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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

SEC Mail Processing Section

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Washington, DC 122

(Mark One)

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

For the fiscal year ended December 31, 2008

or

☐ **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)

09010717

Delaware	**73-1567067**
(State of 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

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 ☑ No ☐

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 ☐ No ☑

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 ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. ☑

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 29, 2008, was approximately $53.0 billion, based upon the closing price of $120.16 per share as reported by the New York Stock Exchange on such date. On February 16, 2009, 443.8 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2009 annual meeting of stockholders — Part III

DEVON ENERGY CORPORATION

INDEX TO FORM 10-K ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION

DEFINITIONS

As used in this document:

"Bbl" or "Bbls" means barrel or barrels.

"Bcf" means billion cubic feet.

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

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

"Btu" means British thermal units, a measure of heating value.

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

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

"Federal Funds Rate" means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

"FPSO" means floating, production, storage and offloading facilities.

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

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

"LIBOR" means London Interbank Offered Rate.

"MBbls" means thousand barrels.

"MBoe" means thousand Boe.

"Mcf" means thousand cubic feet.

"MMBbls" means million barrels.

"MMBoe" means million Boe.

"MMBtu" means million Btu.

"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.

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

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

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 used to prepare the December 31, 2008 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," "believe," or "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, including the supply and demand for oil, gas, NGLs and other products or services, and the prices of oil, gas, NGLs, including regional pricing differentials, and other products or services;
- 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 within the securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks;
- capital expenditure and other contractual obligations;
- 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; 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. In addition to our oil and gas operations, we have marketing and midstream operations primarily in North America. These include marketing gas, crude oil and NGLs, and constructing and operating pipelines, storage and treating facilities and natural gas processing plants. A detailed description of our significant properties and associated 2008 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 a significant portion of our capital budget in low-risk 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 capital in 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;
- controlling operating costs;
- improving performance through our marketing and midstream operations; and
- preserving financial flexibility.

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 2,428 MMBoe at year-end 2008.

During the same time period, we have grown proved reserves from 0.66 Boe[1] per diluted share at the end of 1987 to 5.44 Boe per diluted share at the end of 2008. 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 0.53 Boe per diluted share in 2008, 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.

We achieved a number of significant accomplishments in our operations during 2008, including those discussed below.

- **Drilling Success** — We drilled a record 2,441 gross wells with an overall 98% rate of success. As a result of our success with the drill-bit, we replaced approximately 245% of our 2008 production. We

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[1] Excludes the effects of mergers in 1998 and 2000 that were accounted for as poolings of interests.

added 584 MMBoe of proved reserves during the year with extensions, discoveries and performance revisions, a total which was well in excess of the 238 MMBoe we produced during the year. Consistent with our two-pronged operating strategy, 93% of the wells we drilled were North American development wells, which was the main driver behind our 6% increase in production in 2008.

- **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 31% in 2008, exiting the year at 1.2 Bcfe per day net to our ownership interest. We drilled 659 wells in the Barnett Shale in 2008. We have interests in approximately 3,800 producing wells in the Barnett Shale and hold approximately 715,000 net acres of Barnett Shale leases. At December 31, 2008, we had estimated proved reserves of 894 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, the Washakie basin in Wyoming and the Woodford Shale area in Oklahoma, showed strong production growth in 2008. These four areas, which accounted for approximately 69% of our U.S. onshore production, had production growth in 2008 of 26% compared to 2007.

  We also completed construction and commenced operation of our Northridge natural gas processing plant in southeastern Oklahoma. This plant can process up to 200 MMcf of natural gas per day and will support our growing production in the Woodford Shale.

  We have also leveraged our knowledge of and expertise in the Barnett Shale into other unconventional natural gas plays, such as the Haynesville shale in eastern Texas and western Louisiana, the Cana shale play in western Oklahoma and the Cody play in Montana. We added approximately 800,000 net undeveloped acres to our lease inventory, positioning us with more than 1.4 million net acres in emerging unconventional natural gas plays.

  In addition to production growth, our U.S. onshore properties also demonstrated measurable growth in proved reserves. U.S. onshore proved reserves grew 416 MMBoe due to extensions, discoveries and performance revisions. This was almost three times our U.S. onshore production in 2008 of 146 MMBoe. Our drilling activities increased our 2008 U.S. onshore proved reserves by 27% compared to the end of 2007.

- **Marketing and Midstream** — Our marketing and midstream business delivered another record setting year with operating profit increasing by 31% to $668 million.

- **Jackfish** — We ramped up production from our 100%-owned Jackfish thermal heavy oil project in the Alberta oil sands to 22,000 Bbls per day by the end of the year. In 2009, we expect to achieve our peak production target of 35,000 Bbls per day. Additionally, we received regulatory approval for the second phase of Jackfish. 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 heavy oil play in Alberta by 14%, exiting the year at approximately 45,000 Boe per day. We drilled 425 wells at Lloydminster in 2008, which added 19 MMBoe of proved reserves.

- **Divestiture of African Properties** — We substantially completed our Egypt and West Africa divestiture programs. We have now sold all of our oil and gas producing properties in Africa. These divestitures generated just over $3.0 billion of sales proceeds. After income taxes and purchase price adjustments, such proceeds totaled $2.2 billion and generated after-tax gains of $0.8 billion.

  Pursuant to accounting rules for discontinued operations, the amounts in this document related to continuing operations for 2008 and all prior years presented do not include amounts related to our operations in Egypt and West Africa.

- **Polvo** — We experienced numerous mechanical issues with our offshore development project that delayed our expected production growth. By the end of 2008, we had solved the mechanical issues and are now producing at 17,000 Bbls per day. We expect production to increase in 2009. We have a 60% working interest in Polvo.

- **Gulf of Mexico Exploration and Development** — 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 (25% working interest), Jack in 2004 (25% working interest) and Kaskida in 2006 (30% working interest). These achievements, along with our 2008 developments discussed below, support our positive view of the Lower Tertiary and demonstrate the potential of our exploration strategy on growth of long-term production, reserves and value.

  Specific Gulf of Mexico developments in 2008 included the following:

  - At Cascade, we commenced drilling the first of two initial producing wells and continued work on the production facilities and subsea equipment. We anticipate first production at Cascade in 2010. When Cascade begins producing, it will utilize the Gulf's first FPSO.
  - At Jack and St. Malo, our partners focused on development concepts for the two fields. Particular consideration has been given to joint development of the two fields that could employ the use of a single, semi-submersible production facility.
  - At Kaskida, the largest of our Lower Tertiary discoveries, we are currently drilling an appraisal well.

Financial Information about Segments and Geographical Areas

Notes 18 and 20 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 markets for oil, gas and NGLs are 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 2009, all of our oil production was 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 2009, approximately 75% of our 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 24% of our production was committed under various long-term contracts, which dedicate the gas to a purchaser for an extended period of time, but still at market sensitive prices. The remaining 1% 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 2009, approximately 97% 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 for sale.

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 2008, 2007 or 2006.

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 and financial strength.

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, tribal, local and international laws and regulations, including, but not limited to, laws and regulations related to the acquisition of seismic data; the location of wells; drilling and casing of wells; well production; spill prevention plans; emissions permitting; 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 gas wells; and the unitization or pooling of oil and 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 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 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 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 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.

In December 2008, the provincial government of Alberta enacted a new royalty regime. The new regime provides for new royalties for conventional oil, gas, NGL and bitumen production effective January 1, 2009. The royalties are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects.

This royalty regime reduced our proved reserves as of December 31, 2008 by 28 MMBoe. Additionally, this regime is expected to reduce future earnings and cash flows from our oil and gas properties located in Alberta. The actual effect on our future earnings and cash flows of this royalty regime will be determined based on, among other things, our production rates from wells in Alberta, the proportion of our Alberta production to our overall production, our product mix in Alberta, commodity prices and foreign exchange rates.

Pricing and Marketing in Canada

Any oil or 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 federal 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

Some 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, tribal, 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 emission of certain gases into the atmosphere; 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. 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. Devon continues to explore energy efficiency measures and greenhouse gas emission reduction opportunities. We also continue to monitor legislative and regulatory climate change developments. 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, 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 and safety and health compliance. While our unreimbursed expenditures in 2008 attributable to 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, 2008, we had approximately 5,500 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.

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, Gas and NGL Prices are Volatile

Our financial results are highly dependent on the prices of and demand for oil, gas and NGLs. A significant downward movement of the prices for these commodities could have a material adverse effect on our revenues, operating cash flows and profitability. Such a downward price movement could also have a material adverse effect on our estimated proved reserves, the carrying value of our oil and gas properties, the level of planned drilling activities 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, gas and NGLs;
- conservation efforts;
- OPEC production levels;
- weather;
- regional pricing differentials;
- 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, gas and NGLs;
- the price and availability of alternative fuels;
- the overall economic environment; and
- governmental regulations and taxes.

Estimates of Oil, 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 rates from oil and gas properties generally decline 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 transportation methods;
- environmental hazards or liabilities; and
- shortages or delays in the availability of services or 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. Typically, during times of high or rising commodity prices, drilling and operating costs will also increase. Higher prices will also generally increase the costs of properties available for acquisition. 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 gas production, such as changing worldwide price and production levels, 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 face political and economic risks and other uncertainties in these areas 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 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 our 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, tribal 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, lessee or operator of oil and gas properties, we are subject to various federal, state, provincial, tribal, 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, 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 hurricanes in the Gulf of Mexico in recent years, we currently do not have coverage for any damage that may be caused by future named windstorms in the Gulf of Mexico.

Certain of Our Investments Are Subject To Risks That 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. During 2007, we purchased asset-backed securities that have an auction rate reset feature ("auction rate securities"). Our auction rate securities generally have contractual maturities of more than 20 years. However, the underlying interest rates on our securities are scheduled to reset every seven to 28 days. Therefore, when we bought these securities, they were generally priced and subsequently traded as short-term investments because of the interest rate reset feature. At December 31, 2008, our auction rate securities totaled $122 million.

Since February 8, 2008, we have experienced difficulty selling our securities due to the failure of the auction mechanism, which provided 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 seven to 28 days until the auction succeeds, the issuer calls the securities or the securities mature. Due to continued auction failures throughout 2008, we consider these investments to be long-term in nature and generally not available for short-term liquidity needs.

Our auction rate securities are rated AAA — the highest rating — by one or more rating agencies and are collateralized by student loans that are substantially guaranteed by the United States government. 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. 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, 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 3,100 miles of pipeline, two natural gas processing plants with 750 MMcf per day of total capacity, and a 15 MBbls per day NGL fractionator. To support our continued development and growing production in the Woodford Shale, located in southeastern Oklahoma, we constructed the Northridge natural gas processing plant in 2008. The Northridge plant has a capacity of 200 MMcf per day.

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 for sale. 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, 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. Existing economic and operating conditions is defined as those 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. Our policies assign responsibilities for compliance in reserves bookings to our Reserve Evaluation Group (the "Group") and 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 reserve estimates and includes the Director — Reserves and Economics and the Senior Advisor — Corporate Reserves. The Group reports independently of any of our operating divisions. The Senior Vice President — Strategic Development 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 2008 reserve estimates for all of our offshore Gulf of Mexico properties and for 99% of our International proved reserves. LaRoche Petroleum Consultants, Ltd. audited the 2008 reserve estimates for 90% of our domestic onshore properties. AJM Petroleum Consultants audited 78% 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 2008, 2007 and 2006.

	2008		2007		2006	
	Prepared	**Audited**	**Prepared**	**Audited**	**Prepared**	**Audited**
U.S.	5%	87%	6%	83%	7%	81%
Canada	—	78%	34%	51%	46%	39%
International	99%	—	99%	—	99%	—
Total	9%	81%	19%	69%	28%	61%

"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 three 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.

The following table sets forth our estimated proved reserves and related estimated cash flow information as of December 31, 2008. These estimates correspond with the method used in presenting the "Supplemental Information on Oil and Gas Operations" in Note 20 to our consolidated financial statements included herein.

	Total Proved Reserves	Proved Developed Reserves	Proved Undeveloped Reserves
Total Reserves			
Oil (MMBbls)	429	301	128
Gas (Bcf)	9,885	8,044	1,841
NGLs (MMBbls)	352	292	60
MMBoe(1)	2,428	1,934	494
Pre-tax future net revenue (in millions)(2)	$26,731	$22,946	$3,785
Pre-tax 10% present value (in millions)(2)	$14,178	$13,279	$ 899
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$10,492		
U.S. Reserves			
Oil (MMBbls)	167	133	34
Gas (Bcf)	8,369	6,681	1,688
NGLs (MMBbls)	317	261	56
MMBoe(1)	1,878	1,508	370
Pre-tax future net revenue (in millions)(2)	$20,284	$17,916	$2,368
Pre-tax 10% present value (in millions)(2)	$10,185	$ 9,945	$ 240
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 7,381		
Canadian Reserves			
Oil (MMBbls)	134	110	24
Gas (Bcf)	1,510	1,357	153
NGLs (MMBbls)	35	31	4
MMBoe(1)	421	367	54
Pre-tax future net revenue (in millions)(2)	$ 4,852	$ 4,569	$ 283
Pre-tax 10% present value (in millions)(2)	$ 2,959	$ 2,931	$ 28
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 2,252		
International Reserves			
Oil (MMBbls)	128	58	70
Gas (Bcf)	6	6	—
NGLs (MMBbls)	—	—	—
MMBoe(1)	129	59	70
Pre-tax future net revenue (in millions)(2)	$ 1,595	$ 461	$1,134
Pre-tax 10% present value (in millions)(2)	$ 1,034	$ 403	$ 631
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 859		

(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 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, 2008. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yielded average prices over the life of our properties of $32.65 per Bbl of oil, $4.75 per Mcf of gas and $16.54 per Bbl of NGLs. These prices compare to the December 31, 2008, NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for gas.

The present value of after-tax future net revenues discounted at 10% per annum ("standardized measure") was $10.5 billion at the end of 2008. Included as part of standardized measure were discounted future income taxes of $3.7 billion. Excluding these taxes, the present value of our pre-tax future net revenue ("pre-tax 10% present value") was $14.2 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 20 to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

As presented in the previous table, we had 1,934 MMBoe of proved developed reserves at December 31, 2008. 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, 2008.

	Total Proved Developed Reserves	Proved Developed Producing Reserves	Proved Developed Non-Producing Reserves
Total Reserves			
Oil (MMBbls)	301	250	51
Gas (Bcf)	8,044	7,051	993
NGLs (MMBbls)	292	259	33
MMBoe	1,934	1,684	250
U.S. Reserves			
Oil (MMBbls)	133	112	21
Gas (Bcf)	6,681	5,851	830
NGLs (MMBbls)	261	230	31
MMBoe	1,508	1,317	191
Canadian Reserves			
Oil (MMBbls)	110	91	19
Gas (Bcf)	1,357	1,194	163
NGLs (MMBbls)	31	29	2
MMBoe	367	319	48
International Reserves			
Oil (MMBbls)	58	47	11
Gas (Bcf)	6	6	—
NGLs (MMBbls)	—	—	—
MMBoe	59	48	11

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 2008 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, 2008. 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, 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, 2008, is set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

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, 2008		Net Wells Completed(2)					
			2008		2007		2006	
	Gross(1)	Net(2)	Productive	Dry	Productive	Dry	Productive	Dry
U.S.	111	73.2	1,033.0	18.5	978.2	21.1	877.1	12.5
Canada	6	4.3	528.9	3.2	531.2	—	593.2	3.3
International	9	1.0	13.8	1.4	9.2	—	6.1	—
Total	**126**	**78.5**	**1,575.7**	**23.1**	**1,518.6**	**21.1**	**1,476.4**	**15.8**

Exploratory Well Activity

	Wells Drilling at December 31, 2008		Net Wells Completed(2)					
			2008		2007		2006	
	Gross(1)	Net(2)	Productive	Dry	Productive	Dry	Productive	Dry
U.S.	13	9.8	13.6	3.8	11.6	4.2	24.5	10.3
Canada	7	4.0	50.1	3.3	83.3	1.5	82.1	1.0
International	1	0.2	—	5.6	—	0.6	—	1.7
Total	**21**	**14.0**	**63.7**	**12.7**	**94.9**	**6.3**	**106.6**	**13.0**

(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, 2008 presented in the tables above, the following table summarizes the results of such wells as of February 1, 2009.

	Productive		Dry		Still In Progress	
	Gross	Net	Gross	Net	Gross	Net
U.S.	25	18.3	2	1.5	97	63.1
Canada	11	7.5	—	—	2	0.8
International	3	0.7	—	—	7	0.6
Total	**39**	**26.5**	**2**	**1.5**	**106**	**64.5**

Well Statistics

The following table sets forth our producing wells as of December 31, 2008.

	Oil Wells		Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S. Onshore	8,265	2,850	19,166	13,075	27,431	15,925
U.S. Offshore	444	309	218	142	662	451
Total U.S.	8,709	3,159	19,384	13,217	28,093	16,376
Canada	3,675	2,704	4,928	2,847	8,603	5,551
International	479	206	—	—	479	206
Grand Total	**12,863**	**6,069**	**24,312**	**16,064**	**37,175**	**22,133**

(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, 2008.

	Developed		Undeveloped	
	Gross(1)	Net(2)	Gross(1)	Net(2)
	(In thousands)			
U.S. Onshore	3,425	2,298	6,444	3,565
U.S. Offshore	337	187	2,228	1,277
Total U.S.	3,762	2,485	8,672	4,842
Canada	3,633	2,265	8,251	5,436
International	198	53	10,654	9,238
Grand Total	**7,593**	**4,803**	**27,577**	**19,516**

(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 22,527 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.

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, 2008, along with their production volumes for the year 2008. Additional summary profile information for our significant properties is provided following the table.

We have certain North American onshore and offshore properties we consider to be significant because they may be the source of significant future growth in proved reserves and production. However, these properties are not included in the following table because as of December 31, 2008, such properties had only minimal, if any, proved reserves or production. Onshore, these properties include the Haynesville, Cana and Cody properties in the U.S. and the Horn River Basin properties in Canada. Offshore, these properties include our deepwater development and exploration properties in the Gulf of Mexico. These properties and our related development plans are discussed along with our other significant properties following the table.

Also, as presented in the table, we had no proved reserves associated with our Jackfish operations as of December 31, 2008. During 2008 and thus far in 2009, we have been producing heavy oil from our Jackfish property. However, due to low crude oil prices and unfavorable operating conditions as of December 31, 2008, our Jackfish reserves did not meet the existing economic and operating condition requirement to be classified as proved at the end of 2008.

	Proved Reserves (MMBoe)(1)	Proved Reserves %(2)	Production (MMBoe)(1)	Production %(2)
U.S.				
Barnett Shale	894	36.8%	66	27.9%
Carthage	209	8.6%	17	7.2%
Permian Basin, Texas	125	5.1%	9	3.6%
Washakie	105	4.3%	7	2.8%
Groesbeck	62	2.5%	7	3.1%
Woodford Shale	48	2.0%	4	1.5%
Other U.S Onshore	334	13.8%	36	15.3%
Total U.S Onshore	**1,777**	**73.1%**	**146**	**61.4%**
Deepwater Producing	56	2.3%	7	3.1%
Other U.S Offshore	45	1.9%	9	3.7%
Total U.S Offshore	**101**	**4.2%**	**16**	**6.8%**
Total U.S	**1,878**	**77.3%**	**162**	**68.2%**
Canada				
Lloydminster	92	3.8%	16	6.6%
Peace River Arch	82	3.4%	8	3.5%
Deep Basin	66	2.8%	10	4.2%
Northeast British Columbia	64	2.6%	9	3.6%
Jackfish	—	—	4	1.5%
Other Canada	117	4.8%	14	6.2%
Total Canada	**421**	**17.4%**	**61**	**25.6%**
International				
Azerbaijan	85	3.5%	6	2.6%
China	18	0.8%	5	2.1%
Brazil	4	0.1%	2	0.6%
Other	22	0.9%	2	0.9%
Total International	**129**	**5.3%**	**15**	**6.2%**
Grand Total	**2,428**	**100.0%**	**238**	**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 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 715,000 net acres located primarily in 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 659 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 173,000 net acres. Our Carthage area wells produce primarily natural gas and NGLs from conventional reservoirs. We drilled 132 gross wells in 2008.

Permian Basin, Texas — Our oil and gas properties in the Permian Basin of west Texas comprise approximately 470,000 net acres located primarily in Andrews, Crane, Ector, Martin, Terry, Ward and Yoakum counties. These properties produce both oil and gas from conventional reservoirs. Our average working interest in these properties is about 40%. We drilled 71 gross wells 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 2008, we drilled 115 gross wells.

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 168,000 net acres of land. The Groesbeck wells produce primarily natural gas from conventional reservoirs. In 2008, we drilled 16 gross wells.

Woodford Shale — Our Woodford Shale properties in southeastern Oklahoma produce natural gas and NGLs from a non-conventional reservoir. Our 54,000 net acres are concentrated in Coal and Hughes counties and have an average working interest of about 57%. In 2008, we drilled 131 gross wells in this area. To support our production in the Woodford Shale, we also brought online a 200 MMcf per day natural gas processing plant in 2008.

2009 Development Plans — We expect 2009 oil, gas and NGL prices will be noticeably lower than those for 2008. As a result, we expect our operating cash flow will also be lower than that for 2008 and will require us to scale back our anticipated capital expenditures in 2009 compared to 2008. Accordingly, we expect to drill fewer wells in 2009 than in 2008 for the key U.S. Onshore areas discussed above.

Our reduction in 2009 drilling activities in these areas is also related to our plan to devote a portion of our planned 2009 capital expenditures to develop three new unconventional natural gas plays. In 2008, we built a position of nearly 1.3 million net acres in these unconventional natural gas plays. In east Texas and north Louisiana we have accumulated approximately 570,000 net acres prospective for the Haynesville shale formation. In western Oklahoma, our Cana leasehold position targets the deep Woodford shale formation in the Anadarko Basin. We hold about 112,000 net acres in the Cana area. In south central Montana, we have accumulated a significant leasehold position for our Cody project area. We hold approximately 575,000 net acres in this region. In 2009, we will continue to evaluate our acreage and drill wells in these emerging plays to assess the reserve and production potential of our acreage position.

U.S. Offshore

Deepwater Producing — Our assets in the Gulf of Mexico include three significant producing properties — Magnolia, Merganser and Nansen — located in deep water (greater than 600 feet). We have a 50% working interest in Merganser and Nansen and a 25% working interest in Magnolia. The three fields are located on federal leases and total approximately 23,000 net acres. The properties produce both oil and gas.

Deepwater Development — In addition to our three significant deepwater producing properties, we will continue development activities on our deepwater Cascade project throughout 2009. Cascade was discovered in 2002 and is located on federal leases encompassing approximately 12,000 net acres. We have a 50% working interest in Cascade. Production from Cascade, which will be primarily oil, is expected to begin in 2010. Cascade will be the first project in the Gulf to utilize an FPSO.

