DEVON ENERGY CORP/DE
Form 10-K
February 25, 2011

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

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

or

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

Commission File Number 001-32318
Devon Energy Corporation
(Exact name of registrant as specified in its charter)

Delaware	**73-1567067**
(State 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 þ No o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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. o

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

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

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2010, was approximately $26.6 billion, based upon the closing price of $60.92 per share as reported by the New York Stock Exchange on such date. On February 10, 2011, 427 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2011 annual meeting of stockholders Part III

DEVON ENERGY CORPORATION

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TO THE SECURITIES AND EXCHANGE COMMISSION

DEFINITIONS

Measurements of Oil, Natural Gas and Natural Gas Liquids

NGL or NGLs means natural gas liquids.

Oil includes crude oil and condensate.

Bbl means barrel of oil. One barrel equals 42 U.S. gallons.

MBbls means thousand barrels.

MMBbls means million barrels.

MBbls/d means thousand barrels per day.

Mcf means thousand cubic feet of natural gas.

MMcf means million cubic feet.

Bcf means billion cubic feet.

Bcfe means billion cubic feet equivalent.

MMcf/d means million cubic feet per day.

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

MBoe means thousand Boe.

MMBoe means million Boe.

MBoe/d means thousand Boe per day.

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

MMBtu means million Btu.

MMBtu/d means million Btu per day.

Geographic Areas

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

International means the discontinued operations of Devon that encompass oil and gas properties that lie outside the United States and Canada.

North America Onshore means the operations of Devon encompassing oil and gas properties in the continental United States and Canada.

U.S. Offshore means the divested operations of Devon that encompassed oil and gas properties in the Gulf of Mexico.

U.S. Onshore means the properties of Devon encompassing oil and gas properties in the continental United States.

Other

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

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

LIBOR means London Interbank Offered Rate.

NYMEX means New York Mercantile Exchange.

SEC means United States Securities and Exchange Commission.

INFORMATION 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, 2010 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 expectatio 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, as well as the prices of oil, gas, NGLs and other products or services, including regional pricing differentials;
- production levels, including Canadian production subject to government royalties, which fluctuate with prices and 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;

public policy and government regulatory changes, including changes in royalty, production tax and income tax regimes, changes in hydraulic fracturing regulation, changes in environmental regulation and liability under federal, state, local or foreign environmental laws and regulations;

terrorism;

occurrence of property acquisitions or divestitures; and

other factors disclosed under Item 2. Properties 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 exploration, development and production of natural gas and oil. Our operations are concentrated in various North American onshore areas in the United States and Canada. We also have offshore operations located in Brazil and Angola that are currently in the process of being divested.

To complement our upstream oil and gas operations in North America, we have a large marketing and midstream operation. With these operations, we market gas, crude oil and NGLs. We also construct and operate pipelines, storage and treating facilities and natural gas processing plants. These midstream facilities are used to transport oil, gas, and NGLs and process natural gas.

We began operations in 1971 as a privately held company. We have been publicly held since 1988, and our common stock is listed on 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

As an enterprise, we aspire to be the premier independent natural gas and oil company in North America. To achieve this, we continuously strive to optimize value for our shareholders by growing cash flows, earnings, production and reserves, all on a per debt-adjusted share basis. We do this by:

- exercising capital discipline;
- investing in oil and gas properties with high operating margins;
- balancing our reserves and production mix between natural gas and liquids;
- maintaining a low overall cost structure;
- improving performance through our marketing and midstream operations; and
- preserving financial flexibility.

Over the decade leading up to 2010, we captured an abundance of resources by carrying out this strategy. We pioneered horizontal drilling in the Barnett Shale and extended this technique to other natural gas shale plays in the United States and Canada. We became proficient with steam-assisted gravity drainage with our Jackfish oil sands development in Alberta, Canada. We achieved key oil discoveries with our drilling in the deepwater Gulf of Mexico and offshore Brazil. We have tripled our proved oil and gas reserves since 2000, and have also assembled an extensive inventory of exploration assets representing additional unproved resources.

Building off our past successes, in November 2009, we announced plans to strategically reposition Devon as a North American onshore exploration and production company. As part of this strategic repositioning, we are bringing forward the value of our offshore assets located in the Gulf of Mexico and countries outside North America by divesting them. As of the end of 2010, we had sold our properties in the Gulf of Mexico, Azerbaijan, China and other International regions, generating $5.6 billion in after-tax proceeds. Additionally, we have entered into agreements to sell our remaining offshore assets in Brazil and Angola and are waiting for the respective governments to approve the divestitures. Once the pending transactions are complete, we expect to have generated more than $8 billion in after-tax proceeds.

This repositioning has allowed us to focus our operations on our premier portfolio of North American onshore assets. Historically, our North American onshore assets have consistently provided us our highest risk-adjusted investment returns. By selling our offshore assets, we are able to conduct an aggressive, yet disciplined, pursuit of the untapped value of these North American onshore opportunities. More specifically,

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given the current challenged market for natural gas prices, our near-term focus is on the oil and liquids-rich opportunities that exist within our balanced portfolio of properties.

Besides investing in our onshore exploration and development opportunities, we are also using the divestiture proceeds to reduce our debt significantly and conduct up to a $3.5 billion common share repurchase program.

Presentation of Discontinued Operations

As a result of our November 2009 repositioning announcement, all amounts in this document related to our International operations are presented as discontinued. Therefore, financial data and operational data, such as reserves, production, wells and acreage, provided in this document exclude amounts related to our International operations unless otherwise provided.

Our U.S. Offshore operations do not qualify as discontinued operations under accounting rules. As such, financial and operational data provided in this document that pertain to our continuing operations include amounts related to our U.S. Offshore operations that were divested in 2010. Where appropriate, we have presented amounts related to our U.S. Offshore assets separate from those of our North American Onshore assets.

Development of Business

Since our first issuance of common stock to the public in 1988, we have executed strategies that have been focused on growth and value creation for our shareholders. We increased our total proved reserves from 8 MMBoe at year-end 1987 to 2,873 MMBoe at year-end 2010. During this same time period, we increased annual production from 1 MMBoe in 1987 to 228 MMBoe in 2010. Our expansion over this time period is attributable to a focused mergers and acquisitions program spanning a number of years, as well as active and successful exploration and development programs in more recent years. Additionally, our growth has provided meaningful value creation for our shareholders. The growth statistics from 1987 to 2010 translate into annual per share growth rates of 8% for production and 11% for reserves.

As a result of this growth, we have become one of the largest independent oil and gas companies in North America. During 2010, we continued to build off our past successes with a number of key accomplishments, including those discussed below.

Drilling Success We drilled 1,584 gross wells in 2010 on our North American onshore properties with a 99% success rate. We increased oil and NGL production from our North American onshore properties by 6% in 2010, to an average of 193 MBoe per day.

Cana-Woodford Shale We drilled 87 wells in the Cana-Woodford Shale play in western Oklahoma and more than doubled our industry-leading leasehold position in the play to more than 240,000 net acres. Our 2010 production exit rate from the Cana-Woodford increased more than 210% over the prior year to an average of 147 MMcf of gas equivalent per day, including 4 MBbls per day of liquids production. We also completed construction and commenced operation of our Cana gas processing plant in 2010.

Permian Basin We exited 2010 with Permian production of 45 MBoe per day, which represented a 16% increase compared to 2009. We have nearly one million net acres of leasehold in the region targeting various oil and liquids-rich play types.

Jackfish In 2010, our net production from our Jackfish oil sands project averaged 25 MBbls per day. Following scheduled facilities maintenance in the third quarter and a third-party pipeline system outage in the fourth quarter, our net Jackfish production ramped back up to 30 MBbls per day at year-end.

Construction of our second Jackfish project is now complete. We expect to begin injecting steam at Jackfish 2 in the second quarter, with first oil production expected by the end of 2011. We applied for regulatory approval of a third phase of Jackfish in the third quarter of 2010.

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Pike We added to our Canadian oil position by acquiring a 50% interest in the Pike oil sands leases. The Pike acreage lies immediately adjacent to our highly successful Jackfish project and has estimated gross recoverable resources that may exceed Jackfish. We are the operator of the project and are currently drilling appraisal wells and acquiring seismic data. The drilling results and seismic will help us determine the optimal configuration for the initial phase of development.

Barnett Shale Our 2010 production exit rate was 1.2 Bcfe per day, including 43 MBbls per day of liquids production. This represents a 16% increase in total production compared to the 2009 exit rate.

Financial Information about Segments and Geographical Areas

Notes 20 and 22 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 and Delivery Commitments

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 or fixed-price contracts associated 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 and short-term agreements at prices negotiated with third parties. Although exact percentages vary daily, as of January 2011, approximately 81% of our oil production was sold under short-term contracts at variable or market-sensitive prices. The remaining 19% of oil production was sold under long-term, market-indexed contracts that are subject to market pricing variations.

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 January 2011, approximately 81% 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 18% 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 January 2011, approximately 83% of our NGL production was sold under short-term contracts at variable or market-sensitive prices. Approximately 9% of our NGL production was sold under short-term, fixed-price contracts. The remaining 8% of NGL production was sold under long-term, market-sensitive price contracts.

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Delivery Commitments

A portion of our production is sold under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. Although exact amounts vary, as of January 2011, we were committed to deliver the following fixed quantities of our oil and natural gas production:

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Oil (MMBbls)	210	14	41	43	112
Natural gas (Bcf)	607	226	223	103	55
NGLs (MMBbls)	13	13			
Total (MMBoe)(1)	324	65	78	60	121

(1) Gas volumes 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. NGLs are converted to Boe on a one-to-one basis with oil.

We expect to fulfill our delivery commitments over the next three years with production from our proved developed reserves. We expect to fulfill our longer-term delivery commitments beyond three years primarily with our proved developed reserves. In certain regions, we expect to fulfill these longer-term delivery commitments with our proved undeveloped reserves. See Note 22 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this report for information related to our proved reserves, including the development of our proved undeveloped reserves.

Our proved reserves have been sufficient to satisfy our delivery commitments during the three most recent years, and we expect such reserves will continue to satisfy our future delivery commitments. However, should our proved reserves not be sufficient to satisfy our future delivery commitments, we can and may use spot market purchases to fulfill the commitments.

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. We have other natural gas processing plants that support our operations, including a plant completed in 2010 that serves the Cana-Woodford Shale production. 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 or other blend-stock and 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.

During 2010, 2009 and 2008, no purchaser accounted for over 10% of our revenues.

Seasonal Nature of Business

Generally, 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.

Public Policy and Government Regulation

The oil and natural gas industry is subject to various types of regulation throughout the world. Laws, rules, regulations and other policy implementations affecting the oil and natural gas industry have been pervasive and are under constant review for amendment or expansion. Pursuant to public policy changes, numerous government agencies have issued extensive laws and regulations binding on the oil and natural 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 public policy changes affecting the oil and natural gas industry are commonplace and because 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 natural gas companies of similar size and financial strength.

During 2010, as part of a strategic restructuring of the company, we sold our properties in the Gulf of Mexico and the majority of our assets outside North America, Additionally, we have entered into agreements to sell our remaining offshore assets in Brazil and Angola and are waiting for the respective governments to approve the divestitures. These divestitures reduce our vulnerability to laws, rules and regulations imposed by foreign governments, as well as those imposed in the United States for offshore exploration and production. The following are significant areas of government control and regulation affecting our operations in the United States and Canada.

Exploration and Production Regulation

Our oil and gas operations are subject to various federal, state, provincial, tribal and local laws and regulations. These laws and regulations relate to matters that include, but are not limited to:

acquisition of seismic data;

location of wells;

drilling and casing of wells;

hydraulic fracturing;

well production;

spill prevention plans;

emissions and discharge permitting;

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;

calculation and disbursement of royalty payments and production taxes;

plugging and abandoning of wells; and

transportation of production.

Our operations also are 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. natural gas and oil leases are granted by the federal government and administered by the Bureau of Land Management 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 federal government 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.

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 and the type and quality of the petroleum product produced. From time to time, the federal and provincial governments of Canada also have established incentive programs such as royalty rate reductions, royalty holidays, tax credits and fixed rate and profit-sharing royalties 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.

Pricing and Marketing in Canada

Any oil or gas export to be made pursuant to an export contract that exceeds a certain duration or a certain quantity requires an exporter to obtain export authorizations 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.

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Environmental and Occupational Regulations

We are subject to various federal, state, provincial, tribal and local 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.

We consider the costs of environmental protection and safety and health compliance necessary and manageable parts of our business. We have been able to plan for and comply with environmental, safety and health initiatives without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and will likely continue to increase. 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.

In 2010, the United States Environmental Protection Agency (EPA) issued rules requiring oil and natural gas companies to track and report their greenhouse gas emissions. For Devon, this involves collecting emissions data at more than 17,000 well sites and numerous natural gas plants and compressor stations. While these rules increase our cost of doing business, we do not anticipate that we would be impacted to any greater degree than other similar oil and natural gas companies.

The Kyoto Protocol was adopted by numerous countries in 1997 and implemented in 2005. The Protocol requires reductions of certain emissions of greenhouse gases. Although the United States has not ratified the Protocol, the other countries in which we operate have. In 2007, Canada ratified the Kyoto Protocol and committed to reducing Canada s greenhouse gas emissions. This commitment was renewed by signing the Copenhagen Accord in 2009 and the Cancun Agreement in 2010. Although there is no framework in place, Canada remains focused on the original reduction target of the Kyoto Protocol and is working to align greenhouse gas policy with the United States. The mandatory reductions on greenhouse gas emissions will create additional costs for the Canadian oil and gas industry, including Devon. Provincially, British Columbia and Alberta have greenhouse gas legislation and regulation that carry some compliance burden for the oil and gas sector. Presently, it is not possible to accurately estimate the costs we could incur to comply with any future laws or regulations developed to achieve emissions reductions in Canada or elsewhere, but such expenditures could be substantial.

In 2006, we established 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 greenhouse gas emission inventory. We last published our emission inventory on January 2008. We will publish another emission inventory on or before March 31, 2011 to comply with a reporting mandate issued by the EPA. Additionally, we continue to explore energy efficiency measures and

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greenhouse emission reduction opportunities. We also continue to monitor legislative and regulatory climate change developments, such as the proposals described above.

Employees

As of December 31, 2010, we had approximately 5,000 employees. We consider labor relations with our employees to be satisfactory. We have not had any work stoppages or strikes pertaining to our employees.

Competition

See Item 1A. Risk Factors.

Availability of Reports

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

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 general supply and demand for oil, gas and NGLs, which impact the prices we ultimately realize on our sales of these commodities. 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, market prices and our realized 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);

differing quality and NGL 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.

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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 and internal controls related to estimating and recording reserves is described in Item 2. Properties Preparation of Reserves Estimates and Reserves Audits.

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 or tertiary recovery techniques, 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;
- 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.

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. They also may have established strategic long-term positions and relationships in areas 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.

Midstream Capacity Constraints and Interruptions Impact Commodity Sales

We rely on midstream facilities and systems to process our natural gas production and to transport our production to downstream markets. Such midstream systems include the systems we operate, as well as systems operated by a number of different third parties. When possible, we gain access to midstream systems that provide the most advantageous downstream market prices available to us.

Regardless of who operates the midstream systems we rely upon, a portion of our production in any region may be interrupted or shut in from time to time due to loss of access to plants, pipelines or gathering systems. Such access could be lost due to a number of factors, including, but not limited to, weather conditions, accidents, field labor issues or strikes. Additionally, we and third-parties may be subject to constraints that limit our ability to construct, maintain or repair midstream facilities needed to process and transport our production. Such interruptions or constraints could negatively impact our production and associated profitability.

Hedging Activities Limit Participation in Commodity Price Increases and Increase Exposure to Counterparty Credit Risk

We periodically enter into hedging activities with respect to a portion of our production to manage our exposure to oil, gas and NGL price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts.

Public Policy, Which Includes Laws, Rules and Regulations, Can Change

Our operations are generally subject to federal laws, rules and regulations in the United States and Canada. In addition, we are also subject to the laws and regulations of various states, provinces, tribal and local governments. Pursuant to public policy changes, 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 public policy 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. Existing laws and regulations can also require us to incur substantial costs to maintain regulatory compliance. Our operating and other compliance costs could increase further if existing laws and regulations are revised or reinterpreted or if new laws and regulations become applicable to our operations. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity, particularly changes related to hydraulic fracturing, income taxes and climate change as discussed below.

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Hydraulic Fracturing The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural-gas industry in the hydraulic-fracturing process. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. This legislation, if adopted, could establish an additional level of regulation and permitting at the federal level.

Income Taxes The U.S. President s recent budget proposals include provisions that would, if enacted, make significant changes to United States tax laws. The most significant change would eliminate the immediate deduction for intangible drilling and development costs.

Climate Change Policy makers in the United States are increasingly focusing on whether the emissions of greenhouse gases, such as carbon dioxide and methane, are contributing to harmful climatic changes. Policy makers at both the United States federal and state level have introduced legislation and proposed new regulations that are designed to quantify and limit the emission of greenhouse gases through inventories and limitations on greenhouse gas emissions. Legislative initiatives to date have focused on the development of cap-and-trade programs. These programs generally would cap overall greenhouse gas emissions on an economy-wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. Cap-and-trade programs would be relevant to our operations because the equipment we use to explore for, develop, produce and process oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the oil, gas and NGLs we sell, emits carbon dioxide and other greenhouse gases.

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 and local 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 public policy 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 occurrence including, but not limited to 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.

International Operations Have Uncertain Political, Economic and Other Risks

Our operations outside North America are based in Brazil and Angola. As noted earlier in this report, we are in the process of divesting our operations outside North America. However, until we cease operating in these locations, 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. These 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.

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, 2010, our auction rate securities totaled $94 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 2009 and 2010, we consider these investments to be long-term in nature and generally not available for short-term liquidity needs. Therefore, we have classified these investments as other long-term assets.

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 problems in the global credit markets, including but not limited to, U.S. subprime mortgage defaults and writedowns by major financial institutions due to deteriorating values of their asset portfolios. These and other

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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*

Property Overview

Our oil and gas operations are concentrated within various North American onshore basins across the United States and Canada. Our properties consist of interests in developed and undeveloped oil and gas leases and mineral acreage in these regions. These ownership interests entitle us to drill for and produce oil, natural gas and NGLs from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, overriding royalty, mineral, and other forms of direct and indirect ownership in oil and gas properties.

As previously mentioned, we have completed substantially all of our offshore divestitures, with the exception of assets in Brazil and Angola. We have entered into agreements to sell these assets and are waiting for the respective governments to approve the divestitures.

