Commitment Runs Deep

Devon Energy

2014 Letter to Shareholders and Form 10-K

devon

Letter to Shareholders

2014 brought about exciting transformation at Devon as we repositioned our asset portfolio and delivered excellent operational and financial results. With a streamlined portfolio, keen focus on operational excellence and strong financial position, we are primed to deliver shareholder value for many years to come.

Early in 2014, we completed the acquisition of our prolific Eagle Ford Shale assets in south Texas, the first of three significant steps to improve the growth trajectory and profitability of our business. A short time later, we completed the innovative formation of EnLink Midstream and saw the market value of our ownership interest increase from $4.8 billion to more than $7.5 billion. We also generated significant value with the sale of $5.1 billion in non-core assets. Our resulting portfolio has greater focus in the heart of some of North America's top basins and favorably positions us to deliver competitive, high-margin growth.

Our repositioned portfolio allowed us to deliver tremendous operating results in 2014. Oil, natural gas and liquids production exceeded Wall Street's expectations, with total top-line growth of 15 percent compared to the prior year. These outstanding results stemmed from the top-tier quality of our assets and a laser focus throughout the organization on execution. Importantly, we delivered this production growth while staying within our original capital spending guidance, in spite of a rapidly increasing cost environment in 2014.

The most significant growth came from the company's U.S. operations, where oil production from our repositioned portfolio increased 37 percent year over year. This substantial growth was driven by strong results from our world-class position in the Eagle Ford and our Permian Basin activity. In Canada, we achieved record oil production at the Jackfish complex, driven by a faster-than-expected ramp-up of Jackfish 3. Also topping expectations, our marketing and midstream business, driven largely through our majority ownership of EnLink, delivered record operating profits in 2014.

During the year, we also saw tremendous improvement in well-completion designs and other technological advances to enhance production, mitigate declines and get the most out of our producing assets. We are relentlessly focused on aligning our people, processes, technologies, strategies and goals to drive superior execution.

The challenging industry conditions of the past several months have reinforced the importance of our solid balance sheet, sound hedge position and significant EnLink optionality. These financial competitive advantages, along with our repositioned portfolio and improved execution, provide us flexibility to continue to invest in high-return projects and maintain operational continuity in our core plays, in spite of the challenged commodity price environment. We have set our 2015 initial capital budget at $4.1 to $4.4 billion for exploration and production projects, a 20 percent decrease from 2014. Despite the lower capital budget, we still expect to grow oil production by 20 to 25 percent this year. We will continue to monitor market conditions and adjust capital as necessary to maintain flexibility.

We must be ever mindful that cycles and fluctuations are inherent in our business. Adapting to change is a key to our ongoing success. But some things, like our core values, never change. We maintain a steadfast commitment to foster a corporate culture based on accountability and integrity, while delivering top-quartile share returns.

Being a premier independent oil and natural gas company in North America requires a social license to operate that is earned through the trust and acceptance of our shareholders, royalty owners, neighbors, policymakers and other stakeholders. Our 2015 Corporate Social Responsibility Report, available on our website at www.devonenergy.com, provides an overview of Devon's safe and responsible operations, community engagement and giving, environmental stewardship, employee wellness and much more.

I have had the honor of leading this great company as president since 2004 and chief executive officer since 2010 and, over that time, the company has achieved many notable milestones. As we enter the next phase of Devon's growth, Dave Hager, our chief operating officer, will become president and CEO upon my retirement in July. Dave has been intimately involved in the transformation of our business. His integrity and focus on creating top-quartile shareholder returns, among his many attributes, will serve our stakeholders well. I am excited about the future of Devon under Dave's leadership.

I look forward to continuing to serve on Devon's board of directors, in the position of vice chairman. Thank you for the opportunity to serve and lead this great company. I firmly believe Devon's best days are still ahead.

John Richels
Vice Chairman
President and Chief Executive Officer

April 6, 2015

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

or

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

Commission File Number 001-32318

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

Delaware	**73-1567067**
(State of other jurisdiction of incorporation or organization)	*(I.R.S. Employer identification No.)*
333 West Sheridan Avenue, Oklahoma City, Oklahoma	**73102-5015**
(Address of principal executive offices)	*(Zip code)*

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

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

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

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

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

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

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

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

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2014, was approximately $32.3 billion, based upon the closing price of $79.40 per share as reported by the New York Stock Exchange on such date. On February 11, 2015, 411.1 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2015 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, 2014 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.

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 natural gas liquids (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 doubled our onshore North American oil production since 2010 to more than 200,000 barrels per day and have a deep inventory of development opportunities. Devon also produces over 1.6 billion cubic feet of natural gas a day and more than 130,000 barrels of natural gas liquids per day.

Additionally, in 2014, we combined substantially all of our U.S. midstream assets with Crosstex Energy, Inc. and Crosstex Energy, LP (together "Crosstex") to form a leading integrated midstream business with enhanced size and scale in key operating regions in the U.S. This midstream business focuses on providing gathering, transmission, processing, fractionation and marketing to producers of natural gas, NGLs, crude oil and condensate.

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, 2014, Devon and its consolidated subsidiaries had approximately 6,600 employees. Approximately 1,100 of such employees are employed by EnLink Midstream Partners, LP ("EnLink") (through its subsidiaries).

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 we believe 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:

- growing and sustaining a premier portfolio of assets focused on high rate-of-return projects;
- achieving superior execution through operational and technical excellence, effective project management and exceptional safety results;
- optimizing cash flow through disciplined capital allocation and cost management; and
- maintaining financial flexibility and a strong balance sheet.

In pursuit of our goal to build value per share, we executed three strategic initiatives in 2014:

- *Eagle Ford Acquisition* – On February 28, 2014, we completed our $6 billion acquisition of interests in certain oil and gas properties, leasehold mineral interests and related assets located in the Eagle Ford from GeoSouthern Energy Corporation ("GeoSouthern"). We funded the acquisition price with cash on hand and debt financing. In connection with the GeoSouthern transaction, we acquired approximately 82,000 net acres located in DeWitt and Lavaca counties in south Texas.
- *MLP Formation* – On March 7, 2014, Devon and Crosstex completed a transaction to combine substantially all of Devon's U.S. midstream assets with Crosstex's assets to form a new midstream business. The new business consists of EnLink and EnLink Midstream, LLC (the "General Partner"), a master limited partnership ("MLP") and a general partner entity, respectively, which are both publicly traded. Devon controls this consolidated entity through its ownership interest in the General Partner.

  In exchange for a controlling interest in both EnLink and the General Partner, we contributed our equity interest in EnLink Midstream Holdings, LP, a newly formed Devon subsidiary ("EnLink Holdings") and $100 million in cash. EnLink Holdings owns midstream assets in the Barnett Shale in north Texas and the Cana- and Arkoma-Woodford Shales in Oklahoma, as well as an economic interest in Gulf Coast Fractionators in Mont Belvieu, Texas. As of December 31, 2014, the General Partner and EnLink each held 50% of EnLink Holdings.
- *Asset Divestitures* – In 2014, we completed the divestitures of certain U.S. and Canadian assets for total cash consideration in excess of $5 billion. Proceeds were primarily used to repay debt resulting from the Eagle Ford acquisition noted above.

The initiatives above resulted in a more focused asset base, allowing us to better allocate capital and employee resources to the highest-value properties and prospects in our portfolio.