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 2008, 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 161 blocks in the Lower Tertiary and we have identified 21 additional prospects to date.

At St. Malo, in which our working interest is 25%, we drilled two delineation wells in 2008. At Jack, where our working interest is 25%, we drilled a second appraisal well in 2008. A sidetrack appraisal well was drilled on the Kaskida unit in 2008 and we commenced an additional delineation well in late 2008. Our working interest in Kaskida is 30%, and we believe Kaskida is the largest of our four Lower Tertiary discoveries to date.

Also in 2008, we participated in a sidetrack delineation well on the Miocene-aged Mission Deep discovery in which we have a 50% working interest. We have identified 14 additional prospects in our deepwater Miocene inventory to date.

In total, we drilled seven exploratory and appraisal wells in the deepwater Gulf of Mexico in 2008. Our working interests in these exploratory opportunities range from 25% to 50%. In 2009, we will continue to perform additional delineation drilling and continue to plan the development of Jack and St. Malo.

Canada

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 2.5 million net acres and have an 89% average working interest in our Lloydminster properties. In 2008, we drilled 425 gross wells in the area.

Peace River Arch — The Peace River Arch is located in west central Alberta. We hold approximately 569,000 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 66 gross wells in the Peace River Arch 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 602,000 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 2008, we drilled 61 gross wells.

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 1.7 million net acres in the area. These properties produce principally natural gas from conventional reservoirs. We hold a 76% average working interest in these properties. We drilled 37 gross wells in the area in 2008.

Jackfish — By the end of 2008, we ramped up production from our 100%-owned Jackfish thermal heavy oil project in the non-conventional oil sands of east central Alberta to 22,000 Bbls per day. We are employing steam-assisted gravity drainage at Jackfish. Production is expected to increase in 2009 to its peak production target of 35,000 Bbls per day. We hold approximately 75,000 net acres in the entire Jackfish area, which can support expansion of the original project. In 2008, we received regulatory approval to develop a second phase of Jackfish. Like the first phase, this second phase of Jackfish is also expected to eventually produce 35,000 Bbls per day of heavy oil production.

2009 Development Plans — Similar to our 2009 plans for our U.S. Onshore areas discussed above, we expect to drill fewer wells in 2009 than in 2008 for the key areas in Canada discussed above. Our plans to drill fewer wells in these areas is also affected by our intentions to devote a portion of our planned 2009 capital expenditures to develop our positions in the Horn River Basin in northeast British Columbia. In 2008, we accumulated approximately 153,000 net acres targeting the Devonian shale in this area. In 2009, we will continue to evaluate our acreage and drill wells in this area to assess the reserve and production potential of our acreage position.

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 2008, we participated in drilling 15 gross wells.

China — Our production in China is from the Panyu development in the Pearl River Mouth Basin in the South China Sea. The 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 seven gross wells in China in 2008.

Brazil — In 2008, we continued to ramp up production from our Polvo development, which we operate with a 60% working interest. Polvo is located offshore in the Campos Basin in Block BM-C-8. We experienced mechanical issues during 2008 at Polvo that delayed bringing a portion of our expected production online. As of December 31, 2008, the mechanical issues appear to have been corrected, and we exited the year with gross production at approximately 17,000 Bbls per day. In addition to our development project at Polvo, we hold acreage in eight exploratory blocks. In aggregate, we have 1.4 million net acres in Brazil. Our working interests range from 18% to 100% in these blocks. We drilled 12 gross wells in Brazil in 2008 and over the next two years we plan to drill up to eight exploratory wells.

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 natural 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. The first phase was scheduled to begin in August 2008, but the defendant settled prior to trial. The second phase was scheduled to begin in February 2009, but the defendants settled prior to trial. Devon was 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 with respect to this lawsuit and, therefore, no liability related to this lawsuit has been recorded.

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 2008.

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 16, 2009, there were 14,074 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 2008 and 2007. Also, included are the quarterly dividends per share paid during 2008 and 2007.

	Price Range of Common Stock		Dividends
	High	Low	Per Share
2008:			
Quarter Ended March 31, 2008	$108.13	$ 74.56	$0.1600
Quarter Ended June 30, 2008	$127.16	$101.31	$0.1600
Quarter Ended September 30, 2008	$127.43	$ 82.10	$0.1600
Quarter Ended December 31, 2008	$ 91.69	$ 54.40	$0.1600
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

Our Board of Directors has approved a program to repurchase up to 50 million shares, which expires on December 31, 2009. As of December 31, 2008, up to 45.5 million shares can be repurchased under the 50 million share repurchase program.

Our Board of Directors has also approved 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 authorized the repurchase of up to 4.8 million shares or a cost of $422 million, whichever amount was reached first. When the 2008 portion of this annual program expired on December 31, 2008, 2.0 million shares had been repurchased under this program for $178 million, or $87.83 per share.

No shares were repurchased under these programs during the fourth quarter of 2008.

Prior to the end of 2008, our Board of Directors authorized the 2009 portion of the annual program. Under this program in 2009, we are authorized to repurchase up to 4.8 million shares or a cost of $360 million, whichever amount is reached first.

As of December 31, 2008, we are authorized to repurchase up to 50.3 million shares under publicly announced programs. This amount is comprised of the 45.5 million remaining shares authorized to be repurchased under the 50 million share repurchase program and the 4.8 million shares authorized to be repurchased under the annual repurchase program in 2009. However, in response to the current economic environment and recent downturn in commodity prices, we have indefinitely suspended activity under both these programs. As a result, we do not anticipate repurchasing shares under these programs in the foreseeable future. Should economic conditions or commodity prices strengthen, we will consider resumption of share repurchases under our authorized programs.

New York Stock Exchange Certifications

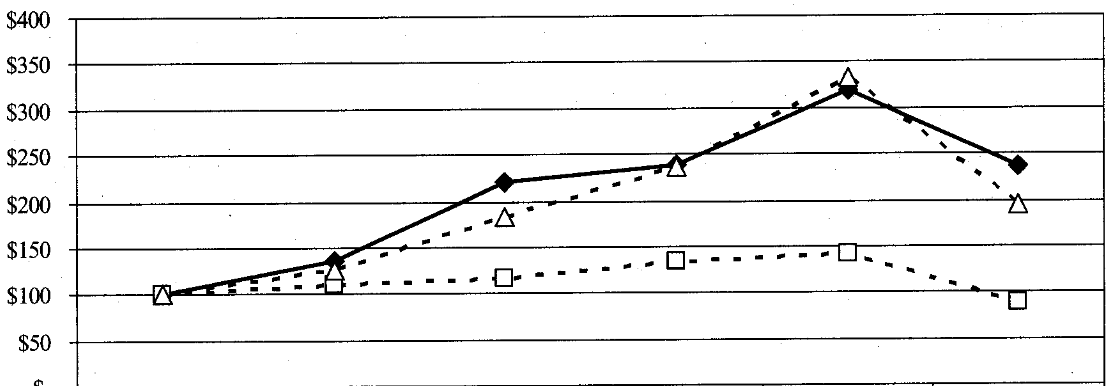
This Form 10-K includes as exhibits the certifications of our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, required to be filed with the SEC pursuant to Section 302 of the Sarbanes Oxley Act of 2002. We have also filed with the New York Stock Exchange the 2008 annual certification of our Chief Executive Officer confirming that we have complied with the New York Stock Exchange corporate governance listing standards.

Performance Graph

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on Devon's common stock with the cumulative total returns of the Standard & Poor's 500 index ("the S&P 500 Index") and the group of companies included in the Crude Petroleum and Natural Gas Standard Industrial Classification code ("the SIC Code"). The graph was prepared based on the following assumptions:

- $100 was invested on December 31, 2003 in Devon's common stock, the S&P 500 Index and the SIC Code, and
- Dividends have been reinvested subsequent to the initial investment.

Comparison of 5-Year Cumulative Total Return
Devon, S&P 500 Index and SIC Code



	2003	2004	2005	2006	2007	2008
Devon	$100.00	$136.78	$221.00	$238.82	$318.85	$237.26
S&P 500	$100.00	$110.88	$116.33	$134.70	$142.10	$89.53
SIC Code	$100.00	$127.03	$182.51	$237.31	$333.59	$195.20

The graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

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,				
	2008	2007	2006	2005	2004
	(In millions, except per share data, ratios, prices and per Boe amounts)				
Operating Results					
Total revenues	$15,211	$11,362	$ 9,767	$10,027	$ 8,549
Total expenses and other income, net(1)	19,244	7,138	6,197	5,649	5,490
(Loss) earnings from continuing operations before income taxes	(4,033)	4,224	3,570	4,378	3,059
Total income tax (benefit) expense	(954)	1,078	936	1,481	970
(Loss) earnings from continuing operations	(3,079)	3,146	2,634	2,897	2,089
Earnings from discontinued operations	931	460	212	33	97
Net (loss) earnings	$(2,148)	$ 3,606	$ 2,846	$ 2,930	$ 2,186
Net (loss) earnings applicable to common stockholders	$(2,153)	$ 3,596	$ 2,836	$ 2,920	$ 2,176
Basic net (loss) earnings per share:					
(Loss) earnings from continuing operations	$ (6.95)	$ 7.05	$ 5.94	$ 6.31	$ 4.31
Earnings from discontinued operations	2.10	1.03	0.48	0.07	0.20
Net (loss) earnings	$ (4.85)	$ 8.08	$ 6.42	$ 6.38	$ 4.51
Diluted net (loss) earnings per share:					
(Loss) earnings from continuing operations	$ (6.95)	$ 6.97	$ 5.87	$ 6.19	$ 4.19
Earnings from discontinued operations	2.10	1.03	0.47	0.07	0.19
Net (loss) earnings	$ (4.85)	$ 8.00	$ 6.34	$ 6.26	$ 4.38
Cash dividends per common share	$ 0.64	$ 0.56	$ 0.45	$ 0.30	$ 0.20
Weighted average common shares outstanding — basic	444	445	442	458	482
Weighted average common shares outstanding — diluted	444	450	448	470	499
Ratio of earnings to fixed charges(1)(2)	N/A	8.78	8.08	8.34	6.65
Ratio of earnings to combined fixed charges and preferred stock dividends(1)(2)	N/A	8.54	7.85	8.13	6.48
Cash Flow Data					
Net cash provided by operating activities	$ 9,408	$ 6,651	$ 5,993	$ 5,612	$ 4,816
Net cash used in investing activities	$ (6,873)	$ (5,714)	$(7,449)	$ (1,652)	$(3,634)
Net cash (used in) provided by financing activities	$ (3,408)	$ (371)	$ 593	$ (3,543)	$(1,001)
Production, Price and Other Data(3)					
Production:					
Oil (MMBbls)	53	55	42	46	54
Gas (Bcf)	940	863	808	819	883
NGLs (MMBbls)	28	26	23	24	24
Total (MMBoe)(4)	238	224	200	206	225
Realized prices without hedges:					
Oil (per Bbl)	$ 86.22	$ 63.98	$ 57.39	$ 48.01	$ 36.42
Gas (per Mcf)	$ 7.73	$ 5.97	$ 6.03	$ 7.08	$ 5.37
NGLs (per Bbl)	$ 44.08	$ 37.76	$ 32.10	$ 29.05	$ 23.06
Combined (per Boe)(4)	$ 54.97	$ 42.90	$ 40.19	$ 42.18	$ 32.26
Production and operating expenses per Boe(4)	$ 11.52	$ 9.68	$ 8.81	$ 7.65	$ 6.38
Depreciation, depletion and amortization of oil and gas properties per Boe(4)	$ 13.68	$ 11.85	$ 10.27	$ 8.56	$ 8.15

	December 31,				
	2008	2007	2006	2005	2004
			(In millions)		
Balance Sheet Data					
Total assets(1)	$31,908	$41,456	$35,063	$30,273	$30,025
Long-term debt	$ 5,661	$ 6,924	$ 5,568	$ 5,957	$ 7,031
Stockholders' equity	$17,060	$22,006	$17,442	$14,862	$13,674

(1) During 2008, we recorded a $10.4 billion ($7.1 billion after income taxes) noncash reduction of the carrying values of certain oil and gas properties as discussed in Note 13 of the consolidated financial statements.

(2) 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.

For the year 2008, earnings were inadequate to cover fixed charges and combined fixed charges and preferred stock dividends by $4.1 billion primarily due to the noncash reduction of the carrying values of certain oil and gas properties referred to above.

(3) 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 excludes the effects of unrealized and realized gains and losses from our derivative financial instruments.

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.

(4) 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 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 2008 Results
- Business and Industry 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
- Modernization of Oil and Gas Reporting

- Forward-Looking Estimates

Overview of Business

Devon is one of the world's leading independent oil and gas exploration and production companies. Our operations are focused primarily in the United States and Canada. However, we also explore for and produce oil and gas in select international areas, including Azerbaijan, Brazil and China. We also own natural gas pipelines and treatment facilities in many of our producing areas, making us one of North America's larger processors of natural gas liquids.

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. Our production mix in 2008 was approximately 65% gas and 35% oil and NGLs such as propane, butane and ethane. We are currently producing 2.6 Bcf of gas each day, or about 3% 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 building oil and gas reserves and production, exercising capital discipline and controlling operating costs. We also use our marketing and midstream operations to improve our overall performance. Finally, we must continually preserve our financial flexibility to achieve sustainable, long-term success.

- **Reserves and production growth** — 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. Additionally, 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 have historically deployed 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. The inverse is also true.

  Approximately two-thirds of our planned 2009 investment in capital projects is dedicated to a foundation of low-risk projects primarily in North America. The remainder of our capital has been identified for longer-term projects primarily in new unconventional natural gas plays in several United States onshore regions, as well as continued offshore activities 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 changes 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.

- **Marketing & midstream performance improvement** — We enhance the value of our oil and gas operations with our marketing and midstream business. By efficiently gathering and processing oil, gas and NGL production, our midstream operations contribute to our strategies to grow reserves and production and manage expenditures. Additionally, by effectively marketing our production, we maximize the prices received for our oil, gas and NGL production in relation to market prices. This is important because our profitability is highly dependent on market prices. 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 sometimes utilize financial hedging arrangements and fixed-price physical delivery contracts. As of February 16, 2009, approximately 10% of our 2009 gas production is associated with financial price collars or fixed-price contracts.

- **Financial flexibility preservation** — As mentioned, commodity prices have been and will continue to be volatile and will continue to impact our profitability and cash flow. We understand this fact and manage our debt levels accordingly to preserve our liquidity and financial flexibility. We generally operate within the cash flow generated by our operations. However, during periods of low commodity prices, we may use our balance sheet strength to access debt or equity markets, allowing us to preserve our business and maintain momentum until markets recover. When prices improve, we can utilize excess operating cash flow to repay debt and invest in our activities that not only maintain but also increase value per share.

Overview of 2008 Results

2008 was a year of contrasts. By many measures, 2008 was the best year in our history. Throughout the year, we achieved key operational successes as we continued to execute on our operating strategy. We drilled a record amount of wells with a 98% success rate and delivered a record amount of operating cash flow. As a result of our operational success and rising commodity prices, in the third quarter of 2008, we reported the largest quarterly earnings in our history.

However, sharp declines in oil, gas and NGL prices during the fourth quarter caused us to record noncash impairments of our oil and gas properties totaling $7.1 billion, net of income taxes. Due to this impairment charge, our record earnings in the third quarter were immediately followed by a record quarterly loss in the fourth quarter.

We account for our oil and gas properties using the full cost accounting method. Full cost impairment calculations require the use of quarter-end prices. As a result, such calculations do not indicate the true fair value of the underlying reserves because of the volatile nature of commodity prices. In fact, the SEC recently recognized that impairment calculations based upon prices as of a single day of the year are not ideal and issued new rules that require the use of 12-month average prices for impairment calculations. These new rules will be effective for our 2009 year-end reporting. Had these new rules been in place as of December 31, 2008, we would not have recognized the noncash impairments.

Key measures of our performance for 2008, as well as certain operational developments, are summarized below:

- Production grew 6% over 2007, to 238 million Boe.
- The combined realized price for oil, gas and NGLs per Boe increased 28% to $54.97.
- Marketing and midstream operating profit climbed to a record $668 million.
- Production and operating costs increased 19% per Boe due to our large-scale projects at Jackfish in Canada and Polvo in Brazil, which are experiencing higher per-unit costs while they are in the early phases of production.
- Operating cash flow reached $9.4 billion, representing a 41% increase over 2008.
- Capitalized costs incurred in our oil and gas exploration and development activities were $9.8 billion in 2008.

Despite these positive results, we reported a net loss of $2.1 billion, or $4.85 per diluted share, for 2008. This represents a $5.8 billion decrease in earnings compared to 2007, which was primarily attributable to the $7.1 billion, net of income tax, property impairments recognized in the fourth quarter of 2008.

From an operational perspective, we completed another successful year with the drill-bit. We drilled a record 2,441 gross wells with an overall 98% rate of success. This success rate enabled us to increase proved reserves by 584 million Boe, which represented nearly 2 and one half times our 2008 production. Consistent with our two-pronged operating strategy, 93% 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 2008. In the Gulf of Mexico, we continued to build off prior years' successful drilling results with our deepwater exploration and development program. At Cascade, we commenced drilling the first of two initial producing wells and continued work on production facilities and subsea equipment. We also continued progressing toward commercial development of our other previous discoveries in the Lower Tertiary trend of the Gulf of Mexico. We also added some 800,000 net undeveloped acres to our lease inventory, positioning us with more than 1.4 million net acres in four emerging unconventional natural gas plays in the United States.

In 2008, we substantially completed our African divestiture program. We have now sold all our oil and gas producing properties in Africa, generating aggregate proceeds of $2.2 billion after income taxes.

Additionally, on October 31, 2008, we transferred our 14.2 million shares of Chevron common stock to Chevron. In exchange, we received Chevron's interest in the Drunkard's Wash coalbed natural gas field in east-central Utah and $280 million in cash. The field has approximately 51,000 net acres and had net production of about 40 million cubic feet of natural gas equivalent per day at the time of the exchange.

Even with the fourth quarter net loss, we strengthened our financial position during 2008. We used cash on hand, operating cash flow, divestiture proceeds and Chevron exchange proceeds to fund $9.4 billion of capital expenditures, reduce debt by $2.1 billion, repurchase $815 million of common and preferred stock and pay $289 million of dividends. At the end of 2008, we had $379 million of cash, and as of January 31, 2009, we had $3.1 billion of availability under our credit lines.

Business and Industry Outlook

As previously mentioned, our current and future earnings depend largely on our ability to replace and grow oil and gas reserves, increase production and exert cost discipline. We must also manage commodity pricing risks to achieve long-term success.

Oil and gas prices reached historical high levels in recent years and during the first half of 2008. We have utilized the record operating cash flows generated by high commodity prices, along with proceeds from our African divestitures, to, among other uses, repay outstanding debt. During 2008 and 2007, we repaid outstanding debt totaling $3.9 billion. During this same period, we also repurchased $1.0 billion of our common stock and redeemed $150 million of preferred stock. High commodity prices have also been a key factor driving cost increases in the oil and gas industry that have exceeded general inflation trends. We are no different from others in the industry in that we have been impacted by these cost increases.

As we exited the third quarter of 2008, oil and gas prices had declined sharply from their recent record levels and declined even further through the end of 2008. In addition, recent problems in the credit markets, steep stock market declines, financial institution failures and government bail-outs provide evidence of a weakening United States and global economy. As a result of the market turmoil and price decreases, oil and gas companies with high debt levels and lack of liquidity have been, and will continue to be, negatively impacted. However, we do not consider ourselves to be in this category based on our current debt level and credit availability.

The only constant in the oil and gas business is volatility, and 2008 presented us with some remarkable reminders. Our response to the current environment is to dramatically cut capital expenditures. We are budgeting exploration and development capital at $3.5 billion to $4.1 billion for 2009. This is less than half of our 2008 investment in exploration and development. With the addition of non-oil and gas capital and other capitalized costs, we are forecasting total 2009 capital expenditures of $4.7 billion to $5.4 billion.

Assuming average benchmark prices of $45.00 per barrel of crude oil and $5.50 per Mcf of gas, our 2009 capital budget will require deficit spending of about $1 billion. Our philosophy has always been to live roughly within our cash flow, and we clearly will not continue to spend at this rate in future years without some improvement in oil and gas prices. However, in order to preserve our business and maintain a level of momentum that will allow us to take advantage of stronger prices when markets recover, we believe it is prudent to use our balance sheet strength to fund this additional $1 billion of spending in 2009. If we see further price weakness in 2009 or beyond, we are prepared to make further cuts.

We are dramatically decreasing our activity across most of our near-term development projects in North America. We will continue activity at a rate that will keep us competitive, but at a far lower level than in 2008. However, we are going to continue the momentum of some of our longer-term growth projects that will position us to bring on new production when oil and gas demand recovers. We are continuing to fund the second phase of our operations at Jackfish and the evaluation and development of our Lower Tertiary assets in the Gulf of Mexico. We will also move forward with the evaluation of our sizable acreage positions in several emerging natural gas plays in North America.

This decrease in development drilling will impact our oil and gas production. We are currently forecasting our 2009 production will be essentially flat with that of 2008.

We are fortunate that we are positioned to withstand the downturn in the global economy and the resulting weakness in oil and gas prices. The strength of our balance sheet and the quality of our oil and gas properties position us to emerge from the current environment and prosper in the future.

