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Devon Energy 2011 Letter to Shareholders and Form 10-K

To further enhance our long-term growth, we have assembled high-impact positions across a number of new oil and liquids-rich plays. These include the Tuscaloosa Marine Shale, several Rockies oil plays, the Mississippian, the Ohio Utica Shale and two plays in the Michigan Basin. Subsequent to establishing these positions, we entered into a joint venture with Sinopec International Petroleum Exploration & Production Corporation (SIPC) whereby SIPC will invest $2.5 billion in exchange for one-third of our 1.4 million net acres in these plays. This transaction enhances our returns and improves capital efficiency by:

- Recovering our investment to date associated with establishing and exploring on the acreage positions,
- Providing a reduction in capital requirements in the future,
- Accelerating activity in these five new plays without diverting capital from our core development projects, and
- Giving us additional financial flexibility to aggressively pursue new play types with less risk

We look forward to our new relationship with SIPC in the development of these projects.

Preserving financial strength and flexibility

In 2011, we were able to comfortably fund our capital program while maintaining our enviable financial position. Our balance sheet remained exceptionally strong as we exited the year with $7.1 billion in cash and short-term investments and a net debt to capitalization ratio of only 11 percent. This financial strength and flexibility provides a compelling strategic advantage as we can allocate capital throughout all market cycles based on our long-term outlook for asset performance, commodity prices and the industry cost environment.

Exercising capital discipline

The foundation of our capital allocation philosophy remains steadfast – to optimize our long-term growth per share. We implement this philosophy by determining the right combination of exploration and development investments, debt levels, share repurchases and dividend payments.

In November, we completed our $3.5 billion share repurchase program initiated in May of 2010. Over the past eight years we have reduced our share count by almost 100 million shares, or roughly 20 percent of shares outstanding, significantly boosting our reserves, production and cash flow per share. During this same time period, we have also increased our dividend seven times or a total of 800 percent. This history of returning capital to shareholders underscores Devon's financial strength and our commitment to exercising capital discipline.

Our vast inventory of exploration and development projects provides the opportunity to deploy significant quantities of capital for the foreseeable future. In 2011, we allocated more than $6 billion of capital to our upstream projects that generate attractive rates of return in the current environment.

Improving performance through our marketing and midstream operations

Complementing our core business, Devon's strategic marketing and midstream presence allows us to improve our effectiveness and maximize the value of our production. Our marketing and midstream activities are closely coordinated alongside our exploration and production operations. This ensures that we employ our capital in areas where we can reliably and economically deliver our oil and gas into strong product markets. In addition, the expansions to our Barnett and Cana natural gas liquids extraction facilities will allow us to capture additional value from our liquids-rich production stream.

Outlook for 2012 and Beyond

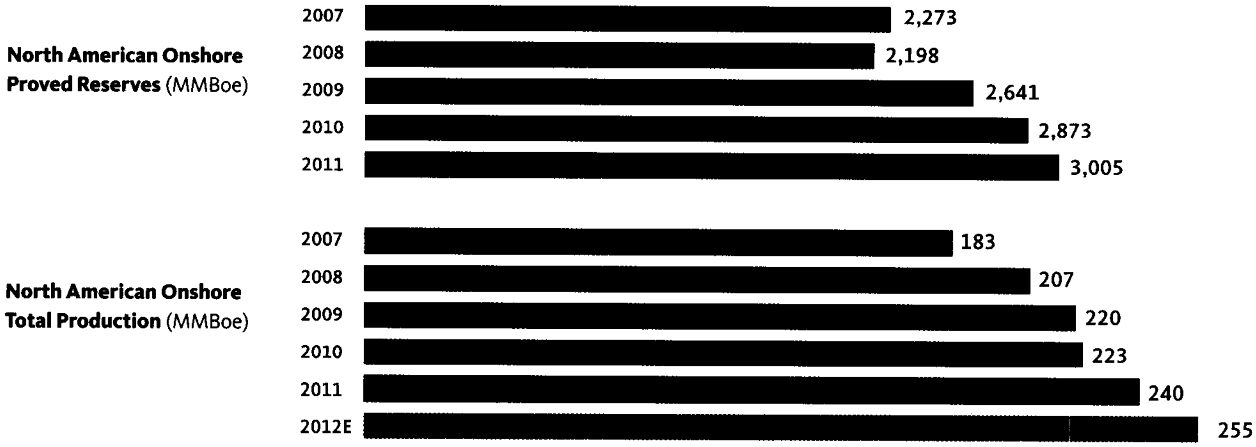
As we embark on the next stage of our journey as a North American onshore company, I could not be more excited about our future. Our balanced portfolio of high-quality oil and gas properties coupled with our dedicated employees provide Devon a strong foundation for success. Devon is the only energy company to be named to both Fortune's "World's Most Admired Companies" and "Best Companies to Work For" lists in each of the past five years. This honor is a testament to the strength of our corporate culture, which is shaped and reinforced by our team of talented employees.

In 2012, virtually all of our upstream capital will be directed to our oil and liquids-rich growth projects. This capital program promises to deliver top-line production growth of approximately 6 percent driven by oil production growth in excess of 20 percent and double-digit growth in natural gas liquids production. By the end of the year, we expect our liquids production to account for 40 percent of our total production, more than half of which will be oil. In addition to the development projects that drive this growth, we will continue to enhance our future growth potential by accelerating our exploration activity and through opportunistic leasehold additions in new oil plays.

Having completed the strategic repositioning that we began in 2009, Devon has emerged as an extremely formidable competitor in North America. We have an industry-leading balance sheet that provides us the flexibility to invest at optimum levels. We have a deep portfolio of oil and liquids-rich growth projects that generate strong returns. We have an aggressive exploration program that is replenishing our inventory for the future. And we have a highly skilled workforce capable of executing on a wide array of opportunities. We are truly positioned to deliver outstanding performance.

John Richels
President and Chief Executive Officer

March 25, 2012



Investing in properties with high operating margins and returns

As we allocate capital to grow our business, it is critical that we remain intently focused on investing in those projects with the highest rates of return. In addition, we are continually reinforcing our position as a low-cost producer through a consistent focus on cost-management and achieving significant scale in our core operating areas. In 2011, Devon's pre-tax cash costs per equivalent barrel of production increased only 2 percent, mitigating much of the impact of an inflationary industry environment and an unfavorable move in the U.S./ Canadian dollar exchange rate.

Another vital factor enabling us to generate strong returns is our balanced exposure to oil, natural gas and natural gas liquids. We have always believed that a balanced portfolio provides better risk-adjusted returns over the long term than one focused entirely on oil or natural gas. This philosophy has served us well as dry-gas economics have eroded in recent years. Our diversified portfolio provides the opportunity to easily refocus our capital on our deep inventory of oil and liquids-rich gas projects, without having to abruptly shift our emphasis or overpay to establish new liquids projects. In 2011, we allocated more than 90 percent of our upstream capital to our high-return oil and liquids-rich growth projects. In 2012, this allocation will approach 100 percent.

Most of our 2011 capital was focused on our cornerstone development projects. In early December, we received regulatory approval for our third, 35,000 barrel per day Jackfish oil sands project in Canada. Construction is underway and plant start-up is targeted for late 2014. The first phase of our Jackfish complex is producing near its 35,000 barrels of oil per day capacity. Jackfish is among the best performing Steam Assisted Gravity Drainage (SAGD) projects in the industry with high per-well production rates, a low steam-oil-ratio and industry-leading operating costs. Our second Jackfish project exited the year producing 14,000 barrels of oil per day and will continue to ramp-up throughout 2012. Each of these 100 percent Devon-owned Jackfish projects represents an estimated 300 million barrels of recoverable oil before royalties. To further leverage Devon's SAGD expertise, we continued our delineation work on our Pike oil sand leases in 2012. Pike is immediately adjacent to Jackfish and is of similar reservoir quality. In aggregate, we expect our net SAGD oil production to grow to more than 150,000 barrels per day by 2020, representing an 18 percent compound annual growth rate through the end of the decade.

In the Mid-Continent region of the United States, we continued the development of our thousands of undrilled liquids-rich locations. In the Barnett Shale in North Texas, we increased fourth-quarter net production to a record 1.32 billion cubic feet equivalent per day, including 47,000 barrels per day of liquids. In the Cana Woodford Shale in western Oklahoma, net production increased to a record 275 million cubic feet of gas equivalent per day at year-end, including more than 12,000 barrels of oil and natural gas liquids. To capture additional value from our growing liquids production, we are expanding our natural gas processing plants in each of these plays.

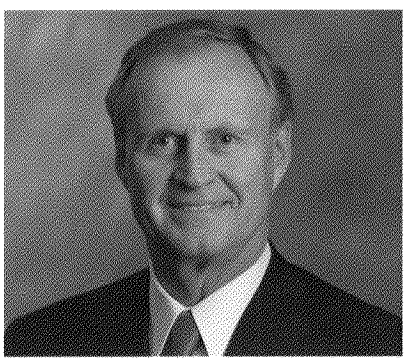
In the Permian Basin, we continue to leverage the horizontal drilling expertise we pioneered in the Barnett Shale. Today, we are the most active horizontal driller in the basin. This reflects the large opportunity set we have across our Permian position. In the current environment, these light oil plays are generating some of the best returns in our portfolio. Oil and natural gas liquids production now accounts for roughly 75 percent of our total production from this prolific basin.

Balancing resource development with resource capture and exploration

In addition to our development opportunities, we continue to bolster our oil project inventory by pursuing a wide range of exploration opportunities across North America. In the Permian and Western Canadian Sedimentary Basins, we are targeting a variety of oil and liquids-rich plays that have emerged across our more than 5 million net prospective acres. Given the recent advances in drilling and completions technology and the stacked-pay nature of these basins, our substantial legacy acreage positions provide Devon with many years of additional growth potential.

Drilling operations are directed from the doghouse control-room on this Devon operated rig in the Cana Woodford Shale. In 2011, Devon drilled more than 200 wells in the oil and liquids-rich Cana field.

Dear Fellow Shareholders:



John Richels
President and Chief Executive Officer

Outstanding Results in a Challenged Environment

In 2011, Devon achieved outstanding results driven by the solid execution of our operational plans and the very successful completion of our strategic repositioning. Net earnings climbed to an all-time record of $4.7 billion. Cash flow totaled $6.5 billion and, when combined with the final proceeds from our strategic repositioning, total cash inflows reached nearly $10 billion. Production from our onshore North America asset base grew to an all-time record of 240 million oil equivalent barrels. Fourth quarter production increased 10 percent over the year-ago quarter, driven by an impressive 21 percent increase in oil and natural gas liquids production. Record production from each of our four core development areas – the Permian Basin, Jackfish, Cana and Barnett – contributed to this solid liquids growth.

Our excellent operating performance translated into another year of strong company-wide reserve growth, boosting year-end proved reserves to an all-time record 3 billion barrels equivalent. With our 2011 drilling program focused on oil and liquids-rich gas, our liquids reserve replacement ratio reached 230 percent. This boosted oil and natural gas liquids to 42 percent of the company's total reserves, more than half of which is oil.

These results are even more impressive when considering the external environment. In 2011, uncertainties related to the global economy remained at the forefront of almost all business activity throughout the world. In light of that, the exploration and production industry faced a number of challenges. Most notable was the wide differential between oil and North American natural gas prices. Although oil prices remained robust, averaging almost $95 per barrel during the year, natural gas prices decreased to an average of about $4 per thousand cubic feet in 2011. Oil prices were supported by strong demand from developing countries and concerns over global supply interruptions. North American natural gas prices, on the other hand, suffered from an oversupplied market. Rising activity levels for oil-directed drilling led to increased service and supply costs, further eroding industry operating margins for natural gas. Devon's outstanding 2011 performance was delivered in spite of these industry challenges.

Successful Execution of Devon's Strategy

Devon's performance reflects our disciplined approach to managing the business. We remain steadfast in our commitment to drive value for our shareholders by maximizing cash flow on a per-share basis, adjusted for debt.

We execute this strategy by:

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

SEC
Mail Processing
Section

APR 2 6 2012

Washington DC
405

(Mark One)

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

For the fiscal year ended December 31, 2011

or

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

Commission File Number 001-32318

DEVON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**73-1567067**
(State of other jurisdiction of incorporation or organization)	*(I.R.S. Employer identification No.)*
20 North Broadway, Oklahoma City, Oklahoma	**73102-8260**
(Address of principal executive offices)	*(Zip code)*

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

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

Title of each class	Name of each exchange on which registered
Common stock, par value $0.10 per share	The New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

Indicate by check mark 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 ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2011, was approximately $32.7 billion, based upon the closing price of $78.81 per share as reported by the New York Stock Exchange on such date. On February 9, 2012, 404.1 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2012 annual meeting of stockholders — Part III

DEVON ENERGY CORPORATION

FORM 10-K
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PART I

PART II

PART III

PART IV

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements regarding our expectations and plans, as well as future events or conditions. Such forward-looking statements are based on our examination of historical operating trends, the information used to prepare our December 31, 2011 reserve reports and other data in our possession or available from third parties. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond our control. Consequently, actual future results could differ materially from our expectations due to a number of factors, such as changes in the supply of and demand for oil, natural gas and NGLs and related products and services; exploration or drilling programs; political or regulatory events; general economic and financial market conditions; and other factors discussed 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 above. We assume no duty to update or revise our forward-looking statements based on new information, future events or otherwise.

PART I

Item 1 and 2. *Business and Properties*

General

Devon Energy Corporation ("Devon") is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Our operations are concentrated in various North American onshore areas in the U.S. and Canada. We also own natural gas pipelines, plants and treatment facilities in many of our producing areas, making us one of North America's larger processors of natural gas.

Devon pioneered the commercial development of natural gas from shale and coalbed formations, and we are a proven leader in using steam to produce oil from the Canadian oil sands. A Delaware corporation formed in 1971, 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). As of December 31, 2011, we had approximately 5,200 employees.

Devon files or furnishes 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 with the U.S. Securities and Exchange Commission ("SEC"). Through our website, http://www.devonenergy.com, we make available electronic copies of the documents we file or furnish to the SEC, the charters of the committees of our Board of Directors and other documents related to our corporate governance (including our Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer). 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.

In addition, the public may read and copy any materials Devon files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington D.C. 20549. The public may also obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov.

Strategy

We aspire to be the premier independent oil and natural gas company in North America and to provide our shareholders with top-quartile returns over the long-term. To achieve this, we strive to optimize our capital investments to maximize growth in cash flows, earnings, production and reserves, all on a per debt-adjusted share basis. We do this by:

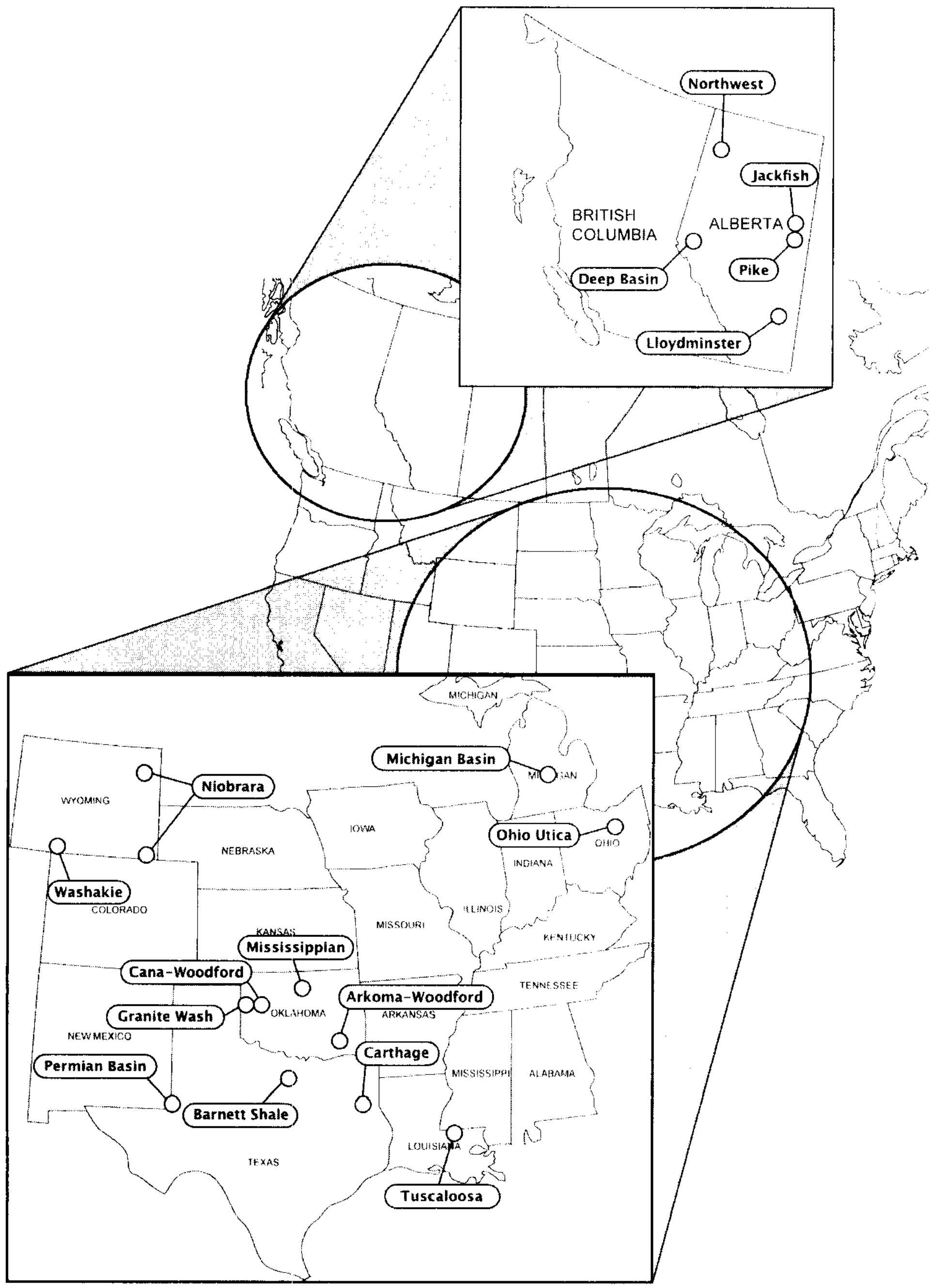
- exercising capital discipline,
- maintaining superior financial strength,
- investing in oil and gas properties with strong full-cycle margins, and
- balancing our production and resource mix between natural gas and liquids.

Growth in cash flow per debt-adjusted share has the greatest long-term correlation to share price appreciation. As a result, we focus on capital investments that sustain and accelerate growth per debt-adjusted share. In an environment that involves challenged natural gas prices and more robust liquids prices, our capital allocation is focused on liquids-based resource capture and development. Our portfolio strikes a good balance between oil, NGLs and natural gas with a cost structure that generates highly competitive full-cycle returns. Within our portfolio, we have a deep inventory of repeatable opportunities diversified across several key resource plays. We also have significant exposure to several emerging plays and new venture opportunities. Finally, the recent divestiture of our offshore operations generated about $8 billion in after-tax proceeds. We used a portion of these proceeds to repurchase $3.5 billion of our common stock and repay debt, giving us one of the strongest balance sheets in our peer group.

Oil and Gas Properties

Property Profiles

The locations of our key properties are presented on the following map. These properties include those that currently have significant proved reserves and production, as well as properties that do not currently have significant levels of proved reserves or production but are expected to be the source of significant future growth in proved reserves and production.



The following table outlines a summary of key data in each of our operating areas for 2011. Notes 21 and 22 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report contain additional information on our segments and geographical areas.

	Proved Reserves December 31, 2011			Production Year Ended December 31, 2011			Total	Gross	Average
	MMBoe(1)	% of Total	% Liquids	MMBoe(1)	% of Total	% Liquids	Net Acres (in thousands)	Wells Drilled	Working Interest
U.S.									
Barnett	1,151	38.3%	22.1%	78	32.4%	21.3%	625	309	89.0%
Cana-Woodford	327	10.9%	36.4%	12	5.1%	26.0%	244	207	51.4%
Permian	189	6.3%	77.8%	18	7.5%	74.5%	1,070	284	80.0%
Carthage	172	5.7%	29.7%	15	6.2%	26.0%	309	31	88.1%
Washakie	98	3.3%	35.9%	8	3.5%	37.5%	157	57	76.0%
Granite Wash	46	1.5%	35.7%	6	2.5%	43.2%	63	59	48.7%
Arkoma-Woodford	37	1.2%	20.0%	5	1.9%	21.6%	42	29	31.3%
New Ventures	—	—%	—%	—	—%	—%	1,370	—	N/M
Other	258	8.6%	24.4%	31	13.0%	19.5%	2,664	113	N/M
Total U.S.	**2,278**	**75.8%**	**30.4%**	**173**	**72.1%**	**28.8%**	**6,544**	**1,089**	**N/M**
Canada									
Jackfish	457	15.2%	100.0%	13	5.3%	100.0%	34	21	100.0%
Northwest	95	3.2%	41.0%	15	6.2%	24.5%	1,829	42	74.0%
Deep Basin	65	2.2%	14.6%	15	6.1%	10.5%	727	29	45.0%
Lloydminster	54	1.8%	78.6%	14	6.0%	81.6%	2,677	197	87.0%
Pike	—	—%	—%	—	—%	—%	59	—	50.0%
Other	56	1.8%	29.3%	10	4.3%	19.1%	1,501	27	N/M
Total Canada	**727**	**24.2%**	**77.6%**	**67**	**27.9%**	**47.1%**	**6,827**	**316**	N/M
Devon	**3,005**	**100.0%**	**41.9%**	**240**	**100.0%**	**33.9%**	**13,371**	**1,405**	**N/M**

(1) Gas proved 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. NGL reserves and production are converted to Boe on a one-to-one basis with oil.

N/M Not meaningful.

U.S.

Barnett Shale — This is our largest property both in terms of production and proved reserves. Our leases are located primarily in Denton, Johnson, Parker, Tarrant and Wise counties in north Texas. The Barnett Shale is a non-conventional reservoir, producing natural gas and NGLs.

We are the largest producer in the Barnett Shale. Since acquiring a substantial position in this field in 2002, we continue to introduce technology and new innovations to enhance production and have transformed this into one of the top producing gas fields in North America. We have drilled nearly 5,000 wells in the Barnett Shale since 2002, yet we still have several thousand remaining drilling locations. In 2012, we plan to drill approximately 300 wells.

In addition, we have a significant processing plant and gathering system in North Texas to service these properties. Currently, these midstream 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. To meet increasing demand from our liquids-rich development drilling, we intend to increase the size of our inlet processing capacity to 890 MMcf per day by early 2013.

Cana-Woodford Shale — Our acreage is located primarily in Oklahoma's Canadian, Blaine, Caddo, and Dewey counties. The Cana-Woodford Shale is a non-conventional reservoir and produces natural gas, NGLs and condensate.

