income from exploration and production activities as reported on page 31 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 31.

	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, 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 (expense) income[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**
YEAR ENDED DEC. 31, 2003[4]												
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[2]	(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[3]	(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] See Note 25 on page 77, FAS 143, *"Asset Retirement Obligations."*
[3] 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 MD&A on pages 30 through 32.
[4] 2003 includes certain reclassifications to conform to 2004 presentation.

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

	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, 2002[2]												
Revenues from net production												
Sales	$ 359	$ 1,302	$ 1,076	$ 2,737	$ 1,121	$ 1,181	$ 229	$ 2,080	$ 4,611	$ 7,348	$ 955	$ 44
Transfers	1,621	1,611	1,193	4,425	1,663	1,560	1,530	1,202	5,955	10,380	–	–
Total	1,980	2,913	2,269	7,162	2,784	2,741	1,759	3,282	10,566	17,728	955	44
Production expenses excluding taxes	(570)	(630)	(782)	(1,982)	(415)	(330)	(680)	(606)	(2,031)	(4,013)	(130)	(4)
Taxes other than on income	(60)	(53)	(226)	(339)	(24)	(114)	–	(77)	(215)	(554)	(36)	–
Proved producing properties: depreciation and depletion	(250)	(844)	(389)	(1,483)	(314)	(345)	(315)	(654)	(1,628)	(3,111)	(86)	(5)
FAS 19 abandonment provision[3]	(12)	(70)	(12)	(94)	(38)	(16)	3	(40)	(91)	(185)	(5)	–
Exploration expenses	1	(179)	(38)	(216)	(106)	(89)	(20)	(160)	(375)	(591)	–	–
Unproved properties valuation	(2)	(24)	(9)	(35)	(14)	(9)	–	(67)	(90)	(125)	–	–
Other (expense) income[4]	(58)	(108)	(193)	(359)	(179)	(202)	(31)	59	(353)	(712)	(5)	(12)
Results before income taxes	1,029	1,005	620	2,654	1,694	1,636	716	1,737	5,783	8,437	693	23
Income tax expense	(362)	(353)	(218)	(933)	(1,202)	(1,097)	(337)	(677)	(3,313)	(4,246)	(208)	–
RESULTS OF PRODUCING OPERATIONS	$ 667	$ 652	$ 402	$ 1,721	$ 492	$ 539	$ 379	$ 1,060	$ 2,470	$ 4,191	$ 485	$ 23

[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] 2002 includes certain reclassifications to conform to 2004 presentation.
[3] See Note 25 on page 77, FAS 143, *"Asset Retirement Obligations."*
[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 MD&A on pages 30 through 32.

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, 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	7.01	4.47	6.40	5.82	4.42	2.49	9.30	3.99	4.41	4.99	2.04	3.24
YEAR ENDED DEC. 31, 2002												
Average sales prices												
Liquids, per barrel	$ 20.75	$ 22.22	$ 21.13	$ 21.34	$ 24.33	$ 21.52	$ 22.07	$ 23.31	$ 22.92	$ 22.36	$ 18.16	$ 18.91
Natural gas, per thousand cubic feet	2.98	3.19	2.60	2.89	0.04	3.11	0.84	2.11	2.24	2.62	0.57	–
Average production costs, per barrel[3]	5.91	4.49	6.24	5.48	3.49	2.50	7.94	3.59	4.03	4.63	2.19	1.58

[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 2004 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, 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 standards and demonstrate a high probability of being produced.

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.

Proved reserves do not include additional quantities that may eventually result from extensions of currently proved areas or from applying the secondary or tertiary recovery processes not yet tested and determined to be economic.

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 reservoir 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 of 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, whose members include the Chief Executive Officer and the Chief Financial Officer. The company's annual reserve activity is also presented to and discussed with the Board of Directors. Other major reserves-related issues are discussed with the Board as necessary throughout the year.