Oil and Gas Properties

Property Profiles

The locations of our oil and gas properties are presented on the following map. Additional information related to these properties follows this map, as well as information describing EnLink's assets.

The following table outlines a summary of key data in each of our operating areas for 2014. 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, at the pressure base standard of each respective state in which the gas is produced, to Boe at the rate of six Mcf of gas per Bbl of oil, based upon the approximate relative energy content of gas and oil. Bitumen and NGL proved reserves and production are converted to Boe on a one-to-one basis with oil.

	Proved Reserves			Production			
	MMBoe	% of Total	% Liquids	MBoe/d	% of Total	% Liquids	Gross Wells Drilled
Anadarko Basin	419	15%	42%	94	14%	45%	130
Barnett Shale	1,037	38%	25%	208	31%	27%	84
Eagle Ford	247	9%	74%	65	10%	78%	242
Mississippian-Woodford Trend	22	1%	73%	20	3%	79%	236
Permian Basin	279	10%	79%	96	14%	77%	324
Rockies	42	2%	48%	20	3%	50%	40
U.S. – other	159	5%	35%	33	5%	32%	5
Total U.S.	2,205	80%	42%	536	80%	48%	1,061
Canadian heavy oil	549	20%	99%	86	12%	95%	205
Total retained properties	2,754	100%	53%	622	92%	55%	1,266
Divested properties	—	N/A	N/A	51	8%	24%	—
Total	2,754	100%	53%	673	100%	52%	1,266

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

The Cana-Woodford play in the Anadarko Basin has emerged as one of the most economic shale plays in North America. We are the largest leaseholder and the largest producer in this play. During 2014, we increased our production by 21 percent. We have several thousand remaining drilling locations. In 2015, we plan to drill approximately 95 gross wells in the Anadarko Basin.

Barnett Shale – This is our largest property 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.

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. In 2015, we plan to drill approximately 10 gross wells.

Eagle Ford – We have approximately 82,000 net acres located in the DeWitt and Lavaca counties in south Texas. The Eagle Ford is an industry-leading, light-oil play and is delivering some of the highest rate-of-return drilling opportunities in North America.

We acquired our position in the Eagle Ford on February 28, 2014 from GeoSouthern and subsequently have produced approximately 24 MMBoe with oil accounting for 61 percent of production from the play. Our acreage in DeWitt County is derisked with at least one well drilled in each of the drilling units, providing us with a significant development drilling inventory. Our development in Lavaca County is less mature, but we have had encouraging results from recently drilled wells. In 2015, we plan to drill approximately 225 gross wells.

In addition, we have a 100 percent interest in the Victoria Express Pipeline (“VEX”) in south Texas. The VEX pipeline is a 56 mile crude oil pipeline from the Eagle Ford to the Port of Victoria terminal that has a current capacity of 50 MBOPD.

Mississippian-Woodford Trend – Our leases are located in north central Oklahoma targeting oil in the Mississippian Lime and Woodford Shale. These areas are being explored and developed under an arrangement with our joint venture partner and independently by us on the acreage outside of our area of mutual interest with our joint venture partner. In 2015, we plan to drill approximately 50 gross wells.

Permian Basin – The Permian Basin has been a legacy asset for Devon and continues to offer exploration and low-risk development opportunities from many geologic reservoirs and play types, including the oil-rich Bone Spring, Wolfcamp Shale, Delaware and various conventional formations. These and other emerging oil and liquids-rich opportunities across our acreage in the Permian Basin will deliver high-margin growth for many years to come. In 2015, we plan to drill approximately 240 gross wells.

Rockies – Our operations are focused on emerging oil opportunities in the Powder River Basin and the Wind River Basin. In the Powder River, we are currently targeting several Cretaceous oil objectives, including the Turner, Parkman and Frontier formations. Recent drilling success in these formations has expanded our drilling inventory, and we expect further growth as we continue to de-risk this emerging light-oil opportunity. In 2015, we plan to drill approximately 40 gross wells in the Powder River Basin.

Canadian Heavy Oil – 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. 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. In 2014, we brought the third phase of Jackfish into operation. Each phase has a gross facility capacity of 35 MBbls per day at each facility. With three phases of Jackfish operating, production increased 8 percent in 2014. We expect each phase to maintain a reasonably flat production profile for greater than 20 years at an average gross production rate of approximately 35 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, 2014. The regulatory application we filed in 2012 for the first phase of this project was approved in 2014 for initial gross capacity of 105 MBbls per day. We operate and hold a 50 percent interest in the Pike project. Our planned activity at Pike in 2015 consists of front-end engineering and design work, as well as further understanding reservoir characteristics.

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 heavy oil production with condensate or other blend-stock and transport the combined product to the Edmonton area for sale. In 2014, we completed a capacity expansion on the Access Pipeline system, increasing the capacity to transport approximately 170,000 barrels of bitumen blend per day, net to our 50% interest. This expansion is expected to create adequate capacity to transport our growing heavy oil production to the Edmonton market hub. Additionally, it will increase the transport capacity of condensate diluent available at our thermal oil facilities.

In addition to our Jackfish and Pike projects, we hold acreage and own producing assets in the Lloydminster region. 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.

In 2015, we plan to drill approximately 130 gross wells in Canada.

Divested Properties – During 2014, we monetized certain assets through an asset divestiture program. See Note 2 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report.

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 2014 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 in this report. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of our reserves included in this report. 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, gas and NGLs 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 fourteen years, including the past seven in his current position. During his career, he has been responsible for reserves estimation as the primary reservoir engineer for projects including, but not limited to:

- Hugoton Gas Field (Kansas);
- Sho-Vel-Tum CO_2 Flood (Oklahoma);

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

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

The Group reports independently of any of our operating divisions. The Group's Director reports to our Vice President of Budget and Reserves, who reports to our Senior Vice President of Business Development, 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 2014, we engaged two such firms to audit 91 percent of our proved reserves. LaRoche Petroleum Consultants, Ltd. audited 90 percent of our 2014 U.S. reserves, and Deloitte LLP audited 95 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 at least once a year separately with our senior reserves engineering personnel and separately with our independent petroleum consultants. 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.

The following table presents our estimated pre-tax cash flow information related to 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 in this report.

	Year Ended December 31, 2014		
	U.S.	Canada	Total
		(In millions)	
Pre-Tax Future Net Revenue (Non-GAAP) (1)			
Proved Developed Reserves	$32,560	$ 4,295	$36,855
Proved Undeveloped Reserves	6,379	9,225	15,604
Total Proved Reserves	$38,939	$13,520	$52,459
Pre-Tax 10% Present Value (Non-GAAP) (1)			
Proved Developed Reserves	$17,907	$ 3,735	$21,642
Proved Undeveloped Reserves	3,134	3,189	6,323
Total Proved Reserves	$21,041	$ 6,924	$27,965

(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 $20.5 billion at the end of 2014. Included as part of standardized measure were discounted future income taxes of $7.5 billion. Excluding these taxes, the present value of our pre-tax future net revenue ("pre-tax 10 percent present value") was $28 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.