The Cana-Woodford is a leading growth area for Devon and has rapidly emerged as one of the most economic shale plays in North America. We are the largest leaseholder and the largest producer in the Cana-Woodford. During 2011, we increased our production by 85%. We have several thousand remaining drilling locations. In 2012, we plan to drill approximately 200 wells.

In addition, we have constructed a gas processing plant with 200 MMcf per day of total capacity. To meet increasing demand from our development drilling, we intend to increase the size of our plant to 350 MMcf per day by mid-2013.

Permian Basin — These properties have been a legacy asset for us and continue to offer both exploration and low-risk development opportunities. Our acreage is located in various counties in west Texas and southeast New Mexico. Our current drilling activity is targeting conventional and non-conventional liquids-rich targets within the Conventional Delaware, Bone Spring, Wolfcamp, Wolfberry and Avalon Shale plays. In 2012, we plan to drill more than 300 wells.

Carthage — Our acreage is located primarily in Harrison, Marion, Panola and Shelby counties in east Texas. These wells produce natural gas and NGLs from conventional reservoirs. In 2012, we plan to drill approximately 35 wells.

Washakie — These leases are concentrated in Wyoming's Carbon and Sweetwater counties. The Washakie wells produce natural gas and NGLs from conventional reservoirs. Targeting the Almond and Lewis formations, we have been among the most active drillers in the Washakie basin for many years.

Granite Wash — Our acreage is concentrated in the Texas Panhandle and western Oklahoma. These properties produce liquids and natural gas from conventional reservoirs. Our legacy land position in the Granite Wash is held by production and provides some of the best economics in our portfolio. High initial production rates and strong liquids yields contribute to the superior full-cycle rates of return. In 2012, we plan to drill approximately 65 wells.

Arkoma-Woodford Shale — Our acreage is located primarily in Coal and Hughes counties in southeastern Oklahoma. These properties produce natural gas and NGLs from a non-conventional reservoir. Our acreage in this play is held by production. In 2012, we do not plan to drill additional wells.

New Ventures — During 2010 and 2011, we made significant acreage acquisitions targeting liquids rich production, including the following five exploration opportunities that we have publicly disclosed.

- Michigan Basin — Our 340,000 acres are located in central Michigan and target oil and gas in the A1 Carbonate and Utica shale.
- Mississippian — Our 230,000 acres are located in northern Oklahoma and target oil in the Mississippian Lime and Woodford shale.
- Niobrara — Our 300,000 acres are located primarily in eastern Wyoming and target oil in the Niobrara, Turner, Cordell, Mowry, Frontier and Parkman plays. Currently, we are using 3D seismic to identify appropriate drilling zones.
- Ohio Utica — Our 235,000 acres are located in Ohio and targets oil in the Utica shale.
- Tuscaloosa — Our 265,000 acres are located in Louisiana and Mississippi and target oil and gas in the silica rich shale zone.

Additionally, in the first quarter of 2012, we expect to close our recently announced transaction in which our new partner will obtain a 33.3% interest in these new ventures properties for approximately $2.5 billion, including a $900 million payment at closing and $1.6 billion toward our share of future drilling costs. We will continue to de-risk the development of these properties with our partner by drilling approximately 125 wells in 2012.

Canada

Jackfish — Jackfish is our thermal heavy oil project in the non-conventional oil sands of east central Alberta. We are the first and only U.S.-based independent energy company to develop and operate an oil sands project in Canada. 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. The second phase of Jackfish began production in the second quarter of 2011 and will continue to increase production throughout 2012. Also, in 2011 we received regulatory approval for the construction of a third phase and will begin construction in 2012. We expect each phase to maintain a flat production profile for greater than 20 years at an average net production rate of approximately 25-30 MBbls per day.

To facilitate the delivery of our heavy oil production, we have a 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.

Northwest — This region includes acreage in west central Alberta and northeast British Columbia. These properties produce liquids-rich natural gas and light gravity oil from conventional reservoirs. In 2012, we plan to drill approximately 25 wells.

The region includes both winter-only and all season access areas. Multi-zone drilling opportunities are common. Since initial exploration in the 1970s, the region has seen significant infrastructure expansion. We own and operate gas gathering and processing facilities in the area, enabling projects to be brought on-stream quickly.

Deep Basin — Our properties in Canada's Deep Basin include portions of west central Alberta and east central British Columbia. The area produces natural gas and liquids from conventional reservoirs. In 2012, we plan to drill approximately 15 wells.

We are one of the major producers in the Deep Basin. We have used our large proprietary two-dimensional and three-dimensional seismic databases to build an extensive inventory of deep to mid-range drilling targets in this area. Most recently, we have been testing light oil targets in the Cardium formation and liquids-rich opportunities in the lower Cretaceous zones, including the Cadomin. The region has winter-only access restrictions in many areas, but offers year-round access in others. We control significant gas processing and transportation infrastructure throughout the region and hold interests in the only major gas facilities in the Wapiti area.

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 the need for steam injection. In 2012, we plan to drill approximately 150 wells.

The region is well-developed with significant infrastructure and is primarily accessible year-round for drilling. Lloydminster is a low-risk, high margin oil development play. We have drilled over 2,300 wells in the area since 2003.

Pike — Our Pike oil sands acreage is situated directly to the south of our Jackfish acreage in east central Alberta and has similar reservoir characteristics to Jackfish. The Pike leasehold is currently undeveloped and has no proved reserves or production as of December 31, 2011. We continued appraisal drilling in 2011 and will carry forward these activities into 2012. The results will help us determine the optimal configuration for the initial phase of development.

Proved Reserves

For estimates of our proved, proved developed and proved undeveloped reserves and the discussion of the contribution by each key property, see Note 22 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report.

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 2011 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 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" of this report. As a result, we have developed internal policies for estimating and recording reserves. Such policies 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, including 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 U.S. (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 eleven years, including the past four in his current position. During his career with Devon and others, he was responsible for reserves estimation as 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), and
- ACG Unit (Caspian Sea).

From 2003 to 2010, he served as the reservoir engineering representative on our internal peer review team. In this role, he reviewed reserves and resource estimates for projects including, but not limited to the Mobile Bay Norphlet Discoveries (Gulf of Mexico Shelf), Cascade Lower Tertiary Development (Gulf of Mexico Deepwater) and Polvo Development (Campos Basin, Brazil).

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 2011, we engaged two such firms to audit 95% of our proved reserves. LaRoche Petroleum Consultants, Ltd. audited the 2011 reserve estimates for 97% of our U.S. onshore properties. AJM Deloitte audited 89% of our Canadian reserves.

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

Production, Production Prices and Production Costs

The following table presents production, price and cost information for each significant field, country and continent.

	Production				Average Sales Price			Production
Year Ended December 31,	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)(1)	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Cost (Per Boe)
2011								
Barnett Shale	1	367	16	78	$94.23	$3.30	$39.00	$ 3.97
Jackfish	13	—	—	13	$58.16	$ —	$ —	$17.28
U.S.	17	740	33	173	$91.19	$3.50	$39.47	$ 5.35
Canada	28	213	4	67	$66.97	$3.87	$55.99	$13.82
North America	45	953	37	240	$76.06	$3.58	$41.10	$ 7.71
2010								
Barnett Shale	1	335	13	70	$77.40	$3.55	$29.97	$ 3.87
Jackfish	9	—	—	9	$52.51	$ —	$ —	$16.81
U.S.	16	716	28	163	$75.81	$3.76	$30.86	$ 5.47
Canada	25	214	4	65	$58.60	$4.11	$46.60	$12.37
North America	41	930	32	228	$65.14	$3.84	$32.61	$ 7.42
2009								
Barnett Shale	—	331	13	69	$58.78	$2.99	$22.36	$ 3.96
Jackfish	8	—	—	8	$41.07	$ —	$ —	$12.75
U.S.	17	743	26	167	$57.56	$3.20	$23.51	$ 5.97
Canada	25	223	4	66	$47.35	$3.66	$33.09	$10.15
North America	42	966	30	233	$51.39	$3.31	$24.71	$ 7.16

(1) Gas production is converted to Boe at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of gas and oil. NGL production is converted to Boe on a one-to-one basis with oil.

Drilling Statistics

The following table summarizes our development and exploratory drilling results.

	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)		
Year Ended December 31,	Productive	Dry	Productive	Dry	Productive	Dry	Total
2011							
U.S.	721.2	5.5	18.8	4.0	740.0	9.5	749.5
Canada	247.6	1.5	19.1	1.0	266.7	2.5	269.2
Total North America	968.8	7.0	37.9	5.0	1,006.7	12.0	1,018.7
2010							
U.S.	855.7	5.3	23.4	1.5	879.1	6.8	885.9
Canada	267.8	—	41.9	1.0	309.7	1.0	310.7
Total North America	1,123.5	5.3	65.3	2.5	1,188.8	7.8	1,196.6
2009							
U.S.	508.0	3.8	6.8	2.0	514.8	5.8	520.6
Canada	307.2	—	28.2	—	335.4	—	335.4
Total North America	815.2	3.8	35.0	2.0	850.2	5.8	856.0

(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 February 1, 2012, results of our wells that were in progress on December 31, 2011.

	Productive		Dry		Still in Progress		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	221	150.7	—	—	43	22.5	264	173.2
Canada	6	5.5	—	—	1	1.0	7	6.5
Total North America	227	156.2	—	—	44	23.5	271	179.7

(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.

Productive Wells

The following table sets forth our producing wells as of December 31, 2011.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	8,319	3,003	20,762	13,613	29,081	16,616
Canada	5,150	3,958	5,584	3,322	10,734	7,280
Total North America	13,469	6,961	26,346	16,935	39,815	23,896

(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.

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 approximately 24,000 of our wells. As operator, we receive reimbursement for direct expenses incurred to perform 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.

Acreage Statistics

The following table sets forth our developed and undeveloped lease and mineral acreage as of December 31, 2011. The acreage in the table includes 0.6 million, 1.2 million and 0.5 million net acres subject to leases that are scheduled to expire during 2012, 2013 and 2014, respectively.

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
			(In thousands)			
U.S.	3,366	2,263	7,105	4,281	10,471	6,544
Canada	3,699	2,286	6,450	4,541	10,149	6,827
Total North America	7,065	4,549	13,555	8,822	20,620	13,371

(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.

Title to Properties

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for taxes not yet due and, in some instances, other encumbrances. We believe that such burdens do not materially detract from the value of 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.

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 timely and efficiently.

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.

Oil, Gas and NGL Marketing

The spot markets for oil, gas and NGLs are subject to volatility as supply and demand factors fluctuate. As detailed below, we sell our production under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties. 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 Note 2 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report for further information.

As of January 2012, our production was sold under the following contracts.

	Short-Tem		Long-Tem	
	Variable	Fixed	Variable	Fixed
Oil	77%	—	23%	—
Natural gas	84%	—	16%	—
NGLs	69%	10%	21%	—

Delivery Commitments

A portion of our production is sold under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. As of January 2012, we were committed to deliver the following fixed quantities of production.

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Oil (MMBbls)	126	14	27	27	58
Natural gas (Bcf)	1,077	341	284	109	343
NGLs (MMBbls)	3	2	1	—	—
Total (MMBoe)(1)	308	73	75	45	115

(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.

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 commitments. However, should our proved reserves not be sufficient to satisfy our delivery commitments, we can and may use spot market purchases to fulfill the commitments.

Customers

During 2011, 2010 and 2009, no purchaser accounted for over 10% of our revenues.

Competition

See "Item 1A. Risk Factors."

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, 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. The following are significant areas of government control and regulation affecting our operations.

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, 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 U.S., 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.

Environmental and Occupational Regulations

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

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.

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.

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. Our policies and internal controls related to estimating and recording reserves are included in "Items 1 and 2. Business and Properties" of this report.

Discoveries or Acquisitions of 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.

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 cost to acquire properties. 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 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 Limits Participation in Commodity Price Increases and Increases Counterparty Credit Risk Exposure

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 contract counterparties 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 U.S. 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.

Hydraulic Fracturing — The U.S. Department of the Interior is considering the possibility of additional regulation of hydraulic fracturing on federal lands. Currently, regulation of hydraulic fracturing is conducted primarily at the state level through permitting and other compliance requirements. We lease federal lands and would be affected by the Interior Department proposal if it were to become law.

Income Taxes — We are subject to federal, state, provincial and local income taxes and our operating cash flow is sensitive to the amount of income taxes we must pay. In the jurisdictions in which we operate, income taxes are assessed on our earnings after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types costs that are considered allowable deductions or the rates assessed on our taxable earnings would all impact our income taxes and resulting operating cash flow. The U.S. President's budget proposals include provisions that would, if enacted, make significant changes to U.S. tax laws. The most significant change to our business would eliminate the immediate deduction for intangible drilling and development costs.

Climate Change — Policy makers in the U.S. 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 U.S. 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

Our business is hazardous and is subject to all of the operating risks normally associated with the exploration, development, production, processing and transportation of oil, natural gas and NGLs. Such risks include potential blowouts, cratering, fires, loss of well control, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals. The occurrence of any of these risks could result in environmental pollution, damage to or destruction of our property, equipment and natural resources, injury to person or loss of life. Additionally, for our non-operated properties, we generally depend on the operator for operational safety and regulatory compliance.

To mitigate financial losses resulting from these operational hazards, we maintain comprehensive general liability insurance, as well as insurance coverage against certain losses resulting from physical damages, loss of well control, business interruption and pollution events that are considered sudden and accidental. We also maintain worker's compensation and employer's liability insurance. However, our insurance coverage does not provide 100% reimbursement of potential losses resulting from these operational hazards. Additionally, insurance coverage is generally not available to us for pollution events that are considered gradual, and we have limited or no insurance coverage for certain risks such as political risk, war and terrorism. Our insurance does not cover penalties or fines assessed by governmental authorities. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our profitability, financial condition and liquidity.

Limited Control on Properties Operated by Others

Certain of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. We have limited influence and control over the operation or future development of such properties, including compliance with environmental, health and safety regulations or the amount of required future capital expenditures. These limitations and our dependence on the operator and other working interest owners for these properties could result in unexpected future costs and adversely affect our financial condition and results of operations.

Item 1B. *Unresolved Staff Comments*

None.

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. *Mine Safety Disclosures*

None.

PART II

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

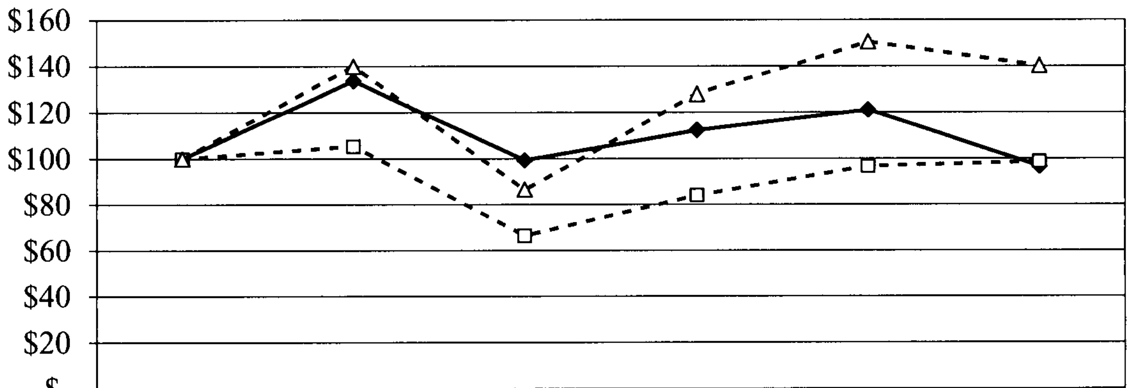
Our common stock is traded on the New York Stock Exchange (the "NYSE"). On February 9, 2012, there were 12,183 holders of record of our common stock. The following table sets forth the quarterly high and low sales prices for our common stock as reported by the NYSE during 2011 and 2010, as well as the quarterly dividends per share paid during 2011 and 2010. 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 Per Share
	High	**Low**	
2011:			
Quarter Ended December 31, 2011	$69.55	$50.74	$0.17
Quarter Ended September 30, 2011	$84.52	$55.14	$0.17
Quarter Ended June 30, 2011	$92.69	$75.50	$0.17
Quarter Ended March 31, 2011	$93.55	$76.96	$0.16
2010:			
Quarter Ended December 31, 2010	$78.86	$63.76	$0.16
Quarter Ended September 30, 2010	$66.21	$59.07	$0.16
Quarter Ended June 30, 2010	$70.80	$58.58	$0.16
Quarter Ended March 31, 2010	$76.79	$62.38	$0.16

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 assuming $100 was invested on December 31, 2006 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



	2006	2007	2008	2009	2010	2011
Devon	$100.00	$133.51	$99.35	$112.35	$121.13	$96.56
S&P 500	$100.00	$105.49	$66.46	$84.05	$96.71	$98.75
SIC Code	$100.00	$139.98	$86.55	$127.91	$150.32	$140.25

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.

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 2011.

Period	Total Number of Shares Purchased(2)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(1)
				(In millions)
October 1 – October 31	3,228,557	$58.52	3,227,800	$108
November 1 – November 30	1,813,994	$66.38	1,618,110	$ —
December 1 – December 31	475,685	$64.68	—	$ —
Total	5,518,236	$61.64	4,845,910	

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. We completed this program in the fourth quarter of 2011. In total, we repurchased 49.2 million common shares for $3.5 billion, or $71.18 per share, under this program.

(2) During the fourth quarter of 2011, we repurchased 672,326 shares from company employees for the payment of personal income tax withholdings resulting from restricted stock vesting and stock option exercises. Such repurchases are in addition to the $3.5 billion repurchase program.

Under the Devon Energy Corporation Incentive Savings Plan (the "Plan"), eligible employees may purchase shares of our common stock through an investment in the Devon Stock Fund (the "Stock Fund"), which is administered by an independent trustee, Fidelity Management Trust Company. Eligible employees purchased approximately 45,000 shares of our common stock in 2011, at then-prevailing stock prices, that they held through their ownership in the Stock Fund. We acquired the shares of our common stock sold under the Plan through open-market purchases. We filed a registration statement on Form S-8 on January 26, 2012 registering any offers and sales of interests in the Plan or the Stock Fund and of the underlying shares of our common stock purchased by Plan participants after that date.

Similarly, under the Devon Canada Corporation Savings Plan (the "Canadian Plan"), eligible Canadian employees may purchase shares of our common stock through an investment in the Canadian Plan, which is administered by an independent trustee, Sun Life Assurance Company of Canada. Eligible Canadian employees purchased approximately 9,000 shares of our common stock in 2011, at then-prevailing stock prices, that they held through their ownership in the Canadian Plan. We acquired the shares sold under the Canadian Plan through open-market purchases. These shares and any interest in the Canadian Plan were offered and sold in reliance on the exemptions for offers and sales of securities made outside of the U.S., including under Regulation S for offers and sales of securities to employees pursuant to an employee benefit plan established and administered in accordance with the law of a country other than the U.S.

Item 6. *Selected Financial Data*

The financial information below should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" of this report.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In millions, except per share amounts)				
Revenues	$11,454	$ 9,940	$ 8,015	$13,858	$ 9,975
Earnings (loss) from continuing operations(1)	$ 2,134	$ 2,333	$ (2,753)	$ (3,039)	$ 2,485
Earnings (loss) per share from continuing operations — Basic	$ 5.12	$ 5.31	$ (6.20)	$ (6.86)	$ 5.56
Earnings (loss) per share from continuing operations — Diluted	$ 5.10	$ 5.29	$ (6.20)	$ (6.86)	$ 5.50
Cash dividends per common share	$ 0.67	$ 0.64	$ 0.64	$ 0.64	$ 0.56
Weighted average common shares outstanding — Basic	417	440	444	444	445
Weighted average common shares outstanding — Diluted	418	441	444	444	450
Total assets(1)	$41,117	$32,927	$29,686	$31,908	$41,456
Long-term debt	$ 5,969	$ 3,819	$ 5,847	$ 5,661	$ 6,924
Stockholders' equity	$21,430	$19,253	$15,570	$17,060	$22,006

(1) During 2009 and 2008, we recorded noncash reductions of the 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.

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 read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report.

Overview of Business

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 executing our strategy, which is outlined in "Items 1 and 2. Business and Properties" of this report

Overview of 2011 Results

2011 was an outstanding year for Devon. We generated record net earnings, increased proved reserves to an all-time high and completed our highly successful strategic repositioning, transforming us into a pure North American onshore company. We have now essentially completed our offshore divestiture program. In aggregate, the divestiture program generated after-tax proceeds of approximately $8 billion, assuming the repatriation of a substantial portion of the foreign proceeds under current U.S. tax law. We also completed our $3.5 billion share repurchase program in the fourth quarter of 2011.

As we have increased our focus on the vast opportunities in our North American onshore portfolio of properties, we are seeing improvements in key measures of our performance, including growth in liquids production and cash flow, both on a per share debt-adjusted basis, which is key to maximizing shareholder value. Key measures of our 2011 production performance, as well as certain other financial measures and operational developments, are summarized below:

- North America Onshore liquids production grew 15% over 2010, to 223 MBoe per day.
- North America Onshore gas production increased 4% compared with 2010, to 2,610 MMcf per day.
- The combined realized price for oil, gas and NGLs per Boe increased 9% to $34.64.
- Oil, gas and NGL derivatives generated net gains of $881 million in 2011, including cash receipts of $392 million.
- Per unit lease operating costs increased 4% to $7.71 per Boe.
- Operating cash flow increased to $6.2 billion, representing a 14% increase over 2010.
- Capitalized costs incurred in our oil and gas activities totaled $6.9 billion in 2011. This includes approximately $1.5 billion for acreage acquisitions and exploration activity.
- Reserves reached an all-time high of 3,005 MMBoe.

Fourth Quarter Operational Developments

- We increased our fourth-quarter liquids production by 21 percent compared to the year-ago period, to 238,000 barrels per day.
- This liquids growth drove our production ten percent higher than the year-ago quarter to a record 680,000 equivalent barrels per day.
- In the fourth-quarter, our exploration and production capital totaled $1.9 billion. This amount includes approximately $400 million of opportunistic leasehold acquisition, consisting of acreage additions in the Ohio Utica and leasehold capture in an undisclosed, new oil opportunity.
- In the Permian Basin, we increased oil and natural gas liquids production 22 percent compared to the fourth-quarter 2010. Liquids production accounted for nearly 75 percent of the 53,000 equivalent barrels per day produced in the Permian Basin during the quarter.
- We completed eight operated Bone Spring wells within the Permian Basin in the fourth quarter. Initial daily production from these wells averaged more than 600 Boe per day per well.
- In total, net production from our Jackfish 1 and Jackfish 2 projects averaged a record 43,000 barrels per day in the fourth quarter, representing a 91 percent increase over the year-ago quarter. Our Jackfish 2 production exited the fourth quarter at 14,000 barrels per day and will continue to ramp-up throughout 2012.
- In early December, we received regulatory approval for our third 35,000 barrel per day Jackfish project. We have begun construction with plant startup targeted for late 2014.
- Immediately adjacent to Jackfish, we are currently drilling appraisal wells and acquiring seismic on our Pike oil sands lease to determine the optimal development plan. In total, we expect Pike will support up to five 35,000 barrel per day projects.
- Fourth-quarter production from our Cana-Woodford Shale play in western Oklahoma increased 83 percent over the fourth quarter of 2010. Net production averaged a record 250 million cubic feet of gas equivalent per day, including 3,100 barrels of oil and 7,400 barrels per day of natural gas liquids.
- Our Barnett Shale production averaged a record 1.32 billion cubic feet of gas equivalent per day in the fourth quarter of 2011, an 11 percent increase over the fourth quarter of 2010. Liquids production accounted for 21 percent of total production, averaging 47,000 barrels per day during the quarter.

