devon

Devon Energy 2012 Letter to Shareholders and Form 10-K

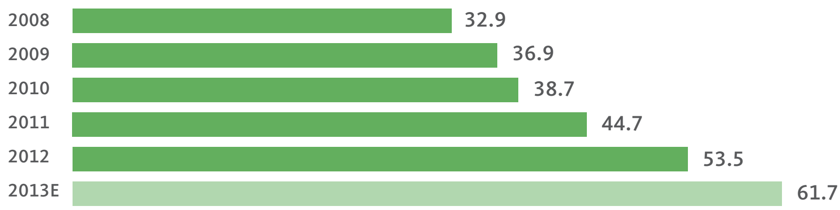
Drilling operations continue day and night on this rig in the Permian Basin. In 2012, Devon drilled more than 240 wells and grew oil production 31 percent in the Permian.

Dear Fellow Shareholders:

2012 was a year of progress for Devon as we continued to transition toward a higher oil weighting in our oil and gas property portfolio. It was also a year of challenges. Regional supply and demand imbalances in North America led to weak product pricing for the majority of our production. In spite of these cyclical pricing headwinds, we stayed focused on the pursuit of our top strategic objective of optimizing long-term growth in cash flow per share adjusted for debt. To consistently grow cash flow, we need a portfolio of assets balanced between oil and natural gas that provides the flexibility to invest in high-return projects in any commodity price environment. Over the last few years, our capital spending has focused almost exclusively on expanding and developing our oil and liquids-rich assets to achieve a more balanced portfolio. Our year-over-year growth in oil production and reserves from existing development projects, combined with our early success in several emerging oil plays, provides clear evidence of our progress. And with the strength of our balance sheet, we have been able to comfortably fund this transition. Undoubtedly, our disciplined approach to allocating capital and managing the business has laid the groundwork for success in the future.

John Richels
President and Chief Executive Officer

Oil Production
(MMBO)



Liquids as % of Total Reserves

Oil Conversion on Track

Record oil production from our Permian Basin and Jackfish development areas drove total oil production up 20 percent over 2011. This marks the sixth consecutive year of North American onshore oil growth for us. Combined with our growth in natural gas liquids, total onshore production reached an all-time record 250 million equivalent barrels in 2012. With a significant portion of our drilling focused on oil, we replaced nearly 260 percent of our oil production during the year with new reserves. These oil additions helped increase oil reserves to 27 percent of total reserves at year end. Including NGLs, liquids now comprise 47 percent of our 3 billion barrels equivalent of total proved reserves.

Joint Ventures Improve Capital Efficiency

To further enhance our long-term growth potential, we have been redeploying the proceeds from the sale of our offshore and international properties. With a goal of establishing low-cost, material positions in new, high-margin oil plays, we have assembled more than 2.5 million net acres across multiple exploration plays.

Subsequent to establishing these land positions, we entered into two separate joint ventures with Sinopec International Petroleum Exploration & Production Corporation and Sumitomo Corporation. Under the terms of the joint venture agreements, Devon received nearly $4 billion in value, including $1.3 billion of up-front cash and $1.6 billion to be paid on Devon's behalf for future drilling costs. In exchange, we gave up roughly 30 percent of our working interest. These unique arrangements allowed us to share the exploration risk across multiple plays, materially enhance our returns and improve our capital efficiency. Not only did we recover more than 100 percent of our costs for acreage and early exploration drilling, these transactions also reduce our future capital demands. This allows us to accelerate activity across these new exploration plays without diverting capital from our core development projects.

Oil Focus Drives Exploration and Development Activity

In 2012, almost all of our upstream capital was allocated to our highest return oil and liquids-rich growth projects. The majority of our activity was concentrated in four cornerstone development areas—the Permian Basin, Jackfish, Barnett and Cana—as well as our emerging oil play in the Mississippian.

In the Permian Basin, we continue to be among the most active horizontal drillers with activity spanning numerous light oil plays. Our development drilling programs in the Bone Spring, Delaware and Wolfcamp Shale are consistently generating high rates of return. These areas drove Devon's 2012 Permian oil production up 31 percent over 2011. To continue to build drilling inventory in the Permian, we have an active exploration program on the eastern flank of the Midland Basin and along the Eastern Shelf. Although we are early in the evaluation of this acreage, we have already seen encouraging results. The Permian Basin once again will be the largest recipient of capital as we look to grow 2013 oil production nearly 40 percent from this prolific basin.

In Canada, construction continued throughout 2012 on our third phase in the Jackfish oil sands complex. This 35,000-barrel-per-day facility was roughly 50 percent complete at year-end, putting us on track for a late 2014 startup. In 2012, our first phase in the Jackfish complex continued its best-in-class performance from both a plant reliability and production efficiency standpoint. At our second Jackfish phase we exited the year producing 20,000 barrels of oil per day. The addition of two new well pads will allow us to eventually utilize the full 35,000-barrel-per-day facility capacity. Each development phase in the 100 percent Devon-owned Jackfish complex represents an estimated 300 million barrels of recoverable oil before royalties. On Devon's 50 percent owned Pike oil sands leases immediately adjacent to the Jackfish complex, we filed an application for regulatory approval for the Pike 1 development. The Pike 1 application is for a project with gross production capacity of 105,000 barrels of oil equivalent per day. In aggregate, we expect our net SAGD oil production to grow to at least 150,000 barrels per day by 2020.

In the Mid-Continent region of the United States, 2012 activity was focused on drilling our best liquids-rich locations. In the Barnett Shale in North Texas, Devon's net production hit an all-time record 1.4 billion cubic feet equivalent per day in the third quarter, including 51,000 barrels per day of liquids. In the Cana-Woodford Shale in Western Oklahoma, net production increased to a record 326 million cubic feet of gas equivalent per day in the fourth quarter, including nearly 18,000 barrels of oil and natural gas liquids. The Cana wells Devon brought online in the second half of 2012 are among the best wells ever drilled in the play.

Also in the Mid-Continent region, we expanded our position in the emerging Mississippian oil play in North Central Oklahoma to roughly 600,000 net acres during the year. While early in our evaluation of this play, drilling results from our initial wells continue to support our target economics. Based on these encouraging results, we gradually ramped up drilling activity throughout 2012 and have another active program planned for 2013. We believe the integration of 3D seismic, core samples, logs and production data into our comprehensive reservoir modeling will ultimately allow us to optimize development of this light-oil resource.

Financial Flexibility in a Challenging Environment

The headwinds we faced in 2012 were principally the result of our product mix and weak price realizations for natural gas, natural gas liquids and Canadian oil. While these challenging market conditions were out of our control, they underscore the importance of our strategy to maintain a strong balance sheet and a diverse portfolio of assets. In spite of reduced cash flow resulting from low commodity prices, Devon's financial strength allowed us the flexibility to continue to fund a robust exploration and development capital program directed entirely towards oil and our high return liquids-rich opportunities. At year-end our financial position remained rock-solid. With $7 billion of cash and short-term investments and manageable debt levels, we continue to maintain superior access to capital.

Outlook for 2013 and Beyond

Our 2013 capital program will support robust drilling of our highest margin oil and liquids-rich projects. This capital program promises to deliver company-wide oil production growth in the mid-teens, while simultaneously allowing us to benefit from the capital efficiencies of our joint ventures where exploration and de-risking of our emerging oil plays is ongoing. As always, we will remain intensely focused on maintaining our position as a low-cost producer.

Along with pursuing our operational goals in 2013, we also are examining and considering other initiatives to unlock value for our shareholders. It's been noted by us, by many of our shareholders and by other industry observers that Devon's current stock price does not adequately reflect the underlying value of our assets. Accordingly, we continue to examine and consider any and every initiative to unlock value that makes sense from a long-term value-creation perspective. Where we are not investing, because the assets do not currently compete effectively for capital within our portfolio, we are considering how we might monetize or bring forward the value associated with those assets. Similarly, if we have assets that we do not believe are being appropriately reflected in our stock price, we are working to determine how that value might be realized or more appropriately reflected in our stock.

The evaluation of such alternatives is nothing new at Devon. Long-term Devon shareholders know we have never hesitated to take action to unlock value. Over the last decade alone, we have sold more than $18 billion of assets at very favorable prices. These sales include the assets we disposed in the strategic repositioning of our company to focus on the North American onshore business. In addition, we have bought back almost 25 percent of our common stock, more than any other independent exploration and production company. Rest assured, any initiative with which we move forward will not be to generate a short-lived bump in our stock price, but rather to create long-term value for our shareholders.

Subsequent to 2012, Devon continued its tradition of increasing the return of capital to our shareholders through our dividend. In March, our board increased our quarterly dividend by 10 percent to $0.22 per share. This marks the eighth dividend increase since 2004, representing an annual compound growth rate of 24 percent. This recent increase reflects our continuing confidence in our long-term strategy, our asset base and our financial strength.

As we progress into 2013, I am excited about Devon's future. Though we continue to face uncertain macro-economic conditions, we believe our disciplined approach to the business and commitment to per-share growth will set Devon apart from its competition. With our talented workforce committed to achieving excellence in execution, controlling costs, maximizing capital efficiency and continuously improving, I am confident we will realize attractive returns for our shareholders in the years to come.

John Richels
President and Chief Executive Officer

April 3, 2013

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

Form 10-K

(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, 2012

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.)*
333 West Sheridan Avenue, Oklahoma City, Oklahoma	**73102-5015**
(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 ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 29, 2012, was approximately $23.3 billion, based upon the closing price of $57.99 per share as reported by the New York Stock Exchange on such date. On February 6, 2013, 406.0 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2013 annual meeting of stockholders — Part III

DEVON ENERGY CORPORATION
FORM 10-K
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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, 2012 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 natural gas liquids ("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

Items 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 bitumen 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 333 West Sheridan, Oklahoma City, OK 73102-5015 (telephone 405/235-3611). As of December 31, 2012, we had approximately 5,700 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 strive to maximize long-term value for our shareholders by delivering strong full-cycle margins on our assets and top-quartile per share returns. In pursuit of this objective, we focus on growing cash flow per share, adjusted for debt, which has the greatest long-term correlation to share price appreciation in our industry. We also focus on growth in earnings, production and reserves, all on a per debt-adjusted share basis. We do this by:

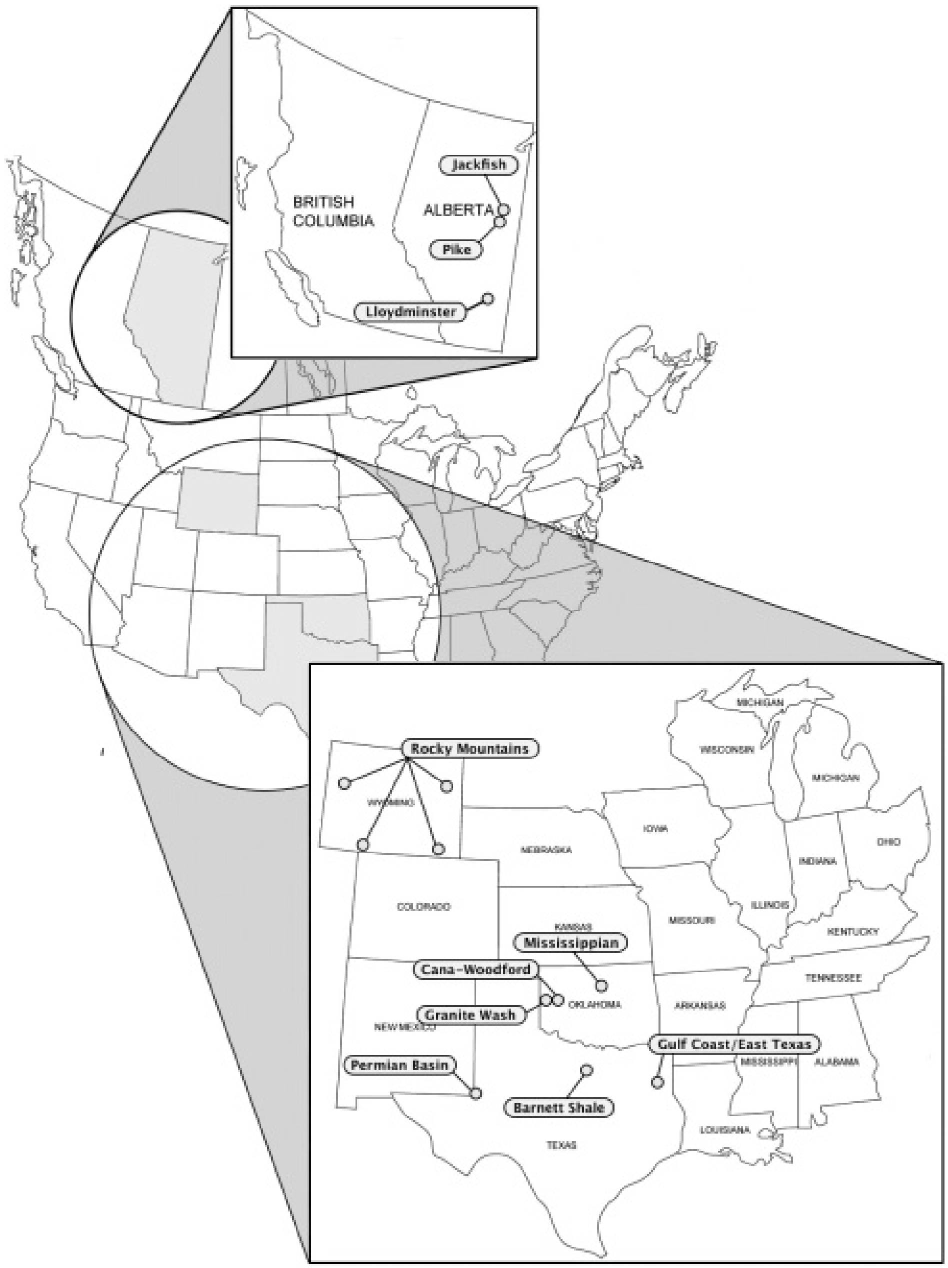
- exercising capital allocation and investment discipline;
- focusing on high-return projects;
- maintaining a low cost structure;
- preserving financial strength and flexibility; and
- balancing our production and resource mix between oil, natural gas and NGLs.

We hold 14 million net acres, of which roughly two-thirds are undeveloped, providing us with a platform for future growth. An important factor in determining the direction of our growth strategy, particularly our capital allocation, is the current and forecasted pricing applicable to our production. Our industry had been operating in an environment that had involved depressed North American gas prices contrasted with more robust prices for oil and NGLs. Consequently, with a production profile that is approximately 60% gas, we have focused our recent capital programs on higher-margin, liquids-based resource capture and development. With recent changes in market conditions that have led to challenged prices for NGLs and Canadian heavy oil, we are refining our capital allocations as needed and evaluating other investment opportunities to maximize and accelerate growth in cash flow per debt-adjusted share.

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 2012. 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. In the following table and throughout this report, we convert our proved reserves and production to Boe. 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. Bitumen and NGL proved reserves and production are converted to Boe on a one-to-one basis with oil.

	Proved Reserves			Production				
	MMBoe	% of Total	% Liquids	MBoe/d	% of Total	% Liquids	Total Net Acres (In thousands)	Gross Wells Drilled
U.S.								
Barnett Shale	1,058	35.7%	23.7%	227.5	33.3%	21.3%	620	322
Cana-Woodford Shale	427	14.4%	41.4%	48.3	7.1%	30.0%	260	164
Permian Basin	227	7.6%	79.6%	61.6	9.0%	77.1%	1,530	241
Gulf Coast/East Texas	221	7.5%	25.0%	61.3	9.0%	23.7%	1,660	50
Rocky Mountains	157	5.3%	37.1%	58.7	8.6%	28.1%	1,165	16
Granite Wash	51	1.7%	41.0%	18.7	2.7%	45.5%	65	48
Mississippian	6	0.2%	61.5%	1.0	0.2%	76.8%	545	35
Other	89	3.1%	32.6%	22.5	3.3%	29.2%	1,155	71
Total U.S.	**2,236**	**75.5%**	34.7%	**499.7**	**73.2%**	31.5%	**7,000**	**947**
Canada								
Canadian Oil Sands	528	17.8%	100.0%	47.6	7.0%	100.0%	90	16
Lloydminster	38	1.3%	86.9%	37.0	5.4%	82.5%	2,740	173
Other	161	5.4%	32.4%	98.0	14.4%	20.2%	4,245	72
Total Canada	**727**	**24.5%**	84.3%	**182.6**	**26.8%**	53.6%	**7,075**	**261**
Devon	**2,963**	**100.0%**	46.9%	**682.3**	**100.0%**	37.4%	**14,075**	**1,208**

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, NGLs and condensate.

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 in excess of 5,000 wells in the Barnett Shale since 2002, yet we still have several thousand remaining drilling locations. In 2013, we plan to drill approximately 150 wells, focused in the areas with the highest liquids content.

In addition, we have a significant processing plant and gathering system in north Texas to service these properties. Our Bridgeport plant is one of the largest processing plants in the U.S., currently with 650 MMcf per day of total capacity, and an additional 140 MMcf expansion expected in 2013 to accommodate increasing demand from our liquids-rich drilling. These midstream assets also include an extensive pipeline system and a 15 MBbls per day NGL fractionator.