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, 2004, total oil-equivalent reserves for the company's consolidated operations were 8.2 billion barrels. (Refer to page 24 for the definition of oil-equivalent reserves.) Nearly 30 percent were in the United States and about 10 percent in Indonesia. For the company's interests in equity affiliates, oil-equivalent reserves were 3.1 billion barrels, nearly 85 percent of which were associated with the company's 50 percent ownership in TCO. Fewer than 20 other individual properties in the company's portfolio of assets each contained between 1 percent and 4 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for about 35 percent of the company's proved reserves total. These other properties were geographically dispersed, located in the United States, South America, Europe, western Africa, the Middle East and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2004 were 2.4 billion barrels. Of this amount, 45 percent, 20 percent and 35 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 60 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 carbon dioxide injection.

ChevronTexaco operates the Boscan Field in Venezuela under a service agreement, but has not recorded reserve quantities for this operation.

The pattern of net reserve changes shown in the following tables, for the three years ending December 31, 2004, is not necessarily indicative of future trends. 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 2002, 2003 and 2004 are shown in the following tables.

TABLE V – RESERVE QUANTITY INFORMATION – Continued

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

	Consolidated Companies										Affiliated Companies	
	United States				International							
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, 2002	1,140	458	703	2,301	1,544	792	1,114	745	4,195	6,496	1,541	487
Changes attributable to:												
Revisions	(33)	(45)	(38)	(116)	164	41	(155)	17	67	(49)	199	–
Improved recovery	81	10	8	99	82	–	22	36	140	239	–	–
Extensions and discoveries	3	38	7	48	301	81	4	8	394	442	–	–
Purchases[1]	–	2	6	8	–	–	–	–	–	8	–	–
Sales[2]	–	–	(3)	(3)	–	–	–	–	–	(3)	–	–
Production	(89)	(74)	(57)	(220)	(115)	(99)	(96)	(109)	(419)	(639)	(51)	(2)
RESERVES AT DEC. 31, 2002	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[3]	**1,011**	**294**	**432**	**1,737**	**1,833**	**676**	**698**	**567**	**3,774**	**5,511**	**1,994**	**468**
DEVELOPED RESERVES[4]												
At Jan. 1, 2002	885	393	609	1,887	923	648	843	517	2,931	4,818	1,007	38
At Dec. 31, 2002	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**

[1] Includes reserves acquired through property exchanges.
[2] Includes reserves disposed of through property exchanges.
[3] Net reserve changes (excluding production) in 2004 consist of 5 million barrels of developed reserves and (209) million barrels of undeveloped reserves for consolidated companies and 315 million barrels of developed reserves and (111) million barrels of undeveloped reserves for affiliated companies.
[4] During 2004, the percentages of undeveloped reserves at December 31, 2003, transferred to developed reserves were 13 percent and 15 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, ChevronTexaco has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, ChevronTexaco 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 167 million barrels as of December 31, 2004. Production began in late 2002.

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 91.

Noteworthy amounts in the categories of proved-reserve changes for 2002 through 2004 in the above table are discussed below:

Revisions In 2002, net revisions reduced liquids volumes worldwide by 49 million barrels for consolidated companies. International areas accounted for a net increase of 67 million barrels. The largest upward net revision internationally was 161 million barrels for a contract extension in Angola. The largest negative net revision was 155 million barrels in Indonesia, mainly for the effect of higher year-end prices on the calculation of reserves associated with cost-oil recovery under a production-sharing contract. In the United States, the total downward net revision was 116 million barrels across many fields in each of the geographic sections. The 199-million-barrel increase for the TCO affiliate was associated with the project approval to expand gas processing facilities.

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 net 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.

Improved Recovery In 2002, improved recovery increased liquids volumes worldwide by 239 million barrels for consolidated companies. The largest increase of 99 million barrels occurred in the United States, primarily in the California region due to pattern modifications, injector conversions and infill drilling on a large heavy oil field under thermal recovery.

Extensions and Discoveries In 2002, extensions and discoveries increased liquids volumes worldwide by 442 million barrels for consolidated companies. The largest increase was 301 million barrels in Africa, principally 172 million barrels reflecting the project sanction of a recent discovery in Nigeria and 96 million barrels associated with approval of several development projects in Angola.