Results of Operations

Revenues

Changes in oil, gas and NGL production, prices and revenues from 2006 to 2008 are shown in the following tables. The amounts for all periods presented exclude results from our Egyptian and West African operations which are presented as discontinued operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

	Total				
	Year Ended December 31,				
	2008	2008 vs 2007(2)	2007	2007 vs 2006(2)	2006
Production					
Oil (MMBbls)	53	−3%	55	+29%	42
Gas (Bcf)	940	+9%	863	+7%	808
NGLs (MMBbls)	28	+10%	26	+10%	23
Total (MMBoe)(1)	238	+6%	224	+12%	200
Realized prices without hedges					
Oil (per Bbl)	$ 86.22	+35%	$63.98	+11%	$57.39
Gas (per Mcf)	$ 7.73	+29%	$ 5.97	−1%	$ 6.03
NGLs (per Bbl)	$ 44.08	+17%	$37.76	+18%	$32.10
Combined (per Boe)(1)	$ 54.97	+28%	$42.90	+7%	$40.19
Revenues ($ in millions)					
Oil	$ 4,567	+31%	$3,493	+44%	$2,434
Gas	7,263	+41%	5,149	+6%	4,874
NGLs	1,243	+28%	970	+30%	749
Total	$13,073	+36%	$9,612	+19%	$8,057

	Domestic				
	Year Ended December 31,				
	2008	2008 vs 2007(2)	2007	2007 vs 2006(2)	2006
Production					
Oil (MMBbls)	17	−9%	19	−3%	19
Gas (Bcf)	726	+14%	635	+12%	566
NGLs (MMBbls)	24	+13%	22	+15%	19
Total (MMBoe)(1)	162	+11%	146	+10%	132
Realized prices without hedges					
Oil (per Bbl)	$98.83	+43%	$69.23	+11%	$62.23
Gas (per Mcf)	$ 7.59	+29%	$ 5.87	−2%	$ 6.02
NGLs (per Bbl)	$41.21	+14%	$36.11	+23%	$29.42
Combined (per Boe)(1)	$50.55	+27%	$39.77	+2%	$39.03
Revenues ($ in millions)					
Oil	$1,698	+29%	$1,313	+8%	$1,218
Gas	5,511	+48%	3,728	+9%	3,407
NGLs	997	+29%	773	+41%	548
Total	$8,206	+41%	$5,814	+12%	$5,173

	Canada				
	Year Ended December 31,				
	2008	2008 vs 2007(2)	2007	2007 vs 2006(2)	2006
Production					
Oil (MMBbls)	22	+34%	16	+26%	13
Gas (Bcf)	212	−6%	227	−6%	241
NGLs (MMBbls)	4	−6%	4	−9%	4
Total (MMBoe)(1)	61	+5%	58	+1%	58
Realized prices without hedges					
Oil (per Bbl)	$71.04	+43%	$49.80	+6%	$46.94
Gas (per Mcf)	$ 8.17	+31%	$ 6.24	+3%	$ 6.05
NGLs (per Bbl)	$61.45	+33%	$46.07	+8%	$42.67
Combined (per Boe)(1)	$57.65	+39%	$41.51	+6%	$39.21
Revenues ($ in millions)					
Oil	$1,535	+91%	$ 804	+33%	$ 603
Gas	1,733	+23%	1,410	−3%	1,456
NGLs	246	+25%	197	−2%	201
Total	$3,514	+46%	$2,411	+7%	$2,260

	International				
	Year Ended December 31,				
	2008	2008 vs 2007(2)	2007	2007 vs 2006(2)	2006
Production					
Oil (MMBbls)	14	−27%	20	+95%	10
Gas (Bcf)	2	+29%	1	−6%	1
NGLs (MMBbls)	—	N/M	—	N/M	—
Total (MMBoe)(1)	15	−26%	20	+92%	10
Realized prices without hedges					
Oil (per Bbl)	$94.05	+33%	$70.60	+15%	$61.35
Gas (per Mcf)	$ 8.27	+33%	$ 6.22	+3%	$ 6.05
NGLs (per Bbl)	$ —	N/M	$ —	N/M	$ —
Combined (per Boe)(1)	$92.91	+33%	$70.11	+16%	$60.60
Revenues ($ in millions)					
Oil	$1,334	−3%	$1,376	+125%	$ 613
Gas	19	+72%	11	−3%	11
NGLs	—	N/M	—	N/M	—
Total	$1,353	−2%	$1,387	+122%	$ 624

(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 gas and oil, which rate is not necessarily indicative of the relationship of gas and oil prices. NGL volumes are converted to Boe on a one-to-one basis with oil.

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

N/M — Not meaningful.

The volume and price changes in the tables above caused the following changes to our oil, gas and NGL sales between 2006 and 2008.

	Oil	Gas	NGL	Total
		(In millions)		
2006 sales	$2,434	$4,874	$ 749	$ 8,057
Changes due to volumes	700	327	76	1,103
Changes due to prices	359	(52)	145	452
2007 sales	3,493	5,149	970	9,612
Changes due to volumes	(104)	462	95	453
Changes due to prices	1,178	1,652	178	3,008
2008 sales	$4,567	$7,263	$1,243	$13,073

Oil Sales

2008 vs. 2007 Oil sales increased $1.2 billion as a result of a 35% increase in our realized price without hedges. The average NYMEX West Texas Intermediate index price increased 38% during the same time period, accounting for the majority of the increase.

Oil sales decreased $104 million due to a two million barrel decrease in production. Our International production decreased approximately six million barrels due to reaching certain cost recovery thresholds of our carried interest in Azerbaijan. We also deferred 0.5 million barrels of oil production due to hurricanes. These decreases were partially offset by additional production resulting from increased development activity at our Jackfish and Lloydminster areas in Canada and at our Polvo development in Brazil.

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

Oil sales increased $359 million as a result of an 11% increase in our realized price without hedges. The average NYMEX West Texas Intermediate index price increased 9% during the same time period, accounting for the majority of the increase.

Gas Sales

2008 vs. 2007 Gas sales increased $1.7 billion as a result of a 29% increase in our realized price without hedges. This increase was largely due to increases in the regional index prices upon which our gas sales are based.

A 77 Bcf increase in production during 2008 caused gas sales to increase by $462 million. Our drilling and development program in the Barnett Shale field in north Texas contributed 83 Bcf to the gas production increase. This increase and the effect of new drilling and development in our other North American properties were partially offset by natural production declines and the deferral of seven Bcf of production in 2008 due to hurricanes.

2007 vs. 2006 A 55 Bcf increase in production caused gas sales to increase by $327 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 without hedges caused gas sales to decrease $52 million in 2007.

Net (Loss) Gain on Oil and Gas Derivative Financial Instruments

The following tables provide financial information associated with our oil and gas hedges from 2006 to 2008. The first table presents the cash settlements and unrealized gains and losses recognized as components of our revenues. The subsequent tables present our oil, gas and NGL prices with, and without, the effects of the cash settlements from 2006 to 2008. The prices do not include the effects of unrealized gains and losses.

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Cash settlements:			
Gas price swaps	$(203)	$ 38	$—
Gas price collars	(221)	2	—
Oil price collars	27	—	—
Total cash settlements (paid) received	(397)	40	—
Unrealized gains (losses) on fair value changes:			
Gas price swaps	(12)	(22)	34
Gas price collars	255	(4)	4
Total unrealized gains (losses) on fair value changes	243	(26)	38
Net (loss) gain on oil and gas derivative financial instruments	$(154)	$ 14	$38

	Year Ended December 31, 2008			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$86.22	$ 7.73	$44.08	$54.97
Cash settlements of hedges	0.51	(0.45)	—	(1.67)
Realized price, including cash settlements	$86.73	$ 7.28	$44.08	$53.30

	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

	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

Our oil and gas derivative financial instruments include price swaps and costless price collars. For the price swaps, we receive a fixed price for our production and pay a variable market price to the contract counterparty. The costless price collars 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 cash-settle the difference with the counterparty. Cash settlements as presented in the tables above represent realized losses or gains related to our price swaps and collars.

During 2008, we received $27 million, or $0.51 per Bbl, from counterparties to settle our oil price collars. We paid $424 million, or $0.45 per Mcf, to counterparties during 2008 to settle our gas price swaps and collars. During 2007, we received $40 million, or $0.04 per Mcf, from counterparties to settle our gas price swaps and collars. In 2006, cash payments related to our gas price swaps and collars were completely offset by cash receipts.

In addition to recognizing these cash settlement effects, we also recognize unrealized changes in the fair values of our oil and gas derivative instruments in each reporting period. We estimate the fair values of our oil and gas derivative financial instruments primarily by using internal discounted cash flow calculations. From time to time, we validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers.

The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Based on the amount of volumes subject to price swaps and collars at December 31, 2008, a 10% increase in these forward curves would have decreased our 2008 unrealized gain for our oil and gas collar derivative financial instruments by approximately $54 million. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with eight separate counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below "investment grade". The threshold for collateral posting decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of December 31, 2008, the credit ratings of all our counterparties were investment grade.

The $243 million net unrealized gain recognized in 2008 was primarily the result of a decrease in the Inside FERC Henry Hub forward curve subsequent to our contract trade dates.

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 2006 and 2008 are shown in the table below.

	Year Ended December 31,				
	2008	2008 vs 2007(1)	2007	2007 vs 2006(1)	2006
	($ in millions)				
Marketing and midstream:					
Revenues	$2,292	+32%	$1,736	+4%	$1,672
Operating costs and expenses	1,624	+32%	1,227	−1%	1,236
Operating profit	$ 668	+31%	$ 509	+17%	$ 436

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

2008 vs. 2007 Marketing and midstream revenues increased $556 million and operating costs and expenses increased $397 million, causing operating profit to increase $159 million. Both revenues and expenses increased primarily due to higher natural gas and NGL prices and increased gas pipeline throughput.

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.

Oil, Gas and NGL Production and Operating Expenses

The details of the changes in oil, gas and NGL production and operating expenses between 2006 and 2008 are shown in the table below.

	Year Ended December 31,				
	2008	2008 vs 2007(1)	2007	2007 vs 2006(1)	2006
Production and operating expenses ($ in millions):					
Lease operating expenses	$2,217	+21%	$1,828	+28%	$1,425
Production taxes	522	+53%	340	—	341
Total production and operating expenses	$2,739	+26%	$2,168	+23%	$1,766
Production and operating expenses per Boe:					
Lease operating expenses	$ 9.32	+14%	$ 8.16	+15%	$ 7.11
Production taxes	2.20	+44%	1.52	−11%	1.70
Total production and operating expenses per Boe	$11.52	+19%	$ 9.68	+10%	$ 8.81

(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")

2008 vs. 2007 LOE increased $389 million in 2008. The largest contributor to this increase, as well as the increase in LOE per Boe, was higher per-unit costs associated with new thermal heavy oil production from our Jackfish operations in Canada as well as new oil production from Brazil. As these large-scale projects are in the early phases of production, per-unit operating costs are higher than the per-unit costs for our overall portfolio of producing properties. LOE also increased $112 million due to our 6% growth in production. Additionally, LOE increased $31 million due to damages to certain of our facilities and transportation systems caused by Hurricane Ike in the third quarter of 2008. These hurricane damages also contributed to the increase in LOE per Boe.

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 effects of inflationary pressure driven by increased competition for field services. Increased demand for these services continued to drive costs higher for materials, equipment and personnel used in both recurring activities as well as well-workover projects during 2007. Furthermore, changes in the exchange rate between the U.S. and Canadian dollar also caused LOE to increase $40 million.

Production Taxes

The following table details the changes in production taxes between 2006 and 2008. 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)
2006 production taxes	$341
Change due to revenues	65
Change due to rate	(66)
2007 production taxes	340
Change due to revenues	123
Change due to rate	59
2008 production taxes	$522

2008 vs. 2007 Production taxes increased $59 million due to an increase in the effective production tax rate in 2008. Our higher production tax rates in 2008 were largely due to higher rates in China, which are based on the level of crude oil prices. As our realized price for crude oil sales in China increases or decreases, production tax rates will increase or decrease in a like manner.

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.

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 2006 and 2008 are shown in the table below.

	Year Ended December 31,				
	2008	2008 vs 2007(1)	2007	2007 vs 2006(1)	2006
Total production volumes (MMBoe)	238	+6%	224	+12%	200
DD&A rate ($ per Boe)	$13.68	+15%	$11.85	+15%	$10.27
DD&A expense ($ in millions)	$3,253	+23%	$2,655	+29%	$2,058

(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 in DD&A of oil and gas properties between 2006 and 2008 due to the changes in production volumes and DD&A rate presented in the table above.

	(In millions)
2006 DD&A	$2,058
Change due to volumes	242
Change due to rate	355
2007 DD&A	2,655
Change due to volumes	164
Change due to rate	434
2008 DD&A	$3,253

2008 vs. 2007 Oil and gas property related DD&A increased $434 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 2008 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 reductions in reserve estimates due to lower 2008 year-end commodity prices and the transfer of previously unproved costs to the depletable base as a result of 2008 drilling activities. In addition to the impact from the higher 2008 rate, our 6% production increase caused oil and gas property related DD&A expense to increase $164 million.

2007 vs. 2006 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 net effect of these increases was partially offset by higher reserve estimates due to higher 2007 year-end commodity prices. In addition to the impact from the higher 2007 rate, our 12% production increase caused oil and gas property related DD&A expense to increase $242 million.

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 offset by two 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,				
	2008	2008 vs 2007(1)	2007	2007 vs 2006(1)	2006
	($ in millions)				
Gross G&A	$1,188	+25%	$ 947	+26%	$ 749
Capitalized G&A	(406)	+30%	(312)	+28%	(243)
Reimbursed G&A	(129)	+6%	(122)	+12%	(109)
Net G&A	$ 653	+27%	$ 513	+29%	$ 397

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

2008 vs. 2007 Gross G&A increased $241 million. The largest contributors to the increase were higher employee compensation and benefits costs. These cost increases, which were largely related to our growth and industry inflation during most of 2008, caused gross G&A to increase $184 million. Of this increase, $79 million related to higher stock compensation.

Stock compensation increased $27 million in the second quarter of 2008 due to a modification of the share-based compensation arrangements for certain of our executives. The modified compensation arrangements provide that executives who meet certain years-of-service and age criteria can retire and continue vesting in outstanding share-based grants. As a condition to receiving the benefits of these modifications, the executives must agree not to use or disclose Devon's confidential information and not to solicit Devon's employees and customers. The executives are required to agree to these conditions at retirement and again in each subsequent year until all grants have vested.

Although this modification does not accelerate the vesting of the executives' grants, it does accelerate the expense recognition as executives approach the years-of-service and age criteria. When the modification was made in the second quarter of 2008, certain executives had already met the years-of-service and age criteria. As a result, we recognized $27 million of share-based compensation expense in the second quarter of 2008 related to this modification. In the fourth quarter of 2008, we recognized an additional $16 million of stock compensation for grants made to these executives. The additional expenses would have been recognized in future reporting periods if the modification had not been made and the executives continued their employment at Devon.

The higher employee compensation and benefits costs, exclusive of the accelerated stock compensation expense, were also the primary factors that caused the $94 million increase in capitalized G&A in 2008.

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 growth and industry inflation during 2007, 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.

The factors discussed above were also the primary factors that caused the $69 million increase in capitalized G&A in 2007.

Interest Expense

The following schedule includes the components of interest expense between 2006 and 2008.

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Interest based on debt outstanding	$ 426	$ 508	$486
Capitalized interest	(111)	(102)	(79)
Other interest	14	24	14
Total interest expense	$ 329	$ 430	$421

Interest based on debt outstanding decreased $82 million from 2007 to 2008. This decrease was largely due to lower average outstanding amounts for commercial paper and credit facility borrowings in 2008 than in 2007. The decrease in borrowings resulted largely from the use of proceeds from our West African divestiture program and cash flow from operations to repay all commercial paper and credit facility borrowings in the second quarter of 2008. Additionally, we retired debentures with a face value of $652 million during 2008, primarily during the third quarter.

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.

Capitalized interest increased from 2007 to 2008 primarily due to higher cumulative costs related to large-scale development projects in the Gulf of Mexico and Brazil, partially offset by lower capitalized interest resulting from the completion of the Access Pipeline in Canada.

Capitalized interest increased from 2006 to 2007 primarily due to higher cumulative costs related to large-scale development projects in the Gulf of Mexico and Brazil. 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 also contributed to the increase.

Change in Fair Value of Other Financial Instruments

The details of the changes in fair value of other financial instruments between 2006 and 2008 are shown in the table below.

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Losses (gains) from:			
Chevron common stock	$ 363	$(281)	$ —
Option embedded in exchangeable debentures	(109)	248	181
Interest rate swaps — fair value changes	(104)	(1)	(3)
Interest rate swaps — settlements	(1)	—	—
Total	$ 149	$ (34)	$178

Chevron Common Stock and Related Embedded Option

Prior to 2007, we recognized unrealized changes in the fair values of our investment in 14.2 million shares of Chevron common stock as part of other comprehensive income. 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. On October 31, 2008, we exchanged these shares of Chevron common stock for Chevron's interest in the Drunkard's Wash properties located in east-central Utah and $280 million in cash. In accordance with the terms of the exchange, the fair value of our investment in the Chevron shares was estimated to be $67.71 per share on the exchange date. Prior to the exchange of these shares, we calculated the fair value of our investment in Chevron common stock using Chevron's published market price.

We also recognized unrealized changes in the fair value of the conversion option embedded in the debentures exchangeable into shares of Chevron common stock. The embedded option was not actively traded in an established market. Therefore, we estimated its fair value using quotes obtained from a broker for trades occurring near the valuation date. Since the exchangeable debentures were retired in August 2008, we will not recognize any future gains or losses from the embedded option.

The loss during 2008 on our investment in Chevron common stock was directly attributable to a $25.62 per share decrease in the estimated fair value while we owned Chevron's common stock during the year. The gain on the embedded option during 2008 was directly attributable to the change in fair value of the Chevron common stock from January 1, 2008 to the maturity date of August 15, 2008. The gain on our investment in Chevron common stock and loss on the embedded option during 2007 were directly attributable to a $19.80 increase in the price per share of Chevron's common stock during 2007.

Interest Rate Swaps

We also recognize unrealized changes in the fair values of our interest rate swaps each reporting period. We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest-rate yields. From time to time, we validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers.

The most significant variable to our cash flow calculations is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by a third party. Based on the notional amount subject to the interest rate swaps at December 31, 2008, a 10% increase in these forward curves would have decreased our 2008 unrealized gain for our interest rate swaps by approximately $3 million.

During 2008, we recorded a $104 million unrealized gain as a result of changes in interest rates subsequent to the trade dates of our contracts.

As previously discussed for our commodity derivative contracts, counterparty credit risk is also a component of interest rate derivative valuations. We have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our interest rate derivative contracts are held with five separate counterparties and have cash collateral posting requirements. Additionally, the credit ratings of all our counterparties were investment grade as of December 31, 2008.

Reduction of Carrying Value of Oil and Gas Properties

During 2008 and 2006, we reduced the carrying values of certain of our 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,			
	2008		2006	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
Full cost ceiling limitations:				
United States	$ 6,538	$4,168	$—	$—
Canada	3,353	2,488	—	—
Brazil	437	437	—	—
Russia	36	17	20	10
Indonesia	15	5	—	—
Unsuccessful exploratory activities — Brazil	—	—	16	16
Total	$10,379	$7,115	$36	$26

2008 Reductions

The 2008 reductions were all recognized in the fourth quarter of 2008 and resulted primarily from a significant decrease in each country's full cost ceiling. The lower ceiling values largely resulted from the effects of sharp declines in oil, gas and NGL prices compared to previous quarter-end prices. To demonstrate this decline, the December 31, 2008 and September 30, 2008 weighted average wellhead prices for the United States, Canada and Brazil are presented in the following table.

	December 31, 2008			September 30, 2008		
Country	Oil	Gas	NGLs	Oil	Gas	NGLs
United States	$42.21	$4.68	$16.16	$97.62	$5.28	$38.00
Canada	$23.23	$5.31	$20.89	$59.72	$6.00	$62.78
Brazil	$26.61	N/A	N/A	$81.56	N/A	N/A

N/A — Not applicable.

The December 31, 2008 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for gas. The September 30, 2008, wellhead prices in the table compare to the NYMEX cash price of $100.64 per Bbl for crude oil and the Henry Hub spot price of $7.12 per MMBtu for gas.

2006 Reductions

As a result of a decline in the estimated future net revenues, the carrying value of our Russian oil and gas 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.

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.

Other Income, Net

The following schedule includes the components of other income between 2006 and 2008.

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Interest and dividend income	$ 75	$89	$100
Hurricane insurance proceeds	162	—	—
Other	(13)	9	15
Total	$224	$98	$115

Interest and dividend income decreased from 2007 to 2008 primarily due to a decrease in interest rates, as well as a decrease in dividends received on our investment in Chevron common stock. 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.

We suffered insured damages in the third quarter of 2005 related to hurricanes that struck the Gulf of Mexico. During 2006 and 2007, we received $480 million as a full settlement of the amount due from our primary insurers and certain of our secondary insurers. During the fourth quarter of 2008, we received $106 million as full settlement of the amount due from our remaining secondary insurers. Our claims under our then existing insurance arrangements included both physical damages and business interruption claims. As of December 31, 2008, we had utilized $424 million of these proceeds as reimbursement of repair costs and deductible amounts, resulting in excess recoveries. The $162 million of excess recoveries was recorded as other income during 2008.

Income Taxes

The following table presents our total income tax (benefit) 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 2006 to 2008, and differ from the U.S. statutory rate, are discussed below.

	Year Ended December 31,		
	2008	2007	2006
Total income tax (benefit) expense (In millions)	$(954)	$1,078	$936
U.S. statutory income tax rate	(35)%	35%	35%
Repatriations and tax policy election changes	8%	—	—
Canadian statutory rate reductions	—	(6)%	(7)%
Texas income-based tax	—	—	1%
Other, primarily taxation on foreign operations	3%	(3)%	(3)%
Effective income tax (benefit) expense rate	(24)%	26%	26%

For 2008, our effective income tax rate differed from the U.S. statutory income tax rate largely due to two related factors. First, during 2008, we repatriated $2.6 billion from certain foreign subsidiaries to the

United States. Second, we made certain tax policy election changes in the second quarter of 2008 to minimize the taxes we otherwise would pay for the cash repatriations, as well as the taxable gains associated with the sales of assets in West Africa. As a result of the repatriation and tax policy election changes, we recognized additional tax expense of $307 million during 2008. Of the $307 million, $290 million was recognized as current income tax expense, and $17 million was recognized as deferred tax expense. Excluding the $307 million of additional tax expense, our effective income tax benefit rate would have been 32% for 2008.

In 2008, 2007 and 2006, deferred income taxes were reduced $7 million, $261 million and $243 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.

Earnings From Discontinued Operations

Our discontinued operations consist of our operations in Egypt and West Africa, including Equatorial Guinea, Cote d'Ivoire, Gabon and other countries in the region.

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 the second quarter of 2008, we sold our assets and terminated our operations in certain West African countries, consisting primarily of Equatorial Guinea and Gabon. As a result of the sales, we recognized gains totaling $736 million ($674 million after income taxes) in 2008 from proceeds of $2.4 billion ($1.7 billion net of income taxes and purchase price adjustments).

In the third quarter of 2008, we sold our assets and terminated our operations in Cote d'Ivoire. As a result of this sale, we recognized a gain of $83 million ($95 million after income taxes) in 2008 from proceeds of $205 million ($163 million net of income taxes and purchase price adjustments).

With the Cote d'Ivoire transaction, we completed the divestiture of all our oil and gas producing properties in Africa. The Africa divestitures generated just over $3.0 billion of sales proceeds. After income taxes and purchase price adjustments, such proceeds totaled $2.2 billion and generated after-tax gains of $0.8 billion.

Following are the components of earnings from discontinued operations between 2006 and 2008.