We also have a substantial midstream business that includes natural gas and NGL processing plants and pipeline systems across North America. In aggregate, we have ownership in approximately 13,000 miles of pipeline and 65 natural gas processing and treating plants. Our most significant concentration of midstream assets is located in north Texas at our Barnett Shale field. These assets include over 3,000 miles of pipeline, two natural gas processing plants with 750 MMcf per day of total capacity, and a 15 MBbls per day NGL fractionator. In 2010, we completed construction of a natural gas processing plant to support the growing development of our Cana-Woodford Shale properties. The Cana plant has an initial capacity of 200 MMcf per day with the design capacity to expand up to 600 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 Alberta with connectivity to a 350 MBbls storage terminal near Edmonton. The dual pipeline system allows us to deliver diluents to Jackfish for the blending of our heavy oil production and transport the combined product to the Edmonton crude oil market for sale. We have a 50% ownership interest in the Access Pipeline.

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The following sections provide additional details of our oil and gas properties, including information about proved reserves, production, wells, acreage and drilling activities.

Property Profiles

The locations of our key properties are presented on the following map.

The following table presents proved reserve information for our key properties as of December 31, 2010, along with their production volumes for the year 2010. Our key properties include those that currently have significant proved reserves or production. These key properties also include properties that do not have current significant levels of proved reserves or production, but are expected be the source of future significant growth in proved reserves and production.

	Proved Reserves (MMBoe)(1)	Proved Reserves %(2)	Production (MMBoe)(1)	Production %(2)
U.S.				
Barnett Shale	1,112	38.7%	70	31.6%
Carthage	182	6.3%	12	5.6%
Cana-Woodford Shale	175	6.1%	7	3.0%
Permian Basin	167	5.8%	16	7.0%
Washakie	95	3.3%	8	3.7%
Arkoma-Woodford Shale	48	1.7%	5	2.1%
Groesbeck	48	1.7%	6	2.6%
Granite Wash	40	1.4%	4	1.8%
Haynesville-Bossier Shale	11	0.4%	1	0.6%
Other U.S. Onshore	229	7.9%	29	13.1%
Total U.S. Onshore	**2,107**	**73.3%**	**158**	**71.1%**
Canada				
Jackfish	440	15.3%	9	4.1%
Northwest	107	3.7%	15	6.6%
Lloydminster	65	2.3%	15	6.7%
Deep Basin	56	2.0%	10	4.5%
Horn River Basin	11	0.4%	1	0.2%
Pike				
Other Canada	87	3.0%	15	6.8%
Total Canada	**766**	**26.7%**	**65**	**28.9%**
North America Onshore	**2,873**	**100.0%**	**223**	**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.

The following profile information includes the location, acreage, formation type, average working interest and 2010 drilling activities of our key properties presented in the table above. Due to the continued depressed natural gas price environment, we are shifting the vast majority of our 2011 drilling activity to focus on the oil and liquids-rich gas properties within our portfolio. For the key properties that are primarily liquids-based, we also provide our 2011 drilling plans in the profile information below.

U.S.

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 630,000 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 89%. We drilled 460 gross wells in 2010 and plan to drill approximately 320 gross wells in 2011.

Carthage The Carthage area in east Texas includes primarily Harrison, Marion, Panola and Shelby counties. Our average working interest is 86% and we hold approximately 225,000 net acres. Our Carthage area wells produce primarily natural gas and NGLs from conventional reservoirs. We drilled 26 gross wells in 2010 in this area.

Cana-Woodford Shale The Cana-Woodford Shale is located primarily in Canadian, Blaine, Caddo, and Dewey counties in western Oklahoma. Our average working interest is 52% and we hold more than 240,000 net acres. Our Cana-Woodford Shale properties produce natural gas, NGLs and condensate from a non-conventional reservoir. We drilled 87 gross wells in 2010 and plan to drill around 220 gross wells in 2011.

Permian Basin Our oil and gas properties in the Permian Basin in west Texas and southeast New Mexico comprise approximately 950,000 net acres. Our drilling activity is targeting the liquids-rich targets within the Avalon Shale, Bone Spring, Wolfberry and undisclosed play types within other conventional reservoirs. Our average working interest in these properties is 53%. In 2010, we drilled 262 gross wells and plan to drill approximately 300 gross wells in 2011.

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 160,000 net acres in the area. The Washakie wells produce primarily natural gas from conventional reservoirs. In 2010, we drilled 93 gross wells.

Arkoma-Woodford Shale Our Arkoma-Woodford Shale properties in southeastern Oklahoma produce natural gas and NGLs from a non-conventional reservoir. Our more than 55,000 net acres are concentrated in Coal and Hughes counties, and we have an average working interest of about 31%. In 2010, we drilled 61 gross wells in this area.

Groesbeck The Groesbeck area of east Texas includes portions of Freestone, Leon, Limestone and Robertson counties. Our average working interest is 72% and we hold about 130,000 net acres of land. The Groesbeck wells produce primarily natural gas from conventional reservoirs. In 2010, we drilled 20 gross wells in this area.

Granite Wash The Granite Wash is concentrated in Hemphill and Wheeler counties in the Texas Panhandle and in western Oklahoma. Our average working interest is approximately 48% and we hold approximately 60,000 net acres of land. The Granite Wash wells produce liquids and natural gas from conventional reservoirs. In 2010, we drilled 29 gross wells in this area and plan to drill approximately 55 gross wells in 2011.

Haynesville-Bossier Shale Our Haynesville Shale acreage position spans across east Texas and north Louisiana with an average working interest of 92%. To date, our drilling activity has been focused on approximately 150,000 acres located in Panola, Shelby and San Augustine counties in east Texas. We drilled 23 gross wells in 2010.

Canada

Jackfish Jackfish is our 100%-owned thermal heavy oil project in the non-conventional oil sands of east central Alberta. We are employing steam-assisted gravity drainage at Jackfish. The first phase of Jackfish is fully operational with a gross facility capacity of 35 MBbls per day. We expect this project to maintain a flat production profile for greater than 20 years at an average net production rate of approximately 25-30 MBbls per day. We have completed construction of the second phase of Jackfish and we have filed a regulatory application for a third phase. The second and third phases of Jackfish are each expected to eventually produce approximately 30 MBbls per day of heavy oil production net of royalties over the life of the projects.

Northwest The Northwest region includes acreage within west central Alberta and northeast British Columbia. We hold approximately 1.9 million net acres in the region, which produces primarily natural gas from conventional reservoirs. Our average working interest in the area is approximately 73%. In 2010, we drilled 67 gross wells and plan to drill about 50 gross wells in 2011.

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 2.4 million net acres and have an 89% average working interest in our Lloydminster properties. In 2010, we drilled 181 gross wells and plan to drill a similar amount of gross wells in 2011.

Deep Basin Our properties in Canada s Deep Basin include portions of west central Alberta and east central British Columbia. We hold approximately 520,000 net acres in the Deep Basin. The area produces natural gas and liquids from conventional reservoirs. Our average working interest in the Deep Basin is 43%. In 2010, we drilled 39 gross wells and plan to drill approximately 30 gross wells in 2011.

Horn River Basin The Horn River Basin, located in northeast British Columbia, is a non-conventional gas reservoir targeting the Devonian Shale. Our leases include approximately 170,000 net acres with a 100% working interest. We drilled 7 gross wells in 2010.

Pike Our 50%-owned Pike oil sands acreage is situated directly to the south of our Jackfish acreage in east central Alberta. This position was attained in 2010 through a joint venture agreement with BP. The Pike leasehold is currently undeveloped and has no proved reserves or production as of December 31, 2010. We began appraisal drilling near the end of 2010 and are acquiring seismic data. The drilling results and seismic will help us determine the optimal configuration for the initial phase of development. We expect to begin the regulatory application process for the first Pike phase around the end of 2011.

Preparation of Reserves Estimates and Reserves Audits

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. To be considered proved, oil and gas reserves must be economically producible before contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Also, the project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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). These same policies also require that reserve estimates be made by professionally qualified reserves estimators (Qualified Estimators), as defined by the Society of Petroleum Engineers standards.

The Group, which is led by Devon s Director of Reserves and Economics, is responsible for the internal review and certification of reserves estimates. We ensure the Group s Director and key members of the Group have appropriate technical qualifications to oversee the preparation of reserves estimates. Such qualifications include any or all of the following:

- an undergraduate degree in petroleum engineering from an accredited university, or equivalent;

- a petroleum engineering license, or similar certification;

memberships in oil and gas industry or trade groups; and

relevant experience estimating reserves.

The current Director of the Group has all of the qualifications listed above. The current Director has been involved with reserves estimation in accordance with SEC definitions and guidance since 1987. He has experience in reserves estimation for projects in the United States (both onshore and offshore), as well as in Canada, Asia, the Middle East and South America. He has been employed by Devon for the past ten years, including the past three in his current position as Director of Reserves and Economics. During his career with Devon and others, he was the primary reservoir engineer for projects including, but not limited to:

- Hugoton Gas Field (Kansas)
- Sho-Vel-Tum CO_2 Flood (Oklahoma)
- West Loco Hills Unit Waterflood and CO_2 Flood (New Mexico)
- Dagger Draw Oil Field (New Mexico)
- Clarke Lake Gas Field (Alberta, Canada)
- Panyu 4-2 and 5-1 Joint Development (Offshore South China Sea)
- ACG Unit (Caspian Sea)

As the primary reservoir engineer, he was responsible for reserves estimation on each of these projects. These reserves estimates were utilized internally and for SEC filings.

From 2003 to 2010, he served as the reservoir engineering representative on our internal Peer Review Team, reviewing reserves and resource estimates for projects including, but not limited to:

- Mobile Bay Norphlet Discoveries (Gulf of Mexico Shelf)
- Cascade Lower Tertiary Development (Gulf of Mexico Deepwater)
- Polvo Development (Campos Basin, Brazil)

Additionally, the Group reports independently of any of our operating divisions. The Group s Director reports to our Vice President of Budget and Reserves, who reports to our Chief Financial Officer. 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. The Group also ensures our Qualified Estimators obtain continuing education related to the fundamentals of SEC proved reserves assignments.

The Group also oversees audits and reserves estimates performed by third-party consulting firms. During 2010, we engaged two such firms to audit a significant portion of our proved reserves. LaRoche Petroleum Consultants, Ltd. audited the 2010 reserve estimates for 94% of our U.S. onshore properties. AJM Petroleum Consultants audited 89% of our Canadian reserves.

Set forth below is a summary of the North American reserves that were evaluated, either by preparation or audit, by independent petroleum consultants for each of the years ended 2010, 2009 and 2008.

	2010		2009		2008	
	Prepared	**Audited**	**Prepared**	**Audited**	**Prepared**	**Audited**

U.S. Onshore		94%		93%		92%
U.S. Offshore	N/A	N/A	100%		100%	
Total U.S.		94%	5%	89%	5%	87%
Canada		89%		91%		78%
Total North America		93%	3%	89%	4%	85%

N/A Not applicable We sold all our U.S. Offshore properties during 2010.

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. The Society of Petroleum Engineers definition of an audit is an examination of a company s proved oil and gas reserves and net cash flow by an independent petroleum

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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 methods and procedures.

In addition to conducting these internal and external reviews, we also have a Reserves Committee that consists of three independent members of our Board of Directors. This committee provides additional oversight of our reserves estimation and certification process. The Reserves Committee assists 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 a minimum of twice a year to discuss reserves issues and policies, and meets separately with our senior reserves engineering personnel and our independent petroleum consultants at those meetings. The responsibilities of the Reserves Committee include the following:

- approve the scope of and oversee an annual review and evaluation of our consolidated oil, gas and NGL reserves;
- oversee the integrity of our reserves evaluation and reporting system;
- oversee and evaluate, prepare and disclose our compliance with legal and regulatory requirements related to our oil, gas and NGL reserves;
- review the qualifications and independence of our independent engineering consultants; and
- monitor the performance of our independent engineering consultants.

Proved Oil, Natural Gas and NGL Reserves

The following table presents our estimated proved reserves by continent and for each significant country as of December 31, 2010. These estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 22 to our consolidated financial statements included in this report.

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)
Proved Reserves				
United States	148	9,065	449	2,107
Canada	533	1,218	30	766
Total North America	681	10,283	479	2,873
Proved Developed Reserves				
United States	131	7,280	353	1,696
Canada	126	1,144	28	346

Total North America	257	8,424	381	2,042
Proved Undeveloped Reserves				
United States	17	1,785	96	411
Canada	407	74	2	420
Total North America	424	1,859	98	831

(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. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

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 2010 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.

Proved Developed Reserves

As presented in the previous table, we had 2,042 MMBoe of proved developed reserves at December 31, 2010. 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, 2010.

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)
Proved Developed Producing Reserves				
United States	123	6,702	318	1,557
Canada	116	1,031	25	314
Total North America	239	7,733	343	1,871
Proved Developed Non-Producing Reserves				
United States	8	578	35	139
Canada	10	113	3	32
Total North America	18	691	38	171

(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. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

Proved Undeveloped Reserves

The following table presents the changes in our total proved undeveloped reserves during 2010 (in MMBoe).

Proved undeveloped reserves as of December 31, 2009	811
Extensions and discoveries	145
Revisions due to prices	13
Revisions other than price	(8)
Sale of reserves	(39)
Conversion to proved developed reserves	(91)

Proved undeveloped reserves as of December 31, 2010	831

At December 31, 2010, we had 831 MMBoe of proved undeveloped reserves. This represents a 2% increase as compared to 2009 and represents 29% of our total proved reserves. A large contributor to the increase was our 2010 drilling activities, which increased our proved undeveloped reserves 145 MMBoe. The divestiture of our Gulf of Mexico properties reduced our proved undeveloped reserves by 39 MMBoe.

As a result of 2010 development activities, we converted 91 MMBoe, or 11%, of the 2009 proved undeveloped reserves to proved developed reserves. This conversion rate implies a nine-year development cycle, which exceeds the five-year general guideline for recording proved undeveloped reserves. However, our

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overall proved undeveloped conversion rate is largely impacted by the pace of development at Jackfish. Excluding our Jackfish reserves, our 2010 proved undeveloped conversion rate implies a development cycle that approximates five years.

At December 31, 2010 and 2009, our Jackfish proved undeveloped reserves were 396 MMBoe and 351 MMBoe, respectively. Development schedules for the Jackfish reserves are primarily controlled by the need to keep the processing plants at their full capacity of 35,000 barrels of oil per day per facility. Processing plant capacity is controlled by factors such as total steam processing capacity, steam-oil ratios and air quality discharge permits. As a result, these reserves will remain classified as proved undeveloped for more than five years. Currently, the development schedule for these reserves extends though the year 2025. We have made significant funding commitments toward the development of the Jackfish reserves.

See Note 22 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this report for further discussion of the contributions by project area of all changes to total proved reserves.

Proved Reserves Cash Flows

The following table presents estimated cash flow information related to our December 31, 2010 estimated proved reserves. Similar to reserves, the cash flow estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 22 to our consolidated financial statements included in this report.

	Total Proved Reserves	Proved Developed Reserves (In millions)	Proved Undeveloped Reserves
Pre-Tax Future Net Revenue(1)			
United States	$ 27,650	$ 23,640	$ 4,010
Canada	19,173	7,222	11,951
Total North America	$ 46,823	$ 30,862	$ 15,961
Pre-Tax 10% Present Value(1)			
United States	$ 12,863	$ 12,093	$ 770
Canada	9,622	5,216	4,406
Total North America	$ 22,485	$ 17,309	$ 5,176
Standardized Measure of Discounted Future Net Cash Flows(1)(2)			
United States	$ 8,843		
Canada	7,509		
Total North America	$ 16,352		

(1)

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.

Future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to December 31, 2010. 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 $59.94 per Bbl of oil, $3.73 per Mcf of gas and $31.11 per Bbl of NGLs. 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, 2010. There can be no assurance that all of the proved reserves will be produced and sold within the periods

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indicated, that the assumed prices will be realized or that existing contracts will be honored or judicially enforced.

The present value of after-tax future net revenues discounted at 10% per annum (standardized measure) was $16.4 billion at the end of 2010. Included as part of standardized measure were discounted future income taxes of $6.1 billion. Excluding these taxes, the present value of our pre-tax future net revenue (pre-tax 10% present value) was $22.5 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.

(2) See Note 22 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data.

Production, Production Prices and Production Costs

The following tables present our production and average sales prices by continent and for each significant field and country for the past three years.

	Year Ended December 31, 2010			
	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total(1) (MMBoe)
Production				
Barnett Shale	1	335	13	70
Other United States fields	15	381	15	93
Total United States	16	716	28	163
Jackfish	9			9
Other Canada fields	16	214	4	56
Total Canada	25	214	4	65
Total North America	41	930	32	228

	Oil (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Combined(1) (Per Boe)
Production Prices				
Barnett Shale	$ 77.40	$ 3.55	$ 29.97	$ 23.48
Total United States	$ 75.81	$ 3.76	$ 30.86	$ 29.06

Jackfish	$	52.51					$	52.51
Total Canada	$	58.60	$	4.11	$	46.60	$	39.11
Total North America	$	65.14	$	3.84	$	32.61	$	31.91

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	Year Ended December 31, 2009 Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total(1) (MMBoe)
Production				
Barnett Shale		331	13	69
Other United States fields	17	412	13	98
Total United States	17	743	26	167
Jackfish	8			8
Other Canada fields	17	223	4	58
Total Canada	25	223	4	66
Total North America	42	966	30	233

	Oil (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Combined(1) (Per Boe)
Production Prices				
Barnett Shale	$ 58.78	$ 2.99	$ 22.36	$ 19.08
Total United States	$ 57.56	$ 3.20	$ 23.51	$ 23.71
Jackfish	$ 41.07			$ 41.07
Total Canada	$ 47.35	$ 3.66	$ 33.09	$ 32.29
Total North America	$ 51.39	$ 3.31	$ 24.71	$ 26.15

	Year Ended December 31, 2008 Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total(1) (MMBoe)
Production				
Barnett Shale		321	12	66
Other United States fields	17	405	12	96
Total United States	17	726	24	162
Jackfish	4			4
Other Canada fields	18	212	4	57
Total Canada	22	212	4	61

Total North America	39	938	28	223

	Oil (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Combined(1) (Per Boe)
Production Prices				
Barnett Shale	$ 97.23	$ 7.38	$ 39.34	$ 43.71
Total United States	$ 98.83	$ 7.59	$ 41.21	$ 50.55
Jackfish	$ 50.67			$ 50.67
Total Canada	$ 71.04	$ 8.17	$ 61.45	$ 57.65
Total North America	$ 83.35	$ 7.73	$ 44.08	$ 52.49

(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. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

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The following table presents our production cost per Boe by continent and for each significant field and country for the past three years. Production costs do not include ad valorem or severance taxes.