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, 2002	341	2,361	4,685	7,387	1,872	4,239	520	3,088	9,719	17,106	2,262	42
Changes attributable to:												
Revisions	16	(200)	(414)	(598)	277	375	15	92	759	161	293	1
Improved recovery	9	11	1	21	42	–	4	10	56	77	–	–
Extensions and discoveries	5	229	161	395	134	227	33	103	497	892	–	–
Purchases[1]	–	65	28	93	–	8	–	–	8	101	–	–
Sales[2]	–	–	(3)	(3)	–	–	–	–	–	(3)	–	–
Production	(46)	(414)	(418)	(878)	(27)	(203)	(54)	(369)	(653)	(1,531)	(66)	–
RESERVES AT DEC. 31, 2002	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[3]	**314**	**1,064**	**2,326**	**3,704**	**2,979**	**5,405**	**502**	**3,538**	**12,424**	**16,128**	**3,413**	**134**
DEVELOPED RESERVES[4]												
At Jan. 1, 2002	284	1,976	3,986	6,246	444	2,920	250	2,231	5,845	12,091	1,477	6
At Dec. 31, 2002	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**

[1] Includes reserves acquired through property exchanges.
[2] Includes reserves disposed of through property exchanges.
[3] Net reserve changes (excluding production) in 2004 consist of (543) billion cubic feet of developed reserves and 490 billion cubic feet of undeveloped reserves for consolidated companies and 883 billion cubic feet of developed reserves and 103 billion cubic feet of undeveloped reserves for affiliated companies.
[4] During 2004, the percentages of undeveloped reserves at December 31, 2003, transferred to developed reserves were 4 percent and 6 percent for consolidated companies and affiliated companies, respectively.

TABLE V – RESERVE QUANTITY INFORMATION – Continued

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.

Noteworthy amounts in the categories of proved-reserve changes for 2002 through 2004 in the table on page 89 are discussed below:

Revisions In 2002, reserves were revised upward by a net 161 billion cubic feet (BCF) for consolidated companies, as increases of 759 BCF internationally were partially offset by net downward revisions of 598 BCF in the United States. Internationally, the majority of the 277 BCF net upward revision in Africa was associated primarily with a performance assessment of several fields and a multifield gas development project. An increase of 375 BCF in the Asia-Pacific region included the effect of securing a contract to supply LNG to China markets from company producing operations in Australia. In the United States, about one-fourth of the 598 BCF net downward revision was associated with two fields in the midcontinent region based on an updated assessment of production performance and changes to operating conditions of the wells. Most of the remaining negative revision was associated with reviews of performance in many fields. For the TCO affiliate in Kazakhstan, the 293 BCF increase related mainly to project approval to expand gas processing facilities.

In 2003, revisions accounted for a net increase of 1,627 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 midcontinent 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 midcontinent region and their associated wells' performance. The 963 BCF increase for TCO was connected with updated analyses of reservoir performance and processing plant yields.

Extensions and Discoveries In 2002, consolidated companies increased reserves by 892 BCF, including 395 BCF in the United States and 227 BCF in the Asia-Pacific region. In the United States, 229 BCF was added in the Gulf of Mexico and 161 BCF in the "Other" region, primarily due to drilling activities. The addition in Asia-Pacific resulted from a gas supply contract in Australia that enabled booking of a previous discovery.

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 included 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.

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.

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										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 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
AT DECEMBER 31, 2002*												
Future cash inflows from production	$ 27,111	$19,671	$ 31,130	$ 77,912	$ 52,513	$ 31,099	$ 28,451	$ 26,531	$ 138,594	$ 216,506	$ 52,457	$ 9,777
Future production costs	(11,071)	(5,167)	(10,077)	(26,315)	(6,435)	(4,534)	(9,552)	(5,970)	(26,491)	(52,806)	(4,959)	(1,730)
Future devel. costs	(1,769)	(748)	(1,116)	(3,633)	(3,454)	(2,516)	(1,989)	(1,868)	(9,827)	(13,460)	(5,377)	(578)
Future income taxes	(4,829)	(4,655)	(6,747)	(16,231)	(25,060)	(10,087)	(7,694)	(6,797)	(49,638)	(65,869)	(11,899)	(2,540)
Undiscounted future net cash flows	9,442	9,101	13,190	31,733	17,564	13,962	9,216	11,896	52,638	84,371	30,222	4,929
10 percent midyear annual discount for timing of estimated cash flows	(4,713)	(2,493)	(6,666)	(13,872)	(8,252)	(6,297)	(3,674)	(3,691)	(21,914)	(35,786)	(18,964)	(3,581)
STANDARDIZED MEASURE NET CASH FLOWS	$ 4,729	$ 6,608	$ 6,524	$ 17,861	$ 9,312	$ 7,665	$ 5,542	$ 8,205	$ 30,724	$ 48,585	$ 11,258	$ 1,348

