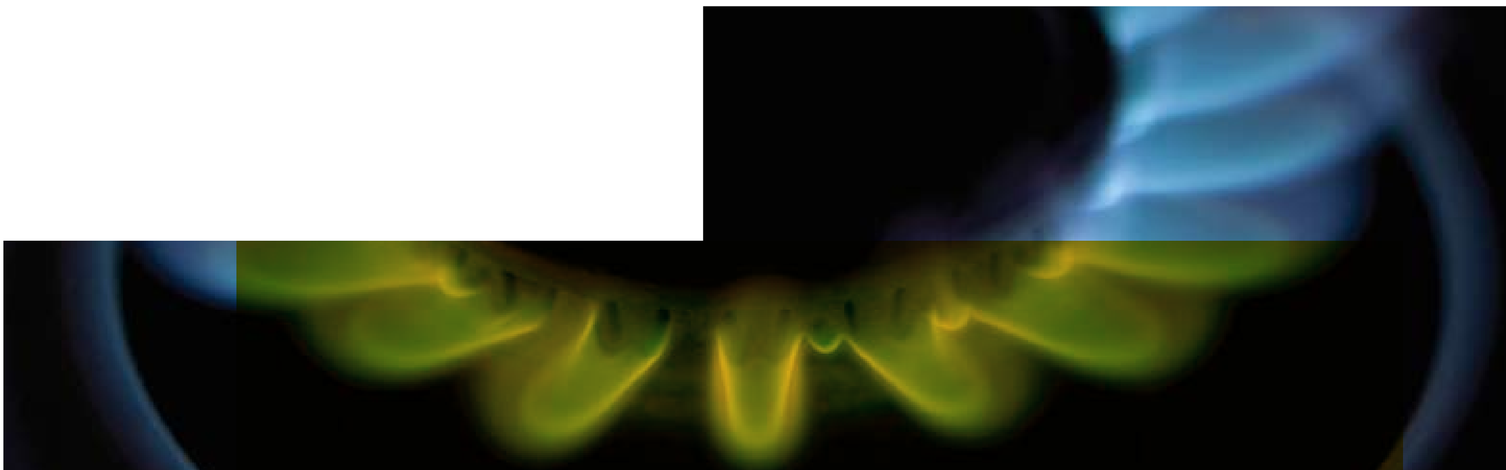
devon

Commitment Runs Deep



**Devon Energy** 2007 Annual Report

**Corporate Profile**

Devon is the largest U.S.-based independent oil and gas producer. Devon's operations are focused primarily in the United States and Canada; however, the company also explores for and produces oil and natural gas in select international areas. We also own natural gas pipelines, processing and treatment facilities in many of our producing areas, making us one of North America's larger processors of natural gas liquids. Devon is included in the S&P 500 Index and trades on the New York Stock Exchange under the ticker symbol DVN.

# Commitment Runs Deep


| | |
|---|---|
| **Letter to Shareholders**<br>Chairman and CEO Larry Nichols reviews Devon's best year as a public company. | 2 |
| **Insight**<br>We respond to questions concerning our business and operating strategies. | 4 |
| **Five-Year Highlights** | 6 |
| **Being a good neighbor**<br>How we have improved lives in one Canadian community. | 8 |
| **It's about giving back**<br>Our employees give back to their hometowns. | 10 |
| **Recognizing the essentials**<br>Devon is acting to reduce carbon emissions. | 12 |
| **Clean air and pure water**<br>We offer examples of our commitment to the environment. | 14 |
| **Everyday energy**<br>Petroleum-based products enhance our quality of life. | 16 |
| **Getting results**<br>A land owner comments on his experience with Devon. | 18 |
| **Developing our full potential**<br>We discuss significant projects and opportunities for growth. | 20 |
| **11-Year Property Data** | 24 |
| **Operating Statistics by Area** | 25 |
| **A reputation for safety**<br>A government official praises Devon as a safe operator. | 26 |
| **Property Highlights** | 28 |
| **Index to Financials** | 33 |
| **Directors and Senior Officers** | 110 |
| **Glossary** | 112 |
| **Investor Information and Stock Performance** | 113 |

Dear Fellow Shareholders: 2007 was the best year in Devon's 20-year history as a public company. We increased oil and natural gas production 12% to 224 million oil-equivalent barrels. This production growth, coupled with robust oil and natural gas prices, drove earnings and cash flow to the highest levels ever. Net earnings reached a record $3.6 billion, or $8.00 per diluted share, and cash flow from operations climbed to $6.7 billion.

J. Larry Nichols

During 2007, we also executed the largest drilling program in the company's history with excellent results. We drilled 2,395 successful oil and natural gas wells, adding almost 400 million equivalent barrels of new reserves at very attractive finding and development costs. This drove year-end proved oil and natural gas reserves to an all-time high of 2.5 billion oil-equivalent barrels.

We also achieved first production in 2007 on three important long-term projects: our Jackfish thermal oil sands project, our Merganser gas field in the deepwater Gulf of Mexico and our Polvo oil development in Brazil's Campos Basin. In addition, we sanctioned for development our first project in the deepwater Gulf of Mexico's Lower Tertiary trend. Yes, Devon's 2007 performance was outstanding on all fronts.

**Committed to Results**

Devon's 2007 growth reflects production increases from each of our geographic segments: the United States, Canada and International. In the United States, Devon continued its reign as the undisputed leader in North America's flagship gas resource play, the Barnett Shale. Our extensive experience base and technological advances are allowing us to drill wells more quickly and to increase per well recoveries. In 2007, only four years after Devon pioneered horizontal drilling in the play, we drilled our 1,000th horizontal Barnett well. During the year, we increased Devon's share of Barnett production by more than one third to 950 million cubic feet equivalent per day. Furthermore, we now expect to reach a production goal for the Barnett of one billion cubic feet of gas equivalent per day in mid-2008, 18 months ahead of schedule.

As first mover in the Barnett, we established the best acreage position in the play, by far. We have thousands of future drilling locations in the best areas of the field, and we acquired this position at a fraction of the cost of the late-comers. As a result, Devon's returns in the Barnett are far superior to that of the competition. Furthermore, we are positioned for continued growth in the Barnett Shale for many years to come.

The Barnett Shale is only one of several key onshore areas in the United States. At Carthage in east Texas, we increased production by 19% in the fourth quarter of 2007 to 277 million cubic feet equivalent per day. In Oklahoma, we are applying our Barnett Shale experience to the Woodford Shale play. In the Rocky Mountains, we continue active development programs in the Washakie and Powder River Basin areas in Wyoming and at Bear Paw in Montana.

Alberta's provincial government rocked the oil and gas industry in 2007 when it announced plans to increase the government's royalty take from energy producers. The rule changes are complex and impact different types of oil and gas production to varying degrees. As a result, Devon has reallocated some capital from Alberta to competing projects with more attractive returns elsewhere in Canada and in the United States. Fortunately, the economic impact of the royalty changes on two of our more significant areas of current investment in Alberta, Jackfish and Lloydminster, will be minimal.

In the fourth quarter of 2007, we completed construction of our 100%-owned Jackfish thermal oil sands project. With construction finished, we are injecting steam underground and oil is flowing to the surface. We expect production from Jackfish to climb gradually to a peak of 35,000 barrels per day and to continue producing at that rate for more than 20 years. We also expect to sanction a second 35,000 barrel per day project, Jackfish 2, in 2008.

Southeast of Jackfish, in the Lloydminster area, we drilled 429 wells in 2007. This enabled us to increase production by 40 percent to 33,500 equivalent barrels per day. We expect to drill a similar number of wells at Lloydminster in 2008.

**Committed to the Future**

Devon's dependable and repeatable development projects underpin the production growth that we delivered in 2007 and expect to deliver in 2008. However, to ensure sustainable growth, the pipeline of development projects must be continually filled. To that end, we are committed to restocking our inventory of development projects through high-impact exploration.

Nothing better demonstrates Devon's long-term commitment and the promise it holds than our projects in the deepwater Lower Tertiary trend in the Gulf of Mexico. We drilled our first well in this emerging resource in 2002. And while we do not expect to produce our first barrel from the play until 2010, the potential of the prize more than justifies the wait.

Since 2002, we have made four significant discoveries in the deepwater Lower Tertiary. Devon's share of these four discoveries could be as much as 900 million barrels of oil. And this is just the beginning. As one of the first participants in the play, Devon was able to establish an extensive acreage position and gain considerable experience. We have a deep inventory of Lower Tertiary drilling prospects that will enable us to continue exploring the trend throughout the next decade.

Cascade, the first of Devon's four Lower Tertiary discoveries, is now entering the development phase. We are also moving closer to development decisions on the other three Lower Tertiary discoveries: Jack, St. Malo and Kaskida. We conducted appraisal drilling operations on each of these projects in 2007 and have more wells planned for 2008. We anticipate completing development plans within the next two years for Jack and St. Malo.

Devon's balanced portfolio of near-term, predictable development projects backed by high-impact, long-term exploration uniquely positions the company for lasting success. In a world where oil and natural gas are increasingly scarce commodities, we are well positioned to help satisfy the demand and reap the rewards.

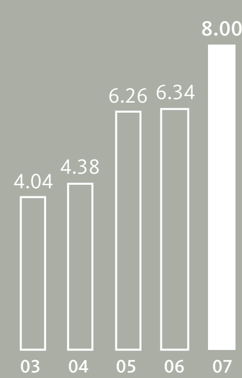
**Commitment Runs Deep**

We say farewell to a member of our senior management team this year. Marian Moon, senior vice president of administration, is retiring after a 24-year career with Devon. I deeply appreciate Marian's years of service and her significant contribution to Devon's success. We will miss her and wish her the very best.

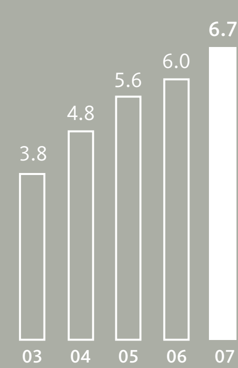
Devon could not have achieved the growth and success we have enjoyed without the commitment of our employees. The company was recently named to *FORTUNE* magazine's list of the "100 Best Companies to Work for." We congratulate each and every member of our team for their contributions to creating the culture that earned this elite recognition.

The theme of this annual report, Commitment Runs Deep, reflects our culture and the promise that Devon has made to our stakeholders. This promise is our commitment to continuous improvement and delivering positive results. It is our commitment to respect the environment and to improve the communities in which we live and work. Most importantly, it is our commitment to treat everyone with honesty, fairness and respect. I am extremely proud of how Devon's employees are delivering on this promise. In the following pages we will share with you some examples of the depth of Devon's commitment.

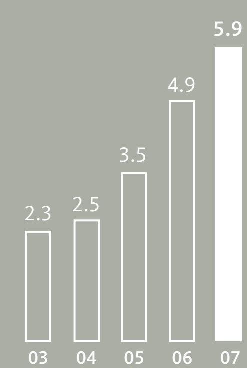
**J. Larry Nichols**
Chairman and Chief Executive Officer
March 20, 2008




**Earnings per Share**
($ Diluted)




**Net Cash Provided by Operating Activities**
($ Billions)




**Exploration and Development Capital**
($ Billions)

**Devon increased net earnings to a record $8.00 per diluted share and cash flow to a record $6.7 billion in 2007. This enabled the company to fund its largest-ever exploration and development capital budget of $5.9 billion.**

# Management responds to investor questions

**Devon plans to utilize a floating production, storage and offloading vessel (FPSO) to develop the Cascade project in the Gulf of Mexico. What are the reasons for that decision?**

There are several reasons for selecting an FPSO for our first Lower Tertiary development project. One is the lack of oil pipeline infrastructure in the vicinity of Cascade. The Cascade prospect is in more than 8,000 feet of water and 130 miles from shore. Shuttle tankers will transport oil from the Cascade FPSO to Gulf Coast refineries. Using an FPSO with shuttle tankers will also allow us to develop the project more quickly than if we were to design, construct and install more permanent facilities.

Another advantage of an FPSO is scalability. Initially, we plan to drill and produce two wells at Cascade. We will monitor and measure the performance of those initial wells as we learn more about the characteristics of the oil reservoir and optimize the number of wells necessary to fully develop the field. This approach will allow us to proceed at a measured pace and increase the scale of the project as our understanding of the reservoir increases. Additionally, by leasing the FPSO and shuttle tankers we will limit our capital investment in the early stages of the project. Although this will be the first FPSO utilized in U.S. waters, the technology has been extensively tested in offshore basins in other parts of the world. Our partner in Cascade, Petrobras, is a world leader in the use of FPSOs.

**Some exploration and production companies have purchased drilling rigs and entered into other non-core businesses. Does Devon plan to do the same?**

There has been a tendency in our industry for some competitors to venture into ancillary businesses, such as owning drilling rigs. This has typically been when prices for oil field services, such as drilling, were on the rise. Experience tells us, however, that as the forces of supply and demand for those services adjust, prices come back down. Consequently, the economic advantage of entering a non-core business can disappear abruptly.

Devon is principally an exploration and production company. This means that we search for new oil and natural gas reserves and produce and market those reserves. Although drilling is necessary to our operations, it is not a core business. We hire specialists because that is what they do best. We have no plans to diversify into any oil field service businesses.

**Devon has not made a major corporate acquisition since 2003. Why not?**

Between 1998 and 2003, Devon completed six progressively larger transactions that totaled more than $22 billion. Why did we stop in 2003? Because reinvestment opportunities within our existing property portfolio were superior to those available through large-scale corporate acquisitions. That does not mean, however, that we abandoned the acquisitions market completely. In 2006, we acquired properties in the Barnett Shale field at a cost of about $2 billion. That transaction enabled us to significantly increase our leadership position in the Barnett Shale.

Today, the investment opportunities we have available through drilling and repurchasing Devon shares continue to be better than the opportunities available through large-scale acquisitions. Will we ever do another corporate acquisition? That is hard to say because economic conditions and opportunities constantly change. But for now, Devon has a strong, growing asset base, with many thousands of potential locations available for drilling. Acquisitions are not necessary for us to enjoy a healthy growth profile.

### Why did you decide against forming a publicly-traded master limited partnership?

Devon announced in July 2007 that we planned to form a master limited partnership (MLP) that would own a minority interest in our marketing and midstream business. A stated reason for the planned transaction was to enable the securities markets to place an independent value on Devon's marketing and midstream operations. We believed that this segment of our business, which generated more than $500 million of operating profit for Devon in 2007, was not fully reflected in the price of our common stock.

At the time we announced our plans for an MLP, the market for yield-driven investments was very receptive. During the second half of 2007, world credit markets were beset by a cascade of bad news and the MLP market deteriorated considerably. This led us to withdraw Devon's prospective offering. Whether or not we reconsider forming an MLP will depend largely upon how the market for such investments rebounds in the future.

### What led to your decision to divest your operations in Africa?

We reached the decision to exit after evaluating the relative risks and rewards of making further investments in Africa versus competing opportunities. We weighed several factors including geopolitical risks, fiscal terms and proximity to markets. We also found it difficult to secure a competitive advantage over large, national oil companies in acquiring the best exploration opportunities in this part of the world. The national oil companies, often backed by foreign governments, can offer incentives to the host countries that we cannot match.

Ultimately, the decision hinged on the allocation of resources – both capital and people. We concluded that Devon could deploy our resources more efficiently and effectively elsewhere. This includes the Lower Tertiary trend in the Gulf of Mexico, the oil sands in Canada and exploration prospects in Brazil and China.

### With many employees in your industry nearing retirement age, what is Devon doing to attract and retain talent?

Hiring and retaining a skilled workforce is, and will continue to be, a challenge to the energy industry as experienced employees retire. Past periods of low commodity prices and underinvestment caused many to leave oil and gas jobs and reduced the number of college students choosing petroleum-related careers. Devon is attempting to reverse this situation in several ways. One is by lending our support to universities that train petroleum professionals. Another is by aggressively recruiting on college campuses and offering attractive internship programs to students pursuing oil and gas careers.

We are also devising compensation and benefit programs with features attractive to both young people entering the workforce and to older, established employees. Devon recently won the attention of the national business press by offering alternative retirement savings plans that address the concerns of employees at all stages of their careers. We are also considering other options that could entice experienced professionals to extend their careers as they transition into retirement. Our goal is for Devon to be among the most desirable employers in our industry. Our recognition in 2008 as one of *FORTUNE* magazine's "100 Best Companies to Work for" indicates that we are succeeding in that pursuit.

# Five-Year Highlights

| YEAR ENDED DECEMBER 31, | | 2003 | 2004 | 2005 | 2006 | 2007 | LAST YEAR CHANGE [4] |
|---|---|---|---|---|---|---|---|
| **Financial Data** [1] (Millions, except per share data) | | | | | | | |
| Total revenues | $ | 6,962 | 8,549 | 10,027 | 9,767 | 11,362 | 16% |
| Total expenses and other income, net [2] | | 4,792 | 5,490 | 5,649 | 6,197 | 7,138 | 15% |
| Earnings before income taxes | | 2,170 | 3,059 | 4,378 | 3,570 | 4,224 | 18% |
| Total income tax expense | | 453 | 970 | 1,481 | 936 | 1,078 | 15% |
| Earnings from continuing operations | | 1,717 | 2,089 | 2,897 | 2,634 | 3,146 | 19% |
| Earnings from discontinued operations | | 14 | 97 | 33 | 212 | 460 | 118% |
| Cumulative effect of change in accounting principle | | 16 | — | — | — | — | N/M |
| Net earnings | | 1,747 | 2,186 | 2,930 | 2,846 | 3,606 | 27% |
| Preferred stock dividends | | 10 | 10 | 10 | 10 | 10 | — |
| Net earnings applicable to common stockholders | $ | 1,737 | 2,176 | 2,920 | 2,836 | 3,596 | 27% |
| Net earnings per share: | | | | | | | |
| Basic | $ | 4.16 | 4.51 | 6.38 | 6.42 | 8.08 | 26% |
| Diluted | $ | 4.04 | 4.38 | 6.26 | 6.34 | 8.00 | 26% |
| Weighted average common shares outstanding: | | | | | | | |
| Basic | | 417 | 482 | 458 | 442 | 445 | 1% |
| Diluted | | 433 | 499 | 470 | 448 | 450 | 1% |
| Net cash provided by operating activities | $ | 3,768 | 4,816 | 5,612 | 5,993 | 6,651 | 11% |
| Cash dividends per common share | $ | 0.10 | 0.20 | 0.30 | 0.45 | 0.56 | 24% |
| Closing common share price | $ | 28.63 | 39.03 | 62.54 | 67.08 | 88.91 | 33% |

| DECEMBER 31, | | 2003 | 2004 | 2005 | 2006 | 2007 | LAST YEAR CHANGE |
|---|---|---|---|---|---|---|---|
| Total assets | $ | 27,162 | 30,025 | 30,273 | 35,063 | 41,456 | 18% |
| Debentures exchangeable into shares of Chevron Corporation common stock [3] | $ | 677 | 692 | 709 | 727 | 641 | (12%) |
| Other long-term debt | $ | 7,903 | 6,339 | 5,248 | 4,841 | 6,283 | 30% |
| Stockholders' equity | $ | 11,056 | 13,674 | 14,862 | 17,442 | 22,006 | 26% |
| Working capital (deficit) | $ | 293 | 772 | 1,272 | (1,433) | 257 | N/M |

| YEAR ENDED DECEMBER 31, | 2003 | 2004 | 2005 | 2006 | 2007 | LAST YEAR CHANGE |
|---|---|---|---|---|---|---|
| **Property Data** [1] | | | | | | |
| Proved reserves (Net of royalties) | | | | | | |
| Oil (MMBbls) | 530 | 484 | 555 | 634 | 677 | 7% |
| Gas (Bcf) | 7,217 | 7,385 | 7,192 | 8,259 | 8,994 | 9% |
| NGLs (MMBbls) | 209 | 232 | 246 | 275 | 321 | 16% |
| Oil, Gas and NGLs (MMBoe) | 1,941 | 1,946 | 2,000 | 2,286 | 2,496 | 9% |
| Production (Net of royalties) | | | | | | |
| Oil (MMBbls) | 47 | 54 | 46 | 42 | 55 | 29% |
| Gas (Bcf) | 858 | 883 | 819 | 808 | 863 | 7% |
| NGLs (MMBbls) | 22 | 24 | 24 | 23 | 26 | 10% |
| Oil, Gas and NGLs (MMBoe) | 211 | 225 | 206 | 200 | 224 | 12% |

(1) The years 2003 through 2007 exclude results from operations in Africa that were discontinued in 2006 and 2007. Revenues, expenses and production in 2003 include only eight and one-fourth months attributable to the Ocean merger. All periods have been adjusted to reflect the two-for-one stock split that occurred on November 15, 2004.
(2) Includes other income, which is netted against other expenses.
(3) Devon owns 14.2 million shares of Chevron Corporation common stock. The majority of these shares are on deposit with an exchange agent for possible exchange for $652 million principal amount of exchangeable debentures.
(4) All percentage changes in this table are based on actual figures and not the rounded numbers shown.
N/M Not a meaningful number.

You can tell a lot about a company by looking at what it values. At Devon, we invest in the long-term prosperity of our business, our people, our communities and the environment. We invest in the technology that drives our industry amid the world's growing demand for energy.

Our commitment runs even deeper than our financial resources. We invest our creativity, our talent and our passion. We invest ourselves in the promise to continually improve as an oil and natural gas producer, to be a good neighbor and to respect the environment.

Within this year's annual report you will read about projects that push the limits of innovation. You will learn about our work to conserve water and reduce greenhouse gas emissions, and you will see how we give back. Throughout the pages of our report, you will see what Devon values, and you will understand our commitment.

Commitment Runs Deep

# Being a good neighbor

The skating rink Devon helped to build is a popular winter gathering place for Austin Deranger and other local children in Conklin, Alberta.

"Our new skating rink has been good for Conklin. My boys, 13-year-old Erwin and 11-year-old Dakota, play hockey there every chance they get. They go right after school and stay until dark. We recently got electricity and heat in the warm-up shack so now the kids will be able to use it more, especially when it is so cold outside. Before we had the rink, there was not much else for kids to do outside except ride their all-terrain vehicles. Devon's skating rink project demonstrates how a company can be a good neighbor and benefit an entire community."

**Ernie Desjarlais**
Resident of Conklin, Alberta

Before Devon helped Conklin, Alberta, build an ice skating rink and warming hut, local children in this community near Devon's Jackfish facilities had few places to go for fun. Today, the rink is a hub of activity and has become a frequent location for physical education classes for a nearby school.

Last winter, our employees held a skate drive for local children and families. The drive exceeded our expectations, and we provided a pair of skates for nearly everyone in the community. Several of our employees also volunteer their time to teach children and families to skate and play hockey.

We strive to be a good neighbor in every area where we operate. Projects such as the ice rink and warming hut in Conklin are examples of our commitment to enhancing the communities where we live and work.

# It's about giving back

## We are dedicated to community involvement and improving the quality of life in the places we work. We take pride in Devon and the company's accomplishments as a profitable energy producer, and we take heart in our role as a good neighbor. We are defined by the character of our employees, who give their time, money, leadership and compassion to help others.

**Community Involvement**

Community involvement is a cornerstone of Devon. We look for ways to support our neighbors, strengthen our schools and promote stability through support of cultural initiatives and civic projects.

In 2007, our employees devoted their time and energy to help low-income families achieve the dream of home ownership through the Habitat for Humanity initiative. This nonprofit organization is dedicated to helping people purchase simple, affordable homes built from the ground up through the love and labor of volunteers. More than 100 of our employees contributed to the effort through a home project in Houston. Over five days, Devon geologists, engineers, accountants, administrators and others worked side by side to build a home for a family with two young children. In north Texas, employees weathered the summer heat to help construct exterior and interior walls and frame the roof of the first Habitat for Humanity home in Wise County.

Helping those less fortunate is a common occurrence at Devon. In Oklahoma City, employees supported the Regional Food Bank of Oklahoma by donating more than 8,500 pounds of food and $60,500 in 2007. And, in Canada, employees loaded the Calgary Inter-Faith Food Bank with 12,250 pounds of donated food they collected in a mere four days.

Our employees throughout North America play a huge role each year in the success of the companywide United Way campaign. Employees in Oklahoma City, Houston, Calgary, Bridgeport, Texas, and field offices across North America gave a record $3.9 million in 2007 to help the United Way fund health and human services organizations in our communities.


Randy Neal, a supervisor in Bridgeport, Texas, helps build a Habitat for Humanity home.

Mark Twain Elementary student Whitney Honea enjoys a day at Devon. More than 250 Oklahoma City employees spend an hour each week tutoring and mentoring students at Mark Twain.

**Strengthening Quality of Life**

Of Devon's many community commitments, none is more important and rewarding than supporting youth and educational opportunities. Devon has established successful partnerships with inner-city, multicultural elementary schools in Oklahoma City and Houston. More than 300 employees serve as tutors and role models, committing more than 7,500 hours to make a difference in the lives of children. Taking time to educate the next generation has also inspired Devon to contribute more than $3 million in 2007 to help fund college scholarships, supplement educational programs and support other projects at colleges and universities.

We also support emergency response organizations through a number of local commitments. The company made a lead gift of $200,000 to support a new police and firefighters' memorial in Fort Worth, Texas. Our company also responded to a community need at the Eaglesham Fire Department in Alberta, Canada, by donating a vehicle to aid its rescue operations. Animals, too, have played a role in how we help improve communities. We have provided four dogs trained for substance detection, tracking and personal protection to area sheriff's departments to serve and protect their respective communities.

Being a good neighbor is a core Devon value. Improving the natural environment is one of the ways Devon's employees demonstrate this value in their communities. Employees in Canada joined with students, industry partners and community members during the 2007 Energy in Action program to plant trees, haul mulch and water shrubs. Energy in Action is an initiative focused on the environment that brings together the petroleum industry and communities. From mid-September to early October, Devon joined other member companies of the Canadian Association of Petroleum Producers to participate in Energy in Action activities in 13 communities across Canada. Devon also supports an organization in Rio de Janeiro, Brazil, that works with local fishing villages to foster environmental education and help protect the environment.

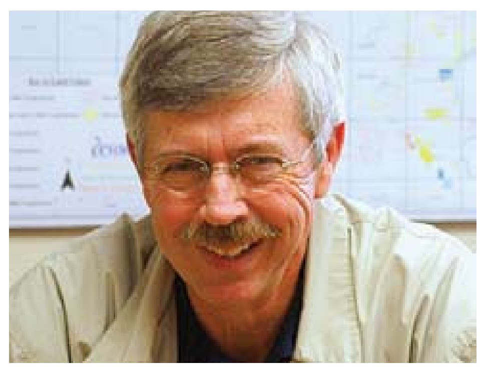
# Recognizing the essentials

In the age of greenhouse gas awareness and climate change, we are not waiting for regulatory mandates or new research. Perhaps more important than the discussions taking place on the Capitol steps are the steps we can take to address the matter.

Part of being a good neighbor is respecting the environment and being aware of what we can do to reduce our impact. Because we recognize climate change is an issue of widespread public concern, we have developed a comprehensive program for reducing emissions of greenhouse gases such as methane and carbon dioxide.

We believe reducing emissions is not only the right thing to do for the environment but also benefits our business. By reducing methane emissions, we keep more gas in the pipeline and available for sale. For example, in 2006, our reduction program accounted for eight billion cubic feet of natural gas. By keeping that volume of gas in the pipeline, we increased our revenue by nearly $50 million.

"We got involved in reducing our greenhouse gas emissions several years ago when we joined the Environmental Protection Agency's Natural Gas STAR program. Since then, we have been installing special equipment and taking other steps to reduce methane and carbon dioxide emissions. It's a program that benefits more than the environment. We are also saving money by keeping more gas in the pipeline, and we are creating a safer place to work. They all go hand in hand. Reducing greenhouse gas emissions is just the result of doing the right thing."



**Don Mayberry**
Devon Production Superintendent
Artesia, New Mexico

## Clean air and pure water

**You may know us as one of the top energy producers in the United States. You may also know us as a leader in the Gulf of Mexico's deep water, the oil sands of Alberta or the shale of north Texas. But there is another side to Devon you may not readily see in our financial statements or in our presentations to Wall Street.**

The work we do to protect the environment, to preserve our natural resources and to ensure the safety of our employees is a fundamental part of our culture. We consistently look for new and innovative ways to reduce our impact on the environment.

**Emissions Inventory**

Since 1990, we have been reducing our greenhouse gas emissions through a growing number of new technologies and innovations. We have spread our efforts across the United States and Canada, surpassing milestones and winning recognition from industry and government partnerships. We reached another important stage of our program in 2007 with development of a monitoring system that allows us to track methane and carbon dioxide emissions from production facilities companywide.

The inventory is a useful tool in our ongoing effort to cut carbon dioxide emissions and to keep methane in the pipeline and available for sale. Using this system, we can evaluate our operations and identify opportunities for reductions. With this information we can determine the most effective locations to deploy emissions reduction technologies such as the installation of vapor recovery units on tank batteries, or the use of modern, low emission valves at well sites, pipelines and compressor stations.

In 2007, we inventoried our annual carbon dioxide emissions from Devon's U.S. operations. Factored against production, our emissions intensity was at or below that of other large North American oil and natural gas producers. Through the inventory we can document reduction in emissions intensity, track our progress, set goals and disclose results to stakeholders.

As concern over climate change issues continues to build, we expect ongoing progress and believe our inventory gives us a solid foundation from which to measure future progress.

**Water Recycling**

Part of what we do as an environmental steward is look for opportunities to conserve our natural resources. Our pioneering effort to recycle water in north Texas is an example of how innovation can benefit the environment and surrounding communities.

The Barnett Shale surrounding Fort Worth is the fastest-growing natural gas field in the nation, producing more than three billion cubic feet of gas per day from a geological formation that extends over 5,000 square miles. However, shale gas is an unconventional resource requiring large amounts of fresh water to stimulate production.

In 2005, we began a recycling program to reclaim water used to stimulate our natural gas wells. We use heat to vaporize waste water recovered from the wells, then condense the steam into distilled water to be reused in other well stimulation projects. Since establishing the program, we have recycled more than five million barrels of water.

Each year, the volume of water we recycle grows. Our program began with two recycling units in 2005. Today the recycling effort has expanded to nine units in the Barnett. The units operate around the clock and each one processes more than 2,500 barrels of water a day.

While we are excited about pioneering water recycling in the Barnett Shale, we are not finished. We continue to enhance the efficiency and economics of recycling to establish new opportunities in other areas where we operate.

We have recycled more than five million barrels of water utilizing units such as this in the Barnett Shale field in north Texas.

# Everyday energy

**Gasoline fuels our cars and natural gas heats our homes, but have you ever wondered what life would be like without the countless products derived from oil and natural gas? In our modern world, we have come to enjoy and expect a certain quality of life that is sustained by everyday things made from these natural resources.**

Think about a typical weekday. You brush your teeth, shower, put on makeup or shave before heading off to work. Without petroleum-based products, you would not have the toothbrush, toothpaste, mouthwash, shampoo, mascara, lipstick, shaving foam or razor for your morning routine. If your eyesight is poor, you could not rely on contact lenses or eyeglasses to sharpen your vision. You would even miss your daily multi-vitamin.

How is petroleum made into so many everyday products? After oil is brought to the surface, it is refined and broken into compounds known as fractions. Different fractions are blended to make a variety of raw materials used in manufacturing. These raw materials provide the basic building blocks for a wide variety of items we use every day.

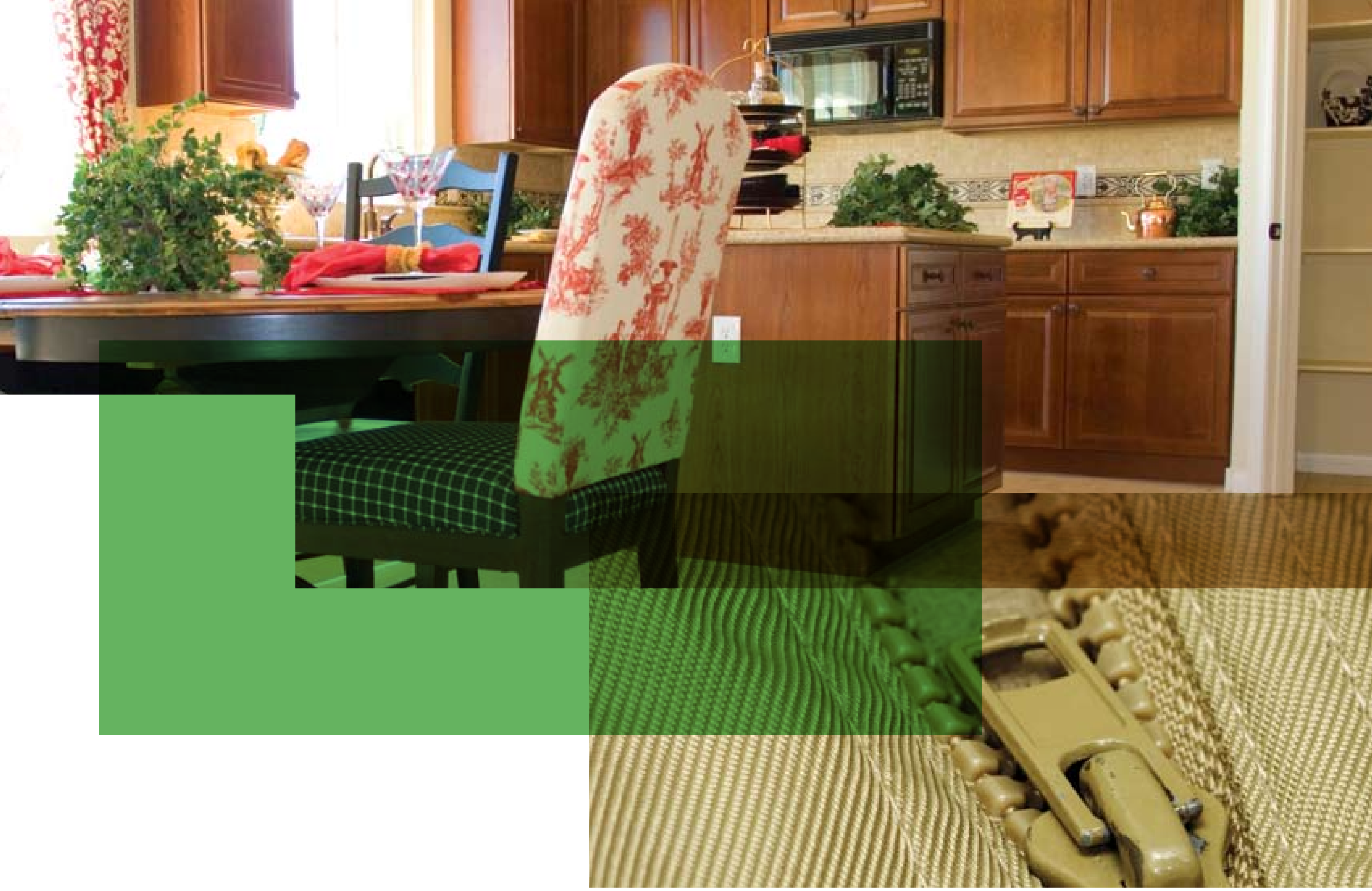
In the kitchen, your coffee pot, drinking cups, egg cartons and cooking utensils are likely made from petroleum products. Refrigerator shelves, dish sponges, trash bags and non-stick pans are also derived from petroleum products.

As you drive or ride the bus to work, do you realize the dashboard, upholstery, windshield wipers, brake fluid and sun visors in the vehicle are also derived from oil and natural gas? Even the asphalt roads we drive on are made from petroleum products.

When you arrive at work, you may log on to a computer to check e-mails, dial your voice mail and jot down messages or daily tasks. Computers, memory chips, telephones, ballpoint pens and ink are made from petroleum products. So are calculators, correction fluid, copy machines, printer cartridges and waste baskets. Even the building itself – from the linoleum floors and laminate countertops to the ceiling tiles and roof shingles – contains a host of petroleum-based products.

If you stop to visit a loved one at the hospital on your way home from work, you probably encounter countless petroleum-based products without notice. Even advanced medical devices such as artificial hearts, prosthetic limbs and hearing aids are made from oil and natural gas products. Anesthetics used to sedate surgery patients and cortisone used to treat arthritis and allergies are also made from petroleum products.

Home again at the end of the day, families depend on baby bottles, disposable diapers, pacifiers, teething rings and stuffed animals when raising their young children. Each of these is made from petroleum products. After school your child may attend a dance class or participate in sports. Without petroleum products, clothing and equipment from ballet tights to soccer balls, footballs, tennis rackets, diving boards and swim goggles would not



exist as we know them today. Your artistic child might not have oil paints and brushes and your musician might not have her instrument or guitar strings.

By the end of the day you are probably looking forward to the weekend when you can enjoy a game of golf, ride your bicycle or go for a long run. Golf balls, light-weight bicycles and the rubber soles on your sneakers are all made from oil and natural gas products.

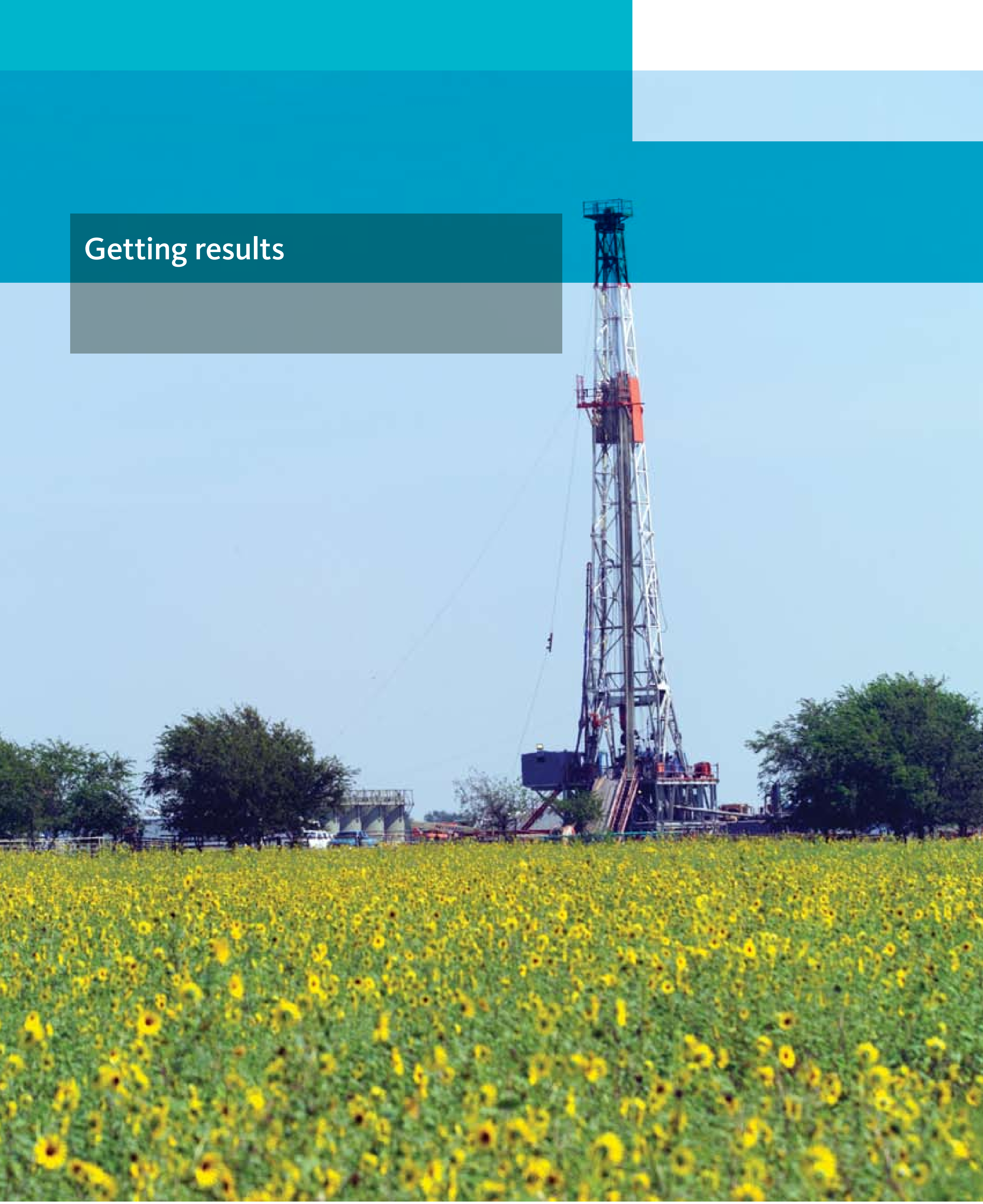
But for now, you crawl into bed, cozy up with pillows and blankets made from petroleum products and fall asleep, only to wake up to your digital alarm clock – also made from petroleum products – and start all over again.