	Year Ended December 31,		
	2010	2009	2008
Barnett Shale	$ 3.87	$ 3.96	$ 4.34
Total United States	$ 5.47	$ 5.97	$ 6.62
Jackfish	$ 16.81	$ 12.75	$ 28.93
Total Canada	$ 12.37	$ 10.15	$ 12.74
Total North America	$ 7.42	$ 7.16	$ 8.29

Drilling Activities and Results

The following tables summarize our development and exploratory drilling results for the past three years.

	Year Ended December 31, 2010					
	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)	
	Productive	Dry	Productive	Dry	Productive	Dry
U.S. Onshore	853.2	5.3	23.4	1.5	876.6	6.8
U.S. Offshore	2.5				2.5	
Total U.S.	855.7	5.3	23.4	1.5	879.1	6.8
Canada	267.8		41.9	1.0	309.7	1.0
Total North America	1,123.5	5.3	65.3	2.5	1,188.8	7.8

	Year Ended December 31, 2009					
	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)	
	Productive	Dry	Productive	Dry	Productive	Dry
U.S. Onshore	506.5	3.0	6.8	1.5	513.3	4.5
U.S. Offshore	1.5	0.8		0.5	1.5	1.3
Total U.S.	508.0	3.8	6.8	2.0	514.8	5.8
Canada	307.2		28.2		335.4	
Total North America	815.2	3.8	35.0	2.0	850.2	5.8

	Year Ended December 31, 2008					
	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)	
	Productive	Dry	Productive	Dry	Productive	Dry
U.S. Onshore	1,024.0	17.5	12.8	2.0	1,036.8	19.5
U.S. Offshore	9.0	1.0	0.8	1.8	9.8	2.8
Total U.S.	1,033.0	18.5	13.6	3.8	1,046.6	22.3
Canada	528.9	3.2	50.1	3.3	579.0	6.5
Total North America	1,561.9	21.7	63.7	7.1	1,625.6	28.8

(1) These well counts represent net wells completed during each year. Net wells are gross wells multiplied by our fractional working interests on the well.

The following table presents the results, as of February 1, 2011, of our wells that were in progress as of December 31, 2010.

	Productive		Dry		Still in Progress		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	47	31.5			193	128.8	240	160.3
Canada	9	6.9			4	3.0	13	9.9
Total North America	56	38.4			197	131.8	253	170.2

(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 on the well.

Well Statistics

The following table sets forth our producing wells as of December 31, 2010.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	7,864	2,741	19,719	13,125	27,583	15,866
Canada	4,980	3,798	5,534	3,258	10,514	7,056
Total North America	12,844	6,539	25,253	16,383	38,097	22,922

(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 on the well.

Acreage Statistics

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2010. The acreage in the table below includes 1.4 million, 0.5 million and 0.9 million net acres subject to leases that are scheduled to expire during 2011, 2012 and 2013, respectively.

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
			(In thousands)			

U.S.	3,249	2,179	6,683	3,806	9,932	5,985
Canada	3,647	2,258	7,571	5,013	11,218	7,271
Total North America	6,896	4,437	14,254	8,819	21,150	13,256

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

(2) Net acres are gross acres multiplied by our fractional working interests on the acreage.

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 23,056 of our wells. As operator, we receive reimbursement for direct expenses incurred in the performance of our duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area. In presenting our financial data, we record the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

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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*

We are involved in various routine legal proceedings incidental to our business. However, to our knowledge as of the date of this report, there were no 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 2010.

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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 10, 2011, there were 12,704 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 2010 and 2009. Also, included are the quarterly dividends per share paid during 2010 and 2009. 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.

	Price Range of Common Stock		Dividends
	High	Low	Per Share
2010:			
Quarter Ended March 31, 2010	$ 76.79	$ 62.38	$ 0.16
Quarter Ended June 30, 2010	$ 70.80	$ 58.58	$ 0.16
Quarter Ended September 30, 2010	$ 66.21	$ 59.07	$ 0.16
Quarter Ended December 31, 2010	$ 78.86	$ 63.76	$ 0.16
2009:			
Quarter Ended March 31, 2009	$ 73.11	$ 38.55	$ 0.16
Quarter Ended June 30, 2009	$ 67.40	$ 43.35	$ 0.16
Quarter Ended September 30, 2009	$ 72.91	$ 48.74	$ 0.16
Quarter Ended December 31, 2009	$ 75.05	$ 62.60	$ 0.16

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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, 2005 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

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.

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Issuer Purchases of Equity Securities

The following table provides information regarding purchases of our common stock that were made by us during the fourth quarter of 2010. All purchases were part of publicly announced plans or programs.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(1) (In millions)
October 1 October 31	330,000	$ 65.64	$ 2,542
November 1 November 30	348,400	$ 71.36	$ 2,517
December 1 December 31	2,917,900	$ 74.82	$ 2,299
Total	3,596,300	$ 73.64	

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires December 31, 2011. As of December 31, 2010, we had repurchased 18.3 million common shares for $1.2 billion, or $65.58 per share under this program.

New York Stock Exchange Certifications

This Form 10-K includes as exhibits the certifications of our Chief Executive Officer and Chief Financial Officer, 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 2010 annual certification of our Chief Executive Officer confirming that we have complied with the New York Stock Exchange corporate governance listing standards.

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

The following selected financial information (not covered by the report of our 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,				
	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Revenues	$ 9,940	$ 8,015	$ 13,858	$ 9,975	$ 9,143
Earnings (loss) from continuing operations(1)	$ 2,333	$ (2,753)	$ (3,039)	$ 2,485	$ 2,316
	$ 5.31	$ (6.20)	$ (6.86)	$ 5.56	$ 5.22

Earnings (loss) per share from continuing operations Basic										
Earnings (loss) per share from continuing operations Diluted	$	5.29	$	(6.20)	$	(6.86)	$	5.50	$	5.15
Cash dividends per common share	$	0.64	$	0.64	$	0.64	$	0.56	$	0.45
Total assets(1)	$	32,927	$	29,686	$	31,908	$	41,456	$	35,063
Long-term debt	$	3,819	$	5,847	$	5,661	$	6,924	$	5,568

(1) During 2009 and 2008, we recorded noncash reductions of carrying value of oil and gas properties totaling $6.4 billion ($4.1 billion after income taxes) and $9.9 billion ($6.7 billion after income taxes), respectively, related to our continuing operations as discussed in Note 15 of the consolidated financial statements.

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 2010 Results
- Business and Industry Outlook
- Results of Operations
- Capital Resources, Uses and Liquidity
- Contingencies and Legal Matters
- Critical Accounting Policies and Estimates
- Forward-Looking Estimates

Overview of Business

Devon is one of North America s leading independent oil and gas exploration and production companies. Our operations are focused in the United States and Canada. 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.

As an enterprise, we strive to optimize value for our shareholders by growing cash flows, earnings, production and reserves, all on a per debt-adjusted share basis. We accomplish this by replenishing our reserves and production and managing other key operational elements that drive our success. These items are discussed more fully below.

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 create value.

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.

High return projects We seek to invest our capital resources into projects where we can generate the highest risk-adjusted investment returns. One factor that can have a significant impact on such returns is our drilling success. Combined with appropriate revenue and cost-management strategies,

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high drilling success rates are important to generating competitive returns on our capital investment. During 2010, we drilled 1,588 gross wells and 99% of those were successful. This success rate is similar to our drilling achievements in recent years, demonstrating a proven track record of success. By accomplishing high drilling success rates, we provide an inventory of reserves growth and a platform of opportunities on our undrilled acreage that can be profitably developed.

Reserves and production balance As evidenced by history, commodity prices are inherently volatile. In addition, oil and gas prices often diverge due to a variety of circumstances. Consequently, we value a balance of reserves and production between gas and liquids that can add stability to our revenue stream when either commodity price is under pressure. Our production mix in 2010 was approximately 68% gas and 32% oil and NGLs such as propane, butane and ethane. Our year-end reserves were approximately 60% gas and 40% liquids. With planned future growth in oil from Jackfish, Pike and other projects, combined with an inventory of shale natural gas plays, we expect to maintain this balance in the future.

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 production is focused in core areas of our operations where we can achieve economies of scale to help manage our operating costs.

Marketing and 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 enhance our project returns and 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 and political conditions, weather, supply disruptions and other local market conditions that are beyond our control. To manage this volatility, we utilize financial hedging arrangements. As of February 10, 2011, approximately 29% of our 2011 gas production is associated with financial price swaps and fixed-price physicals. We also have basis swaps associated with 0.2 Bcf per day of our 2011 gas production. Additionally, approximately 36% of our 2011 oil production is associated with financial price collars. We also have call options that, if exercised, would relate to an additional 16% of our 2011 oil production.

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 2010 Results

2010 was an outstanding year for Devon. We reported record net earnings and reserves and made significant progress on our offshore divestiture program announced in November 2009. We sold our properties in the Gulf of Mexico, Azerbaijan, China and other International regions, generating $5.6 billion in after-tax proceeds and after-tax gains of

$1.7 billion. Additionally, we have entered into agreements to sell our remaining offshore assets in Brazil and Angola and are waiting for the respective governments to approve the divestitures. Once the pending transactions are complete, we expect to have generated more than $8 billion in after-tax proceeds from all our divestitures.

These divestitures have allowed us to begin focusing entirely on our North American Onshore oil and natural gas portfolio. We grew North American Onshore production 1% in 2010 and replaced approximately 175% of our production with the drill bit at very attractive costs. The operational success we had with the drill bit increased our reserves to 2,873 MMBoe, the highest level in our history.

While our total North American Onshore production grew 1% in 2010, our oil and NGL production increased 6% over 2009. Liquids prices began to stabilize in 2009 and continued to strengthen throughout 2010. Although our realized price for gas increased 17% in 2010, gas prices continue to be weak. Considering the current and expected trends in commodity pricing, we have leveraged the value of our balanced portfolio and shifted capital spending toward the more profitable liquids-rich development opportunities currently available to us. The performance of these assets and higher price realizations are reflected in the 2010 earnings increase.

Key measures of our performance for 2010, as well as certain operational developments, are summarized below:

- North America Onshore oil and NGL production grew 6% over 2009, to 71 million Boe.
- North American Onshore gas production decreased 1% compared with 2009, to 152 million Boe.
- The combined realized price for oil, gas and NGLs per Boe increased 22% to $31.91.
- Oil, gas and NGL derivatives generated net gains of $811 million in 2010, including cash receipts of $888 million.
- Per unit lease operating costs increased 4% to $7.42 per Boe.
- Operating cash flow increased to $5.5 billion, representing a 16% increase over 2009.
- Capitalized costs incurred in our oil and gas activities were $6.5 billion in 2010. This includes $1.2 billion for unproved acreage acquisitions.
- Reserves increased to 2,873 MMBoe, an all-time high.

From an operational perspective, we completed another successful year with the drill-bit. We drilled 1,584 gross wells on our North America Onshore properties with a 99% success rate and grew our related proved reserves 9%.

During 2010, we more than doubled our industry-leading leasehold position in the liquids-rich Cana-Woodford shale play in western Oklahoma to more than 240,000 net acres. This allowed us to grow production more than 210% from the end of 2009 to the end of 2010. As a result of the success of our drilling and development efforts in the Cana-Woodford shale, we also constructed a gas processing plant in 2010.

In the Barnett Shale, we exited 2010 with production of 1.2 Bcfe per day, which includes 43 MBbls per day of liquids production. This represents a 16% increase in total production compared to the 2009 exit rate.

In the Permian Basin, we continued to assemble additional liquids-rich acreage. By the end of 2010, we had approximately one million net acres on liquids-rich development opportunities which led to an increase in production of 16% from the end of 2009 to the end of 2010.

Our net production from our Jackfish oil sands project in Canada averaged 25 MBbls per day. Jackfish continues to be one of Canada s most successful steam-assisted gravity drainage projects. Construction of our second Jackfish project is now complete. We expect to have first oil production by the end of 2011. Additionally, we applied for regulatory approval of a third phase of Jackfish in 2010.

During 2010, we used a portion of our offshore divestiture proceeds to invest $1.2 billion in unproved leasehold acquisition focused on oil and liquids-rich gas plays. Our most significant single investment was our $500 million acquisition of a 50% interest in the Pike oil sands. The Pike acreage lies immediately adjacent to the Jackfish project. We began appraisal drilling at Pike near the end of 2010 and are acquiring seismic data. The drilling results and seismic will help us determine the optimal configuration for the initial phase of development. We expect to begin the regulatory application process for the first Pike phase around the end of 2011.

Our performance and offshore divestiture success throughout 2010 enabled us to end the year with a robust level of liquidity. At the end of 2010, we had $3.4 billion of cash and short-term investments and $2.6 billion of available credit.

Business and Industry Outlook

Even though we possess a great deal of financial strength and flexibility, we are fully committed to exercising capital discipline, maximizing profits, maintaining balance sheet strength and optimizing growth per debt-adjusted share. Our portfolio of assets provides a great deal of investment flexibility. At the end of 2010, our proved reserves were comprised of approximately 60% gas and 40% liquids. While gas prices remain challenged in the market, our near-term focus is on the oil and liquids-rich opportunities that exist within our balanced portfolio of properties. As a result, the vast majority of our 2011 drilling activity will be centered on our oil and liquids-rich gas properties. Should the outlook for commodity prices change, we have the flexibility to redirect our capital to ensure we continually focus on the highest-return assets in our portfolio.

Our ability to leverage the depth and breadth of our existing portfolio of properties will be key to the successful execution of our growth and value-creation objectives. With 2.9 billion Boe of proved reserves at the end of 2010, our North American onshore assets will provide many years of visible, economic growth and a good balance between liquids and natural gas. In 2011, we are targeting a 6-8% production increase. However, we expect this growth will be driven by oil and NGLs growth of at least 16%. Additionally, we will continue to use a portion of our offshore divestiture proceeds to repurchase common stock under our $3.5 billion share repurchase program. Therefore, our 2011 production growth will be even higher on a per debt-adjusted share basis.

Results of Operations

As previously stated, we are in the process of divesting our offshore assets. As a result, all amounts in this document related to our International operations are presented as discontinued. Therefore, the production, revenue and expense amounts presented in this Results of Operations section exclude amounts related to our International assets unless otherwise noted.

Even though we have divested our U.S. Offshore operations, these properties do not qualify as discontinued operations under accounting rules. As such, financial and operating data provided in this document that pertain to our continuing operations include amounts related to our U.S. Offshore operations. To facilitate comparisons of our ongoing operations subsequent to the planned divestitures, we have presented amounts related to our U.S. Offshore assets separate from those of our North American Onshore assets where appropriate.

Revenues

Our oil, gas and NGL production volumes are shown in the following table.

	Year Ended December 31,				
	2010	2010 vs. 2009(2)	2009	2009 vs. 2008(2)	2008
Oil (MMBbls)					
U.S. Onshore	14	+17%	12	+3%	11
Canada	25	−1%	25	+17%	22
North America Onshore	39	+5%	37	+12%	33
U.S. Offshore	2	−62%	5	−15%	6
Total	41	−3%	42	+8%	39
Gas (Bcf)					
U.S. Onshore	699	+0%	698	+5%	669
Canada	214	−4%	223	+5%	212
North America Onshore	913	−1%	921	+5%	881
U.S. Offshore	17	−63%	45	−22%	57
Total	930	−4%	966	+3%	938
NGLs (MMBbls)					
U.S. Onshore	28	+10%	25	+9%	24
Canada	4	−6%	4	−5%	4
North America Onshore	32	+8%	29	+7%	28
U.S. Offshore		−55%	1	+27%	
Total	32	+6%	30	+7%	28
Total (MMBoe)(1)					
U.S. Onshore	158	+3%	154	+5%	146
Canada	65	−3%	66	+9%	61
North America Onshore	223	+1%	220	+6%	207
U.S. Offshore	5	−62%	13	−18%	16
Total	228	−2%	233	+4%	223

(1) 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.

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

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The following table presents the prices we realized on our production volumes. These prices exclude any effects due to our oil, gas and NGL derivatives.

	Year Ended December 31,				
	2010	2010 vs. 2009	2009	2009 vs. 2008	2008
Oil (per Bbl)					
U.S. Onshore	$ 75.53	+34%	$ 56.17	−41%	$ 95.63
Canada	$ 58.60	+24%	$ 47.35	−33%	$ 71.04
North America Onshore	$ 64.51	+29%	$ 50.11	−37%	$ 79.45
U.S. Offshore	$ 77.81	+28%	$ 60.75	−42%	$ 104.90
Total	$ 65.14	+27%	$ 51.39	−38%	$ 83.35
Gas (per Mcf)					
U.S. Onshore	$ 3.73	+19%	$ 3.14	−58%	$ 7.43
Canada	$ 4.11	+12%	$ 3.66	−55%	$ 8.17
North America Onshore	$ 3.82	+17%	$ 3.27	−57%	$ 7.61
U.S. Offshore	$ 5.12	+22%	$ 4.20	−56%	$ 9.53
Total	$ 3.84	+16%	$ 3.31	−57%	$ 7.73
NGLs (per Bbl)					
U.S. Onshore	$ 30.78	+32%	$ 23.40	−43%	$ 40.97
Canada	$ 46.60	+41%	$ 33.09	−46%	$ 61.45
North America Onshore	$ 32.55	+32%	$ 24.65	−44%	$ 43.94
U.S. Offshore	$ 38.22	+39%	$ 27.42	−46%	$ 51.11
Total	$ 32.61	+32%	$ 24.71	−44%	$ 44.08
Combined (per Boe)(1)					
U.S. Onshore	$ 28.42	+27%	$ 22.41	−53%	$ 47.91
Canada	$ 39.11	+21%	$ 32.29	−44%	$ 57.65
North America Onshore	$ 31.52	+24%	$ 25.38	50%	$ 50.78
U.S. Offshore	$ 49.06	+26%	$ 38.83	−48%	$ 74.55
Total	$ 31.91	+22%	$ 26.15	−50%	$ 52.49

(1) 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 volume and price changes in the tables above caused the following changes to our oil, gas and NGL sales between 2008 and 2010.