* 2002 includes certain reclassifications to conform to 2004 presentation.

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	**2004**	2003	2002	**2004**	2003	2002
PRESENT VALUE AT JANUARY 1	**$ 50,805**	$ 48,585	$ 23,748	**$ 13,118**	$ 12,606	$ 6,396
Sales and transfers of oil and gas produced net of production costs	**(18,843)**	(16,630)	(13,161)	**(1,602)**	(1,054)	(829)
Development costs incurred	**3,579**	3,451	3,695	**1,104**	750	800
Purchases of reserves	**58**	97	181	**–**	–	–
Sales of reserves	**(3,734)**	(839)	(42)	**–**	–	–
Extensions, discoveries and improved recovery less related costs	**2,678**	5,445	7,472	**–**	–	–
Revisions of previous quantity estimates	**1,611**	1,200	180	**970**	653	917
Net changes in prices, development and production costs	**6,173**	1,857	40,802	**266**	(1,187)	6,722
Accretion of discount	**8,139**	7,903	3,987	**1,818**	1,709	895
Net change in income tax	**(2,332)**	(264)	(18,277)	**(754)**	(359)	(2,295)
Net change for the year	**(2,671)**	2,220	24,837	**1,802**	512	6,210
PRESENT VALUE AT DECEMBER 31	**$ 48,134**	$ 50,805	$ 48,585	**$ 14,920**	$ 13,118	$ 12,606

*2003 and 2002 conformed to 2004 presentation.

David J. O'Reilly, **58**
Chairman of the Board and Chief Executive Officer since the completion of the ChevronTexaco merger in 2001. He held the same positions with Chevron 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 and the Institute for International Economics. He joined ChevronTexaco in 1968.

Peter J. Robertson, **58**
Vice Chairman of the Board since 2002. Since January 2005, 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 ChevronTexaco in 1973.

Samuel H. Armacost, **65**
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)

Robert E. Denham, **59**
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 Economico Mexicano, S.A. de C.V. (1)

Robert J. Eaton, **65**
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 and a Director of Texaco Inc. (2, 4)

Sam Ginn, **67**
Director since 1989. He is 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. (1)

Carla A. Hills, **71**
Lead Director since 2004 and a **Director** since 1993. She is Chairman and Chief Executive Officer of Hills & Company International Consultants. She 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 is a Director of American International Group, Inc.; Lucent Technologies Inc.; and Time Warner Inc. (3, 4)

Franklyn G. Jenifer, **66**
Director since 1993. He is President of The University of Texas at Dallas. Previously he was President of Howard University, Chancellor of the Massachusetts Board of Regents of Higher Education and a Director of Texaco Inc. He is a Member of the Board Directors Alliance for Higher Education, Dallas Citizens Council and the Monitoring Committee for the Louisiana Desegregation Settlement Agreement. (1)

J. Bennett Johnston, **72***
Director since 1997. He is a Partner in Johnston & Associates, LLC, and Johnston Development Company, LLC, consulting and development firms. He served as a U.S. Senator from Louisiana for 24 years. He is President of the U.S. Pacific Economic Cooperation Council and a Director of Nexant, Inc., and Freeport-McMoRan Copper & Gold Inc. (2, 4)

Sam Nunn, **66**
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 and was a Director of Texaco Inc. He is a Director of The Coca-Cola Company; Dell Inc.; Internet Security Systems, Inc.; Scientific-Atlanta, Inc.; and General Electric Company. (2, 3)

Charles R. Shoemate, **65**
Director since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods and was a Director of Texaco Inc. He is a Director of International Paper Company and CIGNA Corporation. (1)

Carl Ware, **61**
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 PGA TOUR Golf Course Properties, Inc., and Cummins Inc. (2, 3)

*Retiring Director; will not stand for reelection at the April 27, 2005, Annual Meeting.