## Products Made From Oil and Natural Gas

air tanks
air conditioners
airplane parts
ammonia
anesthetics
antifreeze
antihistamines
antiseptics
artificial limbs
artificial hearts
artificial turf
asphalt
aspirin
automobile parts
awnings
badminton birdies
ball point pens
balloons
bandages
baseboards
bath tubs
beach umbrellas
beach balls
bedspreads
bicycle tires
blankets
blenders
board game parts
boats
brooms
bubble gum
bug spray
bumpers
buttons
cable housings
camera bags
cameras
candles
candy oils
candy paraffin
car enamel
car battery cases
car sound insulation
car polish
carbon black
carpet sweepers
carpets
cassettes
caulking
ceiling tiles
charcoal lighters
chewing gum
child car seats
cleaning fluid
clotheslines
clothing
coffeemakers
cold cream
combs
compact discs
computer chips
computer disks
computers
cortisone
counter tops
crayons
credit cards
curtains
dashboards
denture adhesives
dentures
deodorant
detergents
dice
digital clocks
dishwashing liquid
disposable lighters
dolls
doormats
dry cleaning fluid
dyes
earphones
electric razors
electrical tape
enamel
epoxy paint
eye shadow
eyeglasses
fabric softener
fabric dye
fan belts
faucet washers
fencing
fertilizers
fiberglass
filters
fishing boots
fishing rods
fishing lures
flashlights
flavoring
flea collars
floor wax
flower pots
foam rubber
folding doors
food preservatives
food packaging
footballs
laminate counter tops
furniture polish
garment bags
gasoline
glue
glycerin
golf balls
golf bags
grease
guitar strings
hair curlers
hair permanents
hair brushes
hair dye
hair dryers
hand lotion
hearing aids
heart valves
helmets
hoses
house paint
hydraulic fluid
hydrochloric acid
hydrogen peroxide
ice buckets
ice chests
ice cube trays
ink
inner tubes
insect repellant
insecticides
insulation
jet fuel
kerosene
kitchen utensils
lacquers
latex paint
laundry baskets
life jackets
light housings
lighter fluid
linoleum
lipstick
livestock feed
loudspeakers
lubricants
luggage
lunch boxes
makeup cases
mascara
matches
mattress covers
medicines
microphones
model cars
mops
motor oil
motorcycle helmets
mouthwash
movie film
nail polish
nail polish remover
newspaper ink
nylon fabric
nylon rope
oil filters
oils
outboard motors
outlet covers
paint rollers
paint brushes
paints
pan handles
panty hose
parachutes
peat moss
percolators
perfumes
permanent-press
pet kennels
petroleum jelly
phonograph records
photo film
photographs
piano keys
picture frames
pillows
ping pong paddles
plant hormones
planters
plastic bags
plastic furniture
plastic dishes
plastic wrap
plexiglass
plumbing fixtures
plywood adhesive
polar fleece
purses
putty
rain gutters
raincoats
rayon fabric
razors
recorders
recycling bins
reflectors
refrigerants
refrigerators
resins
rollerblades
roofing
rubber gloves
rubber cement
rubbing alcohol
saccharin
sacks
safety glass
salad tongs
salad bowls
sandwich bags
satellite parts
sedatives
shampoo
shaving cream
shingles
shoe polish
shoe soles
shoelaces
shoes
shopping bags
shower doors
shower curtains
ski goggles
ski clothing
skis
slacks
slip covers
sneakers
soap dishes
soaps
soft contact lenses
solvents
sports helmets
sports pads
sports car bodies
stretch pants
strollers
styrofoam
sulfa drugs
sunglasses
sweaters
swim goggles
synthetic rubber
T-shirt transfers
tape recorders
telephones
tennis balls
tennis rackets
tent pegs
tents
textiles
tires
toasters
toilet seats
tool racks
tool boxes
toothbrushes
toothpaste
toys
transformer pads
trash bags
tubing
TV cabinets
typewriter ribbons
umbrellas
uniforms
upholstery
vacuum bottles
vaporizers
varnish
videotape
vinyl
vitamin capsules
vitamins
volleyballs
watch bands
water pipes
wheelbarrows
window frames
wind sails
windshield wipers
wire coating
yarn
zippers

**SOURCE:** Independent Petroleum Association of Mountain States (IPAMS)

# Getting results



Devon is the largest gas producer in Texas. In 2007, we drilled 539 wells in the prolific Barnett Shale in north Texas.

**"I was born in Fort Worth and have spent my entire career in north Texas. As a businessman, it has always been important to look for opportunities to give back to my community. Good business means being a good neighbor. I saw Devon demonstrate that philosophy first hand while working on a recent drilling project on my property. They responded quickly and effectively when adjacent residents expressed concern about noise and truck traffic. Devon used ingenuity, compromise and creativity to accommodate the residents. As a result, two wells were successfully drilled on my property. But the best part was that the neighbors were no longer concerned about trucks or noise."**

**Holt Hickman**
Businessman and land owner
Fort Worth, Texas

Sometimes a new application of an old idea is all it takes to achieve a modern technological breakthrough. That is what happened at Devon in 2002. The old idea was horizontal drilling, and the result was a new era for natural gas production from shale.

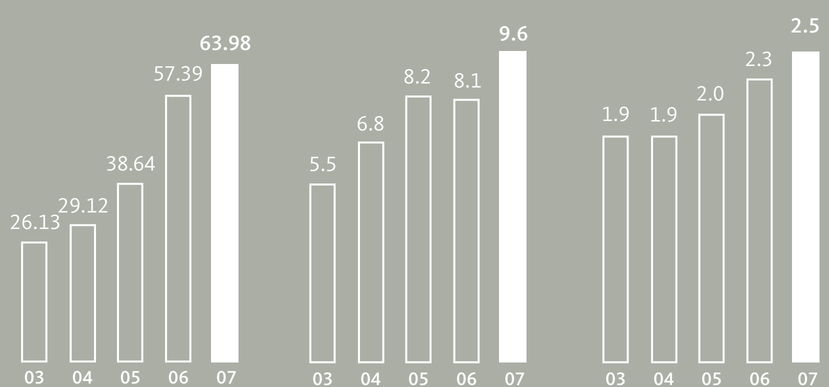
Devon applied horizontal drilling technology to the Barnett Shale following the company's acquisition of Mitchell Energy in 2002 and in 2007 drilled its 1,000th horizontal well. Prior to its acquisition, Mitchell's activities in the Barnett had been confined to vertical drilling in a relatively small area with the most favorable geological characteristics. Following the acquisition, we began experimenting with horizontal drilling as a way to overcome geological challenges.

The pilot program showed encouraging results. By 2004, we expanded our horizontal drilling program beyond the core to the Barnett's more complex areas. Horizontal drilling was the key that opened expansion in the Barnett, and it remains a key to future expansion into shale plays across North America.

# Developing our full potential

## Success for an exploration and production company can be measured in two important ways: by how much oil and natural gas we profitably produce today and tomorrow. Devon excelled in 2007 by both measures. On an oil-equivalent basis, we increased annual production from continuing operations by 12%, to 224 million barrels. We expect to grow production further in 2008 to between 240 million and 247 million equivalent barrels.

**Devon's realized price for oil approached $64 per barrel in 2007, driving oil and gas revenues to $9.6 billion. Our successful exploration and development programs have allowed us to grow proved reserves to a record 2.5 billion barrels.**




**Average Price per Barrel of Oil**
($ per Bbl)

**Oil, Gas and NGL Revenues**
($ Billions)

**Proved Reserves**
(Billion Boe)

Our capacity to increase production is largely dependent upon how successfully we grow proved reserves. Proved reserves are technical estimates of the quantities of oil and gas still underground that can, with reasonable certainty, be recovered under current economic conditions. In 2007, we added 437 million oil-equivalent barrels to our proved reserves. That was nearly twice the amount we produced. Most of the reserve additions, 390 million equivalent barrels, came from successful drilling and positive performance revisions. We drilled 2,440 total wells in 2007, with a success rate of 98%. Development projects such as the Barnett Shale and Carthage in Texas and Lloydminster in Canada underpinned the growth. Exploratory areas such as the deepwater Gulf of Mexico, Brazil and China provide opportunities to increase reserves and production in the future. You can read about some of Devon's more important exploration and development projects on the following pages.

Devon's Jackfish oil sands project in Alberta, Canada, is expected to produce 35,000 barrels per day for more than 20 years.

## Accelerating Growth in the Barnett Shale

Based on both production and reserves, the Barnett Shale in north Texas is Devon's largest and most important asset — and it is still growing. 2007 was a banner year for us in the Barnett, as we increased annual production by 33% to more than 300 billion cubic feet of gas equivalent. We increased proved reserves in the Barnett in 2007 by 19%, finding more than three times the volume of gas we produced. The Barnett Shale is among the largest onshore natural gas fields in North America, and Devon is its largest producer.

We are growing production and reserves in the Barnett by drilling more wells and increasing per-well recoveries. Devon drilled 539 wells in the Barnett Shale in 2007, compared with 383 wells in 2006. This increase was due, in part, because of improved drilling efficiency. We have cut the number of days required to drill a typical horizontal Barnett well by half in just the past three years. Based on fourth-quarter results, we increased per well recoveries from new wells in the Barnett by about 15% in 2007. Almost all of the Barnett wells we drilled in 2007 were horizontal wells. Not only are horizontal wells more efficient than vertical wells, they also cause less surface impact because fewer drilling locations are required.

Another approach we are using in the Barnett to increase production and reserves is infill drilling, or spacing wells closer together. Our first horizontal wells in the Barnett Shale were drilled on about 160 surface acres per well. Next, we began drilling wells on 80 surface acres, or double the initial density. The success of that program led to a 40-acre pilot and we are now testing the viability of 20 surface-acre locations. Not all Barnett acreage will be suitable for the higher density spacing. With more experience we should be able to determine what the optimum well spacing is for all of our Barnett Shale leases.

Today, we have about 3,200 wells producing gas from the Barnett Shale. We hold proved reserves of more than 4.3 trillion cubic feet of gas equivalent, yet our engineers believe we are recovering a fraction of the gas in place. Horizontal and infill drilling and innovative reservoir management practices are enabling us to extract more and more of the clean-burning natural gas locked in the Barnett Shale to meet the country's growing energy demands.

## Full Steam Ahead at Jackfish

In 2007, we started injecting steam at Devon's 100%-owned Jackfish oil sands project in eastern Alberta, Canada. Jackfish has been under construction since 2005 and utilizes the steam-assisted gravity drainage, or SAGD, process. Softened by steam, heavy oil is now flowing to the surface through wells drilled to a depth of about 1,300 feet. That oil is processed in surface facilities and blended with diluents to make it flow more easily. The blended oil is then transported on Devon's 50%-owned Access Pipeline for marketing. Production is expected to ramp up gradually to a peak of 35,000 barrels per day, which is the design capacity of the Jackfish facilities.

We anticipate receiving regulatory approval in 2008 for Jackfish 2, another 35,000 barrel per day SAGD project located on adjoining leases. Jackfish and Jackfish 2 are each expected to recover about 300 million barrels of oil over their more than 20-year productive lives. Devon is the first U.S.-based independent to operate a thermal oil sands project in Canada.

**Lloydminster Oil Volumes Climbing**

In east central Alberta and west central Saskatchewan, Canada, Devon holds more than two million net acres in the Lloydminster area. Production at Lloydminster is from shallow reservoirs between 1,300 and 2,000 feet deep. Lloydminster oil is heavy, but can be brought to the surface without the steam injection process required at Jackfish.

At Lloydminster, we are developing Devon's acreage in the Manatokan, Iron River and End Lake fields. We drilled 429 wells in the Lloydminster area in 2007 with excellent results. We increased 2007 average production to 33,500 equivalent barrels per day, 40% more than in 2006. We plan to drill another 475 wells at Lloydminster in 2008. Because the wells are shallow and relatively inexpensive to drill, finding and development costs are very attractive.

**Exploring the Deep**

Although development projects such as the Barnett Shale and Lloydminster are delivering impressive growth, we believe long-term, sustainable growth requires a significant commitment to high-impact, long-cycle-time exploration. In 2008, we will invest about $1 billion in exploration projects that will not deliver reserves or production for several years, but can provide the seeds for future growth.

Early this decade, we determined that the deepwater Gulf of Mexico would be a focus area for our exploration program. We had an experienced team of deepwater explorationists, many of whom had joined Devon through previous acquisitions. We also had an extensive seismic library and deepwater acreage inventory. We further increased our deepwater acreage position through federal lease sales and joint ventures with other operators. Today, Devon's deepwater lease inventory is among the largest in the Gulf of Mexico.

Our deepwater exploration commitment led to early and notable success with discoveries in both Miocene and Lower Tertiary reservoirs. In the Miocene trend we made discoveries at Sturgis (25% working interest) in 2003 and Mission Deep (50% working interest) in 2006. We are now drilling a Miocene exploratory well at Sturgis North (25% working interest) and plan to drill an appraisal well at Mission Deep later in 2008.

In 2002, we made our first discovery in the Lower Tertiary trend. Lower Tertiary geologic formations are older and deeper than the Miocene-aged rocks. Devon has to date participated in four significant Lower Tertiary discoveries with combined estimated net resources of up to 900 million oil-equivalent barrels. We have also built an inventory of about 20 untested exploratory prospects with combined unrisked resource potential of up to five billion oil-equivalent barrels. This is double Devon's current proved reserve base of about 2.5 billion equivalent barrels.

Our offshore employees travel to and from the Ocean Endeavor aboard helicopters. The drilling rig is under a long-term contract to Devon in the Gulf of Mexico.

Of our four discoveries, Cascade is the first to be sanctioned for development. St. Malo (22.5% working interest) and Jack (25% working interest), discovered in 2003 and 2004 respectively, may be sanctioned in 2009 for development. A successful production test of the Jack No. 2 well in 2006 brought worldwide attention to the Lower Tertiary trend and to Devon's stake in the play. Additional appraisal drilling and facilities design engineering on both St. Malo and Jack are planned for 2008. Should St. Malo and Jack be sanctioned in 2009, first production could occur as early as 2013. Additional appraisal activity is also planned in 2008 for Kaskida (20% working interest), a 2006 discovery.

To provide greater flexibility in accomplishing our deepwater drilling plans, we have entered into long-term contracts for two fifth-generation offshore rigs. We took delivery of the Ocean Endeavor, the first of the two rigs, in 2007. We expect to take delivery of the second rig, the West Sirius, in mid-2008. These rigs are capable of drilling in 10,000 feet of water and to depths greater than 30,000 feet. We will use the rigs for exploratory, appraisal and development wells. The Ocean Endeavor is now drilling the Jack No. 3 appraisal well before moving to drill the initial producing wells at Cascade. We plan to drill a Devon-operated exploratory well with the West Sirius after it arrives in U.S. waters.

**Cascade Sanctioned for Development**

Cascade was the first of Devon's four significant discoveries in the Lower Tertiary trend of the Gulf of Mexico. We drilled the discovery well in 2002 and followed up with two successful appraisal wells in 2005. Devon and Petrobras, the Brazilian national oil company, are equal partners in the 23,000-acre Cascade unit. In 2007, the partners sanctioned the project for commercial development.

Cascade is located in the Walker Ridge lease area under about 8,000 feet of water. We plan to develop the project with a floating production, storage and offloading vessel, or FPSO. Although FPSOs are deployed in many oceans around the world, Cascade is expected to be the first project in the Gulf of Mexico to use this production system. In 2007, the Cascade partners awarded contracts for the FPSO and for two shuttle tankers that will transport oil to the coast.

We expect to begin drilling the first of two initial producing wells at Cascade later this year, with production planned to commence in 2010. Reservoir data gathered from these first two wells will help determine the optimum facilities size and number of producing wells required to fully develop Cascade's potential. This phased approach will allow us to develop the project in a prudent and cost-effective way.

**International Exploration Looks to Brazil and China**

Devon is predominately a North American company. About 95% of our proved reserves, excluding the properties in Africa that we are divesting, are in the United States and Canada. Although currently focused in North America, we are excited about our prospects in Brazil and China. These are countries with stable political, fiscal and regulatory environments and where we have alliances with experienced and capable partners.

Devon established a foothold in Brazil with our 2004 Polvo discovery in the offshore Campos Basin. We began producing oil at Polvo in the second half of 2007 and expect to drill a total of 10 producing wells and three water injection wells. The Polvo facilities, which include a fixed drilling and producing platform and an FPSO, are sized to produce up to 50,000 barrels of oil per day. Devon operates the project with a 60% working interest.

We also hold interests in nine offshore leases in Brazil, encompassing nearly 800,000 net acres. Seven of the lease blocks are in the prolific Campos Basin, and we are partners with Petrobras, Brazil's national oil company, in four of those blocks. In 2008, we plan to drill a high-potential exploratory well on Block BM-C-30. In early 2009, Devon will take delivery under a long-term contract of a deepwater drill ship in Brazil. We plan to drill seven exploratory wells with the drill ship over a two-year period.

China is another country where Devon has established offshore production. Our Panyu field is located in the Pearl River Mouth Basin in the South China Sea. Devon and its partners began producing oil at Panyu in 2003, and to date Devon's share of the production has been about 22 million barrels. We have a 24.5% working interest in the project, which is operated by the Chinese National Offshore Oil Company, known as CNOOC.

In the first quarter of 2008, Devon began drilling an exploratory well on Block 42/05, also in the South China Sea, but in deeper water than Panyu. The BY 6-1-1 well is in 3,200 feet of water and is on trend with a large natural gas discovery made by another operator in 2006. We have also identified other exploratory prospects on Block 42/05 that we plan to test in the future.

In addition to Block 42/05, Devon also holds Blocks 53/30 and 64/18 in the South China Sea and Block 11/34 in the Yellow Sea. During the exploration phase, we have 100% working interests in each exploratory block. CNOOC has the option to participate with a 51% working interest in any discoveries. We believe these lease blocks could hold more than one billion barrels of combined net resource potential for Devon.

## 11-Year Property Data [1]

| | | 1997 | 1998 |
|---|---|---|---|
| **Reserves** (Net of royalties) | | | |
| Oil (MMBbls) | | 219 | 166 |
| Gas (Bcf) | | 1,403 | 1,440 |
| NGLs (MMBbls) | | 24 | 21 |
| Oil, Gas and NGLs (MMBoe) | | 477 | 427 |
| 10% Present Value Before Income Taxes (In millions) [2] | $ | 2,100 | 1,375 |
| **Production** (Net of royalties) | | | |
| Oil (MMBbls) | | 29 | 20 |
| Gas (Bcf) | | 180 | 189 |
| NGLs (MMBbls) | | 3 | 3 |
| Oil, Gas and NGLs (MMBoe) | | 62 | 55 |
| **Average Prices** | | | |
| Oil (per Bbl) | $ | 17.03 | 12.28 |
| Gas (per Mcf) | $ | 2.04 | 1.78 |
| NGLs (per Bbl) | $ | 12.61 | 8.08 |
| Oil, Gas and NGLs (per Boe) | $ | 14.51 | 11.09 |
| **Unit Production and Operating Expense** (per Boe) | $ | 4.63 | 4.29 |

# Operating Statistics by Area [(1)]

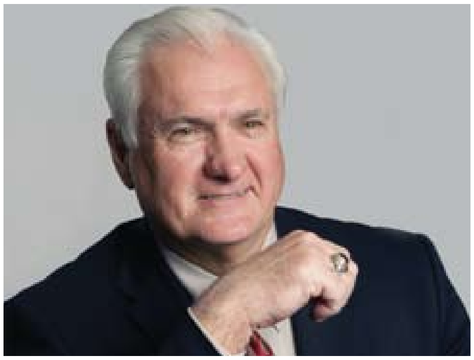
| | | Permian | Mid-Continent | Rocky Mountains | Gulf Coast | U.S. Offshore | Total U.S. | Canada | International | Total Company |
|---|---|---|---|---|---|---|---|---|---|---|
| **Producing Wells at Year-End** | | 8,525 | 7,102 | 6,059 | 4,019 | 682 | 26,387 | 7,975 | 449 | 34,811 |
| **2007 Production** (Net of royalties) | | | | | | | | | | |
| Oil (MMBbls) | | 7 | 1 | 1 | 2 | 8 | 19 | 16 | 20 | 55 |
| Gas (Bcf) | | 34 | 292 | 100 | 132 | 77 | 635 | 227 | 1 | 863 |
| NGLs (MMBbls) | | 3 | 13 | 1 | 4 | 1 | 22 | 4 | — | 26 |
| Oil, Gas and NGLs (MMBoe) | | 15 | 62 | 19 | 28 | 22 | 146 | 58 | 20 | 224 |
| **Average Prices** | | | | | | | | | | |
| Oil price (per Bbl) | $ | 67.87 | 68.22 | 62.02 | 70.28 | 71.95 | 69.23 | 49.80 | 70.60 | 63.98 |
| Gas price (per Mcf) | $ | 6.02 | 5.68 | 4.54 | 6.51 | 7.17 | 5.89 | 6.24 | 6.22 | 5.99 |
| NGLs price (per Bbl) | $ | 34.00 | 35.61 | 19.35 | 40.60 | 36.78 | 36.11 | 46.07 | — | 37.76 |
| Oil, Gas and NGLs (per Boe) | $ | 50.03 | 34.89 | 30.15 | 41.18 | 53.30 | 39.87 | 41.51 | 70.11 | 42.96 |
| **Year-End Reserves** (Net of royalties) | | | | | | | | | | |
| Oil (MMBbls) | | 90 | 6 | 20 | 15 | 39 | 170 | 388 | 119 | 677 |
| Gas (Bcf) | | 248 | 3,972 | 1,191 | 1,354 | 378 | 7,143 | 1,844 | 7 | 8,994 |
| NGLs (MMBbls) | | 26 | 192 | 11 | 52 | 1 | 282 | 39 | — | 321 |
| Oil, Gas and NGLs (MMBoe) | | 156 | 860 | 230 | 293 | 103 | 1,642 | 734 | 120 | 2,496 |
| **Year-End Present Value of Reserves** (In millions) [(2)] | | | | | | | | | | |
| Before income tax | $ | 3,473 | 8,485 | 2,541 | 3,429 | 3,136 | 21,064 | 7,986 | 3,802 | 32,852 |
| After income tax | $ | | | | | | 14,679 | 5,962 | 2,830 | 23,471 |
| **Year-End Leasehold** (Net acres in thousands) | | | | | | | | | | |
| Developed | | 302 | 826 | 549 | 508 | 362 | 2,547 | 2,200 | 54 | 4,801 |
| Undeveloped | | 447 | 533 | 1,378 | 539 | 2,247 | 5,144 | 5,911 | 8,631 | 19,686 |
| **Wells Drilled During 2007** | | 155 | 792 | 480 | 224 | 11 | 1,662 | 748 | 30 | 2,440 |
| **Capital Costs Incurred** (In millions) [(3)] | | | | | | | | | | |
| 2007 Actual | $ | 214 | 1,955 | 411 | 878 | 812 | 4,270 | 1,365 | 466 | 6,101 |
| 2008 Forecast | $ | 225-245 | 1,895-1,975 | 380-405 | 865-915 | 980-1,050 | 4,345-4,590 | 1,305-1,365 | 450-490 | 6,100-6,445 |

(1) Excludes results from discontinued operations.
(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future production and development costs, discounted at 10% in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. Devon believes that the pre-tax 10% present value is a useful measure in addition to the after-tax value as it assists in both the determination of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. The after-tax present value is dependent on the unique tax situation of each individual company while the pre-tax present value is based on prices and discount factors which are consistent from company to company. We also understand that securities analysts use this pre-tax measure in similar ways.
(3) 2007 actual costs incurred and 2008 forecasted capital costs include exploration and production expenditures, capitalized general and administrative costs, capitalized interest costs and asset retirement costs.

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 5-Year Compound Growth Rate | 10-Year Compound Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 439 | 406 | 527 | 444 | 530 | 484 | 555 | 634 | 677 | 9% | 12% |
| 2,785 | 3,045 | 5,024 | 5,836 | 7,217 | 7,385 | 7,192 | 8,259 | 8,994 | 9% | 20% |
| 55 | 50 | 108 | 192 | 209 | 232 | 246 | 275 | 321 | 11% | 29% |
| 958 | 963 | 1,472 | 1,609 | 1,941 | 1,946 | 2,000 | 2,286 | 2,496 | 9% | 18% |
| 5,316 | 17,075 | 6,687 | 15,307 | 20,944 | 20,950 | 32,350 | 22,146 | 32,852 | 17% | 32% |
| | | | | | | | | | | |
| 25 | 37 | 36 | 42 | 47 | 54 | 46 | 42 | 55 | 6% | 7% |
| 295 | 417 | 489 | 761 | 858 | 883 | 819 | 808 | 863 | 3% | 17% |
| 5 | 7 | 8 | 19 | 22 | 24 | 24 | 23 | 26 | 6% | 25% |
| 79 | 113 | 126 | 188 | 211 | 225 | 206 | 200 | 224 | 4% | 14% |
| | | | | | | | | | | |
| 17.78 | 24.99 | 21.41 | 21.71 | 26.13 | 29.12 | 38.64 | 57.39 | 63.98 | 24% | 14% |
| 2.09 | 3.53 | 3.84 | 2.80 | 4.52 | 5.34 | 7.03 | 6.08 | 5.99 | 16% | 11% |
| 13.28 | 20.87 | 16.99 | 14.05 | 18.63 | 23.06 | 29.05 | 32.10 | 37.76 | 22% | 12% |
| 14.22 | 22.38 | 22.19 | 17.61 | 26.04 | 30.38 | 39.89 | 40.38 | 42.96 | 20% | 11% |
| | | | | | | | | | | |
| 4.15 | 4.81 | 5.29 | 4.71 | 5.79 | 6.38 | 7.65 | 8.81 | 9.68 | 16% | 8% |

(1) The years 1997 through 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. The years 2003 through 2007 exclude results from operations in Africa that were discontinued in 2006 and 2007. Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting.
(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future production and development costs, discounted at 10% in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. Devon believes that the pre-tax 10% present value is a useful measure in addition to the after-tax value as it assists in both the determination of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. The after-tax present value is dependent on the unique tax situation of each individual company while the pre-tax present value is based on prices and discount factors which are consistent from company to company. We also understand that securities analysts use this pre-tax measure in similar ways.

# A reputation for safety



**Elliott Smith**
District Manager, Minerals Management Service,
Lafayette District

"At the MMS, we routinely meet with companies throughout the year to discuss operational issues related to safe and clean operations. The MMS District SAFE Award recognizes exemplary performance. The honor represents a high standard for companies to achieve and sets clear expectations for safety and environmental stewardship. To qualify, operators must perform head and shoulders above other companies in their safety and environmental record. Companies that have received the recognition on repeated occasions, such as Devon, consistently demonstrate a commitment to high standards by operating in ways that are safe, clean and incident free."

This is a look at the workings of the Ocean Endeavor, a latest-generation deepwater drilling rig.

Although we have more than 5,000 employees, we enjoy the same type of family atmosphere that existed when Devon was much smaller. This atmosphere encourages employees and contractors to work together to ensure safety in everything they do.

We use peer reviews, collaboration and positive reinforcement to promote safety from our drilling sites and our gas processing plants to our file rooms.

The Safe Actions for Everyone (SAFE) program promotes mutual cooperation. Employees observe colleagues' safety habits, offer positive feedback and help nurture awareness.

Our SAFE program originated among field employees in 2004. As a result, we have seen even lower incident rates, and we are excited about the program's future. Employees and contractors are already sharing responsibility for each other's safety, and we believe that will continue to foster a safe workforce in the years to come.

# Property Highlights


## PERMIAN

### A / Southeast New Mexico

**Profile**
- 75% average working interest in 548,000 acres.
- Key fields include Ingle Wells, Catclaw Draw, Potato Basin, Red Lake, Gaucho, and Outland.
- Produces oil and gas from multiple formations at 1,500' to 16,500'.
- 44.0 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 22 gas wells.
- Drilled and completed 54 oil wells.
- Recompleted 69 wells.

**2008 Plans**
- Drill 29 gas wells.
- Drill 46 oil wells.
- Recomplete 35 wells.

### B / West Texas

**Profile**
- 40% average working interest in 1.1 million acres.
- Key fields include Wasson, Reeves and Anton-Irish to the north; Ozona, Keystone/Kermit, McKnight and Waddell to the south.
- Produces oil and gas from multiple formations at 2,500' to 18,000'.
- 112.3 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 3 gas wells.
- Drilled and completed 25 oil wells.
- Recompleted 54 wells.
- Reactivated 22 wells.

**2008 Plans**
- Drill 2 gas wells.
- Drill 35 oil wells.
- Recomplete 53 wells.
- Reactivate 22 wells.
- Initiate enhanced oil recovery with $CO_2$ at Reeves Unit.


## MID-CONTINENT

### A / Woodford Shale

**Profile**
- 54,000 net acres in the Arkoma Basin in eastern Oklahoma.
- Operated working interests range from 40% to 100%.
- Unconventional natural gas play.
- Produces gas from the Woodford Shale formation at 6,000' to 8,000'.
- 26.6 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 89 horizontal wells (39 operated).
- Drilling focused on acreage evaluation and holding leases by establishing production.
- Finalized acquisition of 3-D seismic.
- Divested non-core acreage.

**2008 Plans**
- Drill 109 horizontal wells (57 operated).
- Reprocess and merge 3-D seismic data.
- Expand gas gathering system capacity.
- Complete construction of 200 million cubic feet per day gas plant.

### B / Barnett Shale

**Profile**
- 727,000 net acres in the Forth Worth Basin of north Texas.
- > 90% average working interest.
- Includes >3,200 producing wells.
- Produces gas from the Barnett Shale formation at 6,500' to 9,200'.
- Largest producer in the state's largest natural gas field.
- 724.1 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 539 wells.
- Increased 2007 net production 33% over 2006.
- Continued 80 surface acre infill program.
- Began 40 surface acre infill pilot.
- Continued to improve drilling efficiencies with new generation rigs.
- Acquired 3-D seismic.

**2008 Plans**
- Drill 500 – 600 wells.
- Continue to develop viable areas with 40 surface acre infill program.
- Initiate 20 surface acre infill pilot in selected areas.
- Re-fracture selected horizontal wells.
- Evaluate western acreage for future expansion.
- Acquire additional 3-D seismic and acreage.
- Continue to expand gas gathering system and reduce line pressure.
- Complete construction of 100 million cubic feet per day gas plant.


## ROCKY MOUNTAINS

### A / Bear Paw

**Profile**
- 814,000 net acres in north central Montana.
- 90% average working interest in federal units.
- 75% average working interest outside federal units.
- Produces gas from the Eagle formation at 800' to 2,000'.
- 18.6 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 55 wells.
- Recompleted 41 wells.
- Acquired 52 square miles of 3-D seismic.
- Expanded gas gathering system capacity.

**2008 Plans**
- Drill 50 wells.
- Continue workover and recompletion program.
- Add compression and perform other gas gathering system improvements.
- Acquire additional 3-D seismic.

## B / Powder River Coalbed Natural Gas

**Profile**
- 75% average working interest in 346,000 acres in northeastern Wyoming.
- Produces coalbed natural gas from the Fort Union Coal formations at 300' to 2,000'.
- 27.5 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled 193 coalbed natural gas wells.
- Initiated full scale development at West Pine Tree Unit.
- Continued development drilling at Juniper Draw.

**2008 Plans**
- Drill 118 coalbed natural gas wells.
- Continue development and initiate first gas sales at West Pine Tree.
- Complete development drilling at Juniper Draw.

## C / Wind River Basin

**Profile**
- 96% working interest in 24,600 acres in central Wyoming.
- Key fields include Beaver Creek and Riverton Dome.
- Produces oil and gas from multiple formations at 3,000' to 12,000'.
- 24.8 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Initiated construction on Madison $CO_2$ enhanced oil recovery project at Beaver Creek.
- Drilled 6 Madison formation wells.
- Recompleted 7 injection wells.
- Installed $CO_2$ pipeline, flowlines and injection lines.
- Completed final wells for 12-well coalbed natural gas pilot at Riverton Dome.

**2008 Plans**
- Drill final 6 wells for Madison $CO_2$ project.
- Initiate $CO_2$ injection in Madison enhanced oil recovery project at Beaver Creek.
- Drill 5 well coalbed natural gas pilot at Beaver Creek.

## D / Washakie

**Profile**
- 76% average working interest in 210,000 acres in southern Wyoming.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 111.1 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 161 wells.
- Improved drilling efficiencies with new generation rigs.
- Installed 63 plunger lifts.
- Installed compression and performed other gas gathering system improvements.
- Continued implementation of automated production control system.

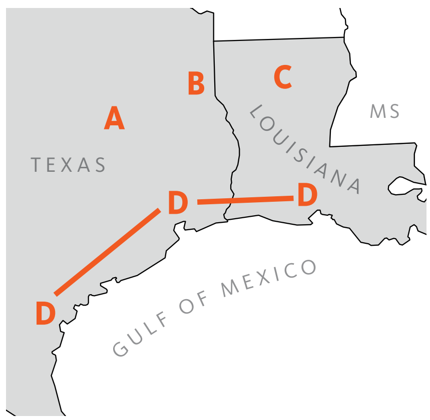
**2008 Plans**
- Drill 112 total wells, including first operated horizontal well.
- Install 100 plunger lifts.
- Add compression and perform other gas gathering system upgrades.
- Continue implementation of automated production control system.

## E / NEBU/32-9 Units

**Profile**
- 25% average working interest in 54,000 acres in the San Juan Basin of northwestern New Mexico.
- Coalbed natural gas development began in the late 1980s and early 1990s.
- Includes 304 coalbed gas wells, 302 conventional wells, gas and water gathering systems and an automated production control system.
- Produces primarily coalbed natural gas from the Fruitland Coal formation at 3,500'.
- 16.5 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 4 coalbed gas wells.
- Drilled and completed 20 conventional gas wells.
- Recompleted 5 conventional wells.
- Completed 271-well workover program.

**2008 Plans**
- Drill 4 coalbed gas wells.
- Drill 17 conventional gas wells.
- Recomplete 8 conventional wells.
- Perform 270-well workover program.




# GULF COAST

## A / Groesbeck Area

**Profile**
- 72% average working interest in 285,000 acres in eastcentral Texas.
- Key fields include Personville, Nan-Su-Gail, Dew, Oaks and Bald Prairie.
- Produces primarily gas from the Travis Peak, Cotton Valley Sand, Bossier and Cotton Valley Lime formations at 6,000' to 13,000'.
- Includes 680 producing wells.
- 48.8 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 17 vertical wells.
- Drilled and completed 4 horizontal wells.
- Recompleted 6 wells.
- Acquired 3-D seismic.

**2008 Plans**
- Drill 6 vertical wells.
- Drill 11 horizontal wells.
- Recomplete 15 wells.
- Acquire 3-D seismic.
- Expand gas gathering system capacity.

## B / Carthage Area

**Profile**
- 85% average working interest in 213,000 acres in east Texas.
- Key fields include Carthage, Bethany, Waskom, Stockman and Appleby.
- Produces primarily gas from the Pettit, Travis Peak and Cotton Valley formations at 5,700' to 9,600'.
- Includes 1,666 producing wells.
- 193.1 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 138 vertical wells, including 31 infill wells.
- Drilled and completed 13 horizontal wells.
- Recompleted 50 wells.
- Acquired additional acreage.

**2008 Plans**
- Drill 99 vertical wells, including 30 infill wells.
- Drill 27 horizontal wells.
- Recomplete 32 wells.
- Acquire additional seismic and acreage.
- Expand gas gathering system capacity.

## C / North Louisiana Area

**Profile**
- 50% average working interest in 667,000 acres in north Louisiana.
- Own mineral interests in 139,000 net acres on trend with lower Cotton Valley/Bossier play.
- Produces from the Hosston, lower Cotton Valley and Bossier formations at 7,000' to 17,000'.
- 16.7 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 5 infill wells at Ruston.
- Initiated 3 field studies to evaluate future potential.

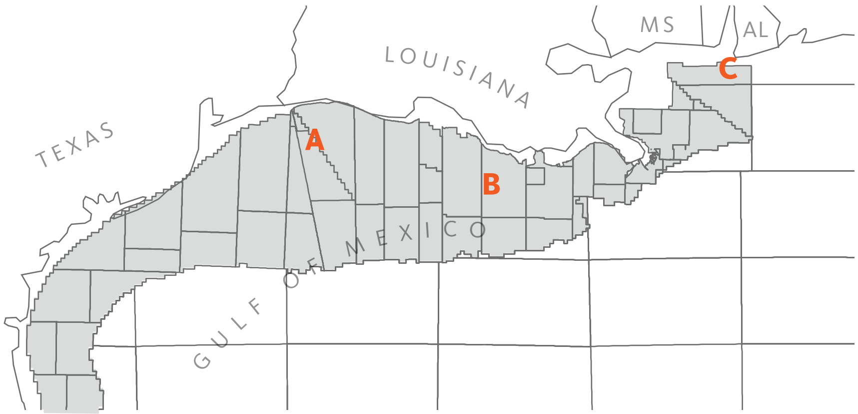
**2008 Plans**
- Drill 17 wells.
- Complete 3 field studies and identify additional drilling locations.

## D / South Texas/South Louisiana

**Profile**
- 66% average working interest in 575,000 acres.
- Key areas include Matagorda, Zapata, Agua Dulce/ N. Brayton, Duval/Hagist, Houston, Central Texas, Coastal Frio and the Patterson Field in Louisiana.
- Produces oil and gas from the Frio/Vicksburg, Yegua, Wilcox and Woodbine trends at 1,500' to 15,000'.
- 34.4 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled and completed 41 wells.
- Drilled 1 successful exploratory well in Matagorda area.
- Recompleted 65 wells.
- Initiated 3-D seismic acquisition in Brazoria area.

**2008 Plans**
- Drill 48 wells.
- Drill 2 exploratory wells in south Louisiana.
- Recomplete 40 wells.
- Continue 3-D seismic acquisition in Brazoria area.




## GULF – SHELF

### Shelf Producing Properties

**Profile**
- Includes 32 blocks located offshore Texas, Louisiana, and Alabama.
- Working interests range from 13% to 100%.
- Produces oil and gas from various formations in water depths up to 600'.
- Mature producing area with opportunities for exploration.
- 45.3 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Drilled 7 wells in Eugene Island area.
- Drilled 1 well in Brazos area.
- Drilled 1 well in Mobile area.
- Recompleted 10 wells.

**2008 Plans**
- Drill 2 wells in Main Pass area.
- Drill 3 wells in Eugene Island area.
- Recomplete 25 wells.

### Shelf Exploration Prospects

**Profile**

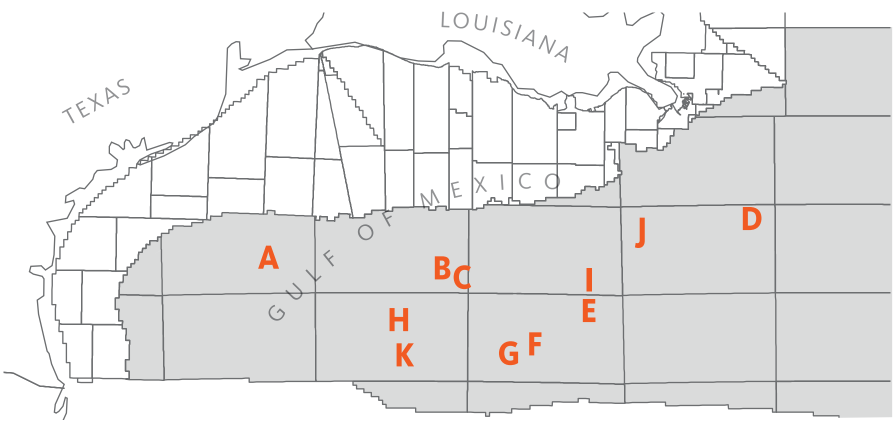
**A / Sunfish**
- West Cameron 291.
- Located offshore Louisiana in 50' of water.
- Target formation: Lower Miocene sands at 15,900'.
- Expected working interest: 75%.

**B / Dampier**
- Ship Shoal 104.
- Located offshore Louisiana in 30' of water.
- Target formation: Upper Miocene sands at 16,600'.
- Working interest: 50%.

**C / Flying Squirrel**
- Mobile 830.
- Located offshore Alabama in 50' of water.
- Target formation: Norphlet sands at 22,000'.
- Expected working interest: 75%.

**2007 Activity**
- Finalized geophysical analyses and drilling contracts.
- Secured farmin agreement at Dampier.

**2008 Plans**
- Secure farmout agreements with industry partners at Sunfish and Flying Squirrel.
- Drill exploratory test wells.




## GULF – DEEPWATER

### A / Nansen

**Profile**
- Includes 3 blocks in central East Breaks area.
- 50% working interest.
- Located offshore Texas in 3,500' of water.
- Produces oil and gas from sands at 9,000' to 14,000'.
- Utilizes the world's first open-hull truss spar.
- 32.5 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Recompleted 2 wells.

**2008 Plans**
- Drill 2 development wells.
- Recomplete 2 wells.

### B / Magnolia

**Profile**
- 25% working interest in Garden Banks 783 and 784.
- Located offshore Louisiana in 4,700' of water.
- 1999 discovery.
- Produces oil and gas from sands at 12,000' to 17,000'.
- Utilizes the world's deepest tension-leg platform.
- 12.3 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Recompleted 2 wells.

**2008 Plans**
- Drill 2 sidetrack wells.
- Recomplete 2 wells.
- Evaluate potential for additional drilling.

### C / Red Hawk

**Profile**
- 50% working interest in Garden Banks 876, 877, 920 and 921.
- Located offshore Louisiana in 5,300' of water.
- 2001 discovery.
- Produces gas from sands at 16,000' to 18,500'.
- Utilizes the world's first cell spar.
- 3.7 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Produced and monitored.

**2008 Plans**
- Recomplete 2 wells.
- Evaluate potential for additional drilling.

### D / Merganser (Independence Hub)

**Profile**
- 50% working interest in Atwater Valley 37.
- Located offshore Louisiana in 8,100' of water.
- 2001 discovery.
- Produces gas from sands at 19,000' to 20,000'.
- Cooperative development of 10 nearby industry discoveries utilizing subsea tie-backs to a central production hub.
- 6.8 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**
- Commenced production from 2 wells.

**2008 Plans**
- Produce and monitor.

## Lower Tertiary Discoveries

**Profile**

### E / Cascade

- 50% working interest in Walker Ridge 206.
- Located offshore Louisiana in 8,200' of water.
- Target formation: Lower Tertiary sands at 25,000' to 27,000'.
- Discovery well drilled in 2002 encountered > 450' of net oil pay.

### F / St. Malo

- 22.5% working interest in Walker Ridge 678.
- Located offshore Louisiana in 6,900' of water.
- Target formation: Lower Tertiary sands at 26,000' to 29,000'.
- Discovery well drilled in 2003 encountered > 450' of net oil pay.

### G / Jack

- 25% working interest in Walker Ridge 759.
- Located offshore Louisiana in 7,000' of water.
- Target formation: Lower Tertiary sands.
- Discovery well drilled in 2004 encountered > 350' of net oil pay.

### H / Kaskida

- 20% working interest in Keathley Canyon 292.
- Located offshore Louisiana in 5,900' of water.
- Target formation: Lower Tertiary sands.
- Discovery well drilled in 2006 encountered approximately 800' of net hydrocarbon bearing sands.
- First Lower Tertiary discovery in Keathley Canyon area.

**2007 Activity**

- Sanctioned phase 1 development at Cascade.
- Submitted Cascade operating and development plans to MMS.
- Awarded Cascade development contracts, including FPSO and shuttle tankers.
- Initiated drilling 2nd and 3rd appraisal wells at St. Malo.
- Initiated drilling 2nd appraisal well at Jack.
- Evaluated development options and facilities designs for Jack and St. Malo.
- Planned for next appraisal operation at Kaskida.
- Acquired 25 additional Lower Tertiary blocks through federal lease sales.

**2008 Plans**

- Drill first of 2 producing wells at Cascade.
- Finish drilling 2nd and 3rd appraisal wells at St. Malo.
- Finish drilling 2nd appraisal well at Jack.
- Drill appraisal well at Kaskida.
- Continue evaluating development options and advance engineering work at Jack, St. Malo and Kaskida.
- Finalize gas export pipeline arrangements at Cascade.