	Oil	Gas	NGLs	Total
		(In millions)		
2008 sales	$ 3,233	$ 7,244	$ 1,243	$ 11,720
Changes due to volumes	258	222	89	569
Changes due to prices	(1,338)	(4,269)	(585)	(6,192)

2009 sales	2,153	3,197	747	6,097
Changes due to volumes	(67)	(122)	46	(143)
Changes due to prices	557	497	254	1,308
2010 sales	$ 2,643	$ 3,572	$ 1,047	$ 7,262

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Oil Sales

2010 vs. 2009 Oil sales increased $557 million as a result of a 27% increase in our realized price. The largest contributor to the increase in our realized price was the increase in the average NYMEX West Texas Intermediate index price over the same time period.

Oil sales decreased $67 million due to a three percent decrease in production. The decrease was comprised of the net effects of a 62% decrease in our U.S. Offshore production and a five percent increase in our North America Onshore production. The decrease in our U.S. Offshore production was primarily due to the divestiture of such properties in the second quarter of 2010. The increased North America Onshore production resulted primarily from continued development of our Permian Basin properties in Texas and our Jackfish thermal heavy oil project in Canada.

2009 vs. 2008 Oil sales decreased $1.3 billion as a result of a 38% decrease in our realized price without hedges. The largest contributor to the decrease in our realized price was the decrease in the average NYMEX West Texas Intermediate index price over the same time period.

Oil sales increased $258 million due to a three million barrel, or 8%, increase in production. The increased production resulted primarily from the continued development of Jackfish in Canada.

Gas Sales

2010 vs. 2009 Gas sales increased $497 million as a result of a 16% increase in our realized price without hedges. This increase was largely due to increases in the North American regional index prices upon which our gas sales are based.

A four percent decrease in production during 2010 caused gas sales to decrease by $122 million. The decrease was primarily due to the divestiture of our U.S. Offshore properties in the second quarter of 2010, as well as higher Canadian government royalties. Also, our other North America Onshore properties decreased one percent due to reduced drilling during most of 2009 in response to lower gas prices. As a result of the reduced drilling activities during 2009, natural declines of existing wells outpaced production gains from new drilling in 2010.

2009 vs. 2008 Gas sales decreased $4.3 billion as a result of a 57% decrease in our realized price without hedges. This decrease was largely due to decreases in the North American regional index prices upon which our gas sales are based.

A three percent increase in production during 2009 caused gas sales to increase by $222 million. Our North America Onshore properties contributed 40 Bcf of higher volumes. This increase included 25 Bcf of higher production in Canada due to a decline in Canadian government royalties, resulting largely from lower gas prices. The remainder of the North America Onshore growth resulted from new drilling and development that exceeded natural production declines, primarily in the Barnett Shale field in north Texas. These increases were partially offset by 12 Bcf of lower production from our U.S. Offshore properties, largely resulting from natural production declines.

NGL Sales

2010 vs. 2009 NGL sales increased $254 million during 2010 as a result of a 32% increase in our realized price. The increase was largely due to an increase in the Mont Belvieu, Texas index price over the same time period. NGL sales increased $46 million in 2010 due to a six percent increase in production. The increase in production was primarily due to increased drilling in North America Onshore areas that have liquids-rich gas.

2009 vs. 2008 NGL sales decreased $585 million as a result of a 44% decrease in our realized price. This decrease was largely due to a decrease in the Mont Belvieu, Texas index price over the same time period. NGL sales increased

$89 million in 2009 due to a seven percent increase in production. The increase in production is primarily due to drilling and development in the Barnett Shale.

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Oil, Gas and NGL Derivatives

The following tables provide financial information associated with our oil, gas and NGL hedges. 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. The prices do not include the effects of unrealized gains and losses.

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In millions)	
Cash settlement receipts (payments):			
Gas derivatives	$ 888	$ 505	$ (424)
Oil derivatives			27
Total cash settlements	888	505	(397)
Unrealized gains (losses) on fair value changes:			
Gas derivatives	12	(83)	243
Oil derivatives	(91)	(38)	
NGL derivatives	2		
Total unrealized gains (losses) on fair value changes	(77)	(121)	243
Oil, gas and NGL derivatives	$ 811	$ 384	$ (154)

	Year Ended December 31, 2010			
	Oil (Per Bbl)	**Gas (Per Mcf)**	**NGLs (Per Bbl)**	**Total (Per Boe)**
Realized price without hedges	$ 65.14	$ 3.84	$ 32.61	$ 31.91
Cash settlements of hedges		0.96		3.90
Realized price, including cash settlements	$ 65.14	$ 4.80	$ 32.61	$ 35.81

	Year Ended December 31, 2009			
	Oil (Per Bbl)	**Gas (Per Mcf)**	**NGLs (Per Bbl)**	**Total (Per Boe)**
Realized price without hedges	$ 51.39	$ 3.31	$ 24.71	$ 26.15
Cash settlements of hedges		0.52		2.16

Realized price, including cash settlements	$ 51.39	$ 3.83	$ 24.71	$ 28.31

	Year Ended December 31, 2008			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 83.35	$ 7.73	$ 44.08	$ 52.49
Cash settlements of hedges	0.70	(0.46)		(1.78)
Realized price, including cash settlements	$ 84.05	$ 7.27	$ 44.08	$ 50.71

Our oil, gas, and NGL derivatives include price swaps, costless collars and basis swaps. For the price swaps, we 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. 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. For the basis swaps, we receive a fixed differential between two index prices and pay a variable differential on the same two index prices to the contract counterparty. Cash settlements presented in the tables above represent net realized gains or losses related to these various instruments.

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Additionally, to facilitate a portion of our price swaps, we have sold gas call options for 2012 and oil call options for 2011 and 2012. The call options give the counterparty the right to place us into a price swap at a predetermined fixed price. The terms of these call options are presented in Item 7A. Quantitative and Qualitative Disclosures about Market Risk of this report.

During 2010 and 2009, we received $888 million, or $0.96 per Mcf, and $505 million, or $0.52 per Mcf, respectively, from counterparties to settle our gas derivatives. During 2008, we paid $424 million, or $0.46 per Mcf to counterparties to settle our gas derivatives and received $27 million, or $0.70 per Bbl from counterparties to settle our oil derivatives. We had no settlements on NGL derivatives in any of these periods.

In addition to recognizing these cash settlement effects, we also recognize unrealized changes in the fair values of our oil, gas and NGL derivative instruments in each reporting period. We estimate the fair values of these derivatives primarily by using internal discounted cash flow calculations. We periodically 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 our gas derivative financial instruments at December 31, 2010, a 10% increase in these forward curves would have decreased our 2010 unrealized gains by approximately $154 million. A 10% increase in the forward curves associated with our oil derivative financial instruments would have increased our 2010 unrealized losses by approximately $142 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. Finally, the amount of production subject to oil, gas and NGL derivatives is not a variable in our cash flow calculations, but it does impact the total derivative values.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with thirteen 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 mark-to-market exposure threshold, above which collateral must be posted, 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, 2010, the credit ratings of all our counterparties were investment grade.

Including the cash settlements discussed above, our oil, gas and NGL derivatives generated net gains of $811 million and $384 million during 2010 and 2009, respectively, and a net loss of $154 million during 2008. In addition to the impact of cash settlements, these net gains and losses were impacted by new positions and settlements that occurred during each period, as well as the relationships between contract prices and the associated forward curves. A summary of our outstanding oil, gas and NGL derivative positions as of December 31, 2010 is included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk of this report.

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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 are shown in the table below.

	Year Ended December 31,				
	2010	2010 vs 2009(1)	2009	2009 vs 2008(1)	2008
	($ in millions)				
Marketing and midstream:					
Revenues	$ 1,867	+22%	$ 1,534	−33%	$ 2,292
Operating costs and expenses	1,357	+33%	1,022	−37%	1,611
Operating profit	$ 510	−0%	$ 512	−25%	$ 681

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

2010 vs. 2009 Marketing and midstream revenues increased $333 million and operating costs and expenses increased $335 million, causing operating profit to decrease $2 million. Both revenues and expenses increased primarily due to higher natural gas and NGL prices, partially offset by the effects of lower gas marketing profits.

2009 vs. 2008 Marketing and midstream revenues decreased $758 million and operating costs and expenses decreased $589 million, causing operating profit to decrease $169 million. Both revenues and expenses decreased primarily due to lower natural gas and NGL prices, partially offset by higher NGL production and gas pipeline throughput.

Lease Operating Expenses (LOE)

The details of the changes in LOE are shown in the table below.

	Year Ended December 31,				
	2010	2010 vs. 2009(1)	2009	2009 vs. 2008(1)	2008
Lease operating expenses ($ in millions):					
U.S. Onshore	$ 832	−1%	$ 838	−6%	$ 893
Canada	797	+18%	673	−13%	776
North American Onshore	1,629	+8%	1,511	−10%	1,669
U.S. Offshore	60	−62%	159	−13%	182
Total	$ 1,689	+1%	$ 1,670	−10%	$ 1,851
Lease operating expenses per Boe:					

U.S. Onshore	$ 5.26	−4%	$ 5.46	−11%	$ 6.11
Canada	$ 12.37	+22%	$ 10.15	−20%	$ 12.74
North American Onshore	$ 7.32	+7%	$ 6.87	−15%	$ 8.06
U.S. Offshore	$ 12.00	+0%	$ 11.98	+6%	$ 11.29
Total	$ 7.42	+4%	$ 7.16	−14%	$ 8.29

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

2010 vs. 2009 LOE increased $19 million in 2010, which included a $118 million increase related to our North America Onshore operations and a $99 million decrease related to our U.S. Offshore operations. North America Onshore LOE increased $78 million due to changes in the exchange rate between the U.S. and

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Canadian dollars. The remainder of the increase in North America Onshore LOE is primarily due to increased costs related to our Jackfish operation in Canada. U.S. Offshore LOE decreased primarily due to property divestitures in the second quarter of 2010. The increase due to exchange rates was also the main contributor to the changes in North America Onshore and total LOE per Boe.

2009 vs. 2008 LOE decreased $181 million in 2009. LOE dropped $182 million due to declining costs for fuel, materials, equipment and personnel, as well as declines in maintenance and well workover projects. Such declines largely resulted from decreasing demand for field services due to lower oil and gas prices. Changes in the exchange rate between the U.S. and Canadian dollar reduced LOE $49 million. Additionally, LOE decreased $31 million as a result of hurricane damages in 2008 to certain of our U.S. Offshore facilities and transportation systems. These factors, excluding the hurricane damage, were also the main contributors to the decrease in LOE per Boe on our North America Onshore properties. Production growth at our large-scale Jackfish project also contributed to a decrease in LOE per Boe. As Jackfish production approached the facility s capacity during 2009, its per-unit costs declined, contributing to lower overall LOE per Boe. The remainder of our four percent company-wide production growth added $81 million to LOE during 2009.

Taxes Other Than Income Taxes

Taxes other than income taxes consist primarily of production taxes and ad valorem taxes assessed by various government agencies on our U.S. Onshore properties. Production taxes are based on a percentage of production revenues that varies by property and government jurisdiction. Ad valorem taxes generally are based on property values as determined by the government agency assessing the tax. The following table details the changes in our taxes other than income taxes.

	Year Ended December 31,				
	2010	2010 vs 2009(1)	2009	2009 vs 2008(1)	2008
	($ in millions)				
Production	$ 210	+59%	$ 132	−57%	$ 306
Ad valorem	165	−6%	175	+8%	162
Other	5	−30%	7	−4%	8
Total	$ 380	+21%	$ 314	−34%	$ 476

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

2010 vs. 2009 Production taxes increased $78 million in 2010. This increase was largely due to higher U.S. Onshore revenues, as well as a decrease in production tax credits associated with certain properties in the state of Texas. Ad valorem taxes decreased $10 million primarily due to lower assessed values of our U.S. Onshore oil and gas property and equipment.

2009 vs. 2008 Production taxes decreased $174 million in 2009. This decrease was largely due to lower U.S. Onshore revenues, as well as an increase in production tax credits associated with certain properties in the state of Texas. Ad valorem taxes increased $13 million primarily due to higher assessed oil and gas property and equipment values.

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 capitalized investment, net of accumulated DD&A and reductions of carrying value, plus future development costs related to proved undeveloped reserves. Generally, when reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, when 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.

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

	Year Ended December 31,				
	2010	2010 vs 2009(1)	2009	2009 vs 2008(1)	2008
Total production volumes (MMBoe)	228	−2%	233	+4%	223
DD&A rate ($ per Boe)	$ 7.36	−6%	$ 7.86	−40%	$ 13.20
DD&A expense ($ in millions)	$ 1,675	−9%	$ 1,832	−38%	$ 2,948

(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 changes in DD&A of oil and gas properties between 2008 and 2010 due to the changes in production volumes and DD&A rate presented in the table above (in millions).

2008 DD&A	$ 2,948
Change due to volumes	130
Change due to rate	(1,246)
2009 DD&A	1,832
Change due to volumes	(43)
Change due to rate	(114)
2010 DD&A	$ 1,675

2010 vs. 2009 Oil and gas property-related DD&A decreased $114 million during 2010 due to a six percent decrease in the DD&A rate. The largest contributors to the rate decrease were our 2010 U.S. Offshore property divestitures and a reduction of the carrying value of our United States oil and gas properties recognized in the first quarter of 2009. This reduction totaled $6.4 billion and resulted from a full cost ceiling limitation. These decreases were partially offset by the effects of costs incurred and the transfer of previously unproved costs to the depletable base as a result of 2010 drilling and development activities, as well as changes in the exchange rate between the U.S. and Canadian dollars.

2009 vs. 2008 Oil and gas property related DD&A decreased $1.2 billion due to a 40% decrease in the DD&A rate. The largest contributors to the rate decrease were reductions of the carrying values of certain of our oil and gas properties recognized in the first quarter of 2009 and the fourth quarter of 2008. These reductions totaled $16.3 billion and resulted from full cost ceiling limitations in the United States and Canada. In addition, the effects of changes in the exchange rate between the U.S. and Canadian dollars also contributed to the rate decrease. These factors were partially offset by the effects of costs incurred and the transfer of previously unproved costs to the depletable base as a result of 2009 drilling activities. Partially offsetting the impact from the lower 2009 DD&A rate was our four percent production increase, which caused oil and gas property related DD&A expense to increase $130 million.

The impact of adopting the SEC s new *Modernization of Oil and Gas Reporting* rules at the end of 2009 had virtually no impact on our DD&A rate.

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

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consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration and production activities, marketing and midstream activities, as well as corporate overhead activities. See the following table for a summary of G&A expenses by component.

	Year Ended December 31,				
	2010	2010 vs 2009(1)	2009	2009 vs 2008(1)	2008
	($ in millions)				
Gross G&A	$ 987	−11%	$ 1,107	+0%	$ 1,103
Capitalized G&A	(311)	−6%	(332)	−2%	(337)
Reimbursed G&A	(113)	−11%	(127)	+5%	(121)
Net G&A	$ 563	−13%	$ 648	+0%	$ 645

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

2010 vs. 2009 Gross G&A decreased $120 million largely due to a decline in employee severance costs. Such costs decreased primarily due to Gulf of Mexico employees that were impacted by the integration of our Gulf of Mexico and International operations into one offshore unit in the second quarter of 2009 and other employee departures during 2009. Gross G&A, as well as capitalized G&A, also decreased subsequent to our mid-year 2010 Gulf of Mexico divestitures as a result of the decline in our workforce. The Gulf of Mexico divestitures were also the main contributor to the decrease in G&A reimbursements. Gross and capitalized G&A also declined due to reduced spending initiatives for certain discretionary cost categories. These decreases were partially offset by an increase due to the effects of changes in the exchange rate between the U.S. and Canadian dollars.

2009 vs. 2008 Gross G&A increased $4 million. This increase was due to approximately $60 million of higher costs for employee compensation and benefits, mostly offset by the effects of our 2009 reduced spending initiatives for certain discretionary cost categories.

Employee cost increases in 2009 included an additional $57 million of severance costs. This increase was primarily due to Gulf of Mexico and other employee departures during 2009. Additionally, postretirement benefit costs increased approximately $50 million. The increases in employee costs were partially offset by a $27 million decrease due to accelerated share-based compensation expense recognized in 2008 resulting from a modification of certain executives compensation arrangements. 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. 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.

Restructuring Costs

The following schedule includes the components of restructuring costs.

	Year Ended December 31, 2010			Year Ended December 31, 2009		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Cash severance	$ (17)	$ 1	$ (16)	$ 66	$ 24	$ 90
Share-based awards	(10)	(5)	(15)	39	24	63
Lease obligations	70		70			
Asset impairments	11		11			
Other	3		3			
Restructuring costs	$ 57	$ (4)	$ 53	$ 105	$ 48	$ 153

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Employee Severance

In the fourth quarter of 2009, we recognized $153 million of estimated employee severance costs associated with the planned divestiture of our offshore assets that was announced in November 2009. This amount was based on estimates of the number of employees that would ultimately be impacted by the divestitures and included amounts related to cash severance costs and accelerated vesting of share-based grants. Of the $153 million total, $105 million related to our U.S. Offshore operations and the remainder related to our International discontinued operations.

During 2010, we divested all of our U.S. Offshore assets and a significant part of our International assets. As a result of these divestitures and associated employee terminations, we decreased our estimate of employee severance costs in 2010 by $31 million. More offshore employees than previously estimated received comparable positions with either the purchaser of the properties or in our U.S. Onshore operations, and this caused the $31 million decrease to our severance estimate. This decrease includes $27 million related to our U.S. Offshore operations and $4 million related to our International discontinued operations.

Lease Obligations

As a result of the divestitures discussed above, we ceased using certain office space that was subject to non-cancellable operating lease arrangements. Consequently, in 2010, we recognized $70 million of restructuring costs that represent the present value of our future obligations under the leases, net of anticipated sublease income. The estimate of lease obligations was based upon certain key estimates that could change over the term of the leases. These estimates include the estimated sublease income that we may receive over the term of the leases, as well as the amount of variable operating costs that we will be required to pay under the leases.

Asset Impairments

In 2010, we recognized $11 million of asset impairment charges for leasehold improvements and furniture associated with the office space we ceased using.

Interest Expense

The following schedule includes the components of interest expense.

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In millions)	
Interest based on debt outstanding	$ 408	$ 437	$ 426
Capitalized interest	(76)	(94)	(111)
Early retirement of debt	19		
Other	12	6	14
Total interest expense	$ 363	$ 349	$ 329

2010 vs. 2009 Interest based on debt outstanding decreased in 2010 primarily due to the retirement of $177 million of 10.125% notes upon their maturity in the fourth quarter of 2009 and the early redemption of our 7.25% senior notes as discussed below.

Capitalized interest decreased during 2010 primarily due to the divestitures of our U.S. Offshore properties during the first half of 2010, which was partially offset by higher capitalized interest associated with our Canadian oil sands development projects.