Production, Production Prices and Production Costs

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

Year Ended December 31,	Production				
	Oil (MBbls/d)	Bitumen (MBbls/d)	Gas (MMcf/d)	NGLs (MBbls/d)	Total (MBoe/d)
2014					
Barnett Shale	2	—	909	54	208
Jackfish	—	56	—	—	56
U.S.	130	—	1,809	137	568
Canada	28	56	111	2	105
Total North America	158	56	1,920	139	673
2013					
Barnett Shale	2	—	1,025	55	228
Jackfish	—	51	—	—	51
U.S.	78	—	1,942	116	517
Canada	39	51	451	10	176
Total North America	117	51	2,393	126	693
2012					
Barnett Shale	2	—	1,075	47	228
Jackfish	—	48	—	—	48
U.S.	58	—	2,055	99	500
Canada	40	48	508	10	182
Total North America	98	48	2,563	109	682

Year Ended December 31,	Average Sales Price				Production Cost (Per Boe)
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	
2014					
Barnett Shale	$95.51	$ —	$3.78	$21.98	$ 5.25
Jackfish	$ —	$55.88	$ —	$ —	$20.59
U.S.	$85.64	$ —	$3.92	$24.46	$ 7.52
Canada	$68.14	$55.88	$3.64	$50.52	$20.10
Total North America	$82.47	$55.88	$3.90	$24.89	$ 9.49
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

Drilling Statistics

The following table summarizes our development and exploratory drilling results.

Year Ended December 31,	Development Wells (1) Productive	Development Wells (1) Dry	Exploratory Wells (1) Productive	Exploratory Wells (1) Dry	Total Wells (1) Productive	Total Wells (1) Dry	Total Wells (1) Total
2014							
U.S.	474.4	0.4	5.0	1.2	479.4	1.6	481.0
Canada	190.8	1.0	—	0.5	190.8	1.5	192.3
Total North America	665.2	1.4	5.0	1.7	670.2	3.1	673.3
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

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

The following table presents the February 1, 2015 results of our wells that were in progress on December 31, 2014.

	Productive		Dry		Still in Progress		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
U.S.	26.0	13.6	—	—	66.0	27.8	92.0	41.4
Canada	5.0	5.0	3.0	2.5	61.0	60.5	69.0	68.0
Total North America	31.0	18.6	3.0	2.5	127.0	88.3	161.0	109.4

(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 in each well.

Productive Wells

The following table sets forth our producing wells as of December 31, 2014.

	Oil Wells (1)		Natural Gas Wells		Total Wells (1)	
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
U.S.	9,927	3,963	15,870	10,586	25,797	14,549
Canada	3,321	3,202	748	538	4,069	3,740
Total North America	13,248	7,165	16,618	11,124	29,866	18,289

(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 in each 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 19,000 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 respective areas. 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, 2014. The acreage in the table includes 0.9 million, 0.3 million and 0.5 million net acres subject to leases that are scheduled to expire during 2015, 2016 and 2017, respectively. As of December 31, 2014, there were no proved undeveloped reserves associated with our expiring acreage. Of the 1.7 million net acres set to expire by December 31, 2017, we will perform operational and administrative actions to continue the lease terms for portions of the acreage that we intend to further assess. However, we do expect to allow a portion of the acreage to expire in the normal course of business. In 2014, we allowed approximately 0.2 million acres to expire.

	Developed		Undeveloped		Total	
	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]
			(In thousands)			
U.S.	2,688	1,735	5,797	2,931	8,485	4,666
Canada	777	582	2,147	995	2,924	1,577
Total North America	3,465	2,317	7,944	3,926	11,409	6,243

(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 in 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.

EnLink Properties

EnLink's assets are comprised of systems and other assets located in four primary regions:

- *Texas* – These assets consist of transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.2 Bcf/d and gathering systems with total capacity of approximately 2.8 Bcf/d.
- *Oklahoma* – These assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 MMcf/d.
- *Louisiana* – The Louisiana assets consist of transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.

- *Ohio River Valley* – The Ohio River Valley ("ORV") operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot operation crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks. EnLink has eight existing brine disposal wells with an injection capacity of approximately 5,000 Bbls/d. Additionally, ORV operations include five condensate stabilization and natural gas compression stations, including two stations under construction, with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression.

Marketing and Midstream Activities

Midstream Operations

Comprising approximately 95% of our 2014 midstream operating profit, EnLink is the primary component of our midstream operations. EnLink's operations primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation and marketing, to producers of natural gas, NGLs, crude oil and condensate, including Devon. EnLink also provides crude oil, condensate and brine services to producers. EnLink connects the wells of natural gas producers in its market areas to its gathering systems, processes natural gas for the removal of NGLs, fractionates NGLs into purity products and markets those products for a fee, transports natural gas and ultimately provides natural gas to a variety of markets. Further, EnLink purchases natural gas from natural gas producers and other supply sources and sells that natural gas to utilities, industrial consumers, other marketers and pipelines.

Oil, Gas and NGL Marketing

The spot markets for oil, gas and NGLs are subject to volatility as supply and demand factors fluctuate. As detailed below, we sell our production under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties. Regardless of the term of the contract, the vast majority of our production is sold at variable, or market-sensitive, prices.

Additionally, we may periodically enter into financial hedging arrangements or fixed-price contracts associated with a portion of our oil, gas and NGL production. These activities are intended to support targeted price levels and to manage our exposure to price fluctuations. See Note 3 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report for further information.

As of January 2015, our production was sold under the following contracts.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	51%	—	49%	—
Natural gas	69%	1%	30%	—
NGLs	63%	13%	24%	—

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, 2014, 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)	180	51	54	47	28
Natural gas (Bcf)	711	382	314	15	—
NGLs (MMBbls)	4	4	—	—	—
Total (MMBoe)	302	118	107	49	28

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 2014, 2013 and 2012, no purchaser accounted for over 10 percent of our operating revenues.

Competition

See “Item 1A. Risk Factors.”

Public Policy and Government Regulation

Our industry is subject to regulation throughout the world. Laws, rules, regulations, taxes, fees and other policy implementation actions affecting our 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 our 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 companies with similar operations, size and financial strength. The following are significant areas of government control and regulation affecting our operations.

Exploration and Production Regulation

Our 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 Canadian oil and gas production. Crown royalties are determined by government regulations and are generally calculated as a percentage of the value of the gross production, net of allowed deductions. The royalty percentage is determined on a sliding-scale based on crown posted prices. The regulations prescribe lower royalty rates for oil sands projects until allowable capital costs have been recovered**.**

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, manageable parts of our business. We have been able to plan for and comply with environmental, safety and health initiatives without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and will likely continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

Item 1A. *Risk Factors*

Our business activities, and our 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;
- geopolitical risks;
- 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, utilize 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 oil, natural gas and NGL production to downstream markets. Such midstream systems include EnLink's systems, as well as other systems operated by us or 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 – Several proposals are before the U.S. Congress and other federal agencies that, if implemented, could either restrict the practice of hydraulic fracturing or subject the process to further regulation, including regulation of hydraulic fracturing on federal lands and tribal reservations; regulation of air emissions; regulation of wastewater discharges from unconventional oil and gas resources; and required disclosure of chemicals and mixtures used in hydraulic fracturing. Many states have already adopted and more states are considering adopting laws and/or regulations that require disclosure of chemicals used in hydraulic fracturing and impose stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to potential environmental and physical impacts. In addition, some states and municipalities have significantly limited drilling activities and/or hydraulic fracturing, or are considering doing so. Although it is not possible at this time to predict the final outcome of these proposals, any new federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could potentially result in increased compliance costs, delays in development or restrictions on our operations.