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Earnings from discontinued operations before income taxes	$1,131	$696	$464
Income tax expense	200	236	252
Earnings from discontinued operations	$ 931	$460	$212

2008 vs. 2007 Earnings from discontinued operations increased $471 million in 2008. Earnings in 2008 included $769 million of after-tax divestiture gains as discussed above. This was $679 million more than the $90 million after-tax gain from the sale of our Egyptian operations in 2007. The increase in 2008 was partially offset by a decrease of $212 million from reduced earnings due to the timing of the 2008 and 2007 divestitures.

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).

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 2006 to 2008. 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.

	2008	2007 (In millions)	2006
Sources of cash and cash equivalents:			
Operating cash flow — continuing operations	$ 9,273	$ 6,162	$ 5,374
Sales of property and equipment	117	76	40
Net credit facility borrowings	—	1,450	—
Net commercial paper borrowings	1	—	1,808
Net decrease in short-term investments	250	202	106
Stock option exercises	116	91	73
Proceeds from exchange of Chevron stock	280	—	—
Cash received from discontinued operations	1,898	—	—
Other	60	44	36
Total sources of cash and cash equivalents	11,995	8,025	7,437
Uses of cash and cash equivalents:			
Capital expenditures	(9,375)	(6,158)	(7,346)
Net credit facility repayments	(1,450)	—	—
Net commercial paper repayments	—	(804)	—
Debt repayments	(1,031)	(567)	(862)
Repurchases of common stock	(665)	(326)	(253)
Redemption of preferred stock	(150)	—	—
Dividends	(289)	(259)	(209)
Total uses of cash and cash equivalents	(12,960)	(8,114)	(8,670)
Decrease from continuing operations	(965)	(89)	(1,233)
Increase from discontinued operations, net of distributions to continuing operations	92	655	370
Effect of foreign exchange rates	(116)	51	13
Net (decrease) increase in cash and cash equivalents	$ (989)	$ 617	$ (850)
Cash and cash equivalents at end of year	$ 384	$ 1,373	$ 756
Short-term investments at end of year	$ —	$ 372	$ 574

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 2008. 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 taxes. As a result, our operating cash flow increased 50% during 2008 primarily due to the $3.0 billion increase in oil, gas and NGL revenues, net of commodity hedge settlements, as discussed in the "Results of Operations" section of this report.

During 2008, 2007 and 2006, our capital expenditures were primarily funded by our operating cash flow. In 2006, we used a combination of commercial paper borrowings and proceeds from the sale of short-term investments to fund the $2.0 billion Chief acquisition in June 2006.

Other Sources of Cash

As needed, we utilize cash on hand and access our credit facilities and commercial paper program as sources of cash to supplement the liquidity provided by our operating cash flow. Additionally, we sometimes acquire 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 2008, we reduced our short-term investment balances by $250 million. We also received $280 million from the exchange of our investment in Chevron common stock, $117 million from the sale of non-oil and gas property and equipment and $116 million from stock option exercises. Another significant source of cash was our African divestiture program. In the second and third quarters of 2008, we received $2.6 billion in proceeds ($1.9 billion net of income taxes and purchase price adjustments) from sales of assets located in Equatorial Guinea and other West African countries. Also, in conjunction with these asset sales, we repatriated an additional $2.6 billion of earnings from certain foreign subsidiaries to the United States.

We used these combined sources of cash in 2008 to fund debt repayments, common stock repurchases, redemptions of preferred stock and dividends on common and preferred stock.

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.

Capital Expenditures

Following are the components of our capital expenditures for the years ended 2008, 2007 and 2006.

	2008	2007	2006
		(In millions)	
U.S. Onshore	$5,618	$3,280	$4,477
U.S. Offshore	1,157	687	572
Canada	1,459	1,232	1,492
International	515	439	274
Total exploration and development	8,749	5,638	6,815
Midstream	452	370	356
Other	174	150	175
Total exploration and development	$9,375	$6,158	$7,346

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 $8.7 billion, $5.6 billion and $6.8 billion in 2008, 2007 and 2006, respectively. The 2008 capital expenditures include $2.6 billion related to acquisitions of properties in Texas, Louisiana, Oklahoma and Canada. The 2006 capital expenditures include $2.0 billion related to the acquisition of the Chief properties. Excluding the effect of these acquisitions, the increase in capital expenditures from 2006 to 2008 was due to increased drilling activities in the Barnett Shale, Gulf of Mexico, Carthage, Cana, Woodford Shale, Groesbeck and Washakie areas of the United States, the Lloydminster and Jackfish projects in Canada, and in the Polvo development in Brazil. Expenditures also increased due to inflationary pressure driven by increased competition for field services.

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. The majority of our midstream expenditures from 2006 to 2008 were related to development activities in the Barnett Shale, the Woodford Shale in southeastern Oklahoma and Jackfish in Canada.

Debt Repayments

During 2008, we repaid $1.5 billion in outstanding credit facility borrowings primarily with proceeds received from the sales of assets under our African divestiture program. Also during 2008, virtually all holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock owned by us. The debentures matured on August 15, 2008. In lieu of delivering our shares of Chevron common stock, we exercised our option to pay the exchanging debenture holders cash totaling $1.0 billion. This amount included the retirement of debentures with a book value of $652 million and a $379 million payment of the related embedded derivative option.

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. In lieu of delivering shares of Chevron common stock, we exercised our option to pay the exchanging debenture holders an amount of cash equal to the market value of Chevron common stock. We paid $167 million in cash to exchangeable 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 payment of the related embedded derivative option.

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

Repurchases of Common Stock

During the three-year period ended December 31, 2008, we repurchased 14.8 million shares at a total cost of $1.2 billion, or $83.98 per share, under various repurchase programs. During 2008, we repurchased 6.5 million shares at a cost of $665 million, or $102.56 per share. 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.

Redemption of Preferred Stock

On June 20, 2008, we redeemed all 1.5 million outstanding shares of our 6.49% Series A cumulative preferred stock. Each share of preferred stock was redeemed for cash at a redemption price of $100 per share, plus accrued and unpaid dividends up to the redemption date.

Dividends

Our common stock dividends were $284 million (or a quarterly rate of $0.16 per share), $249 million (or a quarterly rate of $0.14 per share) and $199 million (or a quarterly rate of $0.1125) in 2008, 2007 and 2006, respectively. Common dividends increased primarily due to the higher quarterly dividend rates.

We also paid $5 million of preferred stock dividends in 2008 and $10 million of preferred stock dividends in both 2007 and 2006. The decrease in the preferred dividends in 2008 was due to the redemption of our preferred stock in the second quarter of 2008.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. During 2008, we repatriated earnings from certain foreign subsidiaries to the United States in conjunction with the divestitures of our assets in West Africa. Subsequent to these repatriations, we do not expect to repatriate similar earnings from our historical operations in the foreseeable future. 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. We expect the combination of these sources of capital will be adequate to fund future capital expenditures, debt repayments and other contractual commitments as discussed later in this section.

Operating Cash Flow

Our operating cash flow has increased approximately 73% since 2006, reaching a total of $9.3 billion in 2008. 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, gas and NGLs we produce.

Commodity Prices — Prices for oil, gas and NGLs 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, which are difficult to predict, create volatility in oil, gas and NGL prices and are beyond our control. Although we expect this volatility to continue throughout 2009, we expect 2009 oil, gas and NGL prices will be noticeably lower than those for 2008. The corresponding reduction in our operating cash flow will require us to scale back certain uses of cash during 2009 compared to 2008, including most notably our capital expenditures.

To mitigate some of the risk inherent in prices, we have utilized various 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 of a portion of our future oil and gas production. Based on contracts in place as of February 16, 2009, in 2009 approximately 10% of our estimated gas production is subject to either price collars 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. However, the inverse is also true during periods of depressed commodity prices such as what we are currently experiencing.

Interest Rates — Our operating cash flow can also be sensitive to interest rate fluctuations. As of January 31, 2009, we had long-term debt of $6.2 billion. This included $6.0 billion of fixed-rate debt and $0.2 billion of variable-rate commercial paper borrowings. The fixed-rate debt bears interest at an overall weighted average rate of 7.23%. We also have interest rate swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. Under the terms of these swaps, we receive a fixed rate and pay a variable rate on a total notional amount of $1.05 billion. Including the effects of these swaps, the weighted-average interest rate related to our fixed-rate debt was 6.64% as of January 31, 2009. The key terms of these interest rate swaps are included in "Item 7A. Quantitative and Qualitative Disclosures of Market Risk."

Credit Losses — Our operating cash flow is also exposed to credit risk in a variety of ways. We are exposed to the credit risk of the customers who purchase our oil, gas and NGL production. We are also exposed to credit risk related to the collection of receivables from our joint-interest partners for their proportionate share of expenditures made on projects we operate. We are also exposed to the credit risk of counterparties to our derivative financial contracts as discussed previously in this report.

The recent deterioration of the global financial and capital markets, combined with the drop in commodity prices, has increased our credit risk exposure. However, we utilize a variety of mechanisms to limit our exposure to the credit risks of our customers, partners and counterparties. Such mechanisms include, under certain conditions, prepayment requirements for commodity sales and collateral posting requirements in our existing derivative contracts.

Credit Availability

We have two revolving lines of credit and a commercial paper program that we intend to access during 2009 to provide liquidity. Although we are reducing our planned 2009 capital expenditures, we anticipate our operating cash flow in 2009 will be approximately $1.0 billion less than our capital expenditures due to significantly lower commodity prices.

We have a $2.65 billion syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The maturity date for $2.15 billion of the Senior Credit Facility is April 7, 2013. The maturity date for the remaining $0.5 billion is April 7, 2012. All amounts outstanding will be due and payable on the respective maturity dates 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 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 January 31, 2009, there were no borrowings under the Senior Credit Facility.

On November 5, 2008, we established a new $700 million 364-day, syndicated, unsecured revolving senior credit facility (the "Short-Term Facility"). The Short-Term Facility provides us with incremental liquidity for near-term capital expenditures.

The Short-Term Facility matures on November 3, 2009. On the maturity date, all amounts outstanding will be due and payable at that time. 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 based on LIBOR or the prime rate. As of January 31, 2009, 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 $2.85 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 January 31, 2009, we had $0.2 billion of commercial paper debt outstanding at an average rate of 3.33%.

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 the consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2008, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2008, as calculated pursuant to the terms of the agreement, was 18.6%.

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.

The following schedule summarizes the capacity of our credit facilities by maturity date, as well as our available capacity as of January 31, 2009.

	Amount (In millions)
Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Short-Term Facility — November 3, 2009 maturity	700
Total credit facilities	3,350
Less:	
Outstanding credit facility borrowings	—
Outstanding commercial paper borrowings	176
Outstanding letters of credit	119
Total available capacity	$3,055

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 stable outlook by both Fitch and Standard & Poor's, and Baa1 with a stable outlook by Moody's.

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 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 Senior Credit Facility. Under the terms of the Senior Credit Facility, a one-notch downgrade would increase the fully-drawn borrowing costs 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, 2008, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures

In February 2009, we provided guidance for our 2009 capital expenditures, which are expected to range from $4.7 billion to $5.4 billion. This estimate is significantly lower than our 2008 capital expenditures, which coincides with the significant decline in current oil, gas and NGL prices, as well as the near-term price expectations. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if oil and gas prices fluctuate from current estimates, we could choose to defer a portion of these planned 2009 capital expenditures until later periods, or accelerate capital expenditures planned for periods beyond 2009 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2009 and the commodity price collars and fixed-price contracts we have in place, we anticipate having adequate capital resources to fund our 2009 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 2009, the repurchase program authorizes the repurchase of up to 4.8 million shares or a cost of $360 million, whichever amount is reached first.

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

In response to the current economic environment and recent downturn in commodity prices, we have indefinitely suspended activity under both these programs. As a result, we do not anticipate repurchasing shares under these programs in the foreseeable future. Should economic conditions or commodity prices strengthen, we will consider resumption of share repurchases under our authorized programs.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2008, 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)	$ 5,817	$ 177	$2,100	$ 10	$3,530
Interest expense(2)	5,392	393	812	520	3,667
Drilling and facility obligations(3)	3,735	1,423	1,472	739	101
Firm transportation agreements(4)	1,994	273	516	421	784
Asset retirement obligations(5)	1,485	138	282	181	884
Lease obligations(6)	833	105	213	206	309
Other(7)	386	108	81	34	163
Total	$19,642	$2,617	$5,476	$2,111	$9,438

(1) Long-term debt amounts represent scheduled maturities of our debt obligations at December 31, 2008, excluding $24 million of net premiums included in the carrying value of debt. Additionally, as of December 31, 2008, we had $1.0 billion of outstanding commercial paper borrowings that were due within one year. In January 2009, we issued $500 million of 5.625% senior notes due 2014 and $700 million of 6.30% senior notes due 2019. The proceeds from the senior notes were used to repay our outstanding commercial paper borrowings. Therefore, the $1.0 billion of commercial paper outstanding as of December 31, 2008 is presented in the "more than 5 years" column.

(2) Interest expense related to our fixed-rate debt represents the scheduled cash payments. Interest related to our variable-rate commercial paper borrowings was calculated using the fixed-rates and scheduled cash payments of the senior notes which were issued in January 2009 to repay our outstanding commercial paper as discussed in note (1) above.

(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 $3.7 billion total is $1.7 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 $1.7 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.

(4) 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.

(5) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2008 balance sheet.

(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 three FPSO's that are related to the Panyu project offshore China, the Polvo project offshore Brazil and the Cascade project offshore the Gulf of Mexico. The Panyu FPSO lease term expires in September 2009. The Polvo FPSO lease term expires in 2014. The Cascade FPSO lease term expires in 2015.

(7) These amounts include $260 million related to uncertain tax positions. Expected pension funding obligations have not been included in this table, but are presented and discussed in the section immediately below.

Pension Funding and Estimates

Funded Status. As compared to the projected benefit obligation, our qualified and nonqualified defined benefit plans were underfunded by $501 million and $230 million at December 31, 2008 and 2007, respectively. A detailed reconciliation of the 2008 changes to our underfunded status is included in Note 8 to the accompanying consolidated financial statements. Of the $501 million underfunded status at the end of 2008, $211 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, 2008, these trusts had investments with a fair value of $50 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 underfunded by $209 million at December 31, 2008. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels.

Our funding policy regarding the qualified defined benefit plans is to contribute the amounts necessary for the plans' assets to approximately equal the present value of benefits earned by the participants, as calculated in accordance with the provisions of the Pension Protection Act ("PPA"). During 2008, investment losses significantly reduced the value of our plans' assets. This decrease was the primary contributor to the significant decrease in the funded status of our pension plans during 2008. The 2008 investment losses, combined with our target funding levels, will cause our 2009 contributions to be higher than those made in recent years. We estimate we will contribute up to approximately $173 million to our qualified pension plans during 2009. However, actual contributions may be less than this amount.

Pension Estimate Assumptions. Our pension expense is recognized on an accrual basis over employees' approximate service periods and is impacted by funding decisions or requirements. We recognized expense for our defined benefit pension plans of $61 million, $41 million and $31 million in 2008, 2007 and 2006, respectively. We estimate that our pension expense will approximate $114 million in 2009. Should our actual 2009 contributions vary significantly from our current estimate of $173 million, our actual 2009 pension expense could vary from this estimate.

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 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 7.25% and 8.40% at December 31, 2008 and 2007, respectively. 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. At December 31, 2008, the target investment allocation for our plan assets is 30% 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 40% debt securities. The target investment allocation for our plan assets at December 31, 2007, 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. 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 7.25% to 6.25%) would increase the expected 2009 pension expense by $5 million.

We discounted our future pension obligations using a weighted average rate of 6.00% and 6.22% at December 31, 2008 and 2007, 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 6.00% to 5.75%) would increase our pension liability at December 31, 2008, by $31 million, and increase estimated 2009 pension expense by $5 million.

At December 31, 2008, we had net actuarial losses of $440 million, which will be recognized as a component of pension expense in future years. These losses are primarily due to the large investment losses on plan assets in 2008, reductions in the discount rate since 2001 and increases in participant wages. We estimate that approximately $45 million and $41 million of the unrecognized actuarial losses will be included in pension expense in 2009 and 2010, respectively. The $45 million estimated to be recognized in 2009 is a component of the total estimated 2009 pension expense of $114 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.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 10 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 our 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. 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.

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.

Judgments and Assumptions

The discounted present value of future net revenues for our proved oil, 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, 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 20 of the accompanying consolidated financial statements for a summary of the amount of our reserves that are prepared or audited by outside petroleum consultants.

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 performance revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged less than 2% 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, 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, 2008 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 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.

Because of the volatile nature of oil and gas prices, it is not possible to predict the timing or magnitude of full cost writedowns. However, considering current and near-term estimates of oil and gas prices, such writedowns may be more likely to occur during 2009 than in recent periods.

The SEC recently revised the requirement to use quarter-end prices to calculate the full cost ceiling. Beginning on December 31, 2009, the ceiling will be calculated using a 12-month average price. See "Modernization of Oil and Gas Reporting" for more information on the SEC's revised rules.

Derivative Financial Instruments

Policy Description

We periodically enter into derivative financial instruments with respect to a portion of our oil and gas production that hedge the future prices received. These instruments are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Our derivative financial instruments include financial price swaps and costless price collars. Under the terms of the swaps, we will receive a fixed price for our production and pay a variable market price to the contract counterparty. The price collars 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 cash-settle the difference with the counterparty to the collars.

We periodically enter into interest rate swaps to manage our exposure to interest rate volatility. We use these swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. Under the terms of these swaps, we receive a fixed rate and pay a variable rate on a total notional amount.

All derivative financial instruments are recognized at their current fair value as either assets or liabilities in 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. Cash settlements with counterparties to our derivative financial instruments also increase or decrease earnings at the time of the settlement.

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 a business combination or other transaction 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 derivative financial instruments held during 2008, 2007 and 2006, we chose not to meet the necessary criteria to qualify our derivative financial instruments for hedge accounting treatment.

Judgments and Assumptions

The estimates of the fair values of our derivative instruments require substantial judgment. We estimate the fair values of our oil and gas derivative financial instruments primarily by using internal discounted cash flow calculations. The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices and regional price differentials.

We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest-rate yields. The most significant variable to our cash flow calculations is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by third parties. Another key input to our cash flow calculations is our estimate of volatility for these forward yields, which we base primarily upon implied volatility. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. These yield and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward interest rate yields.

From time to time, we validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties and/or brokers.

In spite of the recent turmoil in the financial markets, counterparty credit risk has not had a significant effect on our cash flow calculations and derivative valuations. This is primarily the result of two factors. First, we have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with eight separate counterparties, and our interest rate derivative contracts are held with five separate counterparties. Second, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below "investment grade". The threshold for collateral posting decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of December 31, 2008, the credit ratings of all our counterparties were investment grade.

Quarterly changes in our derivative fair value estimates 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 can 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 gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting. Current accounting pronouncements require the purchase method to be used to account for any future acquisitions.

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, 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, 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, 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 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 serve 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 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 performance revisions to our reserve estimates have averaged less than 2%. 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 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.

Judgments and Assumptions

The annual impairment test requires us to estimate the fair values of our own assets and liabilities. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated 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.

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

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

Recently Issued Accounting Standards Not Yet Adopted

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

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

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. Staff Position 132(R)-1 amends FASB Statement No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits*, to require additional disclosures about the types of assets and associated risks in an employer's defined benefit pension or other postretirement plan. Staff Position 132(R)-1 is effective for fiscal years ending after December 15, 2009. We are evaluating the impact the adoption of Staff Position 132(R)-1 will have on our financial statement disclosures. However, our adoption of Staff Position 132(R)-1 will not affect our current accounting for our pension and postretirement plans.

Modernization of Oil and Gas Reporting

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC's full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting our reserve disclosures, including the comparability of our reserves disclosures with those of our peer companies:

- *Pricing mechanism for oil and gas reserves estimation* — The SEC's current rules require proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

- *Reasonable certainty* — The SEC's current definition of proved oil and gas reserves incorporate certain specific concepts such as "lowest known hydrocarbons," which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

  The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

Because the revised rules generally expand the definition of proved reserves, we expect our proved reserve estimates will increase upon adoption of the revised rules. However, we are not able to estimate the magnitude of the potential increase at this time.

- *Unproved reserves* — The SEC's current rules prohibit disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations. We have not yet determined whether we will disclose our probable and possible reserves in documents filed with the SEC.

Forward-Looking Estimates

We are providing our 2009 forward-looking estimates in the following discussion. These estimates are based on our examination of historical operating trends, the information used to prepare our December 31, 2008 reserve reports and other data in our possession or available from third parties. The forward-looking estimates in this discussion were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2009 will be substantially similar to those that existed in 2008, 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 2009 exchange rate of $0.80 U.S. dollar to $1.00 Canadian dollar.

Operating Items

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2009. We estimate that our combined 2009 oil, gas and NGL production will total approximately 235 to 241 MMBoe. Of this total, approximately 97% is estimated to be produced from reserves classified as "proved" at December 31, 2008. 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)
United States Onshore	12	676	25	149
United States Offshore	4	42	—	11
Canada	29	185	3	63
International	15	1	—	15
Total	60	904	28	238

Oil and Gas Prices

We expect our 2009 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. The expected ranges for gas prices are exclusive of the anticipated effects of the 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
United States Onshore	85% to 95%	75% to 85%
United States Offshore	95% to 105%	100% to 110%
Canada	55% to 65%	83% to 93%
International	85% to 95%	N/M

N/M — Not meaningful.

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, earnings and cash flow in 2009.

As of February 3, 2009, our financial commodity contracts pertaining to 2009 consisted only of gas collars. The key terms of these contracts are presented in the following table.

		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
First Quarter	277,056	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.02
Second Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
Third Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
Fourth Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
2009 Average	267,973	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05

To the extent that monthly NYMEX prices in 2009 are outside of the ranges established by the gas collars, we and the counterparties to the contracts will settle the difference. Such settlements will either increase or decrease our revenues for the period. Also, we will mark-to-market the contracts based on their fair values throughout 2009. Changes in the contracts' fair values will also be recorded as increases or decreases to our revenues. The expected ranges of our realized gas prices as a percentage of NYMEX prices, which are presented earlier in this report, do not include any estimates of the impact on our gas prices from monthly settlements or changes in the fair values of our gas collars.

In January 2009, we entered into an early settlement arrangement with one of our counterparties. As a result of this early settlement, we received $36 million in January 2009.

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 2009 marketing and midstream operating profit will be between $375 million and $425 million. We estimate that marketing and midstream revenues will be between $1.075 billion and $1.425 billion, and marketing and midstream expenses will be between $0.700 billion and $1.000 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 2009 lease operating expenses will be between $1.93 billion and $2.27 billion. Additionally, we estimate that our production taxes for 2009 will be between 3.25% and 3.75% of total oil, gas and NGL revenues, excluding the effect on revenues from financial collar contracts upon which production taxes are not assessed.