In the second quarter of 2010, we redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011. The notes were redeemed for $384 million, which represented 100 percent of the principal amount, a make-whole premium of $28 million and $6 million of accrued and unpaid interest. On the date of redemption, these notes also had an unamortized premium of $9 million. The $19 million presented in the table above represents the net of the $28 million make-whole premium and $9 million amortization of the remaining premium.

2009 vs. 2008 Interest based on debt outstanding increased $11 million from 2008 to 2009. This increase was primarily due to interest paid on the $500 million of 5.625% senior unsecured notes and $700 million of 6.30% senior unsecured notes that we issued in January 2009. This was partially offset by lower interest resulting from the retirement of our exchangeable debentures during the third quarter of 2008 and lower interest rates on our floating-rate commercial paper borrowings.

Capitalized interest decreased from 2008 to 2009 primarily due to the sales of our West African exploration and development properties in 2008 and the completion of the Access pipeline transportation system in Canada in the second quarter of 2008.

Interest-Rate and Other Financial Instruments

The details of the changes in our interest-rate and other financial instruments are shown in the table below.

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In millions)	
(Gains) losses from:			
Interest rate swaps cash settlements	$ (44)	$ (40)	$ (1)
Interest rate swaps unrealized fair value changes	30	(66)	(104)
Chevron common stock			363
Option embedded in exchangeable debentures			(109)
Total	$ (14)	$ (106)	$ 149

Interest Rate Swaps

During 2010, 2009 and 2008, we received cash settlements totaling $44 million, $40 million and $1 million, respectively, from counterparties to settle our interest rate swaps.

In addition to recognizing cash settlements, we 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. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers. In 2010, we recorded an unrealized loss of $30 million as a result of changes in interest rates. In 2009 and 2008, we recorded unrealized gains of $66 million and $104 million, respectively, as a result of changes in interest rates.

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, 2010, a 10% increase in these forward curves would have decreased our 2010 unrealized loss for our interest rate swaps by approximately $68 million.

Similar to 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 seven 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 mark-to-market exposure threshold, above which collateral must be posted, 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. The credit ratings of all our counterparties were investment grade as of December 31, 2010.

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Chevron Common Stock and Related Embedded Option

Until October 31, 2008, we owned 14.2 million shares of Chevron common stock and recognized unrealized changes in the fair value of this investment. 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.

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.

Reduction of Carrying Value of Oil and Gas Properties

During 2009 and 2008, we reduced the carrying values of certain of our oil and gas properties due to full cost ceiling limitations. A summary of these reductions and additional discussion is provided below.

	Year Ended December 31, 2009		2008	
	Gross	After Taxes	Gross	After Taxes
	(In millions)			
United States	$ 6,408	$ 4,085	$ 6,538	$ 4,168
Canada			3,353	2,488
Total	$ 6,408	$ 4,085	$ 9,891	$ 6,656

The 2009 reduction was recognized in the first quarter and the 2008 reductions were recognized in the fourth quarter. The reductions resulted from significant decreases in each country s full cost ceiling compared to the immediately preceding quarter. The lower United States ceiling value in the first quarter of 2009 largely resulted from the effects of declining natural gas prices subsequent to December 31, 2008. The lower ceiling values in the fourth quarter of 2008 largely resulted from the effects of sharp declines in oil, gas and NGL prices compared to September 30, 2008.

To demonstrate these declines, the March 31, 2009, December 31, 2008 and September 30, 2008 weighted average wellhead prices are presented in the following table.

March 31, 2009			December 31, 2008			September 30, 2008		
Oil	Gas	NGLs	Oil	Gas	NGLs	Oil	Gas	NGLs

Country	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Bbl)	(Per Mcf)	(Per Bbl)
United States	$ 47.30	$ 2.67	$ 17.04	$ 42.21	$ 4.68	$ 16.16	$ 97.62	$ 5.28	$ 38.00
Canada	N/A	N/A	N/A	$ 23.23	$ 5.31	$ 20.89	$ 59.72	$ 6.00	$ 62.78

N/A Not applicable.

The March 31, 2009 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $49.66 per Bbl for crude oil and the Henry Hub spot price of $3.63 per MMBtu for gas. 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.

Other, net

The following table includes the components of other, net.

	Year Ended December 31,		
	2010	2009	2008
	(In millions)		
Interest and dividend income	$ (13)	$ (8)	$ (54)
Deep water royalties		(84)	
Hurricane insurance proceeds			(162)
Other	(32)	24	(1)
Total	$ (45)	$ (68)	$ (217)

Interest and dividend income decreased from 2008 to 2009 due to a decrease in dividends received on our previously owned investment in Chevron common stock and a decrease in interest received on cash equivalents due to lower rates and balances.

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.

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 was later appealed to the United States Supreme Court, which, in October 2009, declined to review the appellate court s ruling. The Supreme Court s decision ended the MMS s judicial course to enforce the price thresholds.

Prior to September 30, 2009, we had $84 million accrued for potential royalties on various deep water leases. Based upon the Supreme Court s decision, we reduced to zero the $84 million loss contingency accrual in the third quarter of 2009.

In 2008, we recognized $162 million of excess insurance recoveries for damages suffered in 2005 related to hurricanes that struck the Gulf of Mexico. The excess recoveries resulted from business interruption claims on policies that were in effect when the 2005 hurricanes occurred.

Income Taxes

The following table presents our total income tax expense (benefit) and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate.

	Year Ended December 31,		
	2010	2009	2008
Total income tax expense (benefit) (In millions)	$ 1,235	$ (1,773)	$ (1,121)
U.S. statutory income tax rate	35%	(35)%	(35)%
Repatriations and assumed repatriations	4%	1%	7%
State income taxes	1%	(2)%	(1)%
Taxation on Canadian operations	(1)%	(1)%	5%
Other	(4)%	(2)%	(3)%
Effective income tax expense (benefit) rate	35%	(39)%	(27)%

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During 2010 and 2009, pursuant to the completed and planned divestitures of our International assets located outside North America, a portion of our foreign earnings were no longer deemed to be permanently reinvested. Accordingly, we recognized deferred income tax expense of $144 million and $55 million during 2010 and 2009, respectively, related to assumed repatriations of earnings from certain of our foreign subsidiaries.

During 2008, we recognized $312 million of additional income tax expense that resulted from two related factors associated with our foreign operations. 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 $295 million of additional current tax expense and $17 million of additional deferred tax expense. Excluding the $312 million of additional tax expense, our effective income tax benefit rate would have been 34% for 2008.

Earnings From Discontinued Operations

For all years presented in the following tables, our discontinued operations include amounts related to our assets in Azerbaijan, Brazil, China and other minor International properties. Additionally, during 2008, our discontinued operations included amounts related to our assets in West Africa, including Equatorial Guinea, Cote d Ivoire, Gabon and other countries in the region until they were sold. Following are the components of earnings from discontinued operations.

	Year Ended December 31,		
	2010	**2009**	**2008**
Total production (MMBoe)	10	16	18
Combined price without hedges (per Boe)	$ 72.68	$ 59.25	$ 92.72
		(In millions)	
Operating revenues	$ 693	$ 945	$ 1,702
Expenses and other, net:			
Operating expenses	212	496	776
Restructuring costs	(4)	48	
Reduction of carrying value of oil and gas properties		109	494
Gain on sale of oil and gas properties	(1,818)	(17)	(819)
Other, net	(82)	(13)	(7)
Total expenses and other, net	(1,692)	623	444
Earnings before income taxes	2,385	322	1,258
Income tax expense	168	48	367
Earnings from discontinued operations	$ 2,217	$ 274	$ 891

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The following table presents gains on our offshore and African divestiture transactions by year.

	Year Ended December 31,					
	2010		2009		2008	
	Gross	After Taxes	Gross	After Taxes	Gross	After Taxes
	(In millions)					
Azerbaijan	$ 1,543	$ 1,524	$	$	$	$
China Panyu	308	235				
Equatorial Guinea					619	544
Gabon					117	122
Cote d Ivoire			17	17	83	95
Other	(33)	(27)				8
Total	$ 1,818	$ 1,732	$ 17	$ 17	$ 819	$ 769

2010 vs. 2009 Earnings increased $1.9 billion in 2010 primarily as a result of the $1.5 billion gain ($1.5 billion after taxes) from the divestiture of our Azerbaijan operations and the $308 million gain ($235 million after taxes) from the divestiture of our Panyu operations in China. Also, earnings increased $109 million due to the 2009 reductions of carrying value of our oil and gas properties, which primarily related to Brazil. The Brazilian reduction resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin. After drilling this well in the first quarter of 2009, we concluded that the well did not have adequate reserves for commercial viability. As a result, the seismic, leasehold and drilling costs associated with this well contributed to the reduction recognized in the first quarter of 2009.

2009 vs. 2008 Earnings from discontinued operations decreased $617 million in 2009. Our discontinued earnings were impacted by several factors. First, operating revenues declined largely due to a 36% decrease in the price realized on our production, which was driven by a decline in crude oil index prices. Second, both operating revenues and expenses declined due to divestitures that closed in 2008. Earnings also decreased $752 million in 2009 due to larger gains recognized on West African asset divestitures in 2008.

Partially offsetting these decreased earnings in 2009 was the larger reduction of carrying value recognized in 2008 compared to 2009. The reductions largely consisted of full cost ceiling limitations related to our assets in Brazil that were caused by a decline in oil prices.

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.

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Sources and Uses of Cash

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

	2010	2009 (In millions)	2008
Sources of cash and cash equivalents:			
Operating cash flow continuing operations	$ 5,022	$ 4,232	$ 8,448
Divestitures of property and equipment	4,310	34	117
Cash distributed from discontinued operations	2,864		1,898
Commercial paper borrowings		1,431	1
Debt issuance, net of commercial paper repayments		182	
Redemptions of long-term investments	21	7	250
Stock option exercises	111	42	116
Proceeds from exchange of Chevron stock			280
Other	16	8	59
Total sources of cash and cash equivalents	12,344	5,936	11,169
Uses of cash and cash equivalents:			
Capital expenditures	(6,476)	(4,879)	(8,843)
Commercial paper repayments	(1,432)		
Debt repayments	(350)	(178)	(1,031)
Net credit facility repayments			(1,450)
Repurchases of common stock	(1,168)		(665)
Redemption of preferred stock			(150)
Dividends	(281)	(284)	(289)
Purchases of short-term investments	(145)		
Other	(19)	(17)	
Total uses of cash and cash equivalents	(9,871)	(5,358)	(12,428)
Increase (decrease) from continuing operations	2,473	578	(1,259)
Increase (decrease) from discontinued operations, net of distributions to continuing operations	(211)	6	386
Effect of foreign exchange rates	17	43	(116)
Net increase (decrease) in cash and cash equivalents	$ 2,279	$ 627	$ (989)
Cash and cash equivalents at end of year	$ 3,290	$ 1,011	$ 384
Short-term investments at end of year	$ 145	$	$

Operating Cash Flow Continuing Operations

Net cash provided by operating activities (operating cash flow) continued to be a significant source of capital and liquidity in 2010. Changes in operating cash flow from our continuing operations 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 19% during 2010 primarily due to the increase in revenues as discussed in the Results of Operations section of this report.

During 2010, our operating cash flow funded approximately 78% of our cash payments for capital expenditures. However, our capital expenditures for 2010 included $500 million paid to form a heavy oil joint venture and acquire a 50 percent interest in the Pike oil sands in Alberta, Canada. This acquisition was completed in connection with the offshore divestitures discussed below. Excluding this $500 million acquisition, our operating cash flow funded approximately 84% of our capital expenditures during 2010. Offshore divestiture proceeds were used to fund the remainder of our cash-based capital expenditures.

During 2009, our operating cash flow funded approximately 87% of our cash payments for capital expenditures. Commercial paper borrowings were used to fund the remainder of our cash-based capital expenditures. During 2008, our capital expenditures were primarily funded by our operating cash flow and pre-existing cash balances.

Other Sources of Cash Continuing and Discontinued Operations

As needed, we supplement our operating cash flow and available cash by accessing available credit under our senior credit facility and commercial paper program. We may also issue long-term debt to supplement our operating cash flow while maintaining adequate liquidity under our credit facilities. Additionally, we may acquire short-term investments to maximize our income on available cash balances. As needed, we reduce such short-term investment balances to further supplement our operating cash flow and available cash.

During 2010, we divested our U.S. Offshore, Azerbaijan, China and other minor international properties, generating $6.6 billion in pre-tax proceeds net of closing adjustments, or $5.6 billion after taxes. We have used proceeds from these divestitures to repay all our commercial paper borrowings, retire $350 million of other debt that was to mature in October 2011 and begin repurchasing our common shares. In addition, we began redeploying proceeds into our North America Onshore properties, including the $500 million Pike oil sands acquisition mentioned above.

During 2009, we issued $500 million of 5.625% senior unsecured notes due January 15, 2014 and $700 million of 6.30% senior unsecured notes due January 15, 2019. The net proceeds received of $1.187 billion, after discounts and issuance costs, were used primarily to repay Devon s $1.005 billion of outstanding commercial paper as of December 31, 2008. Subsequent to the $1.005 billion commercial paper repayment in January 2009, we utilized additional commercial paper borrowings of $1.431 billion to fund capital expenditures in excess of our operating cash flow.

During 2008, we received $2.6 billion in pre-tax proceeds, or $1.9 billion after 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. Additionally, we reduced our short-term investment balances by $250 million and received $280 million from the exchange of our investment in Chevron common stock.

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Capital Expenditures

Our capital expenditures are presented by geographic area and type in the following table. The amounts in the table below reflect cash payments for capital expenditures, including cash paid for capital expenditures incurred in prior periods. Capital expenditures actually incurred during 2010, 2009 and 2008 were approximately $6.9 billion, $4.7 billion and $10.0 billion, respectively.

	2010	2009 (In millions)	2008
U.S. Onshore	$ 3,689	$ 2,413	$ 5,606
Canada	1,826	1,064	1,459
North American Onshore	5,515	3,477	7,065
U.S. Offshore	376	845	1,157
Total exploration and development	5,891	4,322	8,222
Midstream	236	323	451
Other	349	234	170
Total continuing operations	$ 6,476	$ 4,879	$ 8,843

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 and development of oil and gas properties, which totaled $5.9 billion, $4.3 billion and $8.2 billion in 2010, 2009 and 2008, respectively. The increase in exploration and development capital spending in 2010 was partially due to the $500 million Pike oil sands acquisition mentioned above. Additionally, with rising oil and NGL prices and proceeds from our offshore divestiture program, we are increasing drilling primarily to grow liquids production across our North America Onshore portfolio of properties.

The decline in capital expenditures from 2008 to 2009 was due to decreased drilling activities in most of our operating areas in response to lower commodity prices in 2009 compared to previous years. Also, the 2008 capital expenditures include $2.6 billion related to acquisitions of properties in Texas, Louisiana, Oklahoma and Canada.

Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas gathering and pipeline systems and oil pipelines. Our midstream capital expenditures in 2010 were largely impacted by reduced U.S. Onshore dry gas drilling activities.

Capital expenditures related to corporate activities increased in 2010. This increase is largely driven by the construction of our new headquarters in Oklahoma City.

Net Repayments of Debt

During 2010, we repaid $1.4 billion of commercial paper borrowings and redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011, primarily with proceeds received from our U.S. Offshore divestitures.

During 2009, we repaid our $177 million 10.125% notes upon maturity in the fourth quarter.

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.

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Repurchases of Common Stock

The following table summarizes our repurchases, including unsettled shares, under approved plans during 2010 and 2008 (amounts and shares in millions).

	2010			2008		
Repurchase Program	**Amount**	**Shares**	**Per Share**	**Amount**	**Shares**	**Per Share**
2010 program	$ 1,201	18.3	$ 65.58	$		$
Annual program				178	2.0	$ 87.83
2007 program				487	4.5	$ 109.25
Totals	$ 1,201	18.3	$ 65.58	$ 665	6.5	$ 102.56

No shares were repurchased in 2009. The 2010 program expires on December 31, 2011 and the 2008 program and annual program expired on December 31, 2009.

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

Devon paid common stock dividends of $281 million (or $0.64 per share) in 2010 and $284 million (or $0.64 per share) in both 2009 and 2008, respectively. Devon paid dividends of $5 million in 2008 to preferred stockholders. Devon redeemed its outstanding preferred stock in the second quarter of 2008.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain revolving lines of credit and a commercial paper program, which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity and debt securities that can be issued pursuant to our automatically effective registration statement filed with the SEC. This registration statement can be used to offer short-term and long-term debt securities. Another major source of future liquidity will be proceeds from the sales of our remaining offshore assets in Brazil and Angola. We estimate the combination of these sources of capital will be adequate to fund future capital expenditures, share repurchases, debt repayments and other contractual commitments as discussed later in this section.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, gas and NGLs produced. Due to improving oil and NGL prices, our operating cash flow increased approximately 16% to $5.5 billion in 2010 as compared to 2009. We expect operating cash flow to continue to be our primary source of liquidity.

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. We expect this volatility to continue throughout 2011.

To mitigate some of the risk inherent in prices, we have utilized various price swap, fixed-price physical delivery and price collar contracts to set minimum and maximum prices on our 2011 production. As of February 10, 2011, approximately 29% of our 2011 gas production is associated with financial price swaps and fixed-price physicals. We also have basis swaps associated with 0.2 Bcf per day of our 2011 gas production. Additionally, approximately 36% of our 2011 oil production is associated with financial price collars. We also have call options that, if exercised, would hedge an additional 16% of our 2011 oil production.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price increases 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.

Interest Rates Our operating cash flow can also be sensitive to interest rate fluctuations. As of February 10, 2011, we had total debt of $6.2 billion with an overall weighted average borrowing rate of 6.4%. To manage our exposure to interest rate volatility, we have interest rate swap instruments with a total notional amount of $2.1 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011, or sooner should we elect, based upon us paying a fixed rate and receiving a floating rate. Including the effects of these swaps, the weighted-average interest rate related to our debt was 5.7% as of February 10, 2011.

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. 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, posting of letters of credit, prepayment requirements and collateral posting requirements.

Offshore Divestitures

During 2010, we sold our properties in the Gulf of Mexico, Azerbaijan, China and other International regions, generating $5.6 billion in after-tax proceeds. Additionally, we have entered into agreements to sell our remaining offshore assets in Brazil and Angola and are waiting for the respective governments to approve the divestitures. Once the pending transactions are complete, we expect to have generated more than $8 billion in after-tax proceeds. Similar to 2010, we expect to continue using the divestiture proceeds to invest in North America Onshore exploration and development opportunities, reduce our debt and repurchase our common shares.

