DEVON ENERGY CORP/DE
Form 10-K
February 28, 2008

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 001-32318

Devon Energy Corporation
(Exact name of Registrant as Specified in its Charter)

Delaware	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
20 North Broadway, Oklahoma City, Oklahoma	**73102-8260**
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(405) 235-3611

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	The New York Stock Exchange
4.90% Exchangeable Debentures, due 2008	The New York Stock Exchange
4.95% Exchangeable Debentures, due 2008	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Securities Act). Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 29, 2007, was approximately $34.7 billion, based upon the closing price of $78.29 per share as reported by the New York Stock Exchange on such date. On February 15, 2008, 444,390,145 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2008 annual meeting of stockholders Part III

DEVON ENERGY CORPORATION

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First Amendment to Credit Agreement
Third Amendment to Amended and Restated Credit Agreement
Statement of Computations of Ratio of Earnings to Combined Fixed Charges
Registrant's Significant Subsidiaries
Consent of KPMG LLP
Consent of LaRoche Petroleum Consultants
Consent of Ryder Scott Company, L.P.
Consent of AJM Petroleum Consultants
Certification of J. Larry Nichols Pursuant to Section 302
Certification of Danny J. Heatly Pursuant to Section 302
Certification of J. Larry Nichols Pursuant to Section 906
Certification of Danny J. Heatly Pursuant to Section 906

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DEFINITIONS

As used in this document:

Bbl or Bbls means barrel or barrels.

Bcf means billion cubic feet.

Boe means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

FPSO means floating, production, storage and offloading facilities.

Btu means British Thermal units, a measure of heating value.

Inside FERC refers to the publication *Inside F.E.R.C. s Gas Market Report.*

LIBOR means London Interbank Offered Rate.

MBbls means thousand barrels.

MMBbls means million barrels.

MBoe means thousand Boe.

MMBoe means million Boe.

MMBtu means million Btu.

Mcf means thousand cubic feet.

MMcf means million cubic feet.

MMcfe means million cubic feet of gas equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

NGL or NGLs means natural gas liquids.

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

SEC means United States Securities and Exchange Commission.

Domestic means the properties of Devon in the onshore continental United States and the offshore Gulf of Mexico.

U.S. Onshore means the properties of Devon in the continental United States.

U.S. Offshore means the properties of Devon in the Gulf of Mexico.

Canada means the division of Devon encompassing oil and gas properties located in Canada.

International means the division of Devon encompassing oil and gas properties that lie outside the United States and Canada.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements 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. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, expect, intend, project, estimate, anticipate, believ continue or similar terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- energy markets;
- production levels, including Canadian production subject to government royalties, which fluctuate with prices and production, and international production governed by payout agreements, which affect reported production;
- reserve levels;
- competitive conditions;
- technology;
- the availability of capital resources;
- capital expenditure and other contractual obligations;
- the supply and demand for oil, natural gas, NGLs and other products or services;
- the price of oil, natural gas, NGLs and other products or services;
- currency exchange rates;
- the weather;
- inflation;
- the availability of goods and services;
- drilling risks;
- future processing volumes and pipeline throughput;
- general economic conditions, whether internationally, nationally or in the jurisdictions in which we or our subsidiaries conduct business;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations;
- terrorism;
- occurrence of property acquisitions or divestitures;

the securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks; and

other factors disclosed under Item 2. Properties Proved Reserves and Estimated Future Net Revenue, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this report.

All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

PART I

Item 1. *Business*

General

Devon Energy Corporation, including its subsidiaries (Devon), is an independent energy company engaged primarily in oil and gas exploration, development and production, the transportation of oil, gas, and NGLs and the processing of natural gas. We own oil and gas properties principally in the United States and Canada and, to a lesser degree, various regions located outside North America, including Azerbaijan, Brazil and China. We also own properties in West Africa that we intend to sell in 2008. In addition to our oil and gas operations, we have marketing and midstream operations primarily in North America. These include marketing natural gas, crude oil and NGLs, and constructing and operating pipelines, storage and treating facilities and gas processing plants. A detailed description of our significant properties and associated 2007 developments can be found under Item 2. Properties.

We began operations in 1971 as a privately held company. In 1988, our common stock began trading publicly on the American Stock Exchange under the symbol DVN . In October 2004, we transferred our common stock listing to the New York Stock Exchange. Our principal and administrative offices are located at 20 North Broadway, Oklahoma City, OK 73102-8260 (telephone 405/235-3611).

Strategy

We have a two-pronged operating strategy. First, we invest the vast majority of our capital budget in low-risk exploitation and development projects on our extensive North American property base, which provides reliable and repeatable production and reserves additions. To supplement that low-risk part of our strategy, we also annually invest a measured amount of capital in high-impact, long cycle-time projects to replenish our development inventory for the future. The philosophy that underlies the execution of this strategy is to strive to increase value on a per share basis by:

- building oil and gas reserves and production;
- exercising capital discipline;
- preserving financial flexibility;
- maintaining a low unit-cost structure; and
- improving performance through our marketing and midstream operations.

Development of Business

During 1988, we expanded our capital base with our first issuance of common stock to the public. This transaction began a substantial expansion program that has continued through the subsequent years. This expansion is attributable to both a focused mergers and acquisitions program spanning a number of years and an active ongoing exploration and development drilling program. We have increased our total proved reserves from 8 MMBoe[1] at year-end 1987 to 2,496 MMBoe[2] at year-end 2007.

During the same time period, we have grown proved reserves from 0.66 Boe[1] per diluted share at the end of 1987 to 5.56 Boe[2] per diluted share at the end of 2007. This represents a compound annual growth rate of 11%. We have also increased production from 0.09 Boe[1] per diluted share in 1987 to 0.50 Boe[2] per diluted share in 2007, for a compound annual growth rate of 9%. This per share growth is a direct result of successful execution of our strategic plan and other key transactions and events.

[1] Excludes the effects of mergers in 1998 and 2000 that were accounted for as poolings of interests.
[2] Excludes reserves in West Africa that are held for sale and classified as discontinued operations as of December 31, 2007.

We achieved a number of significant accomplishments in our operations during 2007, including those discussed below.

Drilling Success We drilled 2,440 wells with an overall 98% rate of success. As a result of our success with the drill-bit, our proved reserves increased 9% to reach a record of 2.5 billion Boe at year-end 2007. We added 390 MMBoe of proved reserves during the year with extensions, discoveries and performance revisions, a total 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.

Barnett Shale Growth We continue to retain our positions as the largest producer and largest lease holder in the Barnett Shale area of north Texas. We increased our production from the Barnett Shale area by 33% in 2007, exiting the year at 950 MMcfe per day net to our ownership interest. We drilled 539 wells in the Barnett Shale in 2007, which included our 1,000th horizontal well. We have interests in nearly 3,200 producing wells in the Barnett Shale and hold approximately 727,000 net acres of Barnett Shale leases. At December 31, 2007, we had estimated proved reserves of 724 MMBoe in the Barnett Shale area.

U.S. Onshore Production and Reserves Growth Our U.S. onshore properties, including the Barnett Shale, the Groesbeck and Carthage areas in east Texas and the Washakie basin in Wyoming, showed strong production growth in 2007. These three areas, which accounted for a little over 60% of our U.S. onshore production, had production growth in 2007 of 19% compared to 2006.

In addition to production growth, our U.S. onshore properties also demonstrated measurable growth in proved reserves. U.S. onshore proved reserves grew 282 MMBoe due to extensions, discoveries and performance revisions. This was more than double our U.S. onshore production in 2007 of 125 MMBoe. Our drilling activities increased our 2007 U.S. onshore proved reserves by14% compared to the end of 2006.

Gulf of Mexico Exploration and Development In 2007, we continued to build off prior years successful drilling results with our deepwater Gulf of Mexico exploration and development program. To date, we have drilled four discovery wells in the Lower Tertiary trend Cascade in 2002 (50% working interest), St. Malo in 2003 (22.5% working interest), Jack in 2004 (25% working interest) and Kaskida in 2006 (20% working interest). These achievements, along with our 2007 developments discussed below, support our positive view of the Lower Tertiary and demonstrate the potential of our high-impact exploration strategy on growth of long-term production, reserves and value.

Specific Gulf of Mexico developments in 2007 included the following:

We commenced production from the deepwater Merganser field. At the end of 2007, our combined production from the two Merganser natural gas wells was about 51 MMcf per day. We have a 50% working interest in the Merganser field, which produces into the Independence Hub.

We sanctioned Cascade for phase one development and awarded various service and facilities contracts for he project. We anticipate first production at Cascade in 2010.

We initiated the drilling of delineation wells at St. Malo, Jack, Kaskida and Mission Deep. We have a 50% working interest in Mission Deep, which is a Miocene discovery made in 2006.

We are participating in two Lower Tertiary exploratory wells that were initiated in 2007 Chuck (29.5% working interest) and Green Bay (23% interest). The Chuck well has reached total depth and is being evaluated. Drilling of the Green Bay well toward its target objective continues.

Jackfish We completed construction and commenced steam injection at our 100%-owned Jackfish thermal heavy oil project in the Alberta oil sands. 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. We hope to receive regulatory approval and formally sanction this second phase in the middle of 2008. Like the first phase, this second phase of Jackfish is also expected to eventually produce 35,000 Bbls per day.

Lloydminster Also in Canada, we increased production from the Lloydminster oil play in Alberta by 40% to approximately 33,500 Boe per day. We drilled 429 wells at Lloydminster in 2007, which added 22 million Boe of proved reserves.

Polvo 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. We have a 60% working interest in Polvo.

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.

Pursuant to accounting rules for discontinued operations, the amounts in this document related to continuing operations for 2007 and all prior years presented do not include amounts related to our operations in Egypt and West Africa.