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

Our 2009 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 2009 compared to the costs incurred for such efforts and revisions to our year-end 2008 reserve estimates that, based on prior experience, are likely to be made during 2009. Our reserve estimates as of December 31, 2008 included negative price revisions of 473 MMBoe. The following oil and gas property related DD&A estimates are largely based on the assumption that the year-end 2008 negative price revisions will not reverse during 2009. However, if such negative price revisions reverse, in whole or in part, our actual oil and gas property related DD&A rate could vary materially from our estimate.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $10.25 per Boe and $10.75 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2009 is expected to be between $2.44 billion and $2.56 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $315 million and $335 million in 2008.

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations in 2009 is expected to be between $85 million and $95 million.

General and Administrative Expenses ("G&A")

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

Given these limitations, we estimate our G&A for 2009 will be between $565 million and $605 million. This estimate includes approximately $110 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

Because of the volatile nature of oil and gas prices, it is not possible to predict whether we will incur full cost writedowns in 2009. However, such writedowns may be more likely to occur during 2009 than in recent periods, considering current and near-term estimates of oil and gas prices, which are generally expected to be lower than prices in existence prior to the fourth quarter of 2008.

We recognized full cost ceiling writedowns related to our oil and gas properties in the United States, Canada and Brazil in the fourth quarter of 2008. These writedowns resulted primarily from significant declines in oil and gas prices compared to previous quarter-end prices. The December 31, 2008 weighted average wellhead prices for these countries are presented in the following table.

Country	Oil	Gas	NGLs
United States	$42.21	$4.68	$16.16
Canada	$23.23	$5.31	$20.89
Brazil	$26.61	N/A	N/A

N/A — Not applicable.

The wellhead prices in the table above compare to the December 31, 2008 NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for gas. Should 2009 quarter-end prices approximate or decrease from these December 31, 2008 prices, the likelihood that we will incur full cost writedowns during 2009 will increase.

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 2009 from sales of oil, gas and NGLs and the resulting cash flow. This increases the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors which affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures are generally within our control.

As of January 31, 2009, we had total debt of $6.2 billion. This included $6.0 billion of fixed-rate debt and $0.2 billion of variable-rate commercial paper borrowings. The fixed-rate debt bears interest at an overall weighted average rate of 7.23%. The commercial paper borrowings bear interest at variable rates 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 January 31, 2009, the weighted average variable rate for our commercial paper borrowings was 3.33%. Additionally, any future borrowings under our credit facilities would bear interest at various fixed-rate options for periods up to twelve months and are generally less than the prime rate.

Based on the factors above, we expect our 2009 interest expense to be between $330 million and $340 million. This estimate assumes no material changes in prevailing interest rates or to our existing interest rate swap contracts presented above. This estimate also assumes that our total debt will increase approximately $1.0 billion during 2009, primarily in the form of commercial paper borrowings.

The 2009 interest expense estimate above is comprised of three primary components — interest related to outstanding debt, fees and issuance costs, and capitalized interest. We expect the interest expense in 2009 related to our fixed-rate and floating-rate debt, including net accretion of related discounts, to be between $435 million and $445 million. We expect the interest expense in 2009 related to facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to outstanding debt balances to be between $5 million and $15 million. We also expect to capitalize between $110 million and $120 million of interest during 2009.

Interest Rate Risk Management

We also have interest rate swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. Under the terms of these swaps, we receive a fixed rate and pay a variable rate on a total notional amount of $1.05 billion. The key terms of these interest rate swaps are presented in the following table.

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 500	3.90%	Federal funds rate	July 18, 2013
$ 300	4.30%	Six month LIBOR	July 18, 2011
$ 250	3.85%	Federal funds rate	July 22, 2013
$1,050	4.00%		

Including the effects of these swaps, the weighted-average interest rate related to our fixed-rate debt was 6.64% as of January 31, 2009.

Income Taxes

Our financial income tax rate in 2009 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2009 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 2009 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 2009 will be between 20% and 40%. The current income tax rate is expected to be between 10% and 20%. The deferred income tax rate is expected to be between 10% and 20%. 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 2009 financial income tax rates.

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 2009 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 ranges for drilling, development and facilities expenditures by geographic area. Development capital includes development activity related to reserves classified as proved and drilling that does 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.

	United States Onshore	United States Offshore	Canada	International	Total
			(In millions)		
Development capital . .	$1,520-$1,790	$460-$540	$740-$870	$160-$200	$2,880-$3,400
Exploration capital. . . .	$ 150-$170	$130-$150	$ 40-$50	$200-$230	$ 520-$600
Total	$1,670-$1,960	$590-$690	$780-$920	$360-$430	$3,400-$4,000

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $325 million to $425 million on our marketing and midstream assets, which primarily include our oil pipelines, natural gas processing plants, and gas pipeline systems. Additionally, we expect to capitalize between $460 million and $480 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 $105 million and $115 million for plugging and abandonment charges, and to spend between $230 million and $250 million for other non-oil and gas property fixed assets. We anticipate spending between $40 million and $50 million to fulfill drilling commitments related to our assets held for sale.

Other Cash Uses

Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.16 per share quarterly dividend rate and 444 million shares of common stock outstanding as of December 31, 2008, dividends are expected to approximate $284 million.

We have various defined benefit pension plans. The vast majority of these plans are subject to minimum funding requirements. During 2008, investment losses significantly reduced the funded status of these plans. Accordingly, our 2009 contributions to these plans are expected to be significantly higher than those made in recent years. Depending on the funding targets we may attempt to achieve, we estimate we will contribute between $100 million and $175 million to our pension plans during 2009.

Capital Resources and Liquidity

Our estimated 2009 cash uses, including our drilling and development activities and retirement of maturing debt, are expected to be funded primarily through a combination of our existing cash balances and operating cash flow. 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 $3.1 billion as of January 31, 2009. The amount of operating cash flow to be generated during 2009 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be adequate to fund our capital expenditures and other cash uses for 2009.

If significant other 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.

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 following 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 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.

Based on gas contracts in place as of February 16, 2009 we have approximately 0.3 Bcf per day of gas production in 2009 that is associated with price collars or fixed-price contracts. This amount represents approximately 10% of our estimated 2009 gas production, or 7% of our total Boe production. All of the price collar contracts expire December 31, 2009. Our fixed-price physical delivery contracts extend through 2011. These physical delivery contracts relate to our Canadian 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 gas price collar contracts are presented in the following table.

		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
First Quarter	277,056	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.02
Second Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
Third Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
Fourth Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
2009 Average	267,973	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05

The fair values of our and gas price collars are largely determined by estimates of the forward curves of relevant oil and gas price indexes. At December 31, 2008, a 10% increase in these forward curves would have decreased the net assets recorded for our commodity hedging instruments by approximately $54 million.

Interest Rate Risk

At December 31, 2008, we had debt outstanding of $5.8 billion. Of this amount, $4.8 billion, or 83%, bears interest at fixed rates averaging 7.2%. Additionally, we had $1.0 billion of outstanding commercial paper, bearing interest at floating rates which averaged 3.0%.

We also have interest rate swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. Under the terms of these swaps, we receive a fixed rate and pay a variable rate on a total notional amount of $1.05 billion. The key terms of these interest rate swaps are presented in the following table.

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 500	3.90%	Federal funds rate	July 18, 2013
$ 300	4.30%	Six month LIBOR	July 18, 2011
$ 250	3.85%	Federal funds rate	July 22, 2013
$1,050	4.00%		

The fair values of our interest rate instruments are largely determined by estimates of the forward curves of the Federal Funds rate and LIBOR. At December 31, 2008, a 10% increase in these forward curves would have decreased our net assets by approximately $3 million.

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, 2008 balance sheet.

Item 8. *Financial Statements and Supplementary Data*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND 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.

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, 2008 and 2007, and the related consolidated statements of operations, comprehensive (loss) income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2008. We also have audited Devon Energy Corporation's internal control over financial reporting as of December 31, 2008, 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 Management's Annual Report contained in "Item 9A. Controls and Procedures" of Devon Energy Corporation's Annual Report on Form 10-K. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Devon Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on control criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As described in note 1 to the consolidated financial statements, as of January 1, 2007, Devon Energy Corporation 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 Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109*. Additionally, 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)*.

KPMG LLP

Oklahoma City, Oklahoma
February 25, 2009

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 379	$ 1,364
Short-term investments, at fair value	—	372
Accounts receivable	1,412	1,779
Income taxes receivable	334	30
Derivative financial instruments, at fair value	282	12
Current assets held for sale	27	120
Other current assets	250	237
Total current assets	2,684	3,914
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($4,540 and $3,417 excluded from amortization in 2008 and 2007, respectively)	55,657	48,473
Less accumulated depreciation, depletion and amortization	32,683	20,394
	22,974	28,079
Investment in Chevron Corporation common stock, at fair value	—	1,324
Goodwill	5,579	6,172
Long-term assets held for sale	19	1,512
Other long-term assets, including $199 million at fair value in 2008	652	455
Total assets	$31,908	$41,456
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable — trade	$ 1,819	$ 1,360
Revenues and royalties due to others	496	578
Income taxes payable	37	97
Short-term debt	180	1,004
Current portion of asset retirement obligations, at fair value	138	82
Current liabilities associated with assets held for sale	13	145
Accrued expenses and other current liabilities	452	391
Total current liabilities	3,135	3,657
Debentures exchangeable into shares of Chevron Corporation common stock	—	641
Other long-term debt	5,661	6,283
Derivative financial instruments, at fair value	—	488
Asset retirement obligations, at fair value	1,347	1,236
Liabilities associated with assets held for sale	—	404
Other long-term liabilities	1,026	699
Deferred income taxes	3,679	6,042
Stockholders' equity:		
Preferred stock of $1.00 par value. Authorized 4.5 million shares; issued 1.5 million shares ($150 million aggregate liquidation value) in 2007	—	1
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 443.7 million and 444.2 million shares in 2008 and 2007, respectively	44	44
Additional paid-in capital	6,257	6,743
Retained earnings	10,376	12,813
Accumulated other comprehensive income	383	2,405
Total stockholders' equity	17,060	22,006
Commitments and contingencies (Note 10)		
Total liabilities and stockholders' equity	$31,908	$41,456

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(In millions, except per share amounts)		
Revenues:			
Oil sales	$ 4,567	$ 3,493	$2,434
Gas sales	7,263	5,149	4,874
NGL sales	1,243	970	749
Net (loss) gain on oil and gas derivative financial instruments	(154)	14	38
Marketing and midstream revenues	2,292	1,736	1,672
Total revenues	15,211	11,362	9,767
Expenses and other income, net:			
Lease operating expenses	2,217	1,828	1,425
Production taxes	522	340	341
Marketing and midstream operating costs and expenses	1,624	1,227	1,236
Depreciation, depletion and amortization of oil and gas properties	3,253	2,655	2,058
Depreciation and amortization of non-oil and gas properties	256	203	173
Accretion of asset retirement obligations	86	74	47
General and administrative expenses	653	513	397
Interest expense	329	430	421
Change in fair value of other financial instruments	149	(34)	178
Reduction of carrying value of oil and gas properties	10,379	—	36
Other income, net	(224)	(98)	(115)
Total expenses and other income, net	19,244	7,138	6,197
(Loss) earnings from continuing operations before income taxes	(4,033)	4,224	3,570
Income tax (benefit) expense:			
Current	619	500	528
Deferred	(1,573)	578	408
Total income tax (benefit) expense	(954)	1,078	936
(Loss) earnings from continuing operations	(3,079)	3,146	2,634
Discontinued operations:			
Earnings from discontinued operations before income taxes	1,131	696	464
Income tax expense	200	236	252
Earnings from discontinued operations	931	460	212
Net (loss) earnings	(2,148)	3,606	2,846
Preferred stock dividends	5	10	10
Net (loss) earnings applicable to common stockholders	$(2,153)	$ 3,596	$2,836
Basic net (loss) earnings per share:			
(Loss) earnings from continuing operations	$ (6.95)	$ 7.05	$ 5.94
Earnings from discontinued operations	2.10	1.03	0.48
Net (loss) earnings	$ (4.85)	$ 8.08	$ 6.42
Diluted net (loss) earnings per share:			
(Loss) earnings from continuing operations	$ (6.95)	$ 6.97	$ 5.87
Earnings from discontinued operations	2.10	1.03	0.47
Net (loss) earnings	$ (4.85)	$ 8.00	$ 6.34
Weighted average common shares outstanding:			
Basic	444	445	442
Diluted	444	450	448

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Net (loss) earnings	$(2,148)	$3,606	$2,846
Foreign currency translation:			
Change in cumulative translation adjustment	(1,960)	1,389	(25)
Income tax benefit (expense)	79	(42)	28
Total	(1,881)	1,347	3
Pension and postretirement benefit plans:			
Net actuarial loss and prior service cost arising in current year	(254)	(90)	—
Recognition of net actuarial loss and prior service cost in net earnings	16	14	—
Curtailment of pension benefits	—	16	—
Change in additional minimum pension liability	—	—	30
Income tax benefit (expense)	97	23	(13)
Total	(141)	(37)	17
Investment in Chevron Corporation common stock:			
Unrealized holding gain	—	—	238
Income tax expense	—	—	(86)
Total	—	—	152
Other	—	(1)	(2)
Other comprehensive (loss) income, net of tax	(2,022)	1,309	170
Comprehensive (loss) income	$(4,170)	$4,915	$3,016

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Preferred Stock	Common Stock Shares	Common Stock Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Stockholders' Equity
				(In millions)				
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
Share-based compensation tax benefits	—	—	—	36	—	—	—	36
Balance as of December 31, 2006	1	444	44	6,840	9,114	1,444	(1)	17,422
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
Share-based compensation tax benefits	—	—	—	44	—	—	—	44
Balance as of December 31, 2007	1	444	44	6,743	12,813	2,405	—	22,006
Net loss	—	—	—	—	(2,148)	—	—	(2,148)
Other comprehensive loss	—	—	—	—	—	(2,022)	—	(2,022)
Stock option exercises	—	4	1	123	—	—	(8)	116
Restricted stock grants, net of cancellations	—	3	—	—	—	—	—	—
Common stock repurchased	—	(7)	—	—	—	—	(709)	(709)
Common stock retired	—	—	(1)	(716)	—	—	717	—
Redemption of preferred stock	(1)	—	—	(149)	—	—	—	(150)
Common stock dividends	—	—	—	—	(284)	—	—	(284)
Preferred stock dividends	—	—	—	—	(5)	—	—	(5)
Share-based compensation	—	—	—	196	—	—	—	196
Share-based compensation tax benefits	—	—	—	60	—	—	—	60
Balance as of December 31, 2008	$—	444	$44	$6,257	$10,376	$ 383	$ —	$17,060

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Cash flows from operating activities:			
Net (loss) earnings	$ (2,148)	$ 3,606	$ 2,846
Earnings from discontinued operations, net of tax	(931)	(460)	(212)
Adjustments to reconcile (loss) earnings from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	3,509	2,858	2,231
Deferred income tax (benefit) expense	(1,573)	578	408
Net gain on sales of non-oil and gas property and equipment	(1)	(1)	(5)
Reduction of carrying value of oil and gas properties	10,379	—	36
Other noncash charges	187	177	269
Net increase in working capital	(138)	(499)	(282)
Increase in long-term other assets	(59)	(92)	(58)
Increase (decrease) in long-term other liabilities	48	(5)	141
Cash provided by operating activities — continuing operations	9,273	6,162	5,374
Cash provided by operating activities — discontinued operations	135	489	619
Net cash provided by operating activities	9,408	6,651	5,993
Cash flows from investing activities:			
Proceeds from sales of property and equipment	117	76	40
Capital expenditures	(9,375)	(6,158)	(7,346)
Proceeds from exchange of Chevron Corporation common stock	280	—	—
Purchases of short-term investments	(50)	(934)	(2,395)
Sales of long-term and short-term investments	300	1,136	2,501
Cash used in investing activities — continuing operations	(8,728)	(5,880)	(7,200)
Cash provided by (used in) investing activities — discontinued operations	1,855	166	(249)
Net cash used in investing activities	(6,873)	(5,714)	(7,449)
Cash flows from financing activities:			
Credit facility repayments	(3,191)	(757)	—
Credit facility borrowings	1,741	2,207	—
Net commercial paper borrowings (repayments)	1	(804)	1,808
Debt repayments	(1,031)	(567)	(862)
Preferred stock redemption	(150)	—	—
Proceeds from stock option exercises	116	91	73
Repurchases of common stock	(665)	(326)	(253)
Dividends paid on common and preferred stock	(289)	(259)	(209)
Excess tax benefits related to share-based compensation	60	44	36
Net cash (used in) provided by financing activities	(3,408)	(371)	593
Effect of exchange rate changes on cash	(116)	51	13
Net (decrease) increase in cash and cash equivalents	(989)	617	(850)
Cash and cash equivalents at beginning of year (including cash related to assets held for sale)	1,373	756	1,606
Cash and cash equivalents at end of year (including cash related to assets held for sale)	$ 384	$ 1,373	$ 756

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

Accounting policies used by Devon Energy Corporation and subsidiaries ("Devon") reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are 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 2007, Devon sold its assets and terminated its operations in Egypt. During 2008, Devon sold its assets and terminated its operations in West Africa. These divestiture activities are described more fully in Note 16.

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 gas, crude oil and NGLs, as well as constructing and operating pipelines, storage and treating facilities and natural gas processing plants.

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

Use of Estimates in the Preparation of Financial Statements

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

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

- obligations related to employee benefits; and
- legal and environmental risks and exposures.

Derivative Financial Instruments

Devon is exposed to certain risks relating to its ongoing business operations. Devon's largest areas of risk exposure relate to commodity prices, interest rates and Canadian to U.S. dollar exchange rates. As discussed more fully below, Devon uses derivative instruments primarily to manage commodity price risk and interest rate risk. Besides these derivative instruments, Devon also had an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron common stock. Devon ceased to have this option when the exchangeable debentures matured on August 15, 2008.

Devon periodically enters into derivative financial instruments with respect to a portion of its oil and gas production that hedge the future prices received. These instruments are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Devon's derivative financial instruments include financial price swaps and costless price collars. Under the terms of the swaps, Devon will receive a fixed price for its production and pay a variable market price to the contract counterparty. The price collars 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, Devon will cash-settle the difference with the counterparty to the collars.

Devon periodically enters into interest rate swaps to manage its exposure to interest rate volatility. Devon uses these swaps to mitigate a portion of the fair value effects of interest rate fluctuations on its fixed-rate debt. Under the terms of these swaps, Devon receives a fixed rate and pays a variable rate on a total notional amount.

All derivative financial instruments are recognized at their current fair value as either assets or liabilities in 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. Cash settlements with counterparties to Devon's derivative financial instruments are also recorded in the statement of operations.

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. For derivative financial instruments held during the three-year period ended December 31, 2008, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment.

By using derivative financial instruments to hedge exposures to changes in commodity prices and interest rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom 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 risks associated with commodity price and interest rate contracts are 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 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.

See Note 3 for the amounts included in Devon's accompanying balance sheets and statements of operations associated with its derivative financial instruments.

Discontinued Operations

In November 2006 and January 2007, Devon announced plans to divest its operations in Egypt and West Africa. As a result, all amounts related to Devon's operations in Egypt and West Africa are classified as discontinued operations. The captions assets held for sale and liabilities associated with assets held for sale in the accompanying balance sheets present the assets and liabilities associated with our discontinued operations. See Note 16 for more discussion regarding these divestitures.

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, 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 derivative contracts held during the three-year period ended December 31, 2008 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 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.

Costs associated with unproved properties are excluded from the depletion calculation 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 into the depletion calculation 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 unit-of-production basis. Depreciation and amortization of other property and equipment, including corporate and other midstream assets and leasehold improvements, are provided using the straight-line method based on estimated useful lives ranging from three to 39 years.

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

Investments

Devon reports its investments and other marketable securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity. During the three-year period ended December 31, 2008, Devon's investments consisted of auction rate securities and Chevron Corporation ("Chevron") common stock, which are discussed below.

Auction Rate Securities

At December 31, 2007, Devon held $372 million of auction rate securities. Such securities are rated AAA — the highest rating — by one or more rating agencies and are collateralized by student loans that are substantially guaranteed by the United States government. 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 seven to 28 days. Therefore, these auction rate securities were generally priced and subsequently traded as short-term investments because of the interest rate reset feature. As a result, Devon classified its auction rate securities as short-term investments in the accompanying December 31, 2007 consolidated balance sheet and in prior periods. At December 31, 2008, Devon's auction rate securities totaled $122 million.

Since February 8, 2008, Devon has experienced difficulty selling its securities due to the failure of the auction mechanism, which provided 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 seven to 28 days until the auction succeeds, the issuer calls the securities or the securities mature.

From February 2008, when auctions began failing, to December 31, 2008, issuers have redeemed $30 million of Devon's auction rate securities holdings at par. However, based on continued auction failures and the current market for Devon's auction rate securities, Devon has classified its securities as long-term investments as of December 31, 2008. These securities are included in other long-term assets in the accompanying consolidated balance sheet. Devon has the ability to hold the securities until maturity. At this time, Devon does not believe the values of its long-term securities are impaired.

Chevron Common Stock

Until October 31, 2008, Devon owned approximately 14.2 million shares of Chevron common stock. As described in Note 6, Devon exchanged these shares on October 31, 2008 for cash and certain oil and gas property interests owned by Chevron. These shares were held in connection with debt previously owed by Devon that contained an exchange option.

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, 2008, the change in fair value of other financial instruments caption on Devon's statement of operations includes an unrealized loss of $363 million related to the Chevron common stock and an unrealized gain of $109 million related to the embedded option. For the year ended December 31, 2007, the change in fair value of other 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 year ended December 31, 2006, prior to adopting Statement No. 159, an unrealized loss of $181 million related to the change in fair value of the embedded option were included in the change in fair value of other financial instruments caption on Devon's statement of operations.

As of December 31, 2006, $364 million of after-tax unrealized gains related to Devon's investment in the Chevron common stock was included in accumulated other comprehensive income. This is the amount of unrealized gains that, prior to Devon's adoption of Statement No. 159, had not been recorded in Devon's historical results of operations. Upon the adoption of Statement No. 159 as of January 1, 2007, this $364 million net unrealized gain 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 11.

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 2008, 2007 and 2006. 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, 2008 and 2007. The decrease in goodwill from 2007 to 2008 is largely due to changes in the exchange rate between the U.S. dollar and the Canadian dollar.

	December 31, 2008	December 31, 2007
	(In millions)	
United States	$3,046	$3,049
Canada	2,465	3,055
International	68	68
Total	$5,579	$6,172

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, 2005	$1,216
December 31, 2006	$1,219
December 31, 2007	$2,566
December 31, 2008	$ 685

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 10 for a discussion of amounts recorded for these liabilities.

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

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

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

Major Purchasers

During 2008, 2007 and 2006, no purchaser accounted for more than 10% of Devon's revenues from continuing operations.

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.