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 Shale is a leading growth area for us 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 Shale. During 2012, we increased our production by 45 percent. We have several thousand remaining drilling locations. In 2013, we plan to drill approximately 150 wells.

In addition, we have a significant processing plant and gathering system to service these properties. Our Cana plant currently has 200 MMcf per day of total capacity, and an additional 150 MMcf expansion expected in 2013 to accommodate increasing demand from our liquids-rich drilling.

Permian Basin — Our acreage is located in various counties in west Texas and southeast New Mexico. These properties have been a legacy asset for us and continue to offer both exploration and low-risk development opportunities. We entered into a joint venture arrangement with Sumitomo in 2012, covering approximately 650,000 net acres in the Cline Shale and Midland-Wolfcamp Shale and further strengthening the capital efficiency of our exploration programs. In addition to the Cline and Wolfcamp Shale activity, our current drilling activity continues to target conventional and non-conventional oil and liquids-rich gas targets within the Conventional Delaware, Bone Spring, Midland-Wolfcamp, Wolfberry and Avalon Shale plays. In 2013, we plan to drill approximately 300 wells.

Gulf Coast/East Texas— Our acreage is located primarily in Harrison, Marion, Panola and Shelby counties in the Carthage/Groesbeck areas of east Texas. These wells produce natural gas and NGLs from conventional reservoirs. In 2013, we plan to drill approximately 10 wells, focused in the areas with the highest liquids content.

Rocky Mountains— These leases are primarily concentrated in the Washakie area 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 area for many years. In 2013, we plan to drill approximately 25 wells, focused in the areas with the highest liquids content.

In recent years we also have acquired a significant acreage position in the DJ Basin. This acquired acreage, along with our legacy Powder River Basin acreage, primarily targets oil in the Niobrara formation. These acres are principally located in eastern Wyoming and are being explored using 3D seismic to identify appropriate drilling zones. Furthermore, in early 2012, we entered into a joint venture arrangement with Sinopec to explore and develop the Niobrara and other new venture properties.

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 2013, we plan to drill approximately 50 wells.

Mississippian — These properties represent some of our newest assets, with most of our position acquired since 2011. Located in northern Oklahoma and southern Kansas, these acres target oil in the Mississippian Lime and Woodford Shale and are being explored and developed under our joint venture arrangement with Sinopec and independently by us on the acreage outside of our area of mutual interest with Sinopec. In 2013, we plan to drill approximately 400 wells.

Canada

Canadian Oil Sands — We are the first and only U.S.-based independent energy company to develop and operate a bitumen oil sands project in Canada. We currently have two main projects, Jackfish and Pike, located in Alberta, Canada.

Jackfish is our thermal heavy oil project in the non-conventional oil sands of east central Alberta. We are employing steam-assisted gravity drainage at Jackfish. The first phase of Jackfish is fully operational with a gross facility capacity of 35 MBbls per day. Jackfish production increased 37 percent in 2012 as the second phase of Jackfish, which came on-line in the second quarter of 2011, continued to increase production. Construction of a third phase began in 2012 with plant startup expected by year-end 2014. 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.

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, 2012. We filed a regulatory application in 2012 for the first phase of this project, with gross capacity of 105 MBbls per day, in which we hold a 50 percent interest.

To facilitate the delivery of our heavy oil production, we have a 50 percent interest in the Access Pipeline transportation system in Canada. This pipeline system allows us to blend our Jackfish, and eventually our Pike, heavy oil production with condensate or other blend-stock and transport the combined product to the Edmonton area for sale. The Access Pipeline system is currently undergoing a capacity expansion that we anticipate will be completed in late 2014. This expansion, in which we have a 50% interest, is expected to create adequate capacity to transport our anticipated Jackfish and Pike heavy oil production to the Edmonton market hub. Additionally, it will increase the transport capacity of condensate diluent available at our thermal oil facilities.

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.

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 approximately 2,500 wells in the area since 2003. In 2013, we plan to drill approximately 155 wells.

Proved Reserves

For estimates of our 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 2012 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 twelve years, including the past five in his current position. During his career, he has been 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 2012, we engaged two such firms to audit 92 percent of our proved reserves. LaRoche Petroleum Consultants, Ltd. audited 91 percent of our 2012 U.S. reserves, and Deloitte audited 93 percent 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				
Year Ended December 31,	**Oil (MMBbls)**	**Bitumen (MMBbls)**	**Gas (Bcf)**	**NGLs (MMBbls)**	**Total (MMBoe)**
2012					
Barnett Shale	1	—	393	17	83
Jackfish	—	17	—	—	17
U.S.	21	—	752	36	183
Canada	15	17	186	4	67
Total North America	36	17	938	40	250
2011					
Barnett Shale	1	—	367	16	78
Jackfish	—	13	—	—	13
U.S.	17	—	740	33	173
Canada	15	13	213	4	67
Total North America	32	13	953	37	240
2010					
Barnett Shale	1	—	335	13	70
Jackfish	—	9	—	—	9
U.S.	16	—	716	28	163
Canada	16	9	214	4	65
Total North America	32	9	930	32	228

Year Ended December 31,	Average Sales Price Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Production Cost (Per Boe)
2012					
Barnett Shale	$91.45	$ —	$2.23	$27.57	$ 3.91
Jackfish	$ —	$47.75	$ —	$ —	$19.48
U.S.	$88.68	$ —	$2.32	$28.49	$ 5.79
Canada	$68.08	$47.75	$2.49	$48.63	$15.18
Total North America	$80.35	$47.75	$2.36	$30.42	$ 8.30
2011					
Barnett Shale	$94.23	$ —	$3.30	$39.00	$ 3.97
Jackfish	$ —	$58.16	$ —	$ —	$17.28
U.S.	$91.19	$ —	$3.50	$39.47	$ 5.35
Canada	$74.32	$58.16	$3.87	$55.99	$13.82
Total North America	$83.16	$58.16	$3.58	$41.10	$ 7.71
2010					
Barnett Shale	$77.40	$ —	$3.55	$29.97	$ 3.87
Jackfish	$ —	$52.51	$ —	$ —	$16.81
U.S.	$75.81	$ —	$3.76	$30.86	$ 5.47
Canada	$62.00	$52.51	$4.11	$46.60	$12.37
Total North America	$68.75	$52.51	$3.84	$32.61	$ 7.42

Drilling Statistics

The following table summarizes our development and exploratory drilling results.

Year Ended December 31,	Development Wells (1) Productive	Dry	Exploratory Wells (1) Productive	Dry	Total Wells (1) Productive	Dry	Total
2012							
U.S.	668.2	1.0	24.6	4.9	692.8	5.9	698.7
Canada	209.3	4.0	27.3	1.0	236.6	5.0	241.6
Total North America	877.5	5.0	51.9	5.9	929.4	10.9	940.3
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

(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, 2013, results of our wells that were in progress on December 31, 2012.

	Productive		Dry		Still in Progress		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
U.S.	65.0	53.6	—	—	126.0	65.6	191.0	119.2
Canada	8.0	7.6	—	—	1.0	0.7	9.0	8.3
Total North America	73.0	61.2	—	—	127.0	66.3	200.0	127.5

(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, 2012.

	Oil Wells (1)		Natural Gas Wells		Total Wells	
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
U.S.	8,655	3,202	20,858	13,672	29,513	16,874
Canada	5,316	4,119	5,578	3,320	10,894	7,439
Total North America	13,971	7,321	26,436	16,992	40,407	24,313

(1) Includes bitumen wells.
(2) Gross wells are the sum of all wells in which we own an interest.
(3) 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 25,000 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, 2012. The acreage in the table includes 1.4 million, 0.8 million and 1.6 million net acres subject to leases that are scheduled to expire during 2013, 2014 and 2015, respectively.

	Developed		Undeveloped		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
			(In thousands)			
U.S.	3,195	2,210	7,830	4,790	11,025	7,000
Canada	3,665	2,270	6,635	4,805	10,300	7,075
Total North America	6,860	4,480	14,465	9,595	21,325	14,075

(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

Our marketing and midstream operations provide gathering, compression, treating, processing, fractionation and marketing services to us and other third-parties. We generate revenues from these operations by collecting service fees and selling processed gas and NGLs. The expenses associated with these operations primarily consist of the costs to operate our gathering systems, plants and related facilities, as well as purchases of gas and NGLs.

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, gas and NGL 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 2013, our production was sold under the following contracts.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	76%	—	24%	—
Natural gas	73%	—	27%	—
NGLs	78%	14%	1%	7%

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 December 31, 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 and bitumen (MMBbls)	124	14	30	31	49
Natural gas (Bcf)	1,175	623	374	133	45
NGLs (MMBbls)	10	5	3	2	—
Total (MMBoe)	330	123	95	55	57

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 2012, 2011 and 2010, no purchaser accounted for over 10 percent of our revenues.

Competition

See "Item 1A. Risk Factors."

Public Policy and Government Regulation

The oil and natural gas industry is subject to regulation throughout the world. Laws, rules, regulations and other policy implementation actions affecting the oil and natural gas industry have been pervasive and are under constant review for amendment or expansion. Numerous government agencies have issued extensive laws and regulations which are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. These laws and regulations increase the cost of doing business and consequently affect profitability. Because public policy changes are commonplace, and existing laws and regulations are frequently amended, we are unable to predict the future cost or impact of compliance. However, we do not expect that any of these laws and regulations will affect our operations differently 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 federal, state, provincial, tribal and local laws and regulations. These laws and regulations relate to matters that include:

- 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. These regulations limit the amounts of oil and gas we can produce from our wells and 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. Occasionally the federal and provincial governments of Canada also have established incentive programs, such as royalty rate reductions, royalty holidays, and tax credits, for the purpose of encouraging oil and gas exploration or enhanced recovery projects. These incentives generally increase our revenues, earnings and cash flow.

Marketing in Canada

Any oil or gas export 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 many 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:

- 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 yet 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:

- supply of and 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 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 require substantial compliance costs and 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 and Indian lands. Currently, regulation of hydraulic fracturing is conducted primarily at the state level through permitting and other compliance requirements. We lease federal and Indian 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 of 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. Recently, the U.S. President and other policy makers have proposed provisions that would, if enacted, make significant changes to U.S. tax laws applicable to us. The most significant change to our business would eliminate the immediate deduction for intangible drilling and development costs. Such a change could have a material adverse effect on our profitability, financial condition and liquidity.

Climate Change – Policymakers in the U.S. and Canada are increasingly focusing on whether the emissions of greenhouse gases, such as carbon dioxide and methane, are contributing to harmful climatic changes. Policymakers at both the U.S. federal and state levels have introduced legislation and proposed new regulations that are designed to quantify and limit the emission of greenhouse gases through inventories, limitations and/or taxes on greenhouse gas emissions. Legislative initiatives and discussions to date have focused on the development of cap-and-trade and/or carbon tax programs. A cap-and-trade program 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 could be relevant to us and our operations in several ways. First, the equipment we use to explore for, develop, produce and process oil and natural gas emits greenhouse gases. We could therefore be subject to caps, and penalties if emissions exceeded the caps. Second, the combustion of carbon-based fuels, such as the oil, gas and NGLs we sell, emits carbon dioxide and other greenhouse gases. Therefore, demand for our products could be reduced by imposition of caps and penalties on our customers. Carbon taxes could likewise affect us by being based on emissions from our equipment and/or emissions resulting from use of our products by our customers. Of overriding significance would be the point of regulation or taxation. Application of caps or taxes on companies such as Devon, based on carbon content of produced oil and gas volumes rather than on consumer emissions, could lead to penalties, fees or tax assessments for which there are no mechanisms to pass them through the distribution and consumption chain where fuel use or conservation choices are made. Moreover, because oil and natural gas are used as chemical feedstocks and not solely as fossil fuel, applying a carbon tax to oil and gas at the production stage would be excessive with respect to actual carbon emissions from petroleum fuels.

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 people 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 percent 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***

Not applicable.

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***

Not applicable.

PART II

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

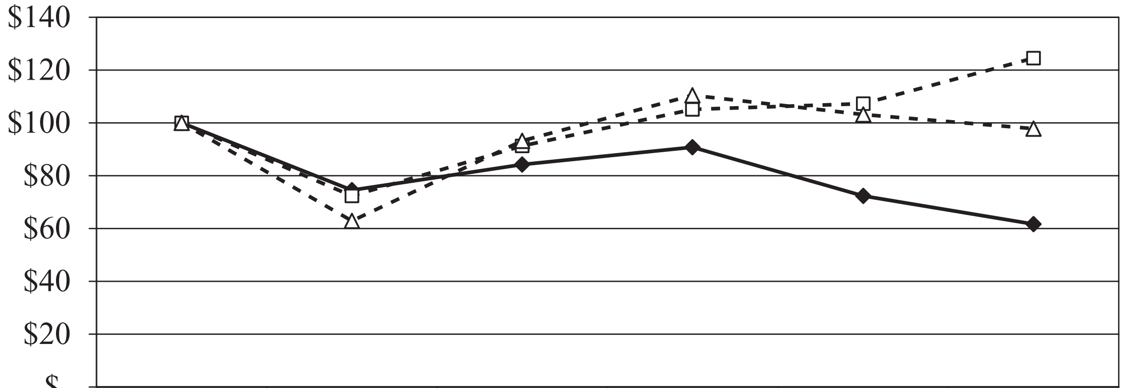
Our common stock is traded on the New York Stock Exchange (the "NYSE"). On February 6, 2013, there were 11,695 holders of record of our common stock. The following table sets forth the quarterly high and low sales prices for our common stock as reported by the NYSE during 2012 and 2011, as well as the quarterly dividends per share paid during 2012 and 2011. We began paying regular quarterly cash dividends on our common stock in the second quarter of 1993. We anticipate continuing to pay regular quarterly dividends in the foreseeable future.

	Price Range of Common Stock		Dividends
	High	Low	Per Share
2012:			
Quarter Ended December 31, 2012	$63.00	$50.89	$0.20
Quarter Ended September 30, 2012	$63.95	$54.56	$0.20
Quarter Ended June 30, 2012	$73.14	$54.01	$0.20
Quarter Ended March 31, 2012	$76.34	$62.13	$0.20
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

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, 2007 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



	2007	2008	2009	2010	2011	2012
Devon	$100.00	$74.41	$84.15	$90.73	$72.32	$61.52
S&P 500	$100.00	$72.13	$91.22	$104.96	$107.17	$124.33
SIC Code	$100.00	$62.75	$93.17	$110.36	$103.06	$97.80

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 the 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 2012. Such purchases represent shares received by us from employees and directors for the payment of personal income tax withholding on restricted stock vesting and stock option exercises.

Period	Total Number of Shares Purchased	Average Price Paid per Share
October 1 - October 31	6,000	$60.15
November 1 - November 30	406,725	$52.72
December 1 - December 31	459,320	$52.24
Total	872,045	$52.52

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. Eligible employees purchased approximately 57,000 shares of our common stock in 2012, 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.

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. Eligible Canadian employees purchased approximately 22,900 shares of our common stock in 2012, 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,				
	2012	2011	2010	2009	2008
	(In millions, except per share amounts)				
Revenues	$ 9,502	$11,454	$ 9,940	$ 8,015	$13,858
Earnings (loss) from continuing operations [1]	$ (185)	$ 2,134	$ 2,333	$ (2,753)	$ (3,039)
Earnings (loss) per share from continuing operations - Basic	$ (0.47)	$ 5.12	$ 5.31	$ (6.20)	$ (6.86)
Earnings (loss) per share from continuing operations - Diluted	$ (0.47)	$ 5.10	$ 5.29	$ (6.20)	$ (6.86)
Cash dividends per common share	$ 0.80	$ 0.67	$ 0.64	$ 0.64	$ 0.64
Weighted average common shares outstanding - Basic	405	417	440	444	444
Weighted average common shares outstanding - Diluted	405	418	441	444	444
Total assets [1]	$43,326	$41,117	$32,927	$29,686	$31,908
Long-term debt	$ 8,455	$ 5,969	$ 3,819	$ 5,847	$ 5,661
Stockholders' equity	$21,278	$21,430	$19,253	$15,570	$17,060

(1) During 2012, 2009 and 2008, we recorded noncash asset impairments totaling $2.0 billion ($1.3 billion after income taxes), $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 2012 Results

As an enterprise, we strive to optimize value for our shareholders by growing cash flow, 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.

2012 was a year of mixed results for Devon. We grew our production 4% and closed two significant joint venture transactions with a combined value of approximately $4.0 billion. Furthermore, with a focus on development of higher-margin oil and bitumen properties in our portfolio, we increased our oil and bitumen production 20% in 2012 and are positioned to deliver similar oil and bitumen growth in 2013. However, this growth was overshadowed by the effects of declining commodity prices, which negatively impacted a number of our 2012 financial performance measures, as well as our year-end proved reserves. Key measures of our 2012 performance are summarized below, which exclude amounts from our discontinued operations.