- We brought six operated Granite Wash wells online in the fourth quarter. Initial production from these wells averaged 1,300 barrels of oil-equivalent per day. Fourth-quarter production from our Granite Wash play reached 19,100 barrels per day, a 47 percent increase over 2010.

Business and Industry Outlook

We possess a great deal of financial strength and flexibility and 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. We expect gas prices will remain challenged in the market throughout 2012. Therefore, our near-term focus is on the oil and liquids-rich opportunities that exist within our balanced portfolio of properties. The vast majority of our 2012 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.

Additionally, our financial and operational flexibility will be further enhanced by the transaction that we announced in early 2012 with Sinopec International Petroleum Exploration & Production Corporation, which we expect to close in the first quarter of 2012. Pursuant to the terms of the agreement, Sinopec will pay $2.5 billion, including a $900 million payment at closing and $1.6 billion toward our share of future drilling costs, and will receive a 33.3% interest in five of our new venture plays.

Our ability to leverage the depth and breadth of our existing portfolio of properties will be important to successfully achieve our growth and value-creation objectives. With 3,005 MMBoe of proved reserves at the end of 2011, our assets will provide many years of visible, economic growth and a good balance between liquids and natural gas. In 2012, we are targeting a 6 percent production increase, which will be fueled by liquids growth approaching 20%.

Results of Operations

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 divested our U.S. Offshore operations in 2010, 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.

Production, Prices and Revenues

	Year Ended December 31,				
	2011	2011 vs. 2010(1)	2010	2010 vs. 2009(1)	2009
Oil (MBbls/d)					
U.S. Onshore	46	+24%	37	+17%	32
Canada	77	+11%	69	−1%	69
North America Onshore	123	+16%	106	+5%	101
U.S. Offshore	—	−100%	5	−62%	14
Total	123	+10%	111	−3%	115
Gas (MMcf/d)					
U.S. Onshore	2,027	+6%	1,914	0%	1,914
Canada	583	−1%	587	−4%	611
North America Onshore	2,610	+4%	2,501	−1%	2,525
U.S. Offshore	—	−100%	46	−63%	123
Total	2,610	+2%	2,547	−4%	2,648
NGLs (MBbls/d)					
U.S. Onshore	90	+17%	77	+10%	70
Canada	10	+2%	10	−6%	11
North America Onshore	100	+15%	87	+8%	81
U.S. Offshore	—	−100%	1	−55%	2
Total	100	+14%	88	+6%	83
Combined (MBoe/d)(2)					
U.S. Onshore	474	+9%	433	+3%	421
Canada	184	+4%	177	−3%	182
North America Onshore	658	+8%	610	+1%	603
U.S. Offshore	—	−100%	14	−62%	36
Total	658	+5%	624	−2%	639

(1) Percentage changes are based on actual figures rather than the rounded figures presented.

(2) Gas production is 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. NGL production is converted to Boe on a one-to-one basis with oil.

	Year Ended December 31,				
	2011(1)	2011 vs. 2010	2010(1)	2010 vs. 2009	2009(1)
Oil (per Bbl)					
U.S. Onshore	$91.19	+21%	$75.53	+34%	$56.17
Canada	$66.97	+14%	$58.60	+24%	$47.35
North America Onshore	$76.06	+18%	$64.51	+29%	$50.11
U.S. Offshore	$ —	−100%	$77.81	+28%	$60.75
Total	$76.06	+17%	$65.14	+27%	$51.39
Gas (per Mcf)					
U.S. Onshore	$ 3.50	−6%	$ 3.73	+19%	$ 3.14
Canada	$ 3.87	−6%	$ 4.11	+12%	$ 3.66
North America Onshore	$ 3.58	−6%	$ 3.82	+17%	$ 3.27
U.S. Offshore	$ —	−100%	$ 5.12	+22%	$ 4.20
Total	$ 3.58	−7%	$ 3.84	+16%	$ 3.31
NGLs (per Bbl)					
U.S. Onshore	$39.47	+28%	$30.78	+32%	$23.40
Canada	$55.99	+20%	$46.60	+41%	$33.09
North America Onshore	$41.10	+26%	$32.55	+32%	$24.65
U.S. Offshore	$ —	−100%	$38.22	+39%	$27.42
Total	$41.10	+26%	$32.61	+32%	$24.71
Combined (per Boe)					
U.S. Onshore	$31.31	+10%	$28.42	+27%	$22.41
Canada	$43.23	+11%	$39.11	+21%	$32.29
North America Onshore	$34.64	+10%	$31.52	+24%	$25.38
U.S. Offshore	$ —	−100%	$49.06	+26%	$38.83
Total	$34.64	+9%	$31.91	+22%	$26.15

(1) Prices presented exclude any effects due to oil, gas and NGL derivatives.

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

	Oil	Gas	NGLs	Total
		(In millions)		
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
Changes due to volumes	268	88	147	503
Changes due to prices	488	(249)	311	550
2011 sales	$3,399	$3,411	$1,505	$8,315

Oil Sales

2011 vs. 2010 Oil sales increased $488 million in 2011 as a result of a 17 percent increase in our realized price without hedges. The largest contributor to the higher realized price was an increase in the average NYMEX West Texas Intermediate price.

Oil sales increased $268 million due to a 10 percent increase in production. The increase in production was driven by the continued development of our Permian Basin properties and our Jackfish thermal heavy oil projects in Canada. This increase was partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010.

2010 vs. 2009 Oil sales increased $557 million as a result of a 27 percent increase in our realized price without hedges. The largest contributor to the higher realized price was an increase in the average NYMEX West Texas Intermediate index price.

Oil sales decreased $67 million due to a 3 percent production decline. The decrease was comprised of the net effects of a 62 percent decrease in our U.S. Offshore production and a 5 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 and our Jackfish thermal heavy oil projects in Canada.

Gas Sales

2011 vs. 2010 Gas sales decreased $249 million in 2011 as a result of a 7 percent decrease in our realized price without hedges. The change in price was largely due to fluctuations of the North American regional index prices upon which our gas sales are based.

Gas sales increased $88 million due to a 2 percent increase in production. The increased production resulted primarily from continued development activities in the Barnett and Cana-Woodford Shales, partially offset by natural declines in our other operating areas. This increase was partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010.

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

Gas sales decreased $122 million due to a 4 percent decrease in production. The decrease was primarily due to the divestiture of our U.S. Offshore properties in the second quarter of 2010. Also, our North American Onshore properties decreased 1 percent due to reduced drilling during most of 2009 in response to lower gas prices.

NGL Sales

2011 vs. 2010 NGL sales increased $311 million in 2011 due to a 26 percent increase in our realized price without hedges. The higher price was largely due to an increase in the Mont Belvieu, Texas hub price.

NGL sales increased $147 million in 2011 due to a 14 percent increase in production. The increased production was primarily due to increased drilling in our Barnett Shale, Cana-Woodford Shale and Granite Wash locations.

2010 vs. 2009 NGL sales increased $254 million in 2010 as a result of a 32 percent increase in our realized price. The higher price was largely due to an increase in the Mont Belvieu, Texas hub price.

NGL sales increased $46 million in 2010 due to a 6 percent increase in production. The increase in production was primarily due to increased drilling in our North American Onshore areas that have liquids-rich gas.

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, 2011	2010	2009
	(In millions)		
Cash settlements:			
Gas derivatives	$416	$888	$ 505
Oil derivatives	(26)	—	—
NGL derivatives	2	—	—
Total cash settlements	392	888	505
Unrealized gains (losses) on fair value changes:			
Gas derivatives	305	12	(83)
Oil derivatives	185	(91)	(38)
NGL derivatives	(1)	2	—
Total unrealized gains (losses)	489	(77)	(121)
Oil, gas and NGL derivatives	$881	$811	$ 384

	Year ended December 31, 2011			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$76.06	$3.58	$41.10	$34.64
Cash settlements of hedges	(0.58)	0.44	0.07	1.63
Realized price, including cash settlements	$75.48	$4.02	$41.17	$36.27

	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

A summary of our outstanding commodity derivatives is included in Note 2 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report. 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 to the collars. For the basis swaps, we receive a fixed differential between two regional gas index prices and pay a variable differential on the same two index prices to the contract counterparty. Cash settlements as presented in the tables above represent realized gains or losses related to these various instruments.

Also, to facilitate a portion of our price swaps, we sold gas call options for 2012 and oil call options for 2011 and 2012. The call options give counterparties the right to purchase production at a predetermined price.

In addition to cash settlements, we also recognize unrealized changes in the fair values of our oil, gas and NGL derivative instruments in each reporting period. The changes in fair value resulted from new positions and settlements that occurred during each period, as well as the relationships between contract prices and the associated forward curves. Including the cash settlements discussed above, our oil, gas and NGL derivatives generated net gains of $881 million, $811 million and $384 million during 2011, 2010 and 2009, respectively.

Marketing and Midstream Revenues and Operating Costs and Expenses

	Year Ended December 31,				
	2011	2011 vs. 2010(1)	2010	2010 vs. 2009(1)	2009
			($ in millions)		
Marketing and midstream:					
Revenues	$2,258	+21%	$1,867	+22%	$1,534
Operating costs and expenses	1,716	+26%	1,357	+33%	1,022
Operating profit	$ 542	+6%	$ 510	0%	$ 512

(1) Percentage changes are based on actual figures rather than the rounded figures presented.

2011 vs. 2010 Marketing and midstream operating profit increased $32 million primarily due to higher gas throughput and higher NGL prices.

2010 vs. 2009 Marketing and midstream operating profit decreased $2 million primarily due to higher natural gas and NGL prices, partially offset by the effects of lower gas marketing profits.

Lease Operating Expenses ("LOE")

	Year Ended December 31,				
	2011	2011 vs. 2010(1)	2010	2010 vs. 2009(1)	2009
LOE ($ in millions):					
U.S. Onshore	$ 925	+11%	$ 832	−1%	$ 838
Canada	926	+16%	797	+18%	673
North America Onshore	1,851	+14%	1,629	+8%	1,511
U.S. Offshore	—	−100%	60	−62%	159
Total	$1,851	+10%	$1,689	+1%	$1,670
LOE per Boe:					
U.S. Onshore	$ 5.35	+2%	$ 5.26	−4%	$ 5.46
Canada	$13.82	+12%	$12.37	+22%	$10.15
North America Onshore	$ 7.71	+5%	$ 7.32	+7%	$ 6.87
U.S. Offshore	$ —	−100%	$12.00	0%	$11.98
Total	$ 7.71	+4%	$ 7.42	+4%	$ 7.16

(1) Percentage changes are based on actual figures rather than the rounded figures presented.

2011 vs. 2010 LOE increased $0.29 per Boe in 2011. LOE increased $0.39 per Boe, excluding the U.S. Offshore operations that were sold in the second quarter of 2010. The largest contributor to the higher North America Onshore unit cost is our oil production growth, particularly at our Jackfish thermal heavy oil projects in

Canada. Such oil projects generally require a higher cost to produce per unit than our gas projects. We also experienced upward pressures on costs in certain operating areas, which increased LOE per Boe. Additionally, LOE per Boe increased $0.15 due to a $36 million increase from changes in the exchange rate between the U.S. and Canadian dollars.

2010 vs. 2009 LOE increased $0.26 per Boe in 2010. LOE increased $0.45 per Boe, excluding costs associated with our U.S. Offshore operations. LOE per Boe increased $0.34 due to a $78 million increase from changes in the exchange rate between the U.S. and Canadian dollars. The remainder of the increase in North America Onshore LOE per Boe was primarily due to increased costs related to our Jackfish operation in Canada.

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

	Year Ended December 31,				
	2011	**2011 vs. 2010(1)**	**2010**	**2010 vs. 2009(1)**	**2009**
DD&A ($ in millions):					
Oil & gas properties	$1,987	+19%	$1,675	−9%	$1,832
Other properties	261	+2%	255	−8%	276
Total	$2,248	+17%	$1,930	−8%	$2,108
DD&A per Boe:					
Oil & gas properties	$ 8.28	+13%	$ 7.36	−6%	$ 7.86
Other properties	$ 1.09	−3%	$ 1.12	−5%	$ 1.18
Total	$ 9.37	+10%	$ 8.48	−6%	$ 9.04

(1) Percentage changes are based on actual figures rather than the rounded figures presented.

A description of how DD&A of our oil and gas properties is calculated is included in Note 1 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report. 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.

2011 vs. 2010 Oil and gas property DD&A increased $221 million during 2011 due to a 13 percent increase in the DD&A rate and $91 million due to our 5 percent increase in production. The largest contributors to the higher rate were our 2011 drilling and development activities and changes in the exchange rate between the U.S. and Canadian dollars. These increases were partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010.

2010 vs. 2009 Oil and gas property DD&A decreased $114 million during 2010 due to a 6 percent decrease in the DD&A rate and $43 million due to our 2 percent decline in production. The largest contributors to the rate decrease were our 2010 U.S. Offshore property divestitures and a $6.4 billion reduction of the carrying value of our U.S. oil and gas properties recognized in the first quarter of 2009. These decreases were partially offset by the effects of costs incurred and transfers of previously unproved costs to the depletable base as a result of our 2010 drilling and development activities, as well as changes in the exchange rate between the U.S. and Canadian dollars.

General and Administrative Expenses ("G&A")

	Year Ended December 31,				
	2011	2011 vs. 2010(1)	2010	2010 vs. 2009(1)	2009
			($ in millions)		
Gross G&A	$1,036	+5%	$ 987	−11%	$1,107
Capitalized G&A	(337)	+8%	(311)	−6%	(332)
Reimbursed G&A	(114)	+1%	(113)	−11%	(127)
Net G&A	$ 585	+4%	$ 563	−13%	$ 648
Net G&A per Boe	$ 2.44	−1%	$2.47	−11%	$ 2.78

(1) Percentage changes are based on actual figures rather than the rounded figures presented.

2011 vs. 2010 Net G&A increased during 2011 primarily due to higher employee compensation and benefits, while net G&A per Boe slightly declined as we grew production at a higher rate than G&A.

2010 vs. 2009 Net G&A on an absolute and per Boe basis decreased largely due to a decline in employee severance costs. Such costs decreased primarily due to employees that were impacted by the integration of our offshore operations into one unit in 2009. In addition, net G&A decreased subsequent to our mid-year 2010 offshore divestitures as a result of the decline in our workforce.

Taxes Other Than Income Taxes

	Year Ended December 31,				
	2011	2011 vs. 2010(1)	2010	2010 vs. 2009(1)	2009
			($ in millions)		
Production	$ 248	+18%	$ 210	+59%	$ 132
Ad valorem and other	176	+4%	170	−7%	182
Total	$ 424	+12%	$ 380	+21%	$ 314
Taxes other than income taxes % of oil, gas and NGL revenue	5.10%	-3%	5.24%	+2%	5.16%

(1) Percentage changes are based on actual figures rather than the rounded figures presented.

Taxes other than income taxes increased in each period primarily due to an increase in our U.S. Onshore revenues, on which the majority of our production taxes are assessed.

Interest Expense

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Interest based on debt outstanding	$414	$408	$437
Capitalized interest	(72)	(76)	(94)
Early retirement of debt	—	19	—
Other	10	12	6
Total	$352	$363	$349

2011 vs. 2010 Interest expense decreased primarily due to costs associated with the early retirement of our $350 million notes in 2010. This was partially offset by higher interest resulting from increased debt balances in 2011.

2010 vs. 2009 Interest expense increased due to costs associated with the early retirement of debt discussed above and a decrease in our capitalized interest. The decrease in capitalized interest resulted primarily from the divestiture of our U.S. Offshore properties in 2010. These increases were partially offset by lower interest on our debt balances resulting from the retirement of $350 million of notes in 2010 and $177 million of notes in 2009.

Restructuring Costs

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Cash severance	$ 9	$(17)	$ 66
Share-based awards	(1)	(10)	39
Lease obligations	(13)	70	—
Asset impairments	2	11	—
Other	1	3	—
Total(1)	$ (2)	$ 57	$105

(1) Restructuring costs related to our discontinued operations totaled $(2) million, $(4) million, and $48 million in 2011, 2010, and 2009, respectively. These costs primarily consist of employee severance and are not included in the table.

In the fourth quarter of 2009, we announced plans to divest our offshore assets. As of December 31, 2011, we had divested all of our U.S. Offshore assets and substantially all of our International assets. Through the end of 2011, we had incurred $202 million of restructuring costs associated with these divestitures.

Employee Severance

This amount was originally based on estimates of the number of employees that would ultimately be impacted by the offshore divestitures and included amounts related to cash severance costs and accelerated vesting of share-based grants. As the divestiture program progressed, we decreased our overall estimate of employee severance costs. More offshore employees than previously estimated received comparable positions with either the purchaser of the properties or in our U.S. Onshore operations.

Lease Obligations

As a result of the divestitures, 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 represented the present value of our future obligations under the leases, net of anticipated sublease income. Our 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.

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

Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, we reduced the carrying value of our U.S. oil and gas properties $6.4 billion, or $4.1 billion after taxes, due to a full cost ceiling limitation. The lower ceiling value largely resulted from the effects of declining natural gas prices subsequent to December 31, 2008. To demonstrate the decline, the March 31, 2009 and December 31, 2008 weighted average wellhead prices are presented in the following table.

March 31, 2009			December 31, 2008		
Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)
$47.30	$2.67	$17.04	$42.21	$4.68	$16.16

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.

Other, net

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Accretion of asset retirement obligations	$ 92	$ 92	$ 91
Interest rate swaps — unrealized fair value changes	88	30	(66)
Interest rate swaps — cash settlements	(77)	(44)	(40)
Interest income	(21)	(13)	(8)
Other	(92)	(32)	(60)
Total	$(10)	$ 33	$(83)

2011 vs. 2010 Other, net decreased primarily due to $88 million of excess insurance recoveries received in 2011 related to certain weather and operational claims. The remainder of the variance primarily relates to the net effect of interest rate swap cash settlements and unrealized fair value changes due to changes in the related interest rates upon which the instruments are based.

2010 vs. 2009 Other, net increased primarily due to the reversal of a $84 million loss contingency accrual in 2009. We had previously accrued $84 million for potential royalties on various deep water leases but due to a federal district court ruling we reversed the accrual in 2009. The remainder of the variance primarily relates to the net effect of interest rate swap cash settlements and unrealized fair value changes due to changes in the related interest rates upon which the instruments are based.

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,		
	2011	2010	2009
Total income tax expense (benefit) (In millions)	$2,156	$1,235	$(1,773)
U.S. statutory income tax rate	35%	35%	(35%)
Assumed repatriations	17%	4%	1%
State income taxes	1%	1%	(2%)
Taxation on Canadian operations	(2%)	(1%)	(1%)
Other	(1%)	(4%)	(2%)
Effective income tax expense (benefit) rate	50%	35%	(39%)

During 2011, 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 $725 million, $144 million and $55 million during 2011, 2010 and 2009, respectively, related to assumed repatriations of earnings from our foreign subsidiaries.

Earnings From Discontinued Operations

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Operating earnings	$ 38	$ 567	$305
Gain on sale of oil and gas properties	2,552	1,818	17
Earnings before income taxes	2,590	2,385	322
Income tax expense	20	168	48
Earnings from discontinued operations	$2,570	$2,217	$274

The earnings in each period were primarily driven by gains on the sales of our oil and gas assets in each period. The following table presents gains on our divestiture transactions by year. Also, in 2009 we reduced the carrying value of our oil and gas properties in Brazil by $109 million due to full cost ceiling limitation resulting from drilling results at the BM-BAR-3 offshore block.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	After Taxes	Gross	After Taxes	Gross	After Taxes
			(In millions)			
Brazil	$2,548	$2,548	$ —	$ —	$—	$—
Azerbaijan	—	—	1,543	1,524	—	—
China — Panyu	—	—	308	235	—	—
Other	4	4	(33)	(27)	17	17
Total	$2,552	$2,552	$1,818	$1,732	$17	$17

Capital Resources, Uses and Liquidity

Sources and Uses of Cash

The following table presents the major source and use categories of our cash and cash equivalents.

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Operating cash flow — continuing operations	$ 6,246	$ 5,022	$ 4,232
Debt activity, net	4,187	(1,782)	1,435
Divestitures of property and equipment	3,380	7,002	34
Capital expenditures	(7,534)	(6,476)	(4,879)
Common stock repurchases and dividends	(2,610)	(1,449)	(284)
Short-term investment activity, net	(1,348)	(124)	7
Other	(56)	86	82
Net increase in cash and cash equivalents	**$ 2,265**	**$ 2,279**	**$ 627**
Cash and cash equivalents at end of year	$ 5,555	$ 3,290	$ 1,011
Short-term investments at end of year	$ 1,503	$ 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 2011. Our operating cash flow increased 24 percent in spite of the $454 million of discretionary contributions made to our pension plans in 2011. The increase was largely due to higher current income taxes in 2010 associated with taxable gains on our U.S. Offshore divestitures and higher commodity prices and production, partially offset by lower realized gains from our commodity derivatives.

During 2011, 2010 and 2009 our operating cash flow funded 83%, 78% and 87% of our cash payments for capital expenditures. As needed, we supplement our operating cash flow and available cash by reducing short-term investment balances or accessing available credit under our credit facilities 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.

Debt Activity, Net

During 2011, we increased our commercial paper borrowings by $3.7 billion and received $0.5 billion from new debt issuances, net of debt maturities. Proceeds were primarily used to fund capital expenditures and common stock repurchases in excess of operating cash flow.

During 2010, we repaid $1.4 billion of commercial paper borrowings and redeemed our $350 million notes, primarily with proceeds received from our U.S. Offshore divestitures.

During 2009, we increased our commercial paper borrowings by $400 million and our term debt $1.0 billion, net of maturities. These proceeds were primarily used to fund capital expenditures in excess of our operating cash flow.

Divestitures of Property and Equipment

The following table presents the components of our divestiture transactions.

