DEVON ENERGY CORP/DE
Form 10-K
February 28, 2014
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

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 x 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 x

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 x 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 x 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 x	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 x

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 28, 2013, was approximately $20.9 billion, based upon the closing price of $51.88 per share as reported by the New York Stock Exchange on such date. On February 12, 2014, 407.4 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2014 annual meeting of stockholders Part III

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INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements as defined by the United States Securities and Exchange Commission (SEC). Such statements are those concerning strategic plans, our expectations and objectives for future operations, as well as other 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, 2013 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; our ability to successfully complete mergers, acquisitions and divestitures; political or regulatory events; general economic and financial market conditions; and other risks and factors discussed in this report.

All subsequent written and oral forward-looking statements attributable to Devon Energy Corporation, 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.

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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. Our portfolio of oil and gas properties provides stable, environmentally responsible production and a platform for future growth. We have nearly doubled our onshore North American oil production since 2008 and have a deep inventory of development opportunities to deliver future oil growth. We produce about 2.4 billion cubic feet of natural gas a day more than 3 percent of all the gas consumed in North America. 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, 2013, we had approximately 5,900 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 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

Our primary goal is to build value per share. 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:

- exploring for undiscovered oil and natural gas reserves,
- purchasing and developing oil and natural gas properties,
- enhancing the value of production through marketing and midstream activities,
- optimizing production operations to control costs, and
- maintaining a strong balance sheet.

We hold 14 million net acres, of which roughly 60 percent 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

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and NGLs. Consequently, we have focused our recent capital programs on higher-margin oil and 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.

In pursuit of our goal to build value per share, we entered into two significant agreements near the end of 2013. On November 20, 2013, we entered into an agreement with GeoSouthern Intermediate Holdings, LLC, to acquire certain oil and gas properties, leasehold mineral interests and related assets located in the Eagle Ford Shale in south Texas for $6 billion in cash. The transaction is expected to close in the first quarter of 2014, and we have the necessary financing in place to fund the acquisition.

On October 21, 2013, Devon, Crosstex Energy, Inc. and Crosstex Energy, L.P. (collectively Crosstex) announced plans to combine substantially all of Devon s U.S. midstream assets with Crosstex s assets to form a new midstream business. The new business will consist of EnLink Midstream Partners, L.P. (the Partnership) and EnLink Midstream, LLC (EnLink), respectively, a master limited partnership and a general partner entity, which will both be publicly traded entities.

In exchange for a controlling interest in both EnLink and the Partnership, Devon will contribute its equity interest in a newly formed Devon subsidiary (EnLink Holdings) and $100 million in cash. EnLink Holdings will own Devon s midstream assets in the Barnett Shale in north Texas and the Cana and Arkoma Woodford Shales in Oklahoma, as well as Devon s economic interest in Gulf Coast Fractionators in Mt. Belvieu, Texas. The Partnership and EnLink will each own 50% of EnLink Holdings. The completion of these transactions is subject to Crosstex Energy, Inc. shareholder approval. Devon expects Crosstex Energy, Inc. shareholders will approve the transaction, allowing Devon and Crosstex to complete the transaction near the end of the first quarter of 2014.

Upon closing of the transactions, the pro forma ownership of EnLink will be approximately:

70% Devon Energy Corporation

30% Current Crosstex Energy, Inc. public stockholders

Upon closing of the transactions, the pro forma ownership of the Partnership will be approximately:

53% Devon Energy Corporation

40% Current Crosstex Energy, L.P. public unitholders

7% the General Partner

In conjunction with the announcement of the GeoSouthern acquisition, we also announced plans to divest certain non-core properties located throughout Canada and the U. S. On February 19, 2014, we announced our first transaction as a part of this divestiture program, in which we agreed to sell the majority of our Canadian conventional assets to Canadian Natural Resources Limited for approximately $2.8 billion ($3.125 billion in Canadian dollars). We expect this non-core divestiture program will generate organizational and operational efficiencies and will allow us to allocate capital and employee resources to higher-value properties and prospects. We expect to complete the majority of the divestitures by the end of 2014. Once the GeoSouthern acquisition and non-core divestitures are complete, we expect oil production will represent more than 30% of our production profile.

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 2013. 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			Gross
	MMBoe	% of Total	% Liquids	MBoe/d	% of Total	% Liquids	Wells Drilled
Anadarko Basin	406	14%	41%	81.7	12%	42%	184
Barnett Shale	1,093	37%	23%	227.7	33%	25%	172
Mississippian-Woodford Trend	32	1%	66%	7.9	1%	75%	232
Permian Basin	269	9%	79%	78.0	11%	78%	348
Rockies	37	1%	47%	21.5	3%	40%	37
Other	161	5%	35%	39.6	6%	35%	5
U.S. core and emerging properties	1,998	67%	36%	456.4	66%	39%	978
Canadian heavy oil	584	20%	99%	83.1	12%	96%	186
Total core and emerging properties	2,582	87%	51%	539.5	78%	48%	1,164
Non-core properties	381	13%	28%	153.4	22%	23%	111
Total	2,963	100%	48%	692.9	100%	42%	1,275

Core and Emerging Properties

Anadarko Basin Our acreage is located primarily in Oklahoma s Canadian, Blaine, Caddo and Dewey counties. The Anadarko Basin is a non-conventional reservoir and produces natural gas, NGLs and condensate.

The Anadarko Basin 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 Anadarko Basin. During 2013, we increased our production by 14 percent. We have several thousand remaining drilling locations. In 2014, we plan to drill approximately 95 wells.

In addition, we have a significant processing plant and gathering system to service these properties. Our Cana plant currently has 350 MMcf per day of total capacity.

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 2014, we plan to drill approximately 80 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 790 MMcf per day of total capacity. These midstream assets also include an extensive pipeline system and a 15 MBbls per day NGL fractionator.

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Mississippian-Woodford Trend 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. These areas 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 2014, we plan to drill approximately 230 wells.

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, 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 2014, we plan to drill approximately 350 wells.

Rockies Our operations are focused in the Powder River basin in Wyoming where we have 150,000 net acres. These acres are principally located in eastern Wyoming in the counties of Campbell, Converse and Johnson. We are currently targeting several Cretaceous oil objectives, including the Turner, Frontier and Parkman formations. To date we have identified roughly 600 risked locations across these three formations. Our activity and associated capital in the Powder River basin is a part of our joint venture agreement with Sinopec Corporation, under which we receive a drilling carry that funds a significant portion of our capital requirements during the carry period. In 2014, we plan to drill roughly 25 wells in the Powder River Basin.

Canadian Heavy Oil 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. In addition, 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.

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 8 percent in 2013 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 southeast 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, 2013. 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 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.

Our Lloydminster 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 2,700 wells in the area since 2003. In 2014, we plan to drill approximately 175 wells.

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Non-Core Properties

Our non-core properties are located throughout the U.S. and Canada and primarily consist of reservoirs that produce dry natural gas. We are in the process of monetizing these assets through a divestiture program we expect to complete by the end of 2014.

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 2013 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 thirteen 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),

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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 2013, we engaged two such firms to audit 91 percent of our proved reserves. LaRoche Petroleum Consultants, Ltd. audited 92 percent of our 2013 U.S. reserves, and Deloitte audited 90 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.

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The following table presents our estimated pretax cash flow information related to its proved reserves. These estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 22 to our consolidated financial statements included herein.

	Year Ended December 31, 2013		
	U.S.	Canada (In millions)	Total
Pre-Tax Future Net Revenue (Non-GAAP) (1)			
Proved Developed Reserves	$ 26,617	$ 4,100	$ 30,717
Proved Undeveloped Reserves	3,255	8,188	11,443
Total Proved Reserves	$ 29,872	$ 12,288	$ 42,160
Pre-Tax 10% Present Value (Non-GAAP) (1)			
Proved Developed Reserves	$ 13,862	$ 3,623	$ 17,485
Proved Undeveloped Reserves	988	2,864	3,852
Total Proved Reserves	$ 14,850	$ 6,487	$ 21,337

(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.

Pre-tax future net revenue and pre-tax 10 percent present value are non-GAAP measures. The present value of after-tax future net revenues discounted at 10 percent per annum (standardized measure) was $15.7 billion at the end of 2013. Included as part of standardized measure were discounted future income taxes of $5.6 billion. Excluding these taxes, the present value of our pre-tax future net revenue (pre-tax 10 percent present value) was $21.3 billion. We believe 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.

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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 (MBbls/d)**	**Bitumen (MBbls/d)**	**Gas (MMcf/d)**	**NGLs (MBbls/d)**	**Total (MBoe/d)**
2013					
Barnett Shale	2.0		1,024.9	54.9	227.7
Jackfish		51.5			51.5
U.S.	77.7		1,941.8	116.0	517.3
Canada	39.1	51.5	451.6	9.7	175.6
Total North America	116.8	51.5	2,393.4	125.7	692.9
2012					
Barnett Shale	1.6		1,074.6	46.8	227.5
Jackfish		47.6			47.6
U.S.	58.7		2,054.5	98.6	499.7
Canada	39.8	47.6	508.3	10.5	182.6
Total North America	98.5	47.6	2,562.8	109.1	682.3
2011					
Barnett Shale	1.8		1,006.0	43.7	213.1
Jackfish		34.8			34.8
U.S.	46.0		2,026.6	90.4	474.1
Canada	41.7	34.8	583.1	9.9	183.6
Total North America	87.7	34.8	2,609.7	100.3	657.7

	Average Sales Price				Production Cost
Year Ended December 31,	**Oil (Per Bbl)**	**Bitumen (Per Bbl)**	**Gas (Per Mcf)**	**NGLs (Per Bbl)**	**(Per Boe)**
2013					
Barnett Shale	$ 97.74	$	$ 2.90	$ 22.45	$ 4.12
Jackfish	$	$ 48.04	$	$	$ 17.98
U.S.	$ 94.52	$	$ 3.10	$ 25.75	$ 6.65
Canada	$ 69.18	$ 48.04	$ 3.05	$ 46.17	$ 15.78
Total North America	$ 86.02	$ 48.04	$ 3.09	$ 27.33	$ 8.97
2012					
Barnett Shale	$ 91.45	$	$ 2.23	$ 27.57	$ 3.91
Jackfish	$	$ 47.57	$	$	$ 19.51
U.S.	$ 88.68	$	$ 2.32	$ 28.49	$ 5.79
Canada	$ 68.29	$ 47.57	$ 2.49	$ 48.63	$ 15.18
Total North America	$ 80.43	$ 47.57	$ 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

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Drilling Statistics

The following table summarizes our development and exploratory drilling results.

	Development Wells (1)		Exploratory Wells (1)		Total Wells (1)		
Year Ended December 31,	**Productive**	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**	**Total**
2013							
U.S.	555.3		56.1	7.0	611.4	7.0	618.4
Canada	211.9	1.0	7.4		219.3	1.0	220.3
Total North America	767.2	1.0	63.5	7.0	830.7	8.0	838.7
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

(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, 2014, results of our wells that were in progress on December 31, 2013.

	Productive		Dry		Still in Progress		Total	
	Gross (1)	**Net (2)**	**Gross (1)**	**Net (2)**	**Gross (1)**	**Net (2)**	**Gross (1)**	**Net (2)**
U.S.	11.0	5.3			73.0	25.8	84.0	31.1
Canada	1.0	1.0			5.0	3.1	6.0	4.1
Total North America	12.0	6.3			78.0	28.9	90.0	35.2

(1) Gross wells are the sum of all wells in which we own an interest.
(2) Net wells are gross wells multiplied by our fractional working interests on the well.

Productive Wells

The following table sets forth our producing wells as of December 31, 2013.

	Oil Wells (1)		Natural Gas Wells		Total Wells	
	Gross (2)	**Net (3)**	**Gross (2)**	**Net (3)**	**Gross (2)**	**Net (3)**

U.S.	9,328	3,669	20,124	13,092	29,452	16,761
Canada	5,416	4,271	5,444	3,249	10,860	7,520
Total North America	14,744	7,940	25,568	16,341	40,312	24,281

(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 24,000 of our wells. As operator, we receive reimbursement for direct expenses incurred to perform our duties, as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area. In presenting our financial data, we record the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

Acreage Statistics

The following table sets forth our developed and undeveloped lease and mineral acreage as of December 31, 2013. The acreage in the table includes 0.7 million, 1.4 million and 0.6 million net acres subject to leases that are scheduled to expire during 2014, 2015 and 2016, respectively. Approximately 18 MMBoe, or 2.5 percent, of our proved undeveloped reserves was attributable to this expiring acreage as of December 31, 2013. Of the 2.7 million net acres set to expire by December 31, 2016, we will perform operational and administrative actions to continue the lease terms for a portion of the acreage, including all the acreage for which we have proved undeveloped reserves at the end of 2013. However, we do expect to allow a portion of the acreage to expire in the normal course of business. In 2013, we allowed approximately 50% of our expiring acreage to expire.

	Developed		Undeveloped		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
	(In thousands)					
U.S.	3,312	2,107	9,281	3,698	12,593	5,805
Canada	3,592	2,221	6,476	4,713	10,068	6,934
Total North America	6,904	4,328	15,757	8,411	22,661	12,739

(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.

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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 2014, our production was sold under the following contracts.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	67%		33%	
Natural gas	76%		20%	4%
NGLs	89%	6%	5%	

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, 2013, 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)	166	24	45	48	49
Natural gas (Bcf)	800	481	251	68	
NGLs (MMBbls)	61	7	11	12	31
Total (MMBoe)	360	111	98	71	80

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 2013, 2012 and 2011, no purchaser accounted for over 10 percent of our operating 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, taxes, fees 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;
- well design;
- 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;
- transportation of production; and
- endangered species and habitat.

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

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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. 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.

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Item 1A. ***Risk Factors***

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

Oil, 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 United States and Canada. In addition, we are also subject to the laws and regulations of various states, provinces, tribal and local governments. Pursuant to public policy changes, numerous government departments and agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which 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 Bureau of Land Management 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 United States President and other policy makers have proposed provisions that would, if enacted, make significant changes to United States 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 United States 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 United States 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

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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.

Cyber Attacks Targeting Our Systems and Infrastructure May Adversely Impact Our Operations

The oil and gas industry has become increasingly dependent on digital technologies to conduct daily operations. Concurrently, the industry has become the subject of increased levels of cyber attack activity. Cyber attacks often attempt to gain unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption and may be carried out by third parties or insiders. The techniques utilized range from highly sophisticated efforts to electronically circumvent network security to more traditional intelligence gathering and social engineering aimed at obtaining information necessary to gain access. Cyber attacks may also be carried out in a manner that does not require gaining unauthorized access, such as by causing denial-of-service attacks. Although we have not suffered material losses related to cyber attacks, if we were successfully attacked we may incur substantial remediation and other costs or suffer other negative consequences. Finally, as the sophistication of cyber attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities.

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

We have no unresolved SEC Staff comments that have been outstanding greater than 180 days from December 31, 2013.

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.