Financial Information about Segments and Geographical Areas

Notes 14 and 15 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this report contain information on our segments and geographical areas.

Oil, Natural Gas and NGL Marketing

The spot market for oil, gas and NGLs is subject to volatility as supply and demand factors fluctuate. As detailed below, we sell our production under both long-term (one year or more) or short-term (less than one year) agreements. Regardless of the term of the contract, the vast majority of our production is sold at variable or market sensitive prices.

Additionally, we may periodically enter into financial hedging arrangements, fixed-price contracts or firm delivery commitments with a portion of our oil and gas production. These activities are intended to support targeted price levels and to manage our exposure to price fluctuations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Oil Marketing

Our oil production is sold under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties. As of February 2008, all of our oil production is sold at variable or market-sensitive prices.

Natural Gas Marketing

Our gas production is also sold under both long-term and short-term agreements at prices negotiated with third parties. Although exact percentages vary daily, as of February 2008, approximately 81% of our natural gas production was sold under short-term contracts at variable or market-sensitive prices. These market-sensitive sales are referred to as "spot market" sales. Another 17% of our production was committed under various long-term contracts, which dedicate the natural gas to a purchaser for an extended period of time but still at market sensitive prices. The remaining 2% of our gas production was sold under long-term fixed price contracts.

NGL Marketing

Our NGL production is sold under both long-term and short-term agreements at prices negotiated with third parties. Although exact percentages vary, as of February 2008, approximately 69% of our NGL production was sold under short-term contracts at variable or market-sensitive prices. The remaining NGL production is sold under long-term market-indexed contracts which are subject to market pricing variations.

Marketing and Midstream Activities

The primary objective of our marketing and midstream operations is to add value to us and other producers to whom we provide such services by gathering, processing and marketing oil, gas and NGL production in a timely and efficient manner. Our most significant midstream asset is the Bridgeport processing plant and gathering system located in north Texas. These facilities serve not only our gas production from the Barnett Shale but also gas production of other producers in the area. Our midstream assets also include our 50% interest in the Access Pipeline transportation system in Canada. This pipeline system allows us to blend our Jackfish heavy oil production with condensate and then transport the combined product to the Edmonton area.

Our marketing and midstream revenues are primarily generated by:

- selling NGLs that are either extracted from the gas streams processed by our plants or purchased from third parties for marketing, and
- selling or gathering gas that moves through our transport pipelines and unrelated third-party pipelines.

Our marketing and midstream costs and expenses are primarily incurred from:

- purchasing the gas streams entering our transport pipelines and plants;
- purchasing fuel needed to operate our plants, compressors and related pipeline facilities;
- purchasing third-party NGLs;
- operating our plants, gathering systems and related facilities; and
- transporting products on unrelated third-party pipelines.

Customers

We sell our gas production to a variety of customers including pipelines, utilities, gas marketing firms, industrial users and local distribution companies. Gathering systems and interstate and intrastate pipelines are used to consummate gas sales and deliveries.

The principal customers for our crude oil production are refiners, remarketers and other companies, some of which have pipeline facilities near the producing properties. In the event pipeline facilities are not conveniently available, crude oil is trucked or shipped to storage, refining or pipeline facilities.

Our NGL production is primarily sold to customers engaged in petrochemical, refining and heavy oil blending activities. Pipelines, railcars and trucks are utilized to move our products to market.

No purchaser accounted for over 10% of our revenues in 2007, 2006 or 2005.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Government Regulation

The oil and gas industry is subject to various types of regulation throughout the world. Legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to this legislation, numerous government agencies have issued extensive laws and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas exploration, production and marketing and midstream activities. These laws and regulations increase the cost of doing business and, consequently, affect profitability. Because new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations. However, we do not expect that any of these laws and regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size.

The following are significant areas of government control and regulation in the United States, Canada and other international locations in which we operate.

Exploration and Production Regulation

Our oil and gas operations are subject to various federal, state, provincial, local and international laws and regulations, including regulations related to the acquisition of seismic data; the location of wells; drilling and casing of wells; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the restoration of properties upon which wells have been drilled; the calculation and disbursement of royalty payments and production taxes; the plugging and abandoning of wells; the transportation of production; and, in international operations, minimum investments in the country of operations.

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units; the number of wells that may be drilled in a unit; the rate of production allowable from oil and natural gas wells; and the unitization or pooling of oil and natural gas properties. In the United States, some states allow the forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases which may make it more difficult to develop oil and gas properties. In addition, state conservation laws generally limit the venting or flaring of natural gas and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Certain of our U.S. oil and natural gas leases are granted by the federal government and administered by various federal agencies, including the Bureau of Land Management and the Minerals Management Service (MMS) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases, and calculation and disbursement of royalty payments to the federal government. The MMS has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding and royalty payment obligations for production from federal lands. The Federal Energy Regulatory Commission also has jurisdiction over certain U.S. offshore activities pursuant to the Outer Continental Shelf Lands Act.

Royalties and Incentives in Canada

The royalty system in Canada is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the parties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, with the royalty rate dependent in part upon prescribed

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reference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced. From time to time, the federal and provincial governments of Canada have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing our revenues, earnings and cash flow.

On October 25, 2007, the provincial government of Alberta announced a new royalty regime. The new regime contemplates the introduction of new royalties for conventional oil, natural gas, NGL and bitumen production effective January 1, 2009. The royalties will be linked to price and production levels and will apply to both new and existing conventional oil and gas activities and oil sands projects.

The implementation of the proposed changes to the royalty regime in Alberta is subject to certain risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to the existing legislation and regulation and development of proprietary software to support the calculation and collection of royalties. Additionally, certain proposed changes contemplate further public and/or industry consultation. Finally, the proposed royalty structure may be modified prior to its implementation.

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 operations. 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.

Pricing and Marketing in Canada

Any oil or natural gas export to be made pursuant to an export contract of a certain duration or covering a certain quantity requires an exporter to obtain an export permit from Canada s National Energy Board (NEB). The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere.

Investment Canada Act

The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. In certain circumstances, the acquisition of natural resource properties may be considered to be a transaction requiring such approval.

Production Sharing Contracts

Many of our international licenses are governed by production sharing contracts (PSCs) between the concessionaires and the granting government agency. PSCs are contracts that define and regulate the framework for investments, revenue sharing, and taxation of mineral interests in foreign countries. Unlike most domestic leases, PSCs have defined production terms and time limits of generally 30 years. PSCs also generally contain sliding scale revenue sharing provisions. As a result, at either higher production rates or higher cumulative rates of return, PSCs generally allow the government agency to retain higher fractions of revenue.

Environmental and Occupational Regulations

We are subject to various federal, state, provincial, local and international laws and regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment.

Environmental laws and regulations relate to, among other things, assessing the environmental impact of seismic acquisition, drilling or construction activities; the generation, storage, transportation and disposal of waste materials; the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations; and the development of emergency response and spill contingency plans.

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The application of worldwide standards, such as ISO 14000 governing Environmental Management Systems, is required to be implemented for some international oil and gas operations.

In 1997, numerous countries participated in an international conference under the United Nations Framework Convention on Climate Change and adopted an agreement known as the Kyoto Protocol (the Protocol). The Protocol became effective February 16, 2005, and requires reductions of certain emissions that contribute to atmospheric levels of greenhouse gases (GHG). Certain countries in which we operate (but not the United States) have ratified the Protocol. Pursuant to its ratification of the Protocol in April 2007, the federal government of Canada released its Regulatory Framework for Air Emissions, a plan to implement mandatory reductions in GHG emissions by way of regulation under existing legislation. The mandatory reductions on GHG emissions will create additional costs for the Canadian oil and gas industry. Certain provinces in Canada have also implemented legislation and regulations to reduce GHG emissions, which will also have a cost associated with compliance. Presently, it is not possible to accurately estimate the costs we could incur to comply with any laws or regulations developed to achieve emissions reductions in Canada or elsewhere, but such expenditures could be substantial.

In 2006, we published our Corporate Climate Change Position and Strategy. Key components of the strategy include initiation of energy efficiency measures, tracking emerging climate change legislation and publication of a corporate GHG emission inventory, which occurred in January 2008. All provisions of the strategy are completed or are in progress.

We consider the costs of environmental protection and safety and health compliance necessary and manageable parts of our business. With the efforts of our Environmental, Health and Safety Department, we have been able to plan for and comply with environmental and safety and health initiatives without materially altering our operating strategy. We anticipate making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. While our unreimbursed expenditures in 2007 concerning such matters were immaterial, we cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, salt water or other substances. However, we do not maintain 100% coverage concerning any environmental claim, and no coverage is maintained with respect to any penalty or fine required to be paid because of a violation of law.

Employees

As of December 31, 2007, we had approximately 5,000 employees. We consider labor relations with our employees to be satisfactory. We have not had any work stoppages or strikes pertaining to our employees.

Competition

See Item 1A. Risk Factors.

Availability of Reports

Through our website, http://www.devonenergy.com, we make available electronic copies of the charters of the committees of our Board of Directors, other documents related to our corporate governance (including our Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer), and documents we file or furnish to the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to these reports. Access to these electronic filings is available free of charge as soon as reasonably practicable after filing or furnishing them to the SEC. Printed copies of our committee charters or other governance documents and filings can be requested by writing to our corporate secretary at the address on the cover of this report.

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Item 1A. *Risk Factors*

Our business activities, and the oil and gas industry in general, are subject to a variety of risks. If any of the following risk factors should occur, our profitability, financial condition or liquidity could be materially impacted. As a result, holders of our securities could lose part or all of their investment in Devon.