Share Based Compensation

Devon grants stock options, restricted stock awards and other types of share-based awards to members of its Board of Directors and selected employees. All such awards are measured at fair value on the date of grant and are recognized as a component of general and administrative expenses in the accompanying statements of operations over the applicable vesting periods.

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.

During 2008, Devon repatriated earnings from certain foreign subsidiaries to the United States in conjunction with the divestitures of its assets in West Africa. Subsequent to these repatriations, Devon does not expect to repatriate similar earnings from its historical operations in the foreseeable future. As a result, undistributed earnings of foreign subsidiaries included in continuing operations were determined to be permanently reinvested as of December 31, 2008. Therefore, no U.S. deferred income taxes were provided on such amounts as of December 31, 2008. 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.

Additional information regarding Devon's unrecognized tax benefits, including changes in such amounts during 2008 and 2007, is provided in Note 15.

Net (Loss) Earnings Per Common Share

Basic (loss) earnings per share is computed by dividing (loss) earnings applicable to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share is calculated using the treasury stock method to reflect the potential dilution that could occur if Devon's dilutive outstanding stock options were exercised.

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.

Recently Issued Accounting Standards Not Yet Adopted

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

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

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. Staff Position 132(R)-1 amends FASB Statement No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits*, to require additional disclosures about the types of assets and associated risks in an employer's defined benefit pension or other postretirement plan. Staff Position 132(R)-1 is effective for fiscal years ending after December 15, 2009. Devon is evaluating the impact the adoption of Staff Position 132(R)-1 will have on its financial statement disclosures. However, Devon's adoption of Staff Position 132(R)-1 will not affect its current accounting for its pension and postretirement plans.

Modernization of Oil and Gas Reporting

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC's full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting Devon's reserve disclosures, including the comparability of its reserves disclosures with those of its peer companies:

- *Pricing mechanism for oil and gas reserves estimation* — The SEC's current rules require proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

- *Reasonable certainty* — The SEC's current definition of "proved oil and gas reserves" incorporate certain specific concepts such as "lowest known hydrocarbons," which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

  The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

  Because the revised rules generally expand the definition of proved reserves, Devon expects its proved reserve estimates will increase upon adoption of the revised rules. However, Devon is not able to estimate the magnitude of the potential increase at this time.

- *Unproved reserves* — The SEC's current rules prohibit disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations. Devon has not yet determined whether it will disclose its probable and possible reserves in documents filed with the SEC.

2. Accounts Receivable

The components of accounts receivable include the following:

	December 31,	
	2008	2007
	(In millions)	
Oil, gas and NGL revenues	$ 789	$1,140
Joint interest billings	263	240
Marketing and midstream revenues	153	183
Production tax credits	170	134
Other	42	87
Gross accounts receivable	1,417	1,784
Allowance for doubtful accounts	(5)	(5)
Net accounts receivable	$1,412	$1,779

3. Derivative Financial Instruments

As discussed in Note 1, Devon periodically enters into commodity and interest rate derivative financial instruments. Also, during the first eight months of 2008 and all of 2007 and 2006, Devon held an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron common stock.

The following table presents the fair values of derivative assets and liabilities included in the accompanying balance sheets. None of Devon's derivative instruments included in the table have been designated as hedging instruments.

	Balance Sheet Caption	Asset Derivatives	Liability Derivatives
		(In millions)	
December 31, 2008:			
Gas price collars	Derivative financial instruments, current	$255	$ —
Interest rate swaps	Derivative financial instruments, current	27	—
Interest rate swaps	Long-term other assets	77	—
Total derivatives		$359	$ —
December 31, 2007:			
Gas price swaps	Derivative financial instruments, current	$ 12	$ —
Embedded option	Derivative financial instruments, long-term	—	488
Total derivatives		$ 12	$488

The following table presents the cash settlements and unrealized gains and losses on fair value changes included in the accompanying statements of operations associated with these derivative financial instruments. None of Devon's derivative instruments included in the table have been designated as hedging instruments.

	Statement of Operations Caption	2008	2007	2006
			(In millions)	
Cash settlements:				
Oil price collars	Net (loss) gain on oil and gas derivative financial instruments	$ 27	$ —	$ —
Gas price collars	Net (loss) gain on oil and gas derivative financial instruments	(221)	2	—
Gas price swaps	Net (loss) gain on oil and gas derivative financial instruments	(203)	38	—
Interest rate swaps	Change in fair value of other financial instruments	1	—	—
Total cash settlements		(396)	40	—
Unrealized gains (losses):				
Gas price collars	Net (loss) gain on oil and gas derivative financial instruments	255	(4)	4
Gas price swaps	Net (loss) gain on oil and gas derivative financial instruments	(12)	(22)	34
Interest rate swaps	Change in fair value of other financial instruments	104	1	3
Embedded option	Change in fair value of other financial instruments	109	(248)	(181)
Total unrealized gains (losses)		456	(273)	(140)
Net gain (loss) recognized on statement of operations		$ 60	$(233)	$(140)

4. Other Current Assets

The components of other current assets include the following:

	December 31, 2008	December 31, 2007
	(In millions)	
Inventories	$195	$145
Prepaid assets	49	46
Other	6	46
Other current assets	$250	$237

5. Property and Equipment and Asset Retirement Obligations

Property and equipment consists of the following:

	December 31, 2008	December 31, 2007
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 47,634	$ 42,141
Not subject to amortization	4,540	3,417
Accumulated depreciation, depletion and amortization	(31,574)	(19,507)
Net oil and gas properties	20,600	26,051
Other property and equipment	3,483	2,915
Accumulated depreciation and amortization	(1,109)	(887)
Net other property and equipment	2,374	2,028
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 22,974	$ 28,079

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2008. Evaluation of most of these properties, and therefore the inclusion of their costs in amortized capital costs, is expected to be completed within three to seven years.

	Costs Incurred In				
	2008	2007	2006	Prior to 2006	Total
		(In millions)			
Acquisition costs	$1,673	$152	$ 951	$229	$3,005
Exploration costs	654	243	125	129	1,151
Development costs	161	34	22	1	218
Capitalized interest	92	37	19	18	166
Total oil and gas properties not subject to amortization	$2,580	$466	$1,117	$377	$4,540

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.

Asset Retirement Obligations

Following is a reconciliation of the asset retirement obligations for the years ended December 31, 2008 and 2007.

	Year Ended December 31,	
	2008	2007
	(In millions)	
Asset retirement obligations as of beginning of year	$1,318	$ 857
Liabilities incurred	59	57
Liabilities settled	(86)	(68)
Liabilities assumed by others	—	(3)
Revision of estimated obligation	244	311
Accretion expense on discounted obligation	86	74
Foreign currency translation adjustment	(136)	90
Asset retirement obligations as of end of year	1,485	1,318
Less current portion	138	82
Asset retirement obligations, long-term	$1,347	$1,236

During 2008 and 2007, Devon recognized revisions to its asset retirement obligations totaling $244 million and $311 million, respectively. The primary factors causing the 2008 fair value increase were an overall increase in abandonment cost estimates and a decrease in the discount rate used to present value the obligations. In addition, higher abandonment cost estimates related to certain offshore platforms that were destroyed by Hurricane Ike resulted in an $82 million increase in 2008. See additional discussion regarding this revision in Note 10 — Hurricane Contingencies. 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.

6. Investment in Chevron Corporation Common Stock

Until October 31, 2008, Devon owned 14.2 million shares of Chevron common stock. These shares were held in connection with debt owed by Devon that contained an exchange option. The exchange option allowed the debt holders, prior to the debt's maturity of August 15, 2008, to exchange the debt for shares of Chevron common stock owned by Devon. However, Devon had the option to settle any exchanges with cash equal to the market value of Chevron common stock at the time of the exchange. Devon settled exchange requests during 2008 and 2007 by paying $1.0 billion during 2008 and $0.2 billion during 2007.

On October 31, 2008, Devon transferred its 14.2 million shares of Chevron common stock to Chevron. In exchange, Devon received Chevron's interest in the Drunkard's Wash coalbed natural gas field in east-central Utah and $280 million in cash. The field has approximately 51,000 net acres and had net production of about 40 million cubic feet of natural gas equivalent per day (unaudited) at the time of the exchange.

7. Debt and Related Expenses

A summary of Devon's debt is as follows:

	December 31, 2008	December 31, 2007
	(In millions)	
Senior Credit Facility borrowings	$ —	$1,450
Commercial paper	1,005	1,004
Debentures exchangeable into shares of Chevron common stock:		
4.90% retired on August 15, 2008	—	381
4.95% retired on August 15, 2008	—	271
Discount on exchangeable debentures	—	(11)
Other debentures and notes:		
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
Other	10	—
Net premium on other debentures and notes	24	31
	5,841	7,928
Less amount classified as short-term debt	180	1,004
Long-term debt	$5,661	$6,924

Debt maturities as of December 31, 2008, excluding premiums and discounts, are as follows (in millions):

2009	$ 177
2010	—
2011	2,100
2012	10
2013	—
2014 and thereafter	3,530
Total	$5,817

Credit Lines

Devon has two revolving lines of credit that can be accessed to provide liquidity as needed. As of December 31, 2008, Devon's combined available capacity under these credit facilities, net of $119 million of outstanding letters of credit and $1.0 billion of outstanding commercial paper, was $2.2 billion.

Devon has a $2.65 billion syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The maturity date for $2.15 billion of the Senior Credit Facility is April 7, 2013. The maturity date for the remaining $0.5 billion is April 7, 2012. All amounts outstanding will be due and payable on the respective maturity dates 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 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 $1.9 million that is payable quarterly in arrears. As of December 31, 2008, there were no borrowings under the Senior Credit Facility.

On November 5, 2008, Devon established a new $700 million 364-day, syndicated, unsecured revolving senior credit facility (the "Short-Term Facility"). The Short-Term Facility provides Devon with incremental liquidity for near-term capital expenditures.

The Short-Term Facility matures on November 3, 2009. On the maturity date, all amounts outstanding will be due and payable at that time. 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 based on LIBOR or the prime rate. The Short-Term Facility currently provides for an annual facility fee of approximately $0.7 million that is payable quarterly in arrears. As of December 31, 2008, 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. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2008, Devon was in compliance with this covenant. Devon's debt-to-capitalization ratio at December 31, 2008, as calculated pursuant to the terms of the agreement, was 18.6%.

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 $2.85 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, 2008, Devon had $1.0 billion of commercial paper debt outstanding at an average rate of 3.00%. The average borrowing rate for Devon's $1.0 billion of commercial paper debt outstanding at December 31, 2007 was 5.07%.

In January 2009, Devon issued $500 million of 5.625% senior notes due January 15, 2014 and $700 million of 6.30% senior notes due January 15, 2019. The net proceeds from issuance of this debt were used primarily to repay Devon's outstanding commercial paper as of December 31, 2008. Therefore, the $1.0 billion of outstanding commercial paper is classified as long-term debt in the accompanying 2008 consolidated balance sheet. Outstanding commercial paper is classified as short-term debt in the accompanying 2007 consolidated balance sheet.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2008, as listed in the table presented at the beginning of this note.

Ocean Debt

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

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

10.125% Debentures due November 15, 2009

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

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

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

7.95% Notes due April 15, 2032

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

Interest Expense

The following schedule includes the components of interest expense between 2006 and 2008.

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Interest based on debt outstanding	$ 426	$ 508	$486
Capitalized interest	(111)	(102)	(79)
Other interest	14	24	14
Total interest expense	$ 329	$ 430	$421

8. 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 for the Qualified Plans' assets to approximately equal the present value of benefits earned by the participants, as calculated in accordance with the provisions of the Pension Protection Act. As of December 31, 2008 and 2007, the fair values of the Qualified Plans' assets were $430 million and $619 million, respectively. The assets were $209 million less and $62 million more, respectively, than the related accumulated benefit obligation. The 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 $50 million and $59 million at December 31, 2008 and 2007, respectively, 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 continue to receive a discretionary match of a percentage of their contributions to the 401(k) Plan. These participants also receive additional, nondiscretionary contributions by Devon calculated as a percentage of annual compensation. The percentage varies 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 continue to accrue benefits under the existing provisions of such plans. Employees who elected to participate in the enhanced defined contribution structure receive enhanced contributions to the 401(k) Plan and retain the benefits that they had accrued under the defined benefit plan as of December 31, 2007. However, such employees are only 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 do not have an election and only participate in the 401(k) Plan and the enhanced defined contribution structure.

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

Change in Measurement Date

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. Statement No. 158 requires the measurement of plan assets and benefit obligations as of the date of the employer's fiscal year-end, beginning with fiscal years ending after December 15, 2008. Although not required until 2008, Devon adopted this measurement-date requirement in the second quarter of 2007 and changed its measurement date from November 30 to December 31. As a result, Devon used data as of December 31, 2006 to remeasure its plans assets and benefit obligations previously measured using data as of November 30, 2006. As a result of the remeasurement, Devon recognized the following amounts in the second quarter of 2007.

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

Benefit Obligations and Plan Assets

The following table presents the status of Devon's pension and other postretirement benefit plans for 2008 and 2007. 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, 2008 and 2007 was $795 million and $693 million, respectively.

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 849	$ 768	$ 71	$ 52
Effect of change in measurement date	—	(23)	—	(1)
Service cost	41	30	1	1
Interest cost	54	46	4	3
Participant contributions	—	—	2	2
Plan amendments	9	17	—	23
Curtailment gain	—	(16)	—	—
Foreign exchange rate changes	(6)	6	—	—
Actuarial loss (gain)	17	51	(15)	(2)
Benefits paid	(33)	(30)	(7)	(7)
Benefit obligation at end of year	931	849	56	71
Change in plan assets:				
Fair value of plan assets at beginning of year	619	590	—	—
Effect of change in measurement date	—	3	—	—
Actual return on plan assets	(178)	47	—	—
Employer contributions	25	6	5	5
Participant contributions	—	—	2	2
Benefits paid	(33)	(30)	(7)	(7)
Foreign exchange rate changes	(3)	3	—	—
Fair value of plan assets at end of year	430	619	—	—
Funded status at end of year	$(501)	$(230)	$(56)	$(71)
Amounts recognized in balance sheet:				
Noncurrent assets	$ 2	$ 3	$ —	$ —
Current liabilities	(10)	(8)	(5)	(6)
Noncurrent liabilities	(493)	(225)	(51)	(65)
Net amount	$(501)	$(230)	$(56)	$(71)
Amounts recognized in accumulated other comprehensive income:				
Net actuarial loss (gain)	$ 440	$ 208	$(13)	$ 2
Prior service cost (benefit)	28	22	13	15
Total	$ 468	$ 230	$ —	$ 17

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 $9 and $6 million for 2008 and 2007, respectively, which were transferred from the trusts established for the Supplemental Plans.

Certain of Devon's pension plans have a projected benefit obligation in excess of plan assets at December 31, 2008 and 2007. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

	December 31,	
	2008	2007
	(In millions)	
Projected benefit obligation	$921	$834
Fair value of plan assets	$417	$601

Certain of Devon's pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2008 and 2007. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

	December 31,	
	2008	2007
	(In millions)	
Accumulated benefit obligation	$784	$135
Fair value of plan assets	$417	$ —

The plan assets included in the above two tables exclude the Supplemental Plan trusts, which had a total value of $50 million and $59 million at December 31, 2008 and 2007, respectively.

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 2008, 2007 and 2006.

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 41	$ 30	$ 23	$ 1	$ 1	$ 1
Interest cost	54	46	39	4	3	3
Expected return on plan assets	(50)	(49)	(44)	—	—	—
Curtailment and settlement expense	—	1	—	—	—	—
Plan amendment	—	—	—	—	1	—
Recognition net actuarial loss	14	12	12	—	1	1
Recognition of prior service cost	2	1	1	2	—	—
Total net periodic benefit cost	61	41	31	7	6	5
Other comprehensive income:						
Actuarial loss (gain) arising in current year	245	54	—	(15)	(3)	—
Prior service cost arising in current year	9	17	—	—	22	—
Recognition of net actuarial loss in net periodic benefit cost	(14)	(12)	—	—	(1)	—
Recognition of prior service cost in net periodic benefit cost	(2)	(1)	—	(2)	—	—
Curtailment of pension benefits	—	(16)	—	—	—	—
Change in additional minimum pension liability	—	—	30	—	—	—
Total other comprehensive income (loss)	238	42	30	(17)	18	—
Total recognized	$299	$ 83	$ 61	$ 10	$24	$ 5

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 2009.

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Net actuarial loss (gain)	$45	$(1)
Prior service cost	4	2
Total	$49	$ 1

Assumptions

The following table presents the weighted average actuarial assumptions that were used to determine benefit obligations and net periodic benefit costs for 2008, 2007 and 2006.

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
Assumptions to determine benefit obligations:						
Discount rate	6.00%	6.22%	5.72%	6.00%	6.00%	5.50%
Rate of compensation increase	7.00%	7.00%	7.00%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	6.18%	5.96%	5.72%	6.00%	5.75%	5.75%
Expected return on plan assets	8.40%	8.40%	8.40%	N/A	N/A	N/A
Rate of compensation increase	7.00%	7.00%	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 2008 and 2007 benefit obligations for the pension plans, the 7% compensation increase in the table above represents the assumed increase 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.

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, 2008, the target investment allocation for Devon's plan assets was 30% 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 40% debt securities. Derivatives or other speculative investments considered high-risk are generally prohibited.

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

The following table presents the weighted-average asset allocation for Devon's pension plans at December 31, 2008 and 2007, and the target allocation for 2009 by asset category:

	2009	2008	2007
Asset category:			
Equity securities	60%	59%	83%
Debt securities	40%	41%	17%
Total	100%	100%	100%

Other assumptions — For measurement of the 2008 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 2009. 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, 2008 other postretirement benefits obligation and the 2009 service and interest cost components of net periodic benefit cost.

	One Percent Increase	One Percent Decrease
	(In millions)	
Effect on benefit obligation	$ 3	$ (3)
Effect on service and interest costs	$—	$—

Expected Cash Flows

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

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Devon's 2009 contributions	$183	$ 5
Benefit payments:		
2009	$ 35	$ 5
2010	$ 35	$ 5
2011	$ 38	$ 5
2012	$ 41	$ 5
2013	$ 46	$ 5
2014 to 2018	$307	$24

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 2009, $10 million of pension benefits is expected to be funded from the trusts established for the Supplemental Plans and all $5 million of other postretirement benefits is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

Other Benefit Plans

Devon's 401(k) Plan covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors.

As previously discussed in "Revisions to Retirement Plans" above, in 2007 Devon adopted an enhanced defined contribution structure related to its 401(k) Plan 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, continue to receive a discretionary match of a percentage of their contributions to the 401(k) Plan. These participants 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.

The following table presents Devon's expense related to these defined contribution plans during 2008, 2007 and 2006.

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
401(k) plan	$21	$18	$15
Enhanced contribution plan	12	—	—
Canadian pension and savings plans	16	14	12
Total expense	$49	$32	$27

9. Stockholders' Equity

The authorized capital stock of Devon consists of 1 billion 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.

Devon's Board of Directors has designated 2.9 million 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. At December 31, 2008, 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.

Preferred Stock Redemption

On June 20, 2008, Devon redeemed all 1.5 million outstanding shares of its 6.49% Series A cumulative preferred stock. Each share of preferred stock was redeemed for cash at a redemption price of $100 per share, plus accrued and unpaid dividends up to the redemption date.

Stock Repurchases

Devon's Board of Directors has approved an ongoing, annual stock repurchase program to minimize dilution resulting from restricted stock issued to, and options exercised by, employees. Also, Devon's Board of Directors approved a program in 2007 to repurchase up to 50 million shares. This program expires on December 31, 2009 and was created as a potential use of the proceeds received from Devon's West African property divestitures. Devon's Board of Directors also approved a separate 50 million share repurchase program in August 2005, which expired on December 31, 2007.

In response to the current economic environment and recent downturn in commodity prices, Devon has indefinitely suspended activity under its authorized programs. As a result, Devon does not anticipate repurchasing shares under these programs in the foreseeable future. Should economic conditions or commodity prices strengthen, Devon will consider resumption of share repurchases under its authorized programs.

During the three-year period ended December 31, 2008, Devon repurchased 14.8 million shares at a total cost of $1.2 billion, or $83.98 per share, under these repurchase programs. The following table summarizes Devon's repurchases under these plans during 2008, 2007 and 2006 (amounts and shares in millions).

	2008			2007			2006		
Repurchase Program	Amount	Shares	Per Share	Amount	Shares	Per Share	Amount	Shares	Per Share
Annual program	$178	2.0	$ 87.83	$ —	—	$ —	$ —	—	$ —
2007 program	487	4.5	$109.25	326	4.1	$79.80	—	—	$ —
2005 program	—	—	$ —	—	—	$ —	253	4.2	$59.61
Totals	$665	6.5	$102.56	$326	4.1	$79.80	$253	4.2	$59.61

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 $284 million (or $0.64 per share), $249 million (or $0.56 per share) and $199 million (or $0.45 per share) in 2008, 2007 and 2006 respectively. Devon paid dividends of $5 million in 2008 and $10 million in both 2007 and 2006 to preferred stockholders. The decrease in preferred stock dividend in 2008 is due to the redemption of the preferred stock in the second quarter of 2008.

10. Commitments and Contingencies

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

Environmental Matters

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

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2008, Devon's balance sheet included $1 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 natural 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. The first phase was scheduled to begin in August 2008, but the defendant settled prior to trial. The second phase was scheduled to begin in February 2009, but the defendants settled prior to trial. Devon was 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 with respect to this lawsuit and, therefore, no liability related to this lawsuit has been recorded.

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 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 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. In October 2007 a federal district court ruled in favor of a plaintiff who had challenged the legality of including price thresholds in deep water leases. Additionally, in January 2009 a federal appellate court upheld this district court ruling. This judgment is subject to further appeals.

As of December 31, 2008, Devon had $83 million accrued for potential royalties on various deep water leases. Due to the uncertainty of this issue caused by the favorable federal court decisions and potential Congressional actions, Devon has ceased accruing additional royalties on its affected leases. Devon will continue to monitor developments and adjust its accruals as necessary.

Hurricane Contingencies

Prior to September 1, 2006, Devon maintained a comprehensive insurance program that included coverage for physical damage to its offshore facilities caused by hurricanes. This program also included substantial business interruption coverage, which entitled Devon to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and gas prices. Also, the terms of the historical insurance included a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible.

Devon suffered insured damages in the third quarter of 2005 related to hurricanes that struck the Gulf of Mexico. During 2006 and 2007, Devon received $480 million as a full settlement of the amount due from its primary insurers and certain of its secondary insurers. During the fourth quarter of 2008, Devon received $106 million as full settlement of the amount due from its remaining secondary insurers. Devon's claims under its then existing insurance arrangements included both physical damages and business interruption claims. As of December 31, 2008, Devon had used $424 million of these proceeds as reimbursement of repair costs and deductible amounts, resulting in excess recoveries. The $162 million of excess recoveries was recorded as other income in the accompanying statement of operations during 2008.