Credit Availability

We have a $2.65 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility) that can be accessed to provide liquidity as needed. The maturity date for $2.19 billion of the Senior Credit Facility is April 7, 2013. The maturity date for the remaining $0.46 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.

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $2.2 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit 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.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. The credit agreement defines total funded debt as funds received through the issuance of debt securities such as debentures, bonds, notes payable, credit facility borrowings and short-term commercial paper borrowings. In addition, total funded debt includes all obligations with respect to payments received in consideration for oil, gas and NGL production yet to be acquired or produced at the time of payment. Funded debt excludes our outstanding letters of credit and trade payables. The credit agreement defines total capitalization as the sum of funded debt and stockholders equity adjusted for noncash financial writedowns, such as full cost ceiling impairments. As of December 31, 2010, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2010, as calculated pursuant to the terms of the agreement, was 15.1%.

Our access to funds from the Senior Credit 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 facility includes covenants that require us to report a condition or event having a material adverse effect, the obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

The following schedule summarizes the capacity of our Senior Credit Facility by maturity date, as well as our available capacity as of February 10, 2011 (in millions).

April 7, 2012 maturity	$ 463
April 7, 2013 maturity	2,187
Total Senior Credit Facility	2,650
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	625
Outstanding letters of credit	39
Total available capacity	$ 1,986

As presented in the table above, we had $625 million of commercial paper borrowings as of February 10, 2011. Although we ended 2010 with $3.4 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from our International offshore divestitures. For the time being, we have decided not to repatriate these proceeds to the United States or permanently invest them in Canada. This decision is based on our ongoing evaluation of our future cash needs across our operations in the United States and Canada, as well as the relatively low borrowing rates on our short-term borrowings. If we do not repatriate these proceeds to the United States in the near-term, we may continue to increase our commercial paper borrowings to supplement our operating cash flow in funding our common stock repurchases and capital expenditures.

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.

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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, 2010, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures

Our 2011 capital expenditures are expected to range from $5.4 billion to $6.0 billion. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if commodity prices fluctuate from current estimates, we could choose to defer a portion of these planned 2011 capital expenditures until later periods, or accelerate capital expenditures planned for periods beyond 2011 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2011, our existing commodity hedging contracts, available cash balances and credit availability, we anticipate having adequate capital resources to fund our 2011 capital expenditures.

Common Stock Repurchase Program

As a result of the success we have experienced with our offshore divestiture program, we announced a share repurchase program in May 2010. The program authorizes the repurchase of up to $3.5 billion of our common shares and expires December 31, 2011. As of February 10, 2011, we had repurchased $1.6 billion, or 23.5 million of our shares at an average price of $69.60. We will continue to use proceeds from our offshore divestiture program in 2011 to fund our repurchase program.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2010, 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)		
North American Onshore:					
Purchase obligations(1)	$ 7,710	$ 551	$ 1,471	$ 1,568	$ 4,120
Debt(2)	5,628	1,812	9	582	3,225
Interest expense(3)	4,645	392	544	502	3,207
Drilling and facility obligations(4)	1,163	747	410	6	
Firm transportation agreements(5)	1,734	282	487	408	557
Asset retirement obligations(6)	1,497	74	102	110	1,211
Lease obligations(7)	489	58	104	77	250
Other(8)	389	59	141	156	33

Total North America Onshore	23,255	3,975	3,268	3,409	12,603
Offshore:					
Drilling and facility obligations(4)	595	314	281		
Asset retirement obligations(6)	24			24	
Lease obligations(7)	111	38	58	15	
Total Offshore	730	352	339	39	
Grand Total	$ 23,985	$ 4,327	$ 3,607	$ 3,448	$ 12,603

(1) Purchase obligation amounts represent contractual commitments to purchase condensate at market prices for use at our heavy oil projects in Canada. We have entered into these agreements because the condensate is an integral part of the heavy oil production process and any disruption in our ability to obtain condensate could negatively affect our ability to produce and transport heavy oil at these locations. Our total obligation related to condensate purchases expires in 2021. This value of the obligation in the table above is based on the contractual volumes and our internal estimate of future condensate market prices.

(2) Debt amounts represent scheduled maturities of our debt obligations at December 31, 2010, excluding $2 million of net premiums included in the carrying value of debt.

(3) Interest expense relates to our fixed-rate debt and represents the scheduled cash payments. We had no variable-rate debt outstanding as of December 31, 2010.

(4) 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. Our offshore commitment primarily relates to a long-term contract for a deepwater drilling rig being used in Brazil. Our lease and remaining commitments for this rig will be assumed by the buyer of our assets in Brazil when the associated divestiture transaction closes.

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

(6) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2010 balance sheet.

(7) Lease obligations for our North America onshore operations consist primarily of non-cancelable leases for office space and equipment used in our daily operations. Lease obligations for our offshore operations consist primarily of an FPSO in Brazil. The Polvo FPSO lease term expires in 2014. Our lease and remaining commitments for this FPSO will be assumed by the buyer of our assets in Brazil when the associated divestiture transaction closes.

(8) These amounts include $193 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 $492 million and $448 million at December 31, 2010 and 2009, respectively. A detailed reconciliation of the 2010 changes to our underfunded status is in Note 8 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this report. Of the $492 million underfunded status at the end of 2010, $198 million is attributable to various nonqualified defined benefit plans that have no plan assets. However, we have established certain trusts to fund the benefit obligations of such nonqualified plans. As of December 31, 2010, these trusts had investments with a fair value of $36 million. The value of these trusts is in noncurrent other assets in our consolidated balance sheets included in Item 8. Financial Statements and Supplementary Data of this report.

As compared to the accumulated benefit obligation, our qualified defined benefit plans were underfunded by $218 million at December 31, 2010. 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. While we did have investment gains in 2010 and 2009, the investment losses experienced during 2008 significantly reduced the value of our plans assets. We estimate we will contribute approximately $84 million to our qualified pension plans during 2011. However, actual contributions may be different than this amount.

Our funding policy regarding the nonqualified defined benefit plans is to supplement as needed the amounts accumulated in the related trusts with available cash and cash equivalents.

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 $85 million, $119 million and $61 million in 2010, 2009 and 2008, respectively. We estimate that our pension expense will approximate $91 million in 2011. Should our actual 2011 contributions to qualified and nonqualified plans vary significantly from our current estimate of $93 million, our actual 2011 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 6.94% and 7.18% at December 31, 2010 and 2009, 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, 2010, the target allocations for plan assets were 47.5% for equity securities, 40% for fixed-income securities and 12.5% for other investment types. Equity securities consist of investments in large capitalization and small capitalization companies, both domestic and international. Fixed-income securities include corporate bonds of investment-grade companies from diverse industries, United States Treasury obligations and asset-backed securities. Other investment types include short-term investment funds and a hedge fund of funds. 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 would increase the expected 2011 pension expense by $6 million.

We discounted our future pension obligations using a weighted average rate of 5.50% and 6.00% at December 31, 2010 and 2009. 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. High quality corporate bond yield indices are considered 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 would increase our pension liability at December 31, 2010, by $37 million, and increase estimated 2011 pension expense by $5 million.

At December 31, 2010, we had net actuarial losses of $357 million, which will be recognized as a component of pension expense in future years. These losses are primarily due to investment losses on plan assets in 2008, reductions in the discount rate since 2001 and increases in participant wages. We estimate that approximately $32 million and $26 million of the unrecognized actuarial losses will be included in pension expense in 2011 and 2012, respectively. The $32 million estimated to be recognized in 2011 is a component of the total estimated 2011 pension expense of $91 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 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this report.

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 Method of Accounting and Proved Reserves

Policy Description

We follow the full cost method of accounting for our oil and gas properties. Under this method all costs associated with property acquisition, exploration and development activities are capitalized, including our internal costs that can be directly identified with such activities. Capitalized costs are depleted on 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 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.

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. 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.

Judgments and Assumptions

Our estimates of proved reserves are a major component of the depletion and full cost ceiling calculations. Additionally, our proved reserves represent the element of these calculations that require 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 22 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, when 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. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

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 future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to the end of each quarterly period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. 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 calculated average price is adjusted using the contract prices for such hedges. None of our outstanding derivative contracts at December 31, 2010 qualified for hedge accounting treatment.

Because the ceiling calculation dictates the use of prices that are not representative of future prices 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 cyclical and, for any particular 12-month period, can be either higher or lower than our long-term price forecast, which is a more appropriate input for estimating 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. In addition, due to the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates. However, decreases in estimates of proved reserves would generally increase our depletion rate and, thus, our depletion expense. Decreases in our proved reserves may also increase the likelihood of recognizing a full cost ceiling writedown.

Derivative Financial Instruments

Policy Description

We periodically enter into derivative financial instruments with respect to a portion of our oil, gas and NGL production that hedge the future prices received. These instruments are used to manage the inherent uncertainty of future revenues due to commodity price volatility. Our commodity derivative financial instruments include financial price swaps, basis swaps, costless price collars and call options. Additionally, we periodically enter into interest rate swaps to manage our exposure to interest rate volatility. Under the terms of certain of our interest-rate swaps, we receive a fixed rate and pay a variable rate on a total notional amount. The remainder of our swaps represent forward starting swaps, under which we will pay a fixed rate and receive a floating 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. For derivative financial instruments held during 2010, 2009 and 2008, we chose not to meet the necessary criteria to qualify our derivative financial instruments for hedge accounting treatment. Cash settlements with counterparties to our derivative financial instruments also increase or decrease earnings at the time of the settlement.

Judgments and Assumptions

The estimates of the fair values of our derivative instruments require substantial judgment. We estimate the fair values of our commodity 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 primarily using United States Treasury bill rates. 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. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted using the LIBOR and money market futures rates. 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.

We periodically 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 thirteen separate counterparties, and our interest rate derivative contracts are held with seven 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 mark-to-market exposure 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, 2010, the credit ratings of all our counterparties were investment grade.

Because we have chosen not to qualify our derivatives for hedge accounting treatment, changes in the fair values of derivatives can have a significant impact on our results of operations. Generally, changes in derivative fair values 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.

Goodwill

Policy Description

Accounting for the acquisition of a business requires the allocation of the purchase price to the tangible and intangible net assets acquired with any excess recorded as goodwill. Goodwill is assessed 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, which we conduct as of October 31 each year, requires us to estimate the fair values of our own assets and liabilities. Because quoted market prices are not available for our reporting units, we must estimate the fair values to conduct the goodwill impairment test. The most significant judgments involved in estimating the fair values of our reporting units relate to the valuation of our property and equipment. We develop estimated fair values of our property and equipment by performing various quantitative analyses based upon information related to comparable companies, comparable transactions and premiums paid.

In our comparable companies analysis, we review the public stock market trading multiples for selected publicly traded independent exploration and production companies with financial and operating characteristics that are comparable to our respective reporting units. Such characteristics are market capitalization, location of proved reserves and the characterization of the reserves. In our comparable transactions analysis, we review certain acquisition multiples for selected independent exploration and production company transactions and oil and gas asset packages announced recently. In our 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 and one month prior to the announcement of the transaction. We use this information to determine the mean and median premiums paid.

We then use the comparable company multiples, comparable transaction multiples, transaction premiums and other data to develop valuation estimates of our property and equipment. We also use market and other data to develop valuation estimates of the other assets and liabilities included in our reporting units. At October 31, 2010, the date of our last impairment test, the fair values of our United States and Canadian reporting units substantially exceeded their related carrying values.

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.

Income Taxes

Policy Description

We are required to estimate federal, state, provincial and foreign income taxes for each jurisdiction in which we operate. This process involves estimating the actual current tax exposure together with assessing future tax consequences resulting in deferred income taxes. We account for deferred income taxes 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.

Judgments and Assumptions

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal, state, provincial and foreign tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period applied at the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. The accruals for deferred tax assets and liabilities are subject to a significant amount of judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Material changes in these accruals may occur in the future, based on the progress of ongoing tax audits, changes in legislation and resolution of pending tax matters.

Forward-Looking Estimates

We are providing our 2011 forward-looking estimates in this section. These estimates were based on our examination of historical operating trends, the information used to prepare our December 31, 2010, reserve reports and other data in our possession or available from third parties. The forward-looking estimates in this report were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2011 will be similar to 2010, unless otherwise noted. We make reference to the Disclosure Regarding Forward-Looking Statements at the beginning of this report. Amounts related to our Canadian operations have been converted to U.S. dollars using an estimated average 2011 exchange rate of $0.95 dollar to $1.00 Canadian dollar.

During 2011, our operations are substantially comprised of our ongoing North America Onshore operations. We also have International operations in Brazil and Angola that we are divesting. We have entered into agreements to sell our assets in Brazil for $3.2 billion and our assets in Angola for $70 million, plus contingent consideration. As a result of these divestitures, all revenues, expenses and capital related to our International operations are reported as discontinued operations in our financial statements. Additionally, all forward-looking estimates in this document exclude amounts related to our International operations, unless otherwise noted.

North America Onshore Operating Items

The following 2011 estimates relate only to our North America Onshore assets.

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2011. We estimate that our combined oil, gas and NGL production will total approximately 236 to 240 MMBoe.

	Oil (MMBbls)	**Gas (Bcf)**	**NGLs (MMBbls)**	**Total (MMBoe)**
U.S. Onshore	17	736	34	174
Canada	28	199	3	64
North America Onshore	45	935	37	238

Oil and Gas Prices

We expect our 2011 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 prices are exclusive of the anticipated effects of the financial contracts presented in the Commodity Price Risk Management section below.

The NYMEX price for oil is determined using 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 using the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC*.

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	Expected Range of Prices as a % of NYMEX Price Oil	Gas
U.S. Onshore	89% to 99%	80% to 90%
Canada	63% to 73%	82% to 92%
North America Onshore	73% to 83%	80% to 90%

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, gas and NGL 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 2011.

As of February 10, 2011, our financial commodity contracts pertaining to 2011 consisted of oil price collars, oil call options, gas price swaps, gas basis swaps and NGL basis swaps. The key terms of these contracts are presented in the following tables.

	Gas Price Swaps	
Period	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
Total year 2011	730,226	$ 5.49

	Gas Basis Swaps		
Period	**Index**	**Volume (MMBtu/d)**	**Weighted Average Differential to Henry Hub ($/MMBtu)**
Total year 2011	Panhandle Eastern Pipeline	150,000	$ 0.33

		Oil Price Collars			
		Floor Price		Ceiling Price	
Period	**Volume (Bbls/d)**	**Floor Range ($/Bbl)**	**Weighted Average Price ($/Bbl)**	**Ceiling Range ($/Bbl)**	**Weighted Average Price ($/Bbl)**
Total year 2011	45,000	$ 75.00 - $75.00	$ 75.00	$ 105.00 - $116.10	$ 108.89

Period	Oil Call Options Sold Volume (Bbls /d)	Oil Call Options Sold Weighted Average Price ($/Bbl)
Total year 2011	19,500	$ 95.00

Period	NGL Basis Swaps Volume (Bbls/d)	Pay Natural Gasoline ($/Bbl)	Receive Oil ($/Bbl)
Total year 2011	500	$ 70.77	$ 80.52

To the extent that monthly NYMEX prices in 2011 are outside of the ranges established by the collars or differ from those established by the swaps, we and the counterparties to the contracts will cash-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 2011. Changes in the contracts fair values will also be recorded as increases or decreases to our revenues. The expected ranges of our realized prices as a percentage of NYMEX prices, which are presented earlier in this report, do not include any estimates of the impact on our prices from monthly settlements or changes in the fair values of our price collars and swaps.

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 and NGL content 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 2011 marketing and midstream operating profit will be between $485 million and $535 million. We estimate that marketing and midstream revenues will be between $1.485 billion and $1.760 billion, and marketing and midstream expenses will be between $1.000 billion and $1.225 billion.

Production and Operating Expenses

These expenses, which include transportation costs, 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, as well as the amount of repair and workover activity required. Additionally, lease operating expenses associated with oil production, particularly heavy oil production, are generally higher than operating expenses associated with gas and NGL production. 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 2011 lease operating expenses will be between $1.78 billion and $1.88 billion.

Taxes Other Than Income Taxes

Our taxes other than income taxes primarily consist of production taxes and ad valorem taxes that relate to our U.S. Onshore properties and are assessed by various government agencies. Production taxes are based on a percentage of production revenues that varies by property and government jurisdiction. Ad valorem taxes generally are based on property values as determined by the government agency assessing the tax. Over time, a certain property s assessed value will increase or decrease due to changes in commodity sales prices, production volumes and proved reserves. Therefore, ad valorem taxes will generally move in the same direction as our oil, gas and NGL sales but in a less predictable manner compared to production taxes. Additionally, both production and ad valorem taxes will increase or decrease due to changes in the rates assessed by the government agencies.

Given these uncertainties, we estimate that our taxes other than income taxes for 2011 will be between 5.20% and 6.20% of total oil, gas and NGL sales.

Depreciation, Depletion and Amortization (DD&A)

Our 2011 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 2011 compared to the costs incurred for such efforts, revisions to our year-end 2010 reserve estimates that, based on prior experience, are likely to be made during 2011, as well as potential carrying value reductions that result from full cost ceiling tests.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $7.40 per Boe and $8.00 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2010 is expected to be between $1.76 billion and $1.90 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas fixed assets will total between $265 million and $295 million in 2011.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2011 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 2011 will be between $590 million and $630 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.

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 2011 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 that affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures, are generally within our control.

As of December 31, 2010, we had total debt of $5.6 billion, which is exclusively fixed-rate debt at an overall weighted average rate of 7.1%. Our debt includes $1.75 billion that is scheduled to mature on September 30, 2011. We also have access to the commercial paper market and our credit lines. Any commercial paper or credit line borrowings would bear interest at variable rates.

Based on the factors above, we expect our 2011 interest expense to be between $300 million and $340 million. The estimated interest expense is exclusive of the anticipated effects of the interest rate swap contracts presented in the Interest Rate Risk Management section below.

The 2011 interest expense estimate above is comprised of three primary components interest related to outstanding debt, fees and issuance costs and capitalized interest. We expect interest expense in 2011 related to our outstanding debt, including net accretion of related discounts, to be between $380 million and $420 million. We expect interest expense in 2011 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. During 2011, we also expect to capitalize between $85 million and $95 million of interest, of which $45 to $55 million relates to our continuing oil and gas activities and the remainder relates to certain corporate construction projects and our discontinued operations.

Interest Rate Risk Management

From time to time, we enter into interest rate swaps. Such contracts are used to manage our exposure to interest rate volatility.