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. 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 feed stocks 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. Changes in or additions to public policy regarding the protection of the environment could have a significant impact on our operations and profitability.

Insurance Does Not Cover All Risks

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

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

Limited Control on Properties Operated by Others

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

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

Our 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. We apply technical and process controls in line with the National Institute of Standards & Technology framework to secure corporate information assets. In addition, we participate in information sharing partnerships to collect relevant threat intelligence and pro-actively identify and mitigate targeted 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. 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*

Not applicable.

Item 3. *Legal Proceedings*

We are involved in various routine legal proceedings incidental to our business. However, to our knowledge as of the date of this report, there were no material pending legal proceedings to which we are a party or to which any of our property is subject.

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

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

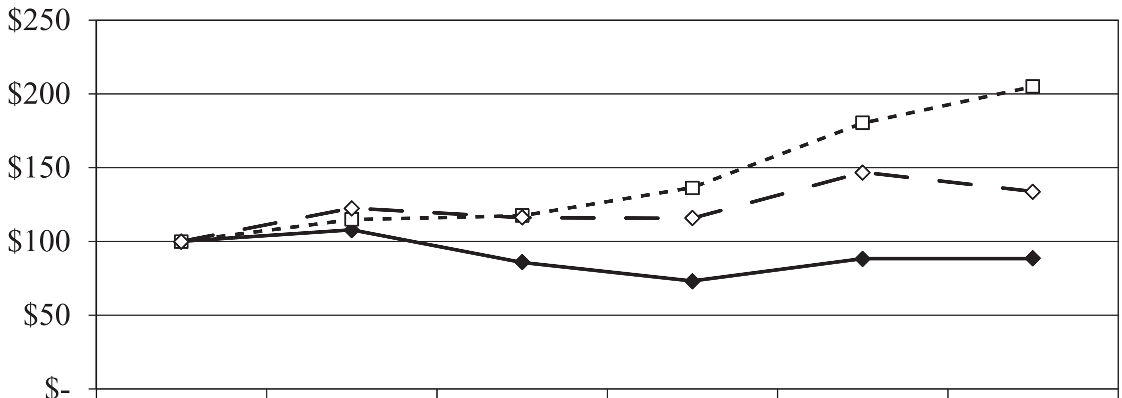
Our common stock is traded on the New York Stock Exchange (the "NYSE"). On February 11, 2015, there were 8,605 holders of record of our common stock. The following table sets forth the quarterly high and low sales prices for our common stock as reported by the NYSE during 2014 and 2013, as well as the quarterly dividends per share paid during 2014 and 2013. 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
2014:			
Quarter Ended December 31, 2014	$68.80	$51.76	$0.24
Quarter Ended September 30, 2014	$80.01	$67.58	$0.24
Quarter Ended June 30, 2014	$80.63	$66.75	$0.24
Quarter Ended March 31, 2014	$66.95	$57.67	$0.22
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

Performance Graph

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on Devon's common stock with the cumulative total returns of the Standard & Poor's 500 index ("the S&P 500 Index") and 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, 2009 in Devon's common stock, the S&P 500 Index and the peer group and dividends have been reinvested subsequent to the initial investment.

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



	2009	2010	2011	2012	2013	2014
Devon	$100.00	$107.82	$85.94	$73.10	$88.23	$88.55
S&P 500	$100.00	$115.06	$117.49	$136.30	$180.44	$205.14
Peer Group	$100.00	$122.49	$116.31	$115.80	$146.87	$133.73

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

Issuer Purchases of Equity Securities

The following table provides information regarding purchases of our common stock that were made by us during the fourth quarter of 2014.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
October 1 – October 31	1,036	$60.00
November 1 – November 30	39	$57.07
December 1 – December 31	343,187	$59.94
Total	344,262	$59.94

(1) Share repurchases 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.

Under the Devon Energy Corporation Incentive Savings Plan (the "Plan"), eligible employees may purchase shares of our common stock through an investment in the Devon Stock Fund (the "Stock Fund"), which is administered by an independent trustee. Eligible employees purchased approximately 57,300 shares of our common stock in 2014, 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, Sun Life Assurance Company of Canada. Shares sold under the Canadian Plan were acquired 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. In 2014, there were no shares purchased by Canadian employees.

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,				
	2014	2013	2012	2011	2010
	(In millions, except per share amounts)				
Operating revenues	$19,566	$10,397	$ 9,501	$11,445	$ 9,935
Earnings (loss) from continuing operations [1]	$ 1,691	$ (20)	$ (185)	$ 2,134	$ 2,333
Earnings (loss) from continuing operations attributable to Devon	$ 1,607	$ (20)	$ (185)	$ 2,134	$ 2,333
Earnings (loss) from continuing operations per share attributable to Devon – Basic	$ 3.93	$ (0.06)	$ (0.47)	$ 5.12	$ 5.31
Earnings (loss) from continuing operations per share attributable to Devon – Diluted	$ 3.91	$ (0.06)	$ (0.47)	$ 5.10	$ 5.29
Cash dividends per common share	$ 0.94	$ 0.86	$ 0.80	$ 0.67	$ 0.64
Weighted average common shares outstanding – Basic	409	406	404	417	440
Weighted average common shares outstanding – Diluted	411	406	404	418	441
Total assets [1]	$50,637	$42,877	$43,326	$41,117	$32,927
Long-term debt	$ 9,830	$ 7,956	$ 8,455	$ 5,969	$ 3,819
Stockholders' equity	$26,341	$20,499	$21,278	$21,430	$19,253

(1) During 2014, 2013 and 2012, we recorded noncash asset impairments totaling $2.0 billion ($1.9 billion after income taxes), $2.0 billion ($1.4 billion after income taxes) and $2.0 billion ($1.3 billion after income taxes), respectively.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

Introduction

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report.

Overview of 2014 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.

2014 was a year of strong execution and strengthening of the portfolio for Devon. We completed three strategic portfolio transformation initiatives that were focused on building value per share.

On February 28, 2014, we acquired certain of GeoSouthern's Eagle Ford assets and operations in south Texas for approximately $6.0 billion. This acquisition included approximately 250 MMBoe of proved reserves. Additionally, since closing the transaction, we have produced approximately 24 MMBoe from our Eagle Ford development, with oil accounting for approximately 61% of our production from the play.

On March 7, 2014, we completed a transaction to combine substantially all of our U.S. midstream assets with Crosstex's assets to form EnLink, a new midstream business that we control. This transaction is described more fully in Note 2 to the financial statements included in "Item 8. Financial Statements and Supplementary Data" in this report. Subsequent to the formation of EnLink's midstream business, EnLink acquired additional oil and gas pipeline assets.

The results of operations from our assets contributed to EnLink are included in our consolidated financial statements for all periods presented. Additionally, the results of operations for all assets contributed to EnLink are included in our consolidated financial statements subsequent to the completion of the transaction. The portions of EnLink's net earnings and stockholders' equity not attributable to Devon's controlling interest are shown separately as noncontrolling interests in our consolidated comprehensive statements of earnings and consolidated balance sheets.

Finally, we completed our asset divestitures of certain U.S. and Canadian properties through two significant transactions. On April 1, 2014, we sold Canadian conventional assets for $2.8 billion ($3.125 billion Canadian dollars), and on August 29, 2014, we sold certain U.S. assets for $2.2 billion.