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PART II

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

Our common stock is traded on the New York Stock Exchange (the NYSE). On February 5, 2014, there were 10,893 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 2013 and 2012, as well as the quarterly dividends per share paid during 2013 and 2012. 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
2013:			
Quarter Ended December 31, 2013	$ 66.92	$ 57.58	$ 0.22
Quarter Ended September 30, 2013	$ 60.38	$ 52.00	$ 0.22
Quarter Ended June 30, 2013	$ 61.10	$ 50.81	$ 0.22
Quarter Ended March 31, 2013	$ 61.80	$ 51.63	$ 0.20
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

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Performance Graph

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on Devon s common stock with the cumulative total returns of the Standard & Poor s 500 index (the S&P 500 Index), the group of companies included in the Crude Petroleum and Natural Gas Standard Industrial Classification code (the SIC Code) and a peer group of companies to which we compare our performance. The peer group includes Anadarko Petroleum Corporation, Apache Corporation, Chesapeake Energy Corporation, ConocoPhillips, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Occidental Petroleum Corporation, Pioneer Natural Resources Company and Talisman Energy, Inc. The graph was prepared assuming $100 was invested on December 31, 2008 in Devon s common stock, the S&P 500 Index, the SIC Code and the peer group and dividends have been reinvested subsequent to the initial investment.

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.

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Issuer Purchases of Equity Securities

The following table provides information regarding purchases of our common stock that were made by us during the fourth quarter of 2013. 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	1,077	$ 63.22
November 1 November 30	118,940	$ 60.62
December 1 December 31	331,389	$ 60.59
Total	451,406	$ 60.61

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 52,500 shares of our common stock in 2013, 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 10,800 shares of our common stock in 2013, 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,				
	2013	2012	2011	2010	2009
	(In millions, except per share amounts)				
Operating revenues	$ 10,397	$ 9,501	$ 11,445	$ 9,935	$ 8,010
Earnings (loss) from continuing operations [(1)]	$ (20)	$ (185)	$ 2,134	$ 2,333	$ (2,753)
Earnings (loss) per share from continuing operations Basic	$ (0.06)	$ (0.47)	$ 5.12	$ 5.31	$ (6.20)
Earnings (loss) per share from continuing operations Diluted	$ (0.06)	$ (0.47)	$ 5.10	$ 5.29	$ (6.20)
Cash dividends per common share	$ 0.86	$ 0.80	$ 0.67	$ 0.64	$ 0.64
Weighted average common shares outstanding Basic	406	404	417	440	444
Weighted average common shares outstanding Diluted	406	404	418	441	444
Total assets [(1)]	$ 42,877	$ 43,326	$ 41,117	$ 32,927	$ 29,686
Long-term debt	$ 7,956	$ 8,455	$ 5,969	$ 3,819	$ 5,847
Stockholders equity	$ 20,499	$ 21,278	$ 21,430	$ 19,253	$ 15,570

(1) During 2013, 2012 and 2009, we recorded noncash asset impairments totaling $2.0 billion ($1.4 billion after income taxes), $2.0 billion ($1.3 billion after income taxes) and $6.4 billion ($4.1 billion after income taxes), respectively.

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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 2013 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.

2013 was another year of strong execution and exciting change for Devon. Our oil-focused drilling programs not only accomplished impressive oil production growth, but also expanded margins and improved operating cash flow. Additionally, we took steps to high-grade our portfolio. We did this by announcing an accretive Eagle Ford Shale acquisition, an innovative midstream combination, and the initiation of an asset divestiture program. These actions will provide the platform from which we will deliver outstanding high-margin growth in 2014 and for many years to come.

Key measures of our 2013 performance are summarized below, which exclude amounts from our discontinued operations.

	Year Ended December 31,				
	2013	Change	2012	Change	2011
	($ in millions, except per share amounts)				
Net earnings (loss)	$ (20)	+89%	$ (185)	-109%	$ 2,134
Adjusted earnings [1]	$ 1,734	+33%	$ 1,305	-49%	$ 2,578
Earnings (loss) per share	$ (0.06)	+87%	$ (0.47)	-109%	$ 5.10
Adjusted earnings per share [1]	$ 4.26	+32%	$ 3.22	-48%	$ 6.17
Production (MBoe/d)	692.9	+2%	682.3	+4%	657.7
Realized price per Boe	$ 33.70	+18%	$ 28.65	-17%	$ 34.64
Adjusted operating income per Boe [2]	$ 19.86	+2%	$ 19.41	-23%	$ 25.11
Operating cash flow	$ 5,436	+10%	$ 4,930	-21%	$ 6,246
Capitalized costs	$ 6,643	-22%	$ 8,474	+9%	$ 7,795
Shareholder distributions [3]	$ 348	+8%	$ 324	-88%	$ 2,610
Reserves (MMBoe)	2,963	0%	2,963	-1%	3,005

(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 United States (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 2013 net loss resulted from noncash asset impairments, which reduced our earnings by $2.0 billion ($1.4 billion after tax). Excluding the asset impairments and other items typically excluded by securities analysts, our adjusted earnings were $1.7 billion, or $4.26 per diluted share. This compares to adjusted earnings of $1.3 billion, or $3.22 per diluted share in 2012.

Our 2013 adjusted earnings, adjusted earnings per share and adjusted operating income per Boe all increased compared to 2012. The improved 2013 results were driven primarily by increases in gas prices, oil volumes and oil realizations. These factors also contributed to higher adjusted operating cash flow, which combined with a reduction in capitalized costs, caused our cash flow deficit to narrow considerably in 2013.

Business and Industry Outlook

North American crude oil and natural gas prices have historically been volatile based on supply and demand dynamics and we expect this volatility to continue into 2014. Although natural gas prices improved in 2013 compared to 2012, natural gas continues to be challenged due to an imbalance between supply and demand across North America. However, arctic air movements across North America during the early weeks of 2014 have caused natural gas demand to surge. As storage inventories have significantly declined in response to the recent weather conditions, natural gas prices have surpassed $5 per Mcf for the first time since the summer of 2010. Further helping demand, new uses of natural gas in industrial, power and other sectors will continue to help support price dynamics. Nevertheless, we still expect natural gas prices to be range-bound as natural gas supply continues to grow, particularly in the U.S. Looking to 2014, we expect natural gas prices will remain relatively consistent or possibly increase moderately from 2013 levels.

Similar to natural gas in recent years, a surge in the supply of natural gas liquids has kept prices challenged. The majority of our natural gas is comprised of ethane, one of the most price-challenged liquids processed from the natural gas stream. We expect 2014 natural gas liquids prices will be range-bound and remain relatively flat compared to 2013.

Crude oil prices remained relatively stable throughout 2013, and oil continues to be more valuable than natural gas on a relative energy-equivalent basis. As a result, we and other producers have been focused on growing oil production. North American crude oil supply continues to increase due to the continued use of horizontal drilling technology throughout the U.S. and expansions of heavy oil production operations primarily in Canada. Global crude oil demand is expected to grow with supply in 2014. As crude oil supply grows, transportation capacity to downstream markets will be increasingly important. Bottlenecks and other transportation limitations may continue to add volatility among U.S. and Canadian grades of oil. However, we expect 2014 oil prices will remain relatively consistent with 2013.

We exited 2013 with a production profile comprised of roughly 55 percent natural gas, 25 percent oil, and 20 percent natural gas liquids. Recognizing the relative value of crude oil, we are devoting the vast majority of our 2014 capital investment toward growing our oil production, particularly the sweet grades of oil found in the U.S. To make a significant shift in our production profile, we expect to complete a $6 billion acquisition of Eagle Ford Shale assets in the first quarter of 2014 and divest non-core, dry natural gas assets throughout 2014. Once these transactions are complete, we expect oil will represent more than 30 percent of our production profile.

Further enhancing the value of our assets, we are combining substantially all of our U.S. midstream assets with Crosstex Energy, Inc. s and Crosstex Energy, L.P. s assets to form a new midstream business. The new business will consist of EnLink Midstream Partners, L.P. (the Partnership) and EnLink Midstream, LLC (EnLink), a master limited partnership and a general partner entity, which will both be publicly traded entities. The new midstream business will own Devon s midstream assets in the Barnett Shale in north Texas and the Cana and Arkoma Woodford Shales in Oklahoma, as well as Devon s economic interest in Gulf Coast Fractionators in Mt. Belvieu, Texas. Devon will own a 70 percent controlling interest in EnLink and an approximate 53 percent controlling interest in the Partnership.

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.

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Oil, Gas and NGL Production

	Year Ended December 31,				
	2013	Change	2012	Change	2011
Oil (MBbls/d)					
Anadarko Basin	9.1	+38%	6.6	+52%	4.4
Barnett Shale	2.0	+22%	1.6	-12%	1.8
Mississippian-Woodford Trend	4.7	+625%	0.7	N/M	
Permian Basin	46.4	+28%	36.3	+30%	27.8
Rockies	7.8	+30%	6.0	+38%	4.3
Other	3.0	+5%	2.8	+12%	2.6
U.S. core and emerging properties	73.0	+35%	54.0	+32%	40.9
Canadian heavy oil	27.9	-3%	28.8	-8%	31.2
Total core and emerging properties	100.9	+22%	82.8	+15%	72.1
Non-core properties	15.9	+2%	15.7	+1%	15.6
Total	116.8	+19%	98.5	+12%	87.7
Bitumen (MBbls/d)					
Canadian heavy oil	51.5	+8%	47.6	+37%	34.8
Gas (MMcf/d)					
Anadarko Basin	285.8	0%	286.3	+25%	229.1
Barnett Shale	1,024.9	-5%	1,074.6	+7%	1,006.0
Mississippian-Woodford Trend	11.6	+701%	1.5	N/M	
Permian Basin	104.8	+24%	84.8	+13%	75.1
Rockies	78.0	-28%	108.6	-23%	140.3
Other	153.8	-12%	175.0	-16%	208.3
U.S. core and emerging properties	1,658.9	-4%	1,730.8	+4%	1,658.8
Canadian heavy oil	22.3	-18%	27.2	-16%	32.3
Total core and emerging properties	1,681.2	-4%	1,758.0	+3%	1,691.1
Non-core properties	712.2	-12%	804.8	-12%	918.6
Total	2,393.4	-7%	2,562.8	-2%	2,609.7
NGLs (MBbls/d)					
Anadarko Basin	24.9	+43%	17.3	+43%	12.2
Barnett Shale	54.9	+17%	46.8	+7%	43.7
Mississippian-Woodford Trend	1.2	+770%	0.1	N/M	
Permian Basin	14.1	+26%	11.2	+29%	8.7
Rockies	0.8	+5%	0.8	-5%	0.8
Other	11.1	+1%	11.0	-11%	12.3
U.S. core and emerging properties	107.0	+23%	87.2	+12%	77.7
Non-core properties	18.7	-14%	21.9	-3%	22.6
Total	125.7	+15%	109.1	+9%	100.3
Combined (MBoe/d)					
Anadarko Basin	81.7	+14%	71.7	+31%	54.7

Barnett Shale	227.7	0%	227.5	+7%	213.1
Mississippian-Woodford Trend	7.9	+662%	1.0	N/M	
Permian Basin	78.0	+27%	61.6	+26%	49.0
Rockies	21.5	-13%	24.9	-13%	28.5
Other	39.6	-8%	43.0	-13%	49.7
U.S. core and emerging properties	456.4	+6%	429.7	+9%	395.0
Canadian heavy oil	83.1	+3%	80.9	+13%	71.4
Total core and emerging properties	539.5	+6%	510.6	+9%	466.4
Non-core properties	153.4	-11%	171.7	-10%	191.3
Total	692.9	+2%	682.3	+4%	657.7

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Oil, Gas and NGL Pricing

	Year Ended December 31,				
	2013 (1)	Change	2012 (1)	Change	2011 (1)
Oil (per Bbl)					
U.S.	$ 94.52	+7%	$ 88.68	-3%	$ 91.19
Canada	$ 69.18	+1%	$ 68.29	-8%	$ 74.32
Total	$ 86.02	+7%	$ 80.43	-3%	$ 83.16
Bitumen (per Bbl)					
Canada	$ 48.04	+1%	$ 47.57	-18%	$ 58.16
Gas (per Mcf)					
U.S.	$ 3.10	+33%	$ 2.32	-34%	$ 3.50
Canada	$ 3.05	+23%	$ 2.49	-36%	$ 3.87
Total	$ 3.09	+31%	$ 2.36	-34%	$ 3.58
NGLs (per Bbl)					
U.S.	$ 25.75	-10%	$ 28.49	-28%	$ 39.47
Canada	$ 46.17	-5%	$ 48.63	-13%	$ 55.99
Total	$ 27.33	-10%	$ 30.42	-26%	$ 41.10
Combined (per Boe)					
U.S.	$ 31.59	+23%	$ 25.59	-18%	$ 31.31
Canada	$ 39.91	+8%	$ 37.01	-14%	$ 43.23
Total	$ 33.70	+18%	$ 28.65	-17%	$ 34.64

(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 (In millions)	NGLs	Total
2011 sales	$ 2,660	$ 739	$ 3,411	$ 1,505	$ 8,315
Change due to volumes	337	273	(52)	137	695
Change due to prices	(98)	(184)	(1,148)	(427)	(1,857)
2012 sales	$ 2,899	$ 828	$ 2,211	$ 1,215	$ 7,153
Change due to volumes	531	65	(152)	181	625
Change due to prices	238	9	639	(142)	744
2013 sales	$ 3,668	$ 902	$ 2,698	$ 1,254	$ 8,522

Volumes 2013 vs. 2012 Upstream sales increased $625 million due to a 15 percent increase in our liquids production, partially offset by a 7 percent decline in our gas production. Oil production was the largest driver of the increase, accounting for 85 percent of the higher sales. Largely due to continued development of our properties in the Permian Basin, the Mississippian-Woodford Trend and the Anadarko Basin, our oil sales increased $531 million. Bitumen sales increased $65 million due to development of our Jackfish thermal heavy oil projects in Canada. Additionally, our NGL sales increased $181 million as a result of continued drilling in the liquids-rich gas portions of the Barnett Shale and the Anadarko Basin. These increases were partially offset by a 7 percent decrease in our 2013 gas production, resulting in a $152 million decline in sales.

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

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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 and the Anadarko Basin. These increases were partially offset by a slight decrease in our 2012 gas production, resulting in a $52 million decline in sales.

Prices 2013 vs. 2012 Upstream sales increased $744 million due to an 18 percent increase in our realized price without hedges. Our gas sales were the most significantly impacted with a $639 million increase in sales. The change in our gas price was largely due to higher North American regional index prices upon which our gas sales are based. Our liquid sales increased $105 million due to higher oil and bitumen sales partially offset by lower NGL sales. The largest contributors to the higher liquids prices were an increase in the average NYMEX West Texas Intermediate index price and a slightly higher bitumen realized price, partially offset by lower NGL prices at the Mont Belvieu, Texas hub.

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.

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 fair value 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 fair value gains and losses.

	Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Cash settlements:			
Oil derivatives	$ 55	$ 259	$ (26)
Gas derivatives	139	610	416
NGL derivatives	1	1	2
Total cash settlements	195	870	392
Gains (losses) on fair value changes:			
Oil derivatives	(243)	150	185
Gas derivatives	(139)	(330)	305
NGL derivatives	(4)	3	(1)
Total gains (losses) on fair value changes	(386)	(177)	489
Oil, gas and NGL derivatives	$ (191)	$ 693	$ 881

	Year Ended December 31, 2013				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$ 86.02	$ 48.04	$ 3.09	$ 27.33	$ 33.70
Cash settlements of hedges	1.30		0.16	0.01	0.77
Realized price, including cash settlements	$ 87.32	$ 48.04	$ 3.25	$ 27.34	$ 34.47

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	Year Ended December 31, 2012				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$ 80.43	$ 47.57	$ 2.36	$ 30.42	$ 28.65
Cash settlements of hedges	7.19		0.65	0.04	3.48
Realized price, including cash settlements	$ 87.62	$ 47.57	$ 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

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 and oil call options for 2014 through 2016. The call options give counterparties the right to purchase production at a predetermined price.