Oil, Natural Gas and NGL Prices are Volatile

Our financial results are highly dependent on the prices of and demand for oil, natural gas and NGLs. A significant downward movement of the prices for these commodities could have a material adverse effect on our estimated proved reserves, revenues and operating cash flows, as well as the level of planned drilling activities. Such a downward price movement could also have a material adverse effect on our profitability, the carrying value of our oil and gas properties and future growth. Historically, prices have been volatile and are likely to continue to be volatile in the future due to numerous factors beyond our control. These factors include, but are not limited to:

- consumer demand for oil, natural gas and NGLs;
- conservation efforts;
- OPEC production levels;
- weather;
- regional market pricing differences;
- differing quality of oil produced (i.e., sweet crude versus heavy or sour crude) and Btu content of gas produced;
- the level of imports and exports of oil, natural gas and NGLs;
- the price and availability of alternative fuels;
- the overall economic environment; and
- governmental regulations and taxes.

Estimates of Oil, Natural Gas and NGL Reserves are Uncertain

The process of estimating oil, gas and NGL reserves is complex and requires significant judgment in the evaluation of available geological, engineering and economic data for each reservoir, particularly for new discoveries. Because of the high degree of judgment involved, different reserve engineers may develop different estimates of reserve quantities and related revenue based on the same data. In addition, the reserve estimates for a given reservoir may change substantially over time as a result of several factors including additional development activity, the viability of production under varying economic conditions and variations in production levels and associated costs. Consequently, material revisions to existing reserve estimates may occur as a result of changes in any of these factors. Such revisions to proved reserves could have a material adverse effect on our estimates of future net revenue, as well as our financial condition and profitability. Additional discussion of our policies regarding estimating and recording reserves is described in Item 2. Properties Proved Reserves and Estimated Future Net Revenue.

Discoveries or Acquisitions of Additional Reserves are Needed to Avoid a Material Decline in Reserves and Production

The production rate from oil and gas properties generally declines as reserves are depleted, while related per unit production costs generally increase, due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future oil, gas and NGL production will decline materially as reserves are produced unless we conduct successful exploration and development activities or, through engineering studies, identify additional producing zones in existing wells, secondary recovery reserves or tertiary recovery reserves, or acquire additional properties containing proved reserves. Consequently, our future oil, gas and NGL production and related per unit production costs are highly dependent upon our level of success in finding or acquiring additional reserves.

Future Exploration and Drilling Results are Uncertain and Involve Substantial Costs

Substantial costs are often required to locate and acquire properties and drill exploratory wells. Such activities are subject to numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The costs of drilling and completing wells are often uncertain. In addition, oil and gas properties can become damaged or drilling operations may be curtailed, delayed or canceled as a result of a variety of factors including, but not limited to:

- unexpected drilling conditions;
- pressure or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;
- marine risks such as capsizing, collisions and hurricanes;
- other adverse weather conditions;
- lack of access to pipelines or other methods of transportation;
- environmental hazards or liabilities; and
- shortages or delays in the delivery of equipment.

A significant occurrence of one of these factors could result in a partial or total loss of our investment in a particular property. In addition, drilling activities may not be successful in establishing proved reserves. Such a failure could have an adverse effect on our future results of operations and financial condition. While both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. We are currently performing exploratory drilling activities in certain international countries. We have been granted drilling concessions in these countries that require commitments on our behalf to incur capital expenditures. Even if future drilling activities are unsuccessful in establishing proved reserves, we will likely be required to fulfill our commitments to make such capital expenditures.

Industry Competition For Leases, Materials, People and Capital Can Be Significant

Strong competition exists in all sectors of the oil and gas industry. We compete with major integrated and other independent oil and gas companies for the acquisition of oil and gas leases and properties. We also compete for the equipment and personnel required to explore, develop and operate properties. Competition is also prevalent in the marketing of oil, gas and NGLs. Higher recent commodity prices have increased drilling and operating costs. Higher prices have also increased the costs of properties available for acquisition, and there are a greater number of publicly traded companies and private-equity firms with the financial resources to pursue acquisition opportunities. Certain of our competitors have financial and other resources substantially larger than ours, and they have also established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as changing worldwide prices and levels of production, the cost and availability of alternative fuels and the application of government regulations.

International Operations Have Uncertain Political, Economic and Other Risks

Our operations outside North America are based primarily in Azerbaijan, Brazil and China. We also have operations in various countries in West Africa that we intend to sell in 2008. In these areas outside of North America, we face political and economic risks and other uncertainties that are more prevalent than what exist for our operations in North America. Such factors include, but are not limited to:

- general strikes and civil unrest;
- the risk of war, acts of terrorism, expropriation, forced renegotiation or modification of existing contracts;
- import and export regulations;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- transportation regulations and tariffs;
- exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- laws and policies of the United States affecting foreign trade, including trade sanctions;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate;
- the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

Foreign countries have occasionally asserted rights to oil and gas properties through border disputes. If a country claims superior rights to oil and gas leases or concessions granted to us by another country, our interests could decrease in value or be lost. Even our smaller international assets may affect our overall business and results of operations by distracting management s attention from our more significant assets. Various regions of the world have a history of political and economic instability. This instability could result in new governments or the adoption of new policies that might result in a substantially more hostile attitude toward foreign investment. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. This could adversely affect our interests and our future profitability.

The impact that future terrorist attacks or regional hostilities may have on the oil and gas industry in general, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities.

Government Laws and Regulations Can Change

Our operations are subject to federal laws and regulations in the United States, Canada and the other countries in which we operate. In addition, we are also subject to the laws and regulations of various states, provinces and local governments. Pursuant to such legislation, numerous government departments and agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Changes in such legislation have affected, and at times in the future could affect, our operations. Political developments can restrict production levels, enact price controls, change environmental protection requirements, and increase taxes, royalties and other amounts payable to governments or governmental agencies. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability. While such legislation can change at any time in the future, those laws and regulations outside North America to which we are subject generally include greater risk of unforeseen change.

Environmental Matters and Costs Can Be Significant

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, provincial, local and international laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from our operations in affected areas. Any future environmental costs of fulfilling our commitments to the environment are uncertain and will be governed by several factors, including future changes to regulatory requirements. There is no assurance that changes in or additions to laws or regulations regarding the protection of the environment will not have a significant impact on our operations and profitability.

Insurance Does Not Cover All Risks

Exploration, development, production and processing of oil, natural gas and NGLs can be hazardous and involve unforeseen occurrences such as hurricanes, blowouts, cratering, fires and loss of well control. These occurrences can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property or the environment. We maintain insurance against certain losses or liabilities in accordance with customary industry practices and in amounts that management believes to be prudent. However, insurance against all operational risks is not available to us. Due to changes in the insurance marketplace following the 2005 hurricanes in the Gulf of Mexico, we currently have only a *de minimis* amount of coverage for any damage that may be caused by future named windstorms in the Gulf of Mexico.

Our Short-Term Investments Are Subject To Risks Which May Affect Their Liquidity and Value

To maximize earnings on available cash balances, we periodically invest in securities that we consider to be short-term in nature and generally available for short-term liquidity needs. Such investments include asset-backed securities that have an auction rate reset feature (auction rate securities). Our auction rate securities are collateralized by student loans which are substantially guaranteed by the United States government, and generally have contractual maturities of more than 20 years. However, 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.

At December 31, 2007, we held $372 million of auction rate securities. 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. 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.

All of our auction rate securities, including those subject to failed auctions, are currently rated AAA the highest rating by one or more rating agencies. However, these investments are subject to general credit, liquidity, market and interest rate risks, which may be exacerbated by continued problems in the global credit markets, including but not limited to, U.S. subprime mortgage defaults, writedowns by major financial institutions due to deteriorating values of their asset portfolios (including leveraged loans, collateralized debt obligations, credit default swaps and other credit-linked products). These and other related factors have affected various sectors of the financial markets and caused credit and liquidity issues. If issuers are unable to successfully close future auctions and their credit ratings deteriorate, our ability to liquidate these securities and fully recover the carrying value of our investment in the near term may be limited. As a result, we may deem such investments to be long-term in nature and generally not available for short-term liquidity needs. Additionally, under such circumstances, we may record an impairment charge on these investments in the future.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

Substantially all of our properties consist of interests in developed and undeveloped oil and gas leases and mineral acreage located in our core operating areas. These interests entitle us to drill for and produce oil, natural gas and NGLs from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, overriding royalty, mineral and net profits interests, foreign government concessions and other forms of direct and indirect ownership in oil and gas properties.

We also have certain midstream assets, including natural gas and NGL processing plants and pipeline systems. Our most significant midstream assets are our assets serving the Barnett Shale region in north Texas. These assets include approximately 2,700 miles of pipeline, two gas processing plants with 750 MMcf per day of total capacity, and a 15 MBbls per day NGL fractionator. To support our production in the Woodford Shale, located in southeast Oklahoma, we plan to bring online a 200 MMcf per day gas processing plant in 2008.

Our midstream assets also include the Access Pipeline transportation system in Canada. This 220-mile dual pipeline system extends from our Jackfish operations in northern Alberta to a 350 MBbls storage terminal in Edmonton. The dual pipeline system allows us to blend the Jackfish heavy oil production with condensate and transport the combined product to the Edmonton crude oil market. We have a 50% ownership interest in the Access Pipeline.

Proved Reserves and Estimated Future Net Revenue

The SEC defines proved oil and gas reserves as the estimated quantities of crude oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

The process of estimating oil, gas and NGL reserves is complex and requires significant judgment as discussed in Item 1A. Risk Factors. As a result, we have developed internal policies for estimating and recording reserves. Our policies regarding booking reserves require proved reserves to be in compliance with the SEC definitions and guidance, and assign responsibilities for compliance in reserves bookings to our Reserve Evaluation Group (the Group). Our policies also require that reserve estimates be made by qualified reserves estimators (QREs), as defined by the Society of Petroleum Engineers standards. A list of our QREs is kept by the Senior Advisor Corporate Reserves. All QREs are required to receive education covering the fundamentals of SEC proved reserves assignments.