Key measures of our performance are summarized below.

	Year Ended December 31,				
	2014	Change	2013	Change	2012
	($ in millions, except per share and per Boe amounts)				
Net earnings (loss) attributable to Devon	$ 1,607	+8184%	$ (20)	+90%	$ (206)
Core earnings attributable to Devon (1)	$ 2,017	+16%	$1,734	+33%	$1,305
Earnings (loss) from continuing operations per share attributable to Devon	$ 3.91	+6933%	$ (0.06)	+87%	$ (0.47)
Core earnings per share attributable to Devon (1)	$ 4.91	+15%	$ 4.26	+32%	$ 3.22
Retained production (MBoe/d)	622	+15%	541	+6%	511
Total production (MBoe/d)	673	-3%	693	+2%	682
Realized price per Boe	$ 40.33	+20%	$33.70	+18%	$28.65
Core operating income per Boe (2)	$ 27.28	+27%	$21.47	+28%	$16.78
Operating cash flow – continuing operations	$ 5,981	+10%	$5,436	+10%	$4,930
Capitalized costs, including acquisitions	$13,559	+104%	$6,643	-22%	$8,474
Shareholder and noncontrolling interest distributions	$ 621	+78%	$ 348	+8%	$ 324
Reserves (MMBoe)	2,754	-7%	2,963	0%	2,963

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

(2) Computed as revenues from commodity sales and marketing and midstream operations, less expenses for lease operations, marketing and midstream operations, cash-based general and administrative, production and property taxes and net financing costs, with the result divided by total production.

Our 2014 net earnings attributable to Devon, core earnings, core earnings per share and core operating income per Boe all increased compared to 2013. The improved 2014 results were driven primarily by increases in production from our retained properties, particularly higher-margin liquids volumes, combined with higher gas and bitumen price realizations. EnLink's earnings growth also contributed to improved 2014 results. These factors, along with our portfolio transformation, drove higher earnings and operating cash flow in 2014.

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 2015.

In the second half of 2014, crude oil prices began a rapid and significant decline as global supply outpaced demand. The decline increased further following OPEC's announcement in late November 2014 that it would not reduce its production targets. This decline continued into 2015 but has started to stabilize with the West Texas Intermediate ("WTI") benchmark generally ranging between $45-$50 per barrel throughout January and early February 2015. If WTI remained at this level throughout 2015, our realized crude price, excluding the effects of hedges, would decrease approximately 50% compared to 2014.

Although natural gas prices improved in 2014 compared to 2013, natural gas continues to be challenged due to an imbalance between supply and demand across North America. We expect most natural gas benchmark prices to be lower in 2015, as supply continues to surpass demand.

Our industry will be challenged by lower commodity prices. However, we have strategically positioned our company so that we can prudently continue investing in our portfolio of assets. First, following our 2014 asset divestitures our portfolio is more focused, and we will concentrate our capital programs on the highest return assets in our portfolio. We exited 2014 with a production profile comprised of roughly 35 percent oil, 20 percent natural gas liquids and 45 percent natural gas. Recognizing the relative value of crude oil, we are devoting the vast majority of our 2015 capital investment toward growing our oil production, particularly the sweet grades of oil found in the U.S.

Second, we have hedged approximately 50 percent of our projected 2015 crude production at a floor price of $91 per barrel and approximately 40 percent of our natural gas production at $4.17 per Mcf. These 2015 contracts had an approximate value of $2 billion at December 31, 2014. Additionally, costs for the services we use are declining in response to lower commodity prices. These factors will partially mitigate the effects of lower commodity prices.

Finally, EnLink's growth as a result of recent acquisitions and planned asset dropdowns from Devon will generate additional cash resources that can be used for our capital investment.

Nevertheless, lower commodity prices create headwinds on our business. Therefore, we are projecting a 20 percent decrease in capital spending in 2015. Such spending will be focused on the oily assets in our portfolio currently generating the highest returns. With this focus on our highest return assets, we expect growth in oil production to be between 20 and 25 percent in 2015.

Results of Operations

All amounts in this document related to our International operations for the year ended December 31, 2012 are presented as discontinued. Therefore, all results from those operations are excluded in the "Results of Operations" section unless otherwise noted.

Oil, Gas and NGL Production

	Year Ended December 31,				
	2014	**Change**	**2013**	**Change**	**2012**
Oil (MBbls/d)					
Anadarko Basin	10	+12%	9	+38%	7
Barnett Shale	2	-2%	2	+22%	2
Eagle Ford	39	N/M	—	N/M	—
Mississippian-Woodford Trend	9	+93%	5	+625%	1
Permian Basin	56	+19%	46	+28%	36
Rockies	9	+13%	8	+31%	6
Other	2	-33%	3	+50%	2
Total U.S.	127	+74%	73	+35%	54
Canada	26	-7%	28	-4%	29
Total retained properties	153	+52%	101	+22%	83
Divested properties	5	-66%	16	+3%	15
Total	158	+36%	117	+19%	98
Bitumen (MBbls/d)					
Canada	56	+8%	51	+8%	48
Gas (MMcf/d)					
Anadarko Basin	310	+9%	285	-0%	285
Barnett Shale	909	-11%	1,025	-5%	1,075
Eagle Ford	86	N/M	—	N/M	—
Mississippian-Woodford Trend	30	+155%	12	+701%	1
Permian Basin	132	+26%	105	+24%	85
Rockies	64	-18%	78	-28%	108
Other	131	-14%	153	-13%	176
Total U.S	1,662	+0%	1,658	-4%	1,730
Canada	23	-19%	28	+30%	22
Total retained properties	1,685	-0%	1,686	-4%	1,752
Divested properties	235	-67%	707	-13%	811
Total	1,920	-20%	2,393	-7%	2,563
NGLs (MBbls/d)					
Anadarko Basin	32	+28%	25	+43%	17
Barnett Shale	54	-1%	55	+17%	47
Eagle Ford	11	N/M	—	N/M	—
Mississippian-Woodford Trend	5	+342%	1	+770%	—
Permian Basin	18	+29%	14	+26%	11
Rockies	1	+24%	1	+7%	1
Other	11	+0%	11	+0%	11
Total U.S.	132	+23%	107	+23%	87
Divested properties	7	-63%	19	-13%	22
Total	139	+10%	126	+15%	109
Combined (MBoe/d)					
Anadarko Basin	94	+15%	82	+14%	72
Barnett Shale	208	-9%	228	+0%	228
Eagle Ford	65	N/M	—	N/M	—
Mississippian-Woodford Trend	20	+160%	8	+662%	1
Permian Basin	96	+23%	78	+27%	62
Rockies	20	-5%	22	-13%	25
Other	33	-13%	38	-7%	41
Total U.S.	536	+18%	456	+6%	429
Canada	86	+2%	85	+4%	81
Total retained properties	622	+15%	541	+6%	510
Divested properties	51	-66%	152	-11%	172
Total	673	-3%	693	+2%	682