In addition to cash settlements, we also recognize fair value changes on 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 incurred net losses of $191 million in 2013 and generated net gains of $693 million and $881 million during 2012 and 2011, respectively.

Marketing and Midstream Revenues and Operating Costs and Expenses

	Year Ended December 31,				
	2013	Change	2012	Change	2011
			($ in millions)		
Revenues	$ 2,066	+25%	$ 1,655	-27%	$ 2,249
Operating costs and expenses	1,553	+25%	1,246	-27%	1,716
Operating profit	$ 513	+25%	$ 409	-23%	$ 533

2013 vs. 2012 Marketing and midstream operating profit increased $104 million, or 25 percent, from the year ended December 31, 2012 to the year ended December 31, 2013.

Our profit largely increased due to the effects of pricing and marketing activities. Our profit increased nearly $40 million due to our NGL and gas marketing. Additionally, changes in pricing led to an increase in operating profit of approximately $32 million. Higher residue natural gas prices were the primary contributor to the higher profit.

Higher gathering and processing volumes were responsible for an increase in operating profit of $21 million. Higher volumes were primarily the result of NGL production. The increase was largely driven by higher inlet volumes at the Cana processing facility, improved efficiencies at the Cana and Bridgeport processing facilities and downtime impacting our Bridgeport processing facility in 2012.

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Operations and maintenance expenses decreased $11 million, or 6 percent primarily due to expenditures for regulatory testing in 2012.

2012 vs. 2011 Marketing and midstream operating profit decreased $124 million, or 23 percent, from the year ended December 31, 2011 to the year ended December 31, 2012.

Our profit largely decreased due to the effects of pricing and marketing activities. Changes in pricing led to a decrease in operating profit of approximately $106 million. Lower residue natural gas and NGL prices were the primary contributor to the lower profit. Additionally, our profit decreased $13 million primarily due to lower profits on our NGL marketing.

Higher gathering, processing and transportation volumes were responsible for an increase in operating profit of $11 million. Higher volumes were primarily the result of additional throughput at Bridgeport and Cana gathering.

Operations and maintenance expenses increased $16 million, or 9 percent primarily due to expenditures for regulatory testing in 2012.

Lease Operating Expenses (LOE)

	Year Ended December 31,				
	2013	Change	2012	Change	2011
LOE ($ in millions):					
U.S.	$ 1,257	+19%	$ 1,059	+14%	$ 925
Canada	1,011	-0%	1,015	+10%	926
Total	$ 2,268	+9%	$ 2,074	+12%	$ 1,851
LOE per Boe:					
U.S.	$ 6.65	+15%	$ 5.79	+8%	$ 5.35
Canada	$ 15.78	+4%	$ 15.18	+10%	$ 13.82
Total	$ 8.97	+8%	$ 8.30	+8%	$ 7.71

2013 vs. 2012 LOE increased $0.67 per Boe largely because of our liquids production growth, particularly in the Permian Basin and the Mississippian-Woodford Trend in the U.S. These projects generally require a higher per unit cost than our gas projects, particularly because they are in the early stages of development. Additionally, we conducted a turnaround at Jackfish 2 in the third quarter of 2013, contributing to higher unit costs in 2013. We also experienced inflationary pressures on costs in certain operating areas, which increased LOE per Boe.

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. We also experienced inflationary pressures on costs in certain operating areas, which increased LOE per Boe.

General and Administrative Expenses (G&A)

	Year Ended December 31,				
	2013	Change	2012	Change	2011
			($ in millions)		
Gross G&A	$ 1,128	-4%	$ 1,171	+13%	$ 1,036
Capitalized G&A	(368)	+3%	(359)	+7%	(337)
Reimbursed G&A	(143)	+19%	(120)	+5%	(114)
Net G&A	$ 617	-11%	$ 692	+18%	$ 585
Net G&A per Boe	$ 2.44	-12%	$ 2.77	+14%	$ 2.44

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2013 vs. 2012 Net G&A and net G&A per Boe decreased largely due to lower personnel expenses and office rent as a result of the Houston office consolidation in 2012 and lower costs as a result of the company-wide implementation of SAP in Q2 2012. Higher reimbursements due to increased liquids drilling activity and reimbursement rates also contributed to the decrease in net G&A and net G&A per Boe.

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 Anadarko Basin.

Production and Property Taxes

	Year Ended December 31,				
	2013	Change	2012 ($ in millions)	Change	2011
Production	$ 275	+23%	$ 224	-10%	$ 248
Property and other	186	-2%	190	+8%	176
Production and property taxes	$ 461	+11%	$ 414	-3%	$ 424
Percentage of oil, gas and NGL revenue:					
Production	3.23%	+3%	3.13%	+5%	2.98%
Property and other	2.18%	-18%	2.65%	+25%	2.12%
Total	5.41%	-6%	5.78%	+13%	5.10%

2013 vs. 2012 Production and property taxes increased primarily due to an increase in our U.S. revenues, on which the majority of our production taxes are assessed.

2012 vs. 2011 Production and property taxes decreased primarily due to a decrease in our U.S. revenues, on which the majority of our production taxes are assessed.

Depreciation, Depletion and Amortization (DD&A)

	Year Ended December 31,				
	2013	Change	2012 ($ in millions)	Change	2011
DD&A:					
Oil & gas properties	$ 2,465	-2%	$ 2,526	+27%	$ 1,987
Other properties	315	+11%	285	+9%	261
Total	$ 2,780	-1%	$ 2,811	+25%	$ 2,248
DD&A per Boe:					
Oil & gas properties	$ 9.75	-4%	$ 10.12	+22%	$ 8.28
Other properties	1.24	+9%	1.14	+5%	1.09
Total	$ 10.99	-2%	$ 11.26	+20%	$ 9.37

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.

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2013 vs. 2012 Oil and gas property DD&A decreased $61 million largely as a result of the asset impairment charges recognized in 2012 and 2013. Depreciation and amortization on our other properties increased $30 million largely from the construction of our new headquarters in Oklahoma City and natural gas pipeline development in the Cana-Woodford Shale.

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.

Asset Impairments

	Year Ended December 31, 2013		Year Ended December 31, 2012	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
U.S. oil and gas assets	$ 1,110	$ 707	$ 1,793	$ 1,142
Canada oil and gas assets	843	632	163	122
Midstream assets	23	14	68	44
Total asset impairments	$ 1,976	$ 1,353	$ 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.

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.

Net Financing Costs

	Year Ended December 31,				
	2013	Change	2012	Change	2011
	($ in millions)				
Interest based on debt outstanding	$ 466	+6%	$ 440	+6%	$ 414
Capitalized interest	(56)	+15%	(48)	-33%	(72)
Other fees and expenses	27	+94%	14	+33%	10
Interest expense	437	+8%	406	+15%	352
Interest income	(20)	-43%	(36)	+69%	(21)
Net financing costs	$ 417	+13%	$ 370	+12%	$ 331

2013 vs. 2012 Net financing costs increased primarily due to additional debt borrowings and associated fees, partially offset by lower weighted average interest rates and higher capitalized interest. Borrowings were primarily used to fund capital expenditures in excess of our operating cash flow and to provide funding for our planned Eagle Ford Shale acquisition that is expected to close in the first quarter of 2014.

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2012 vs. 2011 Net financing costs 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 divestiture proceeds.

Restructuring Costs

	Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Office consolidation:			
Employee severance and retention	$ 13	$ 77	$
Lease obligations and other	41	3	
Total	54	80	
Offshore divestitures:			
Employee severance	$	$ (3)	$ 8
Lease obligations and other		(3)	(10)
Total		(6)	(2)
Restructuring costs [(1)]	$ 54	$ 74	$ (2)

(1) Restructuring costs related to our discontinued operations totaled $(2) million in 2011. These costs primarily consist of employee severance and are not included in the table. There were no costs related to discontinued operations in 2013 or 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 closed our office in Houston, transferred operational responsibilities for assets in south Texas, east Texas and Louisiana to Oklahoma City and incurred $134 million of restructuring costs associated with the consolidation.

Employee severance and retention As of December 31, 2013, we had incurred $90 million of employee severance and retention costs associated with the office consolidation. This included amounts related to cash severance costs and accelerated vesting of share-based grants.

Lease obligations and other As of December 31, 2013, we had incurred $28 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. 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.

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Income Taxes

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

	Year Ended December 31,		
	2013	2012	2011
Total income tax expense (benefit) (in millions)	$ 169	$ (132)	$ 2,156
United States statutory income tax rate	35%	(35%)	35%
State income taxes	23%	6%	1%
Taxation on Canadian operations	9%	(6%)	(2%)
Repatriations	65%	0%	17%
Other	(19%)	(7%)	(1%)
Effective income tax rate	113%	(42%)	50%

Pursuant to the completed and planned divestitures of our International assets located outside North America, a portion of our foreign earnings had been deemed to no longer be indefinitely reinvested. As of December 31, 2012, we had recognized a $936 million deferred income tax liability related to assumed repatriations of earnings from our foreign subsidiaries, including $725 million of deferred income tax expense recognized in 2011.

In the second and fourth quarters of 2013, we repatriated to the U. S. a total of $4.3 billion of our cash held outside of the U. S. In the fourth quarter of 2013, we announced plans to divest of our Canadian non-core properties. These events resulted in incremental income tax expense of $97 million. The incremental expense included $180 million of current income tax expense offset by $83 million of deferred income tax benefit. The $83 million deferred tax benefit was comprised of $180 million of deferred tax benefits that offset the incremental current income tax expense and an additional $97 million of deferred income tax expense accrued in the fourth quarter for assumed repatriations.

In 2013, our state income tax rate is higher than 2012 and 2011 primarily due to the relatively small amount of pre-tax income, resulting from pre-tax income for the U.S. partially offset by a pre-tax loss for Canada. Also, 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 years ended December 31, 2013 and 2012, respectively, because of the relatively small pre-tax income/loss for those periods. For 2013 other was comprised primarily of tax audit adjustments and a favorable tax impact due to acquisition financing.

Earnings (Loss) From Discontinued Operations

	Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Operating earnings	$	$	$ 38
Gain (loss) on sale of oil and gas properties		(16)	2,552
Earnings (loss) before income taxes		(16)	2,590
Income tax expense		5	20
Earnings (loss) from discontinued operations	$	$ (21)	$ 2,570

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The earnings (loss) in each period were primarily driven by gains (losses) on the sales of our oil and gas assets in each period. In 2012 we incurred a loss of $16 million ($21 million net of taxes) for the sale of our assets in Angola. In 2011 we generated a gain of $2.5 billion ($2.5 billion net of taxes) for the sale of our assets in Brazil.

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,		
	2013	2012	2011
		(In millions)	
Operating cash flow continuing operations	$ 5,436	$ 4,930	$ 6,246
Capital expenditures	(6,758)	(8,225)	(7,534)
Debt activity, net	361	1,921	4,187
Shareholder distributions	(348)	(324)	(2,610)
Divestitures of property and equipment	419	1,539	3,380
Other	(24)	81	(46)
Net change in cash and short-term investments	$ (914)	$ (78)	$ 3,623
Cash and short-term investments at end of period	$ 6,066	$ 6,980	$ 7,058

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 2013. Our operating cash flow increased 10 percent during 2013 primarily due to higher commodity prices and production growth, partially offset by higher expenses. 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 cash settlements from our commodity derivatives.

During 2013 our operating cash flow funded approximately 80 percent of our cash payments for capital expenditures. Leveraging our liquidity, we used cash balances, short-term debt and divestiture proceeds to fund the remainder of our cash-based capital expenditures.

Capital Expenditures

	Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Development	$ 4,754	$ 5,183	$ 5,269
Exploration	602	541	378
Acquisition	256	1,329	901
Subtotal	5,612	7,053	6,548
Capitalized G&A and interest	354	343	332
Total oil and gas	5,966	7,396	6,880
Midstream	699	504	333
Corporate and other	93	325	321
Total capital expenditures	$ 6,758	$ 8,225	$ 7,534

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Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling and development of oil and gas properties, which totaled $6.0 billion, $7.4 billion and $6.9 billion in 2013, 2012 and 2011, respectively. The 20 percent decline in exploration, development and acquisition capital spending in 2013 was primarily due to a decline in new venture acreage acquisitions and utilization of the drilling carries in 2013 from our Sinopec and Sumitomo joint venture arrangements. The higher exploration and development capital spending in 2012 and 2011 was primarily due to new venture acreage acquisitions and increased drilling and development. With rising oil prices and proceeds from our offshore divestitures, we increased our onshore North American acreage positions and associated exploration and development activities to drive near-term growth of our 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. The higher 2013 midstream expenditures primarily relate to expansions of our plants serving the Barnett Shale and Cana-Woodford Shale and our Access Pipeline transporting heavy oil in Canada.

Capital expenditures related to other activities decreased in 2013. This decrease is largely driven by the construction of our new headquarters in Oklahoma City, which was completed in 2012.

Debt Activity, Net

During 2013, we increased our debt borrowings by $361 million as a result of issuing $2.25 billion of debt related to the planned Eagle Ford Shale acquisition, which is expected to close in the first quarter of 2014, and repaying approximately $1.9 billion of outstanding short-term debt.

In December 2013, to provide funding for our planned Eagle Ford Shale acquisition, we issued $2.25 billion aggregate principal amount of fixed and floating rate senior notes resulting in cash proceeds of approximately $2.2 billion, net of discounts and issuance costs.

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.

Shareholder Distributions

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

	2013			2012			2011		
	Amount	Shares	Per Share	Amount	Shares	Per Share	Amount	Shares	Per Share
Repurchases	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,332	31.3	$ 74.54
Dividends	$ 348	N/A	$ 0.86	$ 324	N/A	$ 0.80	$ 278	N/A	$ 0.67

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.

Divestitures of Property and Equipment

In 2013, we sold our Thunder Creek operations in Wyoming for approximately $148 million and our Bear Paw Basin assets in Havre, Montana for approximately $73 million. We also sold other minor oil and gas assets.

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.

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, our divestitures primarily related to the divestitures of our offshore assets.

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, including our planned $6 billion acquisition of Eagle Ford Shale assets from GeoSouthern.

Operating Cash Flow and Cash Balances

Our operating cash flow is sensitive to many variables, the most volatile of which are the prices of the oil, gas and NGLs we produce. Due to higher commodity prices, our operating cash flow from continuing operations increased 10 percent to $5.4 billion in 2013. 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 2014.

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, 2013 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, 2013, we had total debt of $12.0 billion with an overall weighted average borrowing rate of 4.1 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.

At the end of 2013, we held approximately $6.1 billion of cash. Included in this total was $1.8 billion of cash held by our foreign subsidiaries. If we were to repatriate a portion or all of the cash 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.

Credit Availability

We have a $3.0 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility) that matures on October 24, 2018. 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, 2013, 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, 2013, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2013, as calculated pursuant to the terms of the agreement, was 25.7 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 $3.0 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, 2013, we had $1.3 billion of borrowings under our commercial paper program.

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 Fitch, BBB+ with a negative outlook by Standard & Poor s, and Baa1 with a review for downgrade by Moody s.

There are no rating triggers in any of our debt 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.

Capital Expenditures

Excluding our planned $6 billion Eagle Ford Shale acquisition, our 2014 capital expenditures are expected to range from $6.4 billion to $6.9 billion, including $5.4 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 2014 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2014 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2014, our existing commodity hedging contracts, available cash balances and credit availability, we anticipate having adequate capital resources to fund our 2014 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 $1.4 billion at the end of 2013. 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 2015.