The Group is responsible for the internal review and certification of reserves estimates and includes the Manager Reserves and Economics and the Senior Advisor Corporate Reserves. The Group reports independently of any of our operating divisions. The Vice President Strategic Planning is directly responsible for overseeing the Group and reports to our President. No portion of the Group s compensation is directly dependent on the quantity of reserves booked.

Throughout the year, the Group performs internal audits of each operating division s reserves. Selection criteria of reserves that are audited include major fields and major additions and revisions to reserves. In addition, the Group reviews reserve estimates with each of the third-party petroleum consultants discussed below.

In addition to internal audits, we engage three independent petroleum consulting firms to both prepare and audit a significant portion of our proved reserves. Ryder Scott Company, L.P. prepared the 2007 reserves estimates for all our offshore Gulf of Mexico properties and for 99% of our International proved reserves. LaRoche Petroleum Consultants, Ltd. audited the 2007 reserves estimates for 88% of our domestic onshore properties. AJM Petroleum Consultants prepared estimates covering 34% of our 2007 Canadian reserves and audited an additional 51% of our Canadian 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**
U.S.	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 reserves that were estimated by our 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.

In addition to conducting these internal and external reviews, we also have a Reserves Committee which consists of four independent members of our Board of Directors. Although we are not required to have a Reserves Committee, we established ours in 2004 to provide additional oversight of our reserves estimation and certification process. The Reserves Committee was designed to assist the Board of Directors with its duties and responsibilities in evaluating and reporting our proved reserves, much like our Audit Committee assists the Board of Directors in supervising our audit and financial reporting requirements. Besides being independent, the members of our Reserves Committee also have educational backgrounds in geology or petroleum engineering, as well as experience relevant to the reserves estimation process.

The Reserves Committee meets at least twice a year to discuss reserves issues and policies, and periodically meets separately with our senior reserves engineering personnel and our independent petroleum consultants. The responsibilities of the Reserves Committee include the following:

perform an annual review and evaluation of our consolidated oil, gas and NGL reserves;

verify the integrity of our reserves evaluation and reporting system;

evaluate, prepare and disclose our compliance with legal and regulatory requirements related to our oil, gas and NGL reserves;

investigate and verify the qualifications and independence of our independent engineering consultants;

monitor the performance of our independent engineering consultants; and

monitor and evaluate our business practices and ethical standards in relation to the preparation and disclosure of reserves.

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The following table sets forth our estimated proved reserves and the related estimated pre-tax future net revenues, pre-tax 10% present value and after-tax standardized measure of discounted future net cash flows as of December 31, 2007. These estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 15 to our consolidated financial statements included herein.

	Total Proved Reserves	Proved Developed Reserves	Proved Undeveloped Reserves
Total Reserves			
Oil (MMBbls)	677	391	286
Gas (Bcf)	8,994	7,255	1,739
NGLs (MMBbls)	321	274	47
MMBoe(1)	2,496	1,874	622
Pre-tax future net revenue (in millions)(2)	$ 62,135	$ 48,654	$ 13,481
Pre-tax 10% present value (in millions)(2)	$ 32,852	$ 26,672	$ 6,180
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 23,471		
U.S. Reserves			
Oil (MMBbls)	170	148	22
Gas (Bcf)	7,143	5,743	1,400
NGLs (MMBbls)	282	244	38
MMBoe(1)	1,642	1,349	293
Pre-tax future net revenue (in millions)(2)	$ 41,324	$ 35,079	$ 6,245
Pre-tax 10% present value (in millions)(2)	$ 21,064	$ 18,435	$ 2,629
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 14,679		
Canadian Reserves			
Oil (MMBbls)	388	195	193
Gas (Bcf)	1,844	1,506	338
NGLs (MMBbls)	39	30	9
MMBoe(1)	734	476	258
Pre-tax future net revenue (in millions)(2)	$ 14,973	$ 11,755	$ 3,218
Pre-tax 10% present value (in millions)(2)	$ 7,986	$ 6,722	$ 1,264
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 5,962		
International Reserves			
Oil (MMBbls)	119	48	71
Gas (Bcf)	7	6	1
NGLs (MMBbls)			
MMBoe(1)	120	49	71
Pre-tax future net revenue (in millions)(2)	$ 5,838	$ 1,820	$ 4,018
Pre-tax 10% present value (in millions)(2)	$ 3,802	$ 1,515	$ 2,287
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 2,830		

(1) Gas reserves are converted to Boe at the rate of six Mcf per Bbl 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 reserves are converted to Boe on a one-to-one basis with oil.

(2) Estimated pre-tax future net revenue represents estimated future revenue to be generated from the production of proved reserves, net of estimated production and development costs and site restoration and abandonment charges. The amounts shown do not give effect to depreciation, depletion and amortization, or to non-property related expenses such as debt service and income tax expense.

These amounts were calculated using prices and costs in effect for each individual property as of December 31, 2007. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yield average prices over the life of our properties of $60.42 per Bbl of oil, $6.01 per Mcf of natural gas and $50.57 per Bbl of NGLs. These prices compare to the December 31, 2007, NYMEX cash price of $96.00 per Bbl for crude oil and the Henry Hub spot price of $6.80 per MMBtu for natural gas.

The present value of after-tax future net revenues discounted at 10% per annum (standardized measure) was $23.5 billion at the end of 2007. Included as part of standardized measure were discounted future income taxes of $9.4 billion. Excluding these taxes, the present value of our pre-tax future net revenue (pre-tax 10% present value) was $32.9 billion. We believe the pre-tax 10% present value is a useful measure in addition to the after-tax standardized measure. The pre-tax 10% present value 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 standardized measure is dependent on the unique tax situation of each individual company, while the pre-tax 10% present value is based on prices and discount factors, which are more consistent from company to company. We also understand that securities analysts use the pre-tax 10% present value measure in similar ways.

(3) See Note 15 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data.

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As presented in the previous table, we had 1,874 MMBoe of proved developed reserves at December 31, 2007. Proved developed reserves consist of proved developed producing reserves and proved developed non-producing reserves. The following table provides additional information regarding our proved developed reserves at December 31, 2007.

	Total Proved Developed Reserves	Proved Developed Producing Reserves	Proved Developed Non-Producing Reserves
Total Reserves			
Oil (MMBbls)	391	286	105
Gas (Bcf)	7,255	6,467	788
NGLs (MMBbls)	274	245	29
MMBoe	1,874	1,609	265
U.S. Reserves			
Oil (MMBbls)	148	129	19
Gas (Bcf)	5,743	5,103	640
NGLs (MMBbls)	244	218	26
MMBoe	1,349	1,198	151
Canadian Reserves			
Oil (MMBbls)	195	122	73
Gas (Bcf)	1,506	1,358	148
NGLs (MMBbls)	30	27	3
MMBoe	476	375	101
International Reserves			
Oil (MMBbls)	48	35	13
Gas (Bcf)	6	6	
NGLs (MMBbls)			
MMBoe	49	36	13

No estimates of our proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency since the beginning of 2007 except in filings with the SEC and the Department of Energy (DOE). Reserve estimates filed with the SEC correspond with the estimates of our reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of our reserves included herein. However, the DOE requires reports to include the interests of all owners in wells that we operate and to exclude all interests in wells that we do not operate.

The prices used in calculating the estimated future net revenues attributable to proved reserves do not necessarily reflect market prices for oil, gas and NGL production subsequent to December 31, 2007. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will be realized or that existing contracts will be honored or judicially enforced.

Production, Revenue and Price History

Certain information concerning oil, natural gas and NGL production, prices, revenues (net of all royalties, overriding royalties and other third party interests) and operating expenses for the three years ended December 31, 2007, is set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

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Drilling Activities

The following tables summarize the results of our development and exploratory drilling activity for the past three years. The tables do not include our Egyptian or West African operations that were discontinued in 2006 and 2007, respectively.

Development Well Activity

	Wells Drilling at December 31, 2007		Net Wells Completed(2)					
			2007		2006		2005	
	Gross(1)	Net(2)	Productive	Dry	Productive	Dry	Productive	Dry
U.S.	151	87.8	978.2	21.1	877.1	12.5	782.3	8.2
Canada	9	6.3	531.2		593.2	3.3	546.8	5.2
International	25	5.0	9.2		6.1		8.8	
Total	**185**	**99.1**	**1,518.6**	**21.1**	**1,476.4**	**15.8**	**1,337.9**	**13.4**

Exploratory Well Activity

	Wells Drilling at December 31, 2007		Net Wells Completed(2)					
			2007		2006		2005	
	Gross(1)	Net(2)	Productive	Dry	Productive	Dry	Productive	Dry
U.S.	15	9.5	11.6	4.2	24.5	10.3	18.6	6.5
Canada	8	5.7	83.3	1.5	82.1	1.0	144.2	12.4
International	7	3.8		0.6		1.7	0.5	1.0
Total	**30**	**19.0**	**94.9**	**6.3**	**106.6**	**13.0**	**163.3**	**19.9**

(1) Gross wells are the sum of all wells in which we own an interest.

(2) Net wells are gross wells multiplied by our fractional working interests therein.

For the wells being drilled as of December 31, 2007 presented in the tables above, the following table summarizes the results of such wells as of February 1, 2008.

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
U.S.	80	40.1	4	2.9	82	54.3

Canada	15	11.5			2	0.5
International			7	4.2	25	4.6
Total	**95**	**51.6**	**11**	**7.1**	**109**	**59.4**

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Well Statistics

The following table sets forth our producing wells as of December 31, 2007. The table does not include our West African operations that were discontinued in 2007.

	Oil Wells		Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.						
Onshore	8,158	2,743	17,547	12,090	25,705	14,833
Offshore	446	311	236	153	682	464
Total U.S.	8,604	3,054	17,783	12,243	26,387	15,297
Canada	3,263	2,336	4,712	2,717	7,975	5,053
International	449	196			449	196
Grand Total	12,316	5,586	22,495	14,960	34,811	20,546

(1) Gross wells are the total number of wells in which we own a working interest.