	Year Ended December 31,		
	2011	**2010**	**2009**
		(In millions)	
Brazil	$3,251	$ —	$—
Gulf of Mexico	—	4,059	—
Azerbaijan	—	1,925	—
China — Panyu and Exploration	—	592	—
Other	129	426	34
Total	$3,380	$7,002	$34

Capital Expenditures

The amounts in the table below reflect cash payments for capital expenditures, including cash paid for capital expenditures incurred in prior periods.

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
U.S. Onshore	$5,128	$3,689	$2,413
Canada	1,571	1,826	1,064
North America Onshore	6,699	5,515	3,477
U.S. Offshore	—	376	845
Total oil and gas	6,699	5,891	4,322
Midstream	333	236	323
Other	502	349	234
Total continuing operations	$7,534	$6,476	$4,879

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 $6.7 billion, $5.9 billion and $4.3 billion in 2011, 2010 and 2009, respectively. The increases in exploration and development capital spending in 2011 and 2010 were primarily due to new venture acreage acquisitions, the 2010 $500 million Pike oil sands acquisition and increased drilling and development. With rising oil prices and proceeds from our offshore divestitures, we have increased our acreage positions and associated exploration and development activities to drive near-term growth of our onshore liquids production.

The increase in North American Onshore exploration and development capital spending in 2010 compared to 2009 was due to the $500 million Pike oil sands acquisition and increased drilling primarily to grow liquids production.

Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas pipeline systems and oil pipelines. Our midstream capital expenditures are largely impacted by oil and gas drilling activities. Therefore, the increase in development drilling also increased midstream capital activities.

Capital expenditures related to other activities increased in 2011. This increase is largely driven by the construction of our new headquarters in Oklahoma City.

Common Stock Repurchases and Dividends

The following table summarizes our repurchases, including unsettled shares, and our common stock dividends (amounts and shares in millions).

	2011			2010			2009		
	Amount	Shares	Per Share	Amount	Shares	Per Share	Amount	Shares	Per Share
Repurchases	$2,299	30.9	$74.49	$1,201	18.3	$65.58	$ N/A	N/A	$ N/A
Dividends	$ 278	N/A	$ 0.67	$ 281	N/A	$ 0.64	$ 284	N/A	$ 0.64

In connection with our offshore divestitures, we conducted a $3.5 billion share repurchase program that we completed in the fourth quarter of 2011. Under the program, we repurchased 49.2 million shares, representing 11% of our outstanding shares, at an average price of $71.18 per share.

Short-Term Investment Activity, Net

During 2011, we had net short-term investment purchases totaling $1.3 billion. These purchases represent our investment of a portion of the International offshore divestiture proceeds into commercial paper, U.S. and Canadian Treasury securities and other marketable securities.

Liquidity

Historically, our primary sources of capital and liquidity have been our operating cash flow and cash on hand. Additionally, we maintain revolving lines of credit and a commercial paper program, which can be accessed as needed to supplement operating cash flow and cash balances. Other available sources of capital and liquidity include debt and equity securities that can be issued pursuant to our shelf registration statement filed with the SEC. We estimate the combination of these sources of capital will be adequate to fund future capital expenditures, debt repayments and other contractual commitments as discussed in this section.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which are the prices of the oil, gas and NGLs we produce. Due to higher liquids production and prices, our operating cash flow from continuing operations increased 24 percent to $6.2 billion in 2011. We expect operating cash flow to continue to be our primary source of liquidity.

Commodity Prices — Prices 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 prices and are beyond our control. We expect this volatility to continue throughout 2012.

To mitigate some of the risk inherent in prices, we have utilized various derivative financial instruments to set minimum and maximum prices on our 2012 production. The key terms to our oil, gas and NGL derivative financial instruments as of December 31, 2011 are presented in Note 2 to the financial statements under "Item 8. Financial Statements and Supplementary Data" of this report.

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 impacted by interest rate fluctuations. As of December 31, 2011, we had total debt of $9.8 billion with an overall weighted average borrowing rate of 4.0 percent. We have derivative financial instruments in place that reduce our weighted-average interest rate to 3.7 percent.

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. Additionally, we are exposed to the credit risk of counterparties to our derivative financial contracts. 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, requiring letters of credit, prepayment requirements or collateral posting requirements.

As 2011, 2010 and 2009 demonstrate, we have a history of investing more than 100% of our operating cash flow into capital development activities to grow our company and maximize value for our shareholders. Therefore, negative movements in any of the variables discussed above would not only impact our operating cash flow, but also would likely impact the amount of capital investment we could or would make.

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. $0.5 billion.

Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of February 9, 2012, we had $1.8 billion of available capacity under our syndicated, unsecured Senior Credit Facility.

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 percent. 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, 2011, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2011, as calculated pursuant to the terms of the agreement, was 22.8 percent.

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.

We also have access to short-term credit under our commercial paper program. In 2011, we increased our commercial paper program from $2.2 billion to $5.0 billion. 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 generally based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found in the commercial paper market. As of February 9, 2012, we had $3.1 billion of borrowings under our commercial paper program.

Although we ended 2011 with approximately $7.1 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from our International offshore divestitures that are held by certain of our foreign subsidiaries. We do not currently expect to repatriate such amounts to the U.S. If we were to repatriate a portion or all of the cash and short-term investments held by these foreign subsidiaries, we would be required to accrue and pay current income taxes in accordance with current U.S. tax law. With these proceeds remaining outside of the U.S., we expect to continue using commercial paper or credit facility borrowings in the U.S. to supplement our U.S. based operating cash flow. We do not expect near-term increases in such borrowings will have a material effect on our overall liquidity or financial condition.

Debt Ratings

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

There are no "rating triggers" in any of our contractual obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. Our cost of borrowing under our Senior Credit Facility is predicated on our corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on any borrowings under our Senior Credit Facility. Under the terms of the Senior Credit Facility, a one-notch downgrade would increase the fully-drawn borrowing costs from LIBOR plus 35 basis points to a new rate of LIBOR plus 45 basis points. A ratings downgrade could also adversely impact our ability to economically access debt markets in the future. As of December 31, 2011, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures

Our 2012 capital expenditures are expected to range from $6.2 billion to $6.8 billion, including $5.5 billion to $5.9 billion for our oil and gas operations. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if commodity prices fluctuate from our current estimates, we could choose to defer a portion of these planned 2012 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2012 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2012, our existing commodity hedging contracts, available cash balances and credit availability, we anticipate having adequate capital resources to fund our 2012 capital expenditures.

Additionally, our financial and operational flexibility will be further enhanced by the transaction that we announced in early 2012 with Sinopec International Petroleum Exploration & Production Corporation, which we expect to close in the first quarter of 2012. Pursuant to the agreement, Sinopec will pay $2.5 billion, including a $900 million payment at closing and $1.6 billion toward our share of future drilling costs, and will receive a 33.3% interest in five of our new venture plays discussed in "Items 1 and 2. Business and Properties" of this report.

The $900 million cash payment at closing will recoup more than 100% of our costs incurred up to the closing date. Additionally, the proceeds from this transaction will significantly reduce our future capital commitments. The drilling carry will fund 70 percent of our capital requirements related to these properties, which results in Sinopec paying 80 percent of the overall development costs during the carry period. This will allow us to accelerate the de-risking and commercialization of the five plays without diverting capital from our core development projects. We expect the entire $1.6 billion carry will be realized by the end of 2014.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2011, 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)		
Debt(1)	$ 9,786	$3,811	$ 500	$ 500	$ 4,975
Interest expense(2)	6,611	374	734	692	4,811
Purchase obligations(3)	8,454	900	1,810	1,829	3,915
Drilling and facility obligations(4)	1,475	919	556	—	—
Operational agreements(5)	2,136	306	585	459	786
Asset retirement obligations(6)	1,563	67	106	113	1,277
Lease obligations(7)	473	63	103	87	220
Other(8)	222	35	136	18	33
Total North America	$30,720	$6,475	$4,530	$3,698	$16,017

(1) Debt amounts represent scheduled maturities of our debt obligations at December 31, 2011, excluding $6 million of net discounts included in the carrying value of debt.

(2) Interest expense represents the scheduled cash payments on our long-term fixed-rate debt.

(3) 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. The value of the obligation in the table above is based on the contractual volumes and our internal estimate of future condensate market prices.

(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.

(5) Operational agreements represent commitments to transport or process certain volumes of oil, gas and NGLs for a fixed fee. We have entered into these agreements to aid the movement of our production to market.

(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, 2011 balance sheet.

(7) Lease obligations consist primarily of non-cancelable leases for office space and equipment used in our daily operations.

(8) These amounts include $165 million related to uncertain tax positions. Future contributions to our qualified pension plans have not been included in the table above. During 2011, we made $454 million of contributions to our pension plans. Consequently, we expect required pension plan contributions will be insignificant for the foreseeable future.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 18 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report.

Critical Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates, judgments 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. We consider the following to be our most critical accounting estimates that involve judgment and have reviewed these critical accounting estimates with the Audit Committee of our Board of Directors.

Full Cost Method of Accounting and Proved Reserves

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. Our engineers prepare our reserve estimates. We then subject certain of our reserve estimates to audits performed by outside petroleum consultants. In 2011, 95% of our reserves were subjected to such audits.

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 percent 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. Applicable rules require future net revenues to be 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. Such rules also dictate that a 10 percent discount factor be used. Therefore, the discounted future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs or our enterprise risk.

Because the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10 percent 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

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. Our commodity derivative financial instruments include financial price swaps, basis swaps, costless price collars and call options.

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 U.S. 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 periodically enter into interest rate swaps to manage our exposure to interest rate volatility. Under the terms of our interest-rate swaps, we receive a fixed rate and pay a variable rate on a total notional amount.

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 or brokers.

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 fourteen separate counterparties, and our interest rate derivative contracts are held with five separate counterparties. Second, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below certain credit rating levels. The mark-to-market exposure threshold for collateral posting decreases as the debt rating falls further below such credit levels. Thresholds generally range from zero to $55 million for the majority of our contracts. As of December 31, 2011, the credit ratings of all our counterparties were within our established guidelines.

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 reported 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" of this report.

Goodwill

The annual impairment test, which we conduct as of October 31 each year, includes an assessment of qualitative factors and 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 using 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 operations. 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. We then 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 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, 2011, the date of our last impairment test, the fair values of our U.S. 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

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 and 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. We also assess factors relative to whether our foreign earnings are considered permanently reinvested. Changes in any of these factors could require recognition of additional deferred, or even current, U.S. income tax expense. 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 to our tax accruals may occur in the future based on the progress of ongoing audits, changes in legislation or resolution of pending matters.

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 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 as discussed in "Item 1A. Risk Factors" of this report. Consequently, we periodically enter into financial hedging activities with respect to a portion of our production through various financial transactions that hedge future prices received. The key terms to all our oil, gas and NGL derivative financial instruments as of December 31, 2011 are presented in Note 2 to the financial statements under "Item 8. Financial Statements and Supplementary Data" of this report.

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2011, a 10 percent increase and 10 percent decrease in the forward curves associated with our commodity derivative instruments would have changed our net asset positions by the following amounts:

	10% Increase	10% Decrease
	(In millions)	
Gain/(loss):		
Gas derivatives	$ (93)	$ 93
Oil derivatives	$(224)	$215

Interest Rate Risk

At December 31, 2011, we had debt outstanding of $9.8 billion. Of this amount, $6.1 billion bears fixed interest rates averaging 6.3 percent. Additionally, we had $3.7 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.45 percent. As of December 31, 2011, we had open interest rate swap positions that are presented in Note 2 to the financial statements under "Item 8. Financial Statements and Supplementary Data" of this report.

The fair values of our interest rate swaps are largely determined by estimates of the forward curves of the Federal Funds rate and LIBOR. A 10 percent change in these forward curves would not materially impact our balance sheet at December 31, 2011.

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 percent unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our December 31, 2011 balance sheet.

Our non-Canadian foreign subsidiaries have a U.S. dollar functional currency. However, one of these foreign subsidiaries holds Canadian-dollar cash and engages in short-term intercompany loans with Canadian subsidiaries that are sometimes based in Canadian dollars. Additionally, at December 31, 2011, we held foreign currency exchange forward contracts to hedge exposures to fluctuations in exchange rates on the Canadian-dollar cash. The increase or decrease in the value of the forward contracts is offset by the increase or decrease to the U.S. dollar equivalent of the Canadian-dollar cash. The value of the intercompany loans increases or decreases from the remeasurement of the loans into the U.S. dollar functional currency. Based on the amount of the intercompany loans as of December 31, 2011, a 10 percent change in the foreign currency exchange rates would not materially impact our balance sheet.

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated comprehensive statements of earnings, cash flows and stockholders' equity for each of the years in the three-year period ended December 31, 2011. We also have audited Devon Energy Corporation's internal control over financial reporting as of December 31, 2011, 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, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011, 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, 2011, 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, 2012

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except per share amounts)		
Revenues:			
Oil, gas and NGL sales	$ 8,315	$7,262	$ 6,097
Oil, gas and NGL derivatives	881	811	384
Marketing and midstream revenues	2,258	1,867	1,534
Total revenues	11,454	9,940	8,015
Expenses and other, net:			
Lease operating expenses	1,851	1,689	1,670
Marketing and midstream operating costs and expenses	1,716	1,357	1,022
Depreciation, depletion and amortization	2,248	1,930	2,108
General and administrative expenses	585	563	648
Taxes other than income taxes	424	380	314
Interest expense	352	363	349
Restructuring costs	(2)	57	105
Reduction of carrying value of oil and gas properties	—	—	6,408
Other, net	(10)	33	(83)
Total expenses and other, net	7,164	6,372	12,541
Earnings (loss) from continuing operations before income taxes	4,290	3,568	(4,526)
Current income tax (benefit) expense	(143)	516	241
Deferred income tax expense (benefit)	2,299	719	(2,014)
Earnings (loss) from continuing operations	2,134	2,333	(2,753)
Earnings from discontinued operations, net of income tax expense	2,570	2,217	274
Net earnings (loss)	$ 4,704	$4,550	$ (2,479)
Basic net earnings per share:			
Basic earnings (loss) from continuing operations per share	$ 5.12	$ 5.31	$ (6.20)
Basic earnings from discontinued operations per share	6.17	5.04	0.62
Basic net earnings (loss) per share	$ 11.29	$10.35	$ (5.58)
Diluted net earnings per share:			
Diluted earnings (loss) from continuing operations per share	$ 5.10	$ 5.29	$ (6.20)
Diluted earnings from discontinued operations per share	6.15	5.02	0.62
Diluted net earnings (loss) per share	$ 11.25	$10.31	$ (5.58)
Comprehensive earnings (loss):			
Net earnings (loss)	$ 4,704	$4,550	$ (2,479)
Other comprehensive income, net of tax:			
Foreign currency translation adjustments	(191)	377	931
Pension and postretirement plans	6	(2)	71
Other comprehensive (loss) earnings, net of tax	(185)	375	1,002
Comprehensive earnings (loss)	$ 4,519	$4,925	$ (1,477)

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Cash flows from operating activities:			
Net earnings (loss)	$ 4,704	$ 4,550	$(2,479)
Earnings from discontinued operations, net of tax	(2,570)	(2,217)	(274)
Adjustments to reconcile earnings (loss) from continuing operations to net cash from operating activities:			
Depreciation, depletion and amortization	2,248	1,930	2,108
Deferred income tax expense (benefit)	2,299	719	(2,014)
Unrealized change in fair value of financial instruments	(401)	107	55
Reduction of carrying value of oil and gas properties	—	—	6,408
Other noncash charges	241	215	288
Net decrease (increase) in working capital	185	(273)	149
Decrease (increase) in long-term other assets	33	32	(6)
Decrease in long-term other liabilities	(493)	(41)	(3)
Cash from operating activities — continuing operations	6,246	5,022	4,232
Cash from operating activities — discontinued operations	(22)	456	505
Net cash from operating activities	6,224	5,478	4,737
Cash flows from investing activities:			
Capital expenditures	(7,534)	(6,476)	(4,879)
Proceeds from property and equipment divestitures	129	4,310	34
Purchases of short-term investments	(6,691)	(145)	—
Redemptions of short-term investments	5,333	—	—
Redemptions of long-term investments	10	21	7
Other	(39)	(19)	(17)
Cash from investing activities — continuing operations	(8,792)	(2,309)	(4,855)
Cash from investing activities — discontinued operations	3,146	2,197	(499)
Net cash from investing activities	(5,646)	(112)	(5,354)
Cash flows from financing activities:			
Net commercial paper borrowings (repayments)	3,726	(1,432)	426
Proceeds from borrowings of long-term debt, net of issuance costs	2,221	—	1,187
Debt repayments	(1,760)	(350)	(178)
Proceeds from stock option exercises	101	111	42
Repurchases of common stock	(2,332)	(1,168)	—
Dividends paid on common stock	(278)	(281)	(284)
Excess tax benefits related to share-based compensation	13	16	8
Net cash from financing activities	1,691	(3,104)	1,201
Effect of exchange rate changes on cash	(4)	17	43
Net increase in cash and cash equivalents	2,265	2,279	627
Cash and cash equivalents at beginning of period (including cash related to assets previously held for sale in 2010 and 2009)	3,290	1,011	384
Cash and cash equivalents at end of period (including cash related to assets previously held for sale in 2010 and 2009)	$ 5,555	$ 3,290	$ 1,011

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,555	$ 2,866
Short-term investments	1,503	145
Accounts receivable	1,379	1,202
Current assets held for sale	21	563
Other current assets	847	779
Total current assets	9,305	5,555
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	61,696	56,012
Not subject to amortization	3,982	3,434
Total oil and gas	65,678	59,446
Other	5,098	4,429
Total property and equipment, at cost	70,776	63,875
Less accumulated depreciation, depletion and amortization	(46,002)	(44,223)
Property and equipment, net	24,774	19,652
Goodwill	6,013	6,080
Long-term assets held for sale	132	859
Other long-term assets	893	781
Total assets	$ 41,117	$ 32,927
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,471	$ 1,411
Revenues and royalties payable	678	538
Short-term debt	3,811	1,811
Current liabilities associated with assets held for sale	48	305
Other current liabilities	730	518
Total current liabilities	6,738	4,583
Long-term debt	5,969	3,819
Asset retirement obligations	1,496	1,423
Liabilities associated with assets held for sale	—	26
Other long-term liabilities	721	1,067
Deferred income taxes	4,763	2,756
Stockholders' equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 404.1 million and 431.9 million shares in 2011 and 2010, respectively	40	43
Additional paid-in capital	3,507	5,601
Retained earnings	16,308	11,882
Accumulated other comprehensive earnings	1,575	1,760
Treasury stock, at cost. 0.4 million shares in 2010	—	(33)
Total stockholders' equity	21,430	19,253
Commitments and contingencies (Note 18)		
Total liabilities and stockholders' equity	$ 41,117	$ 32,927

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Amount					
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
Balance as of December 31, 2009	447	45	6,527	7,613	1,385	—	15,570
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
Net earnings (loss)	—	—	—	4,704	—	—	4,704
Other comprehensive earnings (loss), net of tax	—	—	—	—	(185)	—	(185)
Stock option exercises	2	—	112	—	—	(11)	101
Restricted stock grants, net of cancellations	1	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(2,337)	(2,337)
Common stock retired	(31)	(3)	(2,378)	—	—	2,381	—
Common stock dividends	—	—	—	(278)	—	—	(278)
Share-based compensation	—	—	159	—	—	—	159
Share-based compensation tax benefits	—	—	13	—	—	—	13
Balance as of December 31, 2011	404	$40	$ 3,507	$16,308	$1,575	$ —	$21,430

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Devon Energy Corporation ("Devon") is a leading independent energy company engaged primarily in the exploration, development and production of oil and natural gas. Devon's operations are concentrated in various North American onshore areas in the U.S. and Canada. Devon also owns natural gas pipelines, plants and treatment facilities in many of its producing areas, making it one of North America's larger processors of natural gas.

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

Principles of Consolidation

The accounts of Devon and its wholly owned and controlled subsidiaries are included in the accompanying financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements 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:

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

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. 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 comprehensive statements of earnings.

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

Marketing and midstream revenues are recorded at the time products are sold or services are provided to third parties at a fixed or determinable price, delivery or performance has occurred, title has transferred and 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 2011, 2010 and 2009, no purchaser accounted for more than 10 percent of Devon's revenues from continuing operations.

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.

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. The call options give counterparties the right to purchase production at a predetermined 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.

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 earnings unless specific hedge accounting criteria are met. For derivative financial instruments held during the three-year period ended December 31, 2011, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment. Cash settlements with counterparties on Devon's derivative financial instruments are also recorded in earnings.

By using derivative financial instruments to hedge exposures to changes in commodity prices and interest rates, Devon is exposed to credit 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 certain credit rating levels. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below such credit levels. Thresholds generally range from zero to $55 million for the majority of Devon's contracts. As of December 31, 2011, the credit ratings of all Devon's counterparties were within established guidelines.

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 comprehensive statements of earnings 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 comprehensive statements of earnings.

Generally, Devon uses new shares from approved incentive programs 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 U.S. 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. If the future utilization of some portion of carryforwards is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. 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 U.S. 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, or even current, 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 expense.

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 assumed issuance of common shares for all potentially dilutive securities. Such securities primarily consist of outstanding stock options.

Cash and Cash Equivalents

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

Investments

Devon periodically invests excess cash in U.S. and Canadian Treasury securities and other marketable securities. During 2011, Devon invested a portion of the International offshore divestiture proceeds into such securities, causing short-term investments to increase.

Devon considers securities with original contractual maturities in excess of three months, but less than one year to be short-term investments. Investments with contractual maturities in excess of one year are classified as long-term, unless such investments are classified as trading or available-for-sale.

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. Such debt securities totaled $84 million and $94 million at December 31, 2011 and 2010, respectively and are included in other long-term assets in the accompanying balance sheet. Devon has the ability to hold the securities until maturity and does not believe the values of its long-term securities are impaired.

Property and Equipment

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

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the estimated after-tax future net revenues, discounted at 10 percent 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 tested quarterly and imposed separately on a country-by-country basis.

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. 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, 2011, 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 six 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 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. When the assumptions used to estimate a recorded asset retirement obligation change, a revision is recorded to both the asset retirement obligation and the asset retirement cost. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

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. Such test includes an assessment of qualitative and quantitative factors. 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 2011, 2010 and 2009. Based on these assessments, no impairment of goodwill was required.

The table below provides a summary of Devon's goodwill, by assigned reporting unit. The decrease in Devon's goodwill from 2010 to 2011 was due to changes in the exchange rate between the U.S. dollar and the Canadian dollar.

	December 31,	
	2011	2010
	(In millions)	
U.S.	$3,046	$3,046
Canada	2,967	3,034
Total	$6,013	$6,080

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.

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 consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. When available, Devon measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.
- Level 2 – Inputs consist of 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 – Inputs are not observable from objective sources and have the lowest priority. The most common Level 3 fair value measurement is an internally developed cash flow model.