As of December 31, 2010, our interest rate swaps pertaining to 2011 consisted of instruments with a total notional amount of $2.10 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011, or sooner should we elect. The net settlement amount will be based upon us paying a weighted-average fixed rate

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of 3.92% and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041. The key terms of these contracts are presented in the following tables.

Fixed-to-Floating Swaps

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 300	4.30%	Six month LIBOR	July 18, 2011
100	1.90%	Federal funds rate	August 3, 2012
500	3.90%	Federal funds rate	July 18, 2013
250	3.85%	Federal funds rate	July 22, 2013
$ 1,150	3.82%		

Forward Starting Swaps

Notional (In millions)	Fixed Rate Paid	Variable Rate Received	Expiration
$ 950	3.92%	Three month LIBOR	September 30, 2011

Income Taxes

Our financial income tax rate in 2011 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2011 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by our United States and Canadian operations due to the different tax rates of each country. Also, certain tax deductions and credits will have a fixed impact on 2011 income tax expense regardless of the level of pre-tax earnings that are produced. Additionally, 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 these tax deductions and credits on 2011 financial income tax rates.

Given the uncertainty of pre-tax earnings, we expect that our total financial income tax rate in 2011 will be between 20% and 40%. The current income tax rate is expected to be between 0% and 10%. The deferred income tax rate is expected to be between 20% and 30%.

Capital Resources, Uses and Liquidity

North America Onshore Capital Expenditures

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 2011 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, we estimate that our 2011 oil and gas development and exploration capital expenditures will be between $4.500 billion and $4.900 billion. We estimate that our development capital will be between $3.875 billion and $4.175 billion. Development capital includes 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. Development capital also includes estimates for plugging and abandonment charges. We estimate that our exploration capital will be between $625 million and $725 million. Exploration capital includes exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs. Exploration capital also includes purchases of proved and unproved leasehold acreage. In addition to the development and exploration expenditures, we expect to capitalize between $330 million and $350 million of G&A expenses and between $45 million and $55 million of interest related to our oil and gas activities.

In addition, we expect to spend between $225 million and $300 million on our midstream assets, which primarily include our oil pipelines, gas processing plants, and gas gathering and pipeline systems. We also expect total capital for corporate activities will be between $300 million and $395 million, including approximately $30 million of capitalized interest related to certain construction projects.

Other Cash Uses

In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires on December 31, 2011. Through February 10, 2011, we had repurchased 23.5 million common shares for $1.6 billion, or $69.60 per share.

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 expected share repurchases, 2011 dividends are expected to approximate $264 million.

Capital Resources and Liquidity

Our estimated 2011 cash uses, including our capital activities, are expected to be funded primarily through a combination of our existing cash balances and operating cash flow, supplemented with commercial paper borrowings. At the beginning of 2011, we held $3.4 billion in cash and short-term investments. The amount of operating cash flow to be generated during 2011 is uncertain due to the factors affecting revenues and expenses as previously cited. However, if our operating cash flow were significantly less than our estimates, we would access the commercial paper market. Also, we have credit lines that we could access if deemed necessary. As of February 10, 2011, we had $2.0 billion of available credit under our credit lines.

Another major source of liquidity in 2011 will be the proceeds from the divestiture of our assets in Brazil and, to a lesser extent, the divestiture of our assets in Angola.

These sources of liquidity will allow us to continue repurchasing common shares and investing in the opportunities that exist across our North America Onshore portfolio of properties. We expect our combined capital resources to be adequate to fund our anticipated capital expenditures and other cash uses for 2011.

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 our 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. Consequently, we periodically enter into financial hedging activities with respect to a portion of our oil, gas and NGL production through various financial transactions that hedge the future prices received. These transactions include financial price swaps, basis swaps and costless price collars. Additionally, to facilitate a portion of our price swaps, we have sold gas

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call options for 2012 and oil call options for 2011 and 2012. The key terms of our derivatives in place as of December 31, 2010 are presented in the following tables.

	Gas Price Swaps	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Total year 2011	712,500	$ 5.51

	Gas Basis Swaps		
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Total year 2011	Panhandle Eastern Pipeline	150,000	$ 0.33

	Gas Call Options Sold	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Total year 2012	487,500	$ 6.00

	Oil Price Collars				
		Floor Price		Ceiling Price	
Period	Volume (Bbls/d)	Floor Range ($/Bbl)	Weighted Average Price ($/Bbl)	Ceiling Range ($/Bbl)	Weighted Average Price ($/Bbl)
Total year 2011	45,000	$ 75.00 - $75.00	$ 75.00	$ 105.00 - $116.10	$ 108.89

	Oil Call Options Sold	
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Total year 2011	19,500	$ 95.00
Total year 2012	19,500	$ 95.00

Period	Volume (Bbls/d)	NGL Basis Swaps Pay Natural Gasoline ($/Bbl)	Receive Oil ($/Bbl)
Total year 2011	500	$ 70.77	$ 80.52
Total year 2012	500	$ 71.82	$ 81.92

The fair values of our commodity derivatives presented in the tables above are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2010, a 10% increase in the forward curves associated with our gas derivative instruments would have decreased the fair value of such instruments by approximately $154 million. A 10% increase in the forward curves associated with our oil derivative instruments would have decreased the fair value of these instruments by approximately $142 million.

Interest Rate Risk

At December 31, 2010, we had debt outstanding of $5.6 billion with fixed rates averaging 7.1%.

As of December 31, 2010, our interest rate swaps consisted of instruments with a total notional amount of $2.1 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011, or sooner should we elect. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.92% and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041. The key terms of these contracts are presented in the following tables.

Fixed-to-Floating Swaps

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 300	4.30%	Six month LIBOR	July 18, 2011
100	1.90%	Federal funds rate	August 3, 2012
500	3.90%	Federal funds rate	July 18, 2013
250	3.85%	Federal funds rate	July 22, 2013
$ 1,150	3.82%		

Forward Starting Swaps

Notional (In millions)	Fixed Rate Paid	Variable Rate Received	Expiration
$ 950	3.92%	Three month LIBOR	September 30, 2011

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, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $68 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, 2010 balance sheet.

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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, 2010 and 2009, and the related consolidated statements of operations, comprehensive earnings (loss), stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2010. We also have audited Devon Energy Corporation s internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010, 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, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

KPMG LLP

Oklahoma City, Oklahoma
February 23, 2011

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,866	$ 646
Accounts receivable	1,202	1,208
Current assets held for sale	563	657
Other current assets	924	481
Total current assets	5,555	2,992
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	56,012	52,352
Not subject to amortization	3,434	4,078
Total oil and gas	59,446	56,430
Other .	4,429	4,045
Total property and equipment, at cost	63,875	60,475
Less accumulated depreciation, depletion and amortization	(44,223)	(41,708)
Property and equipment, net	19,652	18,767
Goodwill	6,080	5,930
Long-term assets held for sale	859	1,250
Other long-term assets	781	747
Total assets	$ 32,927	$ 29,686
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,411	$ 1,137
Revenues and royalties due to others	538	486
Short-term debt	1,811	1,432
Current liabilities associated with assets held for sale	305	234
Other current liabilities	518	513
Total current liabilities	4,583	3,802

Long-term debt	3,819	5,847
Asset retirement obligations	1,423	1,418
Liabilities associated with assets held for sale	26	213
Other long-term liabilities	1,067	937
Deferred income taxes	2,756	1,899
Stockholders equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 431.9 million and 446.7 million shares in 2010 and 2009, respectively	43	45
Additional paid-in capital	5,601	6,527
Retained earnings	11,882	7,613
Accumulated other comprehensive earnings	1,760	1,385
Treasury stock, at cost. 0.4 million shares in 2010	(33)	
Total stockholders equity	19,253	15,570
Commitments and contingencies (Note 10)		
Total liabilities and stockholders equity	$ 32,927	$ 29,686

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
	(In millions, except per share amounts)		
Revenues:			
Oil, gas and NGL sales	$ 7,262	$ 6,097	$ 11,720
Oil, gas and NGL derivatives	811	384	(154)
Marketing and midstream revenues	1,867	1,534	2,292
Total revenues	9,940	8,015	13,858
Expenses and other, net:			
Lease operating expenses	1,689	1,670	1,851
Taxes other than income taxes	380	314	476
Marketing and midstream operating costs and expenses	1,357	1,022	1,611
Depreciation, depletion and amortization of oil and gas properties	1,675	1,832	2,948
Depreciation and amortization of non-oil and gas properties	255	276	255
Accretion of asset retirement obligations	92	91	80
General and administrative expenses	563	648	645
Restructuring costs	57	105	
Interest expense	363	349	329
Interest-rate and other financial instruments	(14)	(106)	149
Reduction of carrying value of oil and gas properties		6,408	9,891
Other, net	(45)	(68)	(217)
Total expenses and other, net	6,372	12,541	18,018
Earnings (loss) from continuing operations before income taxes	3,568	(4,526)	(4,160)
Income tax expense (benefit):			
Current	516	241	441
Deferred	719	(2,014)	(1,562)
Total income tax expense (benefit)	1,235	(1,773)	(1,121)
Earnings (loss) from continuing operations	2,333	(2,753)	(3,039)
Discontinued operations:			
Earnings from discontinued operations before income taxes	2,385	322	1,258
Discontinued operations income tax expense	168	48	367
Earnings from discontinued operations	2,217	274	891
Net earnings (loss)	4,550	(2,479)	(2,148)

Preferred stock dividends			5
Net earnings (loss) applicable to common stockholders	$ 4,550	$ (2,479)	$ (2,153)
Basic net earnings (loss) per share:			
Basic earnings (loss) from continuing operations per share	$ 5.31	$ (6.20)	$ (6.86)
Basic earnings from discontinued operations per share	5.04	0.62	2.01
Basic net earnings (loss) per share	$ 10.35	$ (5.58)	$ (4.85)
Diluted net earnings (loss) per share:			
Diluted earnings (loss) from continuing operations per share	$ 5.29	$ (6.20)	$ (6.86)
Diluted earnings from discontinued operations per share	5.02	0.62	2.01
Diluted net earnings (loss) per share	$ 10.31	$ (5.58)	$ (4.85)

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE EARNINGS (LOSS)

	Year Ended December 31, 2010	2009	2008
		(In millions)	
Net earnings (loss)	$ 4,550	$ (2,479)	$ (2,148)
Foreign currency translation:			
Change in cumulative translation adjustment	397	993	(1,960)
Foreign currency translation income tax benefit (expense)	(20)	(62)	79
Foreign currency translation total	377	931	(1,881)
Pension and postretirement benefit plans:			
Net actuarial gain (loss) and prior service cost arising in current year	(33)	59	(239)
Recognition of net actuarial loss and prior service cost in net earnings (loss)	31	54	18
Pension and postretirement benefit plans income tax benefit (expense)		(42)	80
Pension and postretirement benefit plans total	(2)	71	(141)
Other comprehensive earnings (loss), net of tax	375	1,002	(2,022)
Comprehensive earnings (loss)	$ 4,925	$ (1,477)	$ (4,170)

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Preferred Stock	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Stockholders Equity
					(In millions)			
Balance as of December 31, 2007	$ 1	444	$ 44	$ 6,743	$ 12,813	$ 2,405	$	$ 22,006
Net earnings (loss)					(2,148)			(2,148)
Other comprehensive earnings (loss), net of tax						(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
Net earnings (loss)					(2,479)			(2,479)
Other comprehensive earnings (loss), net of tax						1,002		1,002
Stock option exercises		1	1	47			(5)	43
Restricted stock grants, net of cancellations		2						
Common stock repurchased							(40)	(40)
Common stock retired				(45)			45	
Common stock dividends					(284)			(284)
Share-based compensation				260				260
Share-based compensation tax benefits				8				8
		447	45	6,527	7,613	1,385		15,570

Balance as of December 31, 2009							
Net earnings (loss)				4,550			4,550
Other comprehensive earnings (loss), net of tax					375		375
Stock option exercises	2		117			(6)	111
Restricted stock grants, net of cancellations	2						
Common stock repurchased						(1,246)	(1,246)
Common stock retired	(19)	(2)	(1,217)			1,219	
Common stock dividends				(281)			(281)
Share-based compensation			158				158
Share-based compensation tax benefits			16				16
Balance as of December 31, 2010	432	$ 43	$ 5,601	$ 11,882	$ 1,760	$ (33)	$ 19,253

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
	(In millions)		
Cash flows from operating activities:			
Earnings (loss) from continuing operations	$ 2,333	$ (2,753)	$ (3,039)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,930	2,108	3,203
Deferred income tax expense (benefit)	719	(2,014)	(1,562)
Reduction of carrying value of oil and gas properties		6,408	9,891
Unrealized change in fair value of financial instruments	107	55	(456)
Other noncash charges	215	288	623
Net decrease (increase) in working capital	(273)	149	(207)
Decrease (increase) in long-term other assets	32	(6)	(53)
Increase (decrease) in long-term other liabilities	(41)	(3)	48
Cash from operating activities continuing operations	5,022	4,232	8,448
Cash from operating activities discontinued operations	456	505	960
Net cash from operating activities	5,478	4,737	9,408
Cash flows from investing activities:			
Proceeds from property and equipment divestitures	4,310	34	117
Capital expenditures	(6,476)	(4,879)	(8,843)
Proceeds from exchange of Chevron Corporation common stock			280
Purchases of short-term investments	(145)		(50)
Redemptions of long-term investments	21	7	300
Other	(19)	(17)	
Cash from investing activities continuing operations	(2,309)	(4,855)	(8,196)
Cash from investing activities discontinued operations	2,197	(499)	1,323
Net cash from investing activities	(112)	(5,354)	(6,873)
Cash flows from financing activities:			
Net commercial paper (repayments) borrowings	(1,432)	426	1
Debt repayments	(350)	(178)	(1,031)
Proceeds from borrowings of long-term debt, net of issuance costs		1,187	
Credit facility repayments			(3,191)
Credit facility borrowings			1,741
Redemption of preferred stock			(150)

Proceeds from stock option exercises	111	42	116
Repurchases of common stock	(1,168)		(665)
Dividends paid on common and preferred stock	(281)	(284)	(289)
Excess tax benefits related to share-based compensation	16	8	60
Net cash from financing activities	(3,104)	1,201	(3,408)
Effect of exchange rate changes on cash	17	43	(116)
Net increase (decrease) in cash and cash equivalents	2,279	627	(989)
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	1,011	384	1,373
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 3,290	$ 1,011	$ 384

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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

Nature of Business and Principles of Consolidation

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

the Mid-Continent area of the central and southern United States, principally in north and east Texas, as well as 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 onshore areas of the Gulf Coast, principally in south Texas and south Louisiana; and

the provinces of Alberta, British Columbia and Saskatchewan in Canada.

In November 2009, Devon announced plans to strategically reposition itself as a North American onshore exploration and development company. During 2010, Devon divested its properties in the Gulf of Mexico, Azerbaijan, China and other International regions. Additionally, Devon has entered into agreements to sell its remaining offshore assets in Brazil and Angola. These activities are more fully described in Note 5.

Devon also has marketing and midstream operations that perform various activities to support the oil and gas operations of Devon and 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;

derivative financial instruments;

income taxes;

asset retirement obligations;

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

obligations related to employee pension and postretirement benefits; and

legal and environmental risks and exposures.

Derivative Financial Instruments

Devon is exposed to certain risks relating to its ongoing business operations, including risks related 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. Devon does not hold or issue derivative financial instruments for speculative trading purposes. 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, gas and NGL production that hedge the future prices received. These instruments are used to manage the inherent uncertainty of future revenues due to commodity price volatility. Devon s derivative financial instruments include financial price swaps, basis swaps, costless price collars and call options. Under the terms of the price swaps, Devon receives a fixed price for its production and pays a variable market price to the contract counterparty. For the basis swaps, Devon receives a fixed differential between two regional gas index prices and pays a variable differential on the same two index prices 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. Under the terms of a call option, Devon received a cash premium for selling call options. The call options then give the counterparty the right to place us into a price swap at a predetermined fixed price.

Devon periodically enters into interest rate swaps to manage its exposure to interest rate volatility. Devon s interest rate swaps include contracts in which Devon receives a fixed rate and pays a variable rate on a total notional amount. Devon also has forward starting swaps. Under the terms of the forward starting swaps, Devon will net settle these contracts in September 2011 or sooner should Devon elect. The net settlement amount will be based upon Devon paying a fixed rate and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041.

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. For derivative financial instruments held during the three-year period ended December 31, 2010, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment. Cash settlements with counterparties to Devon s derivative financial instruments are also recorded in the statement of operations.

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. Additionally, Devon s derivative contracts generally require cash collateral to be posted if either its or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

our contracts. As of December 31, 2010, the credit ratings of all Devon s counterparties were investment grade.

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.

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

Fair Value Measurements

Certain of Devon s assets and liabilities are measured at fair value at each reporting date. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. This price is commonly referred to as the exit price .

Fair value measurements are classified according to a hierarchy that prioritizes the inputs underlying the valuation techniques. 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 2 measurements are based on inputs other than quoted prices that are generally observable for the asset or liability. Common examples of Level 2 inputs include quoted prices for similar assets and liabilities in active markets or quoted prices for identical assets and liabilities in markets not considered to be active. Level 3 measurements have the lowest priority and are based upon inputs that are not observable from objective sources. The most common Level 3 fair value measurement is an internally developed cash flow model. 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.

See Note 11 for fair value measurements included in Devon s accompanying consolidated balance sheets.

Discontinued Operations

As a result of the November 2009 plan to divest Devon s offshore assets, all amounts related to Devon s International operations are classified as discontinued operations. The Gulf of Mexico properties that were divested in 2010 do not qualify as discontinued operations under accounting rules. As such, amounts in these notes and the accompanying consolidated financial statements that pertain to continuing operations include amounts related to Devon s offshore Gulf of Mexico operations. See Note 5 for additional details of the offshore divestiture program.

The captions assets held for sale and liabilities associated with assets held for sale in the accompanying consolidated balance sheets present the assets and liabilities associated with Devon s discontinued operations. Devon measures its assets held for sale at the lower of its carrying amount or estimated fair value less costs to sell. Additionally, Devon does not recognize depreciation, depletion and amortization on its long-lived assets held for sale.

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to the end of the period. Prior to December 31, 2009, prices and costs used to calculate future net revenues were those as of the end of the appropriate quarterly period. Prices are held constant indefinitely and 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, 2010 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 commodity 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 holding periods ranging from three to five years.

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. Interest costs incurred and attributable to major midstream and corporate construction projects are also capitalized.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Devon s primary investments consist of auction rate securities that totaled $94 million and $115 million at December 31, 2010 and 2009, respectively. These 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.