## Miocene Discoveries

**Profile**

### I / Mission Deep

- 50% working interest in Green Canyon 955.
- Located offshore Louisiana in 7,300' of water.
- Target formation: Miocene sands.
- Discovery well drilled in 2006 encountered > 250' of net oil pay.

### J /Sturgis

- 25% working interest in Atwater Valley 183.
- Located offshore Louisiana in 3,700' of water.
- Target formation: Miocene sands.
- Discovery well drilled in 2003 encountered > 100' of net oil pay.
- Sturgis North exploratory prospect located on Atwater Valley 182.

**2007 Activity**

- Completed drilling sidetrack appraisal well at Mission Deep.

**2008 Plans**

- Drill Mission Deep appraisal well.
- Evaluate Mission Deep development options.
- Drill exploratory well on Sturgis North prospect.

## Deepwater Exploration Prospects

**Profile**

### K / Bass

- Keathley Canyon 596.
- Located offshore Louisiana in 6,450' of water.
- Target formation: Lower Tertiary sands.

### Additional Lower Tertiary Prospect # 1

- Located in Walker Ridge area.
- Located offshore Louisiana in 7,000' of water.
- Target formation: Lower Tertiary sands.

### Additional Miocene Prospect #1

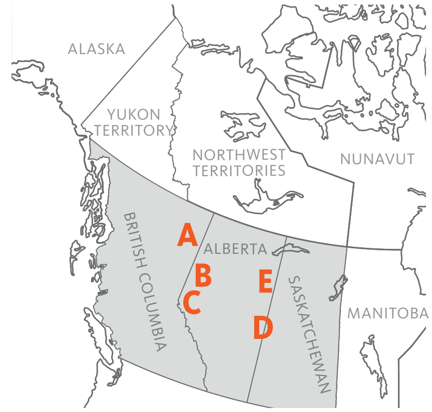
- Located in Mississippi Canyon area.
- Located offshore Louisiana in 3,300' of water.
- Target formation: Miocene sands.

**2007 Activity**

- Initiated drilling 2 exploratory wells.
- Conducted technical evaluations and initiated drilling contracts.
- Commenced long-term contract with delivery of Ocean Endeavor deepwater drilling rig.

**2008 Plans**

- Finish drilling 2 exploratory wells initiated in 2007.
- Finalize technical evaluations and contracts.
- Drill exploratory test wells.
- Commence long-term contract with delivery of West Sirius deepwater drilling rig.




## CANADA

## A / Northeast British Columbia

**Profile**

- 72% average working interest in 1.7 million acres in northwestern Alberta and northeastern British Columbia.
- Key areas include Hamburg/Chinchaga, Ring Border, Peggo, Eagle, Monias, West Jedney and Wargen.
- Primarily winter-only drilling.
- Produces oil and gas from multiple formations including liquid-rich gas from the Halfway and Baldonnel at 2,600' to 5,000'.
- 58.2 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Drilled 64 wells, including:
  23 at Wargen.
  16 at Ring Border.
  11 at Hamburg/Chinchaga.
  7 at West Jedney.

**2008 Plans**

- Drill 37 total wells, including:
  9 at Hamburg/Chinchaga.
  8 at Wargen.
  7 at West Jedney.
  3 at Monias.
  3 at Eagle.

## B / Peace River Arch

**Profile**

- 70% average working interest in 708,000 acres in western Alberta.
- Key areas include Belloy, Cecil, Dunvegan, Knopcik, Valhalla and Tangent.
- Produces liquids-rich gas and light gravity oil from multiple formations at 3,000' to 8,000'.
- 74.2 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Drilled 60 wells, including:
  16 at Dunvegan.
  13 at Cecil.
  6 at Belloy.
  5 at Knopcik.

**2008 Plans**

- Drill 65 total wells, including:
  19 at Dunvegan.
  10 at Cecil.
  5 at Valhalla.
  4 at Knopcik.
  3 at Tangent.

## C / Deep Basin

**Profile**

- 45% average working interest in 1.4 million acres in western Alberta and eastern British Columbia.
- Key areas include Bilbo, Hiding, Blackhawk, Pinto and Wapiti.
- Produces liquids-rich gas from primarily Cretaceous formations at 2,500' to 14,000'.
- 92.4 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Drilled 41 wells, including:
  16 at Wapiti.
  15 at Pinto.
  5 at Blackhawk.
  4 at Bilbo.
  1 at Hiding.

**2008 Plans**

- Drill 49 total wells, including:
  15 at Bilbo.
  14 at Pinto.
  9 at Wapiti.
  5 at Blackhawk.
  5 at Hiding.

## D / Lloydminster

**Profile**

- 97% working interest in 2.1 million acres in eastern Alberta and Saskatchewan.
- Key areas include End Lake, Iron River, Lloydminster and Manatokan.
- Produces primarily conventional, cold flow heavy oil from multiple formations at 1,000' to 2,300'.
- 97.2 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Drilled 429 wells, including:
  281 at Iron River.
  67 at Lloydminster.
  40 at End Lake.
  28 at Manatokan.
- Completed first capacity expansion of Manatokan processing plant.
- Initiated second capacity expansion of Manatokan processing plant.

**2008 Plans**

- Drill 475 total wells, including:
  318 at Iron River.
  53 at Lloydminster.
  46 at Manatokan.
  42 at End Lake.
- Complete second capacity expansion of Manatokan processing plant.

## E / Thermal Heavy Oil

**Profile**

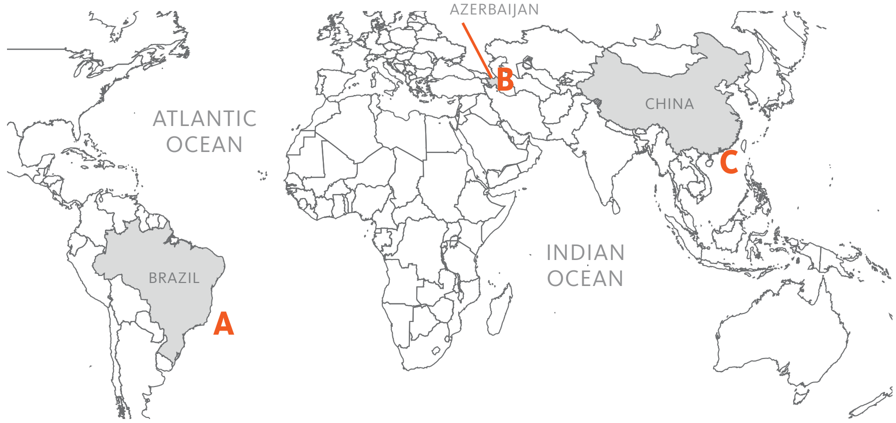
- 97% average working interest in 75,000 acres in eastern Alberta oil sands.
- Key asset is Jackfish (100% interest).
- Steam-Assisted Gravity Drainage (SAGD) is the primary recovery method.
- Jackfish facility capacity of 35,000 barrels of oil per day.
- 233.0 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Completed facility construction and commenced steam injection at Jackfish.
- Sold first barrel of bitumen near year-end at Jackfish.
- Began front-end engineering for Jackfish 2, a look-alike project to Jackfish.
- Completed construction of Access Pipeline.

**2008 Plans**

- Ramp up production at Jackfish.
- Initiate construction at Jackfish 2 pending regulatory approval and internal sanctioning.
- Drill 27 stratigraphic wells to further evaluate the Jackfish area potential.




# INTERNATIONAL

## A / Brazil

**Profile**

- 1.3 million acres in 9 licensed blocks offshore Brazil:
  Block BM-C-8 (Polvo); 60% interest.
  Block BC-2 (Xerelete); 17.65% interest.
  Block BM-BAR-3; 100% interest.
  Block BM-C-30; 25% interest.
  Block BM-C-32; 40% interest.
  Block BM-C-34 (C-M-471); 50% interest.
  Block BM-C-34 (C-M-473); 50% interest.
  Block BM-C-35; 35% interest.
  Block BM-CAL-13; 100% interest.
- Located in the Campos, Barreirinhas and Camamu Basins in water depths ranging from 330' to 9,100'.
- Target oil formations at 7,000' to 16,000'.
- Developing 2004 discovery on block BM-C-8 (Polvo development).
- 8.9 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Completed platform and FPSO installation and commissioning operations at Polvo.
- Drilled and completed 3 development wells at Polvo.
- Commenced first production at Polvo.
- Completed exploratory drilling on block BM-C-8 and obtained government approval for an expanded development area for Polvo.
- Drilled 1 exploratory well on block BC-2 and submitted a declaration of commerciality for Xerelete discovery.
- Conducted seabed logging program on block BM-BAR-3.
- Signed letter of intent to farm out 30% interest in BM-BAR-3 to an industry partner.
- Initiated 3-D seismic reprocessing on blocks BM-C-30, BM-C-32, BM-C-34 and BM-C-35.
- Completed processing of 3-D seismic on block BM-CAL-13.
- Won onshore blocks PN-T-66 and PN-T-86 in the Parnaíba Basin in Bid Round 9.

**2008 Plans**

- Drill and complete 7 development wells at Polvo.
- Reprocess seismic and consider development options on Xerelete discovery.
- Finalize BM-BAR-3 farm-out agreement and attempt to farm out additional interest.
- Reprocess and interpret 3-D seismic on blocks BM-C-30, BM-C-32, BM-C-34 and BM-C-35.
- Drill second exploratory well on BM-C-30.
- Sign concession agreements on blocks PN-T-66 and PN-T-86.

## B / Azerbaijan – ACG

**Profile**

- 5.6% interest in 107,000 acres in the Azeri-Chirag-Gunashli (ACG) oil fields offshore Azerbaijan.
- Initial position obtained in 1999 merger.
- Major oil export pipeline commenced operations in 2006.
- 64.6 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Commenced production from 11 new wells.
- Installed platform, production and drilling facilities in the Deepwater Gunashli area.

**2008 Plans**

- Drill and complete 16 producing wells.
- Commence production from Deepwater Gunashli area.

## C / China

**Profile**

- 7.9 million acres in 5 licensed blocks offshore China:
  Block 15/34 (Panyu); 24.5% interest.
  Block 42/05; 100% interest.
  Block 11/34; 100% interest.
  Block 53/30; 100% interest.
  Block 64/18; 100% interest.
- Located in the South China Sea and Yellow Sea in water depths ranging from 150' to 8,200'.
- Panyu fields produce oil from 1998 and 1999 discoveries.
- 19.7 million barrels of oil-equivalent reserves at 12/31/07.

**2007 Activity**

- Drilled and completed 3 development wells at Panyu, including a successful extended reach well.
- Acquired additional 3-D seismic on block 42/05.
- Acquired blocks 53/30 and 64/18 in South China Sea.

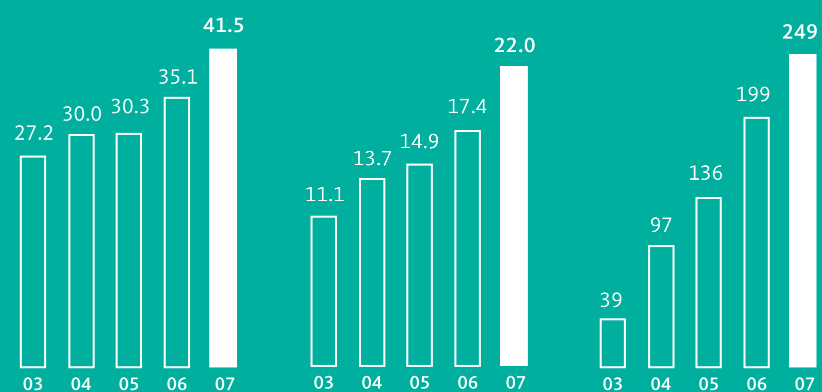
**2008 Plans**

- Drill 6 development wells at Panyu.
- Replace subsea pipelines at both Panyu platforms.
- Drill one exploratory well on block 42/05.
- Drill one exploratory well on block 11/34.
- Acquire 2-D and 3-D seismic on block 53/30.
- Acquired 2-D seismic on block 64/18.

# Index to Financials


| | |
|---|---|
| **Selected 11-Year Financial Data** | **34** |
| **Management's Discussion and Analysis of Financial Condition and Results of Operations** | **36** |
| **Reports of Independent Registered Public Accounting Firm** | **63** |
| **Consolidated Balance Sheets** | **64** |
| **Consolidated Statements of Operations** | **65** |
| **Consolidated Statements of Comprehensive Income** | **66** |
| **Consolidated Statements of Stockholders' Equity** | **67** |
| **Consolidated Statements of Cash Flows** | **68** |
| **Notes to Consolidated Financial Statements** | **69** |
| **Risk Factors to Forward-Looking Estimates** | **109** |


Devon's total assets have grown more than 50% since 2003 to $41.5 billion, while shareholders' equity has nearly doubled to $22 billion. The company paid $249 million in common stock dividends in 2007, more than six times the 2003 dividend amount.




**Total Assets** ($ Billions)

**Stockholders' Equity** ($ Billions)

**Dividends Paid to Common Stock** ($ Millions)

# Selected Eleven-Year Financial Data [1]

| | | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|---|
| **OPERATING RESULTS** (In millions, except per share data) | | | | | |
| Revenues (Net of royalties): | | | | | |
| Oil sales | $ | 497 | 236 | 436 | 906 |
| Gas sales | | 367 | 335 | 616 | 1,474 |
| NGL sales | | 36 | 25 | 68 | 154 |
| Marketing and midstream revenues | | 10 | 8 | 20 | 53 |
| Other income | | 36 | 6 | 23 | 37 |
| Total revenues | | 946 | 610 | 1,163 | 2,624 |
| Production and operating expenses | | 288 | 231 | 328 | 544 |
| Marketing and midstream costs and expenses | | 4 | 3 | 10 | 28 |
| Depreciation, depletion and amortization of property and equipment | | 268 | 212 | 379 | 662 |
| Accretion of asset retirement obligation | | — | — | — | — |
| Amortization of goodwill [2] | | — | — | 16 | 41 |
| General and administrative expenses | | 56 | 48 | 83 | 96 |
| Expenses related to mergers | | — | 13 | 17 | 60 |
| Interest expense | | 51 | 53 | 122 | 155 |
| Change in fair value of financial instruments | | — | — | — | — |
| Reduction of carrying value of oil and gas properties | | 633 | 354 | 476 | — |
| Impairment of Chevron Corporation common stock | | — | — | — | — |
| Income tax expense (benefit) | | (128) | (103) | (75) | 377 |
| Total expenses | | 1,172 | 811 | 1,356 | 1,963 |
| Net earnings (loss) before minority interest, cumulative effect of change in accounting principle and discontinued operations [3] | | (226) | (201) | (193) | 661 |
| Net earnings (loss) | | (218) | (236) | (154) | 730 |
| Preferred stock dividends | | 12 | — | 4 | 10 |
| Net earnings (loss) to common stockholders | $ | (230) | (236) | (158) | 720 |
| Net earnings (loss) per common share: | | | | | |
| Basic | $ | (1.67) | (1.66) | (0.84) | 2.83 |
| Diluted | $ | (1.67) | (1.66) | (0.84) | 2.75 |
| Weighted average shares outstanding: | | | | | |
| Basic | | 137 | 142 | 187 | 255 |
| Diluted | | 151 | 154 | 199 | 263 |
| **BALANCE SHEET DATA** (In millions) | | | | | |
| Total assets | $ | 1,965 | 1,931 | 6,096 | 6,860 |
| Debentures exchangeable into shares of Chevron Corporation common stock [4] | $ | — | — | 760 | 760 |
| Other long-term debt | $ | 576 | 885 | 1,656 | 1,289 |
| Deferred income taxes | $ | 50 | 15 | 313 | 634 |
| Stockholders' equity | $ | 1,006 | 750 | 2,521 | 3,277 |
| Common shares outstanding | | 142 | 142 | 253 | 257 |

(1) The years 1997 to 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. The years 2003 through 2007 exclude results from operations in Africa that were discontinued in 2006 and 2007. All periods prior to the November 15, 2004 two-for-one stock split have been adjusted to reflect the split.
(2) Amortization of goodwill in 1999, 2000 and 2001 resulted from Devon's 1999 acquisition of PennzEnergy. As of January 1, 2002, goodwill is no longer amortized.
(3) Before minority interest in Monterrey Resources, Inc. of ($5) million in 1997, and the cumulative effect of change in accounting principle of $49 and $16 million in 2001 and 2003, respectively, and the results of discontinued operations of $13, ($35) $39, $69, $31, $45, $14, $97, $33, $212 and $460 million in 1997 through 2007, respectively.
(4) Devon owns 14.2 million shares of Chevron Corporation common stock. The majority of these shares are on deposit with an exchange agent for possible exchange for $652 million principal amount of exchangeable debentures. The Chevron shares and debentures were acquired through the 1999 acquisition of PennzEnergy.
N/M Not a meaningful number.

| 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 5-YEAR COMPOUND GROWTH RATE | 10-YEAR COMPOUND GROWTH RATE |
|---|---|---|---|---|---|---|---|---|
| 784 | 909 | 1,218 | 1,589 | 1,794 | 2,434 | 3,493 | 31% | 22% |
| 1,878 | 2,133 | 3,879 | 4,711 | 5,761 | 4,912 | 5,163 | 19% | 30% |
| 131 | 275 | 404 | 548 | 680 | 749 | 970 | 29% | 39% |
| 71 | 999 | 1,461 | 1,701 | 1,792 | 1,672 | 1,736 | 12% | N/M |
| 58 | 35 | 104 | 126 | 198 | 115 | 98 | 23% | 11% |
| 2,922 | 4,351 | 7,066 | 8,675 | 10,225 | 9,882 | 11,460 | 21% | 28% |
| 666 | 886 | 1,224 | 1,439 | 1,579 | 1,766 | 2,168 | 20% | 22% |
| 47 | 808 | 1,174 | 1,339 | 1,342 | 1,236 | 1,227 | 9% | N/M |
| 831 | 1,211 | 1,609 | 1,982 | 1,924 | 2,231 | 2,858 | 19% | 27% |
| — | — | 35 | 42 | 42 | 47 | 74 | N/M | N/M |
| 34 | — | — | — | — | — | — | N/M | N/M |
| 114 | 219 | 306 | 277 | 291 | 397 | 513 | 19% | 25% |
| 1 | — | 7 | — | — | — | — | N/M | N/M |
| 220 | 533 | 502 | 475 | 533 | 421 | 430 | -4% | 24% |
| 2 | (28) | (1) | 62 | 94 | 178 | (34) | 4% | N/M |
| 979 | 651 | 40 | — | 42 | 36 | — | N/M | N/M |
| — | 205 | — | — | — | — | — | N/M | N/M |
| 5 | (193) | 453 | 970 | 1,481 | 936 | 1,078 | N/M | N/M |
| 2,899 | 4,292 | 5,349 | 6,586 | 7,328 | 7,248 | 8,314 | 14% | 22% |
| 23 | 59 | 1,717 | 2,089 | 2,897 | 2,634 | 3,146 | 122% | N/M |
| 103 | 104 | 1,747 | 2,186 | 2,930 | 2,846 | 3,606 | 103% | N/M |
| 10 | 10 | 10 | 10 | 10 | 10 | 10 | 0% | -2% |
| 93 | 94 | 1,737 | 2,176 | 2,920 | 2,836 | 3,596 | 107% | N/M |
| 0.37 | 0.31 | 4.16 | 4.51 | 6.38 | 6.42 | 8.08 | 93% | N/M |
| 0.36 | 0.30 | 4.04 | 4.38 | 6.26 | 6.34 | 8.00 | 93% | N/M |
| 255 | 309 | 417 | 482 | 458 | 442 | 445 | 8% | 12% |
| 259 | 313 | 433 | 499 | 470 | 448 | 450 | 8% | 12% |
| 13,184 | 16,225 | 27,162 | 30,025 | 30,273 | 35,063 | 41,456 | 21% | 36% |
| 649 | 662 | 677 | 692 | 709 | 727 | 641 | -1% | N/M |
| 5,940 | 6,900 | 7,903 | 6,339 | 5,248 | 4,841 | 6,283 | -2% | 27% |
| 2,149 | 2,627 | 3,799 | 4,596 | 4,977 | 5,290 | 6,042 | 18% | 62% |
| 3,259 | 4,653 | 11,056 | 13,674 | 14,862 | 17,442 | 22,006 | 36% | 36% |
| 252 | 314 | 472 | 484 | 443 | 444 | 444 | 7% | 12% |

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

## Overview of 2007 Results and Outlook

2007 was Devon's best year in its 20-year history as a public company. We achieved key operational successes and continued to execute our strategy to increase value per share. As a result, we delivered record amounts for earnings, earnings per share and operating cash flow, and also grew proved reserves to a new all-time high. Key measures of our financial and operating performance for 2007, as well as certain operational developments, are summarized below:

- Production grew 12% over 2006, to 224 million Boe
- Net earnings rose 27%, reaching an all-time high of $3.6 billion
- Diluted net earnings per share increased 26% to a record $8.00 per diluted share
- Net cash provided by operating activities reached $6.7 billion, representing an 11% increase over 2006
- Estimated proved reserves reached a record amount of 2.5 billion Boe
- Discoveries, extensions and performance revisions added 390 million Boe of proved reserves, or 17% of the beginning-of-year proved reserves
- Capital expenditures for oil and gas exploration and development activities were $5.8 billion
- The combined realized price for oil, gas and NGLs per Boe increased 6% to $42.96
- Marketing and midstream operating profit climbed to a record $509 million

Operating costs increased due to the 12% growth in production, inflationary pressure driven by increased competition for field services and the weakened U.S. dollar compared to the Canadian dollar. Per unit lease operating expenses increased 15% to $8.16 per Boe.

During 2007, we used $6.2 billion of cash flow from continuing operations along with other capital resources to fund $6.2 billion of capital expenditures, reduce debt obligations by $567 million, repurchase $326 million of our common stock and pay $259 million in dividends to our stockholders. We also ended the year with $1.7 billion of cash and short-term investments.

From an operational perspective, we completed another successful year with the drill-bit. We drilled 2,440 wells with an overall 98% rate of success. This success rate enabled us to increase our proved reserves by 9% to a record of 2.5 billion Boe at the end of 2007. We added 390 MMBoe of proved reserves during the year with extensions, discoveries and performance revisions, which was well in excess of the 224 MMBoe we produced during the year. Consistent with our two-pronged operating strategy, 92% of the wells we drilled were North American development wells.

Besides completing another successful year of drilling, we also had several other key operational achievements during 2007. In the Gulf of Mexico, we continued to build upon prior years' successful drilling results with our deepwater exploration and development program. We commenced production from the Merganser field, and we also began drilling our first operated exploratory well in the Lower Tertiary trend of the Gulf of Mexico. We also made progress toward commercial development of our four previous discoveries in the Lower Tertiary trend.

At our 100%-owned Jackfish thermal heavy oil project in the Alberta oil sands, we completed construction and commenced steam injection. Oil production from Jackfish is expected to ramp up throughout 2008 toward a peak production target of 35,000 Bbls per day. Additionally, we began front-end engineering and design work on an extension of our Jackfish project. Like the first phase, this second phase of Jackfish is also expected to eventually produce 35,000 Bbls per day.

Finally, we completed construction and fabrication of the Polvo oil development project offshore Brazil and began producing oil from the first of ten planned wells. Polvo, located in the Campos basin, was discovered in 2004 and is our first operated development project in Brazil.

In November 2006 and January 2007, we announced plans to divest our operations in Egypt and West Africa, including Equatorial Guinea, Cote d'Ivoire, Gabon and other countries in the region. Divesting these properties will allow us to redeploy our financial and intellectual capital to the significant growth opportunities we have developed onshore in North America and in the deepwater Gulf of Mexico. Additionally, we will sharpen our focus in North America and concentrate our international operations in Brazil and China, where we have established competitive advantages.

In October 2007, we completed the sale of our operations in Egypt and received proceeds of $341 million. As a result of this sale, we recognized a $90 million after-tax gain in the fourth quarter of 2007. In November 2007, we announced an agreement to sell our operations in Gabon for $205.5 million. We are finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the remaining properties in the West African divestiture package. We are optimistic we can complete these sales during the first half of 2008 and then primarily use the proceeds to repay our outstanding commercial paper and revolving credit facility borrowings and resume common stock repurchases.

Looking to 2008, we announced in February 2008 that we have hedged a meaningful portion of our expected 2008 production with financial price collar and swap arrangements. As of February 15, 2008, approximately 62% of our expected 2008 gas production is subject to either price collars with a floor price of $7.50 per MMBtu and an average ceiling price of $9.43 per MMBtu, or price swaps with an average price of $8.24 per MMBtu. Another 2% of our expected 2008 gas production is subject to fixed-price physical contracts. Also, as of February 15, 2008, approximately 12% of our expected 2008 oil production is subject to price collars with a floor price of $70.00 per barrel and an average ceiling price of $140.23 per barrel.

Additionally, our operational accomplishments in recent years have laid the foundation for continued growth in future years, at competitive unit costs, which we expect will continue to create additional value for our investors. In 2008, we expect to deliver proved reserve additions of 390 to 410 million Boe with related capital expenditures in the range of $6.1 to $6.4 billion. We expect production to increase approximately 9% from 2007 to 2008, which reflects our significant reserve additions in recent years as well as those expected in 2008. Additionally, our exploration program exposes us to high-impact projects in North America and international locations that can fuel more growth in the years to come.

## Results of Operations

### *Revenues*

Changes in oil, gas and NGL production, prices and revenues from 2005 to 2007 are shown in the following tables. The amounts for all periods presented exclude results from our Egyptian and West African operations which are presented as discontinued operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

| | Total Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2007 vs 2006 (2) | 2006 | 2006 vs 2005 (2) | 2005 |
| **Production** | | | | | |
| Oil (MMBbls) | 55 | +29% | 42 | -9% | 46 |
| Gas (Bcf) | 863 | +7% | 808 | -1% | 819 |
| NGLs (MMBbls) | 26 | +10% | 23 | — | 24 |
| Total (MMBoe)(1) | 224 | +12% | 200 | -3% | 206 |
| **Average Prices** | | | | | |
| Oil (per Bbl) | $ 63.98 | +11% | 57.39 | +49% | 38.64 |
| Gas (per Mcf) | $ 5.99 | -1% | 6.08 | -14% | 7.03 |
| NGLs (per Bbl) | $ 37.76 | +18% | 32.10 | +11% | 29.05 |
| Combined (per Boe)(1) | $ 42.96 | +6% | 40.38 | +1% | 39.89 |
| **Revenues ($ in millions)** | | | | | |
| Oil | $ 3,493 | +44% | 2,434 | +36% | 1,794 |
| Gas | 5,163 | +5% | 4,912 | -15% | 5,761 |
| NGLs | 970 | +30% | 749 | +10% | 680 |
| Total | $ 9,626 | +19% | 8,095 | -2% | 8,235 |

| | Domestic Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2007 vs 2006 (2) | 2006 | 2006 vs 2005 (2) | 2005 |
| **Production** | | | | | |
| Oil (MMBbls) | 19 | -3% | 19 | -23% | 25 |
| Gas (Bcf) | 635 | +12% | 566 | +2% | 555 |
| NGLs (MMBbls) | 22 | +15% | 19 | +3% | 18 |
| Total (MMBoe)(1) | 146 | +10% | 132 | -3% | 136 |
| **Average Prices** | | | | | |
| Oil (per Bbl) | $ 69.23 | +11% | 62.23 | +49% | 41.64 |
| Gas (per Mcf) | $ 5.89 | -3% | 6.09 | -14% | 7.08 |
| NGLs (per Bbl) | $ 36.11 | +23% | 29.42 | +10% | 26.68 |
| Combined (per Boe)(1) | $ 39.87 | +1% | 39.31 | -2% | 40.21 |
| **Revenues ($ in millions)** | | | | | |
| Oil | $ 1,313 | +8% | 1,218 | +15% | 1,062 |
| Gas | 3,742 | +9% | 3,445 | -12% | 3,929 |
| NGLs | 773 | +41% | 548 | +13% | 484 |
| Total | $ 5,828 | +12% | 5,211 | -5% | 5,475 |

| | Canada | | | | |
|---|---|---|---|---|---|
| | Year Ended December 31, | | | | |
| | 2007 | 2007 vs 2006 (2) | 2006 | 2006 vs 2005 (2) | 2005 |
| **Production** | | | | | |
| Oil (MMBbls) | 16 | +26% | 13 | -2% | 13 |
| Gas (Bcf) | 227 | -6% | 241 | -8% | 261 |
| NGLs (MMBbls) | 4 | -9% | 4 | -11% | 6 |
| Total (MMBoe)(1) | 58 | +1% | 58 | -7% | 62 |
| **Average Prices** | | | | | |
| Oil (per Bbl) | $ 49.80 | +6% | 46.94 | +75% | 26.88 |
| Gas (per Mcf) | $ 6.24 | +3% | 6.05 | -13% | 6.95 |
| NGLs (per Bbl) | $ 46.07 | +8% | 42.67 | +15% | 37.19 |
| Combined (per Boe)(1) | $ 41.51 | +6% | 39.21 | +3% | 38.17 |
| **Revenues ($ in millions)** | | | | | |
| Oil | $ 804 | +33% | 603 | +71% | 353 |
| Gas | 1,410 | -3% | 1,456 | -20% | 1,814 |
| NGLs | 197 | -2% | 201 | +2% | 196 |
| Total | $ 2,411 | +7% | 2,260 | -4% | 2,363 |

| | International | | | | |
|---|---|---|---|---|---|
| | Year Ended December 31, | | | | |
| | 2007 | 2007 vs 2006 (2) | 2006 | 2006 vs 2005 (2) | 2005 |
| **Production** | | | | | |
| Oil (MMBbls) | 20 | +95% | 10 | +28% | 8 |
| Gas (Bcf) | 1 | -6% | 1 | -42% | 3 |
| NGLs (MMBbls) | — | N/M | — | N/M | — |
| Total (MMBoe)(1) | 20 | +92% | 10 | +23% | 8 |
| **Average Prices** | | | | | |
| Oil (per Bbl) | $ 70.60 | +15% | 61.35 | +26% | 48.59 |
| Gas (per Mcf) | $ 6.22 | +3% | 6.05 | +12% | 5.42 |
| NGLs (per Bbl) | $ — | N/M | — | N/M | — |
| Combined (per Boe)(1) | $ 70.11 | +16% | 60.60 | +27% | 47.57 |
| **Revenues ($ in millions)** | | | | | |
| Oil | $ 1,376 | +125% | 613 | +61% | 379 |
| Gas | 11 | -3% | 11 | -35% | 18 |
| NGLs | — | N/M | — | N/M | — |
| Total | $ 1,387 | +122% | 624 | +57% | 397 |

(1) Gas volumes are converted to Boe or MMBoe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of natural gas and oil, which rate is not necessarily indicative of the relationship of gas and oil prices. NGL volumes are converted to Boe on a one-to-one basis with oil.
(2) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.
N/M Not meaningful.

The average prices shown in the preceding tables include the effect of our oil and gas price hedging activities. Following is a comparison of our average prices with and without the effect of hedges for each of the last three years.

| | Year Ended December 31, 2007 | | | |
|---|---|---|---|---|
| | Oil (Per Bbl) | Gas (Per Mcf) | NGLs (Per Bbl) | Total (Per Boe) |
| Realized price without hedges | $ 63.98 | 5.97 | 37.76 | 42.90 |
| Cash settlements | — | 0.04 | — | 0.18 |
| Realized cash price | 63.98 | 6.01 | 37.76 | 43.08 |
| Net unrealized losses | — | (0.02) | — | (0.12) |
| Realized price with hedges | $ 63.98 | 5.99 | 37.76 | 42.96 |

| | Year Ended December 31, 2006 | | | |
|---|---|---|---|---|
| | Oil (Per Bbl) | Gas (Per Mcf) | NGLs (Per Bbl) | Total (Per Boe) |
| Realized price without hedges | $ 57.39 | 6.03 | 32.10 | 40.19 |
| Cash settlements | — | — | — | — |
| Realized cash price | 57.39 | 6.03 | 32.10 | 40.19 |
| Net unrealized gains | — | 0.05 | — | 0.19 |
| Realized price with hedges | $ 57.39 | 6.08 | 32.10 | 40.38 |

| | | Year Ended December 31, 2005 | | | |
|---|---|---|---|---|---|
| | | Oil (Per Bbl) | Gas (Per Mcf) | NGLs (Per Bbl) | Total (Per Boe) |
| Realized price without hedges | $ | 48.01 | 7.08 | 29.05 | 42.18 |
| Cash settlements | | (9.37) | (0.05) | — | (2.29) |
| Realized price with hedges | $ | 38.64 | 7.03 | 29.05 | 39.89 |

The following table details the effects of changes in volumes and prices on our oil, gas and NGL revenues between 2005 and 2007.

| | | Oil | Gas | NGLs | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| 2005 revenues | $ | 1,794 | 5,761 | 680 | 8,235 |
| Changes due to volumes | | (155) | (77) | (2) | (234) |
| Changes due to realized cash prices | | 795 | (809) | 71 | 57 |
| Changes due to net unrealized hedge gains | | — | 37 | — | 37 |
| 2006 revenues | | 2,434 | 4,912 | 749 | 8,095 |
| Changes due to volumes | | 700 | 329 | 76 | 1,105 |
| Changes due to realized cash prices | | 359 | (53) | 145 | 451 |
| Changes due to net unrealized hedge losses | | — | (25) | — | (25) |
| 2007 revenues | $ | 3,493 | 5,163 | 970 | 9,626 |

*Oil Revenues*

*2007 vs. 2006* Oil revenues increased $700 million due to a 13 million barrel increase in production. The increase in our 2007 oil production was primarily due to our properties in Azerbaijan where we achieved payout of certain carried interests in the last half of 2006. This led to a nine million barrel increase in 2007 as compared to 2006. Production also increased 3.5 million barrels due to increased development activity in our Lloydminster area in Canada. Also, oil sales from our Polvo field in Brazil began during the fourth quarter of 2007, which resulted in 0.5 million barrels of increased production.

Oil revenues increased $359 million as a result of an 11% increase in our realized price. The average NYMEX West Texas Intermediate index price increased 9% during the same time period, accounting for the majority of the increase.

*2006 vs. 2005* Oil revenues decreased $155 million due to a four million barrel decrease in production. Production lost from properties divested in 2005 caused a decrease of four million barrels, and production declines related to our U.S. and Canadian properties caused a decrease of three million barrels. These decreases were partially offset by a three million barrel increase from reaching payout of certain carried interests in Azerbaijan.

Oil revenues increased $795 million as a result of a 49% increase in our realized price. The expiration of oil hedges at the end of 2005 and a 17% increase in the average NYMEX West Texas Intermediate index price caused the increase in our realized oil price.

*Gas Revenues*

*2007 vs. 2006* A 55 Bcf increase in production caused gas revenues to increase by $329 million. Our drilling and development program in the Barnett Shale field in north Texas contributed 53 Bcf to the gas production increase. The June 2006 Chief Holdings LLC ("Chief") acquisition also contributed 12 Bcf of increased production. During 2007, we also began first production from the Merganser field in the deepwater Gulf of Mexico, which resulted in seven Bcf of increased production. These increases and the effects of new drilling and development in our other North American properties were partially offset by natural production declines primarily in Canada.

A 1% decline in our average realized price caused gas revenues to decrease $78 million in 2007.

*2006 vs. 2005* An 11 Bcf decrease in production caused gas revenues to decrease by $77 million. Production lost from the 2005 property divestitures caused a decrease of 35 Bcf. As a result of Hurricanes Katrina, Rita, Dennis and Ivan which occurred in 2005, gas volumes suspended in 2006 were three Bcf more than those suspended in 2005. These decreases were partially offset by the June 2006 Chief acquisition, which contributed 10 Bcf of production during the last half of 2006, and additional production from new drilling and development in our U.S. onshore and offshore properties.

A 14% decline in average prices caused gas revenues to decrease $772 million in 2006. The 2005 average gas price was impacted by the supply disruptions caused by that year's hurricanes.

*Marketing and Midstream Revenues and Operating Costs and Expenses*

The details of the changes in marketing and midstream revenues, operating costs and expenses and the resulting operating profit between 2005 and 2007 are shown in the table below.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2007 vs 2006 (1) | 2006 | 2006 vs 2005 (1) | 2005 |
| Marketing and midstream ($ in millions): | | | | | |
| Revenues | $ 1,736 | +4% | 1,672 | -7% | 1,792 |
| Operating costs and expenses | 1,227 | -1% | 1,236 | -8% | 1,342 |
| Operating profit | $ 509 | +17% | 436 | -3% | 450 |

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

*2007 vs. 2006* Marketing and midstream revenues increased $64 million, while operating costs and expenses decreased $9 million, causing operating profit to increase $73 million. Revenues increased primarily due to higher prices realized on NGL sales.

*2006 vs. 2005* Marketing and midstream revenues decreased $120 million, and operating costs and expenses also decreased $106 million, causing operating profit to decrease $14 million. Both revenues and expenses in 2006 decreased primarily due to lower natural gas prices, partially offset by the effect of higher gas pipeline throughput.

***Oil, Gas and NGL Production and Operating Expenses***

The details of the changes in oil, gas and NGL production and operating expenses between 2005 and 2007 are shown in the table below.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2007 vs 2006 (1) | 2006 | 2006 vs 2005 (1) | 2005 |
| Production and operating expenses ($ in millions): | | | | | |
| Lease operating expenses | $ 1,828 | +28% | 1,425 | +15% | 1,244 |
| Production taxes | 340 | — | 341 | + 2% | 335 |
| Total production and operating expenses | $ 2,168 | +23% | 1,766 | +12% | 1,579 |
| Production and operating expenses per Boe: | | | | | |
| Lease operating expenses | $ 8.16 | +15% | 7.11 | +18% | 6.03 |
| Production taxes | 1.52 | -11% | 1.70 | + 5% | 1.62 |
| Total production and operating expenses per Boe | $ 9.68 | +10% | 8.81 | +15% | 7.65 |

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

*Lease Operating Expenses ("LOE")*

*2007 vs. 2006* LOE increased $403 million in 2007. The largest contributor to this increase was our 12% growth in production, which caused an increase of $168 million. Another key contributor to the LOE increase was the continued effects of inflationary pressure driven by increased competition for field services. Increased demand for these services continue to drive costs higher for materials, equipment and personnel used in both recurring activities as well as well-workover projects. Furthermore, changes in the exchange rate between the U.S. and Canadian dollar also caused LOE to increase $40 million.

*2006 vs. 2005* LOE increased $181 million in 2006 largely due to higher commodity prices. Commodity price increases in 2005 and the first half of 2006 contributed to industry-wide inflationary pressures on materials and personnel costs. Additionally, the availability of higher commodity prices contributed to our decision to perform more well workovers and maintenance projects to maintain or improve production volumes. Commodity price increases also caused operating costs such as ad valorem taxes, power and fuel costs to rise.

A higher Canadian-to-U.S. dollar exchange rate in 2006 caused LOE to increase $34 million. LOE also increased $33 million due to the June 2006 Chief acquisition and the payouts of our carried interests in Azerbaijan in the last half of 2006. The increases in our LOE were partially offset by a decrease of $82 million related to properties that were sold in 2005.

The factors described above were also the primary factors causing LOE per Boe to increase during 2006. Although we divested properties in 2005 that had higher per-unit operating costs, the cost escalation largely related to higher commodity prices and the weaker U.S. dollar had a greater effect on our per unit costs than the property divestitures.

*Production Taxes*

The following table details the changes in production taxes between 2005 and 2007. The majority of our production taxes are assessed on our onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the changes due to revenues in the table primarily relate to changes in oil, gas and NGL revenues from our U.S. onshore properties.

| | | (In millions) |
|---|---|---|
| 2005 production taxes | $ | 335 |
| Change due to revenues | | (25) |
| Change due to rate | | 31 |
| 2006 production taxes | | 341 |
| Change due to revenues | | 65 |
| Change due to rate | | (66) |
| 2007 production taxes | $ | 340 |

*2007 vs. 2006* Production taxes decreased $66 million due to a decrease in the effective production tax rate in 2007. Our lower production tax rates in 2007 were primarily due to an increase in tax credits received on certain horizontal wells in the state of Texas and the increase in Azerbaijan revenues subsequent to the payouts of our carried interests in the last half of 2006. Our Azerbaijan revenues are not subject to production taxes. Therefore, the increased revenues generated in Azerbaijan in 2007 caused our overall rate of production taxes to decrease.

*2006 vs. 2005* Production taxes increased $31 million due to an increase in the effective production tax rate in 2006. A new Chinese "Special Petroleum Gain" tax was the primary contributor to the higher rate.

***Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A")***

DD&A of oil and gas properties is calculated by multiplying the percentage of total proved reserve volumes produced during the year, by the "depletable base." The depletable base represents our net capitalized investment plus future development costs related to proved undeveloped reserves. Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

The changes in our production volumes, DD&A rate per unit and DD&A of oil and gas properties between 2005 and 2007 are shown in the table below.

| | | Year Ended December 31, | | | | |
|---|---|---|---|---|---|---|
| | | 2007 | 2007 vs 2006 (1) | 2006 | 2006 vs 2005 (1) | 2005 |
| Total production volumes (MMBoe) | | 224 | +12% | 200 | -3% | 206 |
| DD&A rate ($ per Boe) | $ | 11.85 | +15% | 10.27 | +20% | 8.56 |
| DD&A expense ($ in millions) | $ | 2,655 | +29% | 2,058 | +16% | 1,767 |

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

The following table details the increases and decreases in DD&A of oil and gas properties between 2005 and 2007 due to the changes in production volumes and DD&A rate presented in the table above.

| | | (In millions) |
|---|---|---|
| 2005 DD&A | $ | 1,767 |
| Change due to volumes | | (51) |
| Change due to rate | | 342 |
| 2006 DD&A | | 2,058 |
| Change due to volumes | | 242 |
| Change due to rate | | 355 |
| 2007 DD&A | $ | 2,655 |

*2007 vs. 2006* The 12% production increase caused oil and gas property related DD&A to increase $242 million. In addition, oil and gas property related DD&A increased $355 million due to a 15% increase in the DD&A rate. The largest contributor to the rate increase was inflationary pressure on both the costs incurred during 2007 as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. Other factors contributing to the rate increase include the transfer of previously unproved costs to the depletable base as a result of 2007 drilling activities and a higher Canadian-to-U.S. dollar exchange rate in 2007. The effect of these increases was partially offset by a decrease resulting from higher reserve estimates due to the effects of higher 2007 year-end commodity prices.