Acquisitions and Divestitures

GeoSouthern Acquisition On November 20, 2013, we entered into an agreement with GeoSouthern Intermediate Holdings, LLC, to acquire certain oil and gas properties, leasehold mineral interests and related assets located in the Eagle Ford Shale in south Texas for $6 billion in cash. The transaction is expected to close in the first quarter of 2014.

To provide funding for the Eagle Ford Shale acquisition, we issued $2.25 billion of senior notes in December 2013. The floating rate senior notes due in 2015 bear interest at a rate equal to three-month LIBOR plus 0.45%, which rate will be reset quarterly. The floating rate senior notes due in 2016 bear interest at a rate equal to three-month LIBOR plus 0.54%, which rate will be reset quarterly. We also entered into a term loan agreement in December 2013 with a group of major financial institutions pursuant to which we may draw up to $2.0 billion to finance, in part, the Eagle Ford Shale acquisition and to pay transaction costs. Half of any loans under the term loan agreement will have a maturity of three years and the other half will have a maturity of five years (the 5-Year Loans). The 5-Year Loans will provide for the partial amortization of principal during the last

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two years that they are outstanding. Loans borrowed under the term loan agreement may, at our election, bear interest at various fixed rate options for periods up to six months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate.

In the event that the Eagle Ford Shale acquisition is not completed on or prior to June 30, 2014, we will be required to redeem each series of new senior notes at 101% of the $2.25 billion aggregate principal amount, plus accrued and unpaid interest.

Crosstex Merger On October 21, 2013, Devon, Crosstex Energy, Inc. and Crosstex Energy, L.P. (collectively Crosstex) announced plans to combine substantially all of Devon s U.S. midstream assets with Crosstex s assets to form a new midstream business. The new business will consist of EnLink Midstream Partners, L.P. (the Partnership) and EnLink Midstream, LLC (EnLink), a master limited partnership and a general partner entity, which will both be publicly traded entities.

In exchange for a controlling interest in both EnLink and the Partnership, Devon will contribute its equity interest in a newly formed Devon subsidiary (EnLink Holdings) and $100 million in cash. EnLink Holdings will own Devon s midstream assets in the Barnett Shale in north Texas and the Cana and Arkoma Woodford Shales in Oklahoma, as well as Devon s economic interest in Gulf Coast Fractionators in Mt. Belvieu, Texas. The Partnership and EnLink will each own 50% of EnLink Holdings. The completion of these transactions is subject to Crosstex Energy, Inc. shareholder approval. Devon expects Crosstex Energy, Inc. shareholders will approve the transaction, allowing Devon and Crosstex to complete the transaction near the end of the first quarter of 2014.

Upon closing of the transactions, the pro forma ownership of EnLink will be approximately:

- 70% Devon Energy Corporation
- 30% Current Crosstex Energy, Inc. public stockholders

Upon closing of the transactions, the pro forma ownership of the Partnership will be approximately:

- 53% Devon Energy Corporation
- 40% Current Crosstex Energy, L.P. public unitholders
- 7% the General Partner

Asset Divestitures In conjunction with the announcement of the Eagle Ford Shale acquisition, we also announced plans to monetize certain non-core assets located throughout Canada and the U. S. The divestitures will likely occur in a number of separate transactions, but we expect to complete the majority of the divestitures by the end of 2014.

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Contractual Obligations

A summary of our contractual obligations as of December 31, 2013, is provided in the following table.

		Payments Due by Period			
	Total	Less Than 1 Year	1-3 Years (In millions)	3-5 Years	More Than 5 Years
Debt [1]	$ 12,042	$ 4,067	$ 500	$ 875	$ 6,600
Interest expense [2]	7,328	472	914	845	5,097
Purchase obligations [3]	6,425	852	1,819	1,756	1,998
Operational agreements [4]	3,449	519	876	723	1,331
Asset retirement obligations [5]	2,228	88	146	141	1,853
Drilling and facility obligations [6]	366	341	25		
Lease obligations [7]	285	41	72	61	111
Other [8]	446	272	78	44	52
Total	$ 32,569	$ 6,652	$ 4,430	$ 4,445	$ 17,042

(1) Debt amounts represent scheduled maturities of our debt obligations at December 31, 2013, excluding $20 million of net discounts included in the carrying value of debt. Included in current debt is the $2.25 billion senior notes related to the GeoSouthern acquisition that will be reclassified to long-term once the transaction closes in the first quarter of 2014.

(2) Interest expense represents the scheduled cash payments on long-term, fixed-rate debt and an estimate of our floating-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 transportation process. Any disruption in our ability to obtain condensate could negatively affect our ability to 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, 2013 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 $243 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

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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 2013, 91 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 United States Treasury bill rates. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices and regional price differentials.

We periodically enter into interest rate swaps to manage our exposure to interest rate volatility. Under the terms of our interest rate swaps, we generally receive a fixed rate and pay a variable rate on a total notional amount. As of December 31, 2013 we had no outstanding interest rate swaps.

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 enter into foreign exchange forward contracts to manage our exposure to fluctuations in exchange rates. Under the terms of our foreign exchange forward contracts, we generally receive U.S. dollars and pay Canadian dollars based on a total notional amount.

We estimate the fair values of our foreign exchange forward contracts primarily by using internal discounted cash flow calculations based upon forward exchange rates. The most significant variable to our cash flow calculations is our observation of forward foreign exchange rates. The resulting future cash inflows or outflows at maturity of the contracts are discounted using Treasury rates. These discounting variables are sensitive to the period of the contract and market volatility.

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 fourteen separate counterparties, and our foreign exchange forward 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 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, 2013, the date of our last impairment test, the fair values of our U.S. and Canadian reporting units exceeded their related carrying values. The fair value of our U.S. reporting unit substantially exceeded its carrying value. However, the fair value of our Canadian reporting is not substantially in excess of its carrying value. As of October 31, 2013, the fair value of our Canadian reporting unit derived by the average of our three valuation methods (comparable company multiples, comparable transaction multiples, and transaction premiums) exceeded its carrying value by approximately 11 percent. As of December 31, 2013, we had $2.8 billion of goodwill allocated to the Canadian reporting unit.

Significant decreases to our stock price, decreases in commodity prices, negative deviations from projected Canadian reporting unit earnings or unfavorable changes in reserves 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.

The accruals for deferred tax assets and liabilities are often based on assumptions that are subject to a significant amount of judgment by management. These assumptions and judgments are reviewed and adjusted as facts and circumstances change. Material changes to our income tax accruals may occur in the future based on the progress of ongoing audits, changes in legislation or resolution of pending matters.

We also assess factors relative to whether our foreign earnings are considered indefinitely reinvested. These factors include forecasted and actual results for both our U.S. and Canadian operations, borrowing conditions in the U.S., and existing United States income tax laws, particularly the laws pertaining to the deductibility of intangible drilling costs and repatriations of foreign earnings. Changes in any of these factors could require recognition of additional deferred, or even current, U.S. income tax expense. We accrue deferred U.S. income tax expense on our foreign earnings when the factors indicate that these earnings are no longer considered indefinitely reinvested.

For our foreign earnings deemed indefinitely reinvested, we do not calculate a hypothetical deferred tax liability on these earnings. Calculating a hypothetical tax on these accumulated earnings is much different from the calculation of the deferred tax liability on our earnings deemed not indefinitely reinvested. A hypothetical tax calculation on the indefinitely reinvested earnings would require the following additional activities:

- Separate analysis of a diverse chain of foreign entities;

- Relying on tax rates on a future remittance that could vary significantly depending on alternative approaches available to repatriate the earnings;

- Determining the nature of a yet-to-be-determined future remittance, such as whether the distribution would be a non-taxable return of capital or a distribution of taxable earnings, and calculation of associated withholding taxes, which would vary significantly depending on the circumstances at the deemed time of remittance; and

- Further analysis of a variety of other inputs such as the earnings, profits, United States/foreign country tax treaty provisions and the related foreign taxes paid by our foreign subsidiaries, whose earnings are deemed permanently reinvested, over a lengthy history of operations.

Because of the administrative burden required to perform these additional activities, it is impracticable to calculate a hypothetical tax on the foreign earnings associated with this separate and more complicated chain of companies.

Non-GAAP Measures

We make reference to adjusted earnings and adjusted earnings per share in Overview of 2013 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, as well as the per share amount, represent 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. Our non-GAAP measures are typically used as a quarterly performance measure. Items may appear to be recurring while comparing on an annual basis. In the below table, restructuring costs were incurred in each of the three year periods, however, these costs relate to different restructuring programs. Amounts excluded for 2013 and a portion of 2012 relate to our office consolidation and amounts excluded for the remaining portion of 2012 and 2011 relate to our offshore divestiture program. For more information on our restructuring programs see Note 6 to the financial statements included in Item 8. Financial Statements and Supplementary Data of this report. We believe these non-GAAP measures facilitate comparisons of our performance to earnings 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.

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Below are reconciliations of our adjusted earnings and earnings per share to their comparable GAAP measures. The reconciliations exclude amounts related to our discontinued operations.

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except per share amounts)		
Net earnings (loss) (GAAP)	$ (20)	$ (185)	$ 2,134
Adjustments (net of taxes):			
Asset impairments	1,353	1,308	
Derivatives and other financial instruments	131	(425)	(546)
Cash settlements on derivatives and financial instruments	139	558	308
U.S. income taxes on foreign earnings	97		744
Restructuring costs	34	49	(2)
Insurance proceeds			(60)
Adjusted earnings (Non-GAAP)	$ 1,734	$ 1,305	$ 2,578
Earnings (loss) per share (GAAP)	$ (0.06)	$ (0.47)	$ 5.10
Adjustments (net of taxes):			
Asset impairments	3.35	3.23	
Derivatives and other financial instruments	0.31	(1.04)	(1.33)
Cash settlements on derivatives and financial instruments	0.34	1.37	0.76
U.S. income taxes on foreign earnings	0.24		1.78
Restructuring costs	0.08	0.13	
Insurance proceeds			(0.14)
Adjusted earnings per share (Non-GAAP)	$ 4.26	$ 3.22	$ 6.17

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 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, 2013 are presented in Note 2 to the financial statements under Item 8. Financial Statements and Supplementary Data of this report.

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The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2013, 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	$ (225)	$ 202
Oil derivatives	$ (594)	$ 545
NGL derivatives	$ (1)	$

Interest Rate Risk

At December 31, 2013, we had total debt of $12.0 billion. Of this amount, $9.9 billion bears fixed interest rates averaging 4.9 percent. The remaining $2.1 billion of debt is comprised of commercial paper borrowings that bear interest rates averaging 0.30 percent and floating rate debt that at December 31, 2013 had rates averaging 0.73 percent. Our commercial paper borrowings typically have maturities between 1 and 90 days.

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, 2013 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 based in Canadian dollars. The value of the Canadian-dollar cash and intercompany loans increases or decreases from the remeasurement of the cash and loans into the U.S. dollar functional currency. Additionally, at December 31, 2013, 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 and intercompany loans. Based on the amount of the cash and intercompany loans as of December 31, 2013, a 10 percent change in the foreign currency exchange rates would not have materially impacted our balance sheet.

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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

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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, 2013 and 2012, 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, 2013. We also have audited Devon Energy Corporation s internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) 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, 2013 and 2012, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with United States 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, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Oklahoma City, Oklahoma

February 28, 2014

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except per share amounts)		
Oil, gas and NGL sales	$ 8,522	$ 7,153	$ 8,315
Oil, gas and NGL derivatives	(191)	693	881
Marketing and midstream revenues	2,066	1,655	2,249
Total operating revenues	10,397	9,501	11,445
Lease operating expenses	2,268	2,074	1,851
Marketing and midstream operating expenses	1,553	1,246	1,716
General and administrative expenses	617	692	585
Production and property taxes	461	414	424
Depreciation, depletion and amortization	2,780	2,811	2,248
Asset impairments	1,976	2,024	
Other operating items	121	92	(11)
Total operating expenses	9,776	9,353	6,813
Operating income	621	148	4,632
Net financing costs	417	370	331
Restructuring costs	54	74	(2)
Other nonoperating items	1	21	13
Earnings (loss) from continuing operations before income taxes	149	(317)	4,290
Income tax expense (benefit)	169	(132)	2,156
Earnings (loss) from continuing operations	(20)	(185)	2,134
Earnings (loss) from discontinued operations, net of tax		(21)	2,570
Net earnings (loss)	$ (20)	$ (206)	$ 4,704
Basic earnings (loss) from continuing operations per share	$ (0.06)	$ (0.47)	$ 5.12
Basic earnings (loss) from discontinued operations per share		(0.05)	6.17
Basic net earnings (loss) per share	$ (0.06)	$ (0.52)	$ 11.29
Diluted earnings (loss) from continuing operations per share	$ (0.06)	$ (0.47)	$ 5.10
Diluted earnings (loss) from discontinued operations per share		(0.05)	6.15
Diluted net earnings (loss) per share	$ (0.06)	$ (0.52)	$ 11.25
Comprehensive earnings (loss):			
Net earnings (loss)	$ (20)	$ (206)	$ 4,704
Other comprehensive earnings (loss), net of tax:			
Foreign currency translation	(548)	194	(191)
Pension and postretirement plans	45	2	6
Other comprehensive earnings (loss), net of tax	(503)	196	(185)

Comprehensive earnings (loss)	$ (523)	$ (10)	$ 4,519

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2013	2012	2011
		(In millions)	
Cash flows from operating activities:			
Net earnings (loss)	$ (20)	$ (206)	$ 4,704
Loss (earnings) from discontinued operations, net of tax		21	(2,570)
Adjustments to reconcile earnings (loss) from continuing operations to net cash from operating activities:			
Depreciation, depletion and amortization	2,780	2,811	2,248
Asset impairments	1,976	2,024	
Deferred income tax expense (benefit)	97	(184)	2,299
Derivatives and other financial instruments	135	(660)	(886)
Cash settlements on derivatives and financial instruments	277	865	485
Other noncash charges	318	240	241
Net change in working capital	(298)	(50)	180
Change in long-term other assets	10	(36)	33
Change in long-term other liabilities	161	105	(488)
Cash from operating activities continuing operations	5,436	4,930	6,246
Cash from operating activities discontinued operations		26	(22)
Net cash from operating activities	5,436	4,956	6,224
Cash flows from investing activities:			
Capital expenditures	(6,758)	(8,225)	(7,534)
Proceeds from property and equipment divestitures	419	1,468	129
Purchases of short-term investments	(1,076)	(4,106)	(6,691)
Redemptions of short-term investments	3,419	3,266	5,333
Other	(3)	14	(29)
Cash from investing activities continuing operations	(3,999)	(7,583)	(8,792)
Cash from investing activities discontinued operations		57	3,146
Net cash from investing activities	(3,999)	(7,526)	(5,646)
Cash flows from financing activities:			
Proceeds from borrowings of long-term debt, net of issuance costs	2,233	2,458	2,221
Net short-term debt borrowing (repayments)	(1,872)	(537)	3,726
Debt repayments			(1,760)
Credit facility borrowings		750	
Credit facility repayments		(750)	
Proceeds from stock option exercises	3	27	101
Repurchases of common stock			(2,332)
Dividends paid on common stock	(348)	(324)	(278)
Excess tax benefits related to share-based compensation	4	5	13
Net cash from financing activities	20	1,629	1,691
Effect of exchange rate changes on cash	(28)	23	(4)

Net change in cash and cash equivalents	1,429	(918)	2,265
Cash and cash equivalents at beginning of period	4,637	5,555	3,290
Cash and cash equivalents at end of period	$ 6,066	$ 4,637	$ 5,555

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,066	$ 4,637
Short-term investments		2,343
Accounts receivable	1,520	1,245
Other current assets	419	746
Total current assets	8,005	8,971
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	73,995	69,410
Not subject to amortization	2,791	3,308
Total oil and gas	76,786	72,718
Other	6,195	5,630
Total property and equipment, at cost	82,981	78,348
Less accumulated depreciation, depletion and amortization	(54,534)	(51,032)
Property and equipment, net	28,447	27,316
Goodwill	5,858	6,079
Other long-term assets	567	960
Total assets	$ 42,877	$ 43,326
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,229	$ 1,451
Revenues and royalties payable	786	750
Short-term debt	4,066	3,189
Other current liabilities	574	613
Total current liabilities	6,655	6,003
Long-term debt	7,956	8,455
Asset retirement obligations	2,140	1,996
Other long-term liabilities	834	901
Deferred income taxes	4,793	4,693
Stockholders equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 406 million shares in 2013 and 2012, respectively	41	41
Additional paid-in capital	3,780	3,688
Retained earnings	15,410	15,778
Accumulated other comprehensive earnings	1,268	1,771

Total stockholders equity	20,499	21,278
Commitments and contingencies (Note 18)		
Total liabilities and stockholders equity	$ 42,877	$ 43,326

See accompanying notes to consolidated financial statements.