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 financial statements that pertain to continuing operations include amounts related to Devon's offshore Gulf of Mexico operations.

The captions assets held for sale and liabilities associated with assets held for sale in the accompanying balance sheets present the assets and liabilities associated with 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.

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.

2. Derivative Financial Instruments

Commodity Derivatives

As of December 31, 2011, Devon had the following open oil derivative positions. Devon's oil derivatives settle against the average of the prompt month NYMEX West Texas Intermediate futures price.

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Q1-Q4 2012	22,000	$107.17	54,000	$85.74	$126.42	19,500	$95.00
Q1-Q4 2013	—	—	7,000	$90.00	$125.12	—	—

As of December 31, 2011, Devon had the following open natural gas derivative positions. Devon's natural gas derivative settle against the Inside FERC first of the month Henry Hub index.

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Q1-Q4 2012 ...	325,000	$5.09	490,000	$4.75	$5.57	487,500	$6.00

	Basis Swaps		
Production Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q1-Q4 2012	El Paso Natural Gas Co. (Permian)	85,000	$(0.14)
Q1-Q4 2012	Panhandle Eastern Pipeline	70,000	$(0.15)
Q1-Q4 2012	Colorado Interstate Gas Co.	10,000	$(0.18)

Interest Rate Derivatives

As of December 31, 2011, Devon had the following open interest rate derivative positions:

Notional	Fixed Rate Received	Variable Rate Paid	Expiration
(In millions)			
$100	1.90%	Federal funds rate	August 2012
750	3.88%	Federal funds rate	July 2013
$850	3.65%		

Foreign Exchange Derivatives

As of December 31, 2011, Devon had the following open foreign exchange rate derivative positions:

	Forward Contract			
Currency	Contract Type	CAD Notional	Fixed Rate Received	Expiration
		(In millions)	(CAD-USD)	
Canadian Dollar	Sell	$305	0.9812	March 30, 2012

Financial Statement Presentation

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

	Comprehensive Statement of Earnings Caption	2011	2010	2009
		(In millions)		
Cash settlements:				
Commodity derivatives	Oil, gas and NGL derivatives	$392	$ 888	$ 505
Interest rate derivatives	Other, net	77	44	40
Foreign exchange derivatives	Other, net	16	—	—
Total cash settlements		485	932	545
Unrealized gains (losses):				
Commodity derivatives	Oil, gas and NGL derivatives	489	(77)	(121)
Interest rate derivatives	Other, net	(88)	(30)	66
Total unrealized gains (losses)		401	(107)	(55)
Net gain recognized on comprehensive statements of earnings		$886	$ 825	$ 490

The following table presents the derivative fair values included in the accompanying balance sheets.

	Balance Sheet Caption	December 31, 2011	December 31, 2010
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$611	$248
Commodity derivatives	Other long-term assets	17	1
Interest rate derivatives	Other current assets	30	100
Interest rate derivatives	Other long-term assets	22	40
Total asset derivatives		$680	$389
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 82	$ 50
Commodity derivatives	Other long-term liabilities	—	142
Total liability derivatives		$ 82	$192

3. Share-Based Compensation

On June 3, 2009, Devon's stockholders adopted the 2009 Long-Term Incentive Plan, which expires on June 2, 2019. This plan authorizes the Compensation Committee, which consists of independent non-management members of Devon's Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards, performance restricted stock awards, Canadian restricted stock units, performance share units, stock appreciation rights and cash-out rights to eligible employees. The plan also authorizes the grant of nonqualified stock options, restricted stock awards, restricted stock units and stock appreciation rights to directors. A total of 21.5 million shares of Devon common stock have been reserved for issuance pursuant to the plan. To calculate shares issued under the plan, options granted represent one share and other awards represent 1.84 shares.

Devon also has stock option plans that were adopted in 2005, 2003 and 1997 under which stock options and restricted stock awards were issued to certain management and professional employees. Options granted under these plans remain exercisable by the employees owning such options, but no new options or restricted stock awards will be granted under these plans. Devon also has stock options outstanding that were assumed as part of its 2003 acquisition of Ocean Energy.

The following table presents the effects of share-based compensation included in Devon's accompanying comprehensive statements of earnings. The vesting for certain share-based awards was accelerated as part of Devon's strategic repositioning. The associated expense for these accelerated awards is included in restructuring costs in the accompanying comprehensive statements of earnings. See Note 4 for further details.

	2011	2010	2009
		(In millions)	
Gross general and administrative expense	$181	$188	$209
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 56	$ 58	$ 66
Related income tax benefit	$ 33	$ 40	$ 43

Stock Options

In accordance with Devon's incentive plans, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which may not exceed eight years from the date of grant. The recipient must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Generally, the service requirement for vesting ranges from zero to four years.

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

	2011	2010	2009
Grant-date fair value	$ 23.11	$ 25.41	$ 22.85
Volatility factor	46.0%	45.3%	47.7%
Dividend yield	1.0%	1.0%	0.9%
Risk-free interest rate	0.8%	1.1%	2.1%
Expected term (in years)	4.2	4.5	4.0

The following table presents a summary of Devon's outstanding stock options.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Intrinsic Value
	(In thousands)		(In years)	(In millions)
Outstanding at December 31, 2010	11,434	$62.64		
Granted	1,962	$66.98		
Exercised	(2,366)	$47.51		
Forfeited	(487)	$73.32		
Outstanding at December 31, 2011	10,543	$66.35	4.31	$40
Vested and expected to vest at December 31, 2011	10,428	$66.33	4.27	$40
Exercisable at December 31, 2011	6,716	$65.39	2.90	$39

The aggregate intrinsic value of stock options that were exercised during 2011, 2010 and 2009 was $81 million, $47 million and $51 million, respectively. As of December 31, 2011, Devon's unrecognized compensation cost related to unvested stock options was $70 million. Such cost is expected to be recognized over a weighted-average period of 3.0 years.

Restricted Stock Awards and Units

These awards and units are subject to the terms, conditions, restrictions and limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, the service requirement for vesting ranges from zero to four years. During the vesting period, recipients of such awards receive dividends that are not subject to restrictions or other limitations. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon's common stock on the grant date of the award or unit, which is expensed over the applicable vesting period. The following table presents a summary of Devon's unvested restricted stock awards and units.

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2010	5,311	$70.60
Granted	2,301	$65.40
Vested	(2,188)	$72.05
Forfeited	(200)	$71.18
Unvested at December 31, 2011	5,224	$67.85

The aggregate fair value of restricted stock awards and units that vested during 2011, 2010 and 2009 was $145 million, $184 million and $165 million, respectively. As of December 31, 2011, Devon's unrecognized compensation cost related to unvested restricted stock awards and units was $305 million. Such cost is expected to be recognized over a weighted-average period of 2.8 years.

Performance Based Restricted Stock Awards

In December 2011, certain members of Devon's senior management were granted performance based share awards. Vesting of the awards is dependent on Devon meeting certain internal performance targets and the recipient meeting certain service requirements. Generally, the service requirement for vesting ranges from zero to four years. If Devon meets or exceeds the performance target, the awards vest after the recipient meets the related requisite service period. If the performance target and service period requirement are not met, the award does not vest. Once vested, recipients are entitled to dividends on the awards. Devon estimates the fair values of the awards as the closing price of Devon's common stock on the grant date of the award, which is expensed over the applicable vesting period. The following table presents a summary of Devon's performance based restricted stock awards.

	Performance Restricted Stock Awards	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2010	—	$ —
Granted	184	$65.10
Unvested at December 31, 2011	184	$65.10

As of December 31, 2011, Devon's unrecognized compensation cost related to these awards was $4 million. Such cost is expected to be recognized over a weighted-average period of 2.4 years.

Performance Share Units

In December 2011, certain members of Devon's senior management were granted performance share units. Each unit that vests entitles the recipient to one share of Devon common stock. The vesting of these units is based on comparing Devon's total shareholder return ("TSR") to the TSR of a predetermined group of fourteen peer companies over the specified two- or three-year performance period. The vesting of units may be between zero and 200 percent of the units granted depending on Devon's TSR as compared to the peer group on the vesting date.

During the vesting period, recipients will receive dividend equivalents with respect to each outstanding performance share unit. The fair value of each performance share unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all grants made under the plan: (i) a risk-free interest rate; (ii) a volatility assumption based on the historical realized price volatility of Devon and the designated peer group; and (iii) an estimated ranking of Devon among the designated peer group. The fair value of the unit on the date of grant is expensed over the applicable vesting period.

The following table presents a summary of Devon's performance share units.

	Performance Share Units	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2010	—	$ —
Granted(1)	171	$81.70
Unvested at December 31, 2011	171	$81.70

(1) A maximum of 341,000 common shares could be awarded based upon Devon's final TSR ranking.

As of December 31, 2011, Devon's unrecognized compensation cost related to unvested units was $8 million. Such cost is expected to be recognized over a weighted-average period of 2.3 years.

4. Restructuring Costs

In the fourth quarter of 2009, Devon announced plans to divest its offshore assets. As of December 31, 2011, Devon had divested all of its U.S. Offshore assets and substantially all of its International assets. Through the end of 2011, Devon had incurred $202 million of restructuring costs associated with these divestitures.

Employee Severance

This amount was originally based on estimates of the number of employees that would ultimately be impacted by the offshore divestitures and included amounts related to cash severance costs and accelerated vesting of share-based grants. As the divestiture program progressed, Devon decreased its overall estimate of employee severance costs. More offshore employees than previously estimated received comparable positions with either the purchaser of the properties or in Devon's U.S. Onshore operations.

Lease Obligations

As a result of the divestitures, Devon ceased using certain office space that was subject to non-cancellable operating lease arrangements. Consequently, in 2010 Devon recognized $70 million of restructuring costs that represented the present value of its future obligations under the leases, net of anticipated sublease income. Devon's 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 Devon may receive over the term of the leases, as well as the amount of variable operating costs that Devon will be required to pay under the leases. In addition, Devon recognized $11 million of asset impairment charges for leasehold improvements and furniture associated with the office space that it ceased using.

Financial Statement Presentation

The schedule below summarizes restructuring costs presented in the accompanying comprehensive statements of earnings. Restructuring costs relating to Devon's discontinued operations totaled $(2) million, $(4) million, and $48 million in 2011, 2010, and 2009, respectively. These costs primarily relate to cash severance and share-based awards and are not included in the schedule below.

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Cash severance	$ 9	$(17)	$ 66
Share-based awards	(1)	(10)	39
Lease obligations	(13)	70	—
Asset impairments	2	11	—
Other	1	3	—
Total	$ (2)	$ 57	$105

The schedule below summarizes activity and balances associated with Devon's restructuring liabilities. Devon's restructuring liabilities related to its discontinued operations totaled $16 million and $23 million at December 31, 2010, and 2009, respectively. There was no liability at the end of 2011. These liabilities primarily relate to cash severance and are not included in the schedule below.

	Other Current Liabilities	Other Long-Term Liabilities	Total
		(In millions)	
Balance as of December 31, 2009	$ 61	$ —	$ 61
Lease obligations incurred	17	51	68
Cash severance settled	(30)	—	(30)
Cash severance revision	(17)	—	(17)
Balance as of December 31, 2010	31	51	82
Lease obligations settled	(8)	(12)	(20)
Cash severance settled	(13)	—	(13)
Lease obligations revision	10	(23)	(13)
Cash severance revision	9	—	9
Balance as of December 31, 2011	$ 29	$ 16	$ 45

5. Other, net

The components of other, net in the accompanying comprehensive statement of earnings include the following:

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Accretion of asset retirement obligations	$ 92	$ 92	$ 91
Interest rate swaps – unrealized fair value changes	88	30	(66)
Interest rate swaps – cash settlements	(77)	(44)	(40)
Interest income	(21)	(13)	(8)
Other	(92)	(32)	(60)
Total	$(10)	$ 33	$(83)

During 2011, Devon received $88 million of excess insurance recoveries related to certain weather and operational claims. In 2009, Devon reversed an $84 million loss contingency accrual. Devon had previously accrued $84 million for potential royalties on various deep water leases but reversed the accrual in 2009 due to a federal district court ruling.

6. Income Taxes

Income Tax Expense (Benefit)

Devon's income tax components are presented in the following table.

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Current income tax (benefit) expense:			
U.S. federal	$ (143)	$ 244	$ 45
Various states	20	16	18
Canada and various provinces	(20)	256	178
Total current tax (benefit) expense	(143)	516	241
Deferred income tax expense (benefit):			
U.S. federal	1,986	781	(1,846)
Various states	95	21	(111)
Canada and various provinces	218	(83)	(57)
Total deferred tax expense (benefit)	2,299	719	(2,014)
Total income tax expense (benefit)	$2,156	$1,235	$(1,773)

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

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Expected income tax expense (benefit) based on U.S. statutory tax rate of 35%	$1,502	$1,249	$(1,584)
Assumed repatriations	725	144	55
State income taxes	70	31	(99)
Taxation on Canadian operations	(91)	(60)	(31)
Other	(50)	(129)	(114)
Total income tax expense (benefit)	$2,156	$1,235	$(1,773)

During 2011, 2010 and 2009, pursuant to the completed and planned divestitures of our International assets located outside North America, a portion of Devon's foreign earnings were no longer deemed to be permanently reinvested. Accordingly, Devon recognized deferred income tax expense of $725 million, $144 million and $55 million during 2011, 2010 and 2009 respectively, related to assumed repatriations of earnings from its foreign subsidiaries.

Deferred Tax Assets and Liabilities

The tax effects of temporary differences that gave rise to Devon's deferred tax assets and liabilities are presented below:

	December 31, 2011	December 31, 2010
	(In millions)	
Deferred tax assets:		
Net operating loss carryforwards	$ 222	$ 159
Asset retirement obligations	447	494
Pension benefit obligations	130	133
Other	117	171
Total deferred tax assets	916	957
Deferred tax liabilities:		
Property and equipment	(4,475)	(3,130)
Fair value of financial instruments	(218)	(70)
Long-term debt	(185)	(198)
Taxes on unremitted foreign earnings	(936)	(211)
Other	(27)	(20)
Total deferred tax liabilities	(5,841)	(3,629)
Net deferred tax liability	$(4,925)	$(2,672)

Devon has recognized $222 million of deferred tax assets related to various carryforwards available to offset future income taxes. The carryforwards consist of $829 million of Canadian net operating loss carryforwards, which expire between 2026 and 2031, and $206 million of state net operating loss carryforwards, which expire primarily between 2012 and 2031. Devon expects the tax benefits from the Canadian net operating loss carryforwards to be utilized between 2013 and 2017. Also, Devon expects the tax benefits from the state net operating loss carryforwards to be utilized between 2012 and 2016. Such expectations are based upon current estimates of taxable income during these periods, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil, gas and NGL prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

As of December 31, 2011, approximately $5.4 billion of Devon's unremitted earnings from its foreign subsidiaries were deemed to be permanently reinvested. As a result, Devon has not recognized a deferred tax liability for U.S. income taxes associated with such earnings. If such earnings were to be remitted to the U.S., Devon may be subject to U.S. income taxes and foreign withholding taxes. However, it is not practical to estimate the amount of additional taxes that may be payable due to the inter-relationship of the various factors involved in making such an estimate.

Unrecognized Tax Benefits

The following table presents changes in Devon's unrecognized tax benefits.

	December 31, 2011	December 31, 2010
	(In millions)	
Balance at beginning of year	$194	$ 272
Tax positions taken in prior periods	(3)	40
Tax positions taken in current year	27	5
Accrual of interest related to tax positions taken	(7)	9
Lapse of statute of limitations	(41)	(5)
Settlements	(5)	(129)
Foreign currency translation	—	2
Balance at end of year	$165	$ 194

Devon's unrecognized tax benefit balance at December 31, 2011 and 2010, included $20 million and $27 million of interest and penalties, respectively. If recognized, all of Devon's unrecognized tax benefits as of December 31, 2011 would affect Devon's effective income tax rate. Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

Jurisdiction	Tax Years Open
U.S. federal	2008-2011
Various U.S. states	2007-2011
Canada federal	2003-2011
Various Canadian provinces	2003-2011

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

7. Earnings (Loss) Per Share

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings (loss) per share. Because a net loss from continuing operations was incurred during 2009, the dilutive shares produce an antidilutive net loss per share result. As a result, the diluted loss per share from continuing operations is same as the basic loss per share amount.

	Earnings	Common Shares	Earnings (Loss) per Share
	(In millions, except per share amounts)		
Year Ended December 31, 2011:			
Earnings from continuing operations	$ 2,134	417	
Attributable to participating securities	(23)	(5)	
Basic earnings per share	2,111	412	$ 5.12
Dilutive effect of potential common shares issuable	—	2	
Diluted earnings per share	$ 2,111	414	$ 5.10
Year Ended December 31, 2010:			
Earnings from continuing operations	$ 2,333	440	
Attributable to participating securities	(26)	(5)	
Basic earnings per share	2,307	435	$ 5.31
Dilutive effect of potential common shares issuable	—	1	
Diluted earnings per share	$ 2,307	436	$ 5.29
Year Ended December 31, 2009:			
Loss from continuing operations	$(2,753)	444	
Attributable to participating securities	31	(5)	
Basic and diluted loss per share	$(2,722)	439	$(6.20)

Certain options to purchase shares of Devon's common stock were excluded from the dilution calculations because the options were antidilutive. These excluded options totaled 3 million, 6 million and 9 million in 2011, 2010 and 2009, respectively.

8. Other Comprehensive Earnings

Components of other comprehensive earnings consist of the following:

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Foreign currency translation:			
Accumulated foreign currency translation at beginning of year	$1,993	$1,616	$ 685
Change in cumulative translation adjustment	(200)	397	993
Income tax benefit (expense)	9	(20)	(62)
Accumulated foreign currency translation at end of year	1,802	1,993	1,616
Pension and postretirement benefit plans:			
Accumulated pension and postretirement benefit at beginning of year	(233)	(231)	(302)
Net actuarial (loss) gain and prior service cost arising in current year	(21)	(33)	59
Income tax benefit (expense)	8	11	(22)
Recognition of net actuarial loss and prior service cost in net earnings	30	31	54
Income tax expense	(11)	(11)	(20)
Accumulated pension and postretirement benefits at end of year	(227)	(233)	(231)
Accumulated other comprehensive earnings, net of tax	$1,575	$1,760	$1,385

9. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Net decrease (increase) in working capital:			
(Increase) decrease in accounts receivable	$(185)	$ 23	$142
Decrease in other current assets	125	21	212
Increase (decrease) in accounts payable	64	37	(91)
Increase in revenues and royalties payable	144	48	—
Increase (decrease) in income taxes payable	78	(203)	(48)
Decrease in other current liabilities	(41)	(199)	(66)
Net decrease (increase) in working capital	$ 185	$(273)	$149
Supplementary cash flow data – total operations:			
Interest paid (net of capitalized interest)	$ 325	$ 359	$314
Income taxes (received) paid	$(383)	$ 955	$ 68

10. Short-Term Investments

The components of short-term investments include the following:

	December 31,	
	2011	2010
	(In millions)	
Commercial paper	$1,013	$ —
U.S. Treasuries	201	145
Other	289	—
Total	$1,503	$145

As of December 31, 2011, the average remaining maturity of these investments was 75 days, with a weighted average yield of 0.28 percent.

11. Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2011	December 31, 2010
	(In millions)	
Oil, gas and NGL sales	$ 928	$ 786
Joint interest billings	247	204
Marketing and midstream revenues	174	165
Other	39	57
Gross accounts receivable	1,388	1,212
Allowance for doubtful accounts	(9)	(10)
Net accounts receivable	$1,379	$1,202

12. Other Current Assets

The components of other current assets include the following:

	December 31, 2011	December 31, 2010
	(In millions)	
Derivative financial instruments	$641	$348
Inventories	102	120
Income tax receivable	35	270
Other	69	41
Other current assets	$847	$779

13. Property and Equipment

See Note 22 for disclosure of Devon's capitalized costs related to its oil and gas exploration and development activities.

In November 2009, Devon announced plans to divest its offshore assets. In 2011, Devon substantially completed its planned divestiture program. In aggregate, Devon's U.S. and International sales generated total proceeds of $10 billion as presented in the following table. Assuming repatriation of a portion of the foreign proceeds under current U.S. tax law the after-tax proceeds from these transactions were approximately $8 billion.

	Cash Proceeds	Year of Divestiture
	(In millions)	
Brazil (discontinued operations)	$ 3,251	2011
Gulf of Mexico (continuing operations)	4,059	2010
Azerbaijan (discontinued operations)	1,925	2010
China — Panyu and Exploration (discontinued operations)	592	2010
Other (discontinued operations)	175	2010
Total	$10,002	

Reductions of Carrying Value

In the first quarter of 2009, Devon reduced the carrying value of its U.S. oil and gas properties $6.4 billion, or $4.1 billion after taxes, due to a full cost ceiling limitation. The reduction resulted from a significant decrease in the full cost ceiling due to the effects of declining natural gas prices subsequent to December 31, 2008.

Sinopec Transaction

In January 2012, Devon announced a transaction with Sinopec International Petroleum Exploration & Production Corporation that Devon expects to close in the first quarter of 2012. Under the agreement, Sinopec will pay $2.5 billion, including $900 million at closing and $1.6 billion toward Devon's share of future drilling costs, and will receive a 33.3% interest in five new venture exploration plays in the United States.

14. Debt and Related Expenses

A summary of Devon's debt is as follows:

	December 31,	
	2011	2010
	(In millions)	
Commercial paper	$3,726	$ —
Other debentures and notes:		
6.875% retired upon maturity on September 30, 2011	—	1,750
5.625% due January 15, 2014	500	500
Non-interest bearing promissory note due June 29, 2014	85	144
2.40% due July 15, 2016	500	—
8.25% due July 1, 2018	125	125
6.30% due January 15, 2019	700	700
4.00% due July 15, 2021	500	—
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
5.60% due July 15, 2041	1,250	—
Other	—	9
Net discount on other debentures and notes	(6)	2
Total debt	9,780	5,630
Less amount classified as short-term debt	3,811	1,811
Long-term debt	$5,969	$3,819

Debt maturities as of December 31, 2011, excluding premiums and discounts, are as follows (in millions):

2012	$3,811
2013	—
2014	500
2015	—
2016	500
2017 and thereafter	4,975
Total	$9,786

Credit Lines

Devon has a $2.65 billion syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). 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, 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. $0.5 billion.

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, 2011, there were no borrowings under the Senior Credit Facility.

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 percent. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in the accompanying 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, 2011, Devon was in compliance with this covenant. Devon's debt-to-capitalization ratio at December 31, 2011, as calculated pursuant to the terms of the agreement, was 22.8 percent.

Commercial Paper

Devon has access to $5.0 billion of short-term credit under its commercial paper program. Commercial paper debt generally has a maturity of between 1 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 generally based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found in the commercial paper market. As of December 31, 2011, Devon's weighted average borrowing rate on its commercial paper borrowings was 0.45 percent.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2011, as listed in the table presented at the beginning of this note.