*2006 vs. 2005* The 3% production decrease caused oil and gas property related DD&A to decrease $51 million. However, oil and gas property related DD&A increased $342 million due to a 20% increase in the DD&A rate. The largest contributor to the rate increase was inflationary pressure on both the costs incurred during 2006 as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. Other factors contributing to the rate increase included the June 2006 Chief acquisition and the transfer of previously unproved costs to the depletable base as a result of 2006 drilling activities. A reduction in reserve estimates due to the effects of lower 2006 year-end commodity prices also contributed to the rate increase.

### *General and Administrative Expenses ("G&A")*

Our net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full cost method of accounting related to exploration and development activities. The other is the amount of G&A reimbursed by working interest owners of properties for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration and production activities, as well as marketing and midstream activities. See the following table for a summary of G&A expenses by component.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2007 vs 2006 (1) | 2006 | 2006 vs 2005 (1) | 2005 |
| | | | (In millions) | | |
| Gross G&A | $ 947 | +26% | 749 | +34% | 560 |
| Capitalized G&A | (312) | +28% | (243) | +54% | (158) |
| Reimbursed G&A | (122) | +12% | (109) | -2% | (111) |
| Net G&A | $ 513 | +29% | 397 | +36% | 291 |

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

*2007 vs. 2006* Gross G&A increased $198 million. The largest contributors to this increase were higher employee compensation and benefits costs. These cost increases, which were related to our continued growth and industry inflation, caused gross G&A to increase $134 million. Of this increase, $55 million related to higher stock compensation. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused a $13 million increase in costs.

*2006 vs. 2005* Gross G&A increased $189 million. Higher employee compensation and benefits costs caused gross G&A to increase $148 million. Of this increase, $34 million represented stock option expense recognized pursuant to our adoption in 2006 of Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment*. An additional $28 million of the increase related to higher restricted stock compensation. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused an $11 million increase in costs.

The factors discussed above were also the primary factors that caused the $69 million and $85 million increases in capitalized G&A in 2007 and 2006, respectively.

### *Interest Expense*

The following schedule includes the components of interest expense between 2005 and 2007.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (In millions) | |
| Interest based on debt outstanding | $ 508 | 486 | 507 |
| Capitalized interest | (102) | (79) | (70) |
| Other interest | 24 | 14 | 96 |
| Total interest expense | $ 430 | 421 | 533 |

Interest based on debt outstanding increased $22 million from 2006 to 2007. This increase was largely due to higher average outstanding amounts for commercial paper and credit facility borrowings in 2007 than in 2006, partially offset by the effects of repaying various maturing notes in 2007 and 2006. Interest based on debt outstanding decreased $21 million from 2005 to 2006 primarily due to the repayment of various maturing notes in 2005 and 2006, partially offset by an increase in commercial paper borrowings during 2006 to fund the June 2006 Chief acquisition.

Capitalized interest increased from 2005 to 2007 primarily due to higher cumulative costs related to the development of the second phase of our Jackfish heavy oil development project in Canada and the construction of the related Access Pipeline. Higher development costs in the Gulf of Mexico and Brazil also contributed to the increase.

During 2005, we redeemed our $400 million 6.75% notes due March 15, 2011 and our zero coupon convertible senior debentures prior to their scheduled maturity dates. The other interest category in the table above includes $81 million in 2005 related to these early retirements.

### *Change in Fair Value of Financial Instruments*

The details of the changes in fair value of financial instruments between 2005 and 2007 are shown in the table below.

| | Year Ended December 31, 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (In millions) | |
| Losses (gains) from: | | | |
| Option embedded in exchangeable debentures | $ 248 | 181 | 54 |
| Chevron common stock | (281) | — | — |
| Interest rate swaps | (1) | (3) | (4) |
| Non-qualifying commodity hedges | — | — | 39 |
| Ineffectiveness of commodity hedges | — | — | 5 |
| Total change in fair value of financial instruments | $ (34) | 178 | 94 |

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron common stock. These unrealized losses were caused primarily by increases in the price of Chevron's common stock.

Effective January 1, 2007 as a result of our adoption of Financial Accounting Standard No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*, we began recognizing unrealized gains and losses on our investment in Chevron common stock in net earnings rather than as part of other comprehensive income. The change in fair value of our investment in Chevron common stock resulted from an increase in the price of Chevron's common stock during 2007.

In 2005, we recognized a $39 million loss on certain oil derivative financial instruments that no longer qualified for hedge accounting because the hedged production exceeded actual and projected production under these contracts. The lower than expected production was caused primarily by hurricanes that affected offshore production in the Gulf of Mexico.

### *Reduction of Carrying Value of Oil and Gas Properties*

During 2006 and 2005, we reduced the carrying value of certain of our oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A detailed description of how full cost ceiling limitations are determined is included in the "Critical Accounting Policies and Estimates" section of this report. A summary of these reductions and additional discussion is provided below.

| | Year Ended December 31, 2006 Gross | 2006 Net of Taxes | 2005 Gross | 2005 Net of Taxes |
|---|---|---|---|---|
| | | (In millions) | | |
| Brazil - unsuccessful exploratory reduction | $ 16 | 16 | 42 | 42 |
| Russia - ceiling test reduction | 20 | 10 | — | — |
| Total | $ 36 | 26 | 42 | 42 |

*2006 Reductions*

During the second quarter of 2006, we drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, we recognized a $16 million impairment of our investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to our Polvo development project in Brazil.

As a result of a decline in projected future net cash flows, the carrying value of our Russian properties exceeded the full cost ceiling by $10 million at the end of the third quarter of 2006. Therefore, we recognized a $20 million reduction of the carrying value of our oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

*2005 Reduction*

Prior to the fourth quarter of 2005, we were capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. At the end of 2005, it was expected that a small initial portion of the proved reserves ultimately expected at Polvo would be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves was not sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, we determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There was no tax benefit related to this Brazilian impairment.

### *Other Income, Net*

The following schedule includes the components of other income between 2005 and 2007.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (In millions) | |
| Interest and dividend income | $ 89 | 100 | 95 |
| Net gain on sales of non-oil and gas property and equipment | 1 | 5 | 150 |
| Loss on derivative financial instruments | — | — | (48) |
| Other | 8 | 10 | 1 |
| Total | $ 98 | 115 | 198 |

Interest and dividend income decreased from 2006 to 2007 primarily due to a decrease in income-earning cash and investment balances, partially offset by an increase in the dividend rate on our investment in Chevron common stock. Interest and dividend income increased from 2005 to 2006 primarily due to an increase in cash and short-term investment balances and higher interest rates.

During 2005, we sold certain non-core midstream assets for a net gain of $150 million. Also during 2005, we incurred a $55 million loss on certain commodity hedges that no longer qualified for hedge accounting and were settled prior to the end of their original term. These hedges related to U.S. and Canadian oil production from properties sold as part of our 2005 property divestiture program. This loss was partially offset by a $7 million gain related to interest rate swaps that were settled prior to the end of their original term in conjunction with the early redemption of the $400 million 6.75% senior notes in 2005.

### *Income Taxes*

The following table presents our total income tax expense related to continuing operations and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate for each of the past three years. The primary factors causing our effective rates to vary from 2005 to 2007, and differ from the U.S. statutory rate, are discussed below.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Total income tax expense (In millions) | $ 1,078 | 936 | 1,481 |
| U.S. statutory income tax rate | 35% | 35% | 35% |
| Canadian statutory rate reductions | (6%) | (7%) | — |
| Texas income-based tax | — | 1% | — |
| Repatriation of earnings | — | — | 1% |
| Other, primarily taxation on foreign operations | (3%) | (3%) | (2%) |
| Effective income tax rate | 26% | 26% | 34% |

In 2007, 2006 and 2005, deferred income taxes were reduced $261 million, $243 million and $14 million, respectively, due to successive Canadian statutory rate reductions that were enacted in each such year.

In 2006, deferred income taxes increased $39 million due to the effect of a new income-based tax enacted by the state of Texas that replaced a previous franchise tax. The new tax was effective January 1, 2007.

In 2005, we recognized $28 million of taxes related to our repatriation of $545 million to the United States. The cash was repatriated to take advantage of U.S. tax legislation that allowed qualifying companies to repatriate cash from foreign operations at a reduced income tax rate. Substantially all of the cash repatriated by us in 2005 related to prior earnings of our Canadian subsidiary.

### *Earnings From Discontinued Operations*

In November 2006 and January 2007, we announced our plans to divest our operations in Egypt and West Africa, including Equatorial Guinea, Cote d'Ivoire, Gabon and other countries in the region. Pursuant to accounting rules for discontinued operations, we have classified all 2007 and prior period amounts related to our operations in Egypt and West Africa as discontinued operations.

In October 2007, we completed the sale of our Egyptian operations and received proceeds of $341 million. As a result of this sale, we recognized a $90 million after-tax gain in the fourth quarter of 2007. In November 2007, we announced an agreement to sell our operations in Gabon for $205.5 million. We are finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the remaining properties in the West African divestiture package. We are optimistic we can complete these sales during the first half of 2008.

Following are the components of earnings from discontinued operations between 2005 and 2007.

| | | Year Ended December 31, | | |
|---|---|---|---|---|
| | | 2007 | 2006 | 2005 |
| | | | (In millions) | |
| Earnings from discontinued operations before income taxes | $ | 696 | 464 | 173 |
| Income tax expense | | 236 | 252 | 140 |
| Earnings from discontinued operations | $ | 460 | 212 | 33 |

*2007 vs. 2006* Earnings from discontinued operations increased $248 million in 2007. In addition to variances caused by changes in production volumes and realized prices, our earnings from discontinued operations in 2007 were impacted by other significant factors. Pursuant to accounting rules for discontinued operations, we ceased recording DD&A in November 2006 related to our Egyptian operations and in January 2007 related to our West African operations. This reduction in DD&A caused earnings from discontinued operations to increase $119 million in 2007. Earnings in 2007 also benefited from the $90 million gain from the sale of our Egyptian operations.

In addition, earnings from discontinued operations increased $90 million in 2007 due to the net effect of reductions in carrying value in 2006 and 2007. Our earnings in 2007 were reduced by $13 million from these reductions, compared to $103 million of reductions recorded in 2006. Due to unsuccessful drilling activities in Nigeria, in the first quarter of 2006, we recognized an $85 million impairment of our investment in Nigeria equal to the costs to drill two dry holes and a proportionate share of block-related costs. There was no income tax benefit related to this impairment. As a result of unsuccessful exploratory activities in Egypt during 2006, the net book value of our Egyptian oil and gas properties, less related deferred income taxes, exceeded the ceiling by $18 million as of the end of September 30, 2006. Therefore, in 2006 we recognized an $18 million after-tax loss ($31 million pre-tax). In the second quarter of 2007, based on drilling activities in Nigeria, we recognized a $13 million after-tax loss ($64 million pre-tax).

*2006 vs. 2005* Earnings from discontinued operations increased $179 million in 2006. This increase was largely due to an increase in realized crude oil prices, partially offset by a 19% decline in oil production.

In addition, earnings from discontinued operations increased $16 million due to the net effect of a $119 million after-tax impairment of our investment in Angola in 2005, partially offset by the 2006 Nigerian and Egyptian impairments totaling $103 million as described above. Our interests in Angola were acquired through the 2003 Ocean Energy merger, and our Angolan drilling program discovered no proven reserves. After drilling three unsuccessful wells in the fourth quarter of 2005, we determined that all of the Angolan capitalized costs should be impaired. As a result, we recognized a $170 million impairment with a $51 million related tax benefit.

## Capital Resources, Uses and Liquidity

The following discussion of capital resources, uses and liquidity should be read in conjunction with the consolidated financial statements included in this report.

### *Sources and Uses of Cash*

The following table presents the sources and uses of our cash and cash equivalents from 2005 to 2007. The table presents capital expenditures on a cash basis. Therefore, these amounts differ from the amounts of capital expenditures, including accruals, that are referred to elsewhere in this document. Additional discussion of these items follows the table.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (In millions) | |
| Sources of cash and cash equivalents: | | | |
| Operating cash flow – continuing operations | $ 6,162 | 5,374 | 5,297 |
| Sales of property and equipment | 76 | 40 | 2,151 |
| Net credit facility borrowings | 1,450 | — | — |
| Net commercial paper borrowings | — | 1,808 | — |
| Net decrease in short-term investments | 202 | 106 | 287 |
| Stock option exercises | 91 | 73 | 124 |
| Other | 44 | 36 | — |
| Total sources of cash and cash equivalents | 8,025 | 7,437 | 7,859 |
| Uses of cash and cash equivalents: | | | |
| Capital expenditures | (6,158) | (7,346) | (3,813) |
| Net commercial paper repayments | (804) | — | — |
| Debt repayments | (567) | (862) | (1,258) |
| Repurchases of common stock | (326) | (253) | (2,263) |
| Dividends | (259) | (209) | (146) |
| Total uses of cash and cash equivalents | (8,114) | (8,670) | (7,480) |
| Increase (decrease) from continuing operations | (89) | (1,233) | 379 |
| Increase from discontinued operations | 655 | 370 | 38 |
| Effect of foreign exchange rates | 51 | 13 | 37 |
| Net increase (decrease) in cash and cash equivalents | $ 617 | (850) | 454 |
| Cash and cash equivalents at end of year | $ 1,373 | 756 | 1,606 |
| Short-term investments at end of year | $ 372 | 574 | 680 |

### *Operating Cash Flow – Continuing Operations*

Net cash provided by operating activities ("operating cash flow") continued to be our primary source of capital and liquidity in 2007. Changes in operating cash flow are largely due to the same factors that affect our net earnings, with the exception of those earnings changes due to such noncash expenses as DD&A, financial instrument fair value changes, property impairments and deferred income tax expense. As a result, our operating cash flow increased in 2007 primarily due to the increase in earnings as discussed in the "Results of Operations" section of this report.

During 2007 and 2006, operating cash flow was primarily used to fund our capital expenditures. Excluding the $2.0 billion Chief acquisition in June 2006, our operating cash flow was sufficient to fund our 2007 and 2006 capital expenditures. During 2005, operating cash flow was sufficient to fund our 2005 capital expenditures and $1.3 billion of debt repayments.

### *Other Sources of Cash*

As needed, we utilize cash on hand and access our available credit under our credit facilities and commercial paper program as sources of cash to supplement our operating cash flow. Additionally, we invest in highly liquid, short-term investments to maximize our income on available cash balances. As needed, we may reduce such short-term investment balances to further supplement our operating cash flow.

During 2007, we borrowed $1.5 billion under our unsecured revolving line of credit and reduced our short-term investment balances by $202 million. We also received $341 million of proceeds from the sale of our Egyptian operations. These sources of cash were used primarily to fund net commercial paper repayments, long-term debt repayments, common stock repurchases and dividends on common and preferred stock.

During 2006, we borrowed $1.8 billion under our commercial paper program and reduced our short-term investment balances by $106 million. These sources of cash were largely used to fund the $2.0 billion acquisition of Chief in June 2006. Also during 2006, we supplemented operating cash flow with cash on hand, which was used to fund scheduled long-term debt maturities, common stock repurchases and dividends on common and preferred stock.

During 2005, we generated $2.2 billion in pre-tax proceeds from sales of property and equipment. These consisted of $2.0 billion related to the sale of non-core oil and gas properties and $164 million related to the sale of non-core midstream assets. Net of related income taxes, these proceeds were $2.0 billion. During 2005, we also reduced short-term investment balances by $287 million. These sources of cash were used primarily to repurchase $2.3 billion of common stock.

*Capital Expenditures*

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling or development of oil and gas properties, which totaled $5.7 billion, $6.8 billion and $3.6 billion in 2007, 2006 and 2005, respectively. The 2006 capital expenditures included $2.0 billion related to the acquisition of the Chief properties. Excluding the effect of the Chief acquisition, the increase in such capital expenditures from 2005 to 2007 was due to inflationary pressure driven by increased competition for field services and increased drilling activities in the Barnett Shale, Gulf of Mexico, Carthage and Groesbeck areas of the United States. Additionally, capital expenditures also increased on our properties in Azerbaijan where we achieved payout of certain carried interests in the last half of 2006.

Our capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas pipeline systems and oil pipelines. These midstream facilities exist primarily to support our oil and gas development operations. Such expenditures were $371 million, $357 million and $121 million in 2007, 2006 and 2005, respectively. The majority of our midstream expenditures from 2005 to 2007 have related to development activities in the Barnett Shale, the Woodford Shale in eastern Oklahoma and Jackfish in Canada.

*Debt Repayments*

During 2007, we repaid the $400 million 4.375% notes, which matured on October 1, 2007. Also during 2007, certain holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock prior to the debentures' August 15, 2008 maturity date. We have the option, in lieu of delivering shares of Chevron common stock, to pay exchanging debenture holders an amount of cash equal to the market value of Chevron common stock. We paid $167 million in cash to debenture holders who exercised their exchange rights. This amount included the retirement of debentures with a book value of $105 million and a $62 million reduction of the related embedded derivative option's balance.

During 2006, we retired the $500 million 2.75% notes and the $178 million ($200 million Canadian) 6.55% notes. We also repaid $180 million of debt acquired in the Chief acquisition.

During 2005, we spent $0.8 billion to retire zero coupon convertible debentures due in 2020 and $400 million 6.75% notes due in 2011 before their scheduled maturity dates. We also spent $0.4 billion to repay various notes that matured in 2005.

*Repurchases of Common Stock*

During the three-year period ended December 31, 2007, we repurchased 55.2 million shares at a total cost of $2.8 billion, or $51.49 per share, under various repurchase programs. During 2007, we repurchased 4.1 million shares at a cost of $326 million, or $79.80 per share. During 2006, we repurchased 4.2 million shares at a cost of $253 million, or $59.61 per share. During 2005, we repurchased 46.9 million shares at a cost of $2.3 billion, or $48.28 per share.

*Dividends*

Our common stock dividends were $249 million, $199 million and $136 million in 2007, 2006 and 2005, respectively. We also paid $10 million of preferred stock dividends in 2007, 2006 and 2005. The increases in common stock dividends from 2005 to 2007 were primarily related to 25% and 50% increases in the quarterly dividend rate in the first quarters of 2007 and 2006, respectively. The increase from 2005 to 2006 was partially offset by a decrease in outstanding shares due to share repurchases.

***Liquidity***

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain revolving lines of credit and a commercial paper program, which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity securities and long-term debt. During 2008, another major source of liquidity will be proceeds from the sales of our operations in West Africa. We expect the combination of these sources of capital will be more than adequate to fund future capital expenditures, debt repayments, common stock repurchases, and other contractual commitments as discussed later in this section.

*Operating Cash Flow*

Our operating cash flow has increased approximately 16% since 2005, reaching a total of $6.2 billion in 2007. We expect operating cash flow to continue to be our primary source of liquidity. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

We periodically deem it appropriate to mitigate some of the risk inherent in oil and natural gas prices. Accordingly, we have utilized price collars to set minimum and maximum prices on a portion of our production. We have also utilized various price swap contracts and fixed-price physical delivery contracts to fix the price to be received for a portion of future oil and natural gas production. Based on contracts in place as of February 15, 2008, in 2008 approximately 64% of our estimated natural gas production and 12% of our estimated oil production are subject to either price collars, swaps or fixed-price contracts. The key terms of these contracts are summarized in the Quantitative and Qualitative Disclosures about Market Risk section of this book.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price increases, as experienced in recent years, can lead to an increase in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also increase, causing a negative impact on our cash flow.

*Credit Availability*

We have two revolving lines of credit and a commercial paper program, which we can access to provide liquidity. At December 31, 2007, our total available borrowing capacity was $1.3 billion.

Our $2.5 billion five-year, syndicated, unsecured revolving line of credit (the “Senior Credit Facility”) matures on April 7, 2012, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, we have the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders.

The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million. Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of December 31, 2007, there were $1.4 billion of borrowings under the Senior Credit Facility at an average rate of 5.27%.

On August 7, 2007, we established a new $1.5 billion 364-day, syndicated, unsecured revolving senior credit facility (the “Short-Term Facility”). This facility provides us with provisional interim liquidity until we receive the proceeds from divestitures of assets in West Africa. The Short-Term Facility was also used to support an increase in our commercial paper program from $2 billion to $3.5 billion.

The Short-Term Facility matures on August 5, 2008. At that time, all amounts outstanding will be due and payable unless the maturity is extended. Prior to August 5, 2008, we have the option to convert any outstanding principal amount of loans under the Short-Term Facility to a term loan, which will be repayable in a single payment on August 4, 2009.

Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods of up to 12 months. Such rates are generally less than the prime rate. We may also elect to borrow at the prime rate. As of December 31, 2007, there were no borrowings under the Short-Term Facility.

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $3.5 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility or the Short-Term Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between one and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2007, we had $1.0 billion of commercial paper debt outstanding at an average rate of 5.07%.

The Senior Credit Facility and Short-Term Facility contain only one material financial covenant. This covenant requires our ratio of total funded debt to total capitalization to be less than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in our consolidated financial statements. As defined in the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2007, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2007, as calculated pursuant to the terms of the agreement, was 23.8%.

Our access to funds from the Senior Credit Facility and Short-Term Facility is not restricted under any "material adverse effect" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or business considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While our credit facilities include covenants that require us to report a condition or event having a material adverse effect, the obligation of the banks to fund the credit facilities is not conditioned on the absence of a material adverse effect.

*Debt Ratings*

We receive debt ratings from the major ratings agencies in the United States. In determining our debt ratings, the agencies consider a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities and capital allocation challenges. Liquidity, asset quality, cost structure, reserve mix, and commodity pricing levels are also considered by the rating agencies. Our current debt ratings are BBB with a positive outlook by Standard & Poor's, Baa1 with a stable outlook by Moody's and BBB with a positive outlook by Fitch.

There are no "rating triggers" in any of our contractual obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. Our cost of borrowing under our Senior Credit Facility and Short-Term Facility is predicated on our corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on any borrowings under our credit facilities. Under the terms of the Senior Credit Facility and the Short-Term Facility, a one-notch downgrade would increase the fully-drawn borrowing costs for the credit facilities from LIBOR plus 35 basis points to a new rate of LIBOR plus 45 basis points. A ratings downgrade could also adversely impact our ability to economically access debt markets in the future. As of December 31, 2007, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

*Capital Expenditures*

In February 2008, we provided guidance for our 2008 capital expenditures, which are expected to range from $6.6 billion to $7.0 billion. This represents the largest planned use of our 2008 operating cash flow, with the high end of the range being 13% higher than our 2007 capital expenditures. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if oil and natural gas prices fluctuate from current estimates, we could choose to defer a portion of these planned 2008 capital expenditures until later periods, or accelerate capital expenditures planned for periods beyond 2008 to achieve the desired balance between sources and uses of liquidity. Based upon current oil and natural gas price expectations for 2008 and the commodity price collars, swaps and fixed-price contracts we have in place, we anticipate having adequate capital resources to fund our 2008 capital expenditures.

*Common Stock Repurchase Programs*

We have an ongoing, annual stock repurchase program to minimize dilution resulting from restricted stock issued to, and options exercised by, employees. In 2008, the repurchase program authorizes the repurchase of up to 4.8 million shares or a cost of $422 million, whichever amount is reached first.

In anticipation of the completion of our West African divestitures, our Board of Directors has approved a separate program to repurchase up to 50 million shares. This program expires on December 31, 2009.

*Exchangeable Debentures*

As of December 31, 2007, our outstanding debt included debentures that are exchangeable for Chevron common stock. These debentures have a scheduled maturity date of August 15, 2008. Although these debentures are now due within one year, we continue to classify this debt as long-term because we have the intent and ability to refinance these debentures on a long-term basis with the available capacity under our existing credit facilities or other long-term financing arrangements.

*Canadian Royalties*

On October 25, 2007, the Alberta government proposed increases to the royalty rates on oil and natural gas production beginning in 2009. We believe this proposal would reduce future earnings and cash flows from our oil and gas properties located in Alberta. Additionally, assuming all other factors are equal, higher royalty rates would likely result in lower levels of capital investment in Alberta relative to our other areas of operation. However, the magnitude of the potential impact, which will depend on the final form of enacted legislation and other factors that impact the relative expected economic returns of capital projects, cannot be reasonably estimated at this time.

*Contractual Obligations*

A summary of our contractual obligations as of December 31, 2007, is provided in the following table.

| | Total | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years |
|---|---|---|---|---|---|
| | | Payments Due by Period (In millions) | | | |
| Long-term debt [(1)] | $ 7,908 | 1,004 | 177 | 4,202 | 2,525 |
| Interest expense [(2)] | 5,412 | 508 | 708 | 545 | 3,651 |
| Drilling and facility obligations [(3)] | 3,935 | 983 | 1,254 | 747 | 951 |
| Asset retirement obligations [(4)] | 1,362 | 91 | 138 | 128 | 1,005 |
| Firm transportation agreements [(5)] | 1,040 | 170 | 329 | 234 | 307 |
| Lease obligations [(6)] | 578 | 104 | 166 | 125 | 183 |
| Other | 134 | 71 | 59 | 4 | — |
| Total | $ 20,369 | 2,931 | 2,831 | 5,985 | 8,622 |

(1) Except for our debentures exchangeable into Chevron common stock, long-term debt amounts represent scheduled maturities of our debt obligations at December 31, 2007, excluding $20 million of net premiums included in the carrying value of debt. Although the maturity date of the exchangeable debentures is August 2008, we have the ability and intent to refinance these borrowings under our credit facilities or other long-term arrangements. Therefore, the $652 million face value of outstanding exchangeable debentures is included in the “3-5 Years” amount. As of December 31, 2007, we owned approximately 14.2 million shares of Chevron common stock. The majority of these shares are held for possible exchange when holders elect to exchange their debentures.
The “Less than 1 Year” amount represents our short-term commercial paper borrowings. The “3-5 Years” amount includes $1.4 billion of borrowings against our Senior Credit Facility. We intend to use the proceeds from the sales of West African assets to repay our outstanding commercial paper and credit facility borrowings. Also, $198 million of letters of credit that have been issued by commercial banks on our behalf are excluded from the table. The majority of these letters of credit, if funded, would become borrowings under our credit facilities. Most of these letters of credit have been granted by financial institutions to support our international and Canadian drilling commitments.

(2) Interest expense amounts represent the scheduled fixed-rate and variable-rate cash payments related to our debt. Interest on our variable-rate debt was estimated based upon expected future interest rates as of December 31, 2007.

(3) Drilling and facility obligations represent contractual agreements with third party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. Included in the $3.9 billion total is $2.4 billion that relates to long-term contracts for three deepwater drilling rigs and certain other contracts for onshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $2.4 billion represents the gross commitment under these contracts. Our ultimate payment for these commitments will be reduced by the amounts billed to our working interest partners. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties. Also included in the $3.9 billion total is $144 million of drilling and facility obligations related to our discontinued operations.

(4) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2007 balance sheet. Included in the $1.4 billion total is $44 million of asset retirement obligations related to our discontinued operations.

(5) Firm transportation agreements represent “ship or pay” arrangements whereby we have committed to ship certain volumes of oil, gas and NGLs for a fixed transportation fee. We have entered into these agreements to aid the movement of our production to market. We expect to have sufficient production to utilize the majority of these transportation services.

(6) Lease obligations consist of operating leases for office space and equipment, an offshore platform spar and FPSO’s. Office and equipment leases represent non-cancelable leases for office space and equipment used in our daily operations.
We have an offshore platform spar that is being used in the development of the Nansen field in the Gulf of Mexico. This spar is subject to a 20-year lease and contains various options whereby we may purchase the lessors’ interests in the spars. We have guaranteed that the spar will have a residual value at the end of the term equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreements. In 2005, we sold our interests in the Boomvang field in the Gulf of Mexico, which has a spar lease with terms similar to those of the Nansen lease. As a result of the sale, we are subleasing the Boomvang Spar. The table above does not include any amounts related to the Boomvang spar lease. However, if the sublessee were to default on its obligation, we would continue to be obligated to pay the periodic lease payments and any guaranteed value required at the end of the term.
We also lease two FPSO’s that are being used in the Panyu project offshore China and the Polvo project offshore Brazil. The Panyu FPSO lease term expires in September 2009. The Polvo FPSO lease term expires in 2014.

*Pension Funding and Estimates*

*Funded Status.* As compared to the “projected benefit obligation,” our qualified and nonqualified defined benefit plans were underfunded by $230 million and $178 million at December 31, 2007 and 2006, respectively. A detailed reconciliation of the 2007 changes to our underfunded status is included in Note 6 to the accompanying consolidated financial statements. Of the $230 million underfunded status at the end of 2007, $198 million is attributable to various nonqualified defined benefit plans that have no plan assets. However, we have established certain trusts to fund the benefit obligations of such nonqualified plans. As of December 31, 2007, these trusts had investments with a fair value of $59 million. The value of these trusts is included in noncurrent other assets in our accompanying consolidated balance sheets.

As compared to the “accumulated benefit obligation,” our qualified defined benefit plans were overfunded by $62 million at December 31, 2007. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. Our current intentions are to provide sufficient funding in future years to ensure the accumulated benefit obligation remains fully funded. The actual amount of contributions required during this period will depend on investment returns from the plan assets and payments made to participants. Required contributions also depend upon changes in actuarial assumptions made during the same period, particularly the discount rate used to calculate the present value of the accumulated benefit obligation. For 2008, we anticipate the accumulated benefit obligation will remain fully funded without contributing to our qualified defined benefit plans. Therefore, we don’t expect to contribute to the plans during 2008.

*Pension Estimate Assumptions.* Our pension expense is recognized on an accrual basis over employees’ approximate service periods and is generally calculated independent of funding decisions or requirements. We recognized expense for our defined benefit pension plans of $41 million, $31 million and $26 million in 2007, 2006 and 2005, respectively. We estimate that our pension expense will approximate $61 million in 2008.

The calculation of pension expense and pension liability requires the use of a number of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the two most critical assumptions affecting pension expense and liabilities are the expected long-term rate of return on plan assets and the assumed discount rate.

We assumed that our plan assets would generate a long-term weighted average rate of return of 8.40% at both December 31, 2007 and 2006. We developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. The target investment allocation for our plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. We expect our long-term asset allocation on average to approximate the targeted allocation. We regularly review our actual asset allocation and periodically rebalance the investments to the targeted allocation when considered appropriate.

Pension expense increases as the expected rate of return on plan assets decreases. A decrease in our long-term rate of return assumption of 100 basis points (from 8.40% to 7.40%) would increase the expected 2008 pension expense by $6 million.

We discounted our future pension obligations using a weighted average rate of 6.22% and 5.72% at December 31, 2007 and 2006, respectively. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled, considering the expected timing of future cash flows related to the plans. This rate is based on high-quality bond yields, after allowing for call and default risk. We consider high quality corporate bond yield indices, such as Moody's Aa, when selecting the discount rate.

The pension liability and future pension expense both increase as the discount rate is reduced. Lowering the discount rate by 25 basis points (from 6.22% to 5.97%) would increase our pension liability at December 31, 2007, by $28 million, and increase estimated 2008 pension expense by $4 million.

At December 31, 2007, we had actuarial losses of $208 million, which will be recognized as a component of pension expense in future years. These losses are primarily due to reductions in the discount rate since 2001 and increases in participant wages. We estimate that approximately $14 million and $12 million of the unrecognized actuarial losses will be included in pension expense in 2008 and 2009, respectively. The $14 million estimated to be recognized in 2008 is a component of the total estimated 2008 pension expense of $61 million referred to earlier in this section.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our defined benefit pension plans will impact future pension expense and liabilities. We cannot predict with certainty what these factors will be in the future.

On August 17, 2006, the Pension Protection Act was signed into law. Beginning in 2008, this act will cause extensive changes in the determination of both the minimum required contribution and the maximum tax deductible limit. Because the new required contribution will approximate our current policy of fully funding the accumulated benefit obligation, the changes are not expected to have a significant impact on future cash flows.

## Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 8 of the accompanying consolidated financial statements.

## Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known.

The critical accounting policies used by management in the preparation of our consolidated financial statements are those that are important both to the presentation of our financial condition and results of operations and require significant judgments by management with regard to estimates used. Our critical accounting policies and significant judgments and estimates related to those policies are described below. We have reviewed these critical accounting policies with the Audit Committee of the Board of Directors.

### *Full Cost Ceiling Calculations*

*Policy Description*

We follow the full cost method of accounting for our oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of properties that can be capitalized on the balance sheet. The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties, excluding future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties, plus the cost of properties not subject to amortization. If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense, except as discussed in the following paragraph. The ceiling limitation is imposed separately for each country in which we have oil and gas properties.

If, subsequent to the end of the quarter but prior to the applicable financial statements being published, prices increase to levels such that the ceiling would exceed the costs to be recovered, a writedown otherwise indicated at the end of the quarter is not required to be recorded. A writedown indicated at the end of a quarter is also not required if the value of additional reserves proved up on properties after the end of the quarter but prior to the publishing of the financial statements would result in the ceiling exceeding the costs to be recovered, as long as the properties were owned at the end of the quarter. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

*Judgments and Assumptions*

The discounted present value of future net revenues for our proved oil, natural gas and NGL reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Certain of our reserve estimates are prepared or audited by outside petroleum consultants, while other reserve estimates are prepared by our engineers. See Note 15 of the accompanying consolidated financial statements.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past five years, annual revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged approximately 1% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and that prices and costs in effect as of the last day of the period are held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Rather, they are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed. In calculating the ceiling, we adjust the end-of-period price by the effect of derivative contracts in place that qualify for hedge accounting treatment. This adjustment requires little judgment as the end-of-period price is adjusted using the contract prices for such hedges. None of our outstanding derivative contracts at December 31, 2007 qualified for hedge accounting treatment.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been volatile. On any particular day at the end of a quarter, prices can be either substantially higher or lower than our long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

***Derivative Financial Instruments***

*Policy Description*

The majority of our historical derivative instruments have consisted of commodity financial instruments used to manage our cash flow exposure to oil and gas price volatility. We have also entered into interest rate swaps to manage our exposure to interest rate volatility. The interest rate swaps mitigate either the cash flow effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the fair value effects of interest rate fluctuations on fixed-rate debt. We also have an embedded option derivative related to the fair value of our debentures exchangeable into shares of Chevron Corporation common stock.

All derivatives are recognized at their current fair value on our balance sheet. Changes in the fair value of derivative financial instruments are recorded in the statement of operations unless specific hedge accounting criteria are met. If such criteria are met for cash flow hedges, the effective portion of the change in the fair value is recorded directly to accumulated other comprehensive income, a component of stockholders' equity, until the hedged transaction occurs. The ineffective portion of the change in fair value is recorded in the statement of operations. If hedge accounting criteria are met for fair value hedges, the change in the fair value is recorded in the statement of operations with an offsetting amount recorded for the change in fair value of the hedged item.

A derivative financial instrument qualifies for hedge accounting treatment if we designate the instrument as such on the date the derivative contract is entered into or the date of an acquisition or business combination that includes derivative contracts. Additionally, we must document the relationship between the hedging instrument and hedged item, as well as the risk-management objective and strategy for undertaking the instrument. We must also assess, both at the instrument's inception and on an ongoing basis, whether the derivative is highly effective in offsetting the change in cash flow of the hedged item.

For the derivative financial instruments we have executed in 2006, 2007 and to date in 2008, we have chosen to not meet the necessary criteria to qualify such instruments for hedge accounting.

*Judgments and Assumptions*

The estimates of the fair values of our commodity derivative instruments require substantial judgment. For these instruments, we obtain forward price and volatility data for all major oil and gas trading points in North America from independent third parties. These forward prices are compared to the price parameters contained in the hedge agreements. The resulting estimated future cash inflows or outflows over the lives of the hedge contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. In addition, we estimate the option value of price floors and price caps using an option pricing model. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices, regional price differentials and interest rates. Fair values of our other derivative instruments require less judgment to estimate and are primarily based on quotes from independent third parties such as counterparties or brokers.

Quarterly changes in estimates of fair value have only a minimal impact on our liquidity, capital resources or results of operations, as long as the derivative instruments qualify for hedge accounting treatment. Changes in the fair values of derivatives that do not qualify for hedge accounting treatment can have a significant impact on our results of operations, but generally will not impact our liquidity or capital resources. Settlements of derivative instruments, regardless of whether they qualify for hedge accounting, do have an impact on our liquidity and results of operations. Generally, if actual market prices are higher than the price of the derivative instruments, our net earnings and cash flow from operations will be lower relative to the results that would have occurred absent these instruments. The opposite is also true. Additional information regarding the effects that changes in market prices will have on our derivative financial instruments, net earnings and cash flow from operations is included in this report.

***Business Combinations***

*Policy Description*

From our beginning as a public company in 1988 through 2003, we grew substantially through acquisitions of other oil and natural gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting, and recent accounting pronouncements require that all future acquisitions will be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. Goodwill is assessed for impairment at least annually.

*Judgments and Assumptions*

There are various assumptions we make in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, we prepare estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by our engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies end-of-period price and cost information to the reserves to arrive at the ceiling amount. By contrast, the fair value of reserves acquired in a business combination must be based on our estimates of future oil, natural gas and NGL prices. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Forecasts of future prices from independent third parties are noted when we make our pricing estimates.

We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

We also apply these same general principles to estimate the fair value of unproved properties acquired in a business combination. These unproved properties generally represent the value of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by what we consider to be an appropriate risk-weighting factor in each particular instance. It is common for the discounted future net revenues of probable and possible reserves to be reduced by factors ranging from 30% to 80% to arrive at what we consider to be the appropriate fair values.

Generally, in our business combinations, the determination of the fair values of oil and gas properties requires much more judgment than the fair values of other assets and liabilities. The acquired companies commonly have long-term debt that we assume in the acquisition, and this debt must be recorded at the estimated fair value as if we had issued such debt. However, significant judgment on our behalf is usually not required in these situations due to the existence of comparable market values of debt issued by peer companies.

Except for the 2002 acquisition of Mitchell Energy & Development Corp., our mergers and acquisitions have involved other entities whose operations were predominantly in the area of exploration, development and production activities related to oil and gas properties. However, in addition to exploration, development and production activities, Mitchell's business also included substantial marketing and midstream activities. Therefore, a portion of the Mitchell purchase price was allocated to the fair value of Mitchell's marketing and midstream facilities and equipment. This consisted primarily of natural gas processing plants and natural gas pipeline systems.

The Mitchell midstream assets primarily served gas producing properties that we also acquired from Mitchell. Therefore, certain of the assumptions regarding future operations of the gas producing properties were also integral to the value of the midstream assets. For example, future quantities of natural gas estimated to be processed by natural gas processing plants were based on the same estimates used to value the proved and unproved gas producing properties. Future expected prices for marketing and midstream product sales were also based on price cases consistent with those used to value the oil and gas producing assets acquired from Mitchell. Based on historical costs and known trends and commitments, we also estimated future operating and capital costs of the marketing and midstream assets to arrive at estimated future cash flows. These cash flows were discounted at rates consistent with those used to discount future net cash flows from oil and gas producing assets to arrive at our estimated fair value of the marketing and midstream facilities and equipment.

In addition to the valuation methods described above, we perform other quantitative analyses to support the indicated value in any business combination. These analyses include information related to comparable companies, comparable transactions and premiums paid.

In a comparable companies analysis, we review the public stock market trading multiples for selected publicly traded independent exploration and production companies with comparable financial and operating characteristics. Such characteristics are market capitalization, location of proved reserves and the characterization of those reserves that we deem to be similar to those of the party to the proposed business combination. We compare these comparable company multiples to the proposed business combination company multiples for reasonableness.

In a comparable transactions analysis, we review certain acquisition multiples for selected independent exploration and production company transactions and oil and gas asset packages announced recently. We compare these comparable transaction multiples to the proposed business combination transaction multiples for reasonableness.

In a premiums paid analysis, we use a sample of selected independent exploration and production company transactions in addition to selected transactions of all publicly traded companies announced recently, to review the premiums paid to the price of the target one day, one week and one month prior to the announcement of the transaction. We use this information to determine the mean and median premiums paid and compare them to the proposed business combination premium for reasonableness.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both the oil and gas properties and non-oil and gas properties, the lower future net earnings will be as a result of higher future depreciation, depletion and amortization expense. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling writedown in the event that subsequent oil and gas prices drop below our price forecast that was used to originally determine fair value. A full cost ceiling writedown would have no effect on our liquidity or capital resources in that period because it is a noncash charge, but it would adversely affect results of operations. As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources, Uses and Liquidity," in calculating our debt-to-capitalization ratio under our credit agreement, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments.

Our estimates of reserve quantities are one of the many estimates that are involved in determining the appropriate fair value of the oil and gas properties acquired in a business combination. As previously disclosed in our discussion of the full cost ceiling calculations, during the past five years, our annual revisions to our reserve estimates have averaged approximately 1%. As discussed in the preceding paragraphs, there are numerous estimates in addition to reserve quantity estimates that are involved in determining the fair value of oil and gas properties acquired in a business combination. The inter-relationship of these estimates makes it impractical to provide additional quantitative analyses of the effects of changes in these estimates.

### *Valuation of Goodwill*

*Policy Description*

Goodwill is tested for impairment at least annually. This requires us to estimate the fair values of our own assets and liabilities in a manner similar to the process described above for a business combination. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination is also required to assess goodwill for impairment.

*Judgments and Assumptions*

Generally, the higher the fair value assigned to both the oil and gas properties and non-oil and gas properties, the lower goodwill would be. A lower goodwill value decreases the likelihood of an impairment charge. However, unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Due to the inter-relationship of the various estimates involved in assessing goodwill for impairment, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates, other than to note the historical average changes in our reserve estimates previously set forth.

## Recently Issued Accounting Standards Not Yet Adopted

In December 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141(R), *Business Combinations*, which replaces Statement No. 141. Statement No. 141(R) retains the fundamental requirements of Statement No. 141 that an acquirer be identified and the acquisition method of accounting (previously called the purchase method) be used for all business combinations. Statement No. 141(R)'s scope is broader than that of Statement No. 141, which applied only to business combinations in which control was obtained by transferring consideration. By applying the acquisition method to all transactions and other events in which one entity obtains control over one or more other businesses, Statement No. 141(R) improves the comparability of the information about business combinations provided in financial reports. Statement No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures identifiable assets acquired, liabilities assumed and any noncontrolling interest in the acquiree, as well as any resulting goodwill. Statement No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We will evaluate how the new requirements of Statement No. 141(R) would impact any business combinations completed in 2009 or thereafter.