(2) Net wells are gross wells multiplied by our fractional working interests therein.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2007. The table does not include our West African operations that were classified as discontinued in 2007.

	Developed		Undeveloped	
	Gross(1)	Net(2)	Gross(1)	Net(2)
	(In thousands)			
U.S.				
Onshore	3,371	2,185	5,611	2,897
Offshore	763	362	4,413	2,247
Total U.S.	4,134	2,547	10,024	5,144
Canada	3,540	2,200	8,754	5,911
International	197	54	9,139	8,631
Grand Total	7,871	4,801	27,917	19,686

(1) Gross acres are the total number of acres in which we own a working interest.

(2) Net acres are gross acres multiplied by our fractional working interests therein.

Operation of Properties

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions.

We are the operator of 21,226 of our wells. As operator, we receive reimbursement for direct expenses incurred in the performance of our duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area. In presenting our financial data, we record the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

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Organization Structure and Property Profiles

Our properties are located within the U.S. onshore and offshore regions, Canada, and certain locations outside North America. The following table presents proved reserve information for our significant properties as of December 31, 2007, along with their production volumes for the year 2007. Included in the table are certain U.S. offshore properties that currently have no proved reserves or production. Such properties are considered significant because they may be the source of significant future growth in proved reserves and production. The table does not include our West African operations that were classified as discontinued in 2007. Additional summary profile information for our significant properties is provided following the table.

	Proved Reserves (MMBoe)(1)	Proved Reserves %(2)	Production (MMBoe)(1)	Production %(2)
U.S.				
Barnett Shale	724	29.0%	50	22.5%
Carthage	193	7.8%	16	7.0%
Permian Basin, Texas	112	4.5%	9	3.9%
Washakie	111	4.4%	6	2.7%
Groesbeck	65	2.6%	6	2.8%
Permian Basin, New Mexico	44	1.8%	7	2.9%
Other U.S Onshore	290	11.5%	30	13.9%
Total U.S. Onshore	1,539	61.6%	124	55.7%
Deepwater Producing	59	2.4%	10	4.5%
Deepwater Development				
Deepwater Exploration				
Other U.S. Offshore	44	1.8%	12	5.0%
Total U.S. Offshore	103	4.2%	22	9.5%
Total U.S.	1,642	65.8%	146	65.2%
Canada				
Jackfish	233	9.3%		
Lloydminster	97	3.9%	12	5.4%
Deep Basin	92	3.7%	11	4.9%
Peace River Arch	74	3.0%	8	3.6%
Northeast British Columbia	58	2.3%	8	3.6%
Other Canada	180	7.2%	19	8.4%
Total Canada	734	29.4%	58	25.9%
International				
Azerbaijan	65	2.6%	13	5.6%
China	20	0.8%	5	2.1%
Brazil	9	0.3%	0.5	0.2%

Other	26	1.1%	1.5	1.0%
Total International	120	4.8%	20	8.9%
Grand Total	2,496	100.0%	224	100.0%

(1) Gas reserves and production are converted to Boe at the rate of six Mcf of gas per Bbl 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 reserves and production are converted to Boe on a one-to-one basis with oil.

(2) Percentage of proved reserves and production the property bears to total proved reserves and production based on actual figures and not the rounded figures included in this table.

U.S. Onshore

Barnett Shale The Barnett Shale, located in north Texas, is our largest property both in terms of production and proved reserves. Our leases include approximately 727,000 net acres located primarily in

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Denton, Johnson, Parker, Tarrant and Wise counties. The Barnett Shale is a non-conventional reservoir and it produces natural gas and NGLs. We have an average working interest of greater than 90%. We drilled 539 gross wells in 2007 and expect to drill between 500 and 600 gross wells in 2008.

Carthage The Carthage area in east Texas includes primarily Harrison, Marion, Panola and Shelby counties. Our average working interest is about 85% and we hold approximately 131,000 net acres. Our Carthage area wells produce primarily natural gas and NGLs from conventional reservoirs. We drilled 152 gross wells in 2007 and plan to drill approximately 122 gross wells in 2008.

Permian Basin, Texas Our oil and gas properties in the Permian Basin of west Texas comprise approximately 464,000 net acres located primarily in Andrews, Crane, Martin, Terry, Ward and Yoakum counties. These properties produce both oil and natural gas from conventional reservoirs. Our average working interest in these properties is about 40%. We drilled 77 gross wells in 2007 and plan to drill approximately 38 gross wells in the area in 2008.

Washakie Our Washakie area leases are concentrated in Carbon and Sweetwater counties in southern Wyoming. Our average working interest is about 76% and we hold about 157,000 net acres in the area. The Washakie wells produce primarily natural gas from conventional reservoirs. In 2007, we drilled 161 gross wells, and we plan to drill approximately 111 gross wells in 2008.

Groesbeck The Groesbeck area of east Texas includes portions of Freestone, Leon, Limestone and Robertson counties. Our average working interest is approximately 72% and we hold about 172,000 net acres of land. The Groesbeck wells produce primarily natural gas from conventional reservoirs. In 2007, we drilled 21 gross wells, and we anticipate drilling approximately 16 additional gross wells in 2008.

Permian Basin, New Mexico Our Permian Basin properties in southeastern New Mexico produce conventional oil and natural gas. We hold about 286,000 net acres concentrated in Eddy and Lea counties and have an average working interest of about 75% in these properties. In 2007, we drilled 78 gross wells in this area, and we expect to drill approximately 94 gross wells in 2008.

U.S. Offshore

Deepwater Producing Our assets in the Gulf of Mexico include four significant producing properties Magnolia, Merganser, Nansen and Red Hawk located in deep water (greater than 600 feet). We have a 50% working interest in these properties. They are located on federal leases and total approximately 46,000 net acres. The properties produce both oil and natural gas.

Deepwater Development In addition to our four significant deepwater producing properties, we are in the process of developing our deepwater Cascade project discovered in 2002. Cascade is located on federal leases encompassing approximately 12,000 net acres. We have a 50% working interest in Cascade. In 2007, we sanctioned development plans and awarded various service and facility contracts including contracts for an FPSO and shuttle tankers. The first of two development wells is planned for 2008. Production from Cascade, which will be primarily oil, is expected to begin in 2010.

Deepwater Exploration Our exploration program in the Gulf of Mexico is focused primarily on deepwater opportunities. Our deepwater exploratory prospects include Miocene-aged objectives (five million to 24 million years) and older and deeper Lower Tertiary objectives. We hold federal leases comprising approximately one million net acres in our deepwater exploration inventory.

In 2006, a successful production test of the Jack No. 2 well provided evidence that our Lower Tertiary properties may be a source of meaningful future reserve and production growth. Through 2007, we have drilled four discovery wells in the Lower Tertiary. These include Cascade in 2002 (see Deepwater Development above), St. Malo in 2003, Jack in 2004 and Kaskida in 2006. We currently hold 194 blocks in the Lower Tertiary and we have identified 21 additional prospects to date.

At St. Malo, in which our working interest is 22.5%, we expect to complete two delineation wells in 2008. At Jack, where our working interest is 25%, we expect to complete a second appraisal well in early 2008. A second well (Cortez Bank) was drilled on the Kaskida unit in 2007 and other well operations are planned for 2008. Our working interest in Kaskida is 20%, and we believe Kaskida is the largest of our four Lower Tertiary discoveries to date. The Kaskida discovery was our first in the Keathley Canyon deepwater lease area. Of our additional 21 Lower Tertiary exploration prospects we have identified, 15 are on our Keathley Canyon acreage.

Also in 2007, we participated in a delineation well on the Miocene-aged Mission Deep prospect in which we have a 50% working interest. We have identified 15 additional prospects in our deepwater Miocene inventory to date.

In total, we drilled one exploratory and one delineation well in the deepwater Gulf of Mexico in 2007 and plan to drill between 10 and 12 such wells in 2008. Our working interests in these exploratory opportunities range from 20% to 50%.

Canada

Jackfish We are currently developing our 100%-owned Jackfish thermal heavy oil project in the non-conventional oil sands of east central Alberta. We are employing steam-assisted gravity drainage at Jackfish, and we began steam injection in the third quarter of 2007. Production is expected to ramp up throughout 2008 toward a peak production target of 35,000 Bbls per day . We hold approximately 73,000 net acres in the entire Jackfish area, which can support expansion of the original project. We requested regulatory approval in late September 2006 to increase the scope and size of the original project. In 2007, we began front-end engineering and design work on this extension of the Jackfish project. We hope to receive regulatory approval and formally sanction this second phase in the middle of 2008. Like the first phase, this second phase of Jackfish is also expected to eventually produce 35,000 Bbls per day of heavy oil production.

Lloydminster Our Lloydminster properties are located to the south and east of Jackfish in eastern Alberta and western Saskatchewan. Lloydminster produces heavy oil by conventional means without steam injection. We hold 2.1 million net acres and have a 97% average working interest in our Lloydminster properties. In 2007, we drilled 429 gross wells in the area and plan to drill approximately 475 gross wells in 2008.

Deep Basin Our properties in Canada s Deep Basin include portions of west central Alberta and east central British Columbia. We hold approximately 609,000 net acres in the Deep Basin. The area produces primarily natural gas and natural gas liquids from conventional reservoirs. Our average working interest in the Deep Basin is 45%. In 2007, we drilled 41 gross wells and plan to drill approximately 49 gross wells in the area in 2008.

Peace River Arch The Peace River Arch is located in west central Alberta. We hold approximately 494,000 net acres in the area, which produces primarily natural gas and NGLs from conventional reservoirs. Our average working interest in the area is approximately 70%. We drilled 60 gross wells in the Peace River Arch in 2007, and we expect to drill approximately 65 additional gross wells in 2008.