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

In January 2009, Devon issued $1.2 billion of senior notes. The net proceeds were used primarily to repay outstanding commercial paper as of December 31, 2008. These notes are unsecured and unsubordinated obligations of Devon.

Non-Interest Bearing Promissory Note due June 29, 2014

In June 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. The present value of the note was $139 million on the issue date based upon an effective interest rate of 3.125%. At December 31, 2011, the note had a carrying value of $85 million, which is presented as short-term debt in the accompanying balance sheet because it is expected to be repaid during 2012.

2.40% Notes due July 15, 2016, 4.00% Notes due July 15, 2021 and 5.60% Notes due July 15, 2041

In July 2011, Devon issued $2.25 billion of senior notes. The net proceeds were used to repay outstanding commercial paper debt. These notes are unsecured and unsubordinated obligations of Devon.

Ocean Debt

On April 25, 2003, Devon merged with Ocean Energy, Inc. and assumed certain debt instruments. The table below summarizes the debt assumed that remains outstanding as of December 31, 2011, including the fair value of the debt at April 25, 2003, and the effective interest rate of the debt after determining the fair values using April 25, 2003, market interest rates. The premiums resulting from fair values exceeding face values are being amortized using the effective interest method. Both notes are general unsecured obligations of Devon.

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

7.875% Debentures due September 30, 2031

In October 2001, Devon, through Devon Financing Corporation, U.L.C. ("Devon Financing"), a wholly owned finance subsidiary, sold 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 were used to fund a portion of the acquisition of Anderson Exploration.

7.95% Notes due April 15, 2032

In March 2002, Devon sold these notes, which are unsecured and unsubordinated obligations of Devon. The net proceeds were used to retire other indebtedness.

Interest Expense

The following schedule includes the components of interest expense.

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Interest based on debt outstanding	$414	$408	$437
Capitalized interest	(72)	(76)	(94)
Early retirement of debt	—	19	—
Other	10	12	6
Total	$352	$363	$349

15. Asset Retirement Obligations

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

	Year Ended December 31,	
	2011	2010
	(In millions)	
Asset retirement obligations as of beginning of year	$1,497	$1,513
Liabilities incurred	53	55
Liabilities settled	(82)	(129)
Revision of estimated obligation	25	194
Liabilities assumed by others	—	(269)
Accretion expense on discounted obligation	92	92
Foreign currency translation adjustment	(22)	41
Asset retirement obligations as of end of year	1,563	1,497
Less current portion	67	74
Asset retirement obligations, long-term	$1,496	$1,423

During 2010, Devon recognized a revision to its asset retirement obligations totaling $194 million. The increase was primarily due to 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.

16. Retirement Plans

Devon has various non-contributory defined benefit pension plans, including qualified plans and nonqualified 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 nonqualified plans provide retirement benefits for certain employees whose benefits under the qualified plans are limited by income tax regulations. The nonqualified plans' benefits are based on the employees' years of service and compensation. For certain nonqualified plans, Devon has established trusts to fund these plans' benefit obligations. The total value of these trusts was $32 million and $36 million at December 31, 2011 and 2010, respectively, and is included in other long-term assets in the accompanying balance sheets. For the remaining nonqualified 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 that provide benefits for substantially all U.S. employees. The 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 such plans are estimated based on Devon's future cost-sharing intentions. Devon's funding policy for the 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 funded status of Devon's qualified and nonqualified 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, 2011 and 2010 was $1.2 billion and $1.0 billion, respectively. Devon's benefit obligations and plan assets are measured each year as of December 31. Devon's 2011 pension plan contributions of $454 million presented in the table were primarily discretionary. After these contributions, the projected benefit obligation for Devon's qualified plans was fully funded as of December 31, 2011.

	Pension Benefits		Postretirement Benefits	
	2011	2010	2011	2010
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,124	$ 980	$ 43	$ 64
Service cost	37	33	1	1
Interest cost	60	58	2	3
Actuarial loss (gain)	123	82	(8)	1
Plan amendments	—	5	5	(22)
Plan settlements	—	—	(4)	—
Foreign exchange rate changes	(1)	2	—	—
Participant contributions	—	—	3	2
Benefits paid	(40)	(36)	(5)	(6)
Benefit obligation at end of year	1,303	1,124	37	43
Change in plan assets:				
Fair value of plan assets at beginning of year	632	532	—	—
Actual return on plan assets	141	69	—	—
Employer contributions	454	66	7	4
Participant contributions	—	—	3	2
Plan settlements	—	—	(5)	—
Benefits paid	(40)	(36)	(5)	(6)
Foreign exchange rate changes	—	1	—	—
Fair value of plan assets at end of year	1,187	632	—	—
Funded status at end of year	$ (116)	$ (492)	$(37)	$(43)
Amounts recognized in balance sheet:				
Noncurrent assets	$ 116	$ 2	$ —	$ —
Current liabilities	(10)	(9)	(3)	(4)
Noncurrent liabilities	(222)	(485)	(34)	(39)
Net amount	$ (116)	$ (492)	$(37)	$(43)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 348	$ 357	$ (9)	$ (5)
Prior service cost (credit)	18	21	(5)	(12)
Total	$ 366	$ 378	$(14)	$(17)

The plan assets for pension benefits in the table above exclude the assets held in trusts for the nonqualified plans. However, employer contributions for pension benefits in the table above include $8 million for both 2011 and 2010, which were transferred from the trusts established for the nonqualified plans.

Certain of Devon's pension plans have a projected benefit obligation and accumulated benefit obligation in excess of plan assets at December 31, 2011 and 2010 as presented in the table below.

	December 31,	
	2011	2010
	(In millions)	
Projected benefit obligation	$232	$1,110
Accumulated benefit obligation	$189	$ 996
Fair value of plan assets	$ —	$ 616

Net Periodic Benefit Cost and Other Comprehensive Earnings

The following table presents the components of net periodic benefit cost and other comprehensive earnings.

	Pension Benefits			Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 37	$ 33	$ 43	$ 1	$ 1	$ 1
Interest cost	60	58	58	2	3	3
Expected return on plan assets	(42)	(36)	(35)	—	—	—
Curtailment and settlement expense	—	—	5	(3)	—	—
Recognition of net actuarial loss (gain)	32	27	45	—	—	(1)
Recognition of prior service cost	3	3	3	(2)	1	2
Total net periodic benefit cost	90	85	119	(2)	5	5
Other comprehensive earnings:						
Actuarial loss (gain) arising in current year	23	50	(66)	(7)	1	7
Prior service cost (credit) arising in current year	—	4	—	5	(22)	—
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost	(32)	(27)	(45)	3	—	1
Recognition of prior service cost, including curtailment, in net periodic benefit cost	(3)	(3)	(8)	2	(1)	(2)
Total other comprehensive (loss) earnings	(12)	24	(119)	3	(22)	6
Total recognized	$ 78	$109	$ —	$ 1	$(17)	$11

The following table presents the estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive earnings into net periodic benefit cost during 2012.

	Pension Benefits	Postretirement Benefits
	(In millions)	
Net actuarial loss (gain)	$24	$(1)
Prior service cost (credit)	3	(1)
Total	$27	$(2)

Assumptions

The following table presents the weighted average actuarial assumptions used to determine obligations and periodic costs.

	Pension Benefits			Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
Assumptions to determine benefit obligations:						
Discount rate	4.65%	5.50%	6.00%	4.25%	4.90%	5.70%
Rate of compensation increase	4.97%	6.94%	6.95%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	5.50%	6.00%	6.00%	4.90%	5.70%	6.00%
Expected return on plan assets	6.48%	6.94%	7.18%	N/A	N/A	N/A
Rate of compensation increase	6.94%	6.95%	6.95%	N/A	N/A	N/A

Discount rate — Future pension and postretirement obligations are discounted at the end of each year based on the rate at which obligations could be effectively settled, considering the timing of estimated future cash flows related to the plans. This rate is based on high-quality bond yields, after allowing for call and default risk.

Rate of compensation increase — For measurement of the 2011 benefit obligation for the pension plans, a 4.97% compensation increase was assumed.

Expected return on plan assets — The expected rate of return on plan assets was determined by evaluating input from external consultants and economists, as well as long-term inflation assumptions. Devon expects the long-term asset allocation to approximate the targeted allocation. Therefore, the expected long-term rate of return on plan assets is based on the target allocation of investment types. See the pension plan assets section below for more information on Devon's target allocations.

Other assumptions — For measurement of the 2011 benefit obligation for the other postretirement medical plans, an 8.2% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2029 and remain at that level thereafter. Assumed health care cost-trend rates affect the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have changed the postretirement benefits obligation as of December 31, 2011, by $2 million and would change the 2012 service and interest cost components of net periodic benefit cost by less than $1 million.

Pension Plan Assets

Devon's overall investment objective for its pension plans' assets is to achieve stability of the plans' funded status while providing long-term growth of invested capital and income to ensure benefit payments can be funded when required. To assist in achieving this objective, Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. Derivatives or other speculative investments considered high risk are generally prohibited. The following table presents Devon's target allocation for its pension plan assets. Devon made significant contributions to its qualified pension plans in 2011. As a result, Devon revised its target allocations in 2011.

	December 31,	
	2011	2010
Fixed income	70%	40%
Equity	20%	47.5%
Other	10%	12.5%

The fair values of Devon's pension assets are presented by asset class in the following tables.

	As of December 31, 2011				
			Fair Value Measurements Using:		
	Actual Allocation	Total	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
		($ In millions)			
Fixed-income securities:					
U.S. Treasury obligations	43.9%	$ 522	$ 27	$495	$—
Corporate bonds	24.8%	294	265	29	—
Other bonds	3.1%	36	36	—	—
Total fixed-income securities	71.8%	852	328	524	—
Equity securities:					
Global (large, mid, small cap)	18.0%	214	—	214	—
Other securities:					
Hedge fund & alternative investments	8.9%	106	16	—	90
Short-term investment funds	1.3%	15	—	15	—
Total other securities	10.2%	121	16	15	90
Total investments	100.0%	$1,187	$344	$753	$90

	As of December 31, 2010				
			Fair Value Measurements Using:		
	Actual Allocation	Total	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
		($ In millions)			
Equity securities:					
U.S. large cap	22.3%	$141	$ —	$141	$—
U.S. small cap	14.1%	89	89	—	—
International large cap	14.4%	91	50	41	—
Total equity securities	50.8%	321	139	182	—
Fixed-income securities:					
Corporate bonds	22.0%	139	139	—	—
U.S. Treasury obligations	10.9%	69	69	—	—
Other bonds	4.6%	29	29	—	—
Total fixed-income securities	37.5%	237	237	—	—
Other securities:					
Hedge funds	9.2%	58	—	—	58
Short-term investment funds	2.5%	16	—	16	—
Total other securities	11.7%	74	—	16	58
Total investments	100.0%	$632	$376	$198	$58

The following methods and assumptions were used to estimate the fair values in the tables above.

Fixed-income securities — Devon's fixed-income securities consist of U.S. Treasury obligations, bonds issued by investment-grade companies from diverse industries, and asset-backed securities. These fixed-income securities are actively traded securities that can be redeemed upon demand. The fair values of these Level 1 securities are based upon quoted market prices.

Devon's fixed income securities also include commingled funds that primarily invest in long-term bonds and U.S. Treasury securities. These fixed income securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers.

Equity securities — Devon's equity securities include a commingled global equity fund that invests in large, mid and small capitalization stocks across the world's developed and emerging markets. These equity securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers.

At December 31, 2010, Devon's equity securities consisted of investments in U.S. large and small capitalization companies and international large capitalization companies. These equity securities were actively traded securities that could be redeemed upon demand. The fair values of these Level 1 securities are based upon quoted market prices.

At December 31, 2010, Devon's equity securities also included a commingled fund that invested in large capitalization companies. These equity securities could be redeemed on demand but were not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers.

Other securities — Devon's other securities include commingled, short-term investment funds. These securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by investment managers.

Devon's hedge fund and alternative investments include an investment in an actively traded global mutual fund that focuses on alternative investment strategies and a hedge fund of funds that invests both long and short using a variety of investment strategies. Devon's hedge fund of funds is not actively traded and Devon is subject to redemption restrictions with regards to this investment. The fair value of this Level 3 investment represents the fair value as determined by the hedge fund manager.

Included below is a summary of the changes in Devon's Level 3 plan assets (in millions).

December 31, 2009	$ 51
Purchases	3
Investment returns	4
December 31, 2010	58
Purchases	33
Investment returns	(1)
December 31, 2011	$ 90

Expected Cash Flows

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

	Pension Benefits	Postretirement Benefits
	(In millions)	
Devon's 2012 contributions	$ 9	$ 3
Benefit payments:		
2012	$ 44	$ 3
2013	$ 49	$ 3
2014	$ 52	$ 3
2015	$ 56	$ 3
2016	$ 61	$ 3
2017 to 2021	$390	$14

Expected contributions included in the table above include amounts related to Devon's qualified plans, nonqualified plans and postretirement plans. Of the benefits expected to be paid in 2012, the $9 million of pension benefits is expected to be funded from the trusts established for the nonqualified plans and the $3 million of other postretirement benefits is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

Defined Contribution Plans

Devon maintains several defined contribution plans covering its employees in the U.S. and Canada. Such plans include Devon's 401(k) plan, enhanced contribution plan and Canadian pension and savings plan. Contributions are primarily based upon percentages of annual compensation and years of service. In addition, each plan is subject to regulatory limitations by each respective government. The following table presents Devon's expense related to these defined contribution plans.

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
401(k) and enhanced contribution plans	$33	$32	$34
Canadian pension and savings plans	21	17	15
Total	$54	$49	$49

17. Stockholders' Equity

The authorized capital stock of Devon consists of 1 billion shares of common stock, par value $0.10 per share, and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

Devon's Board of Directors has designated 2.9 million shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock"). At December 31, 2011, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $1.00 or 100 times the aggregate per share amount of all dividends (other than stock dividends) declared on common stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 100 votes per share on all matters submitted to a vote of the stockholders. Devon, at its option, may redeem shares of the Series A Junior Participating Preferred Stock in whole at any time and in part from time to time, at a redemption price equal to 100 times the current per share market price of Devon's common stock on the date of the mailing of the notice of redemption. The Series A Junior Preferred Stock ranks prior to the common stock but junior to all other classes of Preferred Stock.

Stock Repurchases

During 2010, Devon's Board of Directors announced a share repurchase program that authorized the repurchase of up to $3.5 billion of its common shares. Devon completed the repurchase program in the fourth quarter of 2011. In total, Devon repurchased 49.2 million shares for $3.5 billion, or $71.18 per share. The following table summarizes Devon's repurchases under the 2010 program by year (amounts and shares in millions).

	2011			2010		
	Amount	**Shares**	**Per Share**	**Amount**	**Shares**	**Per Share**
Repurchases	$2,299	30.9	$74.49	$1,201	18.3	$65.58

Dividends

Devon paid common stock dividends of $278 million (or $0.67 per share), $281 million (or $0.64 per share) and $284 million (or $0.64 per share) in 2011, 2010 and 2009 respectively. In the second quarter of 2011, Devon increased its dividend rate from $0.16 per share to $0.17 per share.

18. Commitments and Contingencies

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

Royalty Matters

Numerous natural gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates, which resulted in underpayment of royalties in connection with natural gas and NGLs produced and sold from federal and Indian owned or controlled lands. Devon does not currently believe that it is subject to material exposure with respect to such royalty matters.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act and similar state statutes. In response to liabilities associated with these activities, loss accruals primarily consist of estimated uninsured costs associated with remediation. Devon's monetary exposure for environmental matters is not expected to be material.

Chief Redemption Matters

In 2006, Devon acquired Chief Holdings LLC ("Chief") from the owners of Chief, including Trevor Rees-Jones, the majority owner of Chief. In 2008, a former owner of Chief filed a petition against Rees-Jones, as the former majority owner of Chief, and Devon, as Chief's successor pursuant to the 2006 acquisition. The petition claimed, among other things, violations of the Texas Securities Act, fraud and breaches of Rees-Jones' fiduciary responsibility to the former owner in connection with Chief's 2004 redemption of the owner's minority ownership stake in Chief.

On June 20, 2011, a court issued a judgment against Rees-Jones for $196 million, of which $133 million of the judgment was also issued against Devon. Both Rees-Jones and Devon are appealing the judgment. However, if the appeal is unsuccessful, Devon can and will seek full payment of the judgment and any related interest, costs and expenses from Rees-Jones pursuant to an existing indemnification agreement between Rees-Jones, certain other parties and Devon. Devon does not expect to have any net exposure as a result of the judgment. However, because Devon does not have a legal right of set off with respect to the judgment, Devon has recorded in its December 31, 2011, balance sheet both a $133 million liability relating to the judgment with an offsetting $133 million receivable relating to its right to be indemnified by Rees-Jones and certain other parties pursuant to the indemnification agreement.

Other Matters

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

Commitments

The following is a schedule by year of Devon's commitments that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2011.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases
		(In millions)		
2012	$ 900	$ 919	$ 306	$ 63
2013	905	456	302	56
2014	905	100	283	47
2015	905	—	250	44
2016	924	—	209	43
Thereafter	3,915	—	786	220
Total	$8,454	$1,475	$2,136	$473

Devon has certain purchase obligations related to its heavy oil projects in Canada to purchase condensate at market prices. Devon entered into these agreements because the condensate is an integral part of the heavy oil production process and any disruption in Devon's ability to obtain condensate could negatively affect its ability to produce and transport heavy oil at these locations. Devon's total obligation related to condensate purchases expires in 2021. The value of these purchase obligations presented in the table above is based on the contractual volumes and Devon's internal estimate of future condensate market prices.

Devon has certain drilling and facility obligations under contractual agreements with third-party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction.

Devon has certain operational agreements whereby Devon has committed to transport or process certain volumes of oil, gas and NGLs for a fixed fee. Devon has entered into these agreements to aid the movement of its production to market.

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense included in general and administrative expenses under operating leases, net of sub-lease income, was $42 million, $57 million and $56 million in 2011, 2010 and 2009, respectively.

19. Fair Value Measurements

The following tables provide carrying value and fair value measurement information for Devon's financial assets and liabilities. The carrying values of cash, accounts receivable, other current receivables, accounts payable, other payables and accrued expenses included in the accompanying balance sheets approximated fair value at December 31, 2011 and December 31, 2010. These assets and liabilities are not presented in the following table. Additionally, information regarding the fair values of Devon's pension plan assets is provided in Note 16.

	Carrying Amount	Total Fair Value	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2011 assets (liabilities):					
Cash equivalents	$ 5,123	$ 5,123	$1,369	$ 3,754	$ —
Short-term investments	$ 1,503	$ 1,503	$ 490	$ 1,013	$ —
Long-term investments	$ 84	$ 84	$ —	$ —	$ 84
Commodity derivatives	$ 628	$ 628	$ —	$ 628	$ —
Commodity derivatives	$ (82)	$ (82)	$ —	$ (82)	$ —
Interest rate derivatives	$ 52	$ 52	$ —	$ 52	$ —
Debt	$(9,780)	$(11,380)	$ —	$(11,295)	$(85)

	Carrying Amount	Total Fair Value	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2010 assets (liabilities):					
Cash equivalents	$ 2,335	$ 2,335	$2,335	$ —	$ —
Short-term investments	$ 145	$ 145	$ 145	$ —	$ —
Long-term investments	$ 94	$ 94	$ —	$ —	$ 94
Commodity derivatives	$ 249	$ 249	$ —	$ 249	$ —
Commodity derivatives	$ (192)	$ (192)	$ —	$ (192)	$ —
Interest rate derivatives	$ 140	$ 140	$ —	$ 140	$ —
Debt	$(5,630)	$(6,629)	$ —	$(6,485)	$(144)

The following methods and assumptions were used to estimate the fair values in the tables above.

Level 1 Fair Value Measurements

Cash equivalents and short-term investments — Amounts consist primarily of U.S. and Canadian Treasury bills and money market investments. The fair value approximates the carrying value.

Level 2 Fair Value Measurements

Cash equivalents and short-term investments — Amounts consist primarily of commercial paper investments. The fair value is based upon quotes from brokers, which generally approximate the carrying value.

Commodity and interest rate derivatives — The fair values of commodity and interest rate derivatives are estimated using internal discounted cash flow calculations based upon forward curves and quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the agreements.

Debt — Devon's debt instruments do not actively trade in an established market. The fair values of its fixed-rate debt are estimated based on rates available for debt with similar terms and maturity. The fair value of Devon's variable-rate commercial paper borrowings is the carrying value.

Level 3 Fair Value Measurements

Debt — Devon's Level 3 debt consisted of a non-interest bearing promissory note. Due to the lack of an active market, quoted marked prices for this note were not available. Therefore, Devon used valuation techniques that rely on unobservable inputs to estimate the fair value of its promissory note. The fair value of this debt is estimated using internal discounted cash flow calculations based upon estimated future payment schedules and a 3.125% interest rate. As a result of using these inputs, Devon concluded the estimated fair value of its non-interest bearing promissory note approximated the carrying value as of December 31, 2011 and December 31, 2010.

Long-term investments — Devon's long-term investments presented in the tables above consisted entirely of auction rate securities. Due to auction failures and the lack of an active market for Devon's auction rate securities, quoted market prices for these securities were not available. Therefore, Devon used valuation techniques that rely on unobservable inputs to estimate the fair values of its long-term auction rate securities. These inputs were based on the AAA credit rating of the securities, the probability of full repayment of the securities considering the U.S. government guarantees substantially all of the underlying student loans, the collection of all accrued interest to date and continued receipts of principal at par. As a result of using these inputs, Devon concluded the estimated fair values of its long-term auction rate securities approximated the par values as of December 31, 2011 and December 31, 2010.

Included below is a summary of the changes in Devon's Level 3 fair value measurements.

	Year Ended December 31,	
	2011	**2010**
	(In millions)	
Long-term investments balance at beginning of period	$ 94	$ 115
Redemptions of principal	(10)	(21)
Long-term investments balance at end of period	$ 84	$ 94
Debt balance at beginning of period	$(144)	$ —
Issuance of promissory note	—	(139)
Foreign exchange translation adjustment	1	(9)
Accretion of promissory note	(5)	(3)
Redemptions of principal	63	7
Debt balance at end of period	$ (85)	$(144)

20. Discontinued Operations

For the three-year period ended December 31, 2011, Devon's discontinued operations included amounts related to its assets in Azerbaijan, Brazil, China, Angola and other minor International properties. By the end of 2011, Devon had sold all these assets except for its assets in Angola. Devon has entered into an agreement to sell its Angolan assets. Upon closing, Devon will receive $70 million and the right to future contingent consideration based on achievement of certain objectives.