The policy underlying the insurance program terms described above expired on August 31, 2006. Due to significant changes in the insurance marketplace, Devon no longer has coverage for damage that may be caused by named windstorms from the Gulf of Mexico. As a result, Devon's current insurance program includes coverage for physical damage and business interruption but does not have such coverage for damages or business interruption caused from named windstorms.

During the third quarter of 2008, Hurricanes Ike and Gustav damaged certain of Devon's oil and gas facilities and transportation systems in the Gulf of Mexico. These damages relate to both production operations that will be repaired and restored and production operations that will not be restored. These damages are uninsured losses because they resulted from named windstorms.

For the damaged facilities and transportation systems for which Devon intends to resume operations after repairs have been made, a loss of $31 million was recognized in 2008. This loss is included in lease operating expenses in the accompanying statement of operations.

The facilities for which Devon will not restore production operations consist of certain platforms that were completely destroyed. Devon has begun performing asset retirement activities associated with the destroyed platforms and related wells. The time and effort required to complete such activities is expected to be significant due to the hazardous conditions created by the hurricanes. As a result, the estimated costs to complete the asset retirement activities are $82 million higher than Devon's previously estimated asset retirement obligations related to the destroyed platforms and related wells. Therefore, in 2008, Devon increased its asset retirement obligations by $82 million with a corresponding increase to oil and gas property and equipment in the accompanying balance sheet. Based on the projected timing of the retirement activities, half of this asset retirement obligation increase was recorded to the current portion and half was recorded to the long-term portion.

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 $3.7 billion total of "Drilling and Facility Obligations" in the table below is $1.7 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 $1.7 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 $46 million, $43 million and $36 million in 2008, 2007 and 2006, 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 the Nansen operating lease was $12 million in 2008, 2007 and 2006, 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 is also leasing an FPSO that is being used in the Polvo project offshore Brazil. This lease expires in 2014. Devon expects to begin production from its Cascade development in the Gulf of Mexico in 2010. As a result, Devon has entered into a contract to lease an FPSO. This lease expires in 2015. Total rental expense included in lease operating expenses under the China and Brazil operating leases was $25 million, $17 million and $9 million in 2008, 2007 and 2006, 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, 2008. The schedule includes $42 million of drilling and facility obligations related to Devon's discontinued operations (see Note 16).

Year Ending December 31,	Drilling and Facility Obligations	Firm Transportation Agreements	Office and Equipment Leases	Spar Leases	FPSO Leases
		(In millions)			
2009	$1,423	$ 273	$ 57	$ 11	$ 37
2010	897	271	41	11	59
2011	575	245	37	11	54
2012	387	223	33	22	54
2013	352	198	30	13	54
Thereafter	101	784	163	105	41
Total payments	$3,735	$1,994	$361	$173	$299

11. 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, 2008 and 2007.

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, 2008 and 2007. These assets and liabilities are not presented in the following tables.

	As of December 31, 2008				
			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):					
Long-term investments	$ 122	$ 122	$ —	$ —	$ 122
Gas price collars	$ 255	$ 255	$ —	$ 255	$ —
Interest rate swaps	$ 104	$ 104	$ —	$ 104	$ —
Debt	$(5,841)	$(6,106)	$(1,005)	$(5,101)	$ —
Asset retirement obligations	$(1,485)	$(1,485)	$ —	$ —	$(1,485)

	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	$ —	$ —
Gas price swaps	$ 12	$ 12	$ —	$ 12	$ —
Embedded option in exchangeable debentures	$ (488)	$ (488)	$ —	$ (488)	$ —
Debt	$(7,928)	$(9,055)	$(1,140)	$(7,915)	$ —
Asset retirement obligations	$(1,318)	$(1,318)	$ —	$ —	$(1,318)

The fair values are classified according to a hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table above, this hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 3 inputs have the lowest priority. Devon uses appropriate valuation techniques based on the available inputs to measure the fair values of its assets and liabilities. When available, Devon measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value. 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

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

Debt — The fair value of Devon's variable-rate commercial paper borrowings is the carrying value. Certain of Devon's 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

Gas price swaps and collars — The fair values of the 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 was not actively traded in an established market. Therefore, its fair value was estimated using quotes obtained from a broker for trades near the fair value measurement date.

Debt — Certain of Devon's 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.

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 obligations — 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. Reconciliations of the beginning and ending balances of Devon's asset retirement obligations, including revisions of the estimated fair values in 2008 and 2007, are presented in Note 5.

Short-term and long-term investments — Devon's short-term and long-term investments presented in the tables above as of December 31, 2008 and December 31, 2007 consisted entirely of auction rate securities. As of December 31, 2007, Devon estimated the fair values of its short-term investments using quoted market prices. However, due to the auction failures discussed in Note 1 and the lack of an active market for Devon's auction rate securities, quoted market prices for these securities were not available as of December 31, 2008. Therefore, Devon used valuation techniques that rely on unobservable, or Level 3, inputs to estimate the fair values of its long-term auction rate securities as of December 31, 2008. These inputs were based on the AAA credit rating of the securities, the probability of full repayment of the securities considering the United States government guarantees of substantially all of the underlying student loans, the collection of all accrued interest to date and continued receipts of principal at par. Devon also has the ability to hold these securities until their scheduled maturity dates. As a result of using these inputs, Devon concluded the estimated fair values of its long-term auction rate securities approximated the par values as of December 31, 2008. At this time, Devon does not believe the values of its long-term securities are impaired.

Included below is a summary of the changes in Devon's Level 3 short-term and long-term investments during 2008 (in millions).

Beginning balance	$ —
Transfers from Level 1 to Level 3	129
Redemptions of principal	(7)
Ending balance	$122

12. 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.

With the approval of Devon's Compensation Committee, Devon modified the share-based compensation arrangements for certain of Devon's executives in the second quarter of 2008. The modified compensation arrangements provide that executives who meet certain years-of-service and age criteria can retire and continue vesting in outstanding share-based grants. As a condition to receiving the benefits of these modifications, the executives must agree not to use or disclose Devon's confidential information and not to solicit Devon's employees and customers. The executives are required to agree to these conditions at retirement and again in each subsequent year until all grants have vested.

Although this modification does not accelerate the vesting of the executives' grants, it does accelerate the expense recognition as executives approach the years-of-service and age criteria. When the modification was made in the second quarter of 2008, certain executives had already met the years-of-service and age criteria. As a result, Devon recognized an additional $27 million of share-based compensation expense in the second quarter of 2008 related to this modification. This additional expense would have been recognized in future reporting periods if the modification had not been made and the executives continued their employment at Devon.

The following table presents the effects of share-based compensation included in Devon's accompanying statement of operations for the years ended December 31, 2008, 2007 and 2006.

	2008	2007	2006
		(In millions)	
Gross general and administrative expense	$225	$146	$91
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 53	$ 44	$26
Related income tax benefit	$ 62	$ 34	$23

Stock Options

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

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

The following table presents a summary of the grant-date fair values of stock options granted and the related assumptions for the years ended December 31, 2008, 2007 and 2006. All such amounts represent the weighted-average amounts for each year.

	2008	2007	2006
Grant-date fair value	$21.77	$26.43	$22.41
Volatility factor	44.3%	31.6%	32.2%
Dividend yield	0.9%	0.7%	0.5%
Risk-free interest rate	1.2%	5.0%	5.7%
Expected term (in years)	3.8	4.0	4.0

The following table presents a summary of Devon's outstanding stock options as of December 31, 2008, 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, 2007	13,806	$46.66		
Granted	2,175	$67.56		
Exercised	(3,918)	$31.56		
Forfeited	(169)	$68.06		
Outstanding at December 31, 2008	11,894	$55.16	3.8	$180
Vested and expected to vest at December 31, 2008	11,840	$55.08	3.8	$180
Exercisable at December 31, 2008	8,108	$46.35	3.1	$179

The aggregate intrinsic value of stock options that were exercised during 2008, 2007 and 2006 was $263 million, $151 million and $119 million, respectively. As of December 31, 2008, Devon's unrecognized compensation cost related to unvested stock options was $69 million. Such cost is expected to be recognized over a weighted-average period of 2.5 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 limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, restricted stock awards and units vest over a minimum restriction period of at least three years from the date of grant. During the vesting period, recipients of restricted stock awards receive dividends that are not subject to restrictions or other limitations. The fair value of restricted stock awards and units on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon's common stock on the grant date of the award or unit.

The following table presents a summary of Devon's unvested restricted stock awards as of December 31, 2008, including changes during the year then ended.

	Restricted Stock Awards	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2007	5,426	$71.38
Granted	3,283	$69.48
Vested	(2,222)	$64.66
Forfeited	(153)	$71.33
Unvested at December 31, 2008	6,334	$72.66

The aggregate fair value of restricted stock awards that vested during 2008, 2007 and 2006 was $185 million, $136 million and $82 million, respectively. As of December 31, 2008, Devon's unrecognized compensation cost related to unvested restricted stock awards and units was $402 million. Such cost is expected to be recognized over a weighted-average period of 3.0 years.

13. Reduction of Carrying Value of Oil and Gas Properties

During 2008 and 2006, Devon reduced the carrying values 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,			
	2008		2006	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
Full cost ceiling limitations:				
United States	$ 6,538	$4,168	$—	$—
Canada	3,353	2,488	—	—
Brazil	437	437	—	—
Russia	36	17	20	10
Indonesia	15	5	—	—
Unsuccessful exploratory activities — Brazil	—	—	16	16
Total	$10,379	$7,115	$36	$26

2008 Reductions

The 2008 reductions were all recognized in the fourth quarter of 2008 and resulted primarily from a significant decrease in each country's full cost ceiling. The lower ceiling values largely resulted from the effects of sharp declines in oil, gas and NGL prices compared to previous quarter-end prices. To demonstrate this decline, the December 31, 2008 and September 30, 2008 weighted average wellhead prices for the United States, Canada and Brazil are presented in the following table.

	December 31, 2008			September 30, 2008		
Country	Oil	Gas	NGLs	Oil	Gas	NGLs
United States	$42.21	$4.68	$16.16	$97.62	$5.28	$38.00
Canada	$23.23	$5.31	$20.89	$59.72	$6.00	$62.78
Brazil	$26.61	N/A	N/A	$81.56	N/A	N/A

N/A — Not applicable.

The December 31, 2008 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for gas. The September 30, 2008, wellhead prices in the table compare to the NYMEX cash price of $100.64 per Bbl for crude oil and the Henry Hub spot price of $7.12 per MMBtu for gas.

2006 Reductions

As a result of a decline in the estimated future net revenues, the carrying value of Devon's Russian oil and gas 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.

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.

14. Other Income

The components of other income include the following:

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Interest and dividend income	$ 75	$89	$100
Hurricane insurance proceeds	162	—	—
Other	(13)	9	15
Total	$224	$98	$115

15. Income Taxes

Income Tax (Benefit) Expense

The (loss) earnings from continuing operations before income taxes and the components of income tax expense (benefit) for the years 2008, 2007 and 2006 were as follows:

	Year Ended December 31, 2008	2007	2006
		(In millions)	
(Loss) earnings from continuing operations before income taxes:			
U.S.	$(2,190)	$2,642	$2,435
Canada	(1,970)	685	751
International	127	897	384
Total	$(4,033)	$4,224	$3,570
Current income tax expense:			
U.S. federal	$ 258	$ 83	$ 292
Various states	31	16	7
Canada and various provinces	152	136	143
International	178	265	86
Total current tax expense	619	500	528
Deferred income tax (benefit) expense:			
U.S. federal	(875)	745	456
Various states	(65)	28	77
Canada and various provinces	(622)	(166)	(105)
International	(11)	(29)	(20)
Total deferred tax (benefit) expense	(1,573)	578	408
Total income tax (benefit) expense	$ (954)	$1,078	$ 936

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, 2008	2007	2006
		(In millions)	
Expected income tax (benefit) expense based on U.S. statutory tax rate of 35%	$(1,411)	$1,478	$1,249
Effect of Canadian tax rate reductions	(7)	(261)	(243)
State income taxes	(29)	30	55
Repatriations and tax policy election changes	307	—	—
Taxation on foreign operations	206	(165)	(120)
Other	(20)	(4)	(5)
Total income tax (benefit) expense	$ (954)	$1,078	$ 936

In 2008, 2007 and 2006, deferred income taxes were reduced $7 million, $261 million and $243 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.

During 2008, Devon repatriated $2.6 billion from certain foreign subsidiaries to the United States. Subsequent to these repatriations, Devon does not expect to repatriate similar earnings from its historical operations in the foreseeable future. Also in the second quarter of 2008, Devon made certain tax policy election changes to minimize the taxes Devon otherwise would pay for the cash repatriations, as well as the taxable gains associated with the sales of assets in West Africa.

As a result of the repatriations, as well as the tax policy election changes, Devon recognized additional tax expense of $307 million during 2008. Of the $307 million, $290 million was recognized as current income tax expense, and $17 million was recognized as deferred tax expense.

Deferred Tax Assets and Liabilities

At December 31, 2008, 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, 2008.

Jurisdiction	Years of Expiration	Carryforward Amounts
		(In millions)
Various U.S. states	2009 — 2022	$ 87
Canada	2025 — 2027	$ 20
Brazil	Indefinite	$179

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2008 and 2007 are presented below:

	December 31, 2008	December 31, 2007
	(In millions)	
Deferred tax assets:		
Net operating loss carryforwards	$ 74	$ 92
Fair value of financial instruments	—	167
Asset retirement obligations	442	387
Pension benefit obligations	172	93
Other	90	123
Total deferred tax assets	778	862
Valuation allowance	(61)	(50)
Net deferred tax assets	717	812
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	(4,229)	(6,152)
Fair value of financial instruments	(132)	—
Chevron Corporation common stock	—	(431)
Long-term debt	(69)	(216)
Other	—	(11)
Total deferred tax liabilities	(4,430)	(6,810)
Net deferred tax liability	$(3,713)	$(5,998)

As shown in the above table, Devon has recognized $717 million of deferred tax assets as of December 31, 2008, net of a $61 million valuation allowance. Included in total deferred tax assets is $74 million related to various carryforwards available to offset future income taxes. The carryforwards include state net operating loss carryforwards, which expire primarily between 2009 and 2022, Canadian net operating loss carryforwards, which expire primarily between 2025 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 2009 and 2013. 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, 2008 and 2007 is $61 million and $64 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 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, 2008 and 2007, Devon had a valuation allowance of $61 million and $50 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, 2008 (in millions).

Balance as of December 31, 2007	$111
Increases (decreases) due to:	
Tax positions taken in current year	159
Accrual of interest related to tax positions taken	16
Lapse of statute of limitations	(11)
Settlements	(8)
Foreign currency translation	(7)
Balance as of December 31, 2008	$260

Devon's unrecognized tax benefit balance at December 31, 2008 and 2007 included $29 million and $14 million of interest and penalties, respectively. Included in Devon's unrecognized tax benefits of $260 million as of December 31, 2008 was $232 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	2003-2008
Various U.S. states	2003-2008
Canada federal	2001-2008
Various Canadian provinces	2001-2008
Various other foreign jurisdictions	2003-2008

Certain statute of limitation expirations are scheduled to occur in the next twelve months. However, Devon is currently in various 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.

16. 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.

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 the second quarter of 2008, Devon sold its assets and terminated its operations in certain West African countries, consisting primarily of Equatorial Guinea and Gabon. As a result of the sales, Devon recognized gains totaling $736 million ($674 million after income taxes) in 2008 from proceeds of $2.4 billion ($1.7 billion net of income taxes and purchase price adjustments).

In the third quarter of 2008, Devon sold its assets and terminated its operations in Cote d'Ivoire. As a result of this sale, Devon recognized a gain of $83 million ($95 million after income taxes) in 2008 from proceeds of $205 million ($163 million net of income taxes and purchase price adjustments).

With the Cote d'Ivoire transaction, Devon completed the divestitures of all its oil and gas producing properties in Africa. The Africa divestitures generated just over $3.0 billion of sales proceeds. After income taxes and purchase price adjustments, such proceeds totaled $2.2 billion and generated after-tax gains of $0.8 billion.

Revenues related to Devon's operations in Egypt and West Africa totaled $349 million, $781 million and $929 million during 2008, 2007 and 2006, 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, 2008 and 2007. As of December 31, 2008, the remaining assets and liabilities primarily are associated with nonproducing oil and gas properties in Angola and Nigeria.

	December 31,	
	2008	2007
	(In millions)	
Assets:		
Cash	$ 5	$ 9
Accounts receivable	—	83
Other current assets	22	28
Current assets	$27	$ 120
Long-term assets — property and equipment, net of accumulated depreciation, depletion and amortization	$19	$1,512
Liabilities:		
Accounts payable — trade	$ 7	$ 23
Revenues and royalties due to others	—	11
Income taxes payable	—	100
Current portion of asset retirement obligations	—	9
Accrued expenses and other current liabilities	6	2
Current liabilities	$13	$ 145
Asset retirement obligations, long-term	$—	$ 35
Deferred income taxes	—	366
Other liabilities	—	3
Long-term liabilities	$—	$ 404

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 2008 and 2007. As a result, earnings from discontinued operations include after-tax losses of $6 million ($6 million pre-tax) and $13 million ($64 million pre-tax) in 2008 and 2007, respectively.

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

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

17. (Loss) Earnings Per Share

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted (loss) earnings per share for 2008, 2007 and 2006. The 2008 diluted per share calculations include an increase of four million common shares outstanding due to dilutive shares. However, because a net loss from continuing operations was generated during 2008, the dilutive shares produce an antidilutive net loss per share result. Therefore, the diluted loss per share from continuing operations reported in the accompanying 2008 statement of operations is the same as the basic loss per share amount.

	Net (Loss) Earnings Applicable to Common Stockholders	Weighted Average Common Shares Outstanding	Net (Loss) Earnings per Share
	(In millions, except per share amounts)		
Year Ended December 31, 2008:			
Loss from continuing operations	$(3,079)		
Less preferred stock dividends	(5)		
Basic and diluted loss per share	$(3,084)	444	$(6.95)
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

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 and 3 million in 2007 and 2006, respectively.

18. 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 20.

Following is certain financial information regarding Devon's segments for 2008, 2007 and 2006. The revenues reported are all from external customers.

	U.S.	Canada	International	Total
		(In millions)		
As of December 31, 2008:				
Current assets	$ 1,925	$ 367	$ 392	$ 2,684
Property and equipment, net of accumulated depreciation, depletion and amortization	17,676	4,355	943	22,974
Goodwill	3,046	2,465	68	5,579
Other assets	360	72	239	671
Total assets	$23,007	$7,259	$1,642	$31,908
Current liabilities	$ 2,227	$ 543	$ 365	$ 3,135
Long-term debt	2,683	2,978	—	5,661
Asset retirement obligations, long-term	694	555	98	1,347
Other liabilities	983	40	3	1,026
Deferred income taxes	2,734	880	65	3,679
Stockholders' equity	13,686	2,263	1,111	17,060
Total liabilities and stockholders' equity	$23,007	$7,259	$1,642	$31,908

	U.S.	Canada	International	Total
		(In millions)		
Year Ended December 31, 2008:				
Revenues:				
Oil sales	$ 1,698	$ 1,535	$1,334	$ 4,567
Gas sales	5,511	1,733	19	7,263
NGL sales	997	246	—	1,243
Net loss on oil and gas derivative financial instruments	(154)	—	—	(154)
Marketing and midstream revenues	2,247	45	—	2,292
Total revenues	10,299	3,559	1,353	15,211
Expenses and other income, net:				
Lease operating expenses	1,193	809	215	2,217
Production taxes	302	4	216	522
Marketing and midstream operating costs and expenses	1,606	18	—	1,624
Depreciation, depletion and amortization of oil and gas properties	1,998	950	305	3,253
Depreciation and amortization of non-oil and gas properties	229	26	1	256
Accretion of asset retirement obligations	42	38	6	86
General and administrative expenses	518	133	2	653
Interest expense	117	212	—	329
Change in fair value of other financial instruments	149	—	—	149
Reduction of carrying value of oil and gas properties	6,538	3,353	488	10,379
Other income, net	(203)	(14)	(7)	(224)
Total expenses and other income, net	12,489	5,529	1,226	19,244
(Loss) earnings from continuing operations before income taxes	(2,190)	(1,970)	127	(4,033)
Income tax (benefit) expense:				
Current	289	152	178	619
Deferred	(940)	(622)	(11)	(1,573)
Total income tax (benefit) expense	(651)	(470)	167	(954)
Loss from continuing operations	(1,539)	(1,500)	(40)	(3,079)
Discontinued operations:				
Earnings from discontinued operations before income taxes	—	—	1,131	1,131
Income tax expense	—	—	200	200
Earnings from discontinued operations	—	—	931	931
Net (loss) earnings	(1,539)	(1,500)	891	(2,148)
Preferred stock dividends	5	—	—	5
Net (loss) earnings applicable to common stockholders	$ (1,544)	$(1,500)	$ 891	$ (2,153)
Capital expenditures, before revision of future asset retirement obligations	$ 8,313	$ 1,639	$ 558	$10,510
Revision of future asset retirement obligations	152	73	19	244
Capital expenditures, continuing operations	$ 8,465	$ 1,712	$ 577	$10,754

	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 obligations, long-term	594	569	73	1,236
Other liabilities	1,137	45	409	1,591
Deferred income taxes	3,980	2,011	51	6,042
Stockholders' equity	12,000	6,703	3,303	22,006
Total liabilities and stockholders' equity	$24,320	$12,865	$4,271	$41,456

	U.S.	Canada	International	Total
		(In millions)		
Year Ended December 31, 2007:				
Revenues:				
Oil sales	$1,313	$ 804	$1,376	$ 3,493
Gas sales	3,728	1,410	11	5,149
NGL sales	773	197	—	970
Net gain on oil and gas derivative financial instruments	14	—	—	14
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 obligations	38	32	4	74
General and administrative expenses	399	119	(5)	513
Interest expense	228	202	—	430
Change in fair value of other 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 taxes	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, before revision of future asset retirement obligations	$4,522	$1,350	$ 455	$ 6,327
Revision of future asset retirement obligations	210	99	2	311
Capital expenditures, continuing operations	$4,732	$1,449	$ 457	$ 6,638

	U.S.	Canada	International	Total
		(In millions)		
Year Ended December 31, 2006:				
Revenues:				
Oil sales	$1,218	$ 603	$613	$2,434
Gas sales	3,407	1,456	11	4,874
NGL sales	548	201	—	749
Net gain on oil and gas derivative financial instruments	38	—	—	38
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 obligations	25	21	1	47
General and administrative expenses	316	92	(11)	397
Interest expense	199	222	—	421
Change in fair value of other 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 taxes	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, before revision of future asset retirement obligations	$5,814	$1,670	$405	$7,889
Revision of future asset retirement obligations	63	71	1	135
Capital expenditures, continuing operations	$5,877	$1,741	$406	$8,024