Northeast British Columbia Our northeast British Columbia properties are located primarily in British Columbia and to a lesser extent in northwestern Alberta. We hold approximately 1.2 million net acres in the area. These properties produce principally natural gas from conventional reservoirs. We hold a 72% average working interest in these properties. We drilled 64 gross wells in the area in 2007, and we plan to drill approximately 37 gross wells in 2008.

International

Azerbaijan Outside North America, Devon s largest international property in terms of proved reserves is the Azeri-Chirag-Gunashli (ACG) oil field located offshore Azerbaijan in the Caspian Sea. ACG produces crude oil from conventional reservoirs. We hold approximately 6,000 net acres in the ACG field and have a 5.6% working interest. In 2007, we participated in drilling 11 gross wells, and we expect to drill approximately 16 gross wells in 2008.

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China Our production in China is from the Panyu development in the Pearl River Mouth Basin in the South China Sea. Panyu fields produce oil from conventional reservoirs. In addition to Panyu, which is located on Block 15/34, we hold leases in four exploratory blocks offshore China. In total, we have 7.9 million net acres under lease in China. We have a 24.5% working interest at Panyu and 100% working interests in the exploratory blocks. We drilled three gross wells in China in 2007, all in the Panyu field. In 2008, we expect to drill approximately six gross wells in the Panyu field, one exploratory well on Block 42/05 and one exploratory well on Block 11/34.

Brazil We commenced oil production in Brazil from our Polvo development area in 2007. Polvo, which we operate with a 60% interest, is located offshore in the Campos Basin in Block BM-C-8. In addition to our development project at Polvo, we hold acreage in eight exploratory blocks. In aggregate, we have 793,000 net acres in Brazil. Our working interests range from 18% to 100% in these blocks. We drilled three gross wells in Brazil in 2007 and plan to drill approximately eight gross wells in 2008.

Title to Properties

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for current taxes not yet due and, in some instances, other encumbrances. We believe that such burdens do not materially detract from the value of such properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry, other than a preliminary review of local records, little investigation of record title is made at the time of acquisitions of undeveloped properties. Investigations, which generally include a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Item 3. *Legal Proceedings*

Royalty Matters

Numerous gas producers and related parties, including us, 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 we are 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. We are not included in the groups of defendants selected for these first two phases. We believe that we have acted reasonably, have legitimate and strong defenses to all allegations in the suit, and have paid royalties in good faith. We do not currently believe that we are subject to material exposure in association with this lawsuit and no related liability has been recorded in our consolidated financial statements.

Other Matters

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

Item 4. ***Submission of Matters to a Vote of Security Holders***

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

PART II

Item 5. *Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock is traded on the New York Stock Exchange (the NYSE). On February 15, 2008, there were 15,923 holders of record of our common stock. The following table sets forth the quarterly high and low sales prices for our common stock as reported by the NYSE during 2006 and 2007. Also, included are the quarterly dividends per share paid during 2006 and 2007.

	Price Range of Common Stock		Dividends
	High	Low	per Share
2006:			
Quarter Ended March 31, 2006	$ 69.97	$ 55.31	$ 0.1125
Quarter Ended June 30, 2006	$ 65.25	$ 48.94	$ 0.1125
Quarter Ended September 30, 2006	$ 74.65	$ 57.19	$ 0.1125
Quarter Ended December 31, 2006	$ 74.48	$ 58.55	$ 0.1125
2007:			
Quarter Ended March 31, 2007	$ 71.24	$ 62.80	$ 0.1400
Quarter Ended June 30, 2007	$ 83.92	$ 69.30	$ 0.1400
Quarter Ended September 30, 2007	$ 85.20	$ 69.01	$ 0.1400
Quarter Ended December 31, 2007	$ 94.75	$ 80.05	$ 0.1400

We began paying regular quarterly cash dividends on our common stock in the second quarter of 1993. We anticipate continuing to pay regular quarterly dividends in the foreseeable future.

Issuer Purchases of Equity Securities

The following table provides information regarding purchases of our common stock that were made by us during the fourth quarter of 2007.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs(1)(2)
October	119,186	$ 85.80	119,186	46,154,915
November	2,147,100	$ 81.15	2,147,100	44,007,815

December	61,300	$ 86.88	61,300	4,800,000
Total	2,327,586	$ 81.54	2,327,586	

(1) In August 2005, we announced that our Board of Directors had authorized the repurchase of up to 50 million shares of our common stock. When this program expired on December 31, 2007, 6.5 million shares had been purchased under this program for $387 million or $59.80 per share. However, none of the fourth quarter purchases in the table above relate to this program.

In June 2007, we announced an ongoing, annual stock repurchase program to minimize dilution resulting from restricted stock issued to, and options exercised by, our employees. In 2007, the repurchase program authorized the repurchase of up to 4.5 million shares until the end of 2007. When the 2007 portion of this annual program expired on December 31, 2007, 4.1 million shares had been repurchased under this program for $326 million, or $79.80 per share. All fourth quarter purchases in the table above relate to this program.

Prior to the end of 2007, our Board of Directors authorized the 2008 portion of the annual program. Under this program in 2008, we are authorized to repurchase up to 4.8 million shares or a cost of $422 million, whichever amount is reached first. In the table above, the 4.8 million shares that may yet be purchased under publicly announced programs at the end of December 2007 represent the shares authorized to be repurchased under the annual repurchase program in 2008.

(2) The 4.8 million shares available for repurchase at the end of 2007 does not include 50 million shares related to a program that was approved by our Board of Directors subsequent to the end of 2007. This program is in anticipation of the completion of our West African divestitures and expires on December 31, 2009.

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Item 6. ***Selected Financial Data***

The following selected financial information (not covered by the report of independent registered public accounting firm) should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and the consolidated financial statements and the notes thereto included in Item 8. Financial Statements and Supplementary Data.

	Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In millions, except per share data, ratios, prices and per Boe amounts)				
Operating Results					
Total revenues	$ 11,362	$ 9,767	$ 10,027	$ 8,549	$ 6,962
Total expenses and other income, net	7,138	6,197	5,649	5,490	4,792
Earnings from continuing operations before income taxes and cumulative effect of change in accounting principle	4,224	3,570	4,378	3,059	2,170
Total income tax expense	1,078	936	1,481	970	453
Earnings from continuing operations before cumulative effect of change in accounting principle	3,146	2,634	2,897	2,089	1,717
Earnings from discontinued operations	460	212	33	97	14
Earnings before cumulative effect of change in accounting principle	3,606	2,846	2,930	2,186	1,731
Cumulative effect of change in accounting principle, net of tax					16
Net earnings	$ 3,606	$ 2,846	$ 2,930	$ 2,186	$ 1,747
Net earnings applicable to common stockholders	$ 3,596	$ 2,836	$ 2,920	$ 2,176	$ 1,737
Basic net earnings per share:					
Earnings from continuing operations	$ 7.05	$ 5.94	$ 6.31	$ 4.31	$ 4.09
Earnings from discontinued operations	1.03	0.48	0.07	0.20	0.03
Cumulative effect of change in accounting principle					0.04
Net earnings	$ 8.08	$ 6.42	$ 6.38	$ 4.51	$ 4.16
Diluted net earnings per share:					
Earnings from continuing operations	$ 6.97	$ 5.87	$ 6.19	$ 4.19	$ 3.97
Earnings from discontinued operations	1.03	0.47	0.07	0.19	0.03
Cumulative effect of change in accounting principle					0.04
Net earnings	$ 8.00	$ 6.34	$ 6.26	$ 4.38	$ 4.04

Cash dividends per common share	$ 0.56	$ 0.45	$ 0.30	$ 0.20	$ 0.10
Weighted average common shares outstanding Basic	445	442	458	482	417
Weighted average common shares outstanding Diluted	450	448	470	499	433
Ratio of earnings to fixed charges(1)	8.78	8.08	8.34	6.65	4.84
Ratio of earnings to combined fixed charges and preferred stock dividends(1)	8.54	7.85	8.13	6.48	4.72
Cash Flow Data					
Net cash provided by operating activities	$ 6,651	$ 5,993	$ 5,612	$ 4,816	$ 3,768
Net cash used in investing activities	$ (5,714)	$ (7,449)	$ (1,652)	$ (3,634)	$ (2,773)
Net cash (used in) provided by financing activities	$ (371)	$ 593	$ (3,543)	$ (1,001)	$ (414)
Production, Price and Other Data(2)					
Production:					
Oil (MMBbls)	55	42	46	54	47
Gas (Bcf)	863	808	819	883	858
NGLs (MMBbls)	26	23	24	24	22
Total (MMBoe)(3)	224	200	206	225	211
Average prices:					
Oil (Per Bbl)	$ 63.98	$ 57.39	$ 38.64	$ 29.12	$ 26.13
Gas (Per Mcf)	$ 5.99	$ 6.08	$ 7.03	$ 5.34	$ 4.52
NGLs (Per Bbl)	$ 37.76	$ 32.10	$ 29.05	$ 23.06	$ 18.63
Combined (Per Boe)(3)	$ 42.96	$ 40.38	$ 39.89	$ 30.38	$ 26.04
Production and operating expenses per Boe(3)	$ 9.68	$ 8.81	$ 7.65	$ 6.38	$ 5.79
Depreciation, depletion and amortization of oil and gas properties per Boe(3)	$ 11.85	$ 10.27	$ 8.56	$ 8.15	$ 7.03

	2007	2006	December 31, 2005 (In millions)	2004	2003
Balance Sheet Data					
Total assets	$ 41,456	$ 35,063	$ 30,273	$ 30,025	$ 27,162
Long-term debt	$ 6,924	$ 5,568	$ 5,957	$ 7,031	$ 8,580
Stockholders equity	$ 22,006	$ 17,442	$ 14,862	$ 13,674	$ 11,056

(1) For purposes of calculating the ratio of earnings to fixed charges and the ratio of earnings to combined fixed charges and preferred stock dividends, (i) earnings consist of earnings from continuing operations before income taxes, plus fixed charges; (ii) fixed charges consist of interest expense, dividends on subsidiary s preferred stock and one-third of rental expense estimated to be attributable to interest; and (iii) preferred stock dividends consist of the amount of pre-tax earnings required to pay dividends on the outstanding preferred stock.