In December 2007, the FASB also issued Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of Accounting Research Bulletin No. 51*. A noncontrolling interest, sometimes called a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. Statement No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Under Statement No. 160, noncontrolling interests in a subsidiary must be reported as a component of consolidated equity separate from the parent's equity. Additionally, the amounts of consolidated net income attributable to both the parent and the noncontrolling interest must be reported separately on the face of the income statement. Statement No. 160 is effective for fiscal years beginning on or after December 15, 2008 and earlier adoption is prohibited. We do not expect the adoption of Statement No. 160 to have a material impact on our financial statements and related disclosures.

## 2008 Estimates

The forward-looking statements provided in this discussion are based on our examination of historical operating trends, the information that was used to prepare the December 31, 2007 reserve reports and other data in our possession or available from third parties. These forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for our oil, natural gas and NGLs during 2008 will be substantially similar to those of 2007, unless otherwise noted. We make reference to the "Disclosure Regarding Forward-Looking Statements" at the beginning of this report. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2008 exchange rate of $0.98 U.S. dollar to $1.00 Canadian dollar.

In January 2007, we announced our intent to divest our West African oil and gas assets and terminate our operations in West Africa, including Equatorial Guinea, Cote d'Ivoire, Gabon and other countries in the region. In November 2007, we announced an agreement to sell our operations in Gabon for $205.5 million. We are finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the remaining properties in this divestiture package. We are optimistic we can complete these sales during the first half of 2008.

All West African related revenues, expenses and capital will be reported as discontinued operations in our 2008 financial statements. Accordingly, all forward-looking estimates in the following discussion exclude amounts related to our operations in West Africa, unless otherwise noted.

Though we have completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus, the following forward-looking estimates do not include any financial and operating effects of potential property acquisitions or divestitures that may occur during 2008, except for West Africa as previously discussed.

### *Oil, Gas and NGL Production*

Set forth below are our estimates of oil, gas and NGL production for 2008. We estimate that our combined 2008 oil, gas and NGL production will total approximately 240 to 247 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2007. The following estimates for oil, gas and NGL production are calculated at the midpoint of the estimated range for total production.

| | Oil (MMBbls) | Gas (Bcf) | NGLs (MMBbls) | Total (MMBoe) |
|---|---|---|---|---|
| U.S. Onshore | 12 | 626 | 23 | 140 |
| U.S. Offshore | 8 | 68 | 1 | 20 |
| Canada | 23 | 198 | 4 | 60 |
| International | 23 | 2 | — | 23 |
| Total | 66 | 894 | 28 | 243 |

### *Oil and Gas Prices*

*Oil and Gas Operating Area Prices*

We expect our 2008 average prices for the oil and gas production from each of our operating areas to differ from the NYMEX price as set forth in the following table. These expected ranges are exclusive of the anticipated effects of the oil and gas financial contracts presented in the "Commodity Price Risk Management" section below.

The NYMEX price for oil is the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma. The NYMEX price for gas is determined to be the first-of-month south Louisiana Henry Hub price index as published monthly in *Inside FERC*.

| | Expected Range of Prices as a % of NYMEX Price | |
|---|---|---|
| | Oil | Gas |
| U.S. Onshore | 85% to 95% | 80% to 90% |
| U.S. Offshore | 90% to 100% | 95% to 105% |
| Canada | 55% to 65% | 85% to 95% |
| International | 85% to 95% | 83% to 93% |

*Commodity Price Risk Management*

From time to time, we enter into NYMEX-related financial commodity collar and price swap contracts. Such contracts are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Although these financial contracts do not relate to specific production from our operating areas, they will affect our overall revenues and average realized oil and gas prices in 2008.

The key terms of our 2008 oil and gas financial collar and price swap contracts are presented in the following tables. The tables include contracts entered into as of February 15, 2008.

**Oil Financial Contracts**

| | Price Collar Contracts | | | |
|---|---|---|---|---|
| | | Floor Price | Ceiling Price | |
| Period | Volume (Bbls/d) | Floor Price ($/Bbl) | Ceiling Range ($/Bbl) | Weighted Average Ceiling Price ($/Bbl) |
| First Quarter | 21,011 | $70.00 | $132.50 - 148.00 | $140.31 |
| Second Quarter | 22,000 | $70.00 | $132.50 - 148.00 | $140.20 |
| Third Quarter | 22,000 | $70.00 | $132.50 - 148.00 | $140.20 |
| Fourth Quarter | 22,000 | $70.00 | $132.50 - 148.00 | $140.20 |
| 2008 Average | 21,754 | $70.00 | $132.50 - 148.00 | $140.23 |

**Gas Financial Contracts**

| | Price Collar Contracts | | | | Price Swap Contracts | |
|---|---|---|---|---|---|---|
| | | Floor Price | Ceiling Price | | | |
| Period | Volume (MMBtu/d) | Floor Price ($/MMBtu) | Ceiling Range ($/MMBtu) | Weighted Average Ceiling Price ($/MMBtu) | Volume (MMBtu/d) | Weighted Average Price ($/MMBtu) |
| First Quarter | 634,011 | $7.50 | $9.00 - 10.25 | $9.43 | 364,670 | $8.23 |
| Second Quarter | 1,080,000 | $7.50 | $9.00 - 10.25 | $9.43 | 620,000 | $8.24 |
| Third Quarter | 1,080,000 | $7.50 | $9.00 - 10.25 | $9.43 | 620,000 | $8.24 |
| Fourth Quarter | 1,080,000 | $7.50 | $9.00 - 10.25 | $9.43 | 620,000 | $8.24 |
| 2008 Average | 969,112 | $7.50 | $9.00 - 10.25 | $9.43 | 556,516 | $8.24 |

To the extent that monthly NYMEX prices in 2008 differ from those established by the gas price swaps, or are outside of the ranges established by the oil and natural gas collars, we and the counterparties to the contracts will settle the difference. Such settlements will either increase or decrease our oil and gas revenues for the period. Also, we will mark-to-market the contracts based on their fair values throughout 2008. Changes in the contracts' fair values will also be recorded as increases or decreases to our oil and gas revenues. The expected ranges of our realized oil and gas prices as a percentage of NYMEX prices, which are presented earlier in this document, do not include any estimates of the impact on our oil and gas prices from monthly settlements or changes in the fair values of our oil and gas price swaps and collars.

### *Marketing and Midstream Revenues and Expenses*

Marketing and midstream revenues and expenses are derived primarily from our gas processing plants and gas pipeline systems. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of gas and NGLs, provisions of contractual agreements and the amount of repair and maintenance activity required to maintain anticipated processing levels and pipeline throughput volumes.

These factors increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that our 2008 marketing and midstream operating profit will be between $510 million and $550 million. We estimate that marketing and midstream revenues will be between $1.61 billion and $2.01 billion, and marketing and midstream expenses will be between $1.10 billion and $1.46 billion.

### *Production and Operating Expenses*

Our production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from the property base, changes in the general price level of services and materials that are used in the operation of the properties, the amount of repair and workover activity required and changes in production tax rates. Oil, gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects.

Given these uncertainties, we expect that our 2008 lease operating expenses will be between $2.17 billion to $2.24 billion. Additionally, we estimate that our production taxes for 2008 will be between 3.5% and 4.0% of total oil, gas and NGL revenues, excluding the effect on revenues from financial collars and price swap contracts upon which production taxes are not assessed.

### *Depreciation, Depletion and Amortization ("DD&A")*

Our 2008 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2008 compared to the costs incurred for such efforts, and the revisions to our year-end 2007 reserve estimates that, based on prior experience, are likely to be made during 2008.

Given these uncertainties, we estimate that our oil and gas property-related DD&A rate will be between $12.75 per Boe and $13.25 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2008 is expected to be between $3.09 billion and $3.20 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $260 million and $270 million in 2008.

### *Accretion of Asset Retirement Obligation*

Accretion of asset retirement obligation in 2008 is expected to be between $75 million and $85 million.

### *General and Administrative Expenses ("G&A")*

Our G&A includes employee compensation and benefits costs and the costs of many different goods and services used in support of our business. G&A varies with the level of our operating activities and the related staffing and professional services requirements. In addition, employee compensation and benefits costs vary due to various market factors that affect the level and type of compensation and benefits offered to employees. Also, goods and services are subject to general price level increases or decreases. Therefore, significant variances in any of these factors from current expectations could cause actual G&A to vary materially from the estimate.

Given these limitations, we estimate our G&A for 2008 will be between $590 million and $610 million. This estimate includes approximately $90 million of non-cash, share-based compensation, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties.

### *Reduction of Carrying Value of Oil and Gas Properties*

We follow the full cost method of accounting for our oil and gas properties described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates." Reductions to the carrying value of our oil and gas properties are largely dependent on the success of drilling results and oil and natural gas prices at the end of our quarterly reporting periods. Due to the uncertain nature of future drilling efforts and oil and natural gas prices, we are not able to predict whether we will incur such reductions in 2008.

### *Interest Expense*

Future interest rates and debt outstanding have a significant effect on our interest expense. We can only marginally influence the prices we will receive in 2008 from sales of oil, gas and NGLs and the resulting cash flow. Likewise, we can only marginally influence the timing of the closing of our West African divestitures and the attendant cash receipts. These factors increase the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors that affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures are generally within our control.

Based on the information related to interest expense set forth below, we expect our 2008 interest expense to be between $340 million and $350 million. This estimate assumes no material changes in prevailing interest rates. This estimate also assumes no material changes in our expected level of indebtedness, except for an assumption that our commercial paper and credit facility borrowings will decrease in conjunction with the planned divestiture of our West African operations, which we are optimistic will be completed by the end of the second quarter of 2008.

The interest expense in 2008 related to our fixed-rate debt, including net accretion of related discounts, will be approximately $385 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of our long-term debt.

Our floating rate debt is comprised of variable-rate commercial paper and borrowings against our senior credit facility. Our floating rate debt is summarized in the following table:

| Debt Instrument | Notional Amount [1] (In millions) | Floating Rate |
|---|---|---|
| Commercial paper | $ 1,004 | Various [2] |
| Senior credit facility | $ 1,450 | Various [3] |

(1) Represents outstanding balance as of December 31, 2007.
(2) The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2007, the average rate on the outstanding balance was 5.07%.
(3) The borrowings under the senior credit facility bear interest at various fixed rate options for periods of up to twelve months and are generally less than the prime rate. As of December 31, 2007, the average rate on the outstanding balance was 5.27%.

Based on estimates of future LIBOR and prime rates as of December 31, 2007, interest expense on floating rate debt, including net amortization of premiums, is expected to total between $70 million and $80 million in 2008.

Our interest expense totals include payments of facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to the debt balances outstanding. We expect between $5 million and $15 million of such items to be included in our 2008 interest expense. Also, we expect to capitalize between $120 million and $130 million of interest during 2008, including amounts related to our discontinued operations.

### *Other Income*

We estimate that our other income in 2008 will be between $55 million and $75 million.

As of the end of 2007, we had received insurance claim settlements related to the 2005 hurricanes that were $150 million in excess of amounts incurred to repair related damages. None of this $150 million excess has been recognized as income, pending the resolution of the amount of future necessary repairs and the settlement of certain claims that have been filed with secondary insurers. Based on the most recent estimates of our costs for repairs, we believe that some amount will ultimately be recorded as other income. However, the timing and amount that would be recorded as other income are uncertain. Therefore, the 2008 estimate for other income above does not include any amount related to hurricane proceeds.

### *Income Taxes*

Our financial income tax rate in 2008 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2008 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U. S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2008 income tax expense regardless of the level of pre-tax earnings that are produced.

Given the uncertainty of pre-tax earnings, we expect that our consolidated financial income tax rate in 2008 will be between 20% and 40%. The current income tax rate is expected to be between 10% and 15%. The deferred income tax rate is expected to be between 10% and 25%. Significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of the aforementioned tax deductions and credits on 2008 financial income tax rates.

### *Discontinued Operations*

As previously discussed, in November 2007, we announced an agreement to sell our operations in Gabon for $205.5 million. We are finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the remaining properties in the West African divestiture package. We are optimistic we can complete these sales during the first half of 2008.

The following table presents the 2008 estimates for production, production and operating expenses and capital expenditures associated with these discontinued operations. These estimates include amounts related to all assets in the West African divestiture package for the first half of 2008. Pursuant to accounting rules for discontinued operations, the West African assets are not subject to DD&A during 2008.

| | |
|---|---|
| Oil production (MMBbls) | 4 |
| Gas production (Bcf) | 3 |
| Total production (MMBoe) | 4 |
| | |
| Production and operating expenses (In millions) | $30 |
| Capital expenditures (In millions) | $50 |

## Year 2008 Potential Capital Resources, Uses and Liquidity

### *Capital Expenditures*

Though we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not "budget," nor can we reasonably predict, the timing or size of such possible acquisitions.

Our capital expenditures budget is based on an expected range of future oil, gas and NGL prices, as well as the expected costs of the capital additions. Should actual prices received differ materially from our price expectations for our future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2008 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

Given the limitations discussed above, the following table shows expected drilling, development and facilities expenditures by geographic area. Development capital includes development activity related to reserves classified as proved as of year-end 2007 and drilling activity in areas that do not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Exploration capital includes exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

| | U.S. Onshore | U.S. Offshore | Canada | International | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| Development capital | $ 2,870 -3,020 | $ 490 -520 | $ 1,070 -1,120 | $ 205 - 220 | $ 4,635 -4,880 |
| Exploration capital | $ 310 - 330 | $ 320 -340 | $ 135 - 145 | $ 185 - 205 | $ 950 - 1,020 |
| Total | $ 3,180 -3,350 | $ 810 -860 | $ 1,205 -1,265 | $ 390 - 425 | $ 5,585 -5,900 |

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $325 million to $375 million on our marketing and midstream assets, which primarily include our oil pipelines, gas processing plants, and gas pipeline systems. We expect to capitalize between $335 million and $345 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $110 million and $120 million of interest. We also expect to pay between $70 million and $80 million for plugging and abandonment charges, and to spend between $130 million and $140 million for other non-oil and gas property fixed assets.

### *Other Cash Uses*

Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.14 per share quarterly dividend rate and 444 million shares of common stock outstanding as of December 31, 2007, dividends are expected to approximate $250 million. Also, we have $150 million of 6.49% cumulative preferred stock upon which we will pay $10 million of dividends in 2008.

### *Capital Resources and Liquidity*

Our estimated 2008 cash uses, including our drilling and development activities, retirement of debt and repurchase of common stock, are expected to be funded primarily through a combination of existing cash and short-term investments, operating cash flow and proceeds from the sale of our assets in West Africa. Any remaining cash uses could be funded by increasing our borrowings under our commercial paper program or with borrowings from the available capacity under our credit facilities, which was approximately $1.3 billion at December 31, 2007. The amount of operating cash flow to be generated during 2008 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be more than adequate to fund our anticipated capital expenditures and other cash uses for 2008. If significant acquisitions or other unplanned capital requirements arise during the year, we could utilize our existing credit facilities and/or seek to establish and utilize other sources of financing.

Our $372 million of short-term investments as of December 31, 2007 consisted entirely of auction rate securities collateralized by student loans which are substantially guaranteed by the United States government. Subsequent to December 31, 2007, we have reduced our auction rate securities holdings to $153 million. However, beginning on February 8, 2008, we experienced difficulty selling additional securities due to the failure of the auction mechanism which provides liquidity to these securities. The securities for which auctions have failed will continue to accrue interest and be auctioned every 28 days until the auction succeeds, the issuer calls the securities or the securities mature. Accordingly, there may be no effective mechanism for selling these securities, and the securities we own may become long-term investments. At this time, we do not believe such securities are impaired or that the failure of the auction mechanism will have a material impact on our liquidity.

## Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, gas and NGL prices, interest rates and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

## Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, gas and NGL production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian natural gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years.

We periodically enter into financial hedging activities with respect to a portion of our oil and gas production through various financial transactions that hedge the future prices received. These transactions include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we will settle the difference with the counterparty to the collars. These financial hedging activities are intended to support oil and gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

Based on natural gas contracts in place as of February 15, 2008 we have approximately 1.6 Bcf per day of gas production in 2008 that is subject to either price swaps or collars or fixed-price contracts. This amount represents approximately 64% of our estimated 2008 gas production, or 40% of our total Boe production. All of these price swap and collar contracts expire December 31, 2008. As of February 15, 2008, we do not have any gas price swaps or collars extending beyond 2008. However, our fixed-price physical delivery contracts extend through 2011. These physical delivery contracts relate to our Canadian natural gas production and range from six Bcf to 14 Bcf per year. These physical delivery contracts are not expected to have a material effect on our realized gas prices from 2009 through 2011.

The key terms of our 2008 gas financial collar and price swap contracts are presented in the following table.

**Gas Financial Contracts**

| | Price Collar Contracts | | | | Price Swap Contracts | |
|---|---|---|---|---|---|---|
| | | Floor Price | Ceiling Price | | | |
| Period | Volume (MMBtu/d) | Floor Price ($/MMBtu) | Ceiling Range ($/MMBtu) | Weighted Average Ceiling Price ($/MMBtu) | Volume (MMBtu/d) | Weighted Average Price ($/MMBtu) |
| First Quarter | 634,011 | $7.50 | $9.00 - 10.25 | $9.43 | 364,670 | $8.23 |
| Second Quarter | 1,080,000 | $7.50 | $9.00 - 10.25 | $9.43 | 620,000 | $8.24 |
| Third Quarter | 1,080,000 | $7.50 | $9.00 - 10.25 | $9.43 | 620,000 | $8.24 |
| Fourth Quarter | 1,080,000 | $7.50 | $9.00 - 10.25 | $9.43 | 620,000 | $8.24 |
| 2008 Average | 969,112 | $7.50 | $9.00 - 10.25 | $9.43 | 556,516 | $8.24 |

Based on oil contracts in place as of February 15, 2008 we have approximately 22,000 Bbls per day of oil production in 2008 that is subject to price collars. This amount represents approximately 12% of our estimated 2008 oil production, or 3% of our total Boe production. All of these price collar contracts expire December 31, 2008. As of February 15, 2008, we do not have any oil price swaps or collars extending beyond 2008.

The key terms of our 2008 oil financial collar contracts are presented in the following table.

**Oil Financial Contracts**

| | Price Collar Contracts | | | |
|---|---|---|---|---|
| | | Floor Price | Ceiling Price | |
| Period | Volume (Bbls/d) | Floor Price ($/Bbl) | Ceiling Range ($/Bbl) | Weighted Average Ceiling Price ($/Bbl) |
| First Quarter | 21,011 | $70.00 | $132.50 - 148.00 | $140.31 |
| Second Quarter | 22,000 | $70.00 | $132.50 - 148.00 | $140.20 |
| Third Quarter | 22,000 | $70.00 | $132.50 - 148.00 | $140.20 |
| Fourth Quarter | 22,000 | $70.00 | $132.50 - 148.00 | $140.20 |
| 2008 Average | 21,754 | $70.00 | $132.50 - 148.00 | $140.23 |

## Interest Rate Risk

At December 31, 2007, we had debt outstanding of $7.9 billion. Of this amount, $5.5 billion, or 69%, bears interest at fixed rates averaging 7.3%. Additionally, we had $1.0 billion of outstanding commercial paper and $1.4 billion of credit facility borrowings bearing interest at floating rates, which averaged 5.07% and 5.27%, respectively. At the end of 2007 and as of February 15, 2008, we did not have any interest rate hedging instruments.

## Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. A 10% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our December 31, 2007 balance sheet.

# Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2007. We also have audited Devon Energy Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Devon Energy Corporation's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Devon Energy Corporation and subsidiaries as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Devon Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on control criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As described in note 1 to the consolidated financial statements, as of January 1, 2007, the Company adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*, and FASB Interpretation No. 48 *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*. During 2007, the Company adopted the measurement date provisions of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statements No. 87, 88, 106, and 132(R)*. Additionally, as of January 1, 2006, the Company adopted Statements of Financial Accounting Standards No. 123(R), *Share-Based Payment*, and as of December 31, 2006, the Company adopted the balance sheet recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132 (R)*.

KPMG LLP

Oklahoma City, Oklahoma
February 26, 2008

# Consolidated Balance Sheets

DEVON ENERGY CORPORATION AND SUBSIDIARIES

| | | December 31, 2007 | 2006 |
|---|---|---|---|
| | | (In millions, except share data) | |
| **ASSETS** | | | |
| Current assets: | | | |
| Cash and cash equivalents | $ | 1,364 | 692 |
| Short-term investments, at fair value | | 372 | 574 |
| Accounts receivable | | 1,779 | 1,324 |
| Deferred income taxes | | 44 | 102 |
| Current assets held for sale | | 120 | 232 |
| Other current assets | | 235 | 288 |
| Total current assets | | 3,914 | 3,212 |
| Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,417 and $3,293 excluded from amortization in 2007 and 2006, respectively) | | 48,473 | 39,585 |
| Less accumulated depreciation, depletion and amortization | | 20,394 | 16,429 |
| | | 28,079 | 23,156 |
| Investment in Chevron Corporation common stock, at fair value | | 1,324 | 1,043 |
| Goodwill | | 6,172 | 5,706 |
| Assets held for sale | | 1,512 | 1,619 |
| Other assets | | 455 | 327 |
| Total assets | $ | 41,456 | 35,063 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | |
| Current liabilities: | | | |
| Accounts payable – trade | $ | 1,360 | 1,154 |
| Revenues and royalties due to others | | 578 | 522 |
| Income taxes payable | | 97 | 82 |
| Short-term debt | | 1,004 | 2,205 |
| Accrued interest payable | | 109 | 114 |
| Current portion of asset retirement obligation, at fair value | | 82 | 53 |
| Current liabilities associated with assets held for sale | | 145 | 173 |
| Accrued expenses and other current liabilities | | 282 | 342 |
| Total current liabilities | | 3,657 | 4,645 |
| Debentures exchangeable into shares of Chevron Corporation common stock | | 641 | 727 |
| Other long-term debt | | 6,283 | 4,841 |
| Financial instruments, at fair value | | 488 | 302 |
| Asset retirement obligation, at fair value | | 1,236 | 804 |
| Liabilities associated with assets held for sale | | 404 | 429 |
| Other liabilities | | 699 | 583 |
| Deferred income taxes | | 6,042 | 5,290 |
| Stockholders' equity: | | | |
| Preferred stock of $1.00 par value. Authorized 4,500,000 shares; issued 1,500,000 ($150 million aggregate liquidation value) | | 1 | 1 |
| Common stock of $0.10 par value. Authorized 800,000,000 shares; issued 444,214,000 in 2007 and 444,040,000 in 2006 | | 44 | 44 |
| Additional paid-in capital | | 6,743 | 6,840 |
| Retained earnings | | 12,813 | 9,114 |
| Accumulated other comprehensive income | | 2,405 | 1,444 |
| Treasury stock, at cost. 11,000 shares in 2006 | | — | (1) |
| Total stockholders' equity | | 22,006 | 17,442 |
| Commitments and contingencies (Note 8) | | | |
| Total liabilities and stockholders' equity | $ | 41,456 | 35,063 |

See accompanying notes to consolidated financial statements.

# Consolidated Statements of Operations

DEVON ENERGY CORPORATION AND SUBSIDIARIES

| | Year Ended December 31, 2007 | 2006 | 2005 |
|---|---|---|---|
| | (In millions, except per share amounts) | | |
| Revenues: | | | |
| Oil sales | $ 3,493 | 2,434 | 1,794 |
| Gas sales | 5,163 | 4,912 | 5,761 |
| NGL sales | 970 | 749 | 680 |
| Marketing and midstream revenues | 1,736 | 1,672 | 1,792 |
| Total revenues | 11,362 | 9,767 | 10,027 |
| Expenses and other income, net: | | | |
| Lease operating expenses | 1,828 | 1,425 | 1,244 |
| Production taxes | 340 | 341 | 335 |
| Marketing and midstream operating costs and expenses | 1,227 | 1,236 | 1,342 |
| Depreciation, depletion and amortization of oil and gas properties | 2,655 | 2,058 | 1,767 |
| Depreciation and amortization of non-oil and gas properties | 203 | 173 | 157 |
| Accretion of asset retirement obligation | 74 | 47 | 42 |
| General and administrative expenses | 513 | 397 | 291 |
| Interest expense | 430 | 421 | 533 |
| Change in fair value of financial instruments | (34) | 178 | 94 |
| Reduction of carrying value of oil and gas properties | — | 36 | 42 |
| Other income, net | (98) | (115) | (198) |
| Total expenses and other income, net | 7,138 | 6,197 | 5,649 |
| Earnings from continuing operations before income tax expense | 4,224 | 3,570 | 4,378 |
| Income tax expense: | | | |
| Current | 500 | 528 | 1,033 |
| Deferred | 578 | 408 | 448 |
| Total income tax expense | 1,078 | 936 | 1,481 |
| Earnings from continuing operations | 3,146 | 2,634 | 2,897 |
| Discontinued operations: | | | |
| Earnings from discontinued operations before income taxes | 696 | 464 | 173 |
| Income tax expense | 236 | 252 | 140 |
| Earnings from discontinued operations | 460 | 212 | 33 |
| Net earnings | 3,606 | 2,846 | 2,930 |
| Preferred stock dividends | 10 | 10 | 10 |
| Net earnings applicable to common stockholders | $ 3,596 | 2,836 | 2,920 |
| Basic net earnings per share: | | | |
| Earnings from continuing operations | $ 7.05 | 5.94 | 6.31 |
| Earnings from discontinued operations | 1.03 | 0.48 | 0.07 |
| Net earnings | $ 8.08 | 6.42 | 6.38 |
| Diluted net earnings per share: | | | |
| Earnings from continuing operations | $ 6.97 | 5.87 | 6.19 |
| Earnings from discontinued operations | 1.03 | 0.47 | 0.07 |
| Net earnings | $ 8.00 | 6.34 | 6.26 |
| Weighted average common shares outstanding: | | | |
| Basic | 445 | 442 | 458 |
| Diluted | 450 | 448 | 470 |

See accompanying notes to consolidated financial statements.

# Consolidated Statements of Comprehensive Income

DEVON ENERGY CORPORATION AND SUBSIDIARIES

| | Year Ended December 31, 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (In millions) | |
| Net earnings | $ 3,606 | 2,846 | 2,930 |
| Foreign currency translation: | | | |
| Change in cumulative translation adjustment | 1,389 | (25) | 181 |
| Income tax benefit (expense) | (42) | 28 | (19) |
| Total | 1,347 | 3 | 162 |
| Derivative financial instruments: | | | |
| Unrealized change in fair value | — | — | (255) |
| Reclassification adjustment for realized (gains) losses included in net earnings | (1) | (2) | 685 |
| Income tax expense | — | — | (141) |
| Total | (1) | (2) | 289 |
| Pension and postretirement benefit plans: | | | |
| Net actuarial loss and prior service cost arising in current year | (90) | — | — |
| Recognition of net actuarial loss and prior service cost in net earnings | 14 | — | — |
| Curtailment of pension benefits | 16 | — | — |
| Change in additional minimum pension liability | — | 30 | (8) |
| Income tax benefit (expense) | 23 | (13) | 3 |
| Total | (37) | 17 | (5) |
| Investment in Chevron Corporation common stock: | | | |
| Unrealized holding gain | — | 238 | 60 |
| Income tax expense | — | (86) | (22) |
| Total | — | 152 | 38 |
| Other comprehensive income, net of tax | 1,309 | 170 | 484 |
| Comprehensive income | $ 4,915 | 3,016 | 3,414 |

See accompanying notes to consolidated financial statements.

# Consolidated Statements of Stockholders' Equity

DEVON ENERGY CORPORATION AND SUBSIDIARIES

| | Preferred Stock | Common Stock Shares | Common Stock Amount | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | Treasury Stock | Total Stockholders' Equity |
|---|---|---|---|---|---|---|---|---|
| | | | | (In millions) | | | | |
| Balance as of December 31, 2004 | $ 1 | 484 | $ 48 | 9,002 | 3,693 | 930 | — | 13,674 |
| Net earnings | — | — | — | — | 2,930 | — | — | 2,930 |
| Other comprehensive income | — | — | — | — | — | 484 | — | 484 |
| Stock option exercises | — | 5 | — | 124 | — | — | — | 124 |
| Restricted stock grants, net of cancellations | — | 1 | — | — | — | — | — | — |
| Common stock repurchased | — | (47) | — | — | — | — | (2,275) | (2,275) |
| Common stock retired | — | — | (4) | (2,269) | — | — | 2,273 | — |
| Common stock dividends | — | — | — | — | (136) | — | — | (136) |
| Preferred stock dividends | — | — | — | — | (10) | — | — | (10) |
| Share-based compensation | — | — | — | 27 | — | — | — | 27 |
| Excess tax benefits on share-based compensation | — | — | — | 44 | — | — | — | 44 |
| Balance as of December 31, 2005 | 1 | 443 | 44 | 6,928 | 6,477 | 1,414 | (2) | 14,862 |
| Net earnings | — | — | — | — | 2,846 | — | — | 2,846 |
| Other comprehensive income | — | — | — | — | — | 170 | — | 170 |
| Adoption of FASB Statement No. 158 | — | — | — | — | — | (140) | — | (140) |
| Stock option exercises | — | 3 | — | 73 | — | — | — | 73 |
| Restricted stock grants, net of cancellations | — | 2 | — | (3) | — | — | — | (3) |
| Common stock repurchased | — | (4) | — | — | — | — | (277) | (277) |
| Common stock retired | — | — | — | (278) | — | — | 278 | — |
| Common stock dividends | — | — | — | — | (199) | — | — | (199) |
| Preferred stock dividends | — | — | — | — | (10) | — | — | (10) |
| Share-based compensation | — | — | — | 84 | — | — | — | 84 |
| Excess tax benefits on share-based compensation | — | — | — | 36 | — | — | — | 36 |
| Balance as of December 31, 2006 | 1 | 444 | 44 | 6,840 | 9,114 | 1,444 | (1) | 17,442 |
| Net earnings | — | — | — | — | 3,606 | — | — | 3,606 |
| Other comprehensive income | — | — | — | — | — | 1,309 | — | 1,309 |
| Adoption of FASB Statement No. 159 | — | — | — | — | 364 | (364) | — | — |
| Adoption of FASB Interpretation No. 48 | — | — | — | — | (11) | — | — | (11) |
| Adoption of FASB Statement No. 158 | — | — | — | — | (1) | 16 | — | 15 |
| Stock option exercises | — | 3 | 1 | 90 | — | — | — | 91 |
| Restricted stock grants, net of cancellations | — | 2 | — | — | — | — | — | — |
| Common stock repurchased | — | (5) | — | — | — | — | (362) | (362) |
| Common stock retired | — | — | (1) | (362) | — | — | 363 | — |
| Common stock dividends | — | — | — | — | (249) | — | — | (249) |
| Preferred stock dividends | — | — | — | — | (10) | — | — | (10) |
| Share-based compensation | — | — | — | 131 | — | — | — | 131 |
| Excess tax benefits on share-based compensation | — | — | — | 44 | — | — | — | 44 |
| Balance as of December 31, 2007 | $ 1 | 444 | $ 44 | 6,743 | 12,813 | 2,405 | — | 22,006 |

See accompanying notes to consolidated financial statements.

# Consolidated Statements of Cash Flows

DEVON ENERGY CORPORATION AND SUBSIDIARIES

| | | Year Ended December 31, 2007 | 2006 | 2005 |
|---|---|---|---|---|
| | | | (In millions) | |
| Cash flows from operating activities: | | | | |
| Net earnings | $ | 3,606 | 2,846 | 2,930 |
| Earnings from discontinued operations, net of tax | | (460) | (212) | (33) |
| Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities: | | | | |
| Depreciation, depletion and amortization | | 2,858 | 2,231 | 1,924 |
| Deferred income tax expense | | 578 | 408 | 448 |
| Net gain on sales of non-oil and gas property and equipment | | (1) | (5) | (150) |
| Reduction of carrying value of oil and gas properties | | — | 36 | 42 |
| Other noncash charges | | 177 | 269 | 127 |
| (Increase) decrease in assets: | | | | |
| Accounts receivable | | (329) | 91 | (151) |
| Other current assets | | (38) | (33) | (16) |
| Long-term other assets | | (92) | (58) | 35 |
| Increase (decrease) in liabilities: | | | | |
| Accounts payable | | 119 | (175) | 247 |
| Income taxes payable | | (28) | (245) | 70 |
| Debt, including current maturities | | — | — | (67) |
| Other current liabilities | | (223) | 80 | (36) |
| Long-term other liabilities | | (5) | 141 | (73) |
| Cash provided by operating activities – continuing operations | | 6,162 | 5,374 | 5,297 |
| Cash provided by operating activities – discontinued operations | | 489 | 619 | 315 |
| Net cash provided by operating activities | | 6,651 | 5,993 | 5,612 |
| Cash flows from investing activities: | | | | |
| Proceeds from sales of property and equipment | | 76 | 40 | 2,151 |
| Capital expenditures, including acquisition of business | | (6,158) | (7,346) | (3,813) |
| Purchases of short-term investments | | (934) | (2,395) | (4,020) |
| Sales of short-term investments | | 1,136 | 2,501 | 4,307 |
| Cash used in investing activities – continuing operations | | (5,880) | (7,200) | (1,375) |
| Cash (provided by) used in investing activities – discontinued operations | | 166 | (249) | (277) |
| Net cash used in investing activities | | (5,714) | (7,449) | (1,652) |
| Cash flows from financing activities: | | | | |
| Net senior credit facility borrowings, net of issuance costs | | 1,450 | — | — |
| Net commercial paper (repayments) borrowings, net of issuance costs | | (804) | 1,808 | — |
| Principal payments on debt, including current maturities | | (567) | (862) | (1,258) |
| Proceeds from stock option exercises | | 91 | 73 | 124 |
| Repurchases of common stock | | (326) | (253) | (2,263) |
| Dividends paid on common and preferred stock | | (259) | (209) | (146) |
| Excess tax benefits related to share-based compensation | | 44 | 36 | — |
| Net cash (used in) provided by financing activities | | (371) | 593 | (3,543) |
| Effect of exchange rate changes on cash | | 51 | 13 | 37 |
| Net increase (decrease) in cash and cash equivalents | | 617 | (850) | 454 |
| Cash and cash equivalents at beginning of year (including cash related to assets held for sale) | | 756 | 1,606 | 1,152 |
| Cash and cash equivalents at end of year (including cash related to assets held for sale) | $ | 1,373 | 756 | 1,606 |
| Supplementary cash flow data: | | | | |
| Interest paid (net of capitalized interest) | $ | 406 | 384 | 593 |
| Income taxes paid (continuing and discontinued operations) | $ | 588 | 960 | 1,092 |

See accompanying notes to consolidated financial statements.

## 1. Summary of Significant Accounting Policies

Accounting policies used by Devon Energy Corporation and subsidiaries ("Devon") reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are briefly discussed below.

### *Nature of Business and Principles of Consolidation*

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of properties. Such activities in the United States are concentrated in the following geographic areas:

- the Mid-Continent area of the central and southern United States, principally in north and east Texas and Oklahoma;
- the Permian Basin within Texas and New Mexico;
- the Rocky Mountains area of the United States stretching from the Canadian border into northern New Mexico;
- the offshore areas of the Gulf of Mexico; and
- the onshore areas of the Gulf Coast, principally in south Texas and south Louisiana.

Devon's Canadian operations are located primarily in the provinces of Alberta, British Columbia and Saskatchewan. Devon's international operations — outside of North America — are located primarily in Azerbaijan, Brazil and China. In October 2007, Devon sold its assets and terminated its operations in Egypt. In January 2007, Devon announced its plans to divest its assets and terminate its operations in West Africa. These divestiture activities are described more fully in Note 13.

Devon also has marketing and midstream operations that perform various activities to support the oil and gas operations of Devon as well as unrelated third parties. Such activities include marketing natural gas, crude oil and NGLs, as well as constructing and operating pipelines, storage and treating facilities and gas processing plants.

The accounts of Devon's controlled subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

### *Use of Estimates in the Preparation of Financial Statements*

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include the following:

- estimates of proved reserves and related estimates of the present value of future net revenues;
- the carrying value of oil and gas properties;
- estimates of the fair value of reporting units and related assessment of goodwill for impairment;
- asset retirement obligations;
- income taxes;
- derivative financial instruments;
- obligations related to employee benefits; and
- legal and environmental risks and exposures.

### *Property and Equipment*

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and that are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the estimated after-tax future net revenues, discounted at 10% per annum, from proved oil, natural gas and NGL reserves plus the cost of properties not subject to amortization. Estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. In calculating future net revenues, prices and costs used are those as of the end of the appropriate quarterly period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including derivative contracts in place that qualify for hedge accounting treatment. None of Devon's outstanding derivative contracts at December 31, 2007 or December 31, 2006 qualified for hedge accounting treatment.

Any excess of the net book value, less related deferred taxes, over the ceiling is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values.

Unproved properties are excluded from amortized capitalized costs until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment quarterly. Significant unproved properties are assessed individually. Costs of insignificant unproved properties are transferred to amortizable costs over average holding periods ranging from three years for onshore properties to seven years for offshore properties.

No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves in a particular country.

Depreciation of midstream pipelines are provided on a units-of-production basis. Depreciation and amortization of other property and equipment, including corporate and other midstream assets and leasehold improvements, are provided using the straight-line method based on estimated useful lives ranging from three to 39 years.

Devon recognizes liabilities for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and midstream pipelines and processing plants when there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

### *Short-Term Investments and Other Marketable Securities*

Devon reports its short-term investments and other marketable securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity. At December 31, 2007 and 2006, Devon's short-term investments consisted of $372 million and $574 million, respectively, of auction rate securities classified as available for sale. Although Devon's auction rate securities generally have contractual maturities of more than 20 years, the underlying interest rates on such securities are scheduled to reset every 28 days. Therefore, these auction rate securities are generally priced and subsequently trade as short-term investments because of the interest rate reset feature. As a result, Devon has classified its auction rate securities as short-term investments in the accompanying consolidated balance sheet.

Devon owns approximately 14.2 million shares of Chevron Corporation ("Chevron") common stock. The majority of these shares are held in connection with debt owed by Devon that contains an exchange option. This exchange option allows the debt holders, prior to the debt's maturity of August 15, 2008, to exchange the debt for the shares of Chevron common stock owned by Devon. However, Devon has the option to settle any exchanges with cash equal to the market value of Chevron common stock at the time of the exchange. As described more fully in Note 4, Devon has paid the cash equivalent of the Chevron common stock to settle all exchange requests through December 31, 2007.

The shares of Chevron common stock and the exchange option embedded in the debt have always been recorded on Devon's balance sheet at fair value. However, pursuant to accounting rules prior to January 1, 2007, only the change in fair value of the embedded option had historically been included in Devon's results of operations. Conversely, the change in fair value of the Chevron common stock had not been included in Devon's results of operations, but instead had been recorded directly to stockholders' equity as part of "accumulated other comprehensive income."

Effective January 1, 2007, Devon adopted Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. Statement No. 159 allows a company the option to value its financial assets and liabilities, on an instrument by instrument basis, at fair value, and include the change in fair value of such assets and liabilities in its results of operations. Devon chose to apply the provisions of Statement No. 159 to its shares of Chevron common stock. Accordingly, beginning with the first quarter of 2007, the change in fair value of the Chevron common stock owned by Devon, along with the change in fair value of the related exchange option, are both included in Devon's results of operations.

For the year ended December 31, 2007, the change in fair value of financial instruments caption on Devon's statement of operations includes an unrealized gain of $281 million related to the Chevron common stock and an unrealized loss of $248 million related to the embedded option. For the years ended December 31, 2006 and 2005, prior to adopting Statement No. 159, unrealized losses of $181 million and $54 million, respectively, related to the change in fair value of the embedded option were included in the change in fair value of financial instruments caption on Devon's statements of operations.

As of December 31, 2006, $364 million of after-tax unrealized gains related to Devon's investment in the Chevron common stock was included in accumulated other comprehensive income. This is the amount of unrealized gains that, prior to Devon's adoption of Statement No. 159, had not been recorded in Devon's historical results of operations. Upon the adoption of Statement No. 159 as of January 1, 2007, this $364 million of unrealized gains was reclassified on Devon's balance sheet from accumulated other comprehensive income to retained earnings.

In conjunction with the adoption of Statement No. 159, Devon also adopted on January 1, 2007 Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*. Statement No. 157 provides a common definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements, but does not require any new fair value measurements. The adoption of Statement No. 157 had no impact on Devon's financial statements, but the adoption did result in additional required disclosures as set forth in Note 5.

### *Goodwill*

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid. Devon performed annual impairment tests of goodwill in the fourth quarters of 2007, 2006 and 2005. Based on these assessments, no impairment of goodwill was required.

The table below provides a summary of Devon's goodwill, by assigned reporting unit, as of December 31, 2007 and 2006. The increase in goodwill from 2006 to 2007 is largely due to changes in the exchange rate between the U.S. dollar and the Canadian dollar.

| | December 31, | |
|---|---|---|
| | 2007 | 2006 |
| | (In millions) | |
| United States | $ 3,050 | 3,053 |
| Canada | 3,054 | 2,585 |
| International | 68 | 68 |
| Total | $ 6,172 | 5,706 |

### *Revenue Recognition and Gas Balancing*

Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline or truck or a tanker lifting has occurred. Cash received relating to future production is deferred and recognized when all revenue recognition criteria are met. Taxes assessed by governmental authorities on oil, gas and NGL revenues are presented separately from such revenues as production taxes in the statement of operations.

Devon follows the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which Devon is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the underproduced owner to recoup its entitled share through production. The liability is priced based on current market prices. No receivables are recorded for those wells where Devon has taken less than its share of production unless all revenue recognition criteria are met. If an imbalance exists at the time the wells' reserves are depleted, settlements are made among the joint interest owners under a variety of arrangements.

Marketing and midstream revenues are recorded at the time products are sold or services are provided to third parties at a fixed or determinable price, delivery or performance has occurred, title has transferred and collectibility of the revenue is probable. Revenues and expenses attributable to Devon's gas and NGL purchase and processing contracts are reported on a gross basis when Devon takes title to the products and has risks and rewards of ownership. The gas purchased under these contracts is processed in Devon-owned plants.

### *Major Purchasers*

During 2007, 2006 and 2005, no purchaser accounted for more than 10% of Devon's revenues from continuing operations.