Oil, Gas and NGL Pricing

	Year Ended December 31,				
	2014 (1)	Change	2013 (1)	Change	2012 (1)
Oil (per Bbl)					
U.S.	$85.64	-9%	$94.52	+7%	$88.68
Canada	$68.14	-1%	$69.18	+1%	$68.29
Total	$82.47	-4%	$86.02	+7%	$80.43
Bitumen (per Bbl)					
Canada	$55.88	+16%	$48.04	+1%	$47.57
Gas (per Mcf)					
U.S.	$ 3.92	+27%	$ 3.10	+33%	$ 2.32
Canada (2)	$ 3.64	+19%	$ 3.05	+23%	$ 2.49
Total	$ 3.90	+26%	$ 3.09	+31%	$ 2.36
NGLs (per Bbl)					
U.S.	$24.46	-5%	$25.75	-10%	$28.49
Canada	$50.52	+9%	$46.17	-5%	$48.63
Total	$24.89	-9%	$27.33	-10%	$30.42
Combined (per Boe)					
U.S.	$37.96	+20%	$31.59	+23%	$25.59
Canada	$53.11	+33%	$39.91	+8%	$37.01
Total	$40.33	+20%	$33.70	+18%	$28.65

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

(2) The reported Canadian gas volumes include 21 and 25 MMcf per day for the years ended 2014 and 2013, respectively, that are produced from certain of our leases and then transported to our Jackfish operations where the gas is used as fuel. However, the revenues and expenses related to this consumed gas are eliminated in our consolidated financial results. With the sale of the vast majority of the Canadian gas business in the second quarter of 2014, the impact of the eliminated gas revenues more significantly impacts our gas price.

Commodity Sales

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

	Oil	Bitumen	Gas	NGLs	Total
			(In millions)		
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
Change due to volumes	1,311	76	(533)	131	985
Change due to prices	(206)	160	572	(123)	403
2014 sales	$4,773	$1,138	$2,737	$1,262	$9,910

Volumes 2014 vs. 2013 Oil, gas and NGL sales increased $985 million due to volumes. The primary driver of the increase resulted from a 74 percent increase in our U.S. oil production. Such growth resulted from our recently acquired Eagle Ford properties and the continued development of our properties in the Permian Basin and Mississippian-Woodford Trend properties. In addition, we continue to grow our NGL production from these plays, which resulted in $131 million of additional sales. Bitumen sales increased $76 million due to development of our Jackfish thermal heavy oil projects in Canada, including Jackfish 3 which had first sales in 2014. These increases were partially offset by a 20 percent decrease in our 2014 gas production, which was impacted by our asset divestitures, resulting in a $533 million decline in sales.

Volumes 2013 vs. 2012 Oil, gas and NGL 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.

Prices 2014 vs. 2013 Oil, gas and NGL sales increased $403 million due to a 20 percent increase in our realized prices without hedges. Our gas sales were the most significantly impacted with a $572 million increase in sales. The change in our realized gas price was largely due to higher North American regional index prices upon which our gas sales are based. Additionally, our bitumen sales increased $160 million due to a 16% increase in our realized price, as a result of tighter bitumen and heavy oil differentials. These increases were partially offset by lower oil and NGL realized prices due to lower NYMEX West Texas Intermediate index prices and lower NGL prices at the Mont Belvieu, Texas index.

Prices 2013 vs. 2012 Oil, gas and NGL sales increased $744 million due to an 18 percent increase in our realized prices 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.

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,		
	2014	2013	2012
	(In millions)		
Cash settlements:			
Oil derivatives	$ 90	$ 55	$ 259
Gas derivatives	(36)	139	610
NGL derivatives	1	1	1
Total cash settlements	55	195	870
Gains (losses) on fair value changes:			
Oil derivatives	1,721	(243)	150
Gas derivatives	213	(139)	(330)
NGL derivatives	—	(4)	3
Total gains (losses) on fair value changes	1,934	(386)	(177)
Oil, gas and NGL derivatives	$1,989	$(191)	$ 693

	Year Ended December 31, 2014				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$82.47	$55.88	$ 3.90	$24.89	$40.33
Cash settlements of hedges	1.56	—	(0.05)	0.02	0.22
Realized price, including cash settlements	$84.03	$55.88	$ 3.85	$24.91	$40.55

	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

	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

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 3 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 2015 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 generated net gains of $2.0 billion in 2014, incurred net losses of $191 million in 2013 and generated net gains of $693 million in 2012.

Marketing and Midstream Revenues and Operating Expenses

	Year Ended December 31,				
	2014	Change	2013	Change	2012
	($ in millions)				
Operating revenues	$ 7,667	+271%	$ 2,066	+25%	$ 1,655
Product purchases	(6,540)	+382%	(1,356)	+31%	(1,039)
Operations and maintenance expenses	(275)	+40%	(197)	-5%	(207)
Operating profit	$ 852	+66%	$ 513	+25%	$ 409
Devon	$ 90	-3%	$ 93	+31%	$ 71
EnLink	762	+81%	420	+24%	338
Total operating profit	$ 852	+66%	$ 513	+25%	$ 409

2014 vs. 2013 Marketing and midstream operating profit increased $339 million, or 66 percent, from the year ended December 31, 2013 to the year ended December 31, 2014.

Our profit largely increased due to higher prices and volumes, partially offset by higher operations and maintenance expenses. Of the $339 million increase, $342 million was attributed to EnLink's operations. Higher profits from EnLink's Texas segment, which includes the Bridgeport facility, and Louisiana segment were the largest drivers of the increase. The Louisiana segment operating profit increased due to acquisitions and completions of additional pipelines.

Devon's marketing activities were the primary driver of the increases in both operating revenues and product purchases. The higher marketing revenues and product purchases are primarily due to commitments we have entered into to secure capacity on downstream oil pipelines. Marketing activities of EnLink also contributed to these increases.

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.

Operations and maintenance expenses decreased $10 million, or 5 percent, primarily due to expenditures for regulatory testing in 2012.

Lease Operating Expenses ("LOE")

	Year Ended December 31,				
	2014	Change	2013	Change	2012
	(In millions, except per Boe amounts)				
LOE:					
U.S.	$1,559	+24%	$1,257	+19%	$1,059
Canada	773	-24%	1,011	-0%	1,015
Total	$2,332	+3%	$2,268	+9%	$2,074
LOE per Boe:					
U.S.	$ 7.52	+13%	$ 6.65	+15%	$ 5.79
Canada	$20.10	+27%	$15.78	+4%	$15.18
Total	$ 9.49	+6%	$ 8.97	+8%	$ 8.30

2014 vs. 2013 Our absolute LOE changed largely as a result of our portfolio transformation initiatives, including our February 2014 purchase of GeoSouthern's Eagle Ford assets and our 2014 divestitures of certain properties in the U.S. and Canada. Higher volumes from development of our Eagle Ford assets, as well as our Permian Basin assets, caused U.S. LOE to increase. This increase was partially offset by the decrease resulting from the U.S. divestitures. The Canadian divestitures were the primary cause of the decrease in Canadian LOE.

Total LOE increased $0.52 per Boe primarily due to higher unit costs related to our Canadian operations. The higher Canadian unit costs largely resulted from the divestiture of the conventional assets in the second quarter of 2014 which resulted in lower total volumes while retaining the relatively higher-cost thermal heavy oil operations. Additionally, higher Jackfish royalties paid in 2014 also contributed to higher Canadian unit costs. As

Canadian royalties increase, our net production volumes decrease, causing upward pressure on our per-unit operating costs. The higher unit cost in the U.S. was primarily related to our liquids production growth, particularly in the Permian Basin and Mississippian-Woodford Trend, where projects generate higher revenues but generally require a higher cost to produce per unit than our gas projects. Additionally, we experienced inflationary pressures on costs in certain operating areas, which also contributed to the higher LOE per Boe.