	Year Ended December 31,				
	2012	Change	2011	Change	2010
	($ in millions, except per share amounts)				
Net earnings (loss)	$ (185)	-109%	$2,134	-9%	$2,333
Adjusted earnings (1)	$1,322	-48%	$2,536	+0%	$2,536
Earnings (loss) per share	$ (0.47)	-109%	$ 5.10	-4%	$ 5.29
Adjusted earnings per share (1)	$ 3.26	-46%	$ 6.07	+6%	$ 5.75
Production (MBoe/d)	682.3	+4%	657.7	+5%	623.6
Realized price per Boe	$28.65	-17%	$34.64	+9%	$31.91
Operating margin per Boe (2)	$19.41	-23%	$25.15	+1%	$24.89
Operating cash flow	$4,930	-21%	$6,246	+24%	$5,022
Adjusted operating cash flow (1)	$4,892	-21%	$6,225	+7%	$5,840
Capitalized costs	$8,474	+9%	$7,795	+13%	$6,920
Shareholder distributions (3)	$ 324	-88%	$2,610	+80%	$1,449
Reserves (MMBoe)	2,963	-1%	3,005	+5%	2,873

(1) Adjusted earnings, adjusted earnings per share and adjusted operating cash flow are not financial measures prepared in accordance with accounting principles generally accepted in the U.S. (GAAP). For a description of adjusted earnings, adjusted earnings per share and adjusted operating cash flow as well as reconciliations to the comparable GAAP measures, see "Non-GAAP Measures" in this Item 7.

(2) Computed as revenues from commodity sales, commodity derivatives settlements, and marketing and midstream operations, less expenses for lease operations, marketing and midstream operations, general and administration, taxes other than income taxes and interest, with the result divided by total production.

(3) Includes common stock dividends and share repurchases.

Our 2012 net loss resulted from noncash asset impairments, which reduced our earnings by $2.0 billion ($1.3 billion after tax). Excluding the asset impairments and other items typically excluded by securities analysts, our adjusted earnings were $1.3 billion, or $3.26 per diluted share. This compares to adjusted earnings of $2.5 billion, or $6.07 per diluted share in 2011.

In spite of growing our production, our 2012 adjusted earnings, adjusted cash flow, operating margin and proved reserves declined largely due to the effects of lower commodity prices. In virtually all our operating areas, we realized lower prices in 2012 due to either declines in benchmarks or widening price differentials. The most significant price declines were associated with our gas and NGL production, for which we experienced realized price decreases of 34% and 26%, respectively. With increasing focus on oil and bitumen production growth, which generally require a higher cost to produce per unit than our gas projects, we were also impacted by upward pressure on operating costs.

We replaced 152% of our 2012 production from proved reserve extensions, discoveries and revisions other than price. Yet, our proved reserves decreased 1% overall due to significant downward revisions resulting from lower gas and NGL prices.

Business and Industry Outlook

During 2012, natural gas traded at prices we have not experienced for a decade. These low prices are the result of a significant imbalance between supply and demand in North America. On the supply side, new technologies, particularly hydraulic fracturing and horizontal drilling, have enabled natural gas producers to bring on line meaningful new supplies of natural gas around North America. On the demand side, the past winter was one of the warmest on record, which reduced demand for natural gas. Consequently, North America has an unusually high amount of gas in storage that will continue to oversupply the market. However, there are some favorable trends. Utilities around the country are switching from coal to natural gas at a meaningful rate. New petro-chemical plants are being built and other industries are expanding in the U.S. Looking to 2013, increased demand should cause natural gas prices to stabilize or possibly to increase moderately from 2012 levels.

As a result of the low natural gas prices, we and other producers have been focused on growing oil, bitumen and liquids-rich gas production. Similar to natural gas, regional imbalances between supply and demand of these liquids have caused price declines. In 2012, the most negative impact to us from these imbalances related to our U.S. NGLs and our Canadian heavy oil. The NGL imbalances have largely resulted from increased liquids-rich gas production without corresponding increases in either NGL pipeline delivery systems or consumer demand. We expect NGL prices will remain challenged for 2013 and, perhaps longer, due to the long-lead time associated with the construction of new petrochemical capacity. Our Canadian heavy oil production has recently been impacted by pipeline outages and refinery downtime. With increasing industry heavy oil production and current pipeline capacity, the pipeline outages and refinery downtimes had greater impacts to producers' realized prices during 2012. Like other producers, we are beginning to use rail to deliver a portion of our heavy oil to downstream markets. We are also optimistic the U.S. government will approve construction of the Keystone XL pipeline. Provided the pipeline outages are not recurring and industry's planned refinery expansions occur during the first half of 2013, the downward pressures on Canadian heavy oil prices should be relatively temporary in nature.

While we are optimistic about the long-term future of prices, we expect benchmark prices will continue to be volatile and in some cases will be challenged in 2013. We are most optimistic about oil prices and believe our oil properties largely represent the highest-return assets in our portfolio. Therefore, our near-term focus will be on these properties. We also realize that we possess a great deal of financial strength, flexibility and liquidity. We will use these resources to develop our portfolio of properties and explore other opportunities to maximize shareholder value, including monetization of our existing assets or entering into new ventures or acquisitions.

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,				
	2012	Change	2011	Change	2010
Oil (MBbls/d)					
U.S. Onshore	58.7	+28%	46.0	+24%	37.0
Canada	39.8	-5%	41.7	-6%	44.2
North America Onshore	98.5	+12%	87.7	+8%	81.2
U.S. Offshore	—	N/M	—	-100%	5.2
Total	98.5	+12%	87.7	+1%	86.4
Bitumen (MBbls/d)					
Canada	47.6	+37%	34.8	+41%	24.7
Gas (MMcf/d)					
U.S. Onshore	2,054.5	+1%	2,026.6	+6%	1,913.8
Canada	508.3	-13%	583.1	-1%	586.9
North America Onshore	2,562.8	-2%	2,609.7	+4%	2,500.7
U.S. Offshore	—	N/M	—	-100%	46.0
Total	2,562.8	-2%	2,609.7	+2%	2,546.7
NGLs (MBbls/d)					
U.S. Onshore	98.6	+9%	90.4	+17%	77.3
Canada	10.5	+6%	9.9	+2%	9.8
North America Onshore	109.1	+9%	100.3	+15%	87.1
U.S. Offshore	—	N/M	—	-100%	0.9
Total	109.1	+9%	100.3	+14%	88.0
Combined (MBoe/d)					
U.S. Onshore	499.7	+5%	474.1	+9%	433.3
Canada	182.6	-1%	183.6	+4%	176.5
North America Onshore	682.3	+4%	657.7	+8%	609.8
U.S. Offshore	—	N/M	—	-100%	13.8
Total	682.3	+4%	657.7	+5%	623.6

	Year Ended December 31,				
	2012 (1)	Change	2011 (1)	Change	2010 (1)
Oil (per Bbl)					
U.S. Onshore	$88.68	-3%	$91.19	+21%	$75.53
Canada	$68.08	-8%	$74.32	+20%	$62.00
North America Onshore	$80.35	-3%	$83.16	+22%	$68.17
U.S. Offshore	$ —	N/M	$ —	-100%	$77.81
Total	$80.35	-3%	$83.16	+21%	$68.75
Bitumen (per Bbl)					
Canada	$47.75	-18%	$58.16	+11%	$52.51
Gas (per Mcf)					
U.S. Onshore	$ 2.32	-34%	$ 3.50	-6%	$ 3.73
Canada	$ 2.49	-36%	$ 3.87	-6%	$ 4.11
North America Onshore	$ 2.36	-34%	$ 3.58	-6%	$ 3.82
U.S. Offshore	$ —	N/M	$ —	-100%	$ 5.12
Total	$ 2.36	-34%	$ 3.58	-7%	$ 3.84
NGLs (per Bbl)					
U.S. Onshore	$28.49	-28%	$39.47	+28%	$30.78
Canada	$48.63	-13%	$55.99	+20%	$46.60
North America Onshore	$30.42	-26%	$41.10	+26%	$32.55
U.S. Offshore	$ —	N/M	$ —	-100%	$38.22
Total	$30.42	-26%	$41.10	+26%	$32.61
Combined (per Boe)					
U.S. Onshore	$25.59	-18%	$31.31	+10%	$28.42
Canada	$37.01	-14%	$43.23	+11%	$39.11
North America Onshore	$28.65	-17%	$34.64	+10%	$31.52
U.S. Offshore	$ —	N/M	$ —	-100%	$49.06
Total	$28.65	-17%	$34.64	+9%	$31.91

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

Commodity Sales

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

	Oil	Bitumen	Gas	NGLs	Total
			(In millions)		
2010 sales	$2,169	$ 474	$ 3,572	$1,047	$ 7,262
Change due to volumes	30	193	88	147	458
Change due to prices	461	72	(249)	311	595
2011 sales	2,660	739	3,411	1,505	8,315
Change due to volumes	337	273	(52)	137	695
Change due to prices	(101)	(181)	(1,148)	(427)	(1,857)
2012 sales	$2,896	$ 831	$ 2,211	$1,215	$ 7,153

Volumes 2012 vs. 2011 – Upstream sales increased $695 million due to a 4 percent increase in production. Oil and bitumen production were the largest drivers of the increase, accounting for nearly 90 percent of the higher sales. As a result of continued development of our liquids-rich properties in the Permian Basin, our oil sales increased $337 million. Bitumen sales increased $273 million due to development of our Jackfish thermal heavy oil projects in Canada. Additionally, our NGL sales increased $137 million as a result of continued drilling in the liquids-rich gas portions of the Barnett Shale, Cana-Woodford Shale and Granite Wash. These increases were partially offset by a slight decrease in our 2012 gas production, resulting in a $52 million decline in sales.

Volumes 2011 vs. 2010 – Upstream sales increased $458 million due to a 5 percent increase in production. Bitumen and NGL volume increases resulted in $340 million higher sales. Additional volumes for both of these products were primarily due to the same reasons discussed in our 2012 vs. 2011 comparison above. Additionally, we saw slight increases in our oil and gas volumes which resulted in $118 million higher sales.

Production information for our key properties is summarized below:

- Permian Basin production increased 26 percent compared to the prior year and 44 percent since 2010. Oil production accounted for nearly 60 percent of our 62,000 Boe per day produced in the Permian Basin during 2012. The 2012 increase in total production was driven by a 30 percent increase in oil production.
- Barnett Shale production increased 7 percent compared to the prior year and 18 percent since 2010. Liquids production accounted for 21 percent of our 1.4 Bcfe per day produced in the Barnett Shale during 2012. The 2012 increase in total production was driven by a 7 percent increase in liquids production.
- Cana-Woodford Shale production increased 45 percent compared to the prior year and 168 percent since 2010. Liquids production accounted for 30 percent of our 290 MMcfe per day produced in Cana during 2012. The 2012 increase in total production was driven by a 67 percent increase in liquids production.
- Canadian Oil Sands production increased 37 percent compared to the prior year and 92 percent since 2010. Bitumen production accounted for all of our 48,000 Boe per day produced in 2012.
- Granite Wash production increased 14 percent compared to the prior year and 68 percent since 2010. Liquids production accounted for 46 percent of our 19,000 Boe per day produced in Granite Wash during 2012. The 2012 increase in production was driven by a 20 percent increase in liquids production.
- By the end of 2012, Mississippian production was up to almost 3,000 Boe per day. We drilled our first 35 wells in 2012. Oil production accounted for 63 percent of our total production in 2012.
- Gulf Coast/East Texas production decreased 14 percent in 2012. Although total production was down, oil production increased 8 percent in 2012. Liquids production accounted for nearly 25 percent of our 368 MMcfe per day produced in Gulf Coast/East Texas during 2012.
- Rocky Mountain production decreased 9 percent in 2012. Although total production was down, oil production increased 17 percent in 2012. Liquids production accounted for 28 percent of our 352 MMcfe per day produced in the Rocky Mountains during 2012.
- Lloydminster production decreased 6 percent in 2012. Oil production accounted for 82 percent of our 37,000 Boe per day produced at Lloydminster during 2012.

Prices 2012 vs. 2011 – Upstream sales decreased $1.9 billion due to a 17 percent decrease in our realized price without hedges. Our gas sales were the most significantly impacted with a $1.1 billion decrease in sales. The change in our gas price was largely due to fluctuations of the North American regional index prices upon which our gas sales are based. We also experienced declines in our NGL, bitumen and oil sales due to our realized price. The largest contributors to the lower liquids prices were lower NGL prices at the Mont Belvieu, Texas hub and wider bitumen differentials to the NYMEX West Texas Intermediate index price.

Prices 2011 vs. 2010 – Upstream sales increased $595 million due to a 9 percent increase in our realized price without hedges. Our realized price for oil, bitumen and NGLs increased primarily due to an increase in the average index price for which each product is sold. Our realized price for gas decreased primarily due to fluctuations of the North American regional index prices upon which our gas sales are based.

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,		
	2012	2011	2010
	(In millions)		
Cash settlements:			
Gas derivatives	$ 610	$416	$888
Oil derivatives	259	(26)	—
NGL derivatives	1	2	—
Total cash settlements	870	392	888
Unrealized gains (losses) on fair value changes:			
Gas derivatives	(330)	305	12
Oil derivatives	150	185	(91)
NGL derivatives	3	(1)	2
Total unrealized gains (losses) on fair value changes	(177)	489	(77)
Oil, gas and NGL derivatives	$ 693	$881	$811

	Year Ended December 31, 2012				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$80.35	$47.75	$2.36	$30.42	$28.65
Cash settlements of hedges	7.18	—	0.65	0.04	3.48
Realized price, including cash settlements	$87.53	$47.75	$3.01	$30.46	$32.13

	Year Ended December 31, 2011				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$83.16	$58.16	$3.58	$41.10	$34.64
Cash settlements of hedges	(0.81)	—	0.44	0.07	1.63
Realized price, including cash settlements	$82.35	$58.16	$4.02	$41.17	$36.27

	Year Ended December 31, 2010				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$68.75	$52.51	$3.84	$32.61	$31.91
Cash settlements of hedges	—	—	0.96	—	3.90
Realized price, including cash settlements	$68.75	$52.51	$4.80	$32.61	$35.81

Cash settlements as presented in the tables above represent realized gains or losses related to these various instruments. A summary of our open commodity derivative positions 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, basis swaps and call options. To facilitate a portion of our price swaps, we sold gas call options for 2012 and 2014 and oil call options for 2011 through 2014. 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 $693 million, $881 million and $811 million during 2012, 2011 and 2010, respectively.

Marketing and Midstream Revenues and Operating Costs and Expenses

	Year Ended December 31,				
	2012	Change	2011	Change	2010
			($ in millions)		
Revenues	$1,656	-27%	$2,258	+21%	$1,867
Operating costs and expenses	1,246	-27%	1,716	+26%	1,357
Operating profit	$ 410	-24%	$ 542	+6%	$ 510

2012 vs. 2011 Marketing and midstream operating profit decreased $132 million primarily due to lower natural gas and NGL prices.

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

Lease Operating Expenses ("LOE")

	Year Ended December 31,				
	2012	Change	2011	Change	2010
LOE ($ in millions):					
U.S. Onshore	$1,059	+14%	$ 925	+11%	$ 832
Canada	1,015	+10%	926	+16%	797
North America Onshore	2,074	+12%	1,851	+14%	1,629
U.S. Offshore	—	N/M	—	-100%	60
Total	$2,074	+12%	$1,851	+10%	$1,689
LOE per Boe:					
U.S. Onshore	$ 5.79	+8%	$ 5.35	+2%	$ 5.26
Canada	$15.18	+10%	$13.82	+12%	$12.37
North America Onshore	$ 8.30	+8%	$ 7.71	+5%	$ 7.32
U.S. Offshore	$ —	N/M	$ —	-100%	$12.00
Total	$ 8.30	+8%	$ 7.71	+4%	$ 7.42

2012 vs. 2011 LOE increased $0.59 per Boe largely because of our oil production growth, particularly at our Jackfish thermal heavy oil projects in Canada and in the Permian Basin in the U.S. Such oil projects generally require a higher cost to produce per unit than our gas projects. We also experienced inflationary pressures on costs in certain operating areas, which increased LOE per Boe.

2011 vs. 2010 LOE increased $0.29 per Boe. 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. We also experienced inflationary pressures on costs in certain operating areas. 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.

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

	Year Ended December 31,				
	2012	Change	2011	Change	2010
DD&A ($ in millions):					
Oil & gas properties	$2,526	+27%	$1,987	+19%	$1,675
Other properties	285	+9%	261	+2%	255
Total	$2,811	+25%	$2,248	+17%	$1,930
DD&A per Boe:					
Oil & gas properties	$10.12	+22%	$ 8.28	+13%	$ 7.36
Other properties	1.14	+5%	1.09	-3%	1.12
Total	$11.26	+20%	$ 9.37	+10%	$ 8.48

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.

2012 vs. 2011 Oil and gas property DD&A increased $460 million due to a 22 percent increase in the DD&A rate and $79 million due to our 4 percent increase in production. The largest contributors to the higher rate were our 2012 drilling and development activities.

2011 vs. 2010 Oil and gas property DD&A increased $221 million 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.

General and Administrative Expenses ("G&A")

	Year Ended December 31,				
	2012	Change	2011	Change	2010
			($ in millions)		
Gross G&A	$1,171	+13%	$1,036	+5%	$ 987
Capitalized G&A	(359)	+7%	(337)	+8%	(311)
Reimbursed G&A	(120)	+5%	(114)	+1%	(113)
Net G&A	$ 692	+18%	$ 585	+4%	$ 563
Net G&A per Boe	$ 2.77	+14%	$ 2.44	-1%	$2.47

2012 vs. 2011 Net G&A and net G&A per Boe increased largely due to higher employee compensation and benefits. Employee costs increased primarily from an expansion of our workforce as part of growing production operations at certain of our key areas, including Jackfish, the Permian Basin and the Cana-Woodford Shale.