19. Supplemental Information to Statements of Cash Flows

Additional information related to Devon's 2008, 2007 and 2006 statements of cash flows are presented below:

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Net increase in working capital:			
Decrease (increase) in accounts receivable	$ 291	$(329)	$ 91
Increase in other current assets	(78)	(38)	(33)
Increase in accounts payable	155	43	168
Increase (decrease) in revenues and royalties due to others	15	76	(343)
Decrease in income taxes payable	(349)	(28)	(245)
(Decrease) increase in other current liabilities	(172)	(223)	80
Net increase in working capital	$ (138)	$(499)	$(282)
Supplementary cash flow data:			
Interest paid (net of capitalized interest)	$ 336	$ 406	$ 384
Income taxes paid (continuing and discontinued operations)	$1,436	$ 588	$ 960
Noncash investing activity — exchange of investment in Chevron common stock for oil and gas properties (see Note 6)	$ 610	$ —	$ —

20. 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,		
	2008	2007	2006
	(In millions)		
Property acquisition costs:			
Proved properties	$ 822	$ 10	$1,113
Unproved properties	1,764	206	1,481
Exploration costs	1,342	891	881
Development costs	6,122	4,994	4,035
Costs incurred	$10,050	$6,101	$7,510

	Domestic		
	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Property acquisition costs:			
Proved properties	$ 822	$ 3	$1,066
Unproved properties	1,411	156	1,366
Exploration costs	844	569	547
Development costs	4,733	3,542	2,558
Costs incurred	$7,810	$4,270	$5,537

	Canada		
	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Property acquisition costs:			
Proved properties	$ —	$ 7	$ 23
Unproved properties	352	49	70
Exploration costs	173	211	217
Development costs	1,131	1,098	1,244
Costs incurred	$1,656	$1,365	$1,554

	International		
	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Property acquisition costs:			
Proved properties	$ —	$ —	$ 24
Unproved properties	1	1	45
Exploration costs	325	111	117
Development costs	258	354	233
Costs incurred	$584	$466	$419

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 $406 million, $312 million and $243 million in the years 2008, 2007 and 2006, 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 $96 million, $65 million and $49 million in the years 2008, 2007 and 2006, 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,		
	2008	2007	2006
	(In millions, except per equivalent barrel amounts)		
Oil, gas and NGL sales	$ 13,073	$ 9,612	$ 8,057
Production and operating expenses	(2,739)	(2,168)	(1,766)
Depreciation, depletion and amortization	(3,253)	(2,655)	(2,058)
Accretion of asset retirement obligations	(86)	(74)	(47)
General and administrative expenses	(199)	(202)	(134)
Reduction of carrying value of oil and gas properties	(10,379)	—	(36)
Income tax benefit (expense)	950	(1,257)	(1,185)
Results of operations	$ (2,633)	$ 3,256	$ 2,831
Depreciation, depletion and amortization per Boe	$ 13.68	$ 11.85	$ 10.27

	Domestic		
	Year Ended December 31,		
	2008	2007	2006
	(In millions, except per equivalent barrel amounts)		
Oil, gas and NGL sales	$ 8,206	$ 5,814	$ 5,173
Production and operating expenses	(1,495)	(1,217)	(1,048)
Depreciation, depletion and amortization	(1,998)	(1,672)	(1,311)
Accretion of asset retirement obligations	(42)	(38)	(25)
General and administrative expenses	(148)	(143)	(94)
Reduction of carrying value of oil and gas properties	(6,538)	—	—
Income tax benefit (expense)	719	(966)	(990)
Results of operations	$(1,296)	$ 1,778	$ 1,705
Depreciation, depletion and amortization per Boe	$ 12.31	$ 11.44	$ 9.89

	Canada		
	Year Ended December 31,		
	2008	2007	2006
	(In millions, except per equivalent barrel amounts)		
Oil, gas and NGL sales	$ 3,514	$2,411	$2,260
Production and operating expenses	(813)	(658)	(550)
Depreciation, depletion and amortization	(950)	(740)	(644)
Accretion of asset retirement obligations	(38)	(32)	(21)
General and administrative expenses	(37)	(36)	(29)
Reduction of carrying value of oil and gas properties	(3,353)	—	—
Income tax benefit (expense)	391	(63)	(144)
Results of operations	$(1,286)	$ 882	$ 872
Depreciation, depletion and amortization per Boe	$ 15.59	$12.73	$11.17

	International		
	Year Ended December 31,		
	2008	2007	2006
	(In millions, except per equivalent barrel amounts)		
Oil, gas and NGL sales	$1,353	$1,387	$ 624
Production and operating expenses	(431)	(293)	(168)
Depreciation, depletion and amortization	(305)	(243)	(103)
Accretion of asset retirement obligations	(6)	(4)	(1)
General and administrative expenses	(14)	(23)	(11)
Reduction of carrying value of oil and gas properties	(488)	—	(36)
Income tax expense	(160)	(228)	(51)
Results of operations	$ (51)	$ 596	$ 254
Depreciation, depletion and amortization per Boe	$20.94	$12.31	$10.02

In 2008, 2007 and 2006, the total and Canadian income tax amounts in the tables above were reduced by $7 million, $261 million and $243 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 2008, 2007 and 2006.

	2008		2007		2006	
	Prepared	Audited	Prepared	Audited	Prepared	Audited
Domestic	5%	87%	6%	83%	7%	81%
Canada	—	78%	34%	51%	46%	39%
International	99%	—	99%	—	99%	—
Total	9%	81%	19%	69%	28%	61%

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

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

Set forth below is a summary of the changes in the net quantities of crude oil, gas and natural gas liquids reserves for each of the three years ended December 31, 2008. Additional discussion of the significant proved reserve changes follows the tables below.

	Total			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 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
Revisions due to prices	(355)	(588)	(20)	(473)
Revisions other than price	16	95	6	38
Extensions and discoveries	132	2,077	67	546
Purchase of reserves	18	252	6	66
Production	(53)	(940)	(28)	(238)
Sale of reserves	(6)	(5)	—	(7)
Proved reserves as of December 31, 2008	429	9,885	352	2,428
Proved developed reserves as of:				
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
December 31, 2008	301	8,044	292	1,934

	Domestic			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
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
Revisions due to prices	(20)	(369)	(18)	(100)
Revisions other than price	5	106	6	28
Extensions and discoveries	12	1,966	65	405
Purchase of reserves	18	250	6	66
Production	(17)	(726)	(24)	(162)
Sale of reserves	(1)	(1)	—	(1)
Proved reserves as of December 31, 2008	167	8,369	317	1,878
Proved developed reserves as of:				
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
December 31, 2008	133	6,681	261	1,508

	Canada			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
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
Revisions due to prices	(349)	(219)	(2)	(387)
Revisions other than price	2	(12)	—	—
Extensions and discoveries	120	111	2	141
Purchase of reserves	—	2	—	—
Production	(22)	(212)	(4)	(61)
Sale of reserves	(5)	(4)	—	(6)
Proved reserves as of December 31, 2008	134	1,510	35	421
Proved developed reserves as of:				
December 31, 2005	103	1,708	41	429
December 31, 2006	112	1,560	33	405
December 31, 2007	195	1,506	30	476
December 31, 2008	110	1,357	31	367

	International(1)			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
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
Revisions due to prices	14	—	—	14
Revisions other than price	9	1	—	10
Extensions and discoveries	—	—	—	—
Purchase of reserves	—	—	—	—
Production	(14)	(2)	—	(15)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2008	128	6	—	129
Proved developed reserves as of:				
December 31, 2005	54	22	—	57
December 31, 2006	59	8	—	60
December 31, 2007	48	6	—	49
December 31, 2008	58	6	—	59

(1) Included in the International quantities of proved reserves as of December 31, 2008, 2007, 2006 and 2005 are 104 MMBoe, 86 MMBoe, 103 MMBoe and 105 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 2008, 2007, 2006 and 2005 in the above tables include:

- *Price Revisions* — Proved reserves must be estimated using the assumption that end-of-period prices and costs remain constant for the duration of the reservoir life. Due to significantly lower oil, gas and NGL prices as of December 31, 2008 compared to prices as of December 31, 2007, the estimated future net revenues associated with certain of Devon's proved reserves were no longer positive. As a result, 473 MMBoe of reserves were not considered proved as of December 31, 2008. Of the

473 MMBoe price revisions, 331 MMBoe related to Devon's Jackfish steam-assisted gravity drainage project in Canada.

The 473 MMBoe price revision also includes 28 MMBoe related to our proved reserves in the Canadian province of Alberta. In December 2008, the provincial government of Alberta enacted a new royalty regime. The new regime provides for new royalties for conventional oil, gas, NGL and heavy oil production effective January 1, 2009. As a result of the newly enacted royalties, our proved reserves decreased as of December 31, 2008.

- *Extensions and Discoveries*:

  2008 — Of the 546 MMBoe of 2008 extensions and discoveries, 252 MMBoe related to the Barnett Shale area in Texas, 101 MMBoe related to Jackfish, 45 MMBoe related to the Carthage area in east Texas, 21 MMBoe related to the Cana shale development area in western Oklahoma, 19 MMBoe related to the Lloydminster heavy oil development in Canada and 17 MMBoe related to the Woodford shale development area in southeastern Oklahoma.

  The 2008 extensions and discoveries included 420 MMBoe related to additions from Devon's infill drilling activities, including 243 MMBoe related to the Barnett Shale, 101 MMBoe related to Jackfish, 22 MMBoe related to Carthage, 18 MMBoe related to Lloydminster and 11 MMBoe related to Cana.

  2007 — Of the 315 MMBoe of 2007 extensions and discoveries, 119 MMBoe related to the Barnett Shale, 34 MMBoe related to Carthage, 22 MMBoe related to Jackfish, 20 MMBoe related to Lloydminster, 17 MMBoe related to Washakie and 15 MMBoe related to the Woodford Shale.

  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 and 20 MMBoe related to Lloydminster.

- *Purchase of Reserves* — The 2008 total included 34 MMBoe located in Utah and 27 MMBoe located in the Permian Basin. The 2006 total included 100 MMBoe located in the Barnett Shale that was acquired in the June 2006 Chief acquisition.

- *Revisions Other Than Price* — The 2008 total included performance revisions of 22 MMBoe in the Barnett Shale. The 2007 total included performance revisions of 39 MMBoe in the Barnett Shale, 13 MMBoe at Jackfish, 13 MMBoe in Carthage and seven 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, 2008	2007	2006
	(In millions)		
Future cash inflows	$ 66,790	$111,156	$ 77,951
Future costs:			
Development	(9,340)	(9,974)	(8,116)
Production	(30,719)	(38,541)	(28,107)
Future income tax expense	(6,989)	(17,930)	(12,396)
Future net cash flows	19,742	44,711	29,332
10% discount to reflect timing of cash flows	(9,250)	(21,105)	(13,581)
Standardized measure of discounted future net cash flows	$ 10,492	$ 23,606	$ 15,751

	Domestic December 31, 2008	2007	2006
	(In millions)		
Future cash inflows	$ 51,284	$ 72,109	$ 47,980
Future costs:			
Development	(6,887)	(5,673)	(4,919)
Production	(24,113)	(24,606)	(18,428)
Future income tax expense	(5,585)	(12,704)	(7,743)
Future net cash flows	14,699	29,126	16,890
10% discount to reflect timing of cash flows	(7,318)	(14,312)	(8,091)
Standardized measure of discounted future net cash flows	$ 7,381	$ 14,814	$ 8,799

	Canada December 31, 2008	2007	2006
	(In millions)		
Future cash inflows	$11,459	$ 28,684	$22,575
Future costs:			
Development	(1,623)	(3,380)	(2,395)
Production	(4,984)	(10,331)	(7,431)
Future income tax expense	(1,137)	(3,729)	(3,614)
Future net cash flows	3,715	11,244	9,135
10% discount to reflect timing of cash flows	(1,463)	(5,282)	(4,318)
Standardized measure of discounted future net cash flows	$ 2,252	$ 5,962	$ 4,817

	International		
	December 31,		
	2008	2007	2006
	(In millions)		
Future cash inflows	$ 4,047	$10,363	$ 7,396
Future costs:			
Development	(830)	(921)	(802)
Production	(1,622)	(3,604)	(2,248)
Future income tax expense	(267)	(1,497)	(1,039)
Future net cash flows	1,328	4,341	3,307
10% discount to reflect timing of cash flows	(469)	(1,511)	(1,172)
Standardized measure of discounted future net cash flows	$ 859	$ 2,830	$ 2,135

Future cash inflows are computed by applying year-end prices (averaging $32.65 per barrel of oil, $4.75 per Mcf of gas and $16.54 per barrel of natural gas liquids at December 31, 2008) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $9.3 billion of future development costs as of the end of 2008, $1.7 billion, $1.6 billion and $1.5 billion are estimated to be spent in 2009, 2010 and 2011, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $9.3 billion of future development costs are $2.0 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,		
	2008	2007	2006
		(In millions)	
Beginning balance	$ 23,606	$15,751	$ 21,629
Oil, gas and NGL sales, net of production costs	(10,135)	(7,242)	(6,157)
Net changes in prices and production costs	(16,013)	9,550	(10,275)
Extensions and discoveries, net of future development costs	1,889	4,162	4,586
Purchase of reserves, net of future development costs	214	51	800
Development costs incurred during the period that reduced future development costs	1,790	1,887	1,466
Revisions of quantity estimates	(1,674)	578	(2,199)
Sales of reserves in place	(8)	(51)	(10)
Accretion of discount	3,307	2,232	3,234
Net change in income taxes	5,773	(2,879)	4,143
Other, primarily changes in timing and foreign exchange rates	1,743	(433)	(1,466)
Ending balance	$ 10,492	$23,606	$ 15,751

21. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2008 and 2007.

	2008				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Revenues	$2,975	$3,548	$5,978	$ 2,710	$15,211
Earnings (loss) from continuing operations	$ 651	$ 594	$2,509	(6,833)	$(3,079)
Earnings from discontinued operations	98	707	109	17	931
Net earnings (loss)	$ 749	$1,301	$2,618	(6,816)	$(2,148)
Basic net earnings (loss) per common share:					
Earnings (loss) from continuing operations	$ 1.46	$ 1.33	$ 5.67	$(15.46)	$ (6.95)
Earnings from discontinued operations	0.22	1.58	0.25	0.04	2.10
Net earnings (loss)	$ 1.68	$ 2.91	$ 5.92	$(15.42)	$ (4.85)
Diluted net earnings (loss) per common share:					
Earnings (loss) from continuing operations	$ 1.44	$ 1.31	$ 5.63	$(15.46)	$ (6.95)
Earnings from discontinued operations	0.22	1.57	0.24	0.04	2.10
Net earnings (loss)	$ 1.66	$ 2.88	$ 5.87	$(15.42)	$ (4.85)

	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

Earnings (Loss) from Continuing Operations

The fourth quarter of 2008 includes reductions of the carrying values of oil and gas properties totaling $10.4 billion ($7.1 billion after income taxes, or $16.10 per diluted share).

The first and second quarters of 2008 include unrealized losses on our commodity hedges of $780 million ($499 million after income taxes, or $1.11 per diluted share) and $912 million ($584 million after income taxes, or $1.30 per diluted share), respectively, as a result of increases in gas prices subsequent to our trade dates. The third quarter of 2008 includes a net unrealized gain of $1.8 billion ($1.2 billion after income taxes, or $2.63 per diluted share), resulting from a decrease in gas prices.

The second quarter of 2008 includes an increase to income tax expense from continuing operations of $312 million (or $0.70 per diluted share) due to repatriations from certain foreign subsidiaries to the United States and tax policy election changes.

The second and fourth quarters 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.

Earnings from Discontinued Operations

The second quarter of 2008 includes a $623 million gain ($529 million after income taxes, or $1.17 per diluted share) as a result of completing the sale of Devon's Equatorial Guinea operations. Also, during the second quarter of 2008, Devon closed the sale of its Gabon operations, which resulted in a $114 million gain ($111 million after income taxes, or $0.25 per diluted share).

The third quarter of 2008 includes an $83 million gain ($101 million after income taxes, or $0.23 per diluted share) as a result of completing the sale of Devon's assets in Cote d'Ivoire.

The second quarter of 2007 includes a reduction of carrying value of oil and gas properties of $64 million ($13 million after income taxes, or $0.03 per diluted share).

The fourth quarter of 2007 includes a $90 million gain ($90 million after income taxes, or $0.20 per diluted share) as a result of completing the sale of Devon's assets in Egypt in October 2007.

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, 2008 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 20, 2009, management concluded that its internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of Devon's internal control over financial reporting as of December 31, 2008 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, 2008, 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 2008 that has materially affected, or is reasonably likely to materially affect, Devon's internal control over financial reporting.

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

Not applicable.

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 30, 2009.

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 30, 2009.

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 30, 2009.

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 30, 2009.

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 30, 2009.

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
1.1	Underwriting Agreement, dated as of January 6, 2009, among Devon Energy Corporation and Banc of America Securities LLC, J.P. Morgan Securities Inc. and UBS Securities LLC, as representatives of the several Underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant's Form 8-K filed on January 9, 2009).
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 on 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 on 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 filed on 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 on 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 filed on July 15, 1999).
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 Certificate of Amendment of Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant's Form 10-Q filed on August 7, 2008).
3.3	Registrant's Bylaws (incorporated by reference to Exhibit 3.2 of Registrant's Form 10-K filed on March 3, 2006).
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).

Exhibit No.	Description
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).
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 on August 4, 2006).
4.6	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., 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 on April 9, 2002).
4.7	Supplemental Indenture No. 1, dated as of March 25, 2002, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., 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	Supplemental Indenture No. 3, dated as of January 9, 2009, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 5.625% Senior Notes due 2014 and the 6.30% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on January 9, 2009).
4.9	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 Trust Company, N.A., 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 on October 31, 2001).
4.10	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 Trust Company, N.A., 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)).
4.11	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 Trust Company, N.A., 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).
4.12	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 Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed 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 on September 28, 2001).
4.13	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 Trust Company, N.A., as Trustee, relating to the 7.25% Senior Notes due 2011 (incorporated by reference to Exhibit 4.19 of Registrant's Form 10-K filed on March 3, 2006).
4.14	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)).

Exhibit No.	Description
4.15	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).
4.16	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 on May 14, 2001).
4.17	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 filed on March 3, 2006).
4.18	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 Trust Company, N.A., 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)).
4.19	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 Trust Company, N.A., 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).
4.20	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 Trust Company, N.A., 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).
4.21	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 Trust Company, N.A.., as Trustee, relating to the 7.50% Senior Notes (incorporated by reference to Exhibit 4.27 of Registrant's Form 10-K filed on March 3, 2006).
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 filed on August 30, 2001).
10.2	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 (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-K filed on February 28, 2008).
10.3	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).
10.4	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 to this Amendment (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-Q filed on November 7, 2007).

Exhibit No.	Description
10.5	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 to this Amendment. (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed on November 7, 2007).
10.6	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 (incorporated by reference to Exhibit 10.7 to Registrant's Form 10-K filed on February 28, 2008).
10.7	Fourth Amendment to Amended and Restated Credit Agreement dated as of April 7, 2008, among Registrant as 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 10.1 of Registrant's Form 10-Q filed on May 7, 2008).
10.8	Fifth Amendment to Amended and Restated Credit Agreement dated as of November 5, 2008, among Registrant as 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 of Registrant's Form 10-Q filed on November 6, 2008).
10.9	364-Day Credit Agreement dated as of November 5, 2008 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 $700 Million Short-Term Credit Facility (incorporated by reference to Exhibit 10.1 of Registrant's Form 10-Q filed on November 6, 2008).
10.10	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).*
10.11	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).*
10.12	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).*
10.13	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).*
10.14	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 on April 28, 2003).*
10.15	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 on April 28, 2003).*
10.16	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).*
10.17	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).*
10.18	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).*

Exhibit No.	Description
10.19	Amended and Restated Form of Employment Agreement between Registrant and Stephen J. Hadden, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt dated December 15, 2008.*
10.20	Form of Award Agreement between Registrant and Stephen J. Hadden, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for stock options granted from the 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.39 to Registrant's Form 10-Q filed on August 4, 2005).*
10.21	Form of Amendment to Nonqualified Stock Option Award Agreements under the Devon Energy Corporation 2005 Long-Term Incentive Plan between Registrant and Stephen J. Hadden, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt (incorporated by reference to Exhibit 10.1 of Registrant's Form 10-Q filed on August 7, 2008).*
10.22	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 filed on August 4, 2005).*
10.23	Form of Non-Management Director Nonqualified Stock Option Award Agreement under the Devon Energy Corporation 2005 Long-Term Incentive Plan between Registrant and all Non-Management Directors (incorporated by reference to Exhibit 10.3 of Registrant's Form 10-Q filed on August 7, 2008).*
10.24	Form of Award Agreement from the 2005 Long-Term Incentive Plan between Registrant and Stephen J. Hadden, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor, William F. Whitsitt and all Non-Management Directors for restricted stock awards (incorporated by reference to Exhibit 10.41 to Registrant's Form 10-Q filed on August 4, 2005).*
10.25	Form of Amendment to Restricted Stock Award Agreements under the Devon Energy Corporation 2005 Long-Term Incentive Plan between Registrant and Stephen J. Hadden, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt (incorporated by reference to Exhibit 10.2 of Registrant's Form 10-Q filed on August 7, 2008).*
10.26	Form of Non-Management Director Restricted Stock Award Agreement under the Devon Energy Corporation 2005 Long-Term Incentive Plan between Registrant and all Non-Management Directors (incorporated by reference to Exhibit 10.4 of Registrant's Form 10-Q filed on August 7, 2008).*
10.27	Amended and Restated Severance Agreement between Registrant and Danny J. Heatly, dated December 15, 2008.*
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, Senior Vice President — Accounting and Chief Accounting 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, Senior Vice President — Accounting and Chief Accounting 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, 2009

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, 2009
/s/ JOHN RICHELS John Richels	President and Director	February 27, 2009
/s/ DANNY J. HEATLY Danny J. Heatly	Senior Vice President — Accounting and Chief Accounting Officer	February 27, 2009
/s/ THOMAS F. FERGUSON Thomas F. Ferguson	Director	February 27, 2009
/s/ DAVID A. HAGER David A. Hager	Director	February 27, 2009
/s/ JOHN A. HILL John A. Hill	Director	February 27, 2009
/s/ ROBERT L. HOWARD Robert L. Howard	Director	February 27, 2009
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 27, 2009
/s/ J. TODD MITCHELL J. Todd Mitchell	Director	February 27, 2009
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 27, 2009