### *Derivative Financial Instruments*

The majority of Devon's derivative financial instruments consist of commodity financial instruments used to manage Devon's cash flow exposure to oil and gas price volatility. Devon has also entered into interest rate swaps to manage its exposure to interest rate volatility. The interest rate swaps mitigate either the cash flow effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the fair value effects of interest rate fluctuations on fixed-rate debt. Devon also has an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron common stock.

All derivative financial instruments are recognized at their current fair value in the fair value of financial instruments caption on the balance sheet. Changes in the fair value of these derivative financial instruments are recorded in the statement of operations unless specific hedge accounting criteria are met. If such criteria are met for cash flow hedges, the effective portion of the change in the fair value is recorded directly to accumulated other comprehensive income, a component of stockholders' equity, until the hedged transaction occurs. The ineffective portion of the change in fair value is recorded in the statement of operations. If such criteria are met for fair value hedges, the change in the fair value is recorded in the statement of operations with an offsetting amount recorded for the change in fair value of the hedged item.

A derivative financial instrument qualifies for hedge accounting treatment if Devon designates the instrument as such on the date the derivative contract is entered into or the date of a business combination or other transaction that includes derivative contracts. Additionally, Devon must document the relationship between the hedging instrument and hedged item, as well as the risk-management objective and strategy for undertaking the instrument. Devon must also assess, both at the instrument's inception and on an ongoing basis, whether the derivative is highly effective in offsetting the change in cash flow of the hedged item.

During 2007 and 2006, Devon entered into and acquired certain commodity derivative instruments. For such instruments, Devon chose not to meet the necessary criteria to qualify these derivative instruments for hedge accounting treatment. Therefore, for the years ended December 31, 2007 and 2006, the changes in fair value related to these instruments were recorded to gas sales in the statements of operations. Such amounts recorded were a $25 million loss and a $37 million gain in 2007 and 2006, respectively.

The following table presents the components of the 2007, 2006 and 2005 change in fair value of financial instruments presented in the accompanying statement of operations. Significant items are discussed in more detail following the table.

| | | 2007 | 2006 | 2005 |
|---|---|---|---|---|
| | | | (In millions) | |
| Losses (gains) from: | | | | |
| Option embedded in exchangeable debentures | $ | 248 | 181 | 54 |
| Chevron common stock | | (281) | — | — |
| Interest rate swaps | | (1) | (3) | (4) |
| Non-qualifying commodity hedges | | — | — | 39 |
| Ineffectiveness of commodity hedges | | — | — | 5 |
| Total change in fair value of financial instruments | $ | (34) | 178 | 94 |

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron common stock (see Note 4). These unrealized losses were caused primarily by increases in the price of Chevron's common stock.

As previously discussed in the Short-Term Investments and Other Marketable Securities section of Note 1, beginning in 2007, the change in fair value of the Chevron common stock owned by Devon is included in Devon's results of operations rather than accumulated other comprehensive income. The unrealized gain on this investment resulted from the increase in the price of Chevron's common stock.

In addition to the changes in fair value of Devon's interest rate swaps presented in the table above, settlements on these interest rate swaps increased interest expense by $4 million, $14 million and $10 million in 2007, 2006 and 2005, respectively.

During 2005, Devon had a number of commodity derivative instruments that qualified for hedge accounting treatment as described above. During 2005, certain of these derivatives ceased to qualify for hedge accounting treatment. In the third quarter of 2005, certain oil derivatives ceased to qualify for hedge accounting primarily as a result of deferred production caused by hurricanes in the Gulf of Mexico. Because these contracts no longer qualified for hedge accounting, Devon recognized $39 million in losses as change in fair value of derivative financial instruments in the accompanying 2005 statement of operations.

In addition to the changes in fair value of non-qualifying commodity hedges presented in the table above, Devon also recognized in 2005 a $55 million loss related to certain oil hedges that no longer qualified for hedge accounting due to the effect of the 2005 property divestiture program. These commodity instruments related to 5,000 barrels per day of U.S. oil production and 3,000 barrels per day of Canadian oil production from properties that were sold as part of Devon's divestiture program. This loss is presented in other income in the 2005 statement of operations.

The following table presents the balances of Devon's accumulated net gain (loss) on cash flow hedges included in accumulated other comprehensive income (in millions).

| | | |
|---|---|---|
| December 31, 2004 | $ | (286) |
| December 31, 2005 | $ | 3 |
| December 31, 2006 | $ | 1 |
| December 31, 2007 | $ | — |

By using derivative financial instruments to hedge exposures to changes in commodity prices and interest rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with counterparties that Devon believes are minimal credit risks. It is Devon's policy to enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers.

Market risk is the change in the value of a derivative financial instrument that results from a change in commodity prices, interest rates or other relevant underlyings. The market risk associated with commodity price and interest rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken. The oil and gas reference prices upon which the commodity hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon. Devon does not hold or issue derivative financial instruments for speculative trading purposes.

### *Stock Options*

Effective January 1, 2006, Devon adopted Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment*, ("SFAS No. 123(R)"), using the modified prospective transition method. SFAS No. 123(R) requires equity-classified, share-based payments to employees, including grants of employee stock options, to be valued at fair value on the date of grant and to be expensed over the applicable vesting period. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized in compensation expense over the applicable vesting period. Also, any previously granted awards that were not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon Devon's adoption of SFAS No. 123(R).

Prior to adopting SFAS No. 123(R), Devon accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* ("APB No. 25") and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

Had the fair value provisions of SFAS No. 123(R) been applied in 2005, Devon's 2005 net earnings and net earnings per share would have differed from the amounts actually reported as shown in the following table (in millions, except per share amounts).

| | | |
|---|---|---|
| Net earnings available to common stockholders, as reported | $ | 2,920 |
| Add share-based employee compensation expense included in reported net earnings, net of related tax expense | | 18 |
| Deduct total share-based employee compensation expense determined under fair value based method for all awards (see Note 9), net of related tax expense | | (44) |
| Net earnings available to common stockholders, pro forma | $ | 2,894 |
| Net earnings per share available to common stockholders: | | |
| As reported: | | |
| Basic | $ | 6.38 |
| Diluted | $ | 6.26 |
| Pro forma: | | |
| Basic | $ | 6.32 |
| Diluted | $ | 6.21 |

Prior to the adoption of SFAS No. 123(R), Devon presented all tax benefits of deductions resulting from the exercise of stock options as operating cash inflows in the statement of cash flows. SFAS No. 123(R) requires the cash inflows resulting from tax deductions in excess of the compensation expense recognized for those stock options ("excess tax benefits") to be classified as financing cash inflows. As required by SFAS No. 123(R), Devon recognized $44 million and $36 million of excess tax benefits as financing cash inflows for 2007 and 2006, respectively. In 2005, excess tax benefits of $44 million were classified as operating cash inflows.

### *Income Taxes*

Devon is subject to current income taxes assessed by the federal and various state jurisdictions in the United States and by other foreign jurisdictions. In addition, Devon accounts for deferred income taxes related to these jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

At December 31, 2007, undistributed earnings of foreign subsidiaries included in continuing operations were determined to be permanently reinvested. Therefore, no U.S. deferred income taxes were provided on such amounts at December 31, 2007. If it becomes apparent that some or all of the undistributed earnings will be distributed, Devon would then record taxes on those earnings.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109.* Interpretation No. 48 prescribes a threshold for recognizing the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. Liabilities for unrecognized tax benefits related to such tax positions are included in other long-term liabilities unless the tax position is expected to be settled within the upcoming year, in which case the liabilities are included in accrued expenses and other current liabilities. Interest and penalties related to unrecognized tax benefits are included in income tax expense.

On January 1, 2007, Devon adopted Interpretation No. 48 and recorded an $11 million reduction to the January 1, 2007 balance of retained earnings related to unrecognized tax benefits. The $11 million included $8 million for related interest and penalties. An additional $3 million of liabilities were recorded with a corresponding increase to goodwill.

As a result of the adoption of Interpretation No. 48, certain liabilities included in income taxes payable and deferred income taxes were reclassified to other current and long-term liabilities in the accompanying balance sheet. The total $14 million increase in liabilities included a $17 million increase to long-term liabilities, partially offset by a $3 million reduction to current liabilities.

Additional information regarding Devon's unrecognized tax benefits, including changes in such amounts during 2007, is provided in Note 12.

### *General and Administrative Expenses*

General and administrative expenses are reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Devon and net of amounts capitalized pursuant to the full cost method of accounting.

### *Net Earnings Per Common Share*

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share, as calculated using the treasury stock method, reflects the potential dilution that could occur if Devon's dilutive outstanding stock options were exercised. For 2005, the calculation of diluted shares also assumed that Devon's previously outstanding zero coupon convertible senior debentures were converted to common stock.

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings per share for 2007, 2006 and 2005.

| | Net Earnings Applicable to Common Stockholders | Weighted Average Common Shares Outstanding | Net Earnings per Share |
|---|---|---|---|
| | (In millions, except per share amounts) | | |
| **Year Ended December 31, 2007:** | | | |
| Earnings from continuing operations | $ 3,146 | | |
| Less preferred stock dividends | (10) | | |
| Basic earnings per share | 3,136 | 445 | $ 7.05 |
| Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options | — | 5 | |
| Diluted earnings per share | $ 3,136 | 450 | $ 6.97 |
| **Year Ended December 31, 2006:** | | | |
| Earnings from continuing operations | $ 2,634 | | |
| Less preferred stock dividends | (10) | | |
| Basic earnings per share | 2,624 | 442 | $ 5.94 |
| Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options | — | 6 | |
| Diluted earnings per share | $ 2,624 | 448 | $ 5.87 |
| **Year Ended December 31, 2005:** | | | |
| Earnings from continuing operations | $ 2,897 | | |
| Less preferred stock dividends | (10) | | |
| Basic earnings per share | 2,887 | 458 | $ 6.31 |
| Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options | — | 8 | |
| Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (increase in net earnings is net of income tax expense of $14 million) (1) | 24 | 4 | |
| Diluted earnings per share | $ 2,911 | 470 | $ 6.19 |

(1) The senior convertible debentures were retired in June 2005 prior to their stated maturity.

Certain options to purchase shares of Devon's common stock were excluded from the dilution calculations because the options were antidilutive. These excluded options totaled 2 million, 3 million and 0.2 million in 2007, 2006 and 2005, respectively.

*Foreign Currency Translation Adjustments*

The U.S. dollar is the functional currency for Devon's consolidated operations except its Canadian subsidiaries, which use the Canadian dollar as the functional currency. Therefore, the assets and liabilities of Devon's Canadian subsidiaries are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' equity. The following table presents the balances of Devon's cumulative translation adjustments included in accumulated other comprehensive income (in millions).

| | |
|---|---|
| December 31, 2004 | $ 1,054 |
| December 31, 2005 | $ 1,216 |
| December 31, 2006 | $ 1,219 |
| December 31, 2007 | $ 2,566 |

*Statements of Cash Flows*

For purposes of the consolidated statements of cash flows, Devon considers all highly liquid investments with original contractual maturities of three months or less to be cash equivalents.

*Commitments and Contingencies*

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Liabilities for environmental remediation or restoration claims are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with Devon's accounting policy for property and equipment. Reference is made to Note 8 for a discussion of amounts recorded for these liabilities.

*Recently Issued Accounting Standards Not Yet Adopted*

In December 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141(R), *Business Combinations*, which replaces Statement No. 141. Statement No. 141(R) retains the fundamental requirements of Statement No. 141 that an acquirer be identified and the acquisition method of accounting (previously called the purchase method) be used for all business combinations. Statement No. 141(R)'s scope is broader than that of Statement No. 141, which applied only to business combinations in which control was obtained by transferring consideration. By applying the acquisition method to all transactions and other events in which one entity obtains control over one or more other businesses, Statement No. 141(R) improves the comparability of the information about business combinations provided in financial reports. Statement No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures identifiable assets acquired, liabilities assumed and any noncontrolling interest in the acquiree, as well as any resulting goodwill. Statement No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Devon will evaluate how the new requirements of Statement No. 141(R) would impact any business combinations completed in 2009 or thereafter.

In December 2007, the FASB also issued Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of Accounting Research Bulletin No. 51*. A noncontrolling interest, sometimes called a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. Statement No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Under Statement No. 160, noncontrolling interests in a subsidiary must be reported as a component of consolidated equity separate from the parent's equity. Additionally, the amounts of consolidated net income attributable to both the parent and the noncontrolling interest must be reported separately on the face of the income statement. Statement No. 160 is effective for fiscal years beginning on or after December 15, 2008 and earlier adoption is prohibited. Devon does not expect the adoption of Statement No. 160 to have a material impact on its financial statements and related disclosures.

## 2. Accounts Receivable

The components of accounts receivable include the following:

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| | (In millions) | |
| Oil, gas and NGL revenue | $ 1,184 | 951 |
| Joint interest billings | 240 | 209 |
| Marketing and midstream revenue | 183 | 138 |
| Other | 177 | 31 |
| Gross accounts receivable | 1,784 | 1,329 |
| Allowance for doubtful accounts | (5) | (5) |
| Net accounts receivable | $ 1,779 | 1,324 |

## 3. Property and Equipment and Asset Retirement Obligations

Property and equipment include the following:

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| | (In millions) | |
| Oil and gas properties: | | |
| Subject to amortization | $ 42,141 | 33,922 |
| Not subject to amortization | 3,417 | 3,293 |
| Accumulated depreciation, depletion and amortization | (19,507) | (15,756) |
| Net oil and gas properties | 26,051 | 21,459 |
| Other property and equipment | 2,915 | 2,370 |
| Accumulated depreciation and amortization | (887) | (673) |
| Net other property and equipment | 2,028 | 1,697 |
| Property and equipment, net of accumulated depreciation, depletion and amortization | $ 28,079 | 23,156 |

The costs not subject to amortization relate to unproved properties, which are excluded from amortized capital costs until it is determined whether or not proved reserves can be assigned to such properties. The excluded properties are assessed for impairment quarterly. Subject to industry conditions, evaluation of most of these properties, and therefore the inclusion of their costs in the amortized capital costs, is expected to be completed within five years.

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2007:

| | Costs Incurred In 2007 | 2006 | 2005 | Prior to 2005 | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| Acquisition costs | $ 223 | 1,226 | 253 | 316 | 2,018 |
| Exploration costs | 424 | 378 | 123 | 92 | 1,017 |
| Development costs | 94 | 114 | 22 | — | 230 |
| Capitalized interest | 68 | 49 | 30 | 5 | 152 |
| Total oil and gas properties not subject to amortization | $ 809 | 1,767 | 428 | 413 | 3,417 |

### *Chief Acquisition*

On June 29, 2006, Devon acquired the oil and gas assets of privately-owned Chief Holdings LLC ("Chief"). Devon paid $2.0 billion in cash and assumed approximately $0.2 billion of net liabilities in the transaction for a total purchase price of $2.2 billion. Devon funded the acquisition price, and the immediate retirement of $180 million of assumed debt, with $718 million of cash on hand and approximately $1.4 billion of borrowings issued under its commercial paper program. The acquired oil and gas properties consisted of 99.7 MMBoe (unaudited) of proved reserves and leasehold totaling 169,000 net acres located in the Barnett Shale area of north Texas. Devon allocated approximately $1.0 billion of the purchase price to proved reserves and approximately $1.2 billion to unproved properties.

### *Property Divestitures*

In November 2006 and January 2007, Devon announced plans to divest its operations in Egypt and West Africa. In October 2007, Devon completed the sale of its Egyptian operations and received proceeds of $341 million. See Note 13 for more discussion regarding these divestitures.

### *Asset Retirement Obligations*

Following is a reconciliation of the asset retirement obligation for the years ended December 31, 2007 and 2006.

| | Year Ended December 31, 2007 | 2006 |
|---|---|---|
| | (In millions) | |
| Asset retirement obligation as of beginning of year | $ 857 | 636 |
| Liabilities incurred | 57 | 102 |
| Liabilities settled | (68) | (59) |
| Liabilities assumed by others | (3) | — |
| Revision of estimated obligation | 311 | 135 |
| Accretion expense on discounted obligation | 74 | 47 |
| Foreign currency translation adjustment | 90 | (4) |
| Asset retirement obligation as of end of year | 1,318 | 857 |
| Less current portion | 82 | 53 |
| Asset retirement obligation, long-term | $ 1,236 | 804 |

During 2007 and 2006, Devon recognized a $311 million and $135 million revision to its asset retirement obligation, respectively. The primary factors causing the 2007 fair value increase were an overall increase in abandonment cost estimates and an increase in the assumed inflation rate. The effect of these factors was partially offset by the effect of an increase in the discount rate used to calculate the present value of the obligations. The primary factor causing the 2006 fair value increase was an overall increase in abandonment cost estimates.

## 4. Debt and Related Expenses

A summary of Devon's short-term and long-term debt is as follows:

| | December 31, 2007 | 2006 |
|---|---|---|
| | (In millions) | |
| Senior Credit Facility borrowings | $ 1,450 | — |
| Commercial paper | 1,004 | 1,808 |
| Debentures exchangeable into shares of Chevron common stock: | | |
| 4.90% due August 15, 2008 | 381 | 444 |
| 4.95% due August 15, 2008 | 271 | 316 |
| Discount on exchangeable debentures | (11) | (33) |
| Other debentures and notes: | | |
| 4.375% due October 1, 2007 | — | 400 |
| 10.125% due November 15, 2009 | 177 | 177 |
| 6.875% due September 30, 2011 | 1,750 | 1,750 |
| 7.25% due October 1, 2011 | 350 | 350 |
| 8.25% due July 1, 2018 | 125 | 125 |
| 7.50% due September 15, 2027 | 150 | 150 |
| 7.875% due September 30, 2031 | 1,250 | 1,250 |
| 7.95% due April 15, 2032 | 1,000 | 1,000 |
| Fair value adjustment on debt related to interest rate swaps | — | (5) |
| Net premium on other debentures and notes | 31 | 41 |
| | 7,928 | 7,773 |
| Less amount classified as short-term debt | 1,004 | 2,205 |
| Long-term debt | $ 6,924 | 5,568 |

Maturities of short-term and long-term debt as of December 31, 2007, excluding premiums and discounts, are as follows (in millions):

| | | |
|---|---|---|
| 2008 | $ | 1,004 |
| 2009 | | 177 |
| 2010 | | — |
| 2011 | | 2,100 |
| 2012 | | 2,102 |
| 2013 and thereafter | | 2,525 |
| Total | $ | 7,908 |

### *Credit Lines*

Devon has two revolving lines of credit that can be accessed to provide liquidity. As of December 31, 2007, Devon's combined available capacity under these credit facilities, net of $198 million of outstanding letters of credit and $1.0 billion of outstanding commercial paper, was $1.3 billion.

Devon's $2.5 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility") matures on April 7, 2012, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, Devon has the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders.

The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million. Amounts borrowed under the Senior Credit Facility may, at the election of Devon, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, Devon may elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $1.8 million that is payable quarterly in arrears. As of December 31, 2007, there were $1.4 billion of borrowings under the Senior Credit Facility at an average rate of 5.27%.

On August 7, 2007, Devon established a new $1.5 billion 364-day, syndicated, unsecured revolving senior credit facility (the "Short-Term Facility"). This facility provides Devon with provisional interim liquidity until the proceeds from divestitures of assets in Africa are received. The Short-Term Facility was also used to support an increase in Devon's commercial paper program from $2 billion to $3.5 billion.

The Short-Term Facility matures on August 5, 2008. At that time, all amounts outstanding will be due and payable unless the maturity is extended. Prior to August 5, 2008, Devon has the option to convert any outstanding principal amount of loans under the Short-Term Facility to a term loan that will be repayable in a single payment on August 4, 2009.

Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods of up to 12 months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Short-Term Facility currently provides for an annual facility fee of approximately $0.8 million that is payable quarterly in arrears. As of December 31, 2007, there were no borrowings under the Short-Term Facility.

The Senior Credit Facility and Short-Term Facility contain only one material financial covenant. This covenant requires Devon's ratio of total funded debt to total capitalization to be less than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in the consolidated financial statements. As defined in the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2007, Devon was in compliance with this covenant. Devon's debt-to-capitalization ratio at December 31, 2007, as calculated pursuant to the terms of the agreement, was 23.8%.

### *Commercial Paper*

Devon also has access to short-term credit under its commercial paper program. Total borrowings under the commercial paper program may not exceed $3.5 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility or the Short-Term Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between one and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2007, Devon had $1.0 billion of commercial paper debt outstanding at an average rate of 5.07%. The average borrowing rate for Devon's $1.8 billion of commercial paper debt outstanding at December 31, 2006 was 5.37%. Outstanding commercial paper is classified as short-term debt in the accompanying consolidated balance sheets.

### *Exchangeable Debentures*

The exchangeable debentures consist of $381 million of 4.90% debentures and $271 million of 4.95% debentures. The exchangeable debentures were issued on August 3, 1998 and mature August 15, 2008. The exchangeable debentures are callable at 100.5% of principal as of December 31, 2007.

The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of Chevron common stock that Devon owns. In lieu of delivering Chevron common stock to an exchanging debenture holder, Devon may, at its option, pay to such holder an amount of cash equal to the market value of the Chevron common stock. At maturity, holders who have not exercised their exchange rights will receive an amount in cash equal to the principal amount of the debentures.

During 2007, certain holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock prior to the debentures' August 15, 2008 maturity date. Devon elected to pay the exchanging debenture holders cash totaling $167 million in lieu of delivering shares of Chevron common stock. As a result of these exchanges, Devon retired outstanding exchangeable debentures with a book value totaling $105 million and reduced the related embedded derivative option's balance by $62 million.

As of December 31, 2007, Devon owned approximately 14.2 million shares of Chevron common stock. The majority of these shares are held for possible exchange when holders redeem their exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 18.6566 shares of Chevron common stock, an exchange rate equivalent to $53.60 per share of Chevron stock.

As of December 31, 2007, the exchangeable debentures are due within one year. However, Devon continues to classify this debt as long-term because it has the intent and ability to refinance these debentures on a long-term basis with the available capacity under its existing credit facilities or other long-tem financing arrangements.

The exchangeable debentures were assumed as part of the 1999 acquisition of PennzEnergy. As a result, the fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. In accordance with derivative accounting standards, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange Chevron common stock that is embedded in the debentures. Accordingly, a discount was recorded on the debentures and is being accreted using the effective interest method, which raised the effective interest rate on the debentures to 7.76%.

### *Other Debentures and Notes*

Following are descriptions of the various other debentures and notes outstanding at December 31, 2007, as listed in the table presented at the beginning of this note.

#### *Ocean Debt*

As a result of the merger with Ocean Energy, Inc., which closed April 25, 2003, Devon assumed $1.8 billion of debt. The table below summarizes the debt assumed that remains outstanding, the fair value of the debt at April 25, 2003, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using April 25, 2003, market interest rates. The premiums resulting from fair values exceeding face values are being amortized using the effective interest method. All of the notes are general unsecured obligations of Devon.

| Debt Assumed | Fair Value of Debt Assumed | Effective Rate of Debt Assumed |
|---|---|---|
| | (In millions) | |
| 7.250% due October 2011 (principal of $350 million) | $ 406 | 4.9% |
| 8.250% due July 2018 (principal of $125 million) | $ 147 | 5.5% |
| 7.500% due September 2027 (principal of $150 million) | $ 169 | 6.5% |

#### *10.125% Debentures due November 15, 2009*

These debentures were assumed as part of the PennzEnergy acquisition. The fair value of the debentures was determined using August 17, 1999, market interest rates. As a result, a premium was recorded on these debentures, which lowered the effective interest rate to 8.9%. The premium is being amortized using the effective interest method.

*6.875% Notes due September 30, 2011 and 7.875% Debentures due September 30, 2031*

On October 3, 2001, Devon, through Devon Financing Corporation, U.L.C. ("Devon Financing"), a wholly-owned finance subsidiary, sold these notes and debentures, which are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the acquisition of Anderson Exploration.

*7.95% Notes due April 15, 2032*

On March 25, 2002, Devon sold these notes, which are unsecured and unsubordinated obligations of Devon. The net proceeds received, after discounts and issuance costs, were $986 million and were used to retire other indebtedness.

***Interest Expense***

The following schedule includes the components of interest expense between 2005 and 2007.

| | | Year Ended December 31, | | |
|---|---|---|---|---|
| | | 2007 | 2006 | 2005 |
| | | | (In millions) | |
| Interest based on debt outstanding | $ | 508 | 486 | 507 |
| Capitalized interest | | (102) | (79) | (70) |
| Other interest | | 24 | 14 | 96 |
| Total interest expense | $ | 430 | 421 | 533 |

During 2005, Devon redeemed its $400 million 6.75% notes due March 15, 2011 and its zero coupon convertible senior debentures prior to their scheduled maturity dates. The other interest category in the table above includes $81 million in 2005 related to these early retirements.

## 5. Fair Value Measurements

Certain of Devon's assets and liabilities are reported at fair value in the accompanying balance sheets. Such assets and liabilities include amounts for both financial and nonfinancial instruments. The following tables provide fair value measurement information for such assets and liabilities as of December 31, 2007 and 2006.

The carrying values of cash and cash equivalents, accounts receivable and accounts payable (including income taxes payable and accrued expenses) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2007 and 2006. These assets and liabilities are not presented in the following tables.

| | | As of December 31, 2007 | | | | |
|---|---|---|---|---|---|---|
| | | | | Fair Value Measurements Using: | | |
| | | Carrying Amount | Total Fair Value | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
| | | | | (In millions) | | |
| Financial Assets (Liabilities): | | | | | | |
| Short-term investments | $ | 372 | 372 | 372 | — | — |
| Investment in Chevron common stock | $ | 1,324 | 1,324 | 1,324 | — | — |
| Oil and gas price swaps and collars | $ | 12 | 12 | — | 12 | — |
| Embedded option in exchangeable debentures | $ | (488) | (488) | — | (488) | — |
| Debt | $ | (7,928) | (9,055) | (1,140) | (7,915) | — |
| Asset retirement obligation | $ | (1,318) | (1,318) | — | — | (1,318) |

| | | | As of December 31, 2006 | | |
|---|---|---|---|---|---|
| | | | Fair Value Measurements Using: | | |
| | Carrying Amount | Total Fair Value | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
| | | | (In millions) | | |
| Financial Assets (Liabilities): | | | | | |
| Short-term investments | $ 574 | 574 | 574 | — | — |
| Investment in Chevron common stock | $ 1,043 | 1,043 | 1,043 | — | — |
| Oil and gas price swaps and collars | $ 39 | 39 | — | 39 | — |
| Interest rate swaps | $ (6) | (6) | — | (6) | — |
| Embedded option in exchangeable debentures | $ (302) | (302) | — | (302) | — |
| Debt | $ (7,773) | (8,725) | (1,056) | (7,669) | — |
| Asset retirement obligation | $ (857) | (857) | — | — | (857) |

Statement No. 157 (see Note 1) establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table above, this hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 3 inputs have the lowest priority. Devon uses appropriate valuation techniques based on the available inputs to measure the fair values of its assets and liabilities. When available, Devon measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value. Devon only uses Level 3 inputs to measure the fair value of its asset retirement obligation.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

### *Level 1 Fair Value Measurements*

*Short-term Investments* — The fair values of these investments are based on quoted market prices. Devon's short-term investments as of December 31, 2007 and 2006 consisted entirely of auction rate securities. All such securities held at December 31, 2007 were collateralized by student loans which are substantially guaranteed by the United States government. Subsequent to December 31, 2007, Devon has reduced its auction rate securities holdings to $153 million. However, beginning on February 8, 2008, Devon experienced difficulty selling certain of the securities due to the failure of the auction mechanism which provides liquidity to these securities. An auction failure means that the parties wishing to sell securities could not do so. The securities for which auctions have failed will continue to accrue interest and be auctioned every 28 days until the auction succeeds, the issuer calls the securities or the securities mature. Accordingly, there may be no effective mechanism for selling these securities, and the securities Devon owns may become long-term investments. At this time, Devon does not believe its auction rate securities are impaired or that the failure of the auction mechanism will have a material impact on its liquidity.

*Investment in Chevron Corporation common stock* — The fair value of this investment is based on a quoted market price.

*Debt* — Certain of the fixed-rate debt instruments actively trade in an established market. The fair values of this debt are based on quotes obtained from brokers.

### *Level 2 Fair Value Measurements*

*Oil and gas price swaps and collars* — The fair values of the oil and gas price swaps and collars are estimated using internal discounted cash flow calculations based upon forward commodity price curves, quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the agreements.

*Embedded option in exchangeable debentures* — The embedded option is not actively traded in an established market. Therefore, its fair value is estimated using quotes obtained from a broker for trades near the fair value measurement date.

*Debt* — Certain of the fixed-rate debt instruments do not actively trade in an established market. The fair values of this debt are estimated by discounting the principal and interest payments at rates available for debt with similar terms and maturity. The fair values of floating-rate debt are estimated to approximate the carrying amounts because the interest rates paid on such debt are generally set for periods of three months or less.

*Interest rate swaps* — The fair values of the interest rate swaps are estimated using internal discounted cash flow calculations based upon forward interest-rate yield curves or quotes obtained from counterparties to the agreements.

***Level 3 Fair Value Measurements***

*Asset retirement obligation* — The fair values of the asset retirement obligations are estimated using internal discounted cash flow calculations based upon Devon's estimates of future retirement costs. A reconciliation of the beginning and ending balances of Devon's asset retirement obligation, including a revision of the estimated fair value in 2007 and 2006, is presented in Note 3.

## 6. Retirement Plans

Devon has various non-contributory defined benefit pension plans, including qualified plans ("Qualified Plans") and nonqualified plans ("Supplemental Plans"). The Qualified Plans provide retirement benefits for U.S. and Canadian employees meeting certain age and service requirements. Benefits for the Qualified Plans are based on the employees' years of service and compensation and are funded from assets held in the plans' trusts.

Devon's funding policy regarding the Qualified Plans is to contribute the amount of funds necessary so that the Qualified Plans' assets will be approximately equal to the related accumulated benefit obligation. As of December 31, 2007 and 2006, the fair values of the Qualified Plans' assets were $619 million and $590 million, respectively, which were $62 million and $59 million more, respectively, than the related accumulated benefit obligation. The actual amount of contributions required during future periods will depend on investment returns from the plan assets during the same period as well as changes in long-term interest rates.

The Supplemental Plans provide retirement benefits for certain employees whose benefits under the Qualified Plans are limited by income tax regulations. The Supplemental Plans' benefits are based on the employees' years of service and compensation. For certain Supplemental Plans, Devon has established trusts to fund these plans' benefit obligations. The total value of these trusts was $59 million at both December 31, 2007 and 2006, and is included in noncurrent other assets in the consolidated balance sheets. For the remaining Supplemental Plans for which trusts have not been established, benefits are funded from Devon's available cash and cash equivalents.

Devon also has defined benefit postretirement plans ("Postretirement Plans") that provide benefits for substantially all U.S. employees. The Postretirement Plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. Benefit obligations for the Postretirement Plans are estimated based on Devon's future cost-sharing intentions. Devon's funding policy for the Postretirement Plans is to fund the benefits as they become payable with available cash and cash equivalents.

***Revisions to Retirement Plans***

In the second quarter of 2007, Devon adopted an enhanced defined contribution structure related to its 401(k) Incentive Savings Plan ("401(k) Plan") to be effective January 1, 2008. Participants in this enhanced defined contribution structure will continue to receive a discretionary match of a percentage of their contributions to the 401(k) Plan. These participants will also receive additional, nondiscretionary contributions by Devon calculated as a percentage of annual compensation. The percentage will vary based on the employees' years of service.

On or before November 15, 2007, existing eligible employees elected to either continue to participate in the defined benefit plan or participate in the enhanced defined contribution structure of the 401(k) Plan. Employees who elected to continue participating in the defined benefit plans will continue to accrue benefits under the existing provisions of such plans. Employees who elected to participate in the enhanced defined contribution structure will receive enhanced contributions to the 401(k) Plan and will retain the benefits that they have accrued under the defined benefit plan as of December 31, 2007. However, such employees will only be entitled to the benefits that have accrued in the defined benefit plans as of December 31, 2007, after all applicable vesting requirements have been met. Employees hired on or after October 1, 2007 will not have an election and will only participate in the 401(k) Plan and the enhanced defined contribution structure.

For those employees who elected to participate in the enhanced defined contribution structure, Devon's pension benefit obligation included $16 million related to projected future years of service for these employees. Because this portion of the employees' benefits was curtailed upon their election, Devon reduced its pension liabilities by $16 million in the fourth quarter of 2007.

***Change in Measurement Date***

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)*.

Statement No. 158 requires the measurement of plan assets and benefit obligations as of the date of the employer's fiscal year-end, beginning with fiscal years ending after December 15, 2008. Although not required until 2008, Devon adopted this measurement-date requirement in the second quarter of 2007 and changed its measurement date from November 30 to December 31. As a result, Devon used data as of December 31, 2006 to remeasure its plans assets and benefit obligations previously measured using data as of November 30, 2006. As a result of the remeasurement, Devon recognized the following amounts in the second quarter of 2007.

| | Increase (Decrease) (In millions) |
|---|---|
| Other long-term liabilities | $ (27) |
| Deferred income tax liabilities | $ 9 |
| Retained earnings | $ (1) |
| Accumulated other comprehensive income | $ 16 |
| General and administrative expenses | $ (3) |

### *Benefit Obligations and Plan Assets*

The following table presents the status of Devon's pension and other postretirement benefit plans for 2007 and 2006. The benefit obligation for pension plans represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for pension plans at December 31, 2007 and 2006 was $693 million and $652 million, respectively.

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In millions) | | | |
| Change in benefit obligation: | | | | |
| Benefit obligation at beginning of year | $ 768 | 666 | 52 | 54 |
| Effect of change in measurement date | (23) | — | (1) | — |
| Service cost | 30 | 23 | 1 | — |
| Interest cost | 46 | 39 | 3 | 3 |
| Participant contributions | — | — | 2 | 2 |
| Plan amendments | 17 | 2 | 23 | 1 |
| Curtailment gain | (16) | — | — | — |
| Foreign exchange rate changes | 6 | 1 | — | — |
| Actuarial loss (gain) | 51 | 66 | (2) | — |
| Benefits paid | (30) | (29) | (7) | (8) |
| Benefit obligation at end of year | 849 | 768 | 71 | 52 |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of year | 590 | 533 | — | — |
| Effect of change in measurement date | 3 | — | — | — |
| Actual return on plan assets | 47 | 79 | — | — |
| Employer contributions | 6 | 6 | 5 | 6 |
| Participant contributions | — | — | 2 | 2 |
| Benefits paid | (30) | (29) | (7) | (8) |
| Foreign exchange rate changes | 3 | 1 | — | — |
| Fair value of plan assets at end of year | 619 | 590 | — | — |
| Funded status at end of year | $ (230) | (178) | (71) | (52) |
| Amounts recognized in balance sheet: | | | | |
| Noncurrent assets | $ 3 | 2 | — | — |
| Current liabilities | (8) | (7) | (6) | (5) |
| Noncurrent liabilities | (225) | (173) | (65) | (47) |
| Net amount | $ (230) | (178) | (71) | (52) |
| Amounts recognized in accumulated other comprehensive income: | | | | |
| Net actuarial loss | $ 208 | 214 | 2 | 6 |
| Prior service cost (benefit) | 22 | 6 | 15 | (7) |
| Total | $ 230 | 220 | 17 | (1) |

The plan assets for pension benefits in the table above exclude the assets held in trusts for the Supplemental Plans. However, employer contributions for pension benefits in the table above include $6 million for both 2007 and 2006, which were transferred from the trusts established for the Supplemental Plans.

Certain of Devon's pension and postretirement plans have a projected benefit obligation in excess of plan assets at December 31, 2007 and 2006. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| | (In millions) | |
| Projected benefit obligation | $ 834 | 755 |
| Fair value of plan assets | $ 601 | 574 |

Certain of Devon's pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2007 and 2006. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| | (In millions) | |
| Accumulated benefit obligation | $ 135 | 121 |
| Fair value of plan assets | $ — | — |

The plan assets included in the above two tables exclude the Supplemental Plan trusts, which had a total value of $59 million at both December 31, 2007 and 2006.

### *Net Periodic Benefit Cost and Other Comprehensive Income*

The following table presents the components of net periodic benefit cost and other comprehensive income for Devon's pension and other postretirement benefit plans for 2007, 2006 and 2005.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| | (In millions) | | | | | |
| Net periodic benefit cost: | | | | | | |
| Service cost | $ 30 | 23 | 18 | 1 | 1 | 1 |
| Interest cost | 46 | 39 | 35 | 3 | 3 | 3 |
| Expected return on plan assets | (49) | (44) | (36) | — | — | — |
| Curtailment and settlement expense | 1 | — | — | — | — | — |
| Plan amendment | — | — | — | 1 | — | — |
| Recognition net actuarial loss | 12 | 12 | 8 | 1 | 1 | — |
| Recognition of prior service cost | 1 | 1 | 1 | — | — | (1) |
| Total net periodic benefit cost | 41 | 31 | 26 | 6 | 5 | 3 |
| Other comprehensive income: | | | | | | |
| Actuarial loss (gain) arising in current year | 54 | — | — | (3) | — | — |
| Prior service cost arising in current year | 17 | — | — | 22 | — | — |
| Recognition of net actuarial loss in net periodic benefit cost | (12) | — | — | (1) | — | — |
| Recognition of prior service cost in net periodic benefit cost | (1) | — | — | — | — | — |
| Curtailment of pension benefits | (16) | — | — | — | — | — |
| Change in additional minimum pension liability | — | 30 | (8) | — | — | — |
| Total other comprehensive income | 42 | 30 | (8) | 18 | — | — |
| Total recognized | $ 83 | 31 | 26 | 24 | 5 | 3 |

The following table presents the estimated net actuarial loss and prior service cost for the pension and other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost during 2008.

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| | (In millions) | |
| Net actuarial loss | $ 14 | — |
| Prior service cost | 2 | 2 |
| Total | $ 16 | 2 |

### *Assumptions*

The following table presents the weighted average actuarial assumptions that were used to determine benefit obligations and net periodic benefit costs for 2007, 2006 and 2005.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Assumptions to determine benefit obligations: | | | | | | |
| Discount rate | 6.22% | 5.72% | 5.72% | 6.00% | 5.50% | 5.75% |
| Rate of compensation increase | 7.00% | 7.00% | 4.50% | N/A | N/A | N/A |
| Assumptions to determine net periodic benefit cost: | | | | | | |
| Discount rate | 5.96% | 5.72% | 5.98% | 5.75% | 5.75% | 6.00% |
| Expected return on plan assets | 8.40% | 8.40% | 8.40% | N/A | N/A | N/A |
| Rate of compensation increase | 7.00% | 4.50% | 4.50% | N/A | N/A | N/A |

*Discount rate* – Future pension and postretirement obligations are discounted at the end of each year based on the rate at which obligations could be effectively settled, considering the timing of estimated future cash flows related to the plans. This rate is based on high-quality bond yields, after allowing for call and default risk. High quality corporate bond yield indices, such as Moody's Aa, are considered when selecting the discount rate.

*Rate of compensation increase* – For measurement of the 2007 benefit obligation for the pension plans, the 7% compensation increase in the table above represents the assumed increase for 2008 through 2011. The rate was assumed to decrease to 5% in the year 2012 and remain at that level thereafter. For measurement of the 2006 benefit obligation for the pension plans, the 7% compensation increase in the table above represents the assumed increase for 2007 and 2008. The rate was assumed to decrease one percent annually to 5% in the year 2010 and remain at that level thereafter. For measurement of the 2005 benefit obligation for the pension plans, the compensation increase in the table above represents the assumed increase for all future years.

*Expected return on plan assets* – Devon's overall investment objective for its retirement plans' assets is to achieve long-term growth of invested capital to ensure payments of retirement benefits obligations can be funded when required. To assist in achieving this objective, Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. At December 31, 2007, the target investment allocation for Devon's plan assets was 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. Derivatives or other speculative investments considered high-risk are generally prohibited.

The expected rate of return on plan assets was determined by evaluating input from external consultants and economists as well as long-term inflation assumptions. Devon expects the long-term asset allocation to approximate the targeted allocation. Therefore, the expected long-term rate of return on plan assets is based on the target allocation of investment types in such assets.

The following table presents the weighted-average asset allocation for Devon's pension plans at December 31, 2007 and 2006, and the target allocation for 2008 by asset category:

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Asset category: | | | |
| Equity securities | 80% | 83% | 83% |
| Debt securities | 20% | 17% | 17% |
| Total | 100% | 100% | 100% |

*Other assumptions* – For measurement of the 2007 benefit obligation for the other postretirement medical plans, an 8.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2008. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2016 and remain at that level thereafter. Assumed health care cost-trend rates affect the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects on the December 31, 2007 other postretirement benefits obligation and the 2008 service and interest cost components of net periodic benefit cost.

| | One Percent Increase | One Percent Decrease |
|---|---|---|
| | (In millions) | |
| Effect on benefit obligation | $ 4 | (4) |
| Effect on service and interest costs | $ — | — |

### *Expected Cash Flows*

The following table presents expected cash flow information for Devon's pension and other postretirement benefit plans.

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| | (In millions) | |
| Devon's 2008 contributions | $ 8 | 6 |
| Benefit payments: | | |
| 2008 | $ 33 | 6 |
| 2009 | $ 34 | 6 |
| 2010 | $ 36 | 6 |
| 2011 | $ 39 | 6 |
| 2012 | $ 43 | 6 |
| 2013 to 2017 | $ 296 | 30 |

Expected contributions included in the table above include amounts related to Devon's Qualified Plans, Supplemental Plans and Postretirement Plans. Of the benefits expected to be paid in 2008, $8 million of pension benefits is expected to be funded from the trusts established for the Supplemental Plans and all $6 million of other postretirement benefits is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

### *Other Benefit Plans*

Devon's 401(k) Plan covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Devon's matching contributions to the plan were $18 million, $15 million and $12 million for the years ended December 31, 2007, 2006 and 2005, respectively.

As previously discussed in "Revisions to Retirement Plans" above, in 2007 Devon adopted an enhanced defined contribution structure related to its 401(k) Plan to be effective January 1, 2008. Participants who elected to participate in this enhanced defined contribution structure, as well as all employees hired on or after October 1, 2007, will continue to receive a discretionary match of a percentage of their contributions to the 401(k) Plan. These participants will also receive additional, nondiscretionary contributions by Devon calculated as a percentage of annual compensation. The percentage will vary based on the employees' years of service.