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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, 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
Net loss				(20)			(20)
Other comprehensive loss, net of tax					(503)		(503)
Stock option exercises			3				3
Common stock repurchased						(36)	(36)
Common stock retired			(36)			36	
Common stock dividends				(348)			(348)
Share-based compensation			121				121
Share-based compensation tax benefits			4				4
Balance as of December 31, 2013	406	$ 41	$ 3,780	$ 15,410	$ 1,268	$	$ 20,499

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 measured 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 2013, 2012 and 2011, no purchaser accounted for more than 10 percent of Devon s operating 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, interest rate risk and foreign exchange risk. Devon does not intend to issue or hold 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 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, 2013, 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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013, Devon held $3 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 consolidation of its U.S. operations announced in October 2012, certain share based awards were accelerated and recognized as a component of restructuring costs 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 basis. 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 indefinitely 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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 United States and Canadian treasury securities and other marketable securities. 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 $62 million and $64 million at December 31, 2013 and 2012, respectively, and are included in other long-term assets in the accompanying balance sheet. Devon has the ability to hold the securities until maturity.

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.

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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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, 2013, 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.

Costs for midstream assets that are in use are depreciated over the assets estimated useful lives, using either the unit-of-production or straight-line method. Depreciation and amortization of other property and equipment, including corporate 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 ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Devon performed annual impairment tests of goodwill in the fourth quarters of 2013, 2012 and 2011. Based on these assessments, no impairment of goodwill was required.

The table below provides a summary of Devon s goodwill, by assigned reporting unit. The decrease in Devon s goodwill from 2012 to 2013 was primarily due to changes in the exchange rate between the United States dollar and the Canadian dollar.

	December 31,	
	2013	2012
	(In millions)	
U.S.	$ 3,020	$ 3,046
Canada	2,838	3,033
Total	$ 5,858	$ 6,079

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

All amounts related to Devon s International operations that were sold in 2012 and 2011 are classified as discontinued operations.

Foreign Currency Translation Adjustments

The United States 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 United States dollars using the applicable exchange rate as of the end of a reporting

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013, 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.

Period	Price Swaps Volume (Bbls/d)	Price Swaps Weighted Average Price ($/Bbl)	Price Collars Volume (Bbls/d)	Price Collars Weighted Average Floor Price ($/Bbl)	Price Collars Weighted Average Ceiling Price ($/Bbl)	Call Options Sold Volume (Bbls/d)	Call Options Sold Weighted Average Price ($/Bbl)
Q1-Q4 2014	75,000	$ 94.14	70,453	$ 89.38	$ 100.58	42,000	$ 116.43
Q1-Q4 2015	37,500	$ 90.15		$	$	22,000	$ 115.45
Q1-Q4 2016		$		$	$	12,500	$ 95.00

As of December 31, 2013, Devon had the following open natural gas derivative positions. The first table presents Devon s natural gas derivatives that settle against the Inside FERC first of the month Henry Hub index. The second table presents Devon s natural gas derivatives that settle against the AECO index.

Period	Price Swaps Volume (MMBtu/d)	Price Swaps Weighted Average Price ($/MMBtu)	Price Collars Volume (MMBtu/d)	Price Collars Weighted Average Floor Price ($/MMBtu)	Price Collars Weighted Average Ceiling Price ($/MMBtu)	Call Options Sold Volume (MMBtu/d)	Call Options Sold Weighted Average Price ($/MMBtu)
Q1-Q4 2014	800,000	$ 4.42	460,000	$ 4.03	$ 4.51	500,000	$ 5.00
Q1-Q4 2015		$		$	$	550,000	$ 5.09
Q1-Q4 2016		$		$	$	110,000	$ 5.00

Period	Basis Swaps Index	Basis Swaps Volume (MMBtu/d)	Basis Swaps Weighted Average Differential to Henry Hub ($/MMBtu)
Q1-Q4 2014	AECO	94,781	$ (0.52)

As of December 31, 2013, Devon had the following open NGL derivative positions. Devon s NGL positions settle against the average of the prompt month OPIS Mont Belvieu, Texas Index.

Period	Basis Swaps Pay

		Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q1-Q4 2014	Natural Gasoline	329	$ (10.85)

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Foreign Currency Derivatives

As of December 31, 2013, Devon had the following open foreign currency derivative position:

Currency	Contract Type	Forward Contract CAD Notional (In millions)	Weighted Average Fixed Rate Received (CAD-USD)	Expiration
Canadian Dollar	Sell	$ 1,002	0.938	March 2014

Financial Statement Presentation

The following table presents the net gains and losses recognized in the accompanying comprehensive statements of earnings associated with derivative financial instruments. Net gains and losses associated with Devon s commodity derivatives are presented in oil, gas and NGL derivatives in the accompanying comprehensive statements of earnings. Net gains and losses associated with Devon s interest rate and foreign currency derivatives are presented in other nonoperating items in the accompanying comprehensive statements of earnings.

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Commodity derivatives	$ (191)	$ 693	$ 881
Interest rate derivatives		(15)	(11)
Foreign currency derivatives	56	(18)	16
Net gains (losses) recognized in comprehensive statements of earnings	$ (135)	$ 660	$ 886

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

	Balance Sheet Caption	December 31 2013	December 31 2012
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$ 75	$ 379
Commodity derivatives	Other long-term assets	28	22
Interest rate derivatives	Other current assets		23
Foreign currency derivatives	Other current assets		1
Total asset derivatives		$ 103	$ 425
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 58	$ 3
Commodity derivatives	Other long-term liabilities	62	29
Foreign currency derivatives	Other current liabilities	1	

Total liability derivatives	$ 121	$ 32

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 did not have an annual long-term incentive grant in 2013 due to revisions in the timing of the employee compensation cycle. The annual long-term incentive grant related to 2013 performance was granted in February 2014. 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 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 6 for further details.

	Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Gross general and administrative expense	$ 157	$ 179	$ 181
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 60	$ 56	$ 56
Related income tax benefit	$ 22	$ 31	$ 33

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of grant. The risk-free interest rate is based on the zero-coupon United States Treasury yield for the expected term of the option at the date of grant. The expected term of the options is based on historical exercise and termination experience for various groups of employees and directors. Each group is determined based on the similarity of their historical exercise and termination behavior. The following table presents a summary of the grant-date fair values of stock options granted and the related assumptions for 2012 and 2011. All such amounts represent the weighted-average amounts for each year. No stock options were granted in 2013.

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

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

	Options (In thousands)	Weighted Average Exercise Price	Weighted Average Remaining Term (In years)	Intrinsic Value (In millions)
Outstanding at December 31, 2012	7,828	$ 69.12		
Exercised	(61)	$ 57.66		
Expired	(1,212)	$ 68.47		
Forfeited	(109)	$ 69.23		
Outstanding at December 31, 2013	6,446	$ 69.35	3.76	$ 1
Vested and expected to vest at December 31, 2013	6,416	$ 69.36	3.75	$ 1
Exercisable at December 31, 2013	5,361	$ 69.50	3.39	$ 1

The aggregate intrinsic value of stock options that were exercised during 2013, 2012 and 2011 was $0.3 million, $34 million and $81 million, respectively. As of December 31, 2013, Devon s unrecognized compensation cost related to unvested stock options was $19 million. Such cost is expected to be recognized over a weighted-average period of 1.6 years.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock Awards and Units

Restricted stock awards and units are subject to the terms, conditions, restrictions and limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, 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 (In thousands)	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2012	5,740	$ 61.75
Granted	258	$ 57.27
Vested	(2,365)	$ 64.13
Forfeited	(341)	$ 59.82
Unvested at December 31, 2013	3,292	$ 59.76

The aggregate fair value of restricted stock awards and units that vested during 2013, 2012 and 2011 was $141 million, $112 million and $145 million, respectively. As of December 31, 2013, Devon s unrecognized compensation cost related to unvested restricted stock awards and units was $166 million. Such cost is expected to be recognized over a weighted-average period of 2.2 years.

Performance Based Restricted Stock Awards

Performance based restricted stock awards are granted to certain members of Devon s senior management. 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 (In thousands)	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2012	408	$ 58.25
Vested	(92)	$ 65.10
Unvested at December 31, 2013	316	$ 56.25

As of December 31, 2013, Devon s unrecognized compensation cost related to these awards was $3 million. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Performance Share Units

Performance share units are granted to certain members of Devon s senior management. 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 United States 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.

	2013		2012		2011	
Grant-date fair value	$61.27	$63.48	$61.27	$63.48	$80.24	$83.15
Risk-free interest rate	0.26%	0.36%	0.26%	0.36%	0.28%	0.43%
Volatility factor	30.3%		30.3%		41.8%	
Contractual term (in years)	3.0		3.0		3.0	

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

	Performance Share Units (In thousands)	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2012	878	$ 66.93
Granted	55	$ 61.57
Forfeited	(8)	$ 63.37
Unvested at December 31, 2013 (1)	925	$ 66.64

(1) A maximum of 1.9 million common shares could be awarded based upon Devon s final TSR ranking.

As of December 31, 2013, Devon s unrecognized compensation cost related to unvested units was $24 million. Such cost is expected to be recognized over a weighted-average period of 1.6 years.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Asset impairments

In 2013 and 2012, Devon recognized asset impairments related to its oil and gas property and equipment and its U.S. midstream assets as presented below.

	Year Ended December 31, 2013		Year Ended December 31, 2012	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
U.S. oil and gas assets	$ 1,110	$ 707	$ 1,793	$ 1,142
Canada oil and gas assets	843	632	163	122
Midstream assets	23	14	68	44
Total asset impairments	$ 1,976	$ 1,353	$ 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 reduced proved reserve values.

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.

5. Other Operating Items

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Accretion of asset retirement obligations	$ 115	$ 110	$ 92
(Gain) loss on sale of assets	9	(13)	(2)
Other	(3)	(5)	(101)
Other operating items	$ 121	$ 92	$ (11)

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

6. 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 closed its office in Houston, transferred operational responsibilities for assets in south Texas, east Texas and Louisiana to Oklahoma City and incurred $134 million of restructuring costs associated with the consolidation.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

	2013	Year Ended December 31, 2012 (In millions)	2011
Office consolidation:			
Employee severance and retention	$ 13	$ 77	$
Lease obligations and other	41	3	
Total	54	80	
Offshore divestitures:			
Employee severance	$	$ (3)	$ 8
Lease obligations and other		(3)	(10)
Total		(6)	(2)
Restructuring costs	$ 54	$ 74	$ (2)

Employee severance and retention As of December 31, 2013, Devon had incurred $90 million of employee severance and retention costs associated with the office consolidation. This included amounts related to cash severance costs and accelerated vesting of share-based grants.

Lease obligations and other As of December 31, 2013, Devon had incurred $28 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. 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.

The schedule below summarizes Devon s restructuring liabilities.

	Other Current Liabilities	Other Long-Term Liabilities (In millions)	Total
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
Employee severance Office consolidation	(43)		(43)
Lease obligations Offshore	(3)	(2)	(5)
Lease obligations and other Office consolidation	21	11	32
Balance as of December 31, 2013	$ 27	$ 18	$ 45

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31, 2013	2012 (In millions)	2011
Current income tax expense (benefit):			
United States federal	$ 73	$ 60	$ (143)
Various states	(5)	(3)	20
Canada and various provinces	4	(5)	(20)
Total current tax expense (benefit)	72	52	(143)
Deferred income tax expense (benefit):			
United States federal	198	(188)	1,986
Various states	59	34	95
Canada and various provinces	(160)	(30)	218
Total deferred tax expense (benefit)	97	(184)	2,299
Total income tax expense (benefit)	$ 169	$ (132)	$ 2,156

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

	Year Ended December 31, 2013	2012 (In millions)	2011
Expected income tax expense (benefit) based on United States statutory tax rate of 35%	$ 52	$ (111)	$ 1,502
Repatriations	97		725
State income taxes	35	20	70
Taxation on Canadian operations	14	(19)	(91)
Other	(29)	(22)	(50)
Total income tax expense (benefit)	$ 169	$ (132)	$ 2,156

Pursuant to the completed and planned divestitures of Devon s International assets located outside North America, a portion of Devon s foreign earnings had been deemed to no longer be indefinitely reinvested. As of December 31, 2012, Devon had recognized a $936 million deferred income tax liability related to assumed repatriations of earnings from its foreign subsidiaries, including $725 million of deferred income tax expense recognized in 2011.

In the second and fourth quarters of 2013, Devon repatriated to the U. S. a total of $4.3 billion of its cash held outside of the U. S. In the fourth quarter of 2013, Devon announced plans to divest of its Canadian conventional assets. These events resulted in an incremental income tax expense of $97 million. The incremental expense included $180 million of current income tax expense offset by $83 million of deferred income tax benefit. The $83 million deferred tax benefit was comprised of $180 million of deferred tax benefits that offset the incremental current income tax expense and an additional $97 million of deferred income tax expense accrued in the fourth quarter for assumed repatriations.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013	December 31, 2012
	(In millions)	
Deferred tax assets:		
Asset retirement obligations	$ 673	$ 618
Foreign tax credits	248	
Net operating loss carryforwards	183	427
Alternative minimum tax credits	105	198
Pension benefit obligations	104	129
Other	163	134
Total deferred tax assets	1,476	1,506
Deferred tax liabilities:		
Property and equipment	(5,895)	(4,970)
Long-term debt	(161)	(198)
Taxes on unremitted foreign earnings	(157)	(936)
Fair value of financial instruments	(7)	(141)
Other	(52)	(76)
Total deferred tax liabilities	(6,272)	(6,321)
Net deferred tax liability	$ (4,796)	$ (4,815)

Devon has recognized a $248 million deferred tax asset related to foreign tax credit carryforwards which expire between 2019 and 2023. Devon expects the tax benefits from the foreign tax credits to be utilized between 2014 and 2016. Devon also has recognized $183 million of deferred tax assets related to various net operating loss carryforwards available to offset future income taxes. The carryforwards consist of $673 million of Canadian net operating loss carryforwards, which expire between 2028 and 2033, and $197 million of state net operating loss carryforwards, which expire primarily between 2014 and 2032. Devon expects the tax benefits from the Canadian net operating loss carryforwards to be utilized between 2014 and 2017 and the state net operating loss carryforwards to be utilized between 2014 and 2020. Devon has also recognized a $105 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.

The expected utilization of Devon s carryforwards and credits is based upon current estimates of taxable income, 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 and credits prior to their expiration.