COMMITTEES OF THE BOARD

1) Audit: Sam Ginn, Chair
2) Public Policy: J. Bennett Johnston, Chair
3) Board Nominating and Governance: Carla A. Hills, Chair
4) Management Compensation: Samuel H. Armacost, Chair

▸ Carla Hills rings the opening bell at the New York Stock Exchange (NYSE) on June 30, 2004. In celebration of the company's 125th anniversary, the Board held its first meeting ever at the NYSE.

Lydia I. Beebe, 52
Corporate Secretary since 2001. Responsible for providing corporate governance counsel to the Board of Directors and senior management, and managing stockholder relations and subsidiary governance. Previously Chevron Corporate Secretary since 1995; Senior Manager, Chevron Tax Department; Manager, Federal Tax Legislation; and Chevron Legal Representative in Washington, D.C. Joined ChevronTexaco in 1977.

John E. Bethancourt, 53
Executive Vice President, Technology and Services, since 2003. Responsible for the technology companies and health, environment and safety as well as project resources, additives and coal operations. Previously ChevronTexaco Vice President, Human Resources, and Texaco Corporate Vice President and President, Production Operations, Texaco Worldwide Exploration and Production. Joined ChevronTexaco in 1974.

Stephen J. Crowe, 57
Vice President and Chief Financial Officer since January 2005. Responsible for comptroller, audit, treasury, tax and investor relations activities. Previously ChevronTexaco Vice President and Comptroller; Chevron Vice President and Comptroller; Vice President, Finance, Chevron Products Company; and Assistant Comptroller, Chevron Corporation. Joined ChevronTexaco in 1972.

John D. Gass, 52
Corporate Vice President and President, ChevronTexaco Global Gas, since 2003. Responsible also for ChevronTexaco's shipping company and pipeline operations. Director of Sasol Chevron Holdings Ltd. and LG-Caltex Oil Corporation. Previously Managing Director, ChevronTexaco Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined ChevronTexaco in 1974.

Mark A. Humphrey, 53
Vice President and Comptroller since January 2005. Responsible for accounting, financial reporting and analysis, funded benefits investments, actuarial functions, and the Finance Shared Services department. Previously ChevronTexaco General Manager, Finance Shared Services, and Vice President, Finance, Chevron Products Company. Joined ChevronTexaco in 1976.

Charles A. James, 50
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 ChevronTexaco in 2002.

George L. Kirkland, 54
Executive Vice President, Upstream and Gas, since January 2005. Responsible for global exploration, production and gas activities. Previously Corporate Vice President and President, ChevronTexaco Overseas Petroleum Inc.; President, ChevronTexaco Exploration and Production Company; and President, Chevron U.S.A. Production Company. Joined ChevronTexaco in 1974.

David M. Krattebol, 60
Vice President and Treasurer since 2001. Previously Chevron Vice President and Treasurer; 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 ChevronTexaco in 1971.

Sam Laidlaw, 49
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 ChevronTexaco in 2003.

John W. McDonald, 53
Vice President, Strategic Planning, since 2002. Responsible for advising senior management in setting the company's strategic direction. Previously President and Managing Director, ChevronTexaco Upstream Europe, ChevronTexaco Overseas Petroleum Inc., and Vice President, Gulf of Mexico Offshore Division, Texaco Exploration and Production Inc. Joined ChevronTexaco in 1975.

Donald L. Paul, 58
Vice President and Chief Technology Officer since 2001. Responsible for ChevronTexaco'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 ChevronTexaco in 1975.

Alan R. Preston, 53
Vice President, Human Resources, since 2003. Previously ChevronTexaco General Manager, Global Remuneration; General Manager, Organization/Compensation, Chevron Corporation; and General Manager, Human Resources, Chevron Products Company. Joined ChevronTexaco in 1973.