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, 2010, issuers have redeemed $58 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 auction rate securities as long-term investments as of December 31, 2010. 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.

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 2010, 2009 and 2008. 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, 2010 and 2009. The increase in Devon s continuing operations goodwill from 2009 to 2010 is due to changes in the exchange rate between the U.S. dollar and the Canadian dollar. Devon removed all its International goodwill in conjunction with the Azerbaijan divestiture that closed in 2010. Such goodwill was presented in long-term assets held for sale in the accompanying December 31, 2009 consolidated balance sheet.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2010	December 31, 2009
	(In millions)	
United States	$ 3,046	$ 3,046
Canada	3,034	2,884
Total (continuing operations)	$ 6,080	$ 5,930
International (assets held for sale)	$	$ 68

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 earnings in stockholders equity. The following table presents the balances of Devon s cumulative translation adjustments included in accumulated other comprehensive earnings (in millions).

December 31, 2007	$ 2,566
December 31, 2008	$ 685
December 31, 2009	$ 1,616
December 31, 2010	$ 1,993

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 sales 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 sales are presented separately from such revenues in the accompanying consolidated statements 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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 collectability of the revenue is probable. Revenues and expenses attributable to oil, gas and NGL purchases, transportation and processing contracts are reported on a gross basis when Devon takes title to the products and has risks and rewards of ownership.

During 2010, 2009 and 2008, 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 requisite service periods. As a result of Devon s strategic repositioning announced in 2009, certain share based awards were accelerated and recognized as a component of restructuring expense in the accompanying 2010 and 2009 statements of operations.

Generally, Devon uses new shares to grant share-based awards and to issue shares upon stock option exercises. Shares repurchased under approved programs are available to be issued as part of Devon s share based awards. However, Devon has historically cancelled these shares upon repurchase.

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.

Devon does not recognize United States deferred income taxes on the unremitted earnings of its foreign subsidiaries that are deemed to be permanently reinvested. When such earnings are no longer deemed permanently reinvested, Devon recognizes the appropriate deferred income tax liabilities.

Devon recognizes the financial statement effects of tax positions 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 other current liabilities. Interest and penalties related to unrecognized tax benefits are included in current income tax

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

expense. Additional information regarding Devon s unrecognized tax benefits, including changes in such amounts during 2010 and 2009, is provided in Note 17.

Net Earnings (Loss) Per Common Share

Devon s basic earnings per share amounts have been computed based on the average number of shares of common stock outstanding for the period. Basic earnings per share includes the effect of participating securities, which primarily consist of Devon s outstanding restricted stock awards. 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.

Cash and Cash Equivalents

Devon considers all highly liquid investments with original contractual maturities of three months or less to be cash equivalents.

2. Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2010	December 31, 2009
	(In millions)	
Oil, gas and NGL sales	$ 786	$ 752
Joint interest billings	182	151
Marketing and midstream revenues	163	188
Production tax credits	46	110
Other	35	19
Gross accounts receivable	1,212	1,220
Allowance for doubtful accounts	(10)	(12)
Net accounts receivable	$ 1,202	$ 1,208

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Derivative Financial Instruments

The following table presents the derivative fair values included in the accompanying consolidated balance sheets. Devon has elected not to designate any of its derivative instruments for hedge accounting treatment.

	Balance Sheet Caption	December 31, 2010	2009
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$ 248	$ 172
Commodity derivatives	Other long-term assets	1	
Interest rate derivatives	Other current assets	100	39
Interest rate derivatives	Other long-term assets	40	131
Total asset derivatives		$ 389	$ 342
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 50	$ 38
Commodity derivatives	Other long-term liabilities	142	
Total liability derivatives		$ 192	$ 38

The following table presents the cash settlements and unrealized gains and losses on fair value changes included in the accompanying consolidated statements of operations associated with these derivative financial instruments.

	Statement of Operations Caption	2010	2009	2008
			(In millions)	
Cash settlements:				
Commodity derivatives	Oil, gas and NGL derivatives	$ 888	$ 505	$ (397)
Interest rate derivatives	Interest-rate and other financial instruments	44	40	1
Total cash settlements		932	545	(396)
Unrealized gains (losses):				
Commodity derivatives	Oil, gas and NGL derivatives	(77)	(121)	243
Interest rate derivatives	Interest-rate and other financial instruments	(30)	66	104
Embedded option	Interest-rate and other financial instruments			109

Total unrealized gains (losses)	(107)	(55)	456
Net gain recognized on statement of operations	$ 825	$ 490	$ 60

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Other Current Assets

The components of other current assets include the following:

	December 31, 2010	December 31, 2009
	(In millions)	
Derivative financial instruments	$ 348	$ 211
Income tax receivable	270	53
Short-term investments	145	
Inventories	120	182
Other	41	35
Other current assets	$ 924	$ 481

5. Property and Equipment

Property and equipment consists of the following:

	December 31, 2010	December 31, 2009
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 56,012	$ 52,352
Not subject to amortization	3,434	4,078
Total	59,446	56,430
Accumulated depreciation, depletion and amortization	(42,676)	(40,312)
Net oil and gas properties	16,770	16,118
Other property and equipment	4,429	4,045
Accumulated depreciation and amortization	(1,547)	(1,396)
Net other property and equipment	2,882	2,649
Property and equipment, net	$ 19,652	$ 18,767

The following is a summary of Devon s oil and gas properties not subject to amortization as of December 31, 2010.

	Costs Incurred In				
	2010	2009	2008	Prior to 2008	Total
	(In millions)				
Acquisition costs	$ 1,188	$ 121	$ 1,049	$ 671	$ 3,029
Exploration costs	130	40	39	5	214
Development costs	159	1	9		169
Capitalized interest	22				22
Total oil and gas properties not subject to amortization	$ 1,499	$ 162	$ 1,097	$ 676	$ 3,434

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Offshore Divestitures

In November 2009, Devon announced plans to reposition itself strategically as a North America onshore exploration and production company. As part of this strategic repositioning, Devon is bringing forward the value of its offshore assets by divesting them.

Closed Transactions

The following table presents Devon s offshore divestiture transactions that closed in 2010. Gross proceeds represent contract prices based upon a January 1, 2010 effective date for the Gulf of Mexico and Azerbaijan divestitures, a May 1, 2010 effective date for the China Panyu divestiture and a September 1, 2010 effective date for the China-Exploration divestiture. After-tax proceeds represent gross proceeds adjusted for customary purchase price adjustments, selling costs and income taxes. The purchase price adjustments consist primarily of net cash flow subsequent to the effective date of the divestitures. Proved reserves in the following table are based upon estimated proved reserves as of the divestiture dates.

	Gross Proceeds	After-Tax Proceeds	Proved Reserves (MMBoe) (Unaudited)
	(In millions)		
Gulf of Mexico (continuing operations)	$ 4,145	$ 3,222	91
Azerbaijan (discontinued operations)	2,000	1,925	56
China Panyu (discontinued operations)	515	405	13
China Exploration (discontinued operations)	77	59	
Other (discontinued operations)	38	38	20
Total	$ 6,775	$ 5,649	180

Proceeds from these divestitures are being used to retire debt and repurchase Devon common shares. Additionally, Devon is using divestiture proceeds to fund North America Onshore exploration and development opportunities, including a joint-venture investment in the Pike oil sands discussed below.

Under full cost accounting rules, sales or other dispositions of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of gain or loss. However, if not recognizing a gain or loss on the disposition would otherwise significantly alter the relationship between a cost center s capitalized costs and proved reserves, then a gain or loss must be recognized.

The Gulf of Mexico divestitures presented above did not significantly alter such relationship for Devon s United States cost center. Therefore, Devon did not recognize a gain in connection with the Gulf of Mexico divestitures. The Azerbaijan divestiture included all of Devon s properties in its Azerbaijan cost center. As a result, Devon recognized a $1,543 million ($1,524 million after-tax) gain during 2010 in connection with the Azerbaijan divestiture. Panyu was Devon s only producing property in its China cost center. As a result, Devon recognized a $308 million ($235 million after-tax) gain in connection with the Panyu divestiture in 2010. These gains are included in earnings from discontinued operations in the accompanying 2010 consolidated statement of operations.

Pending Transactions

Devon has entered into agreements to sell its remaining offshore assets in Brazil and Angola and is waiting for the respective governments to approve the divestitures. The Brazil divestiture is valued at $3.2 billion, and Devon expects to record a gain upon the close of this transaction. For the Angola divestiture, Devon will receive $70 million at closing, and has the potential to receive future consideration that is contingent upon the buyer achieving certain milestones.

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Deepwater Drilling Rigs

As part of its offshore operations, Devon was leasing three deepwater drilling rigs. The Seadrill West Sirius and Ocean Endeavor deepwater drilling rigs were used in Devon s Gulf of Mexico operations. The Transocean Deepwater Discovery is currently being used in Devon s operations in Brazil.

In conjunction with the deepwater Gulf of Mexico divestiture that closed in the second quarter of 2010, the buyer assumed Devon s lease and remaining commitments for the Seadrill West Sirius rig. Subsequent to closing all its Gulf of Mexico divestitures, Devon agreed to pay $31 million to the owner of the Ocean Endeavor rig to terminate the lease. The $31 million lease termination cost is included in oil and gas property and equipment in the accompanying December 31, 2010, consolidated balance sheet. The buyer of Devon s assets in Brazil will assume Devon s lease and remaining commitments for the Transocean Deepwater Discovery rig when the divestiture transaction closes.

Oil Sands Joint Venture

In conjunction with certain offshore divestitures in the second quarter of 2010, Devon formed a heavy oil joint venture to operate and develop the Pike oil sands leases in Alberta, Canada. As a result, Devon acquired a 50 percent interest in the Pike oil sands leases for $500 million. Devon will also fund $155 million of Canadian dollar capital costs on behalf of its joint-venture partner in the form of a non-interest bearing promissory note. The majority of the capital costs are expected to be paid during 2011 and 2012. See Note 6 for more information regarding the promissory note.

Reductions of Carrying Value

In the first quarter of 2009 and the fourth quarter of 2008, Devon reduced the carrying values of its oil and gas properties due to full cost ceiling limitations. These reductions are discussed in Note 15.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Debt and Related Expenses

A summary of Devon s debt is as follows:

	December 31, 2010	December 31, 2009
	(In millions)	
Commercial paper	$	$ 1,432
Other debentures and notes:		
7.25% retired on June 25, 2010		350
6.875% due September 30, 2011	1,750	1,750
5.625% due January 15, 2014	500	500
Non-interest bearing promissory note due June 29, 2014	144	
8.25% due July 1, 2018	125	125
6.30% due January 15, 2019	700	700
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	9	10
Net premium on other debentures and notes	2	12
Total debt	5,630	7,279
Less amount classified as short-term debt	1,811	1,432
Long-term debt	$ 3,819	$ 5,847

Debt maturities as of December 31, 2010, excluding premiums and discounts, are as follows (in millions):

2011	$ 1,812
2012	9
2013	
2014	582
2015	
2016 and thereafter	3,225
Total	$ 5,628

Credit Lines

Devon has a $2,650 million syndicated, unsecured revolving line of credit (the Senior Credit Facility). The maturity date for $2,187 million of the Senior Credit Facility is April 7, 2013. The maturity date for the remaining $463 million 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, 2010, there were no borrowings under the Senior Credit Facility.

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The Senior Credit Facility contains 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, 2010, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at December 31, 2010, as calculated pursuant to the terms of the agreement, was 15.1%.

The following schedule summarizes the capacity of Devon s Senior Credit Facility by maturity date, as well as its available capacity as of December 31, 2010 (in millions).

April 7, 2012 maturity	$ 463
April 7, 2013 maturity	2,187
Total Senior Credit Facility	2,650
Less:	
Outstanding Senior Credit Facility borrowings	
Outstanding commercial paper borrowings	
Outstanding letters of credit	38
Total available capacity	$ 2,612

Commercial Paper

Devon also has access to approximately $2,200 million of short-term credit under its commercial paper program. Any borrowings under the commercial paper program reduce available capacity under the Senior Credit 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.

During the first half of 2010, Devon repaid $1,432 million of commercial paper borrowings primarily with proceeds received from its Gulf of Mexico property divestitures. At December 31, 2010, Devon had no outstanding commercial paper borrowings. The average borrowing rate for Devon s $1,432 million of commercial paper borrowings at December 31, 2009 was 0.29%.

$350 Million 7.25% Senior Notes Due October 1, 2011

On June 25, 2010, Devon redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011, primarily with proceeds received from its Gulf of Mexico divestitures. The notes were redeemed for $384 million, which represented 100 percent of the principal amount, a make-whole premium of $28 million and $6 million of accrued and unpaid interest. On the date of redemption, these notes also had an unamortized premium of $9 million. The $28 million make-whole premium and $9 million amortization of the remaining premium are included in interest expense in the accompanying 2010 consolidated statements of operations.

Non-Interest Bearing Promissory Note Due June 29, 2014

On June 29, 2010, Devon issued a four-year $155 million Canadian dollar non-interest bearing promissory note in connection with the formation of the Pike oil sands joint venture described in Note 5. The present value of the note was $139 million on the issue date based upon an effective interest rate of 3.125%. At

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2010, the note had a carrying value of $144 million, of which $62 million is presented as short-term debt and the remainder is presented as long-term debt in the accompanying consolidated balance sheet.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2010, as listed in the table presented at the beginning of this note.

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.

5.625% Notes due January 15, 2014 and 6.30% Notes due January 15, 2019

On January 9, 2009, Devon sold these notes, which are unsecured and unsubordinated obligations of Devon. The net proceeds from issuance of this debt were used primarily to repay Devon s outstanding commercial paper as of December 31, 2008.

Ocean Debt

As a result of the April 25, 2003 merger with Ocean Energy, Inc., Devon assumed certain debt instruments that remain outstanding at December 31, 2010. The table below summarizes the debt assumed, 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 (In millions)	Effective Rate of Debt Assumed
8.250% due July 2018 (principal of $125 million)	$ 147	5.5%
7.500% due September 2027(principal of $150 million)	$ 169	6.5%

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.

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Interest Expense

The following schedule includes the components of interest expense.

	Year Ended December 31, 2010	2009	2008
	(In millions)		
Interest based on debt outstanding	$ 408	$ 437	$ 426
Capitalized interest	(76)	(94)	(111)
Early retirement of debt	19		
Other	12	6	14
Total	$ 363	$ 349	$ 329

7. Asset Retirement Obligations

The schedule below summarizes changes in Devon s asset retirement obligations.

	Year Ended December 31, 2010	2009
	(In millions)	
Asset retirement obligations as of beginning of year	$ 1,513	$ 1,387
Liabilities incurred	55	56
Liabilities settled	(129)	(123)
Revision of estimated obligation	194	33
Liabilities assumed by others	(269)	(30)
Accretion expense on discounted obligation	92	91
Foreign currency translation adjustment	41	99
Asset retirement obligations as of end of year	1,497	1,513
Less current portion	74	95
Asset retirement obligations, long-term	$ 1,423	$ 1,418

During 2010 and 2009, Devon recognized revisions to its asset retirement obligations totaling $194 million and $33 million, respectively. The primary factors causing the 2010 and 2009 increases were an overall increase in abandonment cost estimates and a decrease in the discount rate used to present value the obligations.

During 2010, Devon reduced its asset retirement obligations by $269 million primarily for those obligations that were assumed by purchasers of Devon s Gulf of Mexico oil and gas properties.

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 certain 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.

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

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fund these plans benefit obligations. The total value of these trusts was $36 million and $39 million at December 31, 2010 and 2009, respectively, and is included in other long-term assets in the accompanying 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.

Benefit Obligations and Funded Status

The following table presents the status of Devon s pension and other postretirement benefit plans. 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, 2010 and 2009 was $1,010 million and $873 million, respectively. Devon s benefit obligations and plan assets are measured each year as of December 31.

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 980	$ 931	$ 64	$ 56
Service cost	33	43	1	1
Interest cost	58	58	3	3
Actuarial loss (gain)	82	4	1	7
Curtailment (gain) loss		(26)		1
Plan amendments	5		(22)	
Foreign exchange rate changes	2	5		
Participant contributions			2	2
Benefits paid	(36)	(35)	(6)	(6)
Benefit obligation at end of year	1,124	980	43	64
Change in plan assets:				
Fair value of plan assets at beginning of year	532	430		
Actual return on plan assets	69	80		
Employer contributions	66	55	4	4
Participant contributions			2	2

Benefits paid	(36)	(35)	(6)	(6)
Foreign exchange rate changes	1	2		
Fair value of plan assets at end of year	632	532		
Funded status at end of year	$ (492)	$ (448)	$ (43)	$ (64)

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	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
	(In millions)			
Amounts recognized in balance sheet:				
Noncurrent assets	$ 2	$ 2	$	$
Current liabilities	(9)	(8)	(4)	(5)
Noncurrent liabilities	(485)	(442)	(39)	(59)
Net amount	$ (492)	$ (448)	$ (43)	$ (64)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 357	$ 334	$ (5)	$ (6)
Prior service cost (credit)	21	20	(12)	11
Total	$ 378	$ 354	$ (17)	$ 5

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 $8 million and $9 million for 2010 and 2009, respectively, which were transferred from the trusts established for the Supplemental Plans.

Certain of Devon s pension plans have a projected benefit obligation and accumulated benefit obligation in excess of plan assets at December 31, 2010 and 2009 as presented in the table below.

	December 31,	
	2010	2009
	(In millions)	
Projected benefit obligation	$ 1,110	$ 967
Accumulated benefit obligation	$ 996	$ 860
Fair value of plan assets	$ 616	$ 517

The plan assets included in the above table exclude the Supplemental Plan trusts, which had a total value of $36 million and $39 million at December 31, 2010 and 2009, respectively.

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Net Periodic Benefit Cost and Other Comprehensive Earnings

The following table presents the components of net periodic benefit cost and other comprehensive earnings for Devon s pension and other postretirement benefit plans.

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 33	$ 43	$ 41	$ 1	$ 1	$ 1
Interest cost	58	58	54	3	3	4
Expected return on plan assets	(37)	(35)	(50)			
Curtailment and settlement expense		5			1	
Recognition of net actuarial loss (gain)	28	45	14		(1)	
Recognition of prior service cost	3	3	2	1	2	2
Total net periodic benefit cost	85	119	61	5	6	7
Other comprehensive earnings:						
Actuarial (gain) loss arising in current year	49	(66)	245	1	7	(15)
Prior service cost (credit) arising in current year	5		9	(22)		
Recognition of net actuarial (loss) gain in net periodic benefit cost	(27)	(45)	(14)		1	