Devon has defined contribution pension plans for its Canadian employees. Devon makes a contribution to each employee that is based upon the employee's base compensation and classification. Such contributions are subject to maximum amounts allowed under the Income Tax Act (Canada). Devon also has a savings plan for its Canadian employees. Under the savings plan, Devon contributes a base percentage amount to all employees and the employee may elect to contribute an additional percentage amount (up to a maximum amount) which is matched by additional Devon contributions. During 2007, 2006 and 2005, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $14 million, $12 million and $10 million, respectively.

## 7. Stockholders' Equity

The authorized capital stock of Devon consists of 800 million shares of common stock, par value $0.10 per share, and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

Effective August 17, 1999, Devon issued 1.5 million shares of 6.49% cumulative preferred stock, Series A, to holders of PennzEnergy 6.49% cumulative preferred stock, Series A. Dividends on the preferred stock are cumulative from the date of original issue and are payable quarterly, in cash, when declared by the Board of Directors. The preferred stock is redeemable at the option of Devon at any time on or after June 2, 2008, in whole or in part, at a redemption price of $100 per share, plus accrued and unpaid dividends to the redemption date.

Devon's Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock") in connection with the adoption of the shareholder rights plan described later in this note. On April 25, 2003, the Board increased the designated shares from 2.0 million to 2.9 million. At December 31, 2007, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $1.00 or 200 times the aggregate per share amount of all dividends (other than stock dividends) declared on common stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 200 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series A Junior Preferred Stock is neither redeemable nor convertible. The Series A Junior Preferred Stock ranks prior to the common stock but junior to all other classes of Preferred Stock.

### *Stock Repurchases*

In June 2007, Devon's Board of Directors approved an ongoing, annual stock repurchase program to minimize dilution resulting from restricted stock issued to, and options exercised by, employees. This repurchase program authorized the repurchase of up to 4.5 million shares in 2007. In 2008, the ongoing annual stock repurchase program authorizes the repurchase of up to 4.8 million shares or $422 million, whichever amount is reached first. In anticipation of the completion of the West African divestitures (see Note 13), Devon's Board of Directors has approved a separate program to repurchase up to 50 million shares. This program expires on December 31, 2009.

These programs are in addition to a 50 million share repurchase program approved by Devon's Board of Directors in August 2005, which expired on December 31, 2007. Additionally, in October 2004 Devon's Board of Directors approved a 50 million share repurchase program that was completed in August 2005.

During the three-year period ended December 31, 2007, Devon repurchased 55.2 million shares at a total cost of $2.8 billion, or $51.49 per share, under these repurchase programs. During 2007, Devon repurchased 4.1 million shares at a cost of $326 million, or $79.80 per share. During 2006, Devon repurchased 4.2 million shares at a cost of $253 million, or $59.61 per share. During 2005, Devon repurchased 46.9 million shares at a cost of $2.3 billion, or $48.28 per share.

### *Shareholder Rights Plan*

Under Devon's shareholder rights plan, stockholders have one-half of one right for each share of common stock held. The rights become exercisable and separately transferable ten business days after (a) an announcement that a person has acquired, or obtained the right to acquire, 15% or more of the voting shares outstanding, or (b) commencement of a tender or exchange offer that could result in a person owning 15% or more of the voting shares outstanding.

Each right entitles its holder (except a holder who is the acquiring person) to purchase either (a) 1/100 of a share of Series A Preferred Stock for $185.00, subject to adjustment or, (b) Devon common stock with a value equal to twice the exercise price of the right, subject to adjustment to prevent dilution. In the event of certain merger or asset sale transactions with another party or transactions that would increase the equity ownership of a shareholder who then owned 15% or more of Devon, each Devon right will entitle its holder to purchase securities of the merging or acquiring party with a value equal to twice the exercise price of the right.

The rights, which have no voting power, expire on August 17, 2009. The rights may be redeemed by Devon for $0.01 per right until the rights become exercisable.

### *Dividends*

Devon paid common stock dividends of $249 million (or $0.56 per share), $199 million (or $0.45 per share) and $136 million (or $0.30 per share) in 2007, 2006 and 2005 respectively. Devon paid $10 million in 2007, 2006 and 2005 to preferred stockholders.

## 8. Commitments and Contingencies

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations after consideration of recorded accruals although actual amounts could differ materially from management's estimate.

### *Environmental Matters*

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon's consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2007, Devon's balance sheet included $3 million of noncurrent accrued liabilities, reflected in other liabilities, related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis* PRP, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

### *Royalty Matters*

Numerous gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates, which resulted in underpayment of royalties in connection with natural gas and NGLs produced and sold from federal and Indian owned or controlled lands. The principal suit in which Devon is a defendant is *United States ex rel. Wright v. Chevron USA, Inc. et al.* (the "Wright case"). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the Wright case back to the Eastern District of Texas to resume proceedings. On April 12, 2007, the court entered a trial plan and scheduling order in which the case will proceed in phases. Two phases have been scheduled to date, with the first scheduled to begin in August 2008 and the second scheduled to begin in February 2009. Devon is not included in the groups of defendants selected for these first two phases. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this lawsuit and no liability has been recorded in connection therewith.

In 1995, the United States Congress passed the Deep Water Royalty Relief Act. The intent of this legislation was to encourage deep water exploration in the Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases. Deep water leases issued in certain years by the Minerals Management Service (the "MMS") have contained price thresholds, such that if the market prices for oil or natural gas exceeded the thresholds for a given year, royalty relief would not be granted for that year. Deep water leases issued in 1998 and 1999 did not include price thresholds. The MMS in 2006 informed Devon and other oil and gas companies that the omission of price thresholds from these leases was an error on its part and was not its intention. Accordingly, the MMS invited Devon and the other affected oil and gas producers to renegotiate the terms and conditions of the 1998 and 1999 leases to add price threshold provisions to the lease agreements for periods after October 1, 2006. Devon has not entered into any renegotiated leases.

The U.S. House of Representatives in January 2007 passed legislation that would have required companies to renegotiate the 1998 and 1999 leases as a condition of securing future federal leases. This legislation was not passed by the U.S. Senate. However, Congress may consider similar legislation in the future. Although Devon has not signed renegotiated leases, it has accrued in its 2007 financial statements approximately $28 million for royalties that would be due if price thresholds were added to its 1998 and 1999 leases effective October 1, 2006.

Additionally, Devon has $22 million accrued at the end of 2007 for royalties related to leases issued under the Deep Water Royalty Relief Act in years other than 1998 or 1999. The leases issued in these other years did include price thresholds, but in October 2007 a federal district court ruled in favor of a plaintiff who had challenged the legality of including price thresholds in these leases. This judgment is subject to appeal, and Devon will continue to accrue for royalties on these leases until the matter is resolved.

### *Hurricane Contingencies*

Historically, Devon maintained a comprehensive insurance program that included coverage for physical damage to its offshore facilities caused by hurricanes. Devon's historical insurance program also included substantial business interruption coverage, which Devon is utilizing to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005. Under the terms of this insurance program, Devon was entitled to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and natural gas prices. Also, the terms of the insurance include a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible.

Based on current estimates of physical damage and the anticipated length of time Devon will have had production suspended, Devon expects its policy recoveries will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the $467 million received in 2006 as a full settlement of the amount due from Devon's primary insurers and $13 million received in 2007 as a full settlement of the amount due from certain of Devon's secondary insurers. As of December 31, 2007, $330 million of these proceeds had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $150 million will be utilized as reimbursement of Devon's anticipated future repair costs. Devon continues to negotiate with its other secondary insurers and expects to receive additional policy recoveries as a result of such negotiations.

Should Devon's total policy recoveries, including the partial settlements already received from Devon's primary and secondary insurers, exceed all repair costs and deductible amounts, such excess will be recognized as other income in the statement of operations in the period in which such determination can be made.

The policy underlying the insurance program terms described above expired on August 31, 2006. Devon's current insurance program includes business interruption and physical damage coverage for its business. However, due to significant changes in the insurance marketplace, Devon has only been able to obtain a *de minimis* amount of coverage for any damage that may be caused by named windstorms in the Gulf of Mexico. Devon has not experienced any losses under this new insurance arrangement through December 31, 2007.

### *Other Matters*

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

### *Commitments*

Devon has certain drilling and facility obligations under contractual agreements with third party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. Included in the $3.9 billion total of "Drilling and Facility Obligations" in the table below is $2.4 billion that relates to long-term contracts for three deepwater drilling rigs and certain other contracts for onshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $2.4 billion represents the gross commitment under these contracts. Devon's ultimate payment for these commitments will be reduced by the amounts billed to its partners when net working interests are ultimately determined. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

Devon has certain firm transportation agreements that represent "ship or pay" arrangements whereby Devon has committed to ship certain volumes of oil, gas and NGLs for a fixed transportation fee. Devon has entered into these agreements to aid the movement of its production to market. Devon expects to have sufficient production to utilize the majority of these transportation services.

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense included in general and administrative expenses under operating leases, net of sub-lease income, was $43 million, $36 million and $35 million in 2007, 2006 and 2005, respectively.

Devon assumed two offshore platform spar leases through the 2003 Ocean merger. The spars are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The Boomvang field was divested as part of the 2005 property divestiture program. The Nansen operating lease is for a 20-year term and contains various options whereby Devon may purchase the lessors' interests in the spar. Total rental expense included in lease operating expenses under both the Nansen and Boomvang operating leases was $12 million, $12 million and $14 million in 2007, 2006 and 2005, respectively. Devon has guaranteed that the Nansen spar will have a residual value at the end of the operating lease equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreement. As a result of the sale of the Boomvang field, Devon is subleasing the Boomvang Spar. If the sublessee were to default on its obligation, Devon would continue to be obligated to pay the periodic lease payments and any guaranteed value required at the end of the term.

Devon has a floating, production, storage and offloading facility ("FPSO") that is being used in the Panyu project offshore China and is being leased under operating lease arrangements. This lease expires in September 2009. Devon also has an FPSO that is being used in the Polvo project offshore Brazil. This lease expires in 2014. Total rental expense included in lease operating expenses under the China and Brazil operating leases was $17 million, $9 million and $7 million in 2007, 2006 and 2005, respectively.

The following is a schedule by year of future minimum payments for drilling and facility obligations, firm transportation agreements and leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2007. The schedule includes $144 million of drilling and facility obligations related to Devon's discontinued operations (see Note 13).

| Year Ending December 31, | Drilling and Facility Obligations | Firm Transportation Agreements | Office and Equipment Leases | Spar Leases | FPSO Leases |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| 2008 | $ 983 | 170 | 62 | 11 | 31 |
| 2009 | 713 | 180 | 51 | 11 | 29 |
| 2010 | 541 | 149 | 41 | 11 | 23 |
| 2011 | 406 | 128 | 36 | 11 | 23 |
| 2012 | 341 | 106 | 21 | 11 | 23 |
| Thereafter | 951 | 307 | 20 | 130 | 33 |
| Total payments | $ 3,935 | 1,040 | 231 | 185 | 162 |

## 9. Share-Based Compensation

On June 8, 2005, Devon's stockholders adopted the 2005 Long-Term Incentive Plan, which expires on June 8, 2013. Devon's stockholders adopted certain amendments to this plan on June 7, 2006. This plan, as amended, authorizes the Compensation Committee, which consists of non-management members of Devon's Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards, Canadian restricted stock units, performance units, performance bonuses, stock appreciation rights and cash-out rights to eligible employees. The plan also authorizes the grant of nonqualified stock options, restricted stock awards and stock appreciation rights to directors. A total of 32 million shares of Devon common stock have been reserved for issuance pursuant to the plan. To calculate shares issued under the plan, options granted represent one share and other awards represent 2.2 shares.

Devon also has stock option plans that were adopted in 2003 and 1997 under which stock options and restricted stock awards were issued to key management and professional employees. Options granted under these plans remain exercisable by the employees owning such options, but no new options or restricted stock awards will be granted under these plans. Devon also has stock options outstanding that were assumed as part of the acquisitions of Ocean, Mitchell Energy & Development Corp., Santa Fe Snyder and PennzEnergy.

As discussed in Note 1, on January 1, 2006, Devon changed its method of accounting for share-based compensation from the APB No. 25 intrinsic value accounting method to the fair value recognition provisions of SFAS No. 123(R). The following table presents the effects of share-based compensation included in Devon's accompanying statement of operations for the years ended December 31, 2007, 2006 and 2005.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (In millions) | |
| Gross general and administrative expense | $ 146 | 91 | 29 |
| Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties | $ 44 | 26 | — |
| Related income tax benefit | $ 34 | 23 | 11 |

### *Stock Options*

Under Devon's 2005 Long-Term Incentive Plan, the exercise price of stock options granted may not be less than the estimated fair market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which may not exceed eight years from the date of grant. The recipient must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Options granted generally have a vesting period that ranges from three to four years.

The fair value of stock options on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires Devon to make several assumptions. The volatility of Devon's common stock is based on the historical volatility of the market price of Devon's common stock over a period of time equal to the expected term of the option and ending on the grant date. The dividend yield is based on Devon's historical and current yield in effect at the date of grant. The risk-free interest rate is based on the zero-coupon U.S. Treasury yield for the expected term of the option at the date of grant. The expected term of the options is based on historical exercise and termination experience for various groups of employees and directors. Each group is determined based on the similarity of their historical exercise and termination behavior.

The following table presents a summary of the grant-date fair values of stock options granted and the related assumptions for the years ended December 31, 2007, 2006 and 2005. All such amounts represent the weighted-average amounts for each year.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Grant-date fair value | $ 26.43 | 22.41 | 19.65 |
| Volatility factor | 31.6% | 32.2% | 31.0% |
| Dividend yield | 0.7% | 0.5% | 0.6% |
| Risk-free interest rate | 5.0% | 5.7% | 4.4% |
| Expected term (in years) | 4.0 | 4.0 | 4.2 |

The following table presents a summary of Devon's outstanding stock options as of December 31, 2007, including changes during the year then ended.

| | Options | Weighted Average Exercise Price | Weighted Average Remaining Contractual Price | Aggregate Intrinsic Value |
|---|---|---|---|---|
| | (In thousands) | | (In years) | (In millions) |
| Outstanding at December 31, 2006 | 15,383 | $ 38.24 | | |
| Granted | 1,913 | $ 87.68 | | |
| Exercised | (3,123) | $ 29.43 | | |
| Forfeited | (367) | $ 53.97 | | |
| Outstanding at December 31, 2007 | 13,806 | $ 46.66 | 3.8 | $ 584 |
| Vested and expected to vest at December 31, 2007 | 13,688 | $ 46.39 | 3.8 | $ 582 |
| Exercisable at December 31, 2007 | 10,059 | $ 35.58 | 3.2 | $ 536 |

The aggregate intrinsic value of stock options that were exercised during 2007, 2006 and 2005 was $151 million, $119 million and $149 million, respectively. As of December 31, 2007, Devon's unrecognized compensation cost related to unvested stock options was $93 million. Such cost is expected to be recognized over a weighted-average period of 2.4 years.

### *Restricted Stock Awards and Units*

Under Devon's 2005 Long-Term Incentive Plan, restricted stock awards and units are subject to the terms, conditions, restrictions and/or limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, restricted stock awards and units vest over a minimum restriction period of at least three years from the date of grant. During the vesting period, recipients of restricted stock awards receive dividends that are not subject to restrictions or other limitations. The fair value of restricted stock awards and units on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon's common stock on the grant date of the award or unit.

The following table presents a summary of Devon's unvested restricted stock awards as of December 31, 2007, including changes during the year then ended.

| | Restricted Stock Awards | Weighted Average Grant-Date Fair Value |
|---|---|---|
| | (In thousands) | |
| Unvested at December 31, 2006 | 5,162 | $ 58.35 |
| Granted | 2,026 | $ 87.81 |
| Vested | (1,574) | $ 51.66 |
| Forfeited | (188) | $ 57.33 |
| Unvested at December 31, 2007 | 5,426 | $ 71.38 |

The aggregate fair value of restricted stock awards that vested during 2007, 2006 and 2005 was $136 million, $82 million and $51 million, respectively. As of December 31, 2007, Devon's unrecognized compensation cost related to unvested restricted stock awards and units was $341 million. Such cost is expected to be recognized over a weighted-average period of 2.8 years.

## 10. Reduction of Carrying Value of Oil and Gas Properties

During 2006 and 2005, Devon reduced the carrying value of certain of its oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A summary of these reductions and additional discussion is provided below.

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| | 2006 | | 2005 | |
| | Gross | Net of Taxes | Gross | Net of Taxes |
| | (In millions) | | | |
| Brazil - unsuccessful exploratory reduction | $ 16 | 16 | 42 | 42 |
| Russia - ceiling test reduction | 20 | 10 | — | — |
| Total | $ 36 | 26 | 42 | 42 |

### *2006 Reductions*

During the second quarter of 2006, Devon drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, Devon recognized a $16 million impairment of its investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to Devon's Polvo development project in Brazil.

As a result of a decline in projected future net cash flows, the carrying value of Devon's Russian properties exceeded the full cost ceiling by $10 million at the end of the third quarter of 2006. Therefore, Devon recognized a $20 million reduction of the carrying value of its oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

### *2005 Reduction*

Prior to the fourth quarter of 2005, Devon was capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. At the end of 2005, it was expected that a small initial portion of the proved reserves ultimately expected at Polvo would be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves was not sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, Devon determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There was no tax benefit related to this Brazilian impairment.

## 11. Other Income

The components of other income include the following:

| | | Year Ended December 31, | | |
|---|---|---|---|---|
| | | 2007 | 2006 | 2005 |
| | | | (In millions) | |
| Interest and dividend income | $ | 89 | 100 | 95 |
| Net gain on sales of non-oil and gas property and equipment | | 1 | 5 | 150 |
| Loss on derivative financial instruments | | — | — | (48) |
| Other | | 8 | 10 | 1 |
| Total | $ | 98 | 115 | 198 |

## 12. Income Taxes

### *Income Tax Expense*

The earnings from continuing operations before income taxes and the components of income tax expense (benefit) for the years 2007, 2006 and 2005 were as follows:

| | | Year Ended December 31, | | |
|---|---|---|---|---|
| | | 2007 | 2006 | 2005 |
| | | | (In millions) | |
| Earnings from continuing operations before income taxes: | | | | |
| U.S. | $ | 2,642 | 2,435 | 3,254 |
| Canada | | 685 | 751 | 899 |
| International | | 897 | 384 | 225 |
| Total | $ | 4,224 | 3,570 | 4,378 |
| Current income tax expense: | | | | |
| U.S. federal | $ | 83 | 292 | 811 |
| Various states | | 16 | 7 | 26 |
| Canada and various provinces | | 136 | 143 | 106 |
| International | | 265 | 86 | 90 |
| Total current tax expense | | 500 | 528 | 1,033 |
| Deferred income tax expense (benefit): | | | | |
| U.S. federal | | 745 | 456 | 271 |
| Various states | | 28 | 77 | (18) |
| Canada and various provinces | | (166) | (105) | 217 |
| International | | (29) | (20) | (22) |
| Total deferred tax expense | | 578 | 408 | 448 |
| Total income tax expense | $ | 1,078 | 936 | 1,481 |

The taxes on the results of discontinued operations presented in the accompanying statements of operations were all related to international operations.

Total income tax expense differed from the amounts computed by applying the U.S. federal income tax rate to earnings from continuing operations before income taxes as a result of the following:

| | | Year Ended December 31, | | |
|---|---|---|---|---|
| | | 2007 | 2006 | 2005 |
| | | | (In millions) | |
| Expected income tax expense based on U.S. statutory tax rate of 35% | $ | 1,478 | 1,249 | 1,532 |
| Effect of Canadian tax rate reductions | | (261) | (243) | (14) |
| State income taxes | | 30 | 55 | 6 |
| Repatriation of earnings | | — | — | 28 |
| Taxation on foreign operations | | (165) | (120) | (50) |
| Other | | (4) | (5) | (21) |
| Total income tax expense | $ | 1,078 | 936 | 1,481 |

In 2007, 2006 and 2005, deferred income taxes were reduced $261 million, $243 million and $14 million, respectively, due to successive Canadian statutory rate reductions that were enacted in each such year.

In 2006, deferred income taxes increased $39 million due to the effect of a new income-based tax enacted by the state of Texas that replaced a previous franchise tax. The new tax was effective January 1, 2007. The $39 million increase is included in 2006 state income taxes in the above table.

In 2005, Devon recognized $28 million of taxes related to its repatriation of $545 million to the United States. The cash was repatriated to take advantage of U.S. tax legislation, which allowed qualifying companies to repatriate cash from foreign operations at a reduced income tax rate. Substantially all of the cash repatriated by Devon in 2005 related to prior earnings of its Canadian subsidiary.

### *Deferred Tax Assets and Liabilities*

At December 31, 2007, Devon had the following net operating loss carryforwards, which are available to reduce future taxable income in the jurisdiction where the net operating loss was incurred. These carryforwards will result in a future tax reduction based upon the future tax rate applicable to the taxable income that is ultimately offset by the net operating loss carryforward. For financial purposes, the tax effects of these carryforwards, net of any valuation allowances, have been recognized as reductions to the net deferred tax liability at December 31, 2007.

| Jurisdiction | Years of Expiration | Carryforward Amounts (In millions) |
|---|---|---|
| Various U.S. states | 2008 – 2026 | $ 494 |
| Canada | 2010 – 2027 | $ 15 |
| Brazil | Indefinite | $ 188 |

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2007 and 2006 are presented below:

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| | (In millions) | |
| Deferred tax assets: | | |
| Net operating loss carryforwards | $ 92 | 57 |
| Fair value of financial instruments | 167 | 97 |
| Asset retirement obligations | 387 | 265 |
| Pension benefit obligations | 93 | 81 |
| Insurance proceeds | 21 | 113 |
| Other | 102 | 103 |
| Total deferred tax assets | 862 | 716 |
| Valuation allowance | (50) | (22) |
| Net deferred tax assets | 812 | 694 |
| Deferred tax liabilities: | | |
| Property and equipment, principally due to nontaxable business combinations, differences in depreciation, and the expensing of intangible drilling costs for tax purposes | (6,152) | (5,374) |
| Chevron Corporation common stock | (431) | (326) |
| Long-term debt | (216) | (148) |
| Other | (11) | (34) |
| Total deferred tax liabilities | (6,810) | (5,882) |
| Net deferred tax liability | $ (5,998) | (5,188) |

As shown in the above table, Devon has recognized $812 million of deferred tax assets as of December 31, 2007, net of a $50 million valuation allowance. Included in total deferred tax assets is $92 million related to various carryforwards available to offset future income taxes. The carryforwards include state net operating loss carryforwards, which expire primarily between 2008 and 2026, Canadian net operating loss carryforwards, which expire primarily between 2010 and 2027, and Brazilian net operating loss carryforwards, which have no expiration. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be “more likely than not.” When the future utilization of some portion of the carryforwards is determined not to be “more likely than not,” a valuation allowance is provided to reduce the recorded tax benefits from such assets.

Devon expects the tax benefits from the state and Canadian net operating loss carryforwards to be utilized between 2008 and 2012. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its state and Canadian tax carryforwards prior to their expiration.

Included in deferred tax assets for net operating loss carryforwards as of December 31, 2007 and 2006 is $64 million and $36 million, respectively, related to the Brazil carryforward. Although this carryforward has no expiration, management is uncertain whether Devon's future taxable income will be sufficient to utilize a substantial portion of its Brazil carryforward. This uncertainty is based upon annual limitations on the amount of net operating loss carryforwards available to reduce taxable income, Devon's lack of historical taxable income in Brazil and the exploratory nature of several of Devon's current projects in Brazil. Therefore, as of December 31, 2007 and 2006, Devon had a valuation allowance of $50 million and $22 million, respectively, related to this carryforward.

### *Unrecognized Tax Benefits*

The following table presents changes in Devon's unrecognized tax benefits for the year ended December 31, 2007 (in millions).

| | |
|---|---|
| Balance as of January 1, 2007 | $ 122 |
| Increases due to: | |
| Tax positions taken in current year | 4 |
| Tax positions taken in prior years | 10 |
| Accrual of interest related to tax positions taken | 3 |
| Decreases due to: | |
| Tax positions taken in prior years | (5) |
| Lapse of statute of limitations | (20) |
| Settlements | (9) |
| Foreign currency translation adjustment | 6 |
| Balance as of December 31, 2007 | $ 111 |

Devon's unrecognized tax benefit balance at January 1, 2007 included $114 million of unrecognized tax benefits before interest and penalties, and $8 million of interest and penalties. Included in Devon's unrecognized tax benefits of $111 million as of December 31, 2007 was $74 million that, if recognized, would affect Devon's effective income tax rate.

Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

| Jurisdiction | Tax Years Open |
|---|---|
| U.S. federal | 2002-2007 |
| Various U.S. states | 2001-2007 |
| Canada federal | 2001-2007 |
| Various Canadian provinces | 2001-2007 |
| Various other foreign jurisdictions | 2003-2007 |

Certain statute of limitation expirations are scheduled to occur in the next twelve months. However, Devon is currently in the final stages of the administrative review process for certain open tax years. In addition, Devon is currently subject to various income tax audits that have not reached the administrative review process. As a result, Devon cannot reasonably anticipate the extent that the liabilities for unrecognized tax benefits will increase or decrease within the next twelve months.

## 13. Discontinued Operations

### *Egypt and West Africa*

In November 2006 and January 2007, Devon announced its plans to divest its operations in Egypt and West Africa, including Equatorial Guinea, Cote d'Ivoire, Gabon and other countries in the region. Pursuant to accounting rules for discontinued operations, Devon has classified all 2007 and prior period amounts related to its operations in Egypt and West Africa as discontinued operations.

In October 2007, Devon completed the sale of its Egyptian operations and received proceeds of $341 million. As a result of this sale, Devon recognized a $90 million after-tax gain in the fourth quarter of 2007. In November 2007, Devon announced an agreement to sell its operations in Gabon for $205.5 million. Devon is finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the remaining properties in the West African divestiture package. Devon is optimistic it can complete these sales during the first half of 2008.

Revenues related to Devon's operations in Egypt and West Africa totaled $781 million, $929 million and $714 million during 2007, 2006 and 2005, respectively. The following table presents the main classes of assets and liabilities associated with Devon's operations in Egypt and West Africa as of December 31, 2007 and 2006.

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| | (In millions) | |
| Assets: | | |
| Cash | $ 9 | 64 |
| Accounts receivable | 83 | 101 |
| Other current assets | 28 | 67 |
| Current assets | $ 120 | 232 |
| Long-term assets – property and equipment, net of accumulated depreciation, depletion and amortization | $ 1,512 | 1,619 |
| Liabilities: | | |
| Accounts payable – trade | $ 23 | 41 |
| Revenues and royalties due to others | 11 | 7 |
| Income taxes payable | 100 | 115 |
| Current portion of asset retirement obligation | 9 | 8 |
| Accrued expenses and other current liabilities | 2 | 2 |
| Current liabilities | $ 145 | 173 |
| Asset retirement obligation, long-term | $ 35 | 38 |
| Deferred income taxes | 366 | 375 |
| Other liabilities | 3 | 16 |
| Long-term liabilities | $ 404 | 429 |

### *Reductions of carrying value related to discontinued operations*

Based on drilling activities in Nigeria, Devon reduced the carrying value of its Nigerian assets held for sale in 2007. As a result, earnings from discontinued operations in 2007 include a $13 million after-tax loss ($64 million pre-tax).

As a result of unsuccessful exploratory activities in Egypt during 2006, the net book value of Devon's Egyptian oil and gas properties, less related deferred income taxes, exceeded the ceiling by $18 million as of the end of September 30, 2006. Therefore, in 2006, Devon recognized an $18 million after-tax loss ($31 million pre-tax).

Due to unsuccessful drilling activities in Nigeria, in the first quarter of 2006, Devon recognized an $85 million impairment of its investment in Nigeria equal to the costs to drill two dry holes and a proportionate share of block-related costs. There was no income tax benefit related to this impairment.

## 14. Segment Information

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three reportable segments: its operations in the U.S., its operations in Canada, and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing activities. Certain information regarding such activities for each segment is included in Note 15.

Following is certain financial information regarding Devon's segments for 2007, 2006 and 2005. The revenues reported are all from external customers.

| | U.S. | Canada | International | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| **As of December 31, 2007:** | | | | |
| Current assets | $ 1,601 | 852 | 1,461 | 3,914 |
| Property and equipment, net of accumulated depreciation, depletion and amortization | 18,019 | 8,909 | 1,151 | 28,079 |
| Goodwill | 3,049 | 3,055 | 68 | 6,172 |
| Other assets | 1,651 | 49 | 1,591 | 3,291 |
| Total assets | $ 24,320 | 12,865 | 4,271 | 41,456 |
| Current liabilities | $ 2,661 | 561 | 435 | 3,657 |
| Long-term debt | 3,948 | 2,976 | — | 6,924 |
| Asset retirement obligation, long-term | 594 | 569 | 73 | 1,236 |
| Other liabilities | 1,137 | 45 | 409 | 1,591 |
| Deferred income taxes | 3,980 | 2,011 | 51 | 6,042 |
| Stockholders' equity | 12,000 | 6,703 | 3,303 | 22,006 |
| Total liabilities and stockholders' equity | $ 24,320 | 12,865 | 4,271 | 41,456 |

| | U.S. | Canada | International | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| **Year Ended December 31, 2007:** | | | | |
| Revenues: | | | | |
| Oil sales | $ 1,313 | 804 | 1,376 | 3,493 |
| Gas sales | 3,742 | 1,410 | 11 | 5,163 |
| NGL sales | 773 | 197 | — | 970 |
| Marketing and midstream revenues | 1,693 | 43 | — | 1,736 |
| Total revenues | 7,521 | 2,454 | 1,387 | 11,362 |
| Expenses and other income, net: | | | | |
| Lease operating expenses | 1,005 | 654 | 169 | 1,828 |
| Production taxes | 212 | 4 | 124 | 340 |
| Marketing and midstream operating costs and expenses | 1,211 | 16 | — | 1,227 |
| Depreciation, depletion and amortization of oil and gas properties | 1,672 | 740 | 243 | 2,655 |
| Depreciation and amortization of non-oil and gas properties | 180 | 21 | 2 | 203 |
| Accretion of asset retirement obligation | 38 | 32 | 4 | 74 |
| General and administrative expenses | 399 | 119 | (5) | 513 |
| Interest expense | 228 | 202 | — | 430 |
| Change in fair value of financial instruments | (32) | (2) | — | (34) |
| Other income, net | (34) | (17) | (47) | (98) |
| Total expenses and other income, net | 4,879 | 1,769 | 490 | 7,138 |
| Earnings from continuing operations before income tax expense (benefit) | 2,642 | 685 | 897 | 4,224 |
| Income tax expense (benefit): | | | | |
| Current | 100 | 135 | 265 | 500 |
| Deferred | 773 | (166) | (29) | 578 |
| Total income tax expense (benefit) | 873 | (31) | 236 | 1,078 |
| Earnings from continuing operations | 1,769 | 716 | 661 | 3,146 |
| Discontinued operations: | | | | |
| Earnings from discontinued operations before income taxes | — | — | 696 | 696 |
| Income tax expense | — | — | 236 | 236 |
| Earnings from discontinued operations | — | — | 460 | 460 |
| Net earnings | 1,769 | 716 | 1,121 | 3,606 |
| Preferred stock dividends | 10 | — | — | 10 |
| Net earnings applicable to common stockholders | $ 1,759 | 716 | 1,121 | 3,596 |
| Capital expenditures, continuing operations | $ 4,522 | 1,350 | 455 | 6,327 |

| | U.S. | Canada | International | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| **As of December 31, 2006:** | | | | |
| Current assets | $ 1,307 | 616 | 1,289 | 3,212 |
| Property and equipment, net of accumulated depreciation, depletion and amortization | 15,253 | 6,929 | 974 | 23,156 |
| Goodwill | 3,053 | 2,585 | 68 | 5,706 |
| Other assets | 1,289 | 35 | 1,665 | 2,989 |
| Total assets | $ 20,902 | 10,165 | 3,996 | 35,063 |
| Current liabilities | $ 3,693 | 569 | 383 | 4,645 |
| Long-term debt | 2,594 | 2,974 | — | 5,568 |
| Asset retirement obligation, long-term | 387 | 360 | 57 | 804 |
| Other liabilities | 864 | 16 | 434 | 1,314 |
| Deferred income taxes | 3,351 | 1,831 | 108 | 5,290 |
| Stockholders' equity | 10,013 | 4,415 | 3,014 | 17,442 |
| Total liabilities and stockholders' equity | $ 20,902 | 10,165 | 3,996 | 35,063 |

| | U.S. | Canada | International | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| **Year Ended December 31, 2006:** | | | | |
| Revenues: | | | | |
| Oil sales | $ 1,218 | 603 | 613 | 2,434 |
| Gas sales | 3,445 | 1,456 | 11 | 4,912 |
| NGL sales | 548 | 201 | — | 749 |
| Marketing and midstream revenues | 1,641 | 31 | — | 1,672 |
| Total revenues | 6,852 | 2,291 | 624 | 9,767 |
| Expenses and other income, net: | | | | |
| Lease operating expenses | 813 | 543 | 69 | 1,425 |
| Production taxes | 235 | 7 | 99 | 341 |
| Marketing and midstream operating costs and expenses | 1,226 | 10 | — | 1,236 |
| Depreciation, depletion and amortization of oil and gas properties | 1,311 | 644 | 103 | 2,058 |
| Depreciation and amortization of non-oil and gas properties | 154 | 18 | 1 | 173 |
| Accretion of asset retirement obligation | 25 | 21 | 1 | 47 |
| General and administrative expenses | 316 | 92 | (11) | 397 |
| Interest expense | 199 | 222 | — | 421 |
| Change in fair value of financial instruments | 181 | (3) | — | 178 |
| Reduction of carrying value of oil and gas properties | — | — | 36 | 36 |
| Other income, net | (43) | (14) | (58) | (115) |
| Total expenses and other income, net | 4,417 | 1,540 | 240 | 6,197 |
| Earnings from continuing operations before income tax expense | 2,435 | 751 | 384 | 3,570 |
| Income tax expense (benefit): | | | | |
| Current | 299 | 143 | 86 | 528 |
| Deferred | 533 | (105) | (20) | 408 |
| Total income tax expense | 832 | 38 | 66 | 936 |
| Earnings from continuing operations | 1,603 | 713 | 318 | 2,634 |
| Discontinued operations: | | | | |
| Earnings from discontinued operations before income taxes | — | — | 464 | 464 |
| Income tax expense | — | — | 252 | 252 |
| Earnings from discontinued operations | — | — | 212 | 212 |
| Net earnings | 1,603 | 713 | 530 | 2,846 |
| Preferred stock dividends | 10 | — | — | 10 |
| Net earnings applicable to common stockholders | $ 1,593 | 713 | 530 | 2,836 |
| Capital expenditures, continuing operations | $ 5,814 | 1,670 | 405 | 7,889 |

| | | U.S. | Canada | International | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| **Year Ended December 31, 2005:** | | | | | |
| Revenues: | | | | | |
| Oil sales | $ | 1,062 | 353 | 379 | 1,794 |
| Gas sales | | 3,929 | 1,814 | 18 | 5,761 |
| NGL sales | | 484 | 196 | — | 680 |
| Marketing and midstream revenues | | 1,780 | 12 | — | 1,792 |
| Total revenues | | 7,255 | 2,375 | 397 | 10,027 |
| Expenses and other income, net: | | | | | |
| Lease operating expenses | | 710 | 498 | 36 | 1,244 |
| Production taxes | | 273 | 6 | 56 | 335 |
| Marketing and midstream operating costs and expenses | | 1,336 | 6 | — | 1,342 |
| Depreciation, depletion and amortization of oil and gas properties | | 1,137 | 570 | 60 | 1,767 |
| Depreciation and amortization of non-oil and gas properties | | 141 | 14 | 2 | 157 |
| Accretion of asset retirement obligation | | 25 | 16 | 1 | 42 |
| General and administrative expenses | | 245 | 59 | (13) | 291 |
| Interest expense | | 224 | 309 | — | 533 |
| Change in fair value of financial instruments | | 86 | 8 | — | 94 |
| Reduction of carrying value of oil and gas properties | | — | — | 42 | 42 |
| Other income, net | | (176) | (10) | (12) | (198) |
| Total expenses and other income, net | | 4,001 | 1,476 | 172 | 5,649 |
| Earnings from continuing operations before income tax expense | | 3,254 | 899 | 225 | 4,378 |
| Income tax expense (benefit): | | | | | |
| Current | | 837 | 106 | 90 | 1,033 |
| Deferred | | 253 | 217 | (22) | 448 |
| Total income tax expense | | 1,090 | 323 | 68 | 1,481 |
| Earnings from continuing operations | | 2,164 | 576 | 157 | 2,897 |
| Discontinued operations: | | | | | |
| Earnings from discontinued operations before income taxes | | — | — | 173 | 173 |
| Income tax expense | | — | — | 140 | 140 |
| Earnings from discontinued operations | | — | — | 33 | 33 |
| Net earnings | | 2,164 | 576 | 190 | 2,930 |
| Preferred stock dividends | | 10 | — | — | 10 |
| Net earnings applicable to common stockholders | $ | 2,154 | 576 | 190 | 2,920 |
| | | | | | |
| Capital expenditures, continuing operations | $ | 2,200 | 1,707 | 88 | 3,995 |

## 15. Supplemental Information on Oil and Gas Operations (Unaudited)

The following supplemental unaudited information regarding the oil and gas activities of Devon is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities*. This supplemental information excludes amounts for all periods presented related to Devon's discontinued operations in Egypt and West Africa.

### *Costs Incurred*

The following tables reflect the costs incurred in oil and gas property acquisition, exploration and development activities:

| | | Total | | |
|---|---|---|---|---|
| | | Year Ended December 31, | | |
| | | 2007 | 2006 | 2005 |
| | | | (In millions) | |
| Property acquisition costs: | | | | |
| Proved properties | $ | 10 | 1,113 | 54 |
| Unproved properties | | 206 | 1,481 | 346 |
| Exploration costs | | 891 | 881 | 826 |
| Development costs | | 4,994 | 4,035 | 2,629 |
| Costs incurred | $ | 6,101 | 7,510 | 3,855 |

| | | Domestic | | |
|---|---|---|---|---|
| | | Year Ended December 31, | | |
| | | 2007 | 2006 | 2005 |
| | | (In millions) | | |
| Property acquisition costs: | | | | |
| Proved properties | $ | 3 | 1,066 | 5 |
| Unproved properties | | 156 | 1,366 | 106 |
| Exploration costs | | 569 | 547 | 422 |
| Development costs | | 3,542 | 2,558 | 1,597 |
| Costs incurred | $ | 4,270 | 5,537 | 2,130 |

| | | Canada | | |
|---|---|---|---|---|
| | | Year Ended December 31, | | |
| | | 2007 | 2006 | 2005 |
| | | (In millions) | | |
| Property acquisition costs: | | | | |
| Proved properties | $ | 7 | 23 | 49 |
| Unproved properties | | 49 | 70 | 239 |
| Exploration costs | | 211 | 217 | 361 |
| Development costs | | 1,098 | 1,244 | 1,020 |
| Costs incurred | $ | 1,365 | 1,554 | 1,669 |

| | | International | | |
|---|---|---|---|---|
| | | Year Ended December 31, | | |
| | | 2007 | 2006 | 2005 |
| | | (In millions) | | |
| Property acquisition costs: | | | | |
| Proved properties | $ | — | 24 | — |
| Unproved properties | | 1 | 45 | 1 |
| Exploration costs | | 111 | 117 | 43 |
| Development costs | | 354 | 233 | 12 |
| Costs incurred | $ | 466 | 419 | 56 |

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses that are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $312 million, $243 million and $158 million in the years 2007, 2006 and 2005, respectively. Also, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $65 million, $49 million and $40 million in the years 2007, 2006 and 2005, respectively.

### *Results of Operations for Oil and Gas Producing Activities*

The following tables include revenues and expenses associated directly with Devon's continuing oil and gas producing activities, including general and administrative expenses directly related to such producing activities. They do not include any allocation of Devon's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Devon's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil, gas and NGL sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences.

| | | Total | | |
|---|---|---|---|---|
| | | Year Ended December 31, | | |
| | | 2007 | 2006 | 2005 |
| | | (In millions, except per equivalent barrel amounts) | | |
| Oil, gas and NGL sales | $ | 9,626 | 8,095 | 8,235 |
| Production and operating expenses | | (2,168) | (1,766) | (1,579) |
| Depreciation, depletion and amortization | | (2,655) | (2,058) | (1,767) |
| Accretion of asset retirement obligation | | (74) | (47) | (42) |
| General and administrative expenses | | (226) | (155) | (105) |
| Reduction of carrying value of oil and gas properties | | — | (36) | (42) |
| Income tax expense | | (1,253) | (1,191) | (1,631) |
| Results of operations | $ | 3,250 | 2,842 | 3,069 |
| Depreciation, depletion and amortization per Boe | $ | 11.85 | 10.27 | 8.56 |

| | Domestic | | |
|---|---|---|---|
| | Year Ended December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions, except per equivalent barrel amounts) | | |
| Oil, gas and NGL sales | $ 5,828 | 5,211 | 5,475 |
| Production and operating expenses | (1,217) | (1,048) | (983) |
| Depreciation, depletion and amortization | (1,672) | (1,311) | (1,137) |
| Accretion of asset retirement obligation | (38) | (25) | (25) |
| General and administrative expenses | (167) | (115) | (84) |
| Income tax expense | (962) | (996) | (1,145) |
| Results of operations | $ 1,772 | 1,716 | 2,101 |
| Depreciation, depletion and amortization per Boe | $ 11.44 | 9.89 | 8.35 |

| | Canada | | |
|---|---|---|---|
| | Year Ended December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions, except per equivalent barrel amounts) | | |
| Oil, gas and NGL sales | $ 2,411 | 2,260 | 2,363 |
| Production and operating expenses | (658) | (550) | (504) |
| Depreciation, depletion and amortization | (740) | (644) | (570) |
| Accretion of asset retirement obligation | (32) | (21) | (16) |
| General and administrative expenses | (36) | (29) | (20) |
| Income tax expense | (63) | (144) | (426) |
| Results of operations | $ 882 | 872 | 827 |
| Depreciation, depletion and amortization per Boe | $ 12.73 | 11.17 | 9.20 |

| | International | | |
|---|---|---|---|
| | Year Ended December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions, except per equivalent barrel amounts) | | |
| Oil, gas and NGL sales | $ 1,387 | 624 | 397 |
| Production and operating expenses | (293) | (168) | (92) |
| Depreciation, depletion and amortization | (243) | (103) | (60) |
| Accretion of asset retirement obligation | (4) | (1) | (1) |
| General and administrative expenses | (23) | (11) | (1) |
| Reduction of carrying value of oil and gas properties | — | (36) | (42) |
| Income tax expense | (228) | (51) | (60) |
| Results of operations | $ 596 | 254 | 141 |
| Depreciation, depletion and amortization per Boe | $ 12.31 | 10.02 | 7.20 |

In 2007, 2006 and 2005, the Canadian income tax amounts in the tables above were reduced by $261 million, $243 million and $14 million, respectively, due to statutory rate reductions that were enacted in each such year.