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.

General and Administrative Expenses ("G&A")

	Year Ended December 31,				
	2014	Change	2013	Change	2012
	(In millions, except per Boe amounts)				
Gross G&A	$1,369	+21%	$1,128	-4%	$1,171
Capitalized G&A	(376)	+2%	(368)	+3%	(359)
Reimbursed G&A	(146)	+2%	(143)	+19%	(120)
Net G&A	$ 847	+37%	$ 617	-11%	$ 692
Net G&A per Boe	$ 3.45	+41%	$ 2.44	-12%	$ 2.77

2014 vs. 2013 Net G&A and net G&A per Boe increased largely due to higher employee compensation and benefits and $22 million in costs in the first quarter of 2014 related to the EnLink and GeoSouthern transactions. The higher employee compensation and benefits costs were primarily related to share-based awards, which cause our G&A to be higher in the period in which our annual share-based grant is made. The grant related to our 2013 compensation cycle was made in the first quarter of 2014. The grant related to our 2012 compensation cycle was made in the fourth quarter of 2012. Additionally, the expansion of our workforce as a part of growing production operations at certain of our key areas also contributed to the increase.

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 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. Further reducing our G&A in 2013 was the timing of our share-based awards, as noted above.

Production and Property Taxes

	Year Ended December 31,				
	2014	Change	2013	Change	2012
	($ in millions)				
Production	$360	+31%	$275	+23%	$224
Property and other	175	-6%	186	-2%	190
Production and property taxes	$535	+16%	$461	+11%	$414
Percentage of oil, gas and NGL sales:					
Production	3.6%	+13%	3.2%	+3%	3.1%
Property and other	1.8%	-19%	2.2%	-18%	2.7%
Total	5.4%	-0%	5.4%	-6%	5.8%

2014 vs. 2013 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.

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.

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

	Year Ended December 31,				
	2014	Change	2013	Change	2012
	(In millions, except per Boe amounts)				
DD&A:					
Oil & gas properties	$2,896	+18%	$2,465	-2%	$2,526
Other assets	423	+34%	315	+11%	285
Total	$3,319	+19%	$2,780	-1%	$2,811
DD&A per Boe:					
Oil & gas properties	$11.79	+21%	$ 9.75	-4%	$10.12
Other assets	1.72	+38%	1.24	+9%	1.14
Total	$13.51	+23%	$10.99	-2%	$11.26

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, the DD&A rate per unit of production will change inversely. However, when the depletable base changes, 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.

2014 vs. 2013 DD&A from our oil and gas properties increased in 2014 largely due to higher DD&A rates. The higher rates resulted from our oil and gas drilling and development activities and the GeoSouthern acquisition, which were partially offset by the asset impairments recognized in 2013 and the asset divestitures. Other DD&A increased primarily due to the EnLink transaction.

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.

Asset Impairments

	Year Ended December 31, 2014		Year Ended December 31, 2013		Year Ended December 31, 2012	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
			(In millions)			
Goodwill	$1,941	$1,941	$ —	$ —	$ —	$ —
U.S. oil and gas assets	—	—	1,110	707	1,793	1,142
Canada oil and gas assets	—	—	843	632	163	122
Midstream assets	12	7	23	14	68	44
Asset impairments	$1,953	$1,948	$1,976	$1,353	$2,024	$1,308

For further discussion of our goodwill and property and equipment impairments, see Note 12 and Note 5, respectively, in "Item 8. Financial Statements and Supplementary Data."

Restructuring Costs

	Year Ended December 31,		
	2014	2013	2012
		(In millions)	
Canadian divestitures	$ 46	$—	$—
Office consolidation	—	54	80
Offshore divestiture	—	—	(6)
Restructuring costs	$ 46	$ 54	$ 74

For further discussion of our Canadian divestitures, office consolidation and offshore divestiture restructuring activities and consolidated financial statements impact, see Note 6 in "Item 8. Financial Statements and Supplementary Data."

Gains on Asset Sales

In conjunction with the divestiture of certain Canadian properties, we recognized gains in the first and second quarters of 2014. Under full cost accounting rules, sales or dispositions of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the disposition would otherwise significantly alter the relationship between a cost center's capitalized costs and proved reserves, then a gain or loss must be recognized. Our Canadian divestitures significantly altered such relationship. Therefore, we recognized a total gain of $1.1 billion ($0.6 billion after-tax) during 2014.

Net Financing Costs

	Year Ended December 31,				
	2014	Change	2013	Change	2012
			(In millions)		
Interest based on debt outstanding	$546	+17%	$466	+6%	$440
Early retirement of debt	48	N/M	—	N/M	—
Capitalized interest	(70)	+26%	(56)	+15%	(48)
Other fees and expenses	12	-55%	27	+94%	14
Interest expense	536	+23%	437	+8%	406
Interest income	(10)	-49%	(20)	-43%	(36)
Net financing costs	$526	+26%	$417	+13%	$370

2014 vs. 2013 Net financing costs increased primarily due to higher average borrowings resulting from the EnLink and GeoSouthern transactions. Additionally, we incurred a $40 million early retirement premium related to the redemption of our 2.4% $500 million senior notes due 2016, 1.2% $650 million senior notes due 2016 and 1.875% $750 million senior notes due 2017 prior to their maturity. In conjunction with the early retirement, we also expensed $8 million in remaining unamortized discount and issuance costs.

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 Eagle Ford acquisition which closed in the first quarter of 2014.

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,		
	2014	2013	2012
Total income tax expense (benefit) (in millions)	$2,368	$169	$(132)
U.S. statutory income tax rate	35%	35%	(35%)
Non-deductible goodwill transactions	23%	0%	0%
Taxation on Canadian operations	(4%)	9%	(6%)
State income taxes	2%	23%	6%
Repatriations	2%	65%	0%
Taxes on EnLink formation	1%	0%	0%
Other	(1%)	(19%)	(7%)
Effective income tax rate	58%	113%	(42%)

For further discussion of our income tax expense (benefit), see Note 7 in "Item 8. Financial Statements and Supplementary Data."

Earnings (Loss) from Discontinued Operations

In 2012, we incurred a loss related to discontinued operations of $16 million ($21 million net of taxes) for the sale of our assets in Angola. There were no operating revenues related to discontinued operations during 2012. In 2014 and 2013, there were no earnings or losses associated with discontinued operations.

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,		
	2014	2013	2012
		(In millions)	
Operating cash flow – continuing operations	$ 5,981	$ 5,436	$ 4,930
Divestitures of property and equipment	5,120	419	1,539
Capital expenditures	(6,988)	(6,758)	(8,225)
Acquisitions of property, equipment and businesses	(6,462)	—	—
Debt activity, net	(2,234)	361	1,921
Shareholder and noncontrolling interests distributions	(621)	(348)	(324)
Stock option proceeds	93	3	27
Proceeds from issuance of subsidiary units	410	—	—
Other	115	(27)	54
Net change in cash and short-term investments	$(4,586)	$ (914)	$ (78)
Cash and short-term investments at end of period	$ 1,480	$ 6,066	$ 6,980

Operating Cash Flow – Continuing Operations

Net cash provided by operating activities continued to be a significant source of capital and liquidity in 2014. Our operating cash flow increased 10 percent during 2014 primarily due to higher realized prices and liquids production growth, partially offset by higher expenses. Our operating cash flow increased 10 percent during 2013 primarily due to higher commodity prices and production growth, partially offset by higher expenses.