2011 vs. 2010 Net G&A increased 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.

Taxes Other Than Income Taxes

	Year Ended December 31,				
	2012	Change	2011	Change	2010
	($ in millions)				
Production	$ 224	-10%	$ 248	+18%	$ 210
Ad valorem and other	190	+8%	176	+4%	170
Taxes other than income taxes	$ 414	-3%	$ 424	+12%	$ 380
Percentage of oil, gas and NGL revenue:					
Production	3.13%	+5%	2.98%	+3%	2.90%
Ad valorem and other	2.65%	+25%	2.12%	-9%	2.34%
Total	5.78%	+13%	5.10%	-3%	5.24%

2012 vs. 2011 Taxes other than income taxes decreased primarily due to a decrease in our U.S. Onshore revenues, on which the majority of our production taxes are assessed.

2011 vs. 2010 Taxes other than income taxes increased 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,				
	2012	Change	2011	Change	2010
	($ in millions)				
Interest based on debt outstanding	$440	+6%	$414	+2%	$408
Capitalized interest	(48)	-33%	(72)	-5%	(76)
Early retirement of debt	—	N/M	—	-100%	19
Other	14	+33%	10	-17%	12
Interest expense	$406	+15%	$352	-3%	$363

2012 vs. 2011 Interest expense increased primarily due to additional debt borrowings and lower capitalized interest, partially offset by lower weighted average interest rates. Borrowings were primarily used to fund capital expenditures in excess of our operating cash flow and 2012 divestiture proceeds.

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.

Restructuring Costs

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Office consolidation:			
Employee severance and retention	$77	$—	$—
Lease obligations and other	3	—	—
Total	80	—	—
Offshore divestitures:			
Employee severance	(3)	8	(27)
Lease obligations and other	(3)	(10)	84
Total	(6)	(2)	57
Restructuring costs (1)	$74	$ (2)	$ 57

(1) Restructuring costs related to our discontinued operations totaled $(2) million and $(4) million in 2011 and 2010, respectively. These costs primarily consist of employee severance and are not included in the table. There were no costs related to discontinued operations in 2012.

Office Consolidation

In October 2012, we announced plans to consolidate our U.S. personnel into a single operations group centrally located at our corporate headquarters in Oklahoma City. As a result, we are in the process of closing our office in Houston and transferring operational responsibilities for assets in South Texas, East Texas and Louisiana to Oklahoma City. This initiative is expected to be substantially complete by the end of the first quarter 2013.

Employee severance – In the fourth quarter of 2012, we recognized $77 million of estimated employee severance costs associated with the office consolidation. This amount was based on estimates of the number employees that would ultimately be impacted by the office consolidation and included amounts related to cash severance costs and accelerated vesting of share-based grants.

Lease obligations and other – As of December 31, 2012, we incurred $3 million of restructuring costs related to certain office space that is subject to non-cancellable operating lease agreements and that we ceased using as a part of the office consolidation. In 2013 we expect to incur approximately $25 million of additional restructuring costs that represent 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.

Divestiture of Offshore Assets

In the fourth quarter of 2009, we announced plans to divest our offshore assets. As of December 31, 2012, we had divested all of our U.S. Offshore and International assets and incurred $196 million of restructuring costs associated with the 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 and other – 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 $13 million of asset impairment charges for leasehold improvements and furniture associated with the office space that we ceased using.

Asset Impairments

	Year Ended December 31, 2012	
	Gross	Net of Taxes
	(In millions)	
U.S. oil and gas assets	$1,793	$1,142
Canada oil and gas assets	163	122
Midstream assets	68	44
Total asset impairments	$2,024	$1,308

Oil and Gas Impairments

Under the full-cost method of accounting, capitalized costs of oil and gas properties are subject to a quarterly full cost ceiling test, which is discussed in Note 1 to the financial statements under "Item 8. Consolidated Financial Statements" of this report.

The oil and gas impairments resulted primarily from declines in the U.S. and Canada full cost ceilings. The lower ceiling values resulted primarily from decreases in the 12-month average trailing prices for oil, natural gas and NGLs, which have reduced proved reserve values.

If pricing conditions do not improve, we may incur full cost ceiling impairments related to our oil and gas property and equipment in 2013.

Midstream Impairments

Due to declining natural gas production resulting from low natural gas and NGL prices, we determined that the carrying amounts of certain of our midstream facilities were not recoverable from estimated future cash flows. Consequently, the assets were written down to their estimated fair values, which were determined using discounted cash flow models.

Other, net

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Accretion of asset retirement obligations	$110	$ 92	$ 92
Interest rate derivatives	15	11	(14)
Foreign currency derivatives	18	(16)	—
Foreign exchange loss (gain)	(15)	25	(7)
Interest income	(36)	(21)	(13)
Other	(14)	(101)	(25)
Other, net	$ 78	$ (10)	$ 33

2012 vs. 2011 Other, net increased primarily due to $88 million of excess insurance recoveries received in 2011 related to certain weather and operational claims.

2011 vs. 2010 Other, net decreased primarily due to excess insurance recoveries received in 2011 as discussed above. The remainder of the variance primarily relates to the net effect of interest rate derivatives 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,		
	2012	2011	2010
Total income tax expense (benefit) (in millions)	$(132)	$2,156	$1,235
U.S. statutory income tax rate	(35%)	35%	35%
State income taxes	6%	1%	1%
Taxation on Canadian operations	(6%)	(2%)	(1%)
Assumed repatriations	0%	17%	4%
Other	(7%)	(1%)	(4%)
Effective income tax rate	(42%)	50%	35%

In the table above, the "other" effect is primarily comprised of permanent tax differences for which the dollar amounts do not increase or decrease as our pre-tax earnings do. Generally, such items typically have an insignificant impact on our effective income tax rate. However, these items have a more noticeable impact to our rate for the year ended December 31, 2012 because of the relatively small pre-tax loss for that period.

During 2011 and 2010, 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 indefinitely reinvested. Accordingly, we recognized deferred income tax expense of $725 million and $144 million during 2011 and 2010, respectively, related to assumed repatriations of earnings from our foreign subsidiaries.

Earnings (Loss) From Discontinued Operations

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Operating earnings	$—	$ 38	$ 567
Gain (loss) on sale of oil and gas properties	(16)	2,552	1,818
Earnings (loss) before income taxes	(16)	2,590	2,385
Income tax expense	5	20	168
Earnings (loss) from discontinued operations	$ (21)	$2,570	$2,217

The earnings (loss) in each period were primarily driven by gains (losses) on the sales of our oil and gas assets in each period. The following table presents gains and losses on our divestiture transactions by year.

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
			(In millions)			
Angola	$ (16)	$ (21)	$ —	$ —	$ —	$ —
Brazil	—	—	2,548	2,548	—	—
Azerbaijan	—	—	—	—	1,543	1,524
China - Panyu	—	—	—	—	308	235
Other	—	—	4	4	(33)	(27)
Total	$ (16)	$ (21)	$2,552	$2,552	$1,818	$1,732

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,		
	2012	2011	2010
		(In millions)	
Operating cash flow - continuing operations	$ 4,930	$ 6,246	$ 5,022
Debt activity, net	1,921	4,187	(1,782)
Divestitures of property and equipment	1,539	3,380	7,002
Capital expenditures	(8,225)	(7,534)	(6,476)
Shareholder distributions	(324)	(2,610)	(1,449)
Other	81	(46)	107
Net change in cash and short-term investments	$ (78)	$ 3,623	$ 2,424
Cash and short-term investments at end of period	$ 6,980	$ 7,058	$ 3,435

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 2012. Our operating cash flow decreased 21 percent during 2012 primarily due to lower commodity prices and higher expenses, partially offset by additional cash flow from our production growth and higher realized gains from our commodity derivatives.

During 2012 our operating cash flow funded approximately three-fourths of our cash payments for capital expenditures, net of divestitures proceeds. Leveraging our liquidity, we used debt to fund the remainder of our cash-based capital expenditures.

Debt Activity, Net

During 2012, we increased our debt borrowings by $1.9 billion as a result of issuing $2.5 billion of long-term debt and repaying approximately $0.6 billion of outstanding short-term debt. The additional borrowings were primarily used to fund capital expenditures in excess of our operating cash flow.

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.

Divestitures of Property and Equipment

During 2012, we closed joint venture transactions with Sinopec and Sumitomo. Sinopec paid approximately $900 million in cash and received a 33.3 percent interest in five of our new ventures exploration plays in the U.S. Sinopec is also funding approximately $1.6 billion of our share of future exploration, development and drilling costs associated with these plays. Sumitomo paid approximately $400 million and received a 30 percent interest in the Cline and Midland-Wolfcamp Shale plays in Texas. Additionally, Sumitomo is funding approximately $1.0 billion of our share of future exploration, development and drilling costs associated with these plays. At December 31, 2012, Sinopec's and Sumitomo's remaining commitment to fund our share of future costs associated with these plays was approximately $2.3 billion.

Also in 2012, we sold our West Johnson County Plant and gathering system in north Texas for approximately $90 million and divested our Angola operations for approximately $71 million.

In 2011 and 2010, our divestitures primarily related to the divestitures of our offshore assets.

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,		
	2012	2011	2010
		(In millions)	
U.S. Onshore	$5,719	$5,128	$3,689
Canada	1,606	1,571	1,826
North America Onshore	7,325	6,699	5,515
U.S. Offshore	—	—	376
Total oil and gas	7,325	6,699	5,891
Midstream	504	333	236
Other	396	502	349
Total continuing operations	$8,225	$7,534	$6,476

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 $7.3 billion, $6.7 billion and $5.9 billion in 2012, 2011 and 2010, respectively. The increases in exploration and development capital spending in 2012 and 2011 were primarily due to new venture acreage acquisitions and increased drilling and development. With rising oil prices and proceeds from our offshore divestitures, we have increased our onshore North American acreage positions and associated exploration and development activities to drive near-term growth of our liquids, particularly oil, production.

Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas gathering 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 decreased in 2012. This decrease is largely driven by the construction of our new headquarters in Oklahoma City being substantially complete in early 2012.

Shareholder Distributions

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

	2012			2011			2010		
	Amount	Shares	Per Share	Amount	Shares	Per Share	Amount	Shares	Per Share
Repurchases	N/A	N/A	N/A	$2,332	31.3	$74.54	$1,168	17.9	$65.28
Dividends	$324	N/A	$0.80	$ 278	N/A	$ 0.67	$ 281	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 percent of our outstanding shares, at an average price of $71.18 per share.

Liquidity

Historically, our primary sources of capital and liquidity have been our operating cash flow, asset divestiture proceeds 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 lower commodity prices, our operating cash flow from continuing operations decreased 21 percent to $4.9 billion in 2012. 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 2013.

To mitigate some of the risk inherent in prices, we have utilized various derivative financial instruments to set minimum prices on our future production. The key terms to our oil, gas and NGL derivative financial instruments as of December 31, 2012 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 generally true during periods of depressed commodity prices or reduced activity.

Interest Rates – Our operating cash flow can also be impacted by interest rate fluctuations. As of December 31, 2012, we had total debt of $11.6 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 3.8 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, prepayments or collateral postings.

As recent years indicate, we have a history of investing more than 100 percent 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 $3.0 billion syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility has an initial maturity date of October 24, 2017. However, prior to the maturity date, we have the option to extend the maturity for up to two additional one-year periods, subject to the approval of the lenders.

Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of December 31, 2012, we had $2.9 billion of available capacity under our syndicated, unsecured Senior Credit Facility, net of letters of credit outstanding.

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 write-downs, such as full cost ceiling impairments. As of December 31, 2012, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2012, as calculated pursuant to the terms of the agreement, was 25.4 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 $5.0 billion of short-term credit under our 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, 2012, we had $3.2 billion of borrowings under our commercial paper program.

At the end of 2012, we held approximately $7.0 billion of cash and short-term investments. Included in this total was $6.5 billion of cash and short-term investments held by our foreign subsidiaries. We do not currently expect to repatriate the $6.5 billion to the U.S. This expectation is based on planned investments to develop and grow our Canadian business, our current forecasts for both our U.S. and Canadian operations, currently favorable borrowing conditions in the U.S., and existing U.S. income tax laws pertaining to repatriations of foreign earnings. Therefore, with limited cash and short-term investments in the U.S., we expect to continue funding our U.S. business with a combination of our U.S.-based operating cash flow and borrowings. We do not expect near-term borrowing increases will have a material negative effect on our overall liquidity or financial condition.

If we were to repatriate a portion or all of the cash and short-term investments held by our foreign subsidiaries, we would recognize and pay current income taxes in accordance with current U.S. tax law. The payment of such additional income tax would materially decrease the amount of cash and short-term investments ultimately available to fund our business.

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 112.5 basis points to a new rate of LIBOR plus 125 basis points. A ratings downgrade could also adversely impact our ability to economically access debt markets in the future. As of December 31, 2012, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures

Our 2013 capital expenditures are expected to range from $6.4 billion to $7.0 billion, including $5.3 billion to $5.8 billion for our oil and gas operations, which include capitalized G&A and interest. 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 2013 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2013 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2013, our existing commodity hedging contracts, available cash balances and credit availability, we anticipate having adequate capital resources to fund our 2013 capital expenditures.

Additionally, our financial and operational flexibility has been further enhanced by the joint venture transactions that we entered into in 2012 with Sinopec and Sumitomo. Pursuant to the joint venture agreements, Sinopec and Sumitomo are subject to drilling carries with remaining commitments that totaled $2.3 billion at the end of 2012. These drilling carries will fund 70 percent of our capital requirements related to joint venture properties, which results in our partners paying approximately 80 percent of the overall development costs during the carry period. This is allowing us to accelerate the de-risking and commercialization of the joint venture properties without diverting capital from our core development projects. We expect the remaining carries will be realized by the end of 2014.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2012, 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)	$11,664	$3,189	$ 500	$1,250	$ 6,725
Interest expense (2)	7,662	456	870	837	5,499
Purchase obligations (3)	6,995	826	1,723	1,705	2,741
Operational agreements (4)	3,496	391	797	682	1,626
Asset retirement obligations (5)	2,095	99	134	140	1,722
Drilling and facility obligations (6)	950	777	173	—	—
Lease obligations (7)	312	50	65	56	141
Other (8)	339	122	149	53	15
Total North America	$33,513	$5,910	$4,411	$4,723	$18,469

(1) Debt amounts represent scheduled maturities of our debt obligations at December 31, 2012, excluding $20 million of net discounts included in the carrying value of debt.

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

(3) Purchase obligation amounts represent contractual commitments primarily to purchase condensate at market prices for use at our heavy oil projects in Canada. We have entered into these agreements because condensate is an integral part of the heavy oil production and transportation processes. 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) 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 downstream markets.
(5) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2012 balance sheet.
(6) 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.
(7) Lease obligations consist primarily of non-cancelable leases for office space and equipment used in our daily operations.
(8) These amounts include $216 million related to uncertain tax positions.

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 2012, 92 percent 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 two 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 write-downs 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 write-downs. 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 write-down.

Derivative Financial Instruments

We periodically enter into derivative financial instruments with respect to a portion of our oil, gas and NGL production to hedge 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.

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 fifteen separate counterparties, and our interest rate derivative contracts are held with four 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.

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 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, 2012, the date of our last impairment test, the fair values of our U.S. and Canadian reporting units 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 could result in 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.

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.

Non-GAAP Measures

We make reference to "adjusted earnings", "adjusted earnings per share" and "adjusted cash flow" in "Overview of 2012 Results" in this Item 7 that are not required by or presented in accordance with GAAP. These non-GAAP measures should not be considered as alternatives to GAAP measures. Adjusted earnings represents net earnings excluding certain non-cash or non-recurring items that are typically excluded by securities analysts in their published estimates of our financial results. Adjusted cash flow represents cash flow from operating activities excluding certain balance sheet changes and non-recurring items that are typically excluded by securities analysts in their published estimates of our financial results. We believe these non-GAAP measures facilitate comparisons of our performance to earnings and cash flow estimates published by securities analysts. We also believe these non-GAAP measures can facilitate comparisons of our performance between periods and to the performance of our peers. The tables below exclude amounts related to our discontinued operations.

Adjusted Earnings and Adjusted Earnings Per Share

Below are reconciliations of our adjusted earnings and earnings per share to their comparable GAAP measures.

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
Earnings (loss) (GAAP)	$ (185)	$2,134	$2,333
Adjustments (net of taxes):			
Asset impairments	1,308	—	—
Oil, gas and NGL derivatives	112	(310)	50
Restructuring costs	49	(2)	36
Interest rate and other financial instruments	21	72	19
Income tax accrual adjustment	17	(42)	(58)
U.S. income taxes on foreign earnings	—	744	144
Insurance proceeds	—	(60)	—
Additional interest costs on debt retirement	—	—	12
Adjusted earnings (Non-GAAP)	$1,322	$2,536	$2,536

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
Diluted earnings per share (GAAP)	$(0.47)	$ 5.10	$ 5.29
Adjustments (net of taxes):			
Asset impairments	3.23	—	—
Oil, gas and NGL derivatives	0.28	(0.74)	0.11
Restructuring costs	0.13	—	0.08
Interest rate and other financial instruments	0.05	0.17	0.04
Income tax accrual adjustment	0.04	(0.10)	(0.13)
U.S. income taxes on foreign earnings	—	1.78	0.33
Insurance proceeds	—	(0.14)	—
Additional interest costs on debt retirement	—	—	0.03
Adjusted earnings per share (Non-GAAP)	$ 3.26	$ 6.07	$ 5.75

Adjusted Cash Flow

Below is a reconciliation of our adjusted cash flow to its comparable GAAP measure.