As of December 31, 2013, Devon s unremitted foreign earnings totaled approximately $4.3 billion. Of this amount, approximately $1.5 billion was deemed to be indefinitely reinvested into the development and growth of Devon s Canadian business. Therefore, Devon has not recognized a deferred tax liability for United States

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

income taxes associated with such earnings. If such earnings were to be repatriated to the U.S., Devon may be subject to United States 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 $2.8 billion of unremitted earnings not to be indefinitely reinvested. Consequently, Devon has recognized a $157 million deferred tax liability associated with such unremitted earnings as of December 31, 2013.

Unrecognized Tax Benefits

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

	December 31, 2013	December 31, 2012
	(In millions)	
Balance at beginning of year	$ 216	$ 165
Tax positions taken in prior periods	(17)	(46)
Tax positions taken in current year	42	92
Accrual of interest related to tax positions taken	5	7
Lapse of statute of limitations		(3)
Foreign currency translation	(3)	1
Balance at end of year	$ 243	$ 216

Devon s unrecognized tax benefit balance at December 31, 2013 and 2012, included $32 million and $27 million, respectively, of interest and penalties. If recognized, $198 million of Devon s unrecognized tax benefits as of December 31, 2013 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
United States federal	2008-2013
Various U.S. states	2008-2013
Canada federal	2004-2013
Various Canadian provinces	2004-2013

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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. 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 (loss)	Common Shares	Earnings (loss) per Share
	(In millions, except per share amounts)		
Year Ended December 31, 2013:			
Loss from continuing operations	$ (20)	406	
Attributable to participating securities	(2)	(4)	
Basic loss per share	(22)	402	$ (0.06)
Dilutive effect of potential common shares issuable			
Diluted loss per share	$ (22)	402	$ (0.06)
Year Ended December 31, 2012:			
Loss from continuing operations	$ (185)	404	
Attributable to participating securities	(3)	(4)	
Basic loss per share	(188)	400	$ (0.47)
Dilutive effect of potential common shares issuable			
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

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 7 million, 9 million and 3 million in 2013, 2012 and 2011, respectively.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Other Comprehensive Earnings

Components of other comprehensive earnings consist of the following:

	Year Ended December 31, 2013	2012	2011
		(In millions)	
Foreign currency translation:			
Beginning accumulated foreign currency translation	$ 1,996	$ 1,802	$ 1,993
Change in cumulative translation adjustment	(574)	203	(200)
Income tax benefit (expense)	26	(9)	9
Ending accumulated foreign currency translation	1,448	1,996	1,802
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(225)	(227)	(233)
Net actuarial gain (loss) and prior service cost arising in current year	48	(47)	(21)
Recognition of net actuarial loss and prior service cost in earnings [(1)]	24	51	30
Income tax expense	(27)	(2)	(3)
Ending accumulated pension and postretirement benefits	(180)	(225)	(227)
Accumulated other comprehensive earnings, net of tax	$ 1,268	$ 1,771	$ 1,575

(1) These accumulated other comprehensive earnings components are included in the computation of net periodic benefit cost, which is a component of general and administrative expenses on the accompanying comprehensive statements of earnings (see Retirement Plans note for additional details).

10. Supplemental Information to Statements of Cash Flows

	Year Ended December 31, 2013	2012	2011
		(In millions)	
Net change in working capital accounts:			
Accounts receivable	$ (288)	$ 140	$ (185)
Other current assets	49	(128)	125
Accounts payable	26	(8)	64
Revenues and royalties payable	35	19	144
Other current liabilities	(120)	(73)	32
Net change in working capital	$ (298)	$ (50)	$ 180
Interest paid (net of capitalized interest)	$ 406	$ 334	$ 325

Income taxes paid (received)	$ 13	$ 100	$ (383)

11. Short-Term Investments

The components of short-term investments include the following:

	December 31, 2013	December 31, 2012
	(In millions)	
Canadian treasury, agency and provincial securities	$	$ 1,865
United States treasuries		429
Other		49
Short-term investments	$	$ 2,343

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2013	December 31, 2012
	(In millions)	
Oil, gas and NGL sales	$ 851	$ 752
Joint interest billings	447	270
Marketing and midstream revenues	172	161
Other	61	72
Gross accounts receivable	1,531	1,255
Allowance for doubtful accounts	(11)	(10)
Net accounts receivable	$ 1,520	$ 1,245

13. Acquisitions and Divestitures

Crosstex Merger

On October 21, 2013, Devon, Crosstex Energy, Inc. and Crosstex Energy, L.P. (collectively Crosstex) announced plans to combine substantially all of Devon s U.S. midstream assets with Crosstex s assets to form a new midstream business. The new business will consist of EnLink Midstream Partners, L.P. (the Partnership) and EnLink Midstream, LLC (EnLink), a master limited partnership and a general partner entity, which will both be publicly traded entities.

In exchange for a controlling interest in both EnLink and the Partnership, Devon will contribute its equity interest in a newly formed Devon subsidiary (EnLink Holdings) and $100 million in cash. EnLink Holdings will own Devon s midstream assets in the Barnett Shale in north Texas and the Cana and Arkoma Woodford Shales in Oklahoma, as well as Devon s economic interest in Gulf Coast Fractionators in Mt. Belvieu, Texas. The Partnership and EnLink will each own 50% of EnLink Holdings. The completion of these transactions is subject to Crosstex Energy, Inc. shareholder approval. Devon expects Crosstex Energy, Inc. shareholders will approve the transaction, allowing Devon and Crosstex to complete the transaction near the end of the first quarter of 2014.

Upon closing of the transactions, the pro forma ownership of EnLink will be approximately:

70% Devon Energy Corporation

30% Current Crosstex Energy, Inc. public stockholders

Upon closing of the transactions, the pro forma ownership of the Partnership will be approximately:

53% Devon Energy Corporation

40% Current Crosstex Energy, L.P. public unitholders

7% the General Partner

GeoSouthern Acquisition

On November 20, 2013, Devon entered into an agreement with GeoSouthern Intermediate Holdings, LLC, to acquire certain oil and gas properties, leasehold mineral interests and related assets located in the Eagle Ford Shale in south Texas for $6 billion in cash. The transaction is expected to close in the first quarter of 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Subsequent Event (unaudited)

In conjunction with the announcement of the GeoSouthern acquisition, Devon also announced plans to divest certain non-core properties located throughout Canada and the U.S. On February 19, 2014, Devon announced its first transaction as part of this divestiture program, in which it agreed to sell the majority of its Canadian conventional assets to Canadian Natural Resources Limited for approximately $2.8 billion ($3.125 billion in Canadian dollars). This transaction is expected to close early in the second quarter of 2014.

14. Debt and Related Expenses

A summary of Devon s debt is as follows:

	December 31, 2013	December 31, 2012
	(In millions)	
Commercial paper	$ 1,317	$ 3,189
Other debentures and notes:		
5.625% due January 15, 2014	500	500
Floating rate due December 15, 2015	500	
2.40% due July 15, 2016	500	500
Floating rate due December 15, 2016	350	
1.20% due December 15, 2016	650	
1.875% due May 15, 2017	750	750
8.25% due July 1, 2018	125	125
2.25% due December 15, 2018	750	
6.30% due January 15, 2019	700	700
4.00% due July 15, 2021	500	500
3.25% due May 15, 2022	1,000	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	750
Net discount on debentures and notes	(20)	(20)
Total debt	12,022	11,644
Less amount classified as short-term debt (1)	4,066	3,189
Long-term debt	$ 7,956	$ 8,455

(1) 2013 short-term debt consists of $2.25 billion of senior notes recently issued in conjunction with the planned GeoSouthern acquisition, $1.3 billion of commercial paper and $500 million of senior notes due January 15, 2014.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt maturities as of December 31, 2013, excluding premiums and discounts, are as follows (in millions):

2014	$ 4,067
2015	
2016	500
2017	750
2018	125
2019 and thereafter	6,600
Total	$ 12,042

Credit Lines

Devon has a $3.0 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility) that matures on October 24, 2018. However, prior to the maturity date, Devon has the option to extend the maturity for up to one additional one-year period, 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, 2013, 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, 2013, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 25.7 percent.

Commercial Paper

Devon has access to $3.0 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, 2013, Devon s weighted average borrowing rate on its commercial paper borrowings was 0.30 percent.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2013, as listed in the table presented at the beginning of this note.

GeoSouthern Debt

In December 2013, in conjunction with the planned GeoSouthern acquisition, Devon issued $2.25 billion aggregate principal amount of fixed and floating rate senior notes resulting in cash proceeds of approximately

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$2.2 billion, net of discounts and issuance costs. The floating rate senior notes due in 2015 bear interest at a rate equal to three-month LIBOR plus 0.45 percent, which rate will be reset quarterly. The floating rate senior notes due in 2016 bears interest at a rate equal to three-month LIBOR plus 0.54 percent, which rate will be reset quarterly. The schedule below summarizes the key terms of these notes ($ in millions).

Floating rate due December 15, 2015	$ 500
Floating rate due December 15, 2016	350
1.20% due December 15, 2016	650
2.25% due December 15, 2018	750
Discount and issuance costs	(2)
Net proceeds	$ 2,248

In the event that GeoSouthern acquisition is not completed on or prior to June 30, 2014, Devon is required to redeem each series of new senior notes at 101% of the aggregate principal amount of such series, plus accrued and unpaid interest. Due to the redemption features, these senior notes were classified as short-term debt on Devon s consolidated balance sheet as of December 31, 2013 and will be reclassified as long-term debt once the acquisition is completed.

Additionally, during December 2013, Devon entered into a term loan agreement with a group of major financial institutions pursuant to which Devon may draw up to $2.0 billion to finance, in part, the GeoSouthern acquisition and to pay transaction costs. Half of any loans under the term loan agreement will have a maturity of three years and the other half will have a maturity of five years (the 5-Year Loans). The 5-Year Loans will provide for the partial amortization of principal during the last two years that they are outstanding. Loans borrowed under the term loan agreement may, at the election of Devon, bear interest at various fixed rate options for periods up to six months. Such rates are generally less than the prime rate. However, Devon may elect to borrow at the prime rate. There were no borrowings under the term loan agreement as of December 31, 2013.

Other Notes

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).

		Date Issued		
	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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013, 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.

Net financing costs

The following schedule includes the components of net financing costs.

	Year Ended December 31, 2013	2012 (In millions)	2011
Interest based on debt outstanding	$ 466	$ 440	$ 414
Capitalized interest	(56)	(48)	(72)
Other fees and expenses	27	14	10
Interest expense	437	406	352
Interest income	(20)	(36)	(21)
Net financing costs	$ 417	$ 370	$ 331

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Asset Retirement Obligations

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

	Year Ended December 31,	
	2013	2012
	(In millions)	
Asset retirement obligations as of beginning of period	$ 2,095	$ 1,563
Liabilities incurred	112	90
Liabilities settled	(83)	(86)
Revision of estimated obligation	104	420
Liabilities assumed by others	(28)	(23)
Accretion expense on discounted obligation	115	110
Foreign currency translation adjustment	(87)	21
Asset retirement obligations as of end of period	2,228	2,095
Less current portion	88	99
Asset retirement obligations, long-term	$ 2,140	$ 1,996

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 $27 million and $31 million at December 31, 2013 and 2012, 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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $1.1 billion and $1.2 billion at December 31, 2013 and 2012, respectively. 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. The projected benefit obligation for Devon s qualified plans was fully funded as of December 31, 2013 and 2012.

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 1,360	$ 1,303	$ 34	$ 37
Service cost	36	43	1	1
Interest cost	51	60	1	1
Actuarial loss (gain)	(158)	95	(3)	(4)
Plan amendments	2	14	(8)	
Plan curtailments		(20)		1
Plan settlements		(93)		
Foreign exchange rate changes	(2)	1		
Participant contributions			3	3
Benefits paid	(112)	(43)	(4)	(5)
Benefit obligation at end of year	1,177	1,360	24	34
Change in plan assets:				
Fair value of plan assets at beginning of year	1,165	1,187		
Actual return on plan assets	(57)	102		
Employer contributions	11	11	1	2
Participant contributions			3	3
Plan settlements		(93)		
Benefits paid	(112)	(43)	(4)	(5)
Foreign exchange rate changes	(1)	1		
Fair value of plan assets at end of year	1,006	1,165		
Funded status at end of year	$ (171)	$ (195)	$ (24)	$ (34)
Amounts recognized in balance sheet:				
Noncurrent assets	$ 47	$ 62	$	$
Current liabilities	(12)	(12)	(3)	(3)
Noncurrent liabilities	(206)	(245)	(21)	(31)
Net amount	$ (171)	$ (195)	$ (24)	$ (34)

Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 279	$ 340	$ (13)	$ (11)
Prior service cost (credit)	23	25	(11)	(4)
Total	$ 302	$ 365	$ (24)	$ (15)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $11 million and $10 million for 2013 and 2012, 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, 2013 and 2012 as presented in the table below.

	December 31, 2013	December 31, 2012
	(In millions)	
Projected benefit obligation	$ 218	$ 257
Accumulated benefit obligation	$ 179	$ 216
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 2013	Pension Benefits 2012	Pension Benefits 2011	Postretirement Benefits 2013	Postretirement Benefits 2012	Postretirement Benefits 2011
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 36	$ 43	$ 37	$ 1	$ 1	$ 1
Interest cost	51	60	60	1	1	2
Expected return on plan assets	(62)	(64)	(42)			
Curtailment and settlement expense		26			1	(3)
Recognition of net actuarial loss (gain) [(1)]	22	24	32	(1)	(1)	
Recognition of prior service cost [(1)]	4	3	3	(1)	(1)	(2)
Total net periodic benefit cost [(2)]	51	92	90		1	(2)
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	(39)	37	23	(3)	(4)	(7)
Prior service cost (credit) arising in current year	2	14		(8)		5
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost	(22)	(45)	(32)	1	1	3
Recognition of prior service cost, including curtailment, in net periodic benefit cost	(4)	(8)	(3)	1	1	2
Total other comprehensive loss (earnings)	(63)	(2)	(12)	(9)	(2)	3
Total recognized	$ (12)	$ 90	$ 78	$ (9)	$ (1)	$ 1

(1) These net periodic benefit costs were reclassified out of other comprehensive earnings in the current period.

(2) Net periodic benefit cost is a component of general and administrative expenses on the accompanying comprehensive statements of earnings.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2014.

	Pension Benefits	Postretirement Benefits
	(In millions)	
Net actuarial loss (gain)	$ 18	$ (1)
Prior service cost (credit)	4	(1)
Total	$ 22	$ (2)

Assumptions

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

	Pension Benefits			Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Assumptions to determine benefit obligations:						
Discount rate	4.80%	3.85%	4.65%	3.65%	3.30%	4.25%
Rate of compensation increase	4.48%	4.48%	4.97%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	3.85%	4.65%	5.50%	3.30%	4.25%	4.90%
Expected return on plan assets	5.48%	5.48%	6.48%	N/A	N/A	N/A
Rate of compensation increase	4.48%	4.97%	6.94%	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 2013 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 2013 benefit obligation for the other postretirement medical plans, a 7.9 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014. 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, 2013, by less than $1 million and would change the 2014 service and interest cost components of net periodic benefit cost by less than $1 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013	December 31, 2012
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, 2013				
			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	24.0%	$ 241	$ 69	$ 172	$
Corporate bonds	39.5%	398	286	112	
Other bonds	3.1%	31	31		
Total fixed-income securities	66.6%	670	386	284	
Equity securities:					
Global (large, mid, small cap)	19.0%	190		190	
Other securities:					
Hedge fund & alternative investments	12.5%	127	15		112
Short-term investment funds	1.9%	19		19	
Total other securities	14.4%	146	15	19	112
Total investments	100.0%	$ 1,006	$ 401	$ 493	$ 112

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

		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

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 United States 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 United States 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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2011	$ 90
Purchases	6
Investment returns	7
December 31, 2012	103
Purchases	
Investment returns	9
December 31, 2013	$ 112

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 2014 contributions	$ 12	$ 3
Benefit payments:		
2014	$ 71	$ 3
2015	$ 74	$ 3
2016	$ 75	$ 3
2017	$ 78	$ 3
2018	$ 81	$ 3
2019 to 2023	$ 450	$ 9

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 2014, the $12 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,		
	2013	2012	2011
		(In millions)	
401(k) and enhanced contribution plans	$ 41	$ 36	$ 33

Canadian pension and savings plans	26	23	21
Total	$ 67	$ 59	$ 54

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013, 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 the 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 $348 million, $324 million and $278 million in 2013, 2012 and 2011 respectively. The quarterly cash dividend was $0.16 per share in 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. Devon increased the dividend rate to $0.22 per share in the second quarter of 2013.