*Quantities of Oil and Gas Reserves*

Set forth below is a summary of the reserves that were evaluated, either by preparation or audit, by independent petroleum consultants for each of the years ended 2007, 2006 and 2005.

| | 2007 | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| | Prepared | Audited | Prepared | Audited | Prepared | Audited |
| Domestic | 6% | 83% | 7% | 81% | 9% | 79% |
| Canada | 34% | 51% | 46% | 39% | 46% | 26% |
| International | 99% | — | 99% | — | 98% | — |
| Total | 19% | 69% | 28% | 61% | 31% | 54% |

"Prepared" reserves are those quantities of reserves that were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of revenues that were estimated by Devon employees and audited by an independent petroleum consultant. An audit is an examination of a company's proved oil and gas reserves and net cash flow by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company, L.P. in each of the years presented. The Canadian reserves were evaluated by the independent petroleum consultants of AJM Petroleum Consultants in each of the years presented. The International reserves were evaluated by the independent petroleum consultants of Ryder Scott Company, L.P. in each of the years presented.

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 2007. Additional discussion of the significant proved reserve changes follows the tables below.

| | Total | | | |
|---|---|---|---|---|
| | Oil (MMBbls) | Gas (Bcf) | Natural Gas Liquids (MMBbls) | Total (MMBoe) |
| Proved reserves as of December 31, 2004 | 484 | 7,385 | 232 | 1,946 |
| Revisions due to prices | (12) | 79 | 4 | 5 |
| Revisions other than price | 19 | (7) | 16 | 35 |
| Extensions and discoveries | 166 | 1,220 | 30 | 399 |
| Purchase of reserves | 2 | 10 | — | 4 |
| Production | (46) | (819) | (24) | (206) |
| Sale of reserves | (58) | (676) | (12) | (183) |
| Proved reserves as of December 31, 2005 | 555 | 7,192 | 246 | 2,000 |
| Revisions due to prices | (22) | (87) | (7) | (44) |
| Revisions other than price | 4 | (107) | 5 | (8) |
| Extensions and discoveries | 139 | 1,490 | 45 | 433 |
| Purchase of reserves | — | 584 | 9 | 106 |
| Production | (42) | (808) | (23) | (200) |
| Sale of reserves | — | (5) | — | (1) |
| Proved reserves as of December 31, 2006 | 634 | 8,259 | 275 | 2,286 |
| Revisions due to prices | 11 | 169 | 5 | 44 |
| Revisions other than price | 31 | 155 | 20 | 75 |
| Extensions and discoveries | 56 | 1,272 | 47 | 315 |
| Purchase of reserves | 1 | 15 | — | 3 |
| Production | (55) | (863) | (26) | (224) |
| Sale of reserves | (1) | (13) | — | (3) |
| Proved reserves as of December 31, 2007 | 677 | 8,994 | 321 | 2,496 |
| Proved developed reserves as of: | | | | |
| December 31, 2004 | 332 | 6,177 | 204 | 1,566 |
| December 31, 2005 | 306 | 6,073 | 216 | 1,535 |
| December 31, 2006 | 318 | 6,484 | 229 | 1,628 |
| December 31, 2007 | 391 | 7,255 | 274 | 1,874 |

| | Domestic | | | |
|---|---|---|---|---|
| | Oil (MMBbls) | Gas (Bcf) | Natural Gas Liquids (MMBbls) | Total (MMBoe) |
| Proved reserves as of December 31, 2004 | 203 | 4,936 | 182 | 1,208 |
| Revisions due to prices | 6 | 58 | 3 | 19 |
| Revisions other than price | 2 | 238 | 19 | 61 |
| Extensions and discoveries | 16 | 793 | 20 | 169 |
| Purchase of reserves | — | — | — | — |
| Production | (25) | (555) | (18) | (136) |
| Sale of reserves | (29) | (306) | (9) | (89) |
| Proved reserves as of December 31, 2005 | 173 | 5,164 | 197 | 1,232 |
| Revisions due to prices | — | (110) | (3) | (22) |
| Revisions other than price | — | (11) | 6 | 5 |
| Extensions and discoveries | 16 | 1,298 | 43 | 274 |
| Purchase of reserves | — | 580 | 9 | 105 |
| Production | (19) | (566) | (19) | (132) |
| Sale of reserves | — | — | — | — |
| Proved reserves as of December 31, 2006 | 170 | 6,355 | 233 | 1,462 |
| Revisions due to prices | 4 | 119 | 5 | 29 |
| Revisions other than price | 6 | 174 | 21 | 56 |
| Extensions and discoveries | 9 | 1,133 | 45 | 242 |
| Purchase of reserves | 1 | 10 | — | 2 |
| Production | (19) | (635) | (22) | (146) |
| Sale of reserves | (1) | (13) | — | (3) |
| Proved reserves as of December 31, 2007 | 170 | 7,143 | 282 | 1,642 |
| Proved developed reserves as of: | | | | |
| December 31, 2004 | 168 | 4,105 | 161 | 1,014 |
| December 31, 2005 | 149 | 4,343 | 175 | 1,049 |
| December 31, 2006 | 147 | 4,916 | 196 | 1,163 |
| December 31, 2007 | 148 | 5,743 | 244 | 1,349 |

| | Canada | | | |
|---|---|---|---|---|
| | Oil (MMBbls) | Gas (Bcf) | Natural Gas Liquids (MMBbls) | Total (MMBoe) |
| Proved reserves as of December 31, 2004 | 147 | 2,420 | 50 | 600 |
| Revisions due to prices | — | 22 | 1 | 4 |
| Revisions other than price | 2 | (242) | (3) | (41) |
| Extensions and discoveries | 144 | 427 | 10 | 225 |
| Purchase of reserves | 2 | 10 | — | 4 |
| Production | (13) | (261) | (6) | (62) |
| Sale of reserves | (29) | (370) | (3) | (94) |
| Proved reserves as of December 31, 2005 | 253 | 2,006 | 49 | 636 |
| Revisions due to prices | (19) | 23 | (4) | (20) |
| Revisions other than price | (1) | (84) | (1) | (16) |
| Extensions and discoveries | 109 | 193 | 2 | 145 |
| Purchase of reserves | — | 4 | — | 1 |
| Production | (13) | (241) | (4) | (58) |
| Sale of reserves | — | (5) | — | (1) |
| Proved reserves as of December 31, 2006 | 329 | 1,896 | 42 | 687 |
| Revisions due to prices | 16 | 50 | — | 25 |
| Revisions other than price | 13 | (19) | (1) | 7 |
| Extensions and discoveries | 46 | 139 | 2 | 72 |
| Purchase of reserves | — | 5 | — | 1 |
| Production | (16) | (227) | (4) | (58) |
| Sale of reserves | — | — | — | — |
| Proved reserves as of December 31, 2007 | 388 | 1,844 | 39 | 734 |
| Proved developed reserves as of: | | | | |
| December 31, 2004 | 123 | 2,043 | 43 | 507 |
| December 31, 2005 | 103 | 1,708 | 41 | 429 |
| December 31, 2006 | 112 | 1,560 | 33 | 405 |
| December 31, 2007 | 195 | 1,506 | 30 | 476 |

| | Oil (MMBbls) | Gas (Bcf) | Natural Gas Liquids (MMBbls) | Total (MMBoe) |
|---|---|---|---|---|
| | International (1) | | | |
| Proved reserves as of December 31, 2004 | 134 | 29 | — | 138 |
| Revisions due to prices | (18) | (1) | — | (18) |
| Revisions other than price | 15 | (3) | — | 15 |
| Extensions and discoveries | 6 | — | — | 5 |
| Purchase of reserves | — | — | — | — |
| Production | (8) | (3) | — | (8) |
| Sale of reserves | — | — | — | — |
| Proved reserves as of December 31, 2005 | 129 | 22 | — | 132 |
| Revisions due to prices | (3) | — | — | (2) |
| Revisions other than price | 5 | (12) | — | 3 |
| Extensions and discoveries | 14 | (1) | — | 14 |
| Purchase of reserves | — | — | — | — |
| Production | (10) | (1) | — | (10) |
| Sale of reserves | — | — | — | — |
| Proved reserves as of December 31, 2006 | 135 | 8 | — | 137 |
| Revisions due to prices | (9) | — | — | (10) |
| Revisions other than price | 12 | — | — | 12 |
| Extensions and discoveries | 1 | — | — | 1 |
| Purchase of reserves | — | — | — | — |
| Production | (20) | (1) | — | (20) |
| Sale of reserves | — | — | — | — |
| Proved reserves as of December 31, 2007 | 119 | 7 | — | 120 |
| Proved developed reserves as of: | | | | |
| December 31, 2004 | 41 | 29 | — | 45 |
| December 31, 2005 | 54 | 22 | — | 57 |
| December 31, 2006 | 59 | 8 | — | 60 |
| December 31, 2007 | 48 | 6 | — | 49 |

(1) Included in the International quantities of proved reserves as of December 31, 2007, 2006, 2005 and 2004 are 86 MMBoe, 103 MMBoe, 105 MMBoe and 115 MMBoe, respectively, which are attributable to production sharing contracts with various foreign governments.

Noteworthy amounts included in the categories of proved reserve changes for the years 2007, 2006 and 2005 in the above tables include:

*Extensions and Discoveries*: *2007* – Of the 315 MMBoe of 2007 extensions and discoveries, 119 MMBoe related to the Barnett Shale area in Texas, 34 MMBoe related to the Carthage area in east Texas, 22 MMBoe related to the Jackfish steam-assisted gravity drainage project in Canada, 20 MMBoe related to the Lloydminster heavy oil development in Canada, 17 MMBoe related to the Washakie area in southern Wyoming and 15 MMBoe related to the Woodford Shale in eastern Oklahoma.

The 2007 extensions and discoveries included 154 MMBoe related to additions from Devon's infill drilling activities, including 96 MMBoe related to the Barnett Shale and 19 MMBoe related to Lloydminster.

*2006* – Of the 433 MMBoe of 2006 extensions and discoveries, 143 MMBoe related to the Barnett Shale, 88 MMBoe related to Jackfish, 30 MMBoe related to Carthage and 20 MMBoe related to Washakie.

The 2006 extensions and discoveries included 202 MMBoe related to additions from Devon's infill drilling activities, including 127 MMBoe related to the Barnett Shale area and 20 MMBoe related to the Lloydminster area in Canada.

*2005* – Of the 399 MMBoe of 2005 extensions and discoveries, 118 MMBoe related to Jackfish, 54 MMBoe related to the Barnett Shale, and 40 MMBoe related to the Deep Basin in Canada.

The 2005 extensions and discoveries included 76 MMBoe related to additions from Devon's infill drilling activities, including 19 MMBoe related to the Barnett Shale, 16 MMBoe related to Carthage and eight MMBoe related to the Permian Basin in New Mexico and west Texas.

*Purchase of Reserves*: The 2006 total included 100 MMBoe located in the Barnett Shale that was acquired in the June 2006 Chief acquisition.

*Sale of Reserves*: The 2005 total included 176 MMBoe of reserves related to non-core oil and gas properties in the offshore Gulf of Mexico an onshore in the United States and Canada.

*Revisions Other Than Price*: The 2007 total included performance revisions of 39 MMBoe in the Barnett Shale, 13 MMBoe at Jackfish, 13 MMBoe in Carthage and 7 MMBoe in China.

### *Standardized Measure of Discounted Future Net Cash Flows*

The tables below reflect the standardized measure of discounted future net continuing cash flows relating to Devon's interest in proved reserves:

| | Total | | |
|---|---|---|---|
| | December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions) | | |
| Future cash inflows | $ 111,156 | 77,951 | 89,144 |
| Future costs: | | | |
| Development | (9,974) | (8,116) | (5,488) |
| Production | (39,047) | (28,537) | (24,296) |
| Future income tax expense | (17,752) | (12,241) | (19,773) |
| Future net cash flows | 44,383 | 29,057 | 39,587 |
| 10% discount to reflect timing of cash flows | (20,912) | (13,428) | (17,958) |
| Standardized measure of discounted future net cash flows | $ 23,471 | 15,629 | 21,629 |

| | Domestic | | |
|---|---|---|---|
| | December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions) | | |
| Future cash inflows | $ 72,109 | 47,980 | 55,954 |
| Future costs: | | | |
| Development | (5,673) | (4,919) | (2,954) |
| Production | (25,112) | (18,858) | (16,213) |
| Future income tax expense | (12,526) | (7,588) | (12,582) |
| Future net cash flows | 28,798 | 16,615 | 24,205 |
| 10% discount to reflect timing of cash flows | (14,119) | (7,938) | (11,258) |
| Standardized measure of discounted future net cash flows | $ 14,679 | 8,677 | 12,947 |

| | Canada | | |
|---|---|---|---|
| | December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions) | | |
| Future cash inflows | $ 28,684 | 22,575 | 26,277 |
| Future costs: | | | |
| Development | (3,380) | (2,395) | (1,984) |
| Production | (10,331) | (7,431) | (6,344) |
| Future income tax expense | (3,729) | (3,614) | (5,986) |
| Future net cash flows | 11,244 | 9,135 | 11,963 |
| 10% discount to reflect timing of cash flows | (5,282) | (4,318) | (5,332) |
| Standardized measure of discounted future net cash flows | $ 5,962 | 4,817 | 6,631 |

| | International | | |
|---|---|---|---|
| | December 31, | | |
| | 2007 | 2006 | 2005 |
| | (In millions) | | |
| Future cash inflows | $ 10,363 | 7,396 | 6,913 |
| Future costs: | | | |
| Development | (921) | (802) | (550) |
| Production | (3,604) | (2,248) | (1,739) |
| Future income tax expense | (1,497) | (1,039) | (1,205) |
| Future net cash flows | 4,341 | 3,307 | 3,419 |
| 10% discount to reflect timing of cash flows | (1,511) | (1,172) | (1,368) |
| Standardized measure of discounted future net cash flows | $ 2,830 | 2,135 | 2,051 |

Future cash inflows are computed by applying year-end prices (averaging $60.42 per barrel of oil, $6.01 per Mcf of gas and $50.57 per barrel of natural gas liquids at December 31, 2007) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $10.0 billion of future development costs as of the end of 2007, $1.9 billion, $1.6 billion and $1.3 billion are estimated to be spent in 2008, 2009 and 2010, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $10.0 billion of future development costs are $2.1 billion of future dismantlement, abandonment and rehabilitation costs.

Future production costs include general and administrative expenses directly related to oil and gas producing activities. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

### *Changes Relating to the Standardized Measure of Discounted Future Net Cash Flows*

Principal changes in the standardized measure of discounted future net continuing cash flows attributable to Devon's proved reserves are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (In millions) | |
| Beginning balance | $ 15,629 | 21,629 | 14,530 |
| Oil, gas and NGL sales, net of production costs | (7,233) | (6,174) | (6,551) |
| Net changes in prices and production costs | 9,582 | (10,439) | 10,606 |
| Extensions and discoveries, net of future development costs | 4,131 | 4,553 | 6,074 |
| Purchase of reserves, net of future development costs | 51 | 786 | 67 |
| Development costs incurred during the period that reduced future development costs | 1,887 | 1,466 | 606 |
| Revisions of quantity estimates | 566 | (2,201) | (610) |
| Sales of reserves in place | (50) | (10) | (2,897) |
| Accretion of discount | 2,214 | 3,234 | 2,096 |
| Net change in income taxes | (2,863) | 4,202 | (4,301) |
| Other, primarily changes in timing and foreign exchange rates | (443) | (1,417) | 2,009 |
| Ending balance | $ 23,471 | 15,629 | 21,629 |

## 16. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2007 and 2006.

| | | 2007 | | | | |
|---|---|---|---|---|---|---|
| | | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Full Year |
| | | (In millions, except per share amounts) | | | | |
| Revenues | $ | 2,473 | 2,929 | 2,763 | 3,197 | 11,362 |
| Earnings from continuing operations | $ | 574 | 824 | 644 | 1,104 | 3,146 |
| Earnings from discontinued operations | | 77 | 80 | 91 | 212 | 460 |
| Net earnings | $ | 651 | 904 | 735 | 1,316 | 3,606 |
| Basic net earnings per common share: | | | | | | |
| Earnings from continuing operations | $ | 1.29 | 1.84 | 1.45 | 2.48 | 7.05 |
| Earnings from discontinued operations | | 0.17 | 0.18 | 0.20 | 0.48 | 1.03 |
| Net earnings | $ | 1.46 | 2.02 | 1.65 | 2.96 | 8.08 |
| Diluted net earnings per common share: | | | | | | |
| Earnings from continuing operations | $ | 1.27 | 1.82 | 1.43 | 2.45 | 6.97 |
| Earnings from discontinued operations | | 0.17 | 0.18 | 0.20 | 0.47 | 1.03 |
| Net earnings | $ | 1.44 | 2.00 | 1.63 | 2.92 | 8.00 |

| | | 2006 | | | | |
|---|---|---|---|---|---|---|
| | | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Full Year |
| | | (In millions, except per share amounts) | | | | |
| Revenues | $ | 2,500 | 2,350 | 2,499 | 2,418 | 9,767 |
| Earnings from continuing operations | $ | 716 | 763 | 653 | 502 | 2,634 |
| Earnings (loss) from discontinued operations | | (16) | 96 | 52 | 80 | 212 |
| Net earnings | $ | 700 | 859 | 705 | 582 | 2,846 |
| Basic net earnings per common share: | | | | | | |
| Earnings from continuing operations | $ | 1.61 | 1.73 | 1.47 | 1.13 | 5.94 |
| Earnings (loss) from discontinued operations | | (0.03) | 0.21 | 0.12 | 0.18 | 0.48 |
| Net earnings | $ | 1.58 | 1.94 | 1.59 | 1.31 | 6.42 |
| Diluted net earnings per common share: | | | | | | |
| Earnings from continuing operations | $ | 1.59 | 1.71 | 1.45 | 1.11 | 5.87 |
| Earnings (loss) from discontinued operations | | (0.03) | 0.21 | 0.12 | 0.18 | 0.47 |
| Net earnings | $ | 1.56 | 1.92 | 1.57 | 1.29 | 6.34 |

### *Earnings from Continuing Operations*

The second quarter and fourth quarter of 2007 include a reduction to income tax expense from continuing operations of $30 million (or $0.07 per diluted share) and $231 million (or $0.52 per diluted share), respectively, due to statutory rate reductions in Canada.

The second quarter of 2006 included a reduction to income tax expense from continuing operations of $243 million (or $0.55 per diluted share) due to statutory rate reductions in Canada and additional income tax expense of $39 million (or $0.09 per diluted share) due to a new income-based tax enacted by the state of Texas.

The second and third quarters of 2006 include $16 million and $20 million, respectively, of reductions of carrying values of oil and gas properties. The after-tax effects of these amounts were $16 million (or $0.04 per share) and $10 million (or $0.02 per share), respectively.

### *Earnings from Discontinued Operations*

The second quarter of 2007 earnings from discontinued operations includes a reduction of carrying value of oil and gas properties of $64 million ($13 million after-tax) or $0.03 per diluted share.

The fourth quarter of 2007 earnings from discontinued operations includes a $90 million gain ($90 million after-tax) or $0.20 per diluted share as a result of completing the sale of Devon's Egyptian operations in October 2007.

Revenues for the first, second, third and fourth quarters of 2007 in the table above exclude $175 million, $215 million, $206 million and $185 million, respectively, related to discontinued operations in West Africa and Egypt.

The first quarter of 2006 earnings from discontinued operations includes a reduction of carrying value of oil and gas properties of $85 million ($85 million after-tax) or $0.19 per share.

Revenues for the first, second, third and fourth quarters of 2006 in the table above exclude $218 million, $267 million, $223 million and $221 million, respectively, related to discontinued operations in West Africa and Egypt.

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

Devon's management is responsible for establishing and maintaining adequate internal control over financial reporting for Devon, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Devon's management, including our principal executive and principal financial officers, Devon conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework, which was completed on February 5, 2008, management concluded that its internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of Devon's internal control over financial reporting as of December 31, 2007 has been audited by KPMG LLP, an independent registered public accounting firm who audited Devon's consolidated financial statements as of and for the year ended December 31, 2007, as stated in their report, which is included on page 63.

# Assumptions and Risks Related to Forward-Looking Estimates

The forward-looking estimates beginning on page 56 are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2007, reserve reports and other data in Devon's possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors.

### Price Volatility

Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond Devon's control and are difficult to predict. In addition to volatility in general, oil, gas and NGL prices may vary considerably due to differences between regional markets, differing quality of oil produced (i.e., sweet crude versus heavy or sour crude), differing Btu contents of gas produced, transportation availability and costs and demand for the various products derived from oil, natural gas and NGLs. Substantially all of Devon's revenues are attributable to sales, processing and transportation of these three commodities. Consequently, Devon's financial results and resources are highly influenced by price volatility.

### Oil, Gas, and NGL Production

Estimates for future production of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable production of these products. There can be no assurance of such stability. Most of Devon's Canadian production of oil, natural gas and NGLs is subject to government royalties that fluctuate with prices. Thus, price fluctuations can affect reported production. Also, Devon's international production of oil is governed by payout agreements with the governments of the countries in which Devon operates. If the payout under these agreements is attained earlier than projected, Devon's net production and proved reserves in such areas could be reduced.

### Marketing and Midstream

Estimates for future processing and transport of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability. Additionally, Devon cautions that its future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally incident to the marketing and midstream business. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks as outlined herein.

### Foreign Exchange

Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Unless otherwise noted, all of the dollar amounts are expressed in U.S. dollars. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2008 exchange rate of $0.98 U.S. dollar to $1.00 Canadian dollar. The actual 2008 exchange rate may vary materially from this estimate. Such variations could have a material effect on our forward-looking estimates.

### Property Acquisitions and Dispositions

Although Devon has completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Except for the operations associated with the planned divestitures of Devon's assets in West Africa, the forward-looking estimates do not include the financial and operating effects of potential property acquisitions or divestitures during the year 2008.

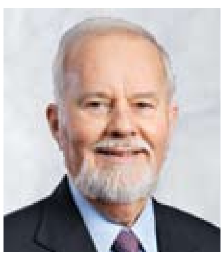
### Resource Potential

The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. This report may contain certain terms, such as resource potential, reserve potential, probable reserves, possible reserves and exploration target size. The SEC guidelines strictly prohibit us from including these terms in filings with the SEC.

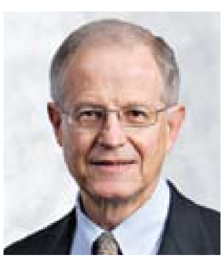
## Directors

**John W. Nichols**, 93, is a co-founder of Devon. He was named chairman emeritus in 1999. Nichols was chairman of the board of directors from the time Devon began operations in 1971 until 1999. He is a founding partner of Blackwood & Nichols Co., which put together the first public oil and gas drilling fund ever registered with the Securities and Exchange Commission. Nichols is a non-practicing Certified Public Accountant.

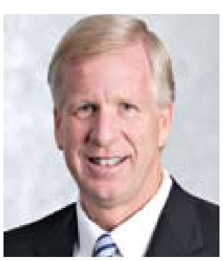
**J. Larry Nichols**, 65, is a co-founder of Devon and has been a director since 1971. He was named chairman of the board of directors in 2000 and serves as chairman of the Dividend Committee. Nichols served as president from 1976 until 2003 and has been chief executive officer since 1980. Nichols serves as a director of Baker Hughes Inc. and Sonic Corp. Nichols has a Bachelor of Arts degree in Geology from Princeton University and a law degree from the University of Michigan.



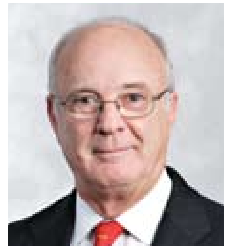
**Thomas F. Ferguson**, 71, joined the board of directors in 1982 and serves as chairman of the Audit Committee. Ferguson retired in 2005 from his position as managing director of United Gulf Management Ltd., a wholly-owned subsidiary of Kuwait Investment Projects Co. KSC. He has represented Kuwait Investment Projects Co. on the boards of various companies in which it invests, including Baltic Transit Bank in Latvia and Tunis International Bank in Tunisia. Ferguson is a Canadian qualified Certified General Accountant and was formerly employed by the Economist Intelligence Unit of London as a financial consultant.



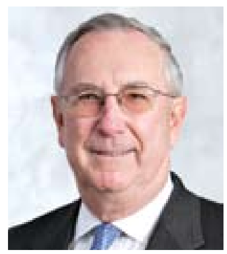
**David M. Gavrin**, 73, joined the board of directors in 1979 and is lead director and chairman of the Compensation Committee. Gavrin has been a private investor since 1989 and is a director and chairman of the board of MetBank Holding Corp. He is also president and a director of Arthur J. Gavrin Foundation Inc. From 1978 to 1988, he was a general partner of Windcrest Partners, a private investment partnership in New York City, and, for 14 years prior to that, he was an officer of Drexel Burnham Lambert Inc.



**David A. Hager**, 51, joined the board of directors in 2007. Hager served as chief operating officer of Kerr-McGee Corp. prior to its merger with Anadarko Petroleum Corp. in 2006. He has more than 25 years of oil and gas exploration and production experience, including an extensive background in planning and executing deepwater exploration and development projects. Hager also serves as a director of Pride International, Inc.

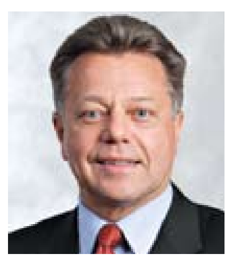


**John A. Hill**, 66, joined the board of directors in 2000 following Devon's merger with Santa Fe Snyder Corp. and serves as chairman of the Governance Committee. He has been with First Reserve Corp., an oil and gas investment management company, since 1983 and is currently its vice chairman and managing director. Prior to creating First Reserve Corp., Hill was president and chief executive officer of several investment banking and asset management companies and served as the deputy administrator of the Federal Energy Administration during the Ford Administration. Hill is chairman of the board of trustees of the Putnam Funds in Boston, a trustee of Sarah Lawrence College and director of various companies controlled by First Reserve Corp.

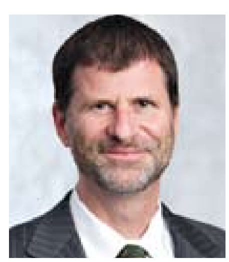


**Robert L. Howard**, 71, joined the board of directors in 2003 and is chairman of the Reserves Committee. Howard served as a director of Ocean Energy Inc. from 1996 to 2003. He retired in 1995 from his position as vice president of Domestic Operations, Exploration and Production, of Shell Oil Co. Howard is also a director of Southwestern Energy Company and McDermott International Inc.

**William J. Johnson**, 73, has been on the board of directors since 1999. Johnson has been a private consultant to the oil and gas industry since 1994. He is president and a director of JonLoc Inc., an oil and gas company of which he and his family are the only stockholders. Johnson has served as a director of Tesoro Corp. since 1996. From 1991 to 1994, Johnson was president, chief operating officer and a director of Apache Corp.



**Michael M. Kanovsky**, 59, joined the board of directors in 1998. He was a co-founder of Northstar Energy Corp. and served on Northstar's board of directors from 1982 to 1998. Kanovsky is president of Sky Energy Corporation and also serves as a director of Accrete Energy Inc., ARC Resources Ltd., Bonavista Petroleum Ltd., Pure Technologies Ltd. and TransAlta Corp.



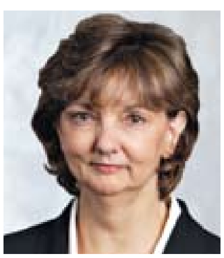
**J. Todd Mitchell**, 49, joined the board of directors in 2002. He currently serves as president of Walton Mitchell & Co., Inc., a private energy investment company. Mitchell served as president of GPM Inc., a family-owned investment company, from 1998 to 2006, and as vice president for strategic planning from 2006 to 2007. He was on the board of directors of Mitchell Energy & Development Corp. from 1993 to 2002.

**Mary P. Ricciardello**, 52, joined the board of directors in 2007. She retired in 2002 after a 20-year career with Reliant Energy Inc., a leading independent power producer and marketer. Ricciardello began her career with Reliant in 1982 and served in various financial management positions with the company including comptroller, vice president and most recently as senior vice president and chief accounting officer. She serves on the boards of U.S. Concrete and Noble Corp. and is a Certified Public Accountant.

**John Richels**, 57, was elected president of Devon in 2004 and joined the board of directors in 2007. He previously served as a senior vice president of Devon and president and chief executive officer of Devon's Canadian subsidiary. Richels joined Devon through its 1998 acquisition of Canadian-based Northstar Energy Corp. Prior to joining Northstar, Richels was managing and chief operating partner of the Canadian-based national law firm, Bennett Jones. Richels previously served as a director of a number of publicly traded companies. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor.

## Senior Officers

**Stephen J. Hadden**, 53, was elected to the position of senior vice president, Exploration and Production, in 2004. In 1977, Hadden joined Texaco, now Chevron Corp., as a field engineer, subsequently holding a series of engineering and management positions in the United States. In 2002, he became an independent consultant. Hadden received a Bachelor of Science degree in chemical engineering from Pennsylvania State University.



**Marian J. Moon**, 57, was elected to the position of senior vice president, Administration, in 1999. Moon is responsible for office administration, information technology, project management, records management and corporate governance. Moon has been with Devon for 24 years and served in various capacities, including manager of Corporate Finance and corporate secretary. Prior to joining Devon, Moon was employed by Amarex Inc., an Oklahoma City-based oil and natural gas production and exploration firm, where her last position was treasurer. Moon is a member of the Society of Corporate Secretaries & Governance Professionals and a graduate of Valparaiso University.

**Frank W. Rudolph**, 50, was elected to the position of senior vice president, Human Resources, in June 2007. In the seven years prior to joining Devon, Rudolph was vice president Human Resources for Banta Corporation, an international printing and supply chain management company with 9,000 employees. His career in human resources began at R. R. Donnelly & Sons and spans more than 25 years. Rudolph has also held human resources management positions at SANWA-Overhead Door Corp., US West Communications, Clark Refining and Marketing, Inc., James River Corporation and Tenneco Packaging. Rudolph holds a Bachelor of Science degree in administration from Illinois State University and a master's degree in industrial relations and management from Loyola University.

**Darryl G. Smette**, 60, was elected to the position of senior vice president, Marketing and Midstream, in 1999. Smette previously held the position of vice president, Marketing and Administrative Planning. His marketing background includes 15 years with Energy Reserves Group Inc./BHP Petroleum (Americas) Inc. He is also an oil and gas industry instructor, approved by the University of Texas Department of Continuing Education. Smette is a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. He holds an undergraduate degree from Minot State University and a master's degree from Wichita State University.

**Lyndon C. Taylor**, 49, was elected to the position of senior vice president and general counsel in February 2007. Taylor had served as Devon's deputy general counsel since August 2005. Prior to joining Devon, Taylor was with Skadden, Arps, Slate, Meagher & Flom, LLP for 20 years, most recently as managing partner of the Houston office's energy practice. He is admitted to practice law in Oklahoma and Texas. Taylor holds a Bachelor of Science degree in industrial engineering from Oklahoma State University and a law degree from the University of Oklahoma.

# Glossary

**Bitumen** / A viscous, tar-like oil that requires nonconventional production methods such as mining or steam-assisted gravity drainage.

**Block** / Refers to a contiguous leasehold position. In federal offshore waters, a block is typically 5,000 acres.

**British thermal unit (Btu)** / A measure of heat value. An Mcf of natural gas is roughly equal to one million Btu.

**Coalbed natural gas** / An unconventional gas resource that is present in certain coal deposits.

**Deep water** / In offshore areas, water depths of greater than 600 feet.

**Delineation well** / A well drilled just outside the proved area of an oil or gas reservoir in an attempt to extend the known boundaries of the reservoir.

**Development well** / A well drilled within the area of an oil or gas reservoir known to be productive. Development wells are relatively low risk.

**Dry hole** / A well found to be incapable of producing oil or gas in sufficient quantities to justify completion.

**Exploitation** / Various methods of optimizing oil and gas production or establishing additional reserves from producing properties through additional drilling or the application of new technology.

**Exploratory well** / A well drilled in an unproved area, either to find a new oil or gas reservoir or to extend a known reservoir. Sometimes referred to as a wildcat.

**Field** / A geographical area under which one or more oil or gas reservoirs lie.

**Floating production, storage and offloading unit (FPSO)** / A moored tanker-type vessel used to develop an offshore oil field. Oil is stored within the FPSO until offloaded to a tanker for transportation to a terminal or refinery.

**Formation** / An identifiable layer of rocks named after the geographical location of its first discovery and dominant rock type.

**Fracture, refracture** / The process of applying hydraulic pressure to an oil or gas bearing geological formation to crack the formation and stimulate the release of oil and gas.

**Gross acres** / The total number of acres in which one owns a working interest.

**Hedge** / A financial contract entered into to manage commodity price risk.

**Increased density/infill** / A well drilled in addition to the number of wells permitted under initial spacing regulations, used to enhance or accelerate recovery, or prevent the loss of proved reserves.

**Independent producer** / A non-integrated oil and gas producer with no refining or retail marketing operations.

**Lease** / A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract.

**London Inter Bank Offering Rate (LIBOR)** / An average of the interest rate on dollar-denominated deposits, also known as Eurodollars, traded between banks in London.

**Natural gas liquids (NGLs)** / Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane and natural gasoline.

**Net acres** / Gross acres multiplied by one's fractional working interest in the property.

**New York Mercantile Exchange (NYMEX)** / The world's largest physical commodity futures exchange. The prices quoted for oil, gas and other commodity transactions on the exchange are the basis for prices paid throughout the world.

**Oil sands** / A complex mixture of sand, water and clay trapping very heavy oil known as bitumen.

**Pilot program** / A small-scale test project used to assess the viability of a concept prior to committing significant capital to a large-scale project.

**Production** / Natural resources, such as oil or gas, taken out of the ground.

**Gross production** / Total production before deducting royalties.

**Net production** / Gross production, minus royalties, multiplied by one's fractional working interest.

**Prospect** / An area designated for the potential drilling of development or exploratory wells.

**Proved reserves** / Estimates of oil, gas and NGL quantities that, with reasonable certainty, are thought to be recoverable from known reservoirs under existing economic and operating conditions.

**Recompletion** / The modification of an existing well for the purpose of producing oil or gas from a different producing formation.

**Reservoir** / A rock formation or trap containing oil and/or natural gas.

**Royalty** / The owner's share of the value of minerals (oil and gas) produced on the property.

**Seismic** / A tool for identifying underground accumulations of oil or gas by sending energy waves or sound waves into the earth and recording the wave reflections. Results indicate the type, size, shape and depth of subsurface rock formations. 2-D seismic provides two-dimensional information while 3-D creates three-dimensional pictures. 4-C, or four-component, seismic utilizes measurement and interpretation of shear wave data. 4-C seismic improves the resolution of seismic images below shallow gas deposits.

**Steam-assisted gravity drainage (SAGD)** / A method of extracting heavy oil from oil sands. Steam is injected under ground, lowering the viscosity of the heavy oil and allowing it to flow to the surface.

**Undeveloped acreage** / Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas.

**Unit** / A contiguous parcel of land deemed to cover one or more common reservoirs, as determined by state or federal regulations. Unit interest owners generally share proportionately in costs and revenues.

**Working interest** / The cost-bearing ownership share of an oil or gas lease.

**Workover** / The process of conducting remedial work, such as cleaning out a well bore, to increase or restore production.

---

VOLUME ACRONYMS

**Bbl** / A standard oil measurement that equals one barrel
(42 U.S. gallons).

**MBbl** / One thousand barrels

**MMBbls** / One million barrels

**MBbld** / One thousand barrels per day

**Mcf** / A standard measurement unit for volumes of natural gas that equals one thousand cubic feet.

**MMcf** / One million cubic feet

**Bcf** / One billion cubic feet

**Tcf** / One trillion cubic feet

**MMcfd** / One million cubic feet per day

**Boe** / A method of equating oil, gas and natural gas liquids. Gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil. NGLs are converted based upon volume: one barrel of natural gas liquids equals one barrel of oil.

**MBoe** / One thousand barrels of oil equivalent

**MMBoe** / One million barrels of oil equivalent

**MBoed** / One thousand barrels of oil equivalent per day

# Investor Information

**Corporate Headquarters**
Devon Energy Corporation
20 North Broadway
Oklahoma City, OK 73102-8260
Telephone: (405) 235-3611
Fax: (405) 552-4550

**Permian, Mid-Continent, Rocky Mountains and Marketing and Midstream Operations**
Devon Energy Corporation
20 North Broadway
Oklahoma City, OK 73102-8260
Telephone: (405) 235-3611
Fax: (405) 552-4550

**Gulf, Gulf Coast and International Operations**
Devon Energy Corporation
Devon Energy Tower
1200 Smith Street
Houston, TX 77002-4313
Telephone: (713) 286-5700

**Canadian Operations**
Devon Canada Corporation
2000, 400 - 3rd Avenue S.W.
Calgary, Alberta T2P 4H2
Telephone: (403) 232-7100

**Royalty Owner Assistance**
Telephone: (405) 228-4800
E-mail: DevonRevenueHotline@dvn.com

**Shareholder Assistance**
For information about transfer or exchange of shares, dividends, address changes, account consolidation, multiple mailings, lost certificates and Form 1099:

**Computershare Trust Company, N.A.**
PO Box 43078
Providence, RI 02940-3078
Toll free: (877) 860-5820
E-mail: web.queries@computershare.com

**Company Contacts**
Vince White, Vice President
Communications and Investor Relations
Telephone: (405) 552-4505
E-mail: vince.white@dvn.com

**Investor Relations**
Zack Hager, Manager, Investor Relations
Telephone: (405) 552-4526
E-mail: zack.hager@dvn.com

Shea Snyder, Assistant Manager, Investor Relations
Telephone: (405) 552-4782
E-mail: shea.snyder@dvn.com

Scott Coody, Supervisor, Investor Relations
Telephone: (405) 552-4735
E-mail: scott.coody@dvn.com

**Media**
Chip Minty, Supervisor, External Communications
Telephone: (405) 228-8647
E-mail: chip.minty@dvn.com

**Publications**
A copy of Devon's annual report to the Securities and Exchange Commission (Form 10-K) and other publications are available at no charge upon request. Direct requests to:

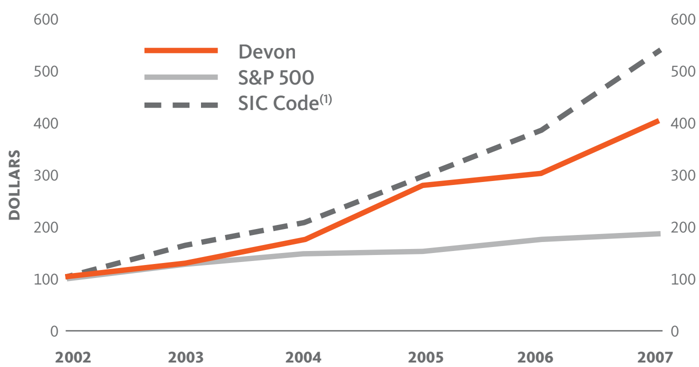
Judy Roberts, Shareholder Services Administrator
Telephone: (405) 552-4570
Fax: (405) 552-7818
E-mail: judy.roberts@dvn.com

**Annual Meeting**
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 4, 2008, on the Third Floor of the Chase Tower, 100 North Broadway, Oklahoma City, OK.

**Independent Auditors**
KPMG LLP
Oklahoma City, OK

**Stock Trading Data**
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 16,000 shareholders of record.

## Stock Performance – 5-Year Cumulative Total Return




(1) Stock Index for Crude Petroleum and Natural Gas

## Common Stock Trading Data

### 2006

| QUARTER | HIGH | LOW | LAST | TOTAL VOLUME |
|---|---|---|---|---|
| First | $ 69.97 | 55.30 | 61.17 | 253,074,600 |
| Second | $ 65.25 | 48.94 | 60.41 | 284,421,100 |
| Third | $ 74.75 | 57.19 | 63.15 | 338,019,000 |
| Fourth | $ 74.49 | 58.55 | 67.08 | 283,929,200 |

### 2007

| QUARTER | HIGH | LOW | LAST | TOTAL VOLUME |
|---|---|---|---|---|
| First | $ 71.24 | 62.80 | 69.22 | 267,618,540 |
| Second | $ 83.92 | 69.30 | 78.29 | 226,144,705 |
| Third | $ 85.20 | 69.01 | 83.20 | 217,392,650 |
| Fourth | $ 94.75 | 80.05 | 88.91 | 222,106,857 |

**Certifications** The Form 10-K which was filed by the company with the Securities and Exchange Commission (SEC) for the fiscal year ending December 31, 2007 includes as exhibits, the certifications of our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, required to be filed with the SEC pursuant to Section 302 of the Sarbanes Oxley Act of 2002. The company has also filed with the New York Stock Exchange the 2007 annual certification of its Chief Executive Officer confirming that the company has complied with the New York Stock Exchange corporate governance listing standards.


This report was printed on certified recycled paper.

Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
FSC
www.fsc.org Cert no. XXX-XXX-000
© 1996 Forest Stewardship Council
XX%


**Forward-Looking Statements** This annual report includes "forward-looking statements" as defined by securities law. Such statements are those concerning Devon's plans, expectations and objectives for future operations including resource potential and exploration target size. These statements address future financial position, business strategy, future capital expenditures, projected oil and gas production and future costs. Devon believes that the expectations reflected in such forward-looking statements are reasonable. However, important risk factors could cause actual results to differ materially from the company's expectations. A discussion of these risk factors can be found on page 109 of this report. Further information is available in the company's Form 10-K and other publicly available reports, which are available free of charge on the company's website, www.devonenergy.com, or will be furnished upon request.

Commitment Runs Deep

www.devonenergy.com

devon