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Cash flow from operating activities (GAAP)	$4,930	$6,246	$5,022
Adjustments (net of taxes):			
Changes in assets and liabilities	(19)	275	282
Cash flow from operating activities before balance sheet changes (Non-GAAP)	4,911	6,521	5,304
Income tax accrual adjustment	(44)	(244)	(329)
Restructuring costs	25	(3)	64
Insurance proceeds	—	(67)	—
Current taxes on divestitures	—	18	783
Current taxes on debt retirement	—	—	18
Adjusted cash flow (Non-GAAP)	$4,892	$6,225	$5,840

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, 2012 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, 2012, 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	$(162)	$156
Oil derivatives	$(214)	$229
NGL derivatives	$ (2)	$ 2

Interest Rate Risk

At December 31, 2012, we had total debt of $11.6 billion. Our long-term debt of $8.4 billion bears fixed interest rates averaging 5.4 percent. The remaining $3.2 billion of commercial paper borrowings bears interest at fixed rates which averaged 0.37 percent. Our commercial paper borrowings typically have maturity rates between 1 and 90 days.

As of December 31, 2012, 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. A 10 percent change in these forward curves would not have materially impacted our balance sheet at December 31, 2012.

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 an 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, 2012 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, 2012, we held foreign currency exchange forward contracts to hedge exposures to fluctuations in exchange rates on the Canadian-dollar cash and intercompany loans. 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, 2012, 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, 2012 and 2011, 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, 2012. We also have audited Devon Energy Corporation's internal control over financial reporting as of December 31, 2012, 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, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012, 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, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Oklahoma City, Oklahoma
February 21, 2013

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
Revenues:			
Oil, gas and NGL sales	$7,153	$ 8,315	$7,262
Oil, gas and NGL derivatives	693	881	811
Marketing and midstream revenues	1,656	2,258	1,867
Total revenues	9,502	11,454	9,940
Expenses and other, net:			
Lease operating expenses	2,074	1,851	1,689
Marketing and midstream operating costs and expenses	1,246	1,716	1,357
Depreciation, depletion and amortization	2,811	2,248	1,930
General and administrative expenses	692	585	563
Taxes other than income taxes	414	424	380
Interest expense	406	352	363
Restructuring costs	74	(2)	57
Asset impairments	2,024	—	—
Other, net	78	(10)	33
Total expenses and other, net	9,819	7,164	6,372
Earnings (loss) from continuing operations before income taxes	(317)	4,290	3,568
Current income tax expense (benefit)	52	(143)	516
Deferred income tax expense (benefit)	(184)	2,299	719
Earnings (loss) from continuing operations	(185)	2,134	2,333
Earnings (loss) from discontinued operations, net of tax	(21)	2,570	2,217
Net earnings (loss)	$ (206)	$ 4,704	$4,550
Basic net earnings (loss) per share:			
Basic earnings (loss) from continuing operations per share	$ (0.47)	$ 5.12	$ 5.31
Basic earnings (loss) from discontinued operations per share	(0.05)	6.17	5.04
Basic net earnings (loss) per share	$ (0.52)	$ 11.29	$10.35
Diluted net earnings (loss) per share:			
Diluted earnings (loss) from continuing operations per share	$ (0.47)	$ 5.10	$ 5.29
Diluted earnings (loss) from discontinued operations per share	(0.05)	6.15	5.02
Diluted net earnings (loss) per share	$ (0.52)	$ 11.25	$10.31
Comprehensive earnings (loss):			
Net earnings (loss)	$ (206)	$ 4,704	$4,550
Other comprehensive earnings (loss), net of tax:			
Foreign currency translation	194	(191)	377
Pension and postretirement plans	2	6	(2)
Other comprehensive earnings (loss), net of tax	196	(185)	375
Comprehensive earnings (loss)	$ (10)	$ 4,519	$4,925

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Cash flows from operating activities:			
Net earnings (loss)	$ (206)	$ 4,704	$ 4,550
(Earnings) loss from discontinued operations, net of tax	21	(2,570)	(2,217)
Adjustments to reconcile earnings from continuing operations to net cash from operating activities:			
Depreciation, depletion and amortization	2,811	2,248	1,930
Asset impairments	2,024	—	—
Deferred income tax expense (benefit)	(184)	2,299	719
Unrealized change in fair value of financial instruments	205	(401)	107
Other noncash charges	240	241	215
Net decrease (increase) in working capital	(50)	185	(273)
Decrease (increase) in long-term other assets	(36)	33	32
Increase (decrease) in long-term other liabilities	105	(493)	(41)
Cash from operating activities - continuing operations	4,930	6,246	5,022
Cash from operating activities - discontinued operations	26	(22)	456
Net cash from operating activities	4,956	6,224	5,478
Cash flows from investing activities:			
Capital expenditures	(8,225)	(7,534)	(6,476)
Proceeds from property and equipment divestitures	1,468	129	4,310
Purchases of short-term investments	(4,106)	(6,691)	(145)
Redemptions of short-term investments	3,266	5,333	—
Other	14	(29)	2
Cash from investing activities - continuing operations	(7,583)	(8,792)	(2,309)
Cash from investing activities - discontinued operations	57	3,146	2,197
Net cash from investing activities	(7,526)	(5,646)	(112)
Cash flows from financing activities:			
Proceeds from borrowings of long-term debt, net of issuance costs	2,458	2,221	—
Net short-term borrowings (repayments)	(537)	3,726	(1,432)
Debt repayments	—	(1,760)	(350)
Credit facility borrowings	750	—	—
Credit facility repayments	(750)	—	—
Proceeds from stock option exercises	27	101	111
Repurchases of common stock	—	(2,332)	(1,168)
Dividends paid on common stock	(324)	(278)	(281)
Excess tax benefits related to share-based compensation	5	13	16
Net cash from financing activities	1,629	1,691	(3,104)
Effect of exchange rate changes on cash	23	(4)	17
Net change in cash and cash equivalents	(918)	2,265	2,279
Cash and cash equivalents at beginning of period	5,555	3,290	1,011
Cash and cash equivalents at end of period	$ 4,637	$ 5,555	$ 3,290

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,637	$ 5,555
Short-term investments	2,343	1,503
Accounts receivable	1,245	1,379
Other current assets	746	868
Total current assets	8,971	9,305
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	69,410	61,696
Not subject to amortization	3,308	3,982
Total oil and gas	72,718	65,678
Other	5,630	5,098
Total property and equipment, at cost	78,348	70,776
Less accumulated depreciation, depletion and amortization	(51,032)	(46,002)
Property and equipment, net	27,316	24,774
Goodwill	6,079	6,013
Other long-term assets	960	1,025
Total assets	$ 43,326	$ 41,117
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,451	$ 1,471
Revenues and royalties payable	750	678
Short-term debt	3,189	3,811
Other current liabilities	613	778
Total current liabilities	6,003	6,738
Long-term debt	8,455	5,969
Asset retirement obligations	1,996	1,496
Other long-term liabilities	901	721
Deferred income taxes	4,693	4,763
Stockholders' equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 406 million and 404 million shares in 2012 and 2011, respectively	41	40
Additional paid-in capital	3,688	3,507
Retained earnings	15,778	16,308
Accumulated other comprehensive earnings	1,771	1,575
Total stockholders' equity	21,278	21,430
Commitments and contingencies (Note 18)		
Total liabilities and stockholders' equity	$ 43,326	$ 41,117

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Total Stockholders' Equity
				(In millions)			
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$1,385	$ —	$15,570
Net earnings	—	—	—	4,550	—	—	4,550
Other comprehensive earnings, 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	—	—	—	4,704	—	—	4,704
Other comprehensive 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
Net loss	—	—	—	(206)	—	—	(206)
Other comprehensive earnings, net of tax	—	—	—	—	196	—	196
Stock option exercises	1	1	49	—	—	(23)	27
Restricted stock grants, net of cancellations	1	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(29)	(29)
Common stock retired	—	—	(52)	—	—	52	—
Common stock dividends	—	—	—	(324)	—	—	(324)
Share-based compensation	—	—	179	—	—	—	179
Share-based compensation tax benefits	—	—	5	—	—	—	5
Balance as of December 31, 2012	406	$ 41	$ 3,688	$15,778	$1,771	$ —	$21,278

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, natural gas and NGLs. 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 2012, 2011 and 2010, 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 intend to 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 to hedge 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 typically 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 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. Devon periodically enters into foreign exchange forward contracts to manage its exposure to fluctuations in exchange rates.

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, 2012, 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, interest rates and foreign currency 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 acceptable 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. As of December 31, 2012, Devon held $63 million of cash collateral, which represented the estimated fair value of certain derivative positions in excess of Devon's credit guidelines. The collateral is reported in other current liabilities in the accompanying balance sheet.

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 generally 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 and the consolidation of its U.S. operations announced in October 2012, 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 indefinitely 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 2012 and 2011, Devon invested a portion of its joint venture proceeds and 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 $64 million and $84 million at December 31, 2012 and 2011, 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, capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, may not exceed the full cost "ceiling" at the end of each quarter. The ceiling is calculated separately for each country and is based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent per annum, net of related tax effects. The 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.

Estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months. 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, 2012, 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 four 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 60 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. Devon's asset retirement obligations include estimated environmental remediation costs which arise from normal operations and are associated with the retirement of such long-lived assets. 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 2012, 2011 and 2010. 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 increase in Devon's goodwill from 2011 to 2012 was due to changes in the exchange rate between the U.S. dollar and the Canadian dollar.

	December 31,	
	2012	2011
	(In millions)	
U.S.	$3,046	$3,046
Canada	3,033	2,967
Total	$6,079	$6,013

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 resulting from improper operation of assets 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.

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. 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 an average exchange rate during the reporting period. 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, 2012, 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.

	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 2013	31,000	$104.13	45,753	$91.19	$115.97	10,000	$120.00
Q1-Q4 2014	4,000	$100.49	2,000	$90.00	$111.13	10,000	$120.00

	Basis Swaps		
Period	**Index**	**Volume (Bbls/d)**	**Weighted Average Differential to WTI ($/Bbl)**
Q1-Q2 2013	Western Canadian Select	3,000	$(19.58)

As of December 31, 2012, Devon had the following open natural gas derivative positions. The first table presents Devon's natural gas swaps and collars that settle against the Inside FERC first of the month Henry Hub index. The second table presents Devon's natural gas swaps and collars that settle against the AECO index.

	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 2013	560,000	$4.18	461,370	$3.53	$4.33	—	—
Q1-Q4 2014	250,000	$4.09	—	—	—	250,000	$5.00

	Price Swaps	
Period	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
Q1-Q4 2013	28,435	$3.64

	Basis Swaps		
Period	**Index**	**Volume (MMBtu/d)**	**Weighted Average Differential to Henry Hub ($/MMBtu)**
Q1-Q4 2013	El Paso Natural Gas	20,000	$(0.12)
Q1-Q4 2013	Panhandle Eastern Pipeline	20,000	$(0.17)

As of December 31, 2012, Devon had the following open NGL derivative positions. Devon's NGL swaps settle against the average of the prompt month OPIS Mont Belvieu, Texas hub.

	Price Swaps		
Period	Product	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)
Q1-Q4 2013	Propane	822	$41.12
Q1-Q4 2013	Ethane	1,973	$15.36

Basis Swaps			
Period	Pay	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q1-Q4 2013	Natural Gasoline	500	$(6.80)

Interest Rate Derivatives

As of December 31, 2012, Devon had the following open interest rate derivative positions:

Notional	Weighted Average Fixed Rate Received	Variable Rate Paid	Expiration
(In millions)			
$ 750	3.88%	Federal funds rate	July 2013

Foreign Currency Derivatives

As of December 31, 2012, Devon had the following open foreign currency derivative positions:

Forward Contract				
Currency	Contract Type	CAD Notional	Weighted Average Fixed Rate Received	Expiration
		(In millions)	(CAD-USD)	
Canadian Dollar	Sell	$755	1.005	March 2013

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	2012	2011	2010
		(In millions)		
Cash settlements:				
Commodity derivatives	Oil, gas and NGL derivatives	$ 870	$392	$ 888
Interest rate derivatives	Other, net	14	77	44
Foreign currency derivatives	Other, net	(19)	16	—
Total cash settlements		865	485	932
Unrealized gains (losses):				
Commodity derivatives	Oil, gas and NGL derivatives	(177)	489	(77)
Interest rate derivatives	Other, net	(29)	(88)	(30)
Foreign currency derivatives	Other, net	1	—	—
Total unrealized gains (losses)		(205)	401	(107)
Net gain recognized on comprehensive statements of earnings		$ 660	$886	$ 825

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

	Balance Sheet Caption	December 31, 2012	December 31, 2011
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$379	$611
Commodity derivatives	Other long-term assets	22	17
Interest rate derivatives	Other current assets	23	30
Interest rate derivatives	Other long-term assets	—	22
Foreign currency derivatives	Other current assets	1	—
Total asset derivatives		$425	$680
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 3	$ 82
Commodity derivatives	Other long-term liabilities	29	—
Total liability derivatives		$ 32	$ 82

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.

In the second quarter of 2012, Devon's stockholders adopted an amendment to the 2009 Long-Term Incentive Plan, which also expires June 2, 2019. This amendment increases the number of shares authorized for issuance from 21.5 million shares to 47.0 million shares. To calculate shares issued under the 2009 Long-Term Incentive Plan subsequent to this amendment, options and stock appreciation rights represent one share and other awards represent 2.38 shares.

Devon also has a stock option plan that was adopted in 2005 under which stock options were issued to certain employees. Options granted under this plan remain exercisable by the employees owning such options, but no new options or restricted stock awards will be granted under this plan. 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 announced in 2009 and the consolidation of its U.S. operations announced in October 2012. 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.

	2012	2011	2010
		(In millions)	
Gross general and administrative expense	$179	$181	$188
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 56	$ 56	$ 58
Related income tax benefit	$ 31	$ 33	$ 40

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.

	2012	2011	2010
Grant-date fair value	$22.20	$23.11	$25.41
Volatility factor	42.5%	46.0%	45.3%
Dividend yield	1.2%	1.0%	1.0%
Risk-free interest rate	1.1%	0.8%	1.1%
Expected term (in years)	6.0	4.2	4.5

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, 2011	10,543	$66.35		
Granted	18	$60.09		
Exercised	(1,390)	$35.16		
Expired	(1,058)	$85.98		
Forfeited	(285)	$68.90		
Outstanding at December 31, 2012	7,828	$69.12	4.24	$0
Vested and expected to vest at December 31, 2012	7,742	$69.14	4.22	$0
Exercisable at December 31, 2012	5,695	$69.35	3.47	$0

The aggregate intrinsic value of stock options that were exercised during 2012, 2011 and 2010 was $34 million, $81 million and $47 million, respectively. As of December 31, 2012, Devon's unrecognized compensation cost related to unvested stock options was $39 million. Such cost is expected to be recognized over a weighted-average period of 2.4 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 restricted stock 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, 2011	5,224	$67.85
Granted	2,870	$53.22
Vested	(2,101)	$68.34
Forfeited	(253)	$67.32
Unvested at December 31, 2012	5,740	$61.75

The aggregate fair value of restricted stock awards and units that vested during 2012, 2011 and 2010 was $112 million, $145 million and $184 million, respectively. As of December 31, 2012, Devon's unrecognized compensation cost related to unvested restricted stock awards and units was $314 million. Such cost is expected to be recognized over a weighted-average period of 2.9 years.

Performance Based Restricted Stock Awards

In December 2012 and 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, 2011	184	$65.10
Granted	224	$52.60
Unvested at December 31, 2012	408	$58.25

As of December 31, 2012, Devon's unrecognized compensation cost related to these awards was $8 million. Such cost is expected to be recognized over a weighted-average period of 2.3 years.

Performance Share Units

In December 2012 and 2011, certain members of Devon's 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.

At the end of the vesting period, recipients receive dividend equivalents with respect to the number of units vested. 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 based on U.S. Treasury rates as of the grant date; (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 the grant-date fair values of performance share units granted and the related assumptions.

	2012	2011
Grant-date fair value	\$61.27 - \$63.48	\$80.24 - \$83.15
Risk-free interest rate	0.26% - 0.36%	0.28% - 0.43%
Volatility factor	30.3%	41.8%
Contractual term (in years)	3.0	3.0

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, 2011	171	\$81.70
Granted	707	\$63.37
Unvested at December 31, 2012 (1)	878	\$66.93

(1) A maximum of 1.8 million common shares could be awarded based upon Devon's final TSR ranking.

As of December 31, 2012, Devon's unrecognized compensation cost related to unvested units was \$40 million. Such cost is expected to be recognized over a weighted-average period of 2.5 years.