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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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, 2013.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases
		(In millions)		
2014	$ 852	$ 341	$ 519	$ 41
2015	874	18	477	38
2016	945	7	399	34
2017	871		388	33
2018	885		335	28
Thereafter	1,998		1,331	111
Total	$ 6,425	$ 366	$ 3,449	$ 285

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 transportation process. Any disruption in Devon s ability to obtain condensate could negatively affect its ability to 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 $26 million, $42 million and $42 million in 2013, 2012 and 2011, respectively.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013 and December 31, 2012. 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 4 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, 2013 assets (liabilities):					
Cash equivalents	$ 5,305	$ 5,305	$ 4,191	$ 1,114	$
Long-term investments	$ 62	$ 62	$	$	$ 62
Commodity derivatives	$ 103	$ 103	$	$ 103	$
Commodity derivatives	$ (120)	$ (120)	$	$ (120)	$
Foreign currency derivatives	$ (1)	$ (1)	$	$ (1)	$
Debt	$ (12,022)	$ (12,908)	$	$ (12,908)	$
December 31, 2012 assets (liabilities):					
Cash equivalents	$ 4,149	$ 4,149	$ 32	$ 4,117	$
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)	$

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 United States 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 approximates 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 and floating-rate debt are estimated based on rates available for debt with similar terms and maturity. The fair value of Devon s commercial paper and credit facility borrowings are the carrying values.

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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 United States 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, 2013 and December 31, 2012.

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

	Year Ended December 31, 2013	2012
	(In millions)	
Long-term investments balance at beginning of period	$ 64	$ 84
Redemptions of principal	(2)	(20)
Long-term investments balance at end of period	$ 62	$ 64

20. Discontinued Operations

Revenues related to Devon s discontinued operations totaled $43 million during 2011. Devon did not have revenues related to its discontinued operations during 2013 or 2012. The following table presents the earnings (loss) from Devon s discontinued operations.

	Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Operating earnings	$	$	$ 38
Gain (loss) on sale of oil and gas properties		(16)	2,552
Earnings (loss) before income taxes		(16)	2,590
Income tax expense		5	20
Earnings (loss) from discontinued operations	$	$ (21)	$ 2,570

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. Segment revenues are all from external customers.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada (In millions)	Total
Year Ended December 31, 2013:			
Oil, gas and NGL sales	$ 5,964	$ 2,558	$ 8,522
Oil, gas and NGL derivatives	$ (197)	$ 6	$ (191)
Marketing and midstream revenues	$ 1,974	$ 92	$ 2,066
Depreciation, depletion and amortization	$ 1,931	$ 849	$ 2,780
Interest expense	$ 392	$ 45	$ 437
Asset impairments	$ 1,133	$ 843	$ 1,976
Earnings (loss) from continuing operations before income taxes	$ 646	$ (497)	$ 149
Income tax expense (benefit)	$ 325	$ (156)	$ 169
Earnings (loss) from continuing operations	$ 321	$ (341)	$ (20)
Property and equipment, net	$ 19,969	$ 8,478	$ 28,447
Total assets	$ 29,317	$ 13,560	$ 42,877
Capital expenditures	$ 4,802	$ 1,841	$ 6,643
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	$ 1,541	$ 114	$ 1,655
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 derivatives	$ 881	$	$ 881
Marketing and midstream revenues	$ 2,050	$ 199	$ 2,249
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

(1) Amounts in the table above do not include assets held for sale related to Devon s discontinued operations, which totaled $153 million in 2011.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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, 2013		
	U.S.	Canada	Total
		(In millions)	
Property acquisition costs:			
Proved properties	$ 19	$ 3	$ 22
Unproved properties	213	3	216
Exploration costs	443	152	595
Development costs	3,838	1,251	5,089
Costs incurred	$ 4,513	$ 1,409	$ 5,922

	Year Ended December 31, 2012		
	U.S.	Canada	Total
		(In millions)	
Property acquisition costs:			
Proved properties	$ 2	$ 71	$ 73
Unproved properties	1,135	32	1,167
Exploration costs	351	315	666
Development costs	4,408	1,691	6,099
Costs incurred	$ 5,896	$ 2,109	$ 8,005

	Year Ended December 31, 2011		
	U.S.	Canada	Total
		(In millions)	
Property acquisition costs:			
Proved properties	$ 34	$ 14	$ 48
Unproved properties	851	72	923
Exploration costs	272	282	554
Development costs	4,130	1,288	5,418
Costs incurred	$ 5,287	$ 1,656	$ 6,943

Costs incurred in the tables above include additions and revisions to Devon s asset retirement obligations. The proceeds received from our joint venture transactions at closing have not been netted against the costs incurred. At December 31, 2013, our partners remaining commitments to fund our future costs associated with these joint venture transactions totaled approximately $1.4 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 $368 million, $359 million and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$337 million in the years 2013, 2012 and 2011, 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 $42 million, $36 million and $45 million in the years 2013, 2012 and 2011, respectively.

Capitalized Costs

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

	December 31, 2013		
	U.S.	Canada	Total
		(In millions)	
Proved properties	$ 51,366	$ 22,629	$ 73,995
Unproved properties	1,277	1,514	2,791
Total oil & gas properties	52,643	24,143	76,786
Accumulated DD&A	(35,848)	(16,613)	(52,461)
Net capitalized costs	$ 16,795	$ 7,530	$ 24,325

	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

The following is a summary of Devon s oil and gas properties not subject to amortization as of December 31, 2013.

	Costs Incurred In				
	2013	2012	2011	Prior to 2011	Total
			(In millions)		
Acquisition costs	$ 207	$ 725	$ 62	$ 848	$ 1,842
Exploration costs	226	129	118	30	503
Development costs	113	132	66	9	320
Capitalized interest	41	33	33	19	126
Total oil and gas properties not subject to amortization	$ 587	$ 1,019	$ 279	$ 906	$ 2,791

Included in the $2.8 billion of oil and gas properties not subject to amortization are approximately $1.6 billion of costs that we deem significant for individual assessment. These costs relate to our investments in the Pike thermal oil project in Canada, the Mississippian-Woodford Trend in Oklahoma and a portion of our properties in the Permian Basin in Texas. Based on our development plans, we expect to begin including the Pike costs in the amortization computation in 2015 when we receive regulatory approval for the first phase of this project and subsequently begin recognizing the associated proved reserves. We are evaluating and developing the Mississippian-Woodford and Permian properties over the next 3 to 4 years. We expect to include the costs in the amortization computation as we complete our evaluation activities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of Operations

The following tables include revenues and expenses associated with Devon s oil and gas 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, 2013		
	U.S.	Canada (In millions)	Total
Oil, gas and NGL sales	$ 5,964	$ 2,558	$ 8,522
Lease operating expenses	(1,257)	(1,011)	(2,268)
General and administrative expenses	(125)	(77)	(202)
Production and property taxes	(380)	(59)	(439)
Depreciation, depletion and amortization	(1,640)	(825)	(2,465)
Asset impairments	(1,110)	(843)	(1,953)
Accretion of asset retirement obligations	(47)	(64)	(111)
Income tax benefit (expense)	(510)	88	(422)
Results of operations	$ 895	$ (233)	$ 662
Depreciation, depletion and amortization per Boe	$ 8.69	$ 12.87	$ 9.75

	Year Ended December 31, 2012		
	U.S.	Canada (In millions)	Total
Oil, gas and NGL sales	$ 4,679	$ 2,474	$ 7,153
Lease operating expenses	(1,059)	(1,015)	(2,074)
General and administrative expenses	(159)	(137)	(296)
Production and property taxes	(340)	(55)	(395)
Depreciation, depletion and amortization	(1,563)	(963)	(2,526)
Asset impairments	(1,793)	(163)	(1,956)
Accretion of asset retirement obligations	(40)	(69)	(109)
Income tax benefit (expense)	99	(3)	96
Results of operations	$ (176)	$ 69	$ (107)
Depreciation, depletion and amortization per Boe	$ 8.55	$ 14.41	$ 10.12

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	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)
General and administrative expenses	(132)	(119)	(251)
Production and property taxes	(357)	(45)	(402)
Depreciation, depletion and amortization	(1,201)	(786)	(1,987)
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

Proved Reserves

The following tables present Devon s estimated proved reserves by product by country.

	Oil (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2010	148	93	241
Revisions due to prices	2	1	3
Revisions other than price	(1)	(5)	(6)
Extensions and discoveries	36	6	42
Production	(17)	(15)	(32)
December 31, 2011	168	80	248
Revisions due to prices	(1)	(5)	(6)
Revisions other than price	(6)	(2)	(8)
Extensions and discoveries	65	7	72
Production	(21)	(15)	(36)
December 31, 2012	205	65	270
Revisions due to prices	1	(1)	
Revisions other than price	(18)		(18)
Extensions and discoveries	69	7	76
Purchase of reserves	1		1
Production	(28)	(15)	(43)
Sale of reserves	(1)		(1)
December 31, 2013	229	56	285
Proved developed reserves as of:			
December 31, 2010	131	82	213
December 31, 2011	146	73	219

December 31, 2012	166	62	228
December 31, 2013	194	56	250
Proved developed-producing reserves as of:			
December 31, 2010	123	72	195
December 31, 2011	139	65	204
December 31, 2012	155	56	211
December 31, 2013	178	51	229
Proved undeveloped reserves as of:			
December 31, 2010	17	11	28
December 31, 2011	22	7	29
December 31, 2012	39	3	42
December 31, 2013	35		35

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Bitumen (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
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
Revisions due to prices		(11)	(11)
Revisions other than price		16	16
Extensions and discoveries		38	38
Production		(19)	(19)
December 31, 2013		552	552
Proved developed reserves as of:			
December 31, 2010		44	44
December 31, 2011		90	90
December 31, 2012		99	99
December 31, 2013		111	111
Proved developed-producing reserves as of:			
December 31, 2010		44	44
December 31, 2011		90	90
December 31, 2012		99	99
December 31, 2013		111	111
Proved undeveloped reserves as of:			
December 31, 2010		396	396
December 31, 2011		367	367
December 31, 2012		429	429
December 31, 2013		441	441

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Gas (Bcf) U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2010	9,065	1,218	10,283
Revisions due to prices	(1)	(60)	(61)
Revisions other than price	(243)	(38)	(281)
Extensions and discoveries	1,410	58	1,468
Purchase of reserves	16	20	36
Production	(740)	(213)	(953)
Sale of reserves		(6)	(6)
December 31, 2011	9,507	979	10,486
Revisions due to prices	(831)	(99)	(930)
Revisions other than price	(287)	(33)	(320)
Extensions and discoveries	1,124	34	1,158
Purchase of reserves	2		2
Production	(752)	(186)	(938)
Sale of reserves	(1)	(11)	(12)
December 31, 2012	8,762	684	9,446
Revisions due to prices	405	161	566
Revisions other than price	(299)	67	(232)
Extensions and discoveries	471	19	490
Purchase of reserves	1		1
Production	(709)	(165)	(874)
Sale of reserves	(81)	(8)	(89)
December 31, 2013	8,550	758	9,308
Proved developed reserves as of:			
December 31, 2010	7,280	1,144	8,424
December 31, 2011	7,957	951	8,908
December 31, 2012	7,391	679	8,070
December 31, 2013	7,707	752	8,459
Proved developed-producing reserves as of:			
December 31, 2010	6,702	1,031	7,733
December 31, 2011	7,409	862	8,271
December 31, 2012	7,091	624	7,715
December 31, 2013	7,425	680	8,105
Proved undeveloped reserves as of:			
December 31, 2010	1,785	74	1,859
December 31, 2011	1,550	28	1,578
December 31, 2012	1,371	5	1,376
December 31, 2013	843	6	849

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Natural Gas Liquids (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2010	449	30	479
Revisions due to prices	4	(1)	3
Revisions other than price	1		1
Extensions and discoveries	102	2	104
Purchase of reserves	2		2
Production	(33)	(4)	(37)
December 31, 2011	525	27	552
Revisions due to prices	(19)	(5)	(24)
Revisions other than price	(13)		(13)
Extensions and discoveries	114	2	116
Production	(36)	(4)	(40)
December 31, 2012	571	20	591
Revisions due to prices	8	3	11
Revisions other than price	(50)	3	(47)
Extensions and discoveries	64	1	65
Production	(41)	(4)	(45)
December 31, 2013	552	23	575
Proved developed reserves as of:			
December 31, 2010	353	28	381
December 31, 2011	402	26	428
December 31, 2012	431	20	451
December 31, 2013	468	23	491
Proved developed-producing reserves as of:			
December 31, 2010	318	26	344
December 31, 2011	372	24	396
December 31, 2012	406	19	425
December 31, 2013	442	21	463
Proved undeveloped reserves as of:			
December 31, 2010	96	2	98
December 31, 2011	123	1	124
December 31, 2012	140		140
December 31, 2013	84		84

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total (MMBoe) [1]		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2010	2,107	766	2,873
Revisions due to prices	6	(27)	(21)
Revisions other than price	(41)	6	(35)
Extensions and discoveries	374	47	421
Purchase of reserves	5	3	8
Production	(173)	(67)	(240)
Sale of reserves		(1)	(1)
December 31, 2011	2,278	727	3,005
Revisions due to prices	(159)	(12)	(171)
Revisions other than price	(67)	(1)	(68)
Extensions and discoveries	367	82	449
Production	(183)	(67)	(250)
Sale of reserves		(2)	(2)
December 31, 2012	2,236	727	2,963
Revisions due to prices	76	18	94
Revisions other than price	(117)	29	(88)
Extensions and discoveries	212	49	261
Purchase of reserves	1		1
Production	(189)	(64)	(253)
Sale of reserves	(14)	(1)	(15)
December 31, 2013	2,205	758	2,963
Proved developed reserves as of:			
December 31, 2010	1,696	346	2,042
December 31, 2011	1,875	348	2,223
December 31, 2012	1,829	294	2,123
December 31, 2013	1,947	315	2,262
Proved developed-producing reserves as of:			
December 31, 2010	1,557	314	1,871
December 31, 2011	1,746	323	2,069
December 31, 2012	1,743	278	2,021
December 31, 2013	1,857	297	2,154
Proved undeveloped reserves as of:			
December 31, 2010	411	420	831
December 31, 2011	403	379	782
December 31, 2012	407	433	840
December 31, 2013	258	443	701

(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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Proved Undeveloped Reserves

The following table presents the changes in Devon s total proved undeveloped reserves during 2013 (in MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2012	407	433	840
Extensions and discoveries	57	38	95
Revisions due to prices	1	(10)	(9)
Revisions other than price	(91)	13	(78)
Conversion to proved developed reserves	(116)	(31)	(147)
Proved undeveloped reserves as of December 31, 2013	258	443	701

At December 31, 2013, Devon had 701 MMBoe of proved undeveloped reserves. This represents a 17 percent decrease as compared to 2012 and represents 24 percent of total proved reserves. Drilling and development activities increased Devon s proved undeveloped reserves 95 MMBoe and resulted in the conversion of 147 MMBoe, or 18 percent, of the 2012 proved undeveloped reserves to proved developed reserves. Costs incurred related to the development and conversion of Devon s proved undeveloped reserves were $1.9 billion for 2013. Additionally, revisions other than price decreased Devon s proved undeveloped reserves 78 MMBoe primarily due to evaluations of certain U.S. onshore dry-gas areas, which Devon does not expect to develop in the next five years. The largest revisions relate to the dry-gas areas in the Cana-Woodford Shale in western Oklahoma, Carthage in east Texas and the Barnett Shale in north Texas.