(2) The amounts presented under Production, Price and Other Data exclude the amounts related to discontinued operations in Egypt and West Africa. The price data presented includes the effects of derivative financial instruments and fixed-price physical delivery contracts.

On April 25, 2003, we completed a merger with Ocean Energy, Inc. Accordingly, only approximately eight months of production from the properties acquired in this merger were included in our total 2003 production volumes. Our production volumes in 2005 were affected by the sale of certain non-core properties in the first half of the year, and the suspension of a portion of our Gulf of Mexico production due to hurricanes in the last half of the year.

(3) Gas volumes are converted to Boe 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. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations*

Introduction

The following discussion and analysis presents management s perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be reviewed in conjunction with our Selected Financial Data and Financial Statements and Supplementary Data. Our discussion and analysis relates to the following subjects:

Overview of Business

Overview of 2007 Results and Outlook

Results of Operations

Capital Resources, Uses and Liquidity

Contingencies and Legal Matters

Critical Accounting Policies and Estimates

Recently Issued Accounting Standards Not Yet Adopted

2008 Estimates

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Overview of Business

Devon is the largest U.S. based independent oil and gas producer and processor of natural gas and natural gas liquids in North America. Our portfolio of oil and gas properties provides stable production and a platform for future growth. Over 90 percent of our production from continuing operations is from North America. We also operate in selected international areas, including Azerbaijan, Brazil and China. Our production mix in 2007 was 64 percent natural gas and 36 percent oil and NGLs such as propane, butane and ethane. We are currently producing 2.4 Bcf of natural gas each day, or about 3 percent of all the gas consumed in North America.

In managing our global operations, we have an operating strategy that is focused on creating and increasing value per share. Key elements of this strategy are replacing oil and gas reserves, growing production and exercising capital discipline. We must also control operating costs and manage commodity pricing risks to achieve long-term success.

Oil and gas reserve replacement Our financial condition and profitability are significantly affected by the amount of proved reserves we own. Oil and gas properties are our most significant assets, and the reserves that relate to such properties are key to our future success. To increase our proved reserves, we must replace quantities produced with additional reserves from successful exploration and development activities or property acquisitions.

Production growth Our profitability and operating cash flows are largely dependent on the amount of oil, gas and NGLs we produce. Growing production from existing properties is difficult because the rate of production from oil and gas properties generally declines as reserves are depleted. As a result, we constantly drill for and develop reserves on properties that provide a balance of near-term and long-term production. In addition, we may acquire properties with proved reserves that we can develop and subsequently produce to help us meet our production goals.

Capital investment discipline Effectively deploying our resources into capital projects is key to maintaining and growing future production and oil and gas reserves. As a result, we deploy virtually all our available cash flow into capital projects. Therefore, maintaining a disciplined approach to investing in capital projects is important to our profitability and financial condition. Our ability to control capital expenditures can be affected by changes in commodity prices. During times of high commodity prices, drilling and related costs often escalate due to the effects of supply versus demand economics. Approximately 83% of our planned 2008 investment in capital projects is dedicated to a foundation of low-risk projects primarily in North America. The remainder of our capital is invested in high-impact projects primarily in the Gulf of Mexico, Brazil and China. By deploying our capital in this manner, we are able to consistently deliver cost-efficient drill-bit growth and provide a strong source of cash flow while balancing short-term and long-term growth targets.

Operating cost controls To maintain our competitive position, we must control our lease operating costs and other production costs. As reservoirs are depleted and production rates decline, per unit production costs will generally increase and affect our profitability and operating cash flows. Similar to capital expenditures, our ability to control operating costs can be affected by significant increases in commodity prices. Our base North American production is focused in core areas of our operations where we can achieve economies of scale to help manage our operating costs.

Commodity pricing risks Our profitability is highly dependent on the prices of oil, natural gas and NGLs. These prices are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and worldwide economic activity, weather and other factors that are beyond our control. To manage this volatility, we will sometimes utilize financial hedging arrangements and fixed-price contracts. During 2007, approximately 5% of our gas production was subject to financial collar and swap contracts or fixed-price physical delivery contracts. Based on contracts in place as of February 15, 2008, during 2008 approximately 64% of our gas production and 12% of our oil production will be subject to financial collar and swap contracts or fixed-price physical delivery contracts.

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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 a 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 off 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.

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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

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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.

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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	NGL	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

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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 a 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 throughout.

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

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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 vs	2006 vs

	2007	**2006(1)**	**2006**	**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	2006

	2007	vs 2006(1)	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.

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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.

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	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		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, 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.

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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.

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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 Financial Statements and Supplementary Data.

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%. 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 Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(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 Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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 Item 7. 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.

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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

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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

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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.

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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%.

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(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

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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 (In millions)	International	Total
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.

Item 7A. *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. See Item 1A. Risk Factors.

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.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

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.

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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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	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
	1	444	44	6,840	9,114	1,444	(1)	17,442

Balance as of December 31, 2006								
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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

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;

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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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.

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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

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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)

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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.

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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.

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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

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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 (In millions)	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 (In millions)	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.

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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

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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	December 31, 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

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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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt Assumed	Fair Value of Debt Assumed (In millions)	Effective Rate of Debt Assumed
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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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)

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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
			(In millions)			
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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (In millions)	One Percent Decrease
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 (In millions)	Other Postretirement Benefits
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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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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).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (In thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In Years)	Aggregate Intrinsic Value (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.

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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 (In thousands)	Weighted Average Grant-Date Fair Value
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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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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

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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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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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).

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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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, (In millions)		
	2007	**2006**	**2005**
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, (In millions)		
	2007	**2006**	**2005**
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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

	Oil (MMBbls)	Gas (Bcf)	Total 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Oil (MMBbls)	Gas (Bcf)	Domestic 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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	International(1)			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (In millions)	2005
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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not Applicable.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Devon, including its consolidated subsidiaries, is made known to the officers who certify Devon s financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, Devon s principal executive and principal financial officers have concluded that Devon s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2007 to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

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 under Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting

There was no change in Devon s internal control over financial reporting during the fourth quarter of 2007 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

Item 9B. ***Other Information***

Not applicable.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information called for by this Item 10 is incorporated hereby by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2008.

Item 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2008.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2008.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2008.

Item 14. ***Principal Accounting Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2008.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) *The following documents are filed as part of this report:*

1. Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements and Consolidated Financial Statement Schedules appearing at Item 8. Financial Statements and Supplementary Data in this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information has been included in the consolidated financial statements or notes thereto.

3. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Registrant, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Registrant s Amendment No. 1 to Form S-4 Registration No. 333-103679, filed March 20, 2003).
2.2	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Registrant, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant s Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
2.3	Offer to Purchase for Cash and Directors Circular dated September 6, 2001 (incorporated by reference to Registrant s and Devon Acquisition Corporation s Schedule 14D-1F filing, filed September 6, 2001).
2.4	Pre-Acquisition Agreement, dated as of August 31, 2001, between Registrant and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant s Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001).
2.5	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant s Form 8-K filed on July 12, 2000).
2.6	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant s Form S-4, File No. 333-82903).
3.1	Registrant s Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant s Form 10-K filed on March 9, 2005).
3.2	Registrant s Bylaws (incorporated by reference to Exhibit 3.2 of Registrant s Form 10-K for the year ended December 31, 2005).
4.1	Rights Agreement dated as of August 17, 1999 between Registrant and BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant s Form 8-K filed on August 18, 1999).
4.2	

	Amendment to Rights Agreement, dated as of May 25, 2000, by and between Registrant and Fleet National Bank, formerly BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant s Form S-4 filed on June 22, 2000).
4.3	Amendment to Rights Agreement, dated as of October 4, 2001, by and between Registrant and Fleet National Bank, formerly Bank Boston, N.A. (incorporated by reference to Exhibit 99.1 to Registrant s Form 8-K filed on October 11, 2001).
4.4	Amendment to Rights Agreement, dated September 13, 2002, between Registrant and Wachovia Bank, N.A. (incorporated by reference to Exhibit 4.9 to Registrant s Registration Statement on Form S-3 File Nos. 333-83156, 333-83156-1, and 333-83156-2 as filed on October 4, 2002).