4. Restructuring Costs

Office Consolidation

In October 2012, Devon announced plans to consolidate its U.S. personnel into a single operations group centrally located at the company's corporate headquarters in Oklahoma City. As a result, Devon is in the process of closing its office in Houston and transferring operational responsibilities for assets in South Texas, East Texas and Louisiana to Oklahoma City. This initiative is expected to be substantially complete by the end of the first quarter 2013.

Including the $80 million recognized in December of 2012, Devon estimates that it will incur approximately $135 million in restructuring costs in connection with this plan. This estimate includes approximately $85 million of employee severance and relocation costs, $35 million of contract termination and other costs and $15 million of employee retention costs. Approximately $25 million of employee costs relates to accelerated vesting of stock awards, which are non-cash charges. Devon expects to recognize the remainder of the restructuring costs during 2013.

Divestiture of Offshore Assets

In the fourth quarter of 2009, Devon announced plans to divest its offshore assets. As of December 31, 2012, Devon had divested all of its U.S. Offshore and International assets and incurred $196 million of restructuring costs associated with the divestitures.

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 and $(4) million in 2011 and 2010, respectively. These costs primarily related to cash severance and share-based awards and are not included in the schedule below. There were no costs related to discontinued operations in 2012.

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Office consolidation:			
Employee severance	$77	$—	$—
Lease obligations	3	—	—
Total	80	—	—
Offshore divestitures:			
Employee severance	(3)	8	(27)
Lease obligations and other	(3)	(10)	84
Total	(6)	(2)	57
Restructuring costs	$74	$ (2)	$ 57

Office Consolidation

Employee severance and retention - In the fourth quarter of 2012, Devon recognized $77 million of estimated employee severance costs associated with the office consolidation. This amount was based on estimates of the number employees that would ultimately be impacted by office consolidation and included amounts related to cash severance costs and accelerated vesting of share-based grants.

Lease obligations and other - As of December 31, 2012, Devon incurred $3 million of restructuring costs related to certain office space that is subject to non-cancellable operating lease agreements and that it ceased using as a part of the office consolidation. In 2013 Devon expects to incur approximately $25 million of additional restructuring costs that represent 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 it may receive over the term of the leases, as well as the amount of variable operating costs that it will be required to pay under the leases.

Divestiture of Offshore Assets

Lease obligations and other - 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 $13 million of asset impairment charges for leasehold improvements and furniture associated with the office space that it ceased using.

The schedule below summarizes Devon's restructuring liabilities. Devon's restructuring liabilities for cash severance related to its discontinued operations totaled $16 million at December 31, 2010 and are not included in the schedule below. There was no liability related to discontinued operations at the end of 2012 or 2011.

	Other Current Liabilities	Other Long-Term Liabilities	Total
		(In millions)	
Balance as of December 31, 2010	$ 31	$ 51	$ 82
Lease obligations - Offshore	2	(35)	(33)
Employee severance - Offshore	(4)	—	(4)
Balance as of December 31, 2011	29	16	45
Employee severance – Office consolidation	49	—	49
Lease obligations - Offshore	(17)	(7)	(24)
Employee severance - Offshore	(9)	—	(9)
Balance as of December 31, 2012	$ 52	$ 9	$ 61

5. Other, net

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

	Year Ended December 31, 2012	2011	2010
		(In millions)	
Accretion of asset retirement obligations	$110	$ 92	$ 92
Interest rate derivatives	15	11	(14)
Foreign currency derivatives	18	(16)	—
Foreign exchange loss (gain)	(15)	25	(7)
Interest income	(36)	(21)	(13)
Other	(14)	(101)	(25)
Other, net	$ 78	$ (10)	$ 33

During 2011, Devon received $88 million of excess insurance recoveries related to certain weather and operational claims.

6. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31, 2012	2011	2010
	(In millions)		
Current income tax expense (benefit):			
U.S. federal	$ 60	$ (143)	$ 244
Various states	(3)	20	16
Canada and various provinces	(5)	(20)	256
Total current tax expense (benefit)	52	(143)	516
Deferred income tax expense (benefit):			
U.S. federal	(188)	1,986	781
Various states	34	95	21
Canada and various provinces	(30)	218	(83)
Total deferred tax expense (benefit)	(184)	2,299	719
Total income tax expense (benefit)	$(132)	$2,156	$1,235

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

	Year Ended December 31, 2012	2011	2010
	(In millions)		
Expected income tax expense (benefit) based on U.S. statutory tax rate of 35%	$(111)	$1,502	$1,249
Assumed repatriations	—	725	144
State income taxes	20	70	31
Taxation on Canadian operations	(19)	(91)	(60)
Other	(22)	(50)	(129)
Total income tax expense (benefit)	$(132)	$2,156	$1,235

During 2011 and 2010, pursuant to the completed and planned divestitures of Devon's International assets located outside North America, a portion of Devon's foreign earnings were no longer deemed to be indefinitely reinvested. Accordingly, Devon recognized deferred income tax expense of $725 million and $144 million during 2011 and 2010 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, 2012	December 31, 2011
	(In millions)	
Deferred tax assets:		
Net operating loss carryforwards	$ 427	$ 222
Asset retirement obligations	618	447
Pension benefit obligations	129	130
Alternative minimum tax credits	198	—
Other	134	117
Total deferred tax assets	1,506	916
Deferred tax liabilities:		
Property and equipment	(4,970)	(4,475)
Fair value of financial instruments	(141)	(218)
Long-term debt	(198)	(185)
Taxes on unremitted foreign earnings	(936)	(936)
Other	(76)	(27)
Total deferred tax liabilities	(6,321)	(5,841)
Net deferred tax liability	$(4,815)	$(4,925)

Devon has recognized $427 million of deferred tax assets related to various carryforwards available to offset future income taxes. The carryforwards consist of $711 million of U.S. federal net operating loss carryforwards, which expire in 2031, $662 million of Canadian net operating loss carryforwards, which expire between 2029 and 2031, and $153 million of state net operating loss carryforwards, which expire primarily between 2013 and 2031. Devon expects the tax benefits from the U.S. federal net operating loss carryforwards to be utilized between 2013 and 2015. Devon expects the tax benefits from the Canadian and state net operating loss carryforwards to be utilized between 2013 and 2017. 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 its tax carryforwards prior to their expiration. Devon has also recognized a $198 million deferred tax asset related to alternative minimum tax credits which have no expiration date and will be available for use against tax on future taxable income.

As of December 31, 2012, Devon's unremitted foreign earnings totaled approximately $8.0 billion. Of this amount, approximately $5.5 billion was deemed to be indefinitely reinvested into the development and growth of our Canadian business. Therefore, Devon has not recognized a deferred tax liability for U.S. income taxes associated with such earnings. If such earnings were to be repatriated 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 such additional taxes that may be payable due to the inter-relationship of the various factors involved in making such an estimate.

Devon has deemed the remaining $2.5 billion of unremitted earnings not to be indefinitely reinvested. Consequently, Devon has recognized a $936 million deferred tax liability associated with such unremitted earnings as of December 31, 2012. Although Devon has recognized this deferred tax liability, Devon does not currently expect to repatriate its foreign earnings. This expectation is based on Devon's current forecasts for both its U.S. and Canadian operations, currently favorable borrowing conditions in the U.S., and existing U.S. income tax laws pertaining to repatriations of foreign earnings.

Unrecognized Tax Benefits

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

	December 31,	
	2012	2011
	(In millions)	
Balance at beginning of year	$165	$194
Tax positions taken in prior periods	(46)	(3)
Tax positions taken in current year	92	27
Accrual of interest related to tax positions taken	7	(7)
Lapse of statute of limitations	(3)	(41)
Settlements	—	(5)
Foreign currency translation	1	—
Balance at end of year	$216	$165

Devon's unrecognized tax benefit balance at December 31, 2012 and 2011, included $27 million and $20 million of interest and penalties, respectively. If recognized, $176 million of Devon's unrecognized tax benefits as of December 31, 2012 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	2008-2012
Various U.S. states	2008-2012
Canada federal	2004-2012
Various Canadian provinces	2004-2012

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 Per Share

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

	Earnings	Common Shares	Earnings per Share
	(In millions, except per share amounts)		
Year Ended December 31, 2012:			
Loss from continuing operations	$ (185)	404	
Attributable to participating securities	(3)	(4)	
Basic and diluted loss per share	$ (188)	400	$(0.47)
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

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 9 million, 3 million and 6 million in 2012, 2011 and 2010, respectively.

8. Other Comprehensive Earnings

Components of other comprehensive earnings consist of the following:

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Foreign currency translation:			
Beginning accumulated foreign currency translation	$1,802	$1,993	$1,616
Change in cumulative translation adjustment	203	(200)	397
Income tax benefit (expense)	(9)	9	(20)
Ending accumulated foreign currency translation	1,996	1,802	1,993
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(227)	(233)	(231)
Net actuarial loss and prior service cost arising in current year	(47)	(21)	(33)
Income tax benefit	16	8	11
Recognition of net actuarial loss and prior service cost in net earnings	51	30	31
Income tax expense	(18)	(11)	(11)
Ending accumulated pension and postretirement benefits	(225)	(227)	(233)
Accumulated other comprehensive earnings, net of tax	$1,771	$1,575	$1,760

9. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Net decrease (increase) in working capital:			
Change in accounts receivable	$ 140	$(185)	$ 23
Change in other current assets	(128)	125	21
Change in accounts payable	(8)	64	37
Change in revenues and royalties payable	19	144	48
Change in other current liabilities	(73)	37	(402)
Net decrease (increase) in working capital	$ (50)	$ 185	$(273)
Supplementary cash flow data – total operations:			
Interest paid (net of capitalized interest)	$ 334	$ 325	$ 359
Income taxes paid (received)	$ 100	$(383)	$ 955

10. Short-Term Investments

The components of short-term investments include the following:

	December 31,	
	2012	2011
	(In millions)	
Canadian treasury, agency and provincial securities	$1,865	$1,155
U.S. treasuries	429	201
Other	49	147
Short-term investments	$2,343	$1,503

11. Accounts Receivable

The components of accounts receivable include the following:

	December 31,	
	2012	2011
	(In millions)	
Oil, gas and NGL sales	$ 752	$ 928
Joint interest billings	270	247
Marketing and midstream revenues	161	174
Other	72	39
Gross accounts receivable	1,255	1,388
Allowance for doubtful accounts	(10)	(9)
Net accounts receivable	$1,245	$1,379

12. Other Current Assets

The components of other current assets include the following:

	December 31, 2012	December 31, 2011
	(In millions)	
Derivative financial instruments	$403	$641
Inventories	110	102
Income tax receivable	119	35
Current assets held for sale	3	21
Other	111	69
Other current assets	$746	$868

13. Property and Equipment

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

Sinopec Transaction

In April 2012, Devon closed its joint venture transaction with Sinopec International Petroleum Exploration & Production Corporation. Pursuant to the agreement, Sinopec paid approximately $900 million in cash and received a 33.3 percent interest in five of Devon's new ventures exploration plays in the U.S. at closing of the transaction. Additionally, Sinopec is required to fund approximately $1.6 billion of Devon's share of future exploration, development and drilling costs associated with these plays. Devon recognized the cash proceeds received at closing as a reduction to U.S. oil and gas property and equipment. No gain or loss was recognized.

Sumitomo Transaction

In September 2012, Devon closed its joint venture transaction with Sumitomo Corporation. At closing, Sumitomo paid approximately $400 million in cash and received a 30 percent interest in the Cline and Midland-Wolfcamp Shale plays in Texas. Additionally, Sumitomo is required to fund approximately $1.0 billion of Devon's share of future exploration, development and drilling costs associated with these plays. Devon recognized the cash proceeds received at closing as a reduction to U.S. oil and gas property and equipment. No gain or loss was recognized.

Asset Impairments

In the third and fourth quarters of 2012, Devon recognized asset impairments related to its oil and gas property and equipment and its U.S. midstream assets as presented below.

	Q3 2012		Q4 2012		Year Ended December 31, 2012	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)					
U.S. oil and gas assets	$1,106	$705	$687	$437	$1,793	$1,142
Canada oil and gas assets	—	—	163	122	163	122
Midstream assets	22	14	46	30	68	44
Total asset impairments	$1,128	$719	$896	$589	$2,024	$1,308

Oil and Gas Impairments

Under the full-cost method of accounting, capitalized costs of oil and gas properties are subject to a quarterly full cost ceiling test, which is discussed in Note 1.

The oil and gas impairments resulted primarily from declines in the U.S. and Canada full cost ceilings. The lower ceiling values resulted primarily from decreases in the 12-month average trailing prices for oil, natural gas and NGLs, which have reduced proved reserve values.

If pricing conditions do not improve, Devon may incur full cost ceiling impairments related to its oil and gas property and equipment in 2013.

Midstream Impairments

Due to declining natural gas production resulting from low natural gas and NGL prices, Devon determined that the carrying amounts of certain of its midstream facilities were not recoverable from estimated future cash flows. Consequently, the assets were written down to their estimated fair values, which were determined using discounted cash flow models. The fair value of Devon's midstream assets is considered a Level 3 fair value measurement.

Offshore Divestitures

In November 2009, Devon announced plans to divest its offshore assets. In 2012, Devon completed its planned divestiture program. In aggregate, Devon's U.S. and International sales generated total proceeds of $10 billion. 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.

14. Debt and Related Expenses

A summary of Devon's debt is as follows:

	December 31,	
	2012	2011
	(In millions)	
Commercial paper	$ 3,189	$3,726
Other debentures and notes:		
5.625% due January 15, 2014	500	500
Non-interest bearing promissory note due June 29, 2014	—	85
2.40% due July 15, 2016	500	500
1.875% due May 15, 2017	750	—
8.25% due July 1, 2018	125	125
6.30% due January 15, 2019	700	700
4.00% due July 15, 2021	500	500
3.25% due May 15, 2022	1,000	—
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	1,250
4.75% due May 15, 2042	750	—
Net discount on other debentures and notes	(20)	(6)
Total debt	11,644	9,780
Less amount classified as short-term debt	3,189	3,811
Long-term debt	$ 8,455	$5,969

Debt maturities as of December 31, 2012, excluding premiums and discounts, are as follows (in millions):

2013	$ 3,189
2014	500
2015	—
2016	500
2017	750
2018 and thereafter	6,725
Total	$11,664

Credit Lines

Devon has a $3.0 billion syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility has an initial maturity date of October 24, 2017. However, prior to the maturity date, Devon has the option to extend the maturity for up to two additional one-year periods, subject to the approval of the lenders.

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 $3.8 million that is payable quarterly in arrears. As of December 31, 2012, 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, as defined in the credit agreement, to be no greater 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 write-downs such as full cost ceiling impairments or goodwill impairments. As of December 31, 2012, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 25.4 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, 2012, Devon's weighted average borrowing rate on its commercial paper borrowings was 0.37 percent.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2012, as listed in the table presented at the beginning of this note.

In 2012, 2011, 2009 and 2002 Devon issued senior notes that are unsecured and unsubordinated obligations of Devon. Devon used the net proceeds to repay outstanding commercial paper and credit facility borrowings. The schedule below summarizes the key terms of these notes ($ in millions).

	May 2012	July 2011	January 2009	March 2002
1.875% due May 15, 2017	$ 750	$ —	$ —	$ —
3.25% due May 15, 2022	1,000	—	—	—
4.75% due May 15, 2042	750	—	—	—
2.40% due July 15, 2016	—	500	—	—
4.00% due July 15, 2021	—	500	—	—
5.60% due July 15, 2041	—	1,250	—	—
5.625% due January 15, 2014	—	—	500	—
6.30% due January 15, 2019	—	—	700	—
7.95% due April 15, 2032	—	—	—	1,000
Discount and issuance costs	(35)	(29)	(13)	(14)
Net proceeds	$2,465	$2,221	$1,187	$ 986

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, 2012, 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 (In millions)	Effective Rate of Debt Assumed
8.250% due July 2018 (principal of $125 million)	$147	5.5%
7.500% due September 2027 (principal of $150 million)	$169	6.5%

7.875% 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.

Interest Expense

The following schedule includes the components of interest expense.

	Year Ended December 31, 2012	2011	2010
	(In millions)		
Interest based on debt outstanding	$440	$414	$408
Capitalized interest	(48)	(72)	(76)
Early retirement of debt	—	—	19
Other	14	10	12
Interest expense	$406	$352	$363

15. Asset Retirement Obligations

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

	Year Ended December 31, 2012	2011
	(In millions)	
Asset retirement obligations as of beginning of period	$1,563	$1,497
Liabilities incurred	90	53
Liabilities settled	(86)	(82)
Revision of estimated obligation	420	25
Liabilities assumed by others	(23)	—
Accretion expense on discounted obligation	110	92
Foreign currency translation adjustment	21	(22)
Asset retirement obligations as of end of period	2,095	1,563
Less current portion	99	67
Asset retirement obligations, long-term	$1,996	$1,496

During 2012, Devon recognized revisions to its asset retirement obligations totaling $420 million. The primary factor contributing to this revision was an overall increase in abandonment cost estimates for certain of its production operations facilities.

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 $31 million and $32 million at December 31, 2012 and 2011, 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 either contributory or non-contributory, depending on the type of plan. 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 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 was $1.2 billion at December 31, 2012 and

2011. Devon's benefit obligations and plan assets are measured each year as of December 31. Devon's 2012 plan settlements relate to a plan amendment which removed a dollar cap on lump sum payments and revised optional forms of payment to include a lump sum distribution feature. 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, 2012 and 2011.