Thomas R. Schuttish, 57
General Tax Counsel since 2002. Responsible for guiding and directing corporate tax activities and managing ChevronTexaco's Tax department. Previously ChevronTexaco Assistant General Tax Counsel and Chevron Assistant General Tax Counsel. Joined ChevronTexaco in 1980.

John S. Watson, 48
Corporate Vice President and President, ChevronTexaco Overseas Petroleum Inc., since January 2005. Responsible for exploration and production activities outside North America. Previously ChevronTexaco Vice President and Chief Financial Officer; Chevron Vice President and Chief Financial Officer; Chevron Vice President, Strategic Planning; and Director, Caltex Petroleum Corporation. Joined ChevronTexaco in 1980.

Raymond I. Wilcox, 59
Corporate Vice President and President, ChevronTexaco Exploration and Production Company, since 2002. Responsible for exploration and production activities in North America. Director of Dynegy Inc. Previously ChevronTexaco Managing Director, Nigeria/Mid-Africa Strategic Business Unit, and Chairman and Managing Director, Chevron Nigeria Limited. Joined ChevronTexaco in 1968.

Patricia A. Woertz, 52
Executive Vice President, Downstream, since 2001. Responsible for worldwide refining, marketing, lubricants, and supply and trading. Director of the American Petroleum Institute. Previously Chevron Corporate Vice President and President, Chevron Products Company, and President, Chevron International Oil Company. Joined ChevronTexaco in 1977.

Patricia E. Yarrington, 48
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 ChevronTexaco Vice President, Strategic Planning; Chevron Vice President, Strategic Planning; President, Chevron Canada Limited; and Comptroller, Chevron Products Company. Joined ChevronTexaco in 1980.

Rhonda I. Zygocki, 47
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, ChevronTexaco Australia Pty Ltd; Adviser to the Chairman of the Board, Chevron Corporation; and Manager, Strategic Planning, Chevron Corporation. Joined ChevronTexaco 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 Patricia A. Woertz. Lydia I. Beebe, Secretary.

STOCKHOLDER AND INVESTOR INFORMATION

STOCK EXCHANGE LISTING
ChevronTexaco 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 ChevronTexaco's transfer agent and registrar:
Mellon Investor Services LLC
85 Challenger Road
Ridgefield Park, NJ 07660-2108
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 27, 2005, at:
ChevronTexaco Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

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
Stockholders of record may sign up on our website for electronic access to future *Annual Reports* and proxy materials, rather than receiving mailed copies, at: www.icsdelivery.com/cvx/index.html. 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
ChevronTexaco Corporation
6001 Bollinger Canyon Road, Bldg. A
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevrontexaco.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.

ChevronTexaco's website, www.chevrontexaco.com, offers facts and figures about the company and the energy industry. 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 15. 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
ChevronTexaco Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2004 are available by writing to:
Policy, Government & Public Affairs
ChevronTexaco 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 ChevronTexaco's website, www.chevrontexaco.com.

LEGAL NOTICE
As used in this report, the term "ChevronTexaco" 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 Statements 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.

PRODUCED BY CHEVRONTEXACO POLICY, GOVERNMENT & PUBLIC AFFAIRS AND COMPTROLLER'S DEPARTMENTS
DESIGN: SEQUEL STUDIO, NEW YORK   PRINTING: GRAPHIC PRESS, LOS ANGELES

INDIVIDUALS NOT IDENTIFIED IN TEXT: Page 7: Reynaldo Rodriguez – Venezuela; Page 8: Dan Yap (left) and Gabriel Ngoi – Singapore; Page 12: John Batiste Jr. – United States; Page 19: (top row, from left) Nayef Al-Shammari, Gregory Luke, Jose Kurian, and Kevin Lahay; (seated, from left) Ibrahim Al-Juma'an and Shereen El-Kady – Partitioned Neutral Zone; Page 22: (left) Ron Steele (left) and Garey Cotton – United States; (top, middle) Gustavo Lopez – United States; (bottom, middle) Jason Lehfeldt – United States; Page 23: (bottom, middle) Chan Hean Kheong (left) and Matthew Sill (seated) – Singapore.

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6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

www.chevrontexaco.com

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