A significant amount of Devon s proved undeveloped reserves at the end of 2013 related to its Jackfish operations. At December 31, 2013 and 2012, Devon s Jackfish proved undeveloped reserves were 441 MMBoe and 429 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

2013 Reserves increased 94 MMBoe primarily due to higher gas prices. Of this increase, 43 MMBoe related to the Barnett Shale and 19 MMBoe related to the Rocky Mountain area.

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.

Revisions Other Than Price

Total revisions other than price for 2013, 2012 and 2011 primarily related to Devon s evaluation of certain dry gas regions, with the largest revisions being made in the Cana-Woodford Shale, Barnett Shale and Carthage area.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Extensions and Discoveries

2013 Of the 261 MMBoe of extensions and discoveries, 76 MMBoe related to the Permian Basin in west Texas and southeast New Mexico, 54 MMBoe related to the Barnett Shale, 42 MMBoe related to the Anadarko Basin, 38 MMBoe related to Jackfish in northeast Alberta, Canada and 32 MMBoe related to the Mississippian-Woodford Trend in north Oklahoma.

The 2013 extensions and discoveries included 175 MMBoe related to additions from Devon s infill drilling activities, including 23 MMBoe at the Cana-Woodford Shale, 54 MMBoe at the Barnett Shale, 38 MMBoe at Jackfish, 33 MMBoe at the Permian Basin and 20 MMBoe at the Mississippian-Woodford Trend.

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.

Standardized Measure

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

	Year Ended December 31, 2013		
	U.S.	Canada	Total
		(In millions)	
Future cash inflows	$ 61,983	$ 33,305	$ 95,288
Future costs:			
Development	(5,448)	(5,308)	(10,756)
Production	(26,663)	(15,709)	(42,372)
Future income tax expense	(9,046)	(2,327)	(11,373)
Future net cash flow	20,826	9,961	30,787
10% discount to reflect timing of cash flows	(10,346)	(4,700)	(15,046)
Standardized measure of discounted future net cash flows	$ 10,480	$ 5,261	$ 15,741

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2012		
	U.S.	Canada (In millions)	Total
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 flow	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 (In millions)	Total
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 flow	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

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 2013 estimates, Devon s future realized prices were assumed to be $88.19 per barrel of oil, $47.44 per barrel of bitumen, $3.10 per Mcf of gas and $26.28 per barrel of natural gas liquids. Of the $10.8 billion of future development costs as of the end of 2013, $1.9 billion, $1.5 billion and $0.7 billion are estimated to be spent in 2014, 2015 and 2016, respectively.

Future development costs include not only development costs, but also future asset retirement costs. Included as part of the $10.8 billion of future development costs are $2.7 billion of future asset retirement costs. The future income tax expenses have been computed using statutory tax rates, giving effect to allowable tax deductions and tax credits under current laws.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2013	2012 (In millions)	2011
Beginning balance	$ 13,221	$ 17,844	$ 16,352
Net changes in prices and production costs	3,018	(9,889)	1,875
Oil, bitumen, gas and NGL sales, net of production costs	(5,613)	(4,388)	(5,811)
Changes in estimated future development costs	399	(1,094)	(440)
Extensions and discoveries, net of future development costs	4,047	4,669	3,714
Purchase of reserves	14	18	57
Sales of reserves in place	(44)	(25)	(2)
Revisions of quantity estimates	(1,040)	162	(228)
Previously estimated development costs incurred during the period	1,986	1,321	1,302
Accretion of discount	1,940	1,420	2,248
Other, primarily changes in timing and foreign exchange rates	(583)	113	(294)
Net change in income taxes	(1,604)	3,070	(929)
Ending balance	$ 15,741	$ 13,221	$ 17,844

23. Supplemental Quarterly Financial Information (Unaudited)

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

	2013 First Quarter	Second Quarter	Third Quarter (In millions, except per share amounts)	Fourth Quarter	Full Year
Operating revenues	$ 1,971	$ 3,088	$ 2,714	$ 2,624	$ 10,397
Earnings (loss) before income taxes	$ (1,962)	$ 997	$ 639	$ 475	$ 149
Net earnings (loss)	$ (1,339)	$ 683	$ 429	$ 207	$ (20)
Basic net earnings (loss) per common share:					
Net earnings (loss)	$ (3.34)	$ 1.69	$ 1.06	$ 0.51	$ (0.06)
Diluted net earnings (loss) per common share:					
Net earnings (loss)	$ (3.34)	$ 1.68	$ 1.05	$ 0.51	$ (0.06)

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2012				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Operating revenues	$ 2,495	$ 2,561	$ 1,865	$ 2,580	$ 9,501
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)
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)
Loss from discontinued operations	(0.06)				(0.05)
Net earnings (loss)	$ 0.97	$ 1.18	$ (1.80)	$ (0.89)	$ (0.52)

Earnings (Loss) from Continuing Operations

The first quarter of 2013 includes U.S. and Canadian asset impairments totaling $1.9 billion ($1.3 billion after income taxes, or $3.25 per diluted share).

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).

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

Not Applicable.

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

Disclosure Controls and Procedures

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

Based on their evaluation, 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, 2013 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 in 1992 by the Committee of Sponsoring Organizations of the Treadway Commission (the 1992 COSO Framework). Based on this evaluation under the 1992 COSO Framework, which was completed on February 19, 2014, management concluded that its internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013 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, 2013, 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 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

Not Applicable.

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PART III

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

The information called for by this Item 10 is incorporated 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, 2014.

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, 2014.

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, 2014.

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, 2014.

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, 2014.

PART IV

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

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

1. Consolidated Financial Statements

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

2. Consolidated Financial Statement Schedules

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

3. Exhibits

Exhibit No.	Description
1.1	Underwriting Agreement, dated December 11, 2013, by and among Registrant and Morgan Stanley & Co. LLC, Barclays Capital Inc. and Goldman, Sachs & Co., as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant s Form 8-K filed December 16, 2013).
2.1	Agreement and Plan of Merger dated October 21, 2013, by and among Registrant, Devon Gas Services, L.P., Acacia Natural Gas Corp I, Inc., Crosstex Energy, Inc., New Public Rangers L.L.C., Boomer Merger Sub, Inc. and Rangers Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Registrant s Form 8-K filed October 22, 2013).
2.2	Contribution Agreement dated October 21, 2013, by and among Registrant, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., Crosstex Energy, L.P. and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.2 to Registrant s Form 8-K filed October 22, 2013).
2.3	Purchase and Sale Agreement dated November 20, 2013, among GeoSouthern Intermediate Holdings, LLC, GeoSouthern Energy Corporation (solely with respect to certain sections specified therein), and Devon Energy Production Company, L.P. (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K/A filed February 18, 2014).
3.1	Registrant s Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant s 10-K for the fiscal year ending December 31, 2012).
3.2	Registrant s Bylaws (incorporated by reference to Exhibit 3.2 of Registrant s Form 8-K filed June 8, 2012).
3.3	Amendment No. 1 to Registrant s Bylaws (incorporated by reference to Exhibit 3.2 to Registrant s Form 8-K filed September 16, 2013).
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 July 12, 2011).
4.2	Supplemental Indenture No. 1, dated as of July 12, 2011, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 2.40% Senior Notes due 2016, the 4.00% Senior Notes due 2021 and the 5.60% Senior Notes due 2041 (incorporated by reference to Exhibit 4.2 to Registrant s Form 8-K filed July 12, 2011).

Exhibit No.	Description
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 May 14, 2012).
4.4	Supplemental Indenture No. 3, dated as of December 19, 2013, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the Floating Rate Senior Notes due 2015, the Floating Rate Senior Notes due 2016, the 1.200% Senior Notes due 2016 and the 2.50% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to Registrant s Form 8-K filed December 19, 2013).
4.5	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 4.1 of Registrant s Form 8-K filed April 9, 2002; File No. 000-30176).
4.6	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 April 9, 2002; File No. 000-30176).
4.7	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 6.30% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to Registrant s Form 8-K filed January 9, 2009; File No. 000-32318).
4.8	Indenture dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. as Issuer, Registrant as Guarantor, and The Bank of New York Mellon 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 as filed October 31, 2001; File No. 333-68694).
4.9	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.; File No. 001-14252).
4.10	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; File No. 001-08094).
4.11	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 Form 8-K filed May 14, 2001; File No. 033-06444).
4.12	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; File No. 001-32318).

Exhibit No.	Description
4.13	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 Inc. s Form 10-K for the year ended December 31, 1997; File No. 001-08094).
4.14	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; File No. 001-08094).
4.15	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 Form 8-K filed May 14, 2001; File No. 033-06444).
4.16	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; File No. 001-32318).
9.1	Voting Agreement dated October 21, 2013, by and among Registrant, Blackstone/GSO Capital Solutions Overseas Master Fund L.P. and Blackstone/GSO Capital Solutions Fund LP (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K filed October 22, 2013).
10.1	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 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K filed October 29, 2012).
10.2	Extension Agreement dated September 3, 2013 to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon NEC Corporation and Devon Canada Corporation, as Canadian Borrowers, Devon Financing Company, L.L.C., the consenting lenders, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender, with respect to Borrower s extension of the Maturity Date from October 24, 2017 to October 24, 2018 (incorporated by reference to Exhibit 10.1 to Registrant s Form 10-Q filed November 6, 2013).
10.3	First Amendment to Credit Agreement dated February 3, 2014, to the 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 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K filed February 7, 2014).
10.4	Credit Agreement dated as of December 16, 2013, among Devon Energy Corporation, as Borrower, Morgan Stanley Senior Funding, Inc., as Administrative Agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K filed December 20, 2013).

Exhibit No.	Description
10.5	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).*
10.6	Devon Energy Corporation 2013 Amendment (effective as of March 6, 2013) to the Devon Energy Corporation 2009 Long-Term Plan (as amended and restated effective June 6, 2012) (incorporated by reference to Exhibit 10.1 to Registrant s Form 10-Q filed May 1, 2013).*
10.7	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).*
10.8	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).*
10.9	Devon Energy Corporation Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K, filed June 8, 2012)*
10.10	Devon Energy Corporation Non-Qualified Deferred Compensation Plan (as Amended and Restated Effective January 1, 2013) (incorporated by reference to Exhibit 10.1 to Registrant s Form 10-Q filed August 7, 2013).*
10.11	Devon Energy Corporation Amendment No. 1, dated July 19, 2013, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (as Amended and Restated Effective January 1, 2013).*
10.12	Devon Energy Corporation Amendment No. 2, dated July 26, 2013, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (as Amended and Restated Effective January 1, 2013).*
10.13	Devon Energy Corporation Amendment No. 3, dated December 16, 2013, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (as Amended and Restated Effective January 1, 2013).*
10.14	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).*
10.15	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).*
10.16	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).*
10.17	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).*
10.18	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).*
10.19	Devon Energy Corporation Incentive Savings Plan (incorporated by reference to Registrant s Form S-8 Registration No. 333-179181, filed January 26, 2012).*

Exhibit No.	Description
10.20	Amended and Restated Form of Employment Agreement between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, John Richels, Frank W. Rudolph, Darryl G. Smette and Lyndon C. Taylor dated December 15, 2008 (incorporated by reference to Exhibit 10.19 to Registrant s Form 10-K filed February 27, 2009).*
10.21	Form of Amendment No. 1 to the Amended and Restated Employment Agreement, incorporated by reference to Exhibit 10.19 to Registrant s Form 10-K filed February 27, 2009, between Registrant and Jeffrey A. Agosta, David A. Hager, R. Alan Marcum, John Richels, Frank W. Rudolph, Darryl G. Smette and Lyndon C. Taylor dated April 19, 2011. (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K filed April 25, 2011).*
10.22	Form of Employment Agreement between Registrant and Tony D. Vaughn dated June 10, 2013 (Amended and Restated Form of Employment Agreement dated December 15, 2008, (Exhibit 10.20 above), as amended by Amendment No. 1 thereto dated April 19, 2011, (Exhibit 10.21 above)).*
10.23	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 and Lyndon C. Taylor for performance based restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K filed December 7, 2011).*
10.24	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, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and Tony D. Vaughn for performance based restricted stock awarded (incorporated by reference to Exhibit 10.16 to Registrant s Form 10-K filed February 21, 2013).*
10.25	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 David A. Hager, R. Alan Marcum, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and Tony D. Vaughn for performance based restricted stock awarded.*
10.26	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 and Lyndon C. Taylor for performance based restricted share units awarded (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K filed December 7, 2011).*
10.27	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 Tony D. Vaughn for performance based restricted share units awarded (incorporated by reference to Exhibit 10.17 to Registrant s Form 10-K filed February 21, 2013).*
10.28	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 David A. Hager, R. Alan Marcum, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and Tony D. Vaughn for performance based restricted share units awarded.*
10.29	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 Tony D. Vaughn for incentive stock options granted (incorporated by reference to Exhibit 10.15 to Registrant s Form 10-K filed February 25, 2011).*

Exhibit No.	Description
10.30	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 Tony D. Vaughn for nonqualified stock options granted (incorporated by reference to Exhibit 10.16 to Registrant s Form 10-K filed February 25, 2011).*
10.31	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).*
10.32	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 Tony D. Vaughn for restricted stock awards (incorporated by reference to Exhibit 10.18 to Registrant s Form 10-K filed February 25, 2011).*
10.33	Form of Notice of Grant of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and all Non-Management Directors for restricted stock awards.*
10.34	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 February 25, 2011).*
10.35	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 (incorporated by reference to Exhibit 10.24 to Registrant s Form 10-K filed February 21, 2013). *
12	Statement of computations of ratio of earnings to fixed charges.
21	Registrant s Significant Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants, Ltd.
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.
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99.1	Report of LaRoche Petroleum Consultants, Ltd.
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101.INS	XBRL Instance Document.

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101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Compensatory plans or arrangements

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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 28, 2014

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 (Principal executive officer)	February 28, 2014
/s/ THOMAS L. MITCHELL Thomas L. Mitchell	Executive Vice President and Chief Financial Officer (Principal financial officer and principal accounting officer)	February 28, 2014
/s/ J. LARRY NICHOLS J. Larry Nichols	Executive Chairman of the Board	February 28, 2014
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 28, 2014
/s/ JOHN E. BETHANCOURT John E. Bethancourt	Director	February 28, 2014
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 28, 2014
/s/ JOHN A. HILL John A. Hill	Director	February 28, 2014
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 28, 2014
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 28, 2014
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 28, 2014
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 28, 2014

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