	Pension Benefits		Postretirement Benefits	
	2012	2011	2012	2011
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,303	$1,124	$ 37	$ 43
Service cost	43	37	1	1
Interest cost	60	60	1	2
Actuarial loss (gain)	95	123	(4)	(8)
Plan amendments	14	—	—	5
Plan curtailments	(20)	—	1	—
Plan settlements	(93)	—	—	(4)
Foreign exchange rate changes	1	(1)	—	—
Participant contributions	—	—	3	3
Benefits paid	(43)	(40)	(5)	(5)
Benefit obligation at end of year	1,360	1,303	34	37
Change in plan assets:				
Fair value of plan assets at beginning of year	1,187	632	—	—
Actual return on plan assets	102	141	—	—
Employer contributions	11	454	2	7
Participant contributions	—	—	3	3
Plan settlements	(93)	—	—	(5)
Benefits paid	(43)	(40)	(5)	(5)
Foreign exchange rate changes	1	—	—	—
Fair value of plan assets at end of year	1,165	1,187	—	—
Funded status at end of year	$ (195)	$ (116)	$ (34)	$ (37)
Amounts recognized in balance sheet:				
Noncurrent assets	$ 62	$ 116	$—	$—
Current liabilities	(12)	(10)	(3)	(3)
Noncurrent liabilities	(245)	(222)	(31)	(34)
Net amount	$ (195)	$ (116)	$ (34)	$ (37)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 340	$ 348	$ (11)	$ (9)
Prior service cost (credit)	25	18	(4)	(5)
Total	$ 365	$ 366	$ (15)	$ (14)

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 $10 million and $8 million for 2012 and 2011, respectively, 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, 2012 and 2011 as presented in the table below.

	December 31, 2012	December 31, 2011
	(In millions)	
Projected benefit obligation	$257	$232
Accumulated benefit obligation	$216	$189
Fair value of plan assets	$—	$—

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		
	2012	2011	2010	2012	2011	2010
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 43	$ 37	$ 33	$ 1	$ 1	$ 1
Interest cost	60	60	58	1	2	3
Expected return on plan assets	(64)	(42)	(36)	—	—	—
Curtailment and settlement expense	26	—	—	1	(3)	—
Recognition of net actuarial loss (gain)	24	32	27	(1)	—	—
Recognition of prior service cost	3	3	3	(1)	(2)	1
Total net periodic benefit cost	92	90	85	1	(2)	5
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	37	23	50	(4)	(7)	1
Prior service cost (credit) arising in current year	14	—	4	—	5	(22)
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost	(45)	(32)	(27)	1	3	—
Recognition of prior service cost, including curtailment, in net periodic benefit cost	(8)	(3)	(3)	1	2	(1)
Total other comprehensive loss (earnings)	(2)	(12)	24	(2)	3	(22)
Total recognized	$ 90	$ 78	$109	$ (1)	$ 1	$ (17)

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 2013.

	Pension Benefits	Postretirement Benefits
	(In millions)	
Net actuarial loss (gain)	$22	$ (1)
Prior service cost (credit)	4	—
Total	$26	$ (1)

Assumptions

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

	Pension Benefits			Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Assumptions to determine benefit obligations:						
Discount rate	3.85%	4.65%	5.50%	3.30%	4.25%	4.90%
Rate of compensation increase	4.48%	4.97%	6.94%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	4.65%	5.50%	6.00%	4.25%	4.90%	5.70%
Expected return on plan assets	5.48%	6.48%	6.94%	N/A	N/A	N/A
Rate of compensation increase	4.97%	6.94%	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 2012 benefit obligation for the pension plans, a 4.48 percent 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 2012 benefit obligation for the other postretirement medical plans, an 8.2 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease annually to an ultimate rate of 5 percent 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, 2012, by $2 million and would change the 2013 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.

	December 31,	
	2012	2011
Fixed income	70%	70%
Equity	20%	20%
Other	10%	10%

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

	As of December 31, 2012				
			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	39.4%	$ 459	$ 65	$394	$—
Corporate bonds	26.5%	308	256	52	—
Other bonds	2.4%	28	28	—	—
Total fixed-income securities	68.3%	795	349	446	—
Equity securities:					
Global (large, mid, small cap)	20.5%	239	—	239	—
Other securities:					
Hedge fund & alternative investments	10.3%	120	17	—	103
Short-term investment funds	0.9%	11	—	11	—
Total other securities	11.2%	131	17	11	103
Total investments	100.0%	$1,165	$366	$696	$103

	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

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.

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, 2010	$ 58
Purchases	33
Investment returns	(1)
December 31, 2011	90
Purchases	6
Investment returns	7
December 31, 2012	$103

Expected Cash Flows

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

	Pension Benefits	Postretirement Benefits
	(In millions)	
Devon's 2013 contributions	$ 11	$ 3
Benefit payments:		
2013	$ 60	$ 3
2014	$ 61	$ 3
2015	$ 63	$ 3
2016	$ 65	$ 3
2017	$ 67	$ 3
2018 to 2022	$386	$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 2013, the $11 million of pension benefits is expected to be funded from the trusts established for the nonqualified plans and the $3 million of 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,		
	2012	2011	2010
		(In millions)	
401(k) and enhanced contribution plans	$36	$33	$32
Canadian pension and savings plans	23	21	17
Total	$59	$54	$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, 2012, 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

In fourth quarter of 2011, Devon completed its 2010 repurchase program. In total, Devon repurchased 49.2 million shares for $3.5 billion, or $71.18 per share.

Dividends

Devon paid common stock dividends of $324 million, $278 million and $281 million in 2012, 2011 and 2010 respectively. The quarterly cash dividend was $0.16 per share in 2010 and the first quarter of 2011. Devon increased the dividend rate to $0.17 per share in the second quarter of 2011 and further increased the dividend rate to $0.20 per share in the first quarter of 2012.

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. Actual amounts could differ materially from management's estimates.

Royalty Matters

Numerous natural gas producers and related parties, including Devon, have been named in various lawsuits alleging royalty underpayments. The suits allege that the producers and related parties used below-market prices, made improper deductions, used improper measurement techniques and entered into gas purchase and processing arrangements with affiliates that resulted in underpayment of royalties in connection with natural gas and NGLs produced and sold. Devon's largest exposure for such matters relates to royalties in New Mexico. 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 remediation costs. 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. Devon does not have a legal right of set off with respect to the judgment. Therefore, it has recorded a $133 million long-term liability relating to the judgment with an offsetting $133 million long-term receivable relating to its right to be indemnified by Rees-Jones and certain other parties pursuant to the indemnification agreement. Both Rees-Jones and Devon appealed the judgment.

In December 2012, the plaintiffs and Rees-Jones reached an agreement in principle to settle all claims related to the 2004 redemption. Under the terms of the agreement, Rees-Jones and Devon will receive full releases for all of the plaintiffs' claims related to the Chief redemption. All settlement payments will be funded entirely by Rees-Jones. The settlement is contingent upon the execution of a formal settlement agreement and release, which is currently being negotiated by the parties. Devon does not expect to have any net exposure as a result of this matter.

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 terms in excess of one year as of December 31, 2012.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases
		(In millions)		
2013	$ 826	$777	$ 391	$ 50
2014	862	173	406	34
2015	861	—	391	31
2016	861	—	340	29
2017	844	—	342	27
Thereafter	2,741	—	1,626	141
Total	$6,995	$950	$3,496	$312

Purchase obligation amounts represent contractual commitments primarily to purchase condensate at market prices for use at Devon's heavy oil projects in Canada. Devon has entered into these agreements because condensate is an integral part of the heavy oil production and transportation processes. 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 the obligation 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 downstream markets.

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, $42 million and $57 million in 2012, 2011 and 2010, respectively.

19. Fair Value Measurements

The following tables provide carrying value and fair value measurement information for certain of 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, 2012 and December 31, 2011. Therefore, such financial assets and liabilities are not presented in the following tables. Additionally, information regarding the fair values of Devon's midstream and pension plan assets is provided in Note 13 and Note 16, respectively.

			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2012 assets (liabilities):					
Cash equivalents	$ 4,149	$ 4,149	$ 200	$ 3,949	$ —
Short-term investments	$ 2,343	$ 2,343	$ 429	$ 1,914	$ —
Long-term investments	$ 64	$ 64	$ —	$ —	$ 64
Commodity derivatives	$ 401	$ 401	$ —	$ 401	$ —
Commodity derivatives	$ (32)	$ (32)	$ —	$ (32)	$ —
Interest rate derivatives	$ 23	$ 23	$ —	$ 23	$ —
Foreign currency derivatives	$ 1	$ 1	$ —	$ 1	$ —
Debt	$(11,644)	$(13,435)	$ —	$(13,435)	$ —

			Fair Value Measurements Using		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2011 assets (liabilities):					
Cash equivalents	$ 5,123	$ 5,123	$ 929	$ 4,194	$ —
Short-term investments	$ 1,503	$ 1,503	$ 201	$ 1,302	$ —
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)

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 securities 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 Canadian agency and provincial securities and commercial paper investments. The fair value is based upon quotes from independent third parties, which approximate the carrying value.

Commodity, interest rate and foreign currency derivatives — The fair values of commodity, interest rate and foreign currency derivatives are estimated using internal discounted cash flow calculations based upon forward curves and data obtained from independent third parties for contracts with similar terms or data 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 and credit facility borrowings are the carrying values.

Level 3 Fair Value Measurements

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 continued receipts of principal at par, the collection of all accrued interest to date, the probability of full repayment of the securities considering the U.S. government guarantees substantially all of the underlying student loans, and the AAA credit rating of the securities. 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, 2012 and December 31, 2011.

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, or similar notes, were not available. Therefore, Devon used valuation techniques that relied on unobservable inputs to estimate the fair value of its promissory note. The fair value of this debt was estimated using internal discounted cash flow calculations based upon estimated future payment schedules and a 3.125 percent 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.

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

	Year Ended December 31,	
	2012	2011
	(In millions)	
Long-term investments balance at beginning of period	$ 84	$ 94
Redemptions of principal	(20)	(10)
Long-term investments balance at end of period	$ 64	$ 84

	Year Ended December 31,	
	2012	2011
	(In millions)	
Debt balance at beginning of period	$ (85)	$(144)
Foreign exchange translation adjustment	(1)	1
Accretion of promissory note	3	(5)
Redemptions of principal	83	63
Debt balance at end of period	$ —	$ (85)

20. Discontinued Operations

In March 2012, Devon received $71 million and recognized a loss of $16 million upon closing the divestiture of its operations in Angola, which completed Devon's offshore divestiture program that was announced in November 2009. In aggregate, Devon's U.S. and International offshore divestitures generated total proceeds of approximately $10 billion, or $8 billion after-tax, assuming repatriation of a substantial portion of the foreign proceeds under current U.S. tax law.

Revenues related to Devon's discontinued operations totaled $43 million and $693 million during 2011 and 2010, respectively. Devon did not have revenues related to its discontinued operations during 2012. The following table presents the earnings (loss) from Devon's discontinued operations.

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Operating earnings	$—	$ 38	$ 567
Gain (loss) on sale of oil and gas properties	(16)	2,552	1,818
Earnings (loss) before income taxes	(16)	2,590	2,385
Income tax expense	5	20	168
Earnings (loss) from discontinued operations	$ (21)	$2,570	$2,217

The following table presents the main classes of assets and liabilities associated with Devon's discontinued operations at December 31, 2011.

	December 31, 2011
	(In millions)
Other current assets	$ 21
Property and equipment, net	132
Total assets	$153
Accounts payable	$ 20
Other current liabilities	28
Total liabilities	$ 48

21. Segment Information

Devon manages its operations through distinct operating segments, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its U.S. operating segments into one reporting segment due to the similar nature of the businesses. However, Devon's Canadian operating segment is reported as a separate reporting segment primarily due to the significant differences between the U.S. and Canadian regulatory environments. 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. Revenues are all from external customers.

	U.S.	Canada	Total
		(In millions)	
Year Ended December 31, 2012:			
Oil, gas and NGL sales	$ 4,679	$ 2,474	$ 7,153
Oil, gas and NGL derivatives	$ 681	$ 12	$ 693
Marketing and midstream revenues	$ 1,542	$ 114	$ 1,656
Depreciation, depletion and amortization	$ 1,824	$ 987	$ 2,811
Interest expense	$ 343	$ 63	$ 406
Asset impairments	$ 1,861	$ 163	$ 2,024
Loss from continuing operations before income taxes	$ (263)	$ (54)	$ (317)
Income tax benefit	$ (97)	$ (35)	$ (132)
Loss from continuing operations	$ (166)	$ (19)	$ (185)
Property and equipment, net	$18,361	$ 8,955	$27,316
Total assets	$24,256	$19,070	$43,326
Capital expenditures	$ 6,511	$ 1,963	$ 8,474
Year Ended December 31, 2011:			
Oil, gas and NGL sales	$ 5,418	$ 2,897	$ 8,315
Oil, gas and NGL derivative	$ 881	$ —	$ 881
Marketing and midstream revenues	$ 2,059	$ 199	$ 2,258
Depreciation, depletion and amortization	$ 1,439	$ 809	$ 2,248
Interest expense	$ 204	$ 148	$ 352
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 assets (1)	$22,622	$18,342	$40,964
Capital expenditures	$ 6,101	$ 1,694	$ 7,795
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
Depreciation, depletion and amortization	$ 1,229	$ 701	$ 1,930
Interest expense	$ 159	$ 204	$ 363
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 assets (1)	$18,320	$13,185	$31,505
Capital expenditures	$ 4,935	$ 1,985	$ 6,920

(1) Amounts in the table above do not include assets held for sale related to Devon's discontinued operations, which totaled $153 million and $1.4 billion in 2011 and 2010, 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, 2012				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	Total
			(In millions)		
Property acquisition costs:					
Proved properties	$ 2	$ —	$ 2	$ 71	$ 73
Unproved properties	1,135	—	1,135	43	1,178
Exploration costs	351	—	351	304	655
Development costs	4,408	—	4,408	1,691	6,099
Costs incurred	$5,896	$ —	$5,896	$2,109	$8,005

	Year Ended December 31, 2011				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	Total
			(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	Total
			(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

Costs incurred in the tables above include additions and revisions to Devon's asset retirement obligations. The proceeds received from our joint venture transactions have not been netted against the costs incurred. At December 31, 2012 the remaining commitment to fund our future costs associated with these joint venture transactions was approximately $2.3 billion.

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 $359 million, $337 million and $311 million in the years 2012, 2011 and 2010, 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 $36 million, $45 million and $37 million in the years 2012, 2011 and 2010, respectively.

Capitalized Costs

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

	December 31, 2012		
	U.S.	Canada	Total
		(In millions)	
Proved properties	$ 46,570	$ 22,840	$ 69,410
Unproved properties	1,703	1,605	3,308
Total oil & gas properties	48,273	24,445	72,718
Accumulated DD&A	(33,098)	(16,039)	(49,137)
Net capitalized costs	$ 15,175	$ 8,406	$ 23,581

	December 31, 2011		
	U.S.	Canada	Total
		(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

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2012.