Revenues related to Devon's discontinued operations totaled $43 million, $693 million and $945 million during 2011, 2010 and 2009, respectively. Earnings from discontinued operations before income taxes totaled $2.6 billion, $2.4 billion and $322 million during 2011, 2010 and 2009, respectively. Earnings before income taxes in 2011 and 2010 were largely impacted by gains on divestiture transactions. The following table presents the gains on the divestitures by year.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	After Tax	Gross	After Tax	Gross	After Tax
			(In millions)			
Brazil	$2,548	$2,548	$ —	$ —	$—	$—
Azerbaijan	—	—	1,543	1,524	—	—
China — Panyu	—	—	308	235	—	—
Other	4	4	(33)	(27)	17	17
Total	$2,552	$2,552	$1,818	$1,732	$17	$17

The following table presents the main classes of assets and liabilities associated with Devon's discontinued operations.

	December 31,	
	2011	2010
	(In millions)	
Cash and cash equivalents	$ —	$424
Other current assets	21	139
Current assets	$ 21	$563
Property and equipment, net	$132	$859
Accounts payable	$ 20	$260
Other current liabilities	28	45
Current liabilities	$ 48	$305
Other long-term liabilities	$ —	$ 26

Reduction of Carrying Value of Oil and Gas Properties

During 2009, Devon reduced the carrying value of its Brazil oil and gas properties by $109 million ($105 million after tax). This reduction resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin that did not have adequate reserves for commercial viability.

21. Segment Information

Devon manages its operations through distinct operating segments, or divisions, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its U.S. divisions into one reporting segment due to the similar nature of the businesses. However, Devon's Canadian division is reported as a separate reporting segment primarily due to the significant differences in the regulatory environment. Devon's segments are all primarily engaged in oil and gas producing activities, and certain information regarding such activities for each segment is included in Note 22. Following is certain financial information regarding Devon's segments. Revenues are all from external customers.

	U.S.	Canada	Total
		(In millions)	
Year Ended December 31, 2011:			
Oil, gas and NGL sales	$ 5,418	$ 2,897	$ 8,315
Oil, gas and NGL derivatives	$ 881	$ —	$ 881
Marketing and midstream revenues	$ 2,059	$ 199	$ 2,258
Interest expense	$ 204	$ 148	$ 352
Depreciation, depletion and amortization	$ 1,439	$ 809	$ 2,248
Earnings from continuing operations before income taxes	$ 3,477	$ 813	$ 4,290
Income tax expense	$ 1,958	$ 198	$ 2,156
Earnings from continuing operations	$ 1,519	$ 615	$ 2,134
Property and equipment, net	$16,989	$ 7,785	$24,774
Total continuing assets(1)	$22,622	$18,342	$40,964
Capital expenditures	$ 6,112	$ 1,708	$ 7,820
Year Ended December 31, 2010:			
Oil, gas and NGL sales	$ 4,742	$ 2,520	$ 7,262
Oil, gas and NGL derivatives	$ 809	$ 2	$ 811
Marketing and midstream revenues	$ 1,742	$ 125	$ 1,867
Interest expense	$ 159	$ 204	$ 363
Depreciation, depletion and amortization	$ 1,229	$ 701	$ 1,930
Earnings from continuing operations before income taxes	$ 2,943	$ 625	$ 3,568
Income tax expense	$ 1,062	$ 173	$ 1,235
Earnings from continuing operations	$ 1,881	$ 452	$ 2,333
Property and equipment, net	$12,379	$ 7,273	$19,652
Total continuing assets (1)	$18,320	$13,185	$31,505
Capital expenditures	$ 5,007	$ 2,107	$ 7,114
Year Ended December 31, 2009:			
Oil, gas and NGL sales	$ 3,958	$ 2,139	$ 6,097
Oil, gas and NGL derivatives	$ 382	$ 2	$ 384
Marketing and midstream revenues	$ 1,498	$ 36	$ 1,534
Interest expense	$ 125	$ 224	$ 349
Depreciation, depletion and amortization	$ 1,498	$ 610	$ 2,108
(Loss) earnings from continuing operations before income taxes	$(4,961)	$ 435	$(4,526)
Income tax (benefit) expense	$(1,894)	$ 121	$(1,773)
(Loss) earnings from continuing operations	$(3,067)	$ 314	$(2,753)
Reduction of carrying value of oil and gas properties	$ 6,408	$ —	$ 6,408
Capital expenditures	$ 3,584	$ 1,099	$ 4,683

(1) Total assets in the table above do not include assets held for sale related to Devon's discontinued operations, which totaled $153 million, $1.4 billion, and $1.9 billion in 2011, 2010 and 2009, respectively.

22. Supplemental Information on Oil and Gas Operations (Unaudited)

Supplemental unaudited information regarding Devon's oil and gas activities is presented in this note. The information is provided separately by country and continent. Additionally, the costs incurred and reserves information for the U.S. is segregated between Devon's onshore and offshore operations. Unless otherwise noted, this supplemental information excludes amounts for all periods presented related to Devon's discontinued operations.

Costs Incurred

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

	Year Ended December 31, 2011				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
			(In millions)		
Property acquisition costs:					
Proved properties	$ 34	$—	$ 34	$ 14	$ 48
Unproved properties	851	—	851	88	939
Exploration costs	272	—	272	266	538
Development costs	4,130	—	4,130	1,288	5,418
Costs incurred	$5,287	$—	$5,287	$1,656	$6,943

	Year Ended December 31, 2010				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
			(In millions)		
Property acquisition costs:					
Proved properties	$ 29	$ —	$ 29	$ 4	$ 33
Unproved properties	592	2	594	590	1,184
Exploration costs	339	89	428	260	688
Development costs	3,126	297	3,423	1,216	4,639
Costs incurred	$4,086	$388	$4,474	$2,070	$6,544

	Year Ended December 31, 2009				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
			(In millions)		
Property acquisition costs:					
Proved properties	$ 17	$ —	$ 17	$ 18	$ 35
Unproved properties	52	11	63	72	135
Exploration costs	122	260	382	152	534
Development costs	2,011	537	2,548	835	3,383
Costs incurred	$2,202	$808	$3,010	$1,077	$4,087

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses that are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $337 million, $311 million and

$332 million in the years 2011, 2010 and 2009, respectively. Also, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $45 million, $37 million and $74 million in the years 2011, 2010 and 2009, respectively.

Capitalized Costs

The following tables reflect the aggregate capitalized costs related to oil and gas activities.

	December 31, 2011		
	U.S.	Canada	North America
		(In millions)	
Proved properties	$ 41,397	$ 20,299	$ 61,696
Unproved properties	2,347	1,635	3,982
Total oil & gas properties	43,744	21,934	65,678
Accumulated DD&A	(29,742)	(14,585)	(44,327)
Net capitalized costs	$ 14,002	$ 7,349	$ 21,351

	December 31, 2010		
	U.S.	Canada	North America
		(In millions)	
Proved properties	$ 36,301	$ 19,711	$ 56,012
Unproved properties	2,156	1,278	3,434
Total oil & gas properties	38,457	20,989	59,446
Accumulated DD&A	(28,546)	(14,130)	(42,676)
Net capitalized costs	$ 9,911	$ 6,859	$ 16,770

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2011.

	Costs Incurred In				
	2011	2010	2009	Prior to 2009	Total
			(In millions)		
Acquisition costs	$ 894	$1,101	$112	$1,037	$3,144
Exploration costs	234	81	6	11	332
Development costs	359	72	1	9	441
Capitalized interest	43	22	—	—	65
Total oil and gas properties not subject to amortization	$1,530	$1,276	$119	$1,057	$3,982

Results of Operations

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

	Year Ended December 31, 2011		
	U.S.	Canada	North America
		(In millions)	
Oil, gas and NGL sales	$ 5,418	$2,897	$ 8,315
Lease operating expenses	(925)	(926)	(1,851)
Depreciation, depletion and amortization	(1,201)	(786)	(1,987)
General and administrative expenses	(132)	(119)	(251)
Taxes other than income taxes	(357)	(45)	(402)
Accretion of asset retirement obligations	(34)	(57)	(91)
Income tax expense	(1,005)	(250)	(1,255)
Results of operations	$ 1,764	$ 714	$ 2,478
Depreciation, depletion and amortization per Boe	$ 6.94	$11.74	$ 8.28

	Year Ended December 31, 2010		
	U.S.	Canada	North America
		(In millions)	
Oil, gas and NGL sales	$4,742	$2,520	$ 7,262
Lease operating expenses	(892)	(797)	(1,689)
Depreciation, depletion and amortization	(998)	(677)	(1,675)
General and administrative expenses	(133)	(83)	(216)
Taxes other than income taxes	(319)	(40)	(359)
Accretion of asset retirement obligations	(42)	(50)	(92)
Income tax expense	(849)	(246)	(1,095)
Results of operations	$1,509	$ 627	$ 2,136
Depreciation, depletion and amortization per Boe	$ 6.11	$10.51	$ 7.36

	Year Ended December 31, 2009		
	U.S.	Canada	North America
		(In millions)	
Oil, gas and NGL sales	$ 3,958	$2,139	$ 6,097
Lease operating expenses	(997)	(673)	(1,670)
Depreciation, depletion and amortization	(1,247)	(585)	(1,832)
General and administrative expenses	(145)	(74)	(219)
Taxes other than income taxes	(258)	(35)	(293)
Reduction of carrying value of oil and gas properties	(6,408)	—	(6,408)
Accretion of asset retirement obligations	(53)	(38)	(91)
Income tax benefit	1,800	(210)	1,580
Results of operations	$(3,350)	$ 524	$(2,836)
Depreciation, depletion and amortization per Boe	$ 7.47	$ 8.84	$ 7.86

Proved Reserves

The following tables present Devon's estimated proved reserves by product for each significant country.

	Oil (MMBbls)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2008	133	34	167	134	301
Revisions due to prices	9	2	11	291	302
Revisions other than price	—	1	1	(8)	(7)
Extensions and discoveries	9	2	11	122	133
Production	(12)	(5)	(17)	(25)	(42)
Sale of reserves	—	(1)	(1)	—	(1)
December 31, 2009	139	33	172	514	686
Revisions due to prices	4	1	5	(24)	(19)
Revisions other than price	2	2	4	9	13
Extensions and discoveries	19	1	20	59	79
Production	(14)	(2)	(16)	(25)	(41)
Sale of reserves	(2)	(35)	(37)	—	(37)
December 31, 2010	148	—	148	533	681
Revisions due to prices	2	—	2	(15)	(13)
Revisions other than price	(1)	—	(1)	11	10
Extensions and discoveries	36	—	36	36	72
Production	(17)	—	(17)	(28)	(45)
December 31, 2011	168	—	168	537	705
Proved developed reserves as of:					
December 31, 2008	111	22	133	110	243
December 31, 2009	119	21	140	149	289
December 31, 2010	131	—	131	126	257
December 31, 2011	146	—	146	163	309
Proved developed-producing reserves as of:					
December 31, 2008	103	9	112	91	203
December 31, 2009	112	12	124	137	261
December 31, 2010	123	—	123	116	239
December 31, 2011	139	—	139	155	294
Proved undeveloped reserves as of:					
December 31, 2008	22	12	34	24	58
December 31, 2009	20	12	32	365	397
December 31, 2010	17	—	17	407	424
December 31, 2011	22	—	22	374	396

	Gas (Bcf)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2008	7,979	390	8,369	1,510	9,879
Revisions due to prices	(661)	(4)	(665)	(29)	(694)
Revisions other than price	119	(62)	57	(14)	43
Extensions and discoveries	1,387	64	1,451	67	1,518
Purchase of reserves	1	—	1	6	7
Production	(698)	(45)	(743)	(223)	(966)
Sale of reserves	—	(1)	(1)	(29)	(30)
December 31, 2009	8,127	342	8,469	1,288	9,757
Revisions due to prices	449	2	451	21	472
Revisions other than price	105	(26)	79	(17)	62
Extensions and discoveries	1,088	7	1,095	131	1,226
Purchase of reserves	12	—	12	9	21
Production	(699)	(17)	(716)	(214)	(930)
Sale of reserves	(17)	(308)	(325)	—	(325)
December 31, 2010	9,065	—	9,065	1,218	10,283
Revisions due to prices	(1)	—	(1)	(60)	(61)
Revisions other than price	(243)	—	(243)	(38)	(281)
Extensions and discoveries	1,410	—	1,410	58	1,468
Purchase of reserves	16	—	16	20	36
Production	(740)	—	(740)	(213)	(953)
Sale of reserves	—	—	—	(6)	(6)
December 31, 2011	9,507	—	9,507	979	10,486
Proved developed reserves as of:					
December 31, 2008	6,469	212	6,681	1,357	8,038
December 31, 2009	6,447	185	6,632	1,213	7,845
December 31, 2010	7,280	—	7,280	1,144	8,424
December 31, 2011	7,957	—	7,957	951	8,908
Proved developed-producing reserves as of:					
December 31, 2008	5,787	64	5,851	1,194	7,045
December 31, 2009	5,860	137	5,997	1,075	7,072
December 31, 2010	6,702	—	6,702	1,031	7,733
December 31, 2011	7,409	—	7,409	862	8,271
Proved undeveloped reserves as of:					
December 31, 2008	1,510	178	1,688	153	1,841
December 31, 2009	1,680	157	1,837	75	1,912
December 31, 2010	1,785	—	1,785	74	1,859
December 31, 2011	1,550	—	1,550	28	1,578

	Natural Gas Liquids (MMBbls)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2008	315	2	317	35	352
Revisions due to prices	(11)	—	(11)	2	(9)
Revisions other than price	36	1	37	—	37
Extensions and discoveries	70	—	70	1	71
Production	(25)	(1)	(26)	(4)	(30)
December 31, 2009	385	2	387	34	421
Revisions due to prices	14	—	14	(1)	13
Revisions other than price	13	3	16	(1)	15
Extensions and discoveries	68	—	68	2	70
Production	(28)	—	(28)	(4)	(32)
Sale of reserves	(3)	(5)	(8)	—	(8)
December 31, 2010	449	—	449	30	479
Revisions due to prices	4	—	4	(1)	3
Revisions other than price	1	—	1	—	1
Extensions and discoveries	102	—	102	2	104
Purchase of reserves	2	—	2	—	2
Production	(33)	—	(33)	(4)	(37)
December 31, 2011	525	—	525	27	552
Proved developed reserves as of:					
December 31, 2008	260	1	261	31	292
December 31, 2009	293	1	294	32	326
December 31, 2010	353	—	353	28	381
December 31, 2011	402	—	402	26	428
Proved developed-producing reserves as of:					
December 31, 2008	230	—	230	29	259
December 31, 2009	265	1	266	28	294
December 31, 2010	318	—	318	26	344
December 31, 2011	372	—	372	24	396
Proved undeveloped reserves as of:					
December 31, 2008	55	1	56	4	60
December 31, 2009	92	1	93	2	95
December 31, 2010	96	—	96	2	98
December 31, 2011	123	—	123	1	124

	Total (MMBoe)(1)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2008	1,777	101	1,878	421	2,299
Revisions due to prices	(113)	1	(112)	289	177
Revisions other than price	57	(8)	49	(11)	38
Extensions and discoveries	311	12	323	135	458
Purchase of reserves	—	—	—	1	1
Production	(154)	(13)	(167)	(66)	(233)
Sale of reserves	—	(1)	(1)	(6)	(7)
December 31, 2009	1,878	92	1,970	763	2,733
Revisions due to prices	92	1	93	(21)	72
Revisions other than price	32	1	33	5	38
Extensions and discoveries	269	2	271	83	354
Purchase of reserves	2	—	2	2	4
Production	(158)	(5)	(163)	(65)	(228)
Sale of reserves	(8)	(91)	(99)	(1)	(100)
December 31, 2010	2,107	—	2,107	766	2,873
Revisions due to prices	6	—	6	(27)	(21)
Revisions other than price	(41)	—	(41)	6	(35)
Extensions and discoveries	374	—	374	47	421
Purchase of reserves	5	—	5	3	8
Production	(173)	—	(173)	(67)	(240)
Sale of reserves	—	—	—	(1)	(1)
December 31, 2011	2,278	—	2,278	727	3,005
Proved developed reserves as of:					
December 31, 2008	1,449	59	1,508	367	1,875
December 31, 2009	1,486	53	1,539	383	1,922
December 31, 2010	1,696	—	1,696	346	2,042
December 31, 2011	1,875	—	1,875	348	2,223
Proved developed-producing reserves as of:					
December 31, 2008	1,298	20	1,318	319	1,637
December 31, 2009	1,354	35	1,389	344	1,733
December 31, 2010	1,557	—	1,557	314	1,871
December 31, 2011	1,746	—	1,746	323	2,069
Proved undeveloped reserves as of:					
December 31, 2008	328	42	370	54	424
December 31, 2009	392	39	431	380	811
December 31, 2010	411	—	411	420	831
December 31, 2011	403	—	403	379	782

(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 2011 (in MMBoe).

	U.S. Onshore	Canada	North America
Proved undeveloped reserves as of December 31, 2010	411	420	831
Extensions and discoveries	118	30	148
Revisions due to prices	(2)	(14)	(16)
Revisions other than price	(56)	5	(51)
Conversion to proved developed reserves	(68)	(62)	(130)
Proved undeveloped reserves as of December 31, 2011	403	379	782

At December 31, 2011, Devon had 782 MMBoe of proved undeveloped reserves. This represents a 6% decrease as compared to 2010 and represents 26% of its total proved reserves. Drilling activities increased Devon's proved undeveloped reserves 148 MMBoe and resulted in the conversion of 130 MMBoe, or 16%, of the 2010 proved undeveloped reserves to proved developed reserves. Additionally, revisions other than price decreased Devon's proved undeveloped reserves 51 MMBoe primarily due to its evaluation of certain U.S. onshore dry-gas areas, which it does not expect to develop in the next five years. The largest revisions relate to the dry-gas areas at Carthage in east Texas and the Barnett Shale in north Texas.

A significant amount of Devon's proved undeveloped reserves at the end of 2011 largely related to its Jackfish operations. At December 31, 2011 and 2010, Devon's Jackfish proved undeveloped reserves were 367 MMBoe and 396 MMBoe, respectively. Development schedules for the Jackfish reserves are primarily controlled by the need to keep the processing plants at their 35,000 barrel daily facility capacity. 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 are classified as proved undeveloped for more than five years. Currently, the development schedule for these reserves extends though the year 2025.

Price Revisions

2011—Reserves decreased 21 MMBoe due to lower gas prices and higher oil prices. The higher oil prices increased Devon's Canadian royalty burden, which reduced Devon's oil reserves.

2010—Reserves increased 72 MMBoe due to higher gas prices, partially offset by the effect of higher oil prices. The higher oil prices increased Devon's Canadian royalty burden, which reduced Devon's oil reserves. Of the 72 MMBoe price revisions, 43 MMBoe related to the Barnett Shale and 22 MMBoe related to the Rocky Mountain area.

2009—Reserves increased 177 MMBoe due to higher oil prices, partially offset by lower gas prices. The increase in oil reserves primarily related to Devon's Jackfish thermal heavy oil reserves in Canada. At the end of 2008, 331 MMBoe of reserves related to Jackfish were not considered proved. However, due to higher prices, these reserves were considered proved as of December 31, 2009. Significantly lower gas prices caused Devon's reserves to decrease 116 MMBoe, which primarily related to its U.S. reserves.

Revisions Other Than Price

Total revisions other than price for 2011 primarily related to Devon's evaluation of certain dry gas regions noted in the proved undeveloped reserves discussion above. Total revisions other than price for 2010 and 2009 primarily related to Devon's drilling and development in the Barnett Shale.

Extensions and Discoveries

2011 — Of the 421 MMBoe of 2011 extensions and discoveries, 162 MMBoe related to the Cana-Woodford Shale in western Oklahoma, 115 MMBoe related to the Barnett Shale, 39 MMBoe related to the Permian Basin, 30 MMBoe related to Jackfish, 19 MMBoe related to the Rocky Mountain area and 17 MMBoe related to the Granite Wash area in the Texas panhandle and western Oklahoma.

The 2011 extensions and discoveries included 168 MMBoe related to additions from Devon's infill drilling activities, including 80 MMBoe at the Cana-Woodford Shale and 77 MMBoe at the Barnett Shale.

2010 — Of the 354 MMBoe of 2010 extensions and discoveries, 101 MMBoe related to the Cana-Woodford Shale, 87 MMBoe related to the Barnett Shale, 55 MMBoe related to Jackfish, 19 MMBoe related to the Permian Basin, 15 MMBoe related to the Rocky Mountain area and 14 MMBoe related to the Carthage area.

The 2010 extensions and discoveries included 107 MMBoe related to additions from Devon's infill drilling activities, including 43 MMBoe at the Barnett Shale and 47 MMBoe at the Cana-Woodford Shale.

2009 — Of the 458 MMBoe of 2009 extensions and discoveries, 204 MMBoe related to the Barnett Shale, 118 MMBoe related to Jackfish, 49 MMBoe related to the Cana-Woodford Shale, 14 MMBoe related to the Rocky Mountain area, 11 MMBoe related to Deepwater Production in the Gulf, 8 MMBoe related to the Carthage area and 7 MMBoe related to the Haynesville Shale area in east Texas.

The 2009 extensions and discoveries included 371 MMBoe related to additions from Devon's infill drilling activities, including 203 MMBoe at the Barnett Shale, 118 MMBoe at Jackfish and 24 MMBoe at the Cana-Woodford Shale.

Sale of Reserves

The 2010 total primarily relates to the divestiture of Devon's Gulf of Mexico properties.

SEC's Modernization of Oil and Gas Reporting

At the end of 2009, Devon adopted the SEC's *Modernization of Oil and Gas Reporting*, as well as the conforming rule changes issued by the Financial Accounting Standards Board. Upon adoption, the two primary rule changes that impacted Devon's year-end reserves estimates were those related to assumptions for pricing and reasonable certainty.

The SEC's prior rules required proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. The revised rules require reserves estimates to be calculated using an average of the first-day-of-the-month price for the preceding 12-month period.

The revised rules amend the definition of proved reserves to permit the use of reliable technologies to establish the reasonable certainty of proved reserves. This revision includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations. This revision also allows proved reserves to be claimed beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty based on reliable technologies. As a result of adopting these provisions of the new rules, Devon's 2009 reserves increased approximately 65 MMBoe, or 2%. This increase is included in the 2009 extensions and discoveries total.

Standardized Measure

The tables below reflect Devon's standardized measure of discounted future net cash flows from its proved reserves.