Exhibit No.	Description
4.5	Amendment to Rights Agreement, dated as of August 1, 2006, by and between Registrant and Computershare Trust Company, N.A. (formerly UMB Bank, n.a.) (incorporated by reference to Exhibit 4.4 to Registrant s Form 10-Q filed August 4, 2006).
4.6	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon, as Trustee, relating to senior debt securities issuable by Registrant (the Senior Indenture) (incorporated by reference to Exhibit 4.1 of Registrant s Form 8-K filed April 9, 2002).
4.7	Supplemental Indenture No. 1, dated as of March 25, 2002, between Registrant and The Bank of New York Mellon, as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant s Form 8-K filed on April 9, 2002).
4.8	Indenture dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. as Issuer, Registrant as Guarantor, and The Bank of New York Mellon, originally The Chase Manhattan Bank, as Trustee, relating to the 6.875% Senior Notes due 2011 and the 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
4.9	Indenture dated as of December 15, 1992 between Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Texas Commerce Bank National Association, as Trustee, relating to the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(o) to Pennzoil Company s Form 10-K filed March 10, 1993 (SEC File No. 1-5591)).
4.10	First Supplemental Indenture dated as of January 13, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Texas Commerce Bank National Association, as Trustee (incorporated by reference to Exhibit 4(p) to Pennzoil Company s Form 10-K for the year ended December 31, 1992).
4.11	Second Supplemental Indenture dated as of October 12, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Texas Commerce Bank National Association, as Trustee (incorporated by reference to Exhibit 4(i) to Pennzoil Company s Form 10-K for the year ended December 31, 1993).
4.12	Third Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Chase Bank of Texas, National Association, as Trustee, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(g) to PennzEnergy Company s Form 10-K for the year ended December 31, 1998).
4.13	Fourth Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Chase Bank of Texas, National Association, as Trustee, supplements the terms of the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(h) to PennzEnergy Company s Form 10-K for the year ended December 31, 1998).
4.14	Fifth Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Chase Bank of Texas, National Association, as Trustee, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95%

	Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4.7 to Registrant s Form 8-K filed on August 18, 1999).
4.15	Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Mellon Bank, N.A., as Trustee (incorporated by reference to Exhibit 4(a) to Pennzoil Company s Form 10-Q for the quarter ended June 30, 1986 (SEC File No. 1-5591)).

Exhibit No.	Description
4.16	First Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and The Bank of New York Mellon, originally Chase Bank of Texas, National Association, as Trustee, supplementing the terms of the 10.125% Debentures due 2009, (incorporated by reference to Exhibit 4.8 to Registrant s Form 8-K filed on August 18, 1999).
4.17	Senior Indenture dated as of September 28, 2001 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon, as Trustee (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on September 28, 2001). Officer s Certificate establishing the terms of the 7.25% Senior Notes due 2011, including the form of global note relating thereto (incorporated by reference to Exhibit 4.2 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on September 28, 2001).
4.18	First Supplemental Indenture, dated December 31, 2005 to Indenture dated as of September 28, 2001 among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor and The Bank of New York Mellon, as Trustee, relating to the 7.25% Senior Notes due 2011 (incorporated by reference to Exhibit 4.19 of Registrant s Form 10-K for the year ended December 31, 2005).
4.19	Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058)).
4.20	First Supplemental Indenture, dated March 30, 1999 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc. s Form 10-Q for the period ended March 31, 1999).
4.21	Second Supplemental Indenture, dated as of May 9, 2001 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.22	Third Supplemental Indenture, dated January 23, 2006 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.23 of Registrant s Form 10-K for the year ended December 31, 2005).
4.23	Senior Indenture dated September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.4 to Ocean Energy s Annual Report on Form 10-K for the year ended December 31, 1997)).
4.24	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon, as Trustee, relating to the 7.50% Senior Notes Due 2027 (incorporated by reference to Exhibit 4.10 to Ocean Energy s Form 10-Q for the period ended March 31, 1999).
4.25	Second Supplemental Indenture, dated as of May 9, 2001 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and The Bank of New York Mellon, as Trustee, relating to the 7.50% Senior

	Notes (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.26	Third Supplemental Indenture, dated December 31, 2005 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor, and The Bank of New York Mellon., as Trustee, relating to the 7.50% Senior Notes (incorporated by reference to Exhibit 4.27 of Registrant s Form 10-K for the year ended December 31, 2005).

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Exhibit No.	Description
10.1	Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Registrant, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (incorporated by reference to Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
10.2	Credit Agreement dated as of August 7, 2007 among Registrant as Borrower, Bank of America, N.A. as Administrative Agent, JPMorgan Chase Bank, N.A. as Syndication Agent, and The Other Lenders Party thereto, Banc of America Securities LLC and J.P. Morgan Securities, Inc. as Joint Lead Arrangers and Book Managers for the $1.5 Billion 364-Day Senior Credit Facility (incorporated by reference to Exhibit 10.1 to Registrant s Form 10-Q filed on November 7, 2007).
10.3	First Amendment to Credit Agreement dated as of December 19, 2007, among Registrant as Borrower, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto.
10.4	Amended and Restated Credit Agreement dated March 24, 2006, effective as of April 7, 2006, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as Canadian Borrowers, Bank of America, N.A. as Administrative Agent, Swing Line Lender and L/C Issuer; JPMorgan Chase Bank, N.A. as Syndication Agent, Bank of Montreal D/B/A Harris Nesbitt , Royal Bank of Canada, Wachovia Bank, National Association as Co-Documentation Agents and The Other Lenders Party Hereto, Banc of America Securities L.L.C. and J.P. Morgan Securities Inc., as Joint Lead Arrangers and Book Managers for the $2.0 billion five-year revolving credit facility (incorporated by reference to Exhibit 10.1 to Registrant s Form 10-Q filed on May 4, 2006).
10.5	First Amendment to Amended and Restated Credit Agreement dated as of June 1, 2006, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto. (incorporated by reference to Exhibit 10.2 to Registrant s Form 10-Q filed on November 7, 2007).
10.6	Second Amendment to Amended and Restated Credit Agreement dated as of September 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto. (incorporated by reference to Exhibit 10.3 to Registrant s Form 10-Q filed on November 7, 2007).
10.7	Third Amendment to Amended and Restated Credit Agreement dated as of December 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto.
10.8	Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Registrant s Form S-8 Registration No. 333-127630, filed August 17, 2005).*
10.9	First Amendment to Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Appendix A to Registrant s Proxy Statement for the 2006 Annual Meeting of Stockholders filed on April 28, 2006).*
10.10	Devon Energy Corporation 2003 Long-Term Incentive Plan (incorporated by reference to Registrant s Form S-8 Registration No. 333-104922, filed May 1, 2003).*
10.11	Devon Energy Corporation 1997 Stock Option Plan (as amended August 29, 2000) (incorporated by reference to Exhibit A to Registrant s Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*
10.12	Ocean Energy, Inc. 1999 Long Term Incentive Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*

10.13	Ocean Energy, Inc. 2001 Long Term Incentive Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.14	Santa Fe Energy Resources Incentive Compensation Plan, as amended (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc. s Annual Report on Form 10-K for the year ended December 31, 1998).*

Exhibit No.	Description
10.15	Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Third Amendment and Restatement (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc. s Quarterly Report on Form 10-Q for the quarter ended March 31, 1996).*
10.16	Santa Fe Energy Resources, Inc. Supplemental Retirement Plan effective as of December 4, 1990 (incorporated by reference to Exhibit 10(h) to Santa Fe Energy Resources, Inc. s Annual Report on Form 10-K for the year ended December 31, 1996).*
10.17	United Meridian Corporation 1994 Outside Director s Nonqualified Stock Option Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.18	Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant s Form 10-Q for the quarter ended June 30, 1997).*
10.19	Form of Employment Agreement between Registrant and Stephen J. Hadden, Marian J. Moon, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette and Lyndon C. Taylor dated January 1, 2002 (incorporated by reference to Exhibit 10.26 of Registrant s Form 10-K for the year ended December 31, 2001).*
10.20	Form of Award Agreement between Registrant and Stephen J. Hadden, Marian J. Moon, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette and Lyndon C. Taylor for stock options granted from the 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.39 to Registrant s Form 10-Q for the quarter ended June 30, 2005).*
10.21	Form of Award Agreement between Registrant and all Non-Management Directors for stock options granted from the 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.40 to Registrant s Form 10-Q for the quarter ended June 30, 2005).*
10.22	Form of Award Agreement from the 2005 Long-Term Incentive Plan between Registrant and Stephen J. Hadden, Marian J. Moon, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and all Non-Management Directors for restricted stock awards (incorporated by reference to Exhibit 10.41 to Registrant s Form 10-Q for the quarter ended June 30, 2005).*
10.23	Severance Agreement between Registrant and Danny J. Heatly, dated September 14, 2004 (incorporated by reference to Exhibit 10.20 to Registrant s Form 10-K for the year ended December 31, 2006).*
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	Registrant s Significant Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants.
23.3	Consent of Ryder Scott Company, L.P.
23.4	Consent of AJM Petroleum Consultants.
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Danny J. Heatly, Vice President Accounting and Chief Accounting Officer (principal financial officer) of Registrant, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Danny J. Heatly, Vice President Accounting and Chief Accounting Officer (principal financial officer) of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906

of the Sarbanes-Oxley Act of 2002.

* Compensatory plans or arrangements

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DEVON ENERGY CORPORATION

By: /s/ J. LARRY NICHOLS

J. Larry Nichols,
Chairman of the Board and
Chief Executive Officer

February 27, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ J. Larry Nichols J. Larry Nichols	Chairman of the Board, Chief Executive Officer and Director	February 27, 2008
/s/ John Richels John Richels	President	February 27, 2008
/s/ Danny J. Heatly Danny J. Heatly	Vice President Accounting and Chief Accounting Officer (principal financial officer)	February 27, 2008
/s/ Thomas F. Ferguson Thomas F. Ferguson	Director	February 27, 2008
/s/ David M. Gavrin David M. Gavrin	Director	February 27, 2008
/s/ David A. Hager David A. Hager	Director	February 27, 2008
/s/ John A. Hill John A. Hill	Director	February 27, 2008
/s/ Robert L. Howard Robert L. Howard	Director	February 27, 2008
/s/ William J. Johnson William J. Johnson	Director	February 27, 2008
/s/ Michael M. Kanovsky Michael M. Kanovsky	Director	February 27, 2008
/s/ J. Todd Mitchell	Director	February 27, 2008

J. Todd Mitchell		
/s/ Mary P. Ricciardello	Director	February 27, 2008
Mary P. Ricciardello		

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INDEX TO EXHIBITS

Exhibit No.	Description
10.3	First Amendment to Credit Agreement dated as of December 19, 2007, among Registrant as Borrower, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto.
10.7	Third Amendment to Amended and Restated Credit Agreement dated as of December 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto.
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	Registrant s Significant Subsidiaries.
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