	Costs Incurred In				
	2012	2011	2010	Prior to 2010	Total
			(In millions)		
Acquisition costs	$ 928	$115	$788	$660	$2,491
Exploration costs	228	142	48	1	419
Development costs	227	70	—	10	307
Capitalized interest	35	36	20	—	91
Total oil and gas properties not subject to amortization	$1,418	$363	$856	$671	$3,308

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, 2012		
	U.S	Canada	Total
		(In millions)	
Oil, gas and NGL sales	$ 4,679	$ 2,474	$ 7,153
Lease operating expenses	(1,059)	(1,015)	(2,074)
Depreciation, depletion and amortization	(1,563)	(963)	(2,526)
General and administrative expenses	(159)	(137)	(296)
Taxes other than income taxes	(340)	(55)	(395)
Asset impairments	(1,793)	(163)	(1,956)
Accretion of asset retirement obligations	(40)	(69)	(109)
Income tax (expense) benefit	99	(3)	96
Results of operations	$ (176)	$ 69	$ (107)
Depreciation, depletion and amortization per Boe	$ 8.55	$ 14.41	$ 10.12

	Year Ended December 31, 2011		
	U.S	Canada	Total
		(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	Total
		(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

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	Total
Proved developed and undeveloped reserves:					
December 31, 2009	139	33	172	111	283
Revisions due to prices	4	1	5	(3)	2
Revisions other than price	2	2	4	(3)	1
Extensions and discoveries	19	1	20	4	24
Production	(14)	(2)	(16)	(16)	(32)
Sale of reserves	(2)	(35)	(37)	—	(37)
December 31, 2010	148	—	148	93	241
Revisions due to prices	2	—	2	1	3
Revisions other than price	(1)	—	(1)	(5)	(6)
Extensions and discoveries	36	—	36	6	42
Production	(17)	—	(17)	(15)	(32)
December 31, 2011	168	—	168	80	248
Revisions due to prices	(1)	—	(1)	(5)	(6)
Revisions other than price	(6)	—	(6)	(2)	(8)
Extensions and discoveries	65	—	65	7	72
Production	(21)	—	(21)	(15)	(36)
December 31, 2012	205	—	205	65	270
Proved developed reserves as of:					
December 31, 2009	119	21	140	97	237
December 31, 2010	131	—	131	82	213
December 31, 2011	146	—	146	73	219
December 31, 2012	166	—	166	62	228
Proved developed-producing reserves as of:					
December 31, 2009	112	12	124	85	209
December 31, 2010	123	—	123	72	195
December 31, 2011	139	—	139	65	204
December 31, 2012	155	—	155	56	211
Proved undeveloped reserves as of:					
December 31, 2009	20	12	32	14	46
December 31, 2010	17	—	17	11	28
December 31, 2011	22	—	22	7	29
December 31, 2012	39	—	39	3	42

	Bitumen (MMBbls)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	Total
Proved developed and undeveloped reserves:					
December 31, 2009	—	—	—	403	403
Revisions due to prices	—	—	—	(21)	(21)
Revisions other than price	—	—	—	12	12
Extensions and discoveries	—	—	—	55	55
Production	—	—	—	(9)	(9)
December 31, 2010	—	—	—	440	440
Revisions due to prices	—	—	—	(16)	(16)
Revisions other than price	—	—	—	16	16
Extensions and discoveries	—	—	—	30	30
Production	—	—	—	(13)	(13)
December 31, 2011	—	—	—	457	457
Revisions due to prices	—	—	—	14	14
Revisions other than price	—	—	—	7	7
Extensions and discoveries	—	—	—	67	67
Production	—	—	—	(17)	(17)
December 31, 2012	—	—	—	528	528
Proved developed reserves as of:					
December 31, 2009	—	—	—	52	52
December 31, 2010	—	—	—	44	44
December 31, 2011	—	—	—	90	90
December 31, 2012	—	—	—	99	99
Proved developed-producing reserves as of:					
December 31, 2009	—	—	—	52	52
December 31, 2010	—	—	—	44	44
December 31, 2011	—	—	—	90	90
December 31, 2012	—	—	—	99	99
Proved undeveloped reserves as of:					
December 31, 2009	—	—	—	351	351
December 31, 2010	—	—	—	396	396
December 31, 2011	—	—	—	367	367
December 31, 2012	—	—	—	429	429

	Gas (Bcf)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	Total
Proved developed and undeveloped reserves:					
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
Revisions due to prices	(831)	—	(831)	(99)	(930)
Revisions other than price	(287)	—	(287)	(33)	(320)
Extensions and discoveries	1,124	—	1,124	34	1,158
Purchase of reserves	2	—	2	—	2
Production	(752)	—	(752)	(186)	(938)
Sale of reserves	(1)	—	(1)	(11)	(12)
December 31, 2012	8,762	—	8,762	684	9,446
Proved developed reserves as of:					
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
December 31, 2012	7,391	—	7,391	679	8,070
Proved developed-producing reserves as of:					
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
December 31, 2012	7,091	—	7,091	624	7,715
Proved undeveloped reserves as of:					
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
December 31, 2012	1,371	—	1,371	5	1,376

	Natural Gas Liquids (MMBbls)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	Total
Proved developed and undeveloped reserves:					
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
Revisions due to prices	(19)	—	(19)	(5)	(24)
Revisions other than price	(13)	—	(13)	—	(13)
Extensions and discoveries	114	—	114	2	116
Production	(36)	—	(36)	(4)	(40)
December 31, 2012	571	—	571	20	591
Proved developed reserves as of:					
December 31, 2009	293	1	294	32	326
December 31, 2010	353	—	353	28	381
December 31, 2011	402	—	402	26	428
December 31, 2012	431	—	431	20	451
Proved developed-producing reserves as of:					
December 31, 2009	265	1	266	28	294
December 31, 2010	318	—	318	26	344
December 31, 2011	372	—	372	24	396
December 31, 2012	406	—	406	19	425
Proved undeveloped reserves as of:					
December 31, 2009	92	1	93	2	95
December 31, 2010	96	—	96	2	98
December 31, 2011	123	—	123	1	124
December 31, 2012	140	—	140	—	140

	Total (MMBoe) (1)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	Total
Proved developed and undeveloped reserves:					
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
Revisions due to price	(159)	—	(159)	(12)	(171)
Revisions other than price	(67)	—	(67)	(1)	(68)
Extensions and discoveries	367	—	367	82	449
Production	(183)	—	(183)	(67)	(250)
Sale of reserves	—	—	—	(2)	(2)
December 31, 2012	2,236	—	2,236	727	2,963
Proved developed reserves as of:					
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
December 31, 2012	1,829	—	1,829	294	2,123
Proved developed-producing reserves as of:					
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
December 31, 2012	1,743	—	1,743	278	2,021
Proved undeveloped reserves as of:					
December 31, 2009	392	39	431	380	811
December 31, 2010	411	—	411	420	831
December 31, 2011	403	—	403	379	782
December 31, 2012	407	—	407	433	840

(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. Bitumen and 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 Devon's total proved undeveloped reserves during 2012 (in MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2011	403	379	782
Extensions and discoveries	134	68	202
Revisions due to prices	(47)	9	(38)
Revisions other than price	(10)	(6)	(16)
Conversion to proved developed reserves	(73)	(17)	(90)
Proved undeveloped reserves as of December 31, 2012	407	433	840

At December 31, 2012, Devon had 840 MMBoe of proved undeveloped reserves. This represents a 7 percent increase as compared to 2011 and represents 28 percent of its total proved reserves. Drilling and development activities increased Devon's proved undeveloped reserves 203 MMBoe and resulted in the conversion of 90 MMBoe, or 12 percent, of the 2011 proved undeveloped reserves to proved developed reserves. Costs incurred related to the development and conversion of Devon's proved undeveloped reserves were $1.3 billion for 2012. Additionally, revisions other than price decreased Devon's proved undeveloped reserves 16 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 2012 largely related to its Jackfish operations. At December 31, 2012 and 2011, Devon's Jackfish proved undeveloped reserves were 429 MMBoe and 367 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 2031.

Price Revisions

2012 - Reserves decreased 171 MMBoe primarily due to lower gas prices. Of this decrease, 100 MMBoe related to the Barnett Shale and 25 MMBoe related to the Rocky Mountain area.

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.

Revisions Other Than Price

Total revisions other than price for 2012 and 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 primarily related to Devon's drilling and development in the Barnett Shale.

Extensions and Discoveries

2012 – Of the 449 MMBoe of extensions and discoveries, 151 MMBoe related to the Cana-Woodford Shale, 95 MMBoe related to the Barnett Shale, 72 MMBoe related to the Permian Basin, 67 MMBoe related to Jackfish, 16 MMBoe related to the Rocky Mountain area and 18 MMBoe related to the Granite Wash area.

The 2012 extensions and discoveries included 229 MMBoe related to additions from Devon's infill drilling activities, including 134 MMBoe at the Cana-Woodford Shale and 82 MMBoe at the Barnett Shale.

2011 – Of the 421 MMBoe of extensions and discoveries, 162 MMBoe related to the Cana-Woodford Shale, 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.

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 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.

Sale of Reserves

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

Standardized Measure

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

	Year Ended December 31, 2012		
	U.S.	Canada	Total
		(In millions)	
Future cash inflows	$ 55,297	$ 33,570	$ 88,867
Future costs:			
Development	(6,556)	(6,211)	(12,767)
Production	(24,265)	(16,611)	(40,876)
Future income tax expense	(6,542)	(1,992)	(8,534)
Future net cash flows	17,934	8,756	26,690
10% discount to reflect timing of cash flows	(9,036)	(4,433)	(13,469)
Standardized measure of discounted future net cash flows	$ 8,898	$ 4,323	$ 13,221

	Year Ended December 31, 2011		
	U.S.	Canada	Total
		(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	Total
		(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

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 2012, the future realized prices averaged $86.57 per barrel of oil, $50.24 per barrel of bitumen, $2.28 per Mcf of gas and $29.19 per barrel of natural gas liquids. Of the $12.8 billion of future development costs as of the end of 2012, $2.3 billion, $1.9 billion and $0.8 billion are estimated to be spent in 2013, 2014 and 2015, respectively.

Future development costs include not only development costs, but also future asset retirement costs. Included as part of the $12.8 billion of future development costs are $2.6 billion of future asset retirement costs. Future production costs include general and administrative expenses directly related to oil and gas producing activities. The future income tax expenses have been computed using statutory tax rates, giving effect to allowable tax deductions and tax credits under current laws.

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

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Beginning balance	$17,844	$16,352	$11,403
Net changes in prices and production costs	(9,889)	1,875	7,423
Oil, gas and NGL sales, net of production costs	(4,388)	(5,811)	(4,998)
Changes in estimated future development costs	(1,094)	(440)	(292)
Extensions and discoveries, net of future development costs	4,669	3,714	3,048
Purchase of reserves	18	57	23
Sales of reserves in place	(25)	(2)	(815)
Revisions of quantity estimates	162	(228)	579
Previously estimated development costs incurred during the period	1,321	1,302	1,559
Accretion of discount	1,420	2,248	1,487
Other, primarily changes in timing and foreign exchange rates	113	(294)	(402)
Net change in income taxes	3,070	(929)	(2,663)
Ending balance	$13,221	$17,844	$16,352

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

	Year Ended December 31, 2012		
	U.S.	Canada	Total
		(In millions)	
Pre-tax future net revenue (1)			
Proved developed reserves	$19,982	$ 2,717	$22,699
Proved undeveloped reserves	4,494	8,031	12,525
Total proved reserves	$24,476	$10,748	$35,224
Pre-tax 10% present value (1)			
Proved developed reserves	$10,764	$ 2,484	$13,248
Proved undeveloped reserves	1,143	2,823	3,966
Total proved reserves	$11,907	$ 5,307	$17,214

(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, asset impairments or non-property related expenses such as debt service and income tax expense.

The present value of after-tax future net revenues discounted at 10 percent per annum ("standardized measure") was $13.2 billion at the end of 2012. Included as part of standardized measure were discounted future income taxes of $4.0 billion. Excluding these taxes, the present value of Devon's pre-tax future net revenue ("pre-tax 10 percent present value") was $17.2 billion. Devon believes the pre-tax 10 percent present value is a useful measure in addition to the after-tax standardized measure. The pre-tax 10 percent 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 percent 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.

	2012				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Revenues	$2,497	$2,559	$ 1,865	$2,581	$ 9,502
Earnings (loss) from continuing operations before income taxes	$ 611	$ 734	$(1,161)	$ (501)	$ (317)
Earnings (loss) from continuing operations	$ 414	$ 477	$ (719)	$ (357)	$ (185)
Loss from discontinued operations	(21)	—	—	—	(21)
Net earnings (loss)	$ 393	$ 477	$ (719)	$ (357)	$ (206)
Basic net earnings (loss) per common share:					
Earnings (loss) from continuing operations	$ 1.03	$ 1.18	$ (1.80)	$ (0.89)	$ (0.47)
Earnings (loss) from discontinued operations	(0.06)	—	—	—	(0.05)
Net earnings (loss)	$ 0.97	$ 1.18	$ (1.80)	$ (0.89)	$ (0.52)
Diluted net earnings (loss) per common share:					
Earnings (loss) from continuing operations	$ 1.03	$ 1.18	$ (1.80)	$ (0.89)	$ (0.47)
Earnings (loss) from discontinued operations	(0.06)	—	—	—	(0.05)
Net earnings (loss)	$ 0.97	$ 1.18	$ (1.80)	$ (0.89)	$ (0.52)

	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

Earnings (Loss) from Continuing Operations

The fourth quarter of 2012 includes U.S. and Canadian asset impairments totaling $0.9 billion ($0.6 billion after income taxes, or $1.46 per diluted share).

The third quarter of 2012 includes U.S. asset impairments totaling $1.1 billion ($0.7 billion after income taxes, or $1.78 per diluted share).

The second quarter of 2011 includes deferred income taxes of $0.7 billion (or $1.71 per diluted share) related to assumed repatriations of foreign earnings that were no longer deemed to be indefinitely 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 Devon's Brazil operations and the related gain was $2.5 billion ($2.5 billion after income taxes, or $6.01 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, our principal executive and principal financial officers have concluded that our 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, 2012 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

Our 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, we conducted an evaluation of the effectiveness of our 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 19, 2013, management concluded that its internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of our internal control over financial reporting as of December 31, 2012 has been audited by KPMG LLP, an independent registered public accounting firm who audited our consolidated financial statements as of and for the year ended December 31, 2012, 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 our internal control over financial reporting during the fourth quarter of 2012 that has materially affected, or is reasonably likely to materially affect, our 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 30, 2013.

Item 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

Item 14. *Principal Accounting Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

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

1. Consolidated Financial Statements

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

2. Consolidated Financial Statement Schedules

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

3. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Registrant, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Registrant's Amendment No. 1 to Form S-4 Registration No. 333-103679, filed March 20, 2003).
2.2	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Registrant, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant's Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
2.3	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 (incorporated by reference to Registrant's and Devon Acquisition Corporation's Schedule 14D-1F filing, filed September 6, 2001).
2.4	Pre-Acquisition Agreement, dated as of August 31, 2001, between Registrant and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001).
2.5	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 12, 2000).
2.6	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant's Form S-4, File No. 333-82903).
3.1	Registrant's Restated Certificate of Incorporation.
3.2	Registrant's Bylaws (incorporated by reference to Exhibit 3.2 of Registrant's Form 8-K filed on June 8, 2012).
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).

Exhibit No.	Description
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	Supplemental Indenture No. 2, dated as of May 14, 2012, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 1.875% Senior Notes due 2017, the 3.250% Senior Notes due 2022 and the 4.750% Senior Notes due 2042 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on May 14, 2012).
4.4	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).
4.5	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).
4.6	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).
4.7	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 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).
4.8	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)).
4.9	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).
4.10	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).
4.11	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
4.12	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)).
4.13	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).
4.14	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).
4.15	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	Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon NEC Corporation and Devon Canada Corporation, as Canadian Borrowers, each lender from time to time party thereto, each L/C Issuer from time to time party thereto, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender with respect to a $3 billion five-year revolving credit facility (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K filed October 29, 2012).
10.3	Devon Energy Corporation 2009 Long-Term Incentive Plan (as amended and restated effective June 6, 2012)(incorporated by reference to Registrant's Form S-8 Registration No.333-182198, filed June 18, 2012).*
10.4	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) .*
10.5	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).*
10.6	Devon Energy Corporation Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K, filed June 8, 2012)*
10.7	Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective November 11, 2008) (incorporated by reference to Exhibit 10.14 to Registrant's Form 10-K, filed February 24, 2012).*
10.8	Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.15 to Registrant's Form 10-K, filed February 24, 2012).*

Exhibit No.	Description
10.9	Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K, filed February 24, 2012).*
10.10	Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.17 to Registrant's Form 10-K, filed February 24, 2012).*
10.11	Devon Energy Corporation Supplemental Executive Retirement Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K, filed February 24, 2012).*
10.12	Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.19 to Registrant's Form 10-K, filed February 24, 2012).*
10.13	Devon Energy Corporation Incentive Savings Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-179181, filed January 26, 2012).*
10.14	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).*
10.15	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).*
10.16	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) 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.*
10.17	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for performance based restricted share units awarded.*
10.18	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).*
10.19	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).*

Exhibit No.	Description
10.20	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).*
10.21	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).*
10.22	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).*
10.23	Form of Letter Agreement amending the restricted stock award agreements and nonqualified 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).*
10.24	Amendment to Incentive Stock Option Award Agreement between Registrant and J. Larry Nichols dated December 19, 2012, amending the Incentive Stock Option Agreements under the 2009 Long-Term Incentive Plan between Registrant and J. Larry Nichols. *
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 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 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 21, 2013

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 21, 2013
/s/ J. LARRY NICHOLS J. Larry Nichols	Executive Chairman of the Board and Director	February 21, 2013
/s/ JEFFREY A. AGOSTA Jeffrey A. Agosta	Executive Vice President and Chief Financial Officer	February 21, 2013
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 21, 2013
/s/ JOHN A. HILL John A. Hill	Director	February 21, 2013
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 21, 2013
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 21, 2013
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 21, 2013
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 21, 2013

Directors

J. Larry Nichols
Executive Chairman, Devon Energy Corporation

John A. Hill (2)
Lead Director
Vice Chairman and Managing Director, First Reserve Corporation

Robert H. Henry (1) (3)
President, Oklahoma City University

Michael M. Kanovsky (1) (4)
President, Sky Energy Corporation

Robert A. Mosbacher Jr. (2) (3) (4)
Chairman, Mosbacher Energy Company

Duane C. Radtke (2) (4)
Owner, President and Chief Executive Officer, Valiant Exploration 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

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, U.S. Operations

Steve Hoppe
Senior Vice President, Midstream

Jeffrey L. Ritenour
Senior Vice President, Investor Relations

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

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

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

Other Information

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Shea Snyder, Director, Investor Communications
Telephone: (405) 552-4782
E-mail: shea.snyder@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
Website: www.computershare.com/investor

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 5, 2013, at the Devon Energy Center Auditorium, 333 W. Sheridan 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 11,300 shareholders of record.

Additional Information
This report and Devon's Corporate Responsibility Report are available at www.devonenergy.com. For print versions of these publications, email investor.relations@dvn.com.

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

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