	Year Ended December 31, 2011		
	U.S.	Canada	North America
		(In millions)	
Future cash inflows	$ 69,305	$ 36,786	$106,091
Future costs:			
Development	(6,817)	(4,678)	(11,495)
Production	(26,217)	(15,063)	(41,280)
Future income tax expense	(11,432)	(3,763)	(15,195)
Future net cash flows	24,839	13,282	38,121
10% discount to reflect timing of cash flows	(13,492)	(6,785)	(20,277)
Standardized measure of discounted future net cash flows	$ 11,347	$ 6,497	$ 17,844

	Year Ended December 31, 2010		
	U.S.	Canada	North America
		(In millions)	
Future cash inflows	$ 58,093	$ 35,948	$ 94,041
Future costs:			
Development	(6,220)	(4,526)	(10,746)
Production	(24,223)	(12,249)	(36,472)
Future income tax expense	(8,643)	(4,209)	(12,852)
Future net cash flows	19,007	14,964	33,971
10% discount to reflect timing of cash flows	(10,164)	(7,455)	(17,619)
Standardized measure of discounted future net cash flows	$ 8,843	$ 7,509	$ 16,352

	Year Ended December 31, 2009		
	U.S.	Canada	North America
		(In millions)	
Future cash inflows	$ 44,571	$28,442	$ 73,013
Future costs:			
Development	(6,814)	(4,132)	(10,946)
Production	(22,184)	(9,847)	(32,031)
Future income tax expense	(3,572)	(3,408)	(6,980)
Future net cash flows	12,001	11,055	23,056
10% discount to reflect timing of cash flows	(6,121)	(5,532)	(11,653)
Standardized measure of discounted future net cash flows	$ 5,880	$ 5,523	$ 11,403

Future cash inflows, development costs and production costs were computed using the same assumptions for prices and costs that were used to estimate Devon's proved oil and gas reserves at the end of each year. For 2011, the prices averaged $67.31 per barrel of oil, $3.51 per Mcf of gas and $39.28 per barrel of natural gas liquids. Of the $11.5 billion of future development costs as of the end of 2011, $1.6 billion, $1.4 billion and $1.1 billion are estimated to be spent in 2012, 2013 and 2014, respectively.

Future development costs include not only development costs, but also future asset retirement costs. Included as part of the $11.5 billion of future development costs are $2.2 billion of future asset retirement costs. Future production costs include general and administrative expenses directly related to oil and gas producing activities. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits but do not reflect the impact of future operations.

The principal changes in Devon's standardized measure of discounted future net cash flows are as follows:

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Beginning balance	$16,352	$11,403	$ 9,393
Oil, gas and NGL sales, net of production costs	(5,794)	(4,982)	(3,915)
Net changes in prices and production costs	1,875	7,423	(1,672)
Extensions and discoveries, net of future development costs	3,714	3,048	2,378
Purchase of reserves, net of future development costs	57	23	6
Development costs incurred that reduced future development costs	1,302	1,559	1,012
Revisions of quantity estimates	(668)	287	4,051
Sales of reserves in place	(2)	(815)	(37)
Accretion of discount	2,248	1,487	1,281
Net change in income taxes	(929)	(2,663)	(51)
Other, primarily changes in timing and foreign exchange rates	(311)	(418)	(1,043)
Ending balance	$17,844	$16,352	$11,403

The following table presents Devon's estimated pretax cash flow information related to its proved reserves.

	Year Ended December 31, 2011		
	U.S.	Canada	North America
		(In millions)	
Pre-Tax Future Net Revenue(1)			
Proved Developed Reserves	$30,473	$ 7,757	$38,230
Proved Undeveloped Reserves	5,798	9,288	15,086
Total Proved Reserves	$36,271	$17,045	$53,316
Pre-Tax 10% Present Value(1)			
Proved Developed Reserves	$15,165	$ 5,830	$20,995
Proved Undeveloped Reserves	1,404	2,508	3,912
Total Proved Reserves	$16,569	$ 8,338	$24,907

(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.

The present value of after-tax future net revenues discounted at 10% per annum ("standardized measure") was $17.8 billion at the end of 2011. Included as part of standardized measure were discounted future income taxes of $7.1 billion. Excluding these taxes, the present value of our pre-tax future net revenue ("pre-tax 10% present value") was $24.9 billion. Devon believes 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.

23. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of Devon's unaudited interim results of operations.

	2011				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Revenues	$2,147	$3,220	$3,502	$2,585	$11,454
Earnings from continuing operations before income taxes	$ 580	$1,378	$1,538	$ 794	$ 4,290
Earnings from continuing operations	$ 389	$ 184	$1,040	$ 521	$ 2,134
Earnings (loss) from discontinued operations	27	2,559	(2)	(14)	2,570
Net earnings	$ 416	$2,743	$1,038	$ 507	$ 4,704
Basic net earnings per common share:					
Earnings from continuing operations	$ 0.91	$ 0.44	$ 2.51	$ 1.29	$ 5.12
Earnings (loss) from discontinued operations	0.06	6.06	—	(0.04)	6.17
Net earnings	$ 0.97	$ 6.50	$ 2.51	$ 1.25	$ 11.29
Diluted net earnings per common share:					
Earnings from continuing operations	$ 0.91	$ 0.43	$ 2.50	$ 1.29	$ 5.10
Earnings (loss) from discontinued operations	0.06	6.05	—	(0.04)	6.15
Net earnings	$ 0.97	$ 6.48	$ 2.50	$ 1.25	$ 11.25

	2010				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Revenues	$3,220	$2,232	$2,353	$2,135	$9,940
(Loss) earnings from continuing operations before income taxes	$1,588	$ 613	$ 699	$ 668	$3,568
(Loss) earnings from continuing operations	$1,074	$ 352	$ 429	$ 478	$2,333
(Loss) earnings from discontinued operations	118	354	1,661	84	2,217
Net (loss) earnings	$1,192	$ 706	$2,090	$ 562	$4,550
Basic net (loss) earnings per common share:					
(Loss) earnings from continuing operations	$ 2.40	$ 0.79	$ 0.99	$ 1.10	$ 5.31
(Loss) earnings from discontinued operations	0.27	0.80	3.82	0.20	5.04
Net (loss) earnings	$ 2.67	$ 1.59	$ 4.81	$ 1.30	$10.35
Diluted net (loss) earnings per common share:					
(Loss) earnings from continuing operations	$ 2.39	$ 0.79	$ 0.98	$ 1.10	$ 5.29
(Loss) earnings from discontinued operations	0.27	0.79	3.81	0.19	5.02
Net (loss) earnings	$ 2.66	$ 1.58	$ 4.79	$ 1.29	$10.31

Earnings (Loss) from Continuing Operations

The second quarter of 2011 includes deferred income taxes of $725 million (or $1.71 per diluted share) related to assumed repatriations of foreign earnings that were no longer deemed to be permanently reinvested in accordance with accounting principles generally accepted in the U.S.

Earnings (Loss) from Discontinued Operations

The second quarter of 2011 includes the divestiture of our Brazil operations and the related gain was $2.5 billion ($2.5 billion after income taxes, or $6.01 per diluted share).

The second quarter of 2010 includes the divestiture of our Panyu operations in China and the related gain was $308 million ($235 million after income taxes, or $0.52 per diluted share).

The third quarter of 2010 includes the divestiture of our Azerbaijan operations and the related gain was $1.5 billion ($1.5 billion after income taxes, or $3.49 per diluted share).

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

Not Applicable.

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

Disclosure Controls and Procedures

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

Based on their evaluation, Devon's principal executive and principal financial officers have concluded that Devon's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2011 to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Management's Annual Report on Internal Control Over Financial Reporting

Devon's management is responsible for establishing and maintaining adequate internal control over financial reporting for Devon, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Devon's management, including our principal executive and principal financial officers, Devon conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework, which was completed on February 21, 2012, management concluded that its internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of Devon's internal control over financial reporting as of December 31, 2011 has been audited by KPMG LLP, an independent registered public accounting firm who audited Devon's consolidated financial statements as of and for the year ended December 31, 2011, as stated in their report, which is included under "Item 8. Financial Statements and Supplementary Data" in this report.

Changes in Internal Control Over Financial Reporting

There was no change in Devon's internal control over financial reporting during the fourth quarter of 2011 that has materially affected, or is reasonably likely to materially affect, Devon's internal control over financial reporting.

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

Not Applicable.

PART III

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2012.

Item 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2012.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2012.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2012.

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

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2012.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

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

1. Consolidated Financial Statements

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

2. Consolidated Financial Statement Schedules

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

3. Exhibits

Exhibit No.	Description
1.1	Underwriting Agreement, dated as of January 6, 2009, among Devon Energy Corporation and Banc of America Securities LLC, J.P. Morgan Securities Inc. and UBS Securities LLC, as representatives of the several Underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant's Form 8-K filed on January 9, 2009).
1.2	Underwriting Agreement, dated as of July 5, 2011, among Devon Energy Corporation, Goldman, Sachs & Co., Morgan Stanley & Co. LLC and UBS Securities LLC, as representatives of the several Underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant's Form 8-K filed on July 7, 2011).
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Registrant, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Registrant's Amendment No. 1 to Form S-4 Registration No. 333-103679, filed March 20, 2003).
2.2	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Registrant, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant's Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
2.3	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 (incorporated by reference to Registrant's and Devon Acquisition Corporation's Schedule 14D-1F filing, filed September 6, 2001).
2.4	Pre-Acquisition Agreement, dated as of August 31, 2001, between Registrant and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001).
2.5	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 12, 2000).
2.6	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant's Form S-4, File No. 333-82903).
3.1	Registrant's Amended and Restated Certificate of Incorporation (incorporated by reference to Appendix A to Registrant's Proxy Statement for the 2011 Annual Meeting of Stockholders filed on April 27, 2011).

Exhibit No.	Description
3.2	Registrant's Bylaws (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K filed on June 9, 2011).
4.1	Indenture, dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 2.40% Senior Notes due 2016, the 4.00% Senior Notes due 2021 and the 5.60% Senior Notes due 2041 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on July 12, 2011).
4.2	Supplemental Indenture No. 1, dated as of July 12, 2011, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 2.40% Senior Notes due 2016, the 4.00% Senior Notes due 2021 and the 5.60% Senior Notes due 2041 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on July 12, 2011).
4.3	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to senior debt securities issuable by Registrant (the "Senior Indenture") (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002).
4.4	Supplemental Indenture No. 1, dated as of March 25, 2002, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on April 9, 2002).
4.5	Supplemental Indenture No. 3, dated as of January 9, 2009, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 5.625% Senior Notes due 2014 and the 6.30% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on January 9, 2009).
4.6	Indenture dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. as Issuer, Registrant as Guarantor, and The Bank of New York Mellon Trust Company, N.A., originally The Chase Manhattan Bank, as Trustee, relating to the 6.875% Senior Notes due 2011 and the 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
4.7	Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058)).
4.8	First Supplemental Indenture, dated March 30, 1999 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc.'s Form 10-Q for the period ended March 31, 1999).
4.9	Second Supplemental Indenture, dated as of May 9, 2001 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.10	Third Supplemental Indenture, dated January 23, 2006 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.23 of Registrant's Form 10-K for the year ended December 31, 2005).

Exhibit No.	Description
4.11	Senior Indenture dated September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.4 to Ocean Energy's Annual Report on Form 10-K for the year ended December 31, 1997)).
4.12	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes Due 2027 (incorporated by reference to Exhibit 4.10 to Ocean Energy's Form 10-Q for the period ended March 31, 1999).
4.13	Second Supplemental Indenture, dated as of May 9, 2001 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes Due 2027 (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.14	Third Supplemental Indenture, dated December 31, 2005 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes Due 2027 (incorporated by reference to Exhibit 4.27 of Registrant's Form 10-K for the year ended December 31, 2005).
10.1	Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Registrant, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (incorporated by reference to Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
10.2	First Amendment to Credit Agreement dated as of December 19, 2007, among Registrant as Borrower, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-K filed February 27, 2009).
10.3	Amended and Restated Credit Agreement dated March 24, 2006, effective as of April 7, 2006, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as Canadian Borrowers, Bank of America, N.A. as Administrative Agent, Swing Line Lender and L/C Issuer; JPMorgan Chase Bank, N.A. as Syndication Agent, Bank of Montreal D/B/A "Harris Nesbitt", Royal Bank of Canada, Wachovia Bank, National Association as Co-Documentation Agents and The Other Lenders Party Hereto, Banc of America Securities L.L.C. and J.P. Morgan Securities Inc., as Joint Lead Arrangers and Book Managers for the $2.0 billion five-year revolving credit facility (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed on May 4, 2006).
10.4	First Amendment to Amended and Restated Credit Agreement dated as of June 1, 2006, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party to this Amendment. (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-Q filed on November 7, 2007).
10.5	Second Amendment to Amended and Restated Credit Agreement dated as of September 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party to this Amendment. (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed on November 7, 2007).

Exhibit No.	Description
10.6	Third Amendment to Amended and Restated Credit Agreement dated as of December 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto (incorporated by reference to Exhibit 10.7 to Registrant's Form 10-K filed February 27, 2009).
10.7	Fourth Amendment to Amended and Restated Credit Agreement dated as of April 7, 2008, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of Registrant's Form 10-Q filed on May 7, 2008).
10.8	Fifth Amendment to Amended and Restated Credit Agreement dated as of November 5, 2008, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.2 of Registrant's Form 10-Q filed on November 6, 2008).
10.9	Devon Energy Corporation 2009 Long-Term Incentive Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-159796, filed June 5, 2009).*
10.10	Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-127630, filed August 17, 2005).*
10.11	First Amendment to Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Appendix A to Registrant's Proxy Statement for the 2006 Annual Meeting of Stockholders filed on April 28, 2006).*
10.12	Devon Energy Corporation 2003 Long-Term Incentive Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-104922, filed May 1, 2003).*
10.13	Devon Energy Corporation 1997 Stock Option Plan (as amended August 29, 2000) (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*
10.14	Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective November 11, 2008).*
10.15	Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012).*
10.16	Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012).*
10.17	Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012).*
10.18	Devon Energy Corporation Supplemental Executive Retirement Plan (amended and restated effective January 1, 2012).*
10.19	Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012).*
10.20	Devon Energy Corporation Incentive Savings Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-179181, filed January 26, 2012).*

Exhibit No.	Description
10.21	Form of Amendment No. 1 to the Amended and Restated Employment Agreement, incorporated by reference to Exhibit 10.19 to Registrant's Form 10-K filed February 27, 2009, between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt dated April 19, 2011. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed April 25, 2011).*
10.22	Amended and Restated Form of Employment Agreement between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt dated December 15, 2008 (incorporated by reference to Exhibit 10.19 to Registrant's Form 10-K filed February 27, 2009).*
10.23	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for performance based restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on December 7, 2011).*
10.24	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for performance based restricted share units awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on December 7, 2011).*
10.25	Form of Incentive Stock Option Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for incentive stock options granted (incorporated by reference to Exhibit 10.15 to Registrant's Form 10-K filed on February 25, 2011).*
10.26	Form of Employee Nonqualified Stock Option Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for nonqualified stock options granted (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K filed on February 25, 2011).*
10.27	Form of Non-Management Director Nonqualified Stock Option Award Agreement under the Devon Energy Corporation 2009 Long-Term Incentive Plan between Registrant and all Non-Management Directors for nonqualified stock options granted (incorporated by reference to Exhibit 10.20 to Registrant's Form 10-K filed on February 25, 2010).*
10.28	Form of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for restricted stock awards (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K filed on February 25, 2011).*
10.29	Form of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and all Non-Management Directors for restricted stock awards (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed on February 25, 2010).*
10.30	Form of Letter Agreement amending the restricted stock award agreements, nonqualified stock option agreements and incentive stock option agreements under the 2009 Long-Term Incentive Plan and the 2005 Long-Term Incentive Plan between Registrant and J. Larry Nichols, John Richels and Darryl G. Smette (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed on February 25, 2011).*

Exhibit No.	Description
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	Registrant's Significant Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants.
23.3	Consent of AJM Deloitte.
31.1	Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of LaRoche Petroleum Consultants.
99.2	Report of AJM Deloitte.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Compensatory plans or arrangements

SIGNATURES

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

DEVON ENERGY CORPORATION

By: /s/ JOHN RICHELS

John Richels

President and Chief Executive Officer

February 23, 2012

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

/s/ JOHN RICHELS John Richels	President, Chief Executive Officer and Director	February 23, 2012
/s/ J. LARRY NICHOLS J. Larry Nichols	Executive Chairman and Director	February 23, 2012
/s/ JEFFREY A. AGOSTA Jeffrey A. Agosta	Executive Vice President and Chief Financial Officer	February 23, 2012
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 23, 2012
/s/ JOHN A. HILL John A. Hill	Director	February 23, 2012
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 23, 2012
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 23, 2012
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 23, 2012
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 23, 2012

INDEX TO EXHIBITS

Exhibit No.	Description
10.14	Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective November 11, 2008).*
10.15	Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012).*
10.16	Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012).*
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99.1	Report of LaRoche Petroleum Consultants.
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101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Compensatory plans or arrangements

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Directors

J. Larry Nichols
Executive Chairman, Devon Energy Corporation

John A. Hill (2)
Lead Director
Vice Chairman and Managing Director, First Reserve Corporation, an oil and gas investment management company

Robert H. Henry (1) (3)
President, Oklahoma City University and former U.S. Judge for the Tenth Circuit Court of Appeals

Michael M. Kanovsky (1) (4)
President, Sky Energy Corporation and Co-founder, Northstar Energy Corporation

Robert A. Mosbacher Jr. (2) (3) (4)
Chairman, Mosbacher Energy Company, an independent oil and gas exploration and production company

Duane C. Radtke (2) (4)
Owner, President and Chief Executive Officer, Valiant Exploration LLC and non-executive Chairman, NFR Energy LLC

John Richels
President and Chief Executive Officer, Devon Energy Corporation

Mary P. Ricciardello (1) (3)
Former Senior Vice President and Chief Accounting Officer, Reliant Energy, Inc.

(1) Audit Committee
(2) Compensation Committee
(3) Governance Committee
(4) Reserves Committee

Senior Executives

J. Larry Nichols
Executive Chairman

John Richels
President and Chief Executive Officer

Jeff A. Agosta
Executive Vice President and Chief Financial Officer

David A. Hager
Executive Vice President, Exploration and Production

R. Alan Marcum
Executive Vice President, Administration

Frank W. Rudolph
Executive Vice President, Human Resources

Darryl G. Smette
Executive Vice President, Marketing, Midstream and Supply Chain

Lyndon C. Taylor
Executive Vice President and General Counsel

William F. Whitsitt
Executive Vice President, Public Affairs

Other Executives

Sue Alberti
Senior Vice President, Marketing

Bradley A. Foster
Senior Vice President, Mid-Continent Division

Steve Hoppe
Senior Vice President, Midstream

Gregory T. Kelleher
Senior Vice President, Southern Division

Jeffrey L. Ritenour
Senior Vice President, Exploration and Production Technical Support

Chris Seasons
Senior Vice President, Canadian Division and President, Devon Canada

Tony D. Vaughn
Senior Vice President, Exploration and Production Strategic Services

Vincent W. White
Senior Vice President, Communications and Investor Relations

Other Information

Investor Relations Contacts
Vince White, Senior Vice President, Communications and Investor Relations
Telephone: (405) 552-4505
E-mail: vince.white@dvn.com

Shea Snyder, Director, Investor Communications
Telephone: (405) 552-4782
E-mail: shea.snyder@dvn.com

Scott Coody, Director, Investor Relations
Telephone: (405) 552-4735
E-mail: scott.coody@dvn.com

Media Contact
Chip Minty, Manager, Media Relations
Telephone: (405) 228-8647
E-mail: chip.minty@dvn.com

Shareholder Assistance
For information about transfer or exchange of shares, dividends, address changes, account consolidation, multiple mailings, lost certificates and Form 1099, contact:

Computershare Trust Company, N.A.
PO Box 43078
Providence, RI 02940-3078
Toll free: (877) 860-5820
E-mail: web.queries@computershare.com

Royalty Owner Assistance
Telephone: (405) 228-4800
E-mail: DevonRevenueHotline@dvn.com

Annual Meeting
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 6, 2012, at the Skirvin Hotel, Continental Room, 1 Park Avenue, Oklahoma City, OK.

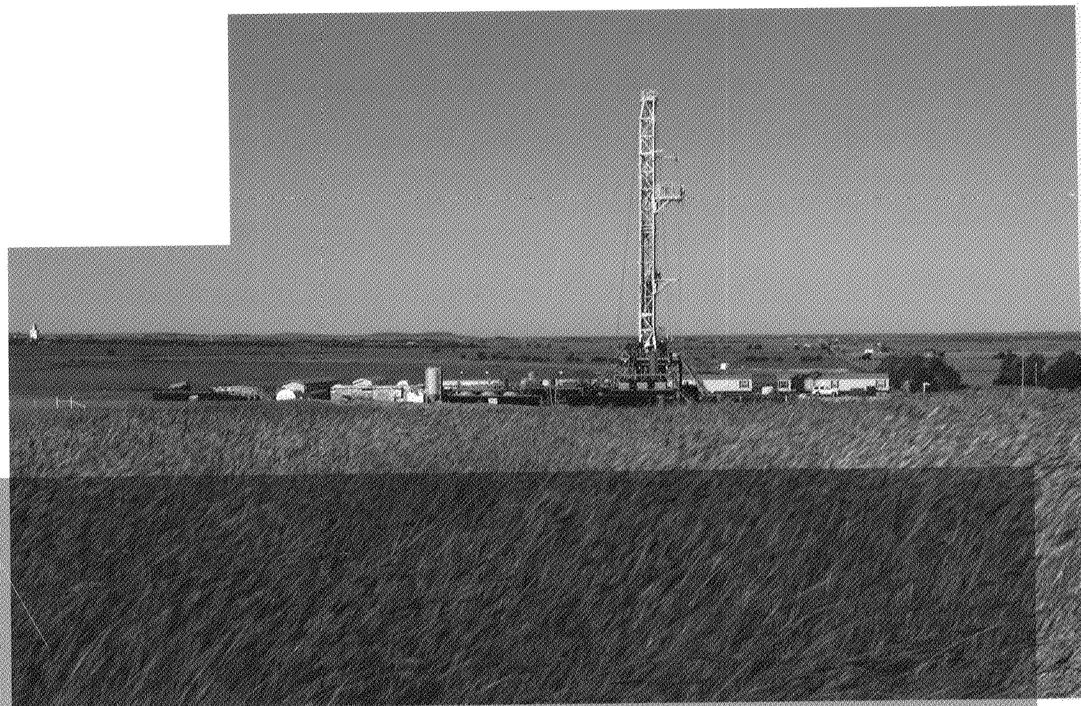
Independent Auditors
KPMG LLP
Oklahoma City, OK

Stock Trading Data
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 11,900 shareholders of record.

Additional Information
This report and Devon's Corporate Responsibility Report are available at www.devonenergy.com. Print versions of these publications are also available upon request to:

Judy Roberts, Shareholder Services Administrator
Telephone: (405) 552-4570
Email: judy.roberts@dvn.com

Forward-Looking Statements See Information Regarding Forward-Looking Statements on page two of this report.



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devon