Excluding the $6.5 billion attributable to the GeoSouthern and other acquisitions, our operating cash flow funded approximately 86 percent of our cash payments for capital expenditures during 2014. Leveraging our liquidity, we used cash balances, short-term debt and divestiture proceeds to fund the remainder of our cash-based capital expenditures.

Divestitures of Property and Equipment

During 2014, we completed our Canadian asset divestiture program and received proceeds of approximately $2.9 billion. Additionally, we completed the divestment of certain of our U.S. assets and received proceeds of approximately $2.2 billion.

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 two key joint venture transactions. Under one of these arrangements, our joint venture partner paid approximately $900 million in cash and received a 33.3 percent interest in five of our exploration plays in the U.S. Our joint venture partner is also funding approximately $1.6 billion of our share of future exploration, development and drilling costs associated with these plays. Under the second transaction, our joint venture partner paid approximately $400 million and received a 30 percent interest in the Cline and Midland-Wolfcamp Shale plays in Texas. Additionally, our joint venture partner 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.

Capital Expenditures

	Year Ended December 31,		
	2014	2013	2012
		(In millions)	
Development	$ 5,014	$4,754	$5,183
Exploration	353	602	541
Acquisition of oil and gas properties	6,179	256	1,329
Capitalized G&A and interest	368	354	343
Total oil and gas	11,914	5,966	7,396
Midstream	380	455	167
Corporate and other	109	93	325
Devon capital expenditures	12,403	6,514	7,888
EnLink, including acquisitions	1,047	244	337
Total capital expenditures	$13,450	$6,758	$8,225

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations, other corporate activities and EnLink growth and maintenance activities. The vast majority of our capital expenditures are for the acquisition, drilling and development of oil and gas properties, which totaled $11.9 billion, $6.0 billion and $7.4 billion in 2014, 2013 and 2012, respectively. The increase in capital spending was primarily due to the GeoSouthern acquisition. Excluding acquisitions, exploration and development capital spending decreased 4 percent, primarily due to utilization of the drilling carries in 2014 from our joint venture arrangements. In 2013, utilization of these drilling carries contributed to a 20 percent decline in exploration, development and acquisition capital spending, along with a decline in new venture acreage acquisitions. Exploration and development capital spending in 2012 was primarily related 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 systems and oil pipelines. Our midstream capital expenditures are largely impacted by our oil and gas drilling activities. Our 2014 and 2013 midstream capital expenditures largely related to the expansion of our Access Pipeline in Canada. Additionally, our 2014 midstream capital expenditures also related to pipeline construction and expansion in the Eagle Ford. During 2014, EnLink's capital expenditures totaled approximately $1.0 billion. The higher expenditures primarily resulted from the acquisition of additional oil and gas pipeline assets. EnLink's 2013 and 2012 capital expenditures primarily related to expansions of plants serving the Barnett Shale and Cana-Woodford Shale.

Capital expenditures related to other activities decreased in 2014 and 2013 compared to 2012. This decrease is largely driven by the construction of our new headquarters in Oklahoma City, which was completed in 2012.

Debt Activity, Net

During 2014, we decreased our net debt borrowings by $2.2 billion. The decrease was primarily related to the repayment of debt used to fund the GeoSouthern transaction. This was partially offset by $555 million of net borrowings from EnLink to fund its operations.

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 acquisition and repaying approximately $1.9 billion of outstanding short-term debt.

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.

Shareholder and Noncontrolling Interests Distributions

The following table summarizes our common stock dividends (amounts in millions). In the second quarter of 2014, we increased our quarterly dividend to $0.24 per share.

	2014		2013		2012	
	Amount	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Dividends	$386	$0.94	$348	$0.86	$324	$0.80

In conjunction with the formation of EnLink in the first quarter of 2014, we made a payment of $100 million to noncontrolling interests. Further, EnLink and its General Partner distributed $135 million to non-Devon unitholders during 2014.

Stock Option Proceeds

We received $93 million, $3 million and $27 million from stock option proceeds in 2014, 2013 and 2012, respectively.

Proceeds from Issuance of Subsidiary Units

During 2014, EnLink sold approximately 14.8 million limited partner units to the public, raising net proceeds of approximately $410 million.

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

Operating Cash Flow 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 realized prices and increased liquids production growth during 2014, our operating cash flow from continuing operations increased 10 percent to $6.0 billion in 2014. 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. In the fourth quarter of 2014, oil and NGL prices decreased significantly. We expect this volatility to continue throughout 2015 and expect 2015 oil, gas and NGL prices will be noticeably lower than those for 2014. The corresponding reduction in our operating cash flow will require us to scale back certain uses of cash during 2015 compared to 2014, including most notably our capital expenditures.

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, 2014 are presented in Note 3 to the financial statements under "Item 8. Financial Statements and Supplementary Data" of this report. Additional discussion on the extent of our hedged production is included in the "Business and Industry Outlook" section above.

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, 2014, we had total debt of $11.3 billion with an overall weighted-average borrowing rate of 4.6 percent. Of the $11.3 billion of total debt, $2.0 billion is comprised of floating rate debt that bear interest rates averaging 0.74 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 2014, we held approximately $1.5 billion of cash. Included in this total was $1.2 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 decrease the amount of cash ultimately available to fund our business.

Credit Availability

We have a $3.0 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility). The maturity date for $30 million of the Senior Credit Facility is October 24, 2017. The maturity date for $164 million of the Senior Credit Facility is October 24, 2018. The maturity date for the remaining $2.8 billion is October 24, 2019. This credit facility supports our $3.0 billion commercial paper program. 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, 2014, there were no borrowings under the Senior Credit Facility.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65 percent. The credit agreement defines total funded debt as funds received through the issuance of debt securities such as debentures, bonds, notes payable, credit facility borrowings and short-term commercial paper borrowings. In addition, total funded debt includes all obligations with respect to payments received in consideration for oil, gas and NGL production yet to be acquired or produced at the time of payment. Funded debt excludes our outstanding letters of credit and trade payables. The credit agreement defines total capitalization as the sum of funded debt and stockholders' equity adjusted for noncash financial write-downs, such as full cost ceiling and goodwill impairments. As of December 31, 2014, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2014, as calculated pursuant to the terms of the agreement, was 20.9 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, 2014, we had $932 million of borrowings under our commercial paper program.

EnLink has a $1.0 billion unsecured revolving credit facility. On February 5, 2015, the commitments under EnLink's credit facility were increased to $1.5 billion. The General Partner also has a $250 million revolving credit facility. As of December 31, 2014, there were $14 million in outstanding letters of credit and $237 million borrowed under the $1.0 billion credit facility and no outstanding borrowings under the $250 million credit facility. All of EnLink's and the General Partner's debt is non-recourse to Devon.

Debt Ratings

We and EnLink receive debt ratings from the major ratings agencies in the U.S. However, the General Partner does not receive debt ratings. In determining those debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, commodity pricing levels, liquidity, asset quality, reserve mix, debt levels, cost structure, planned asset sales, near-term and long-term growth opportunities and capital allocation challenges.

There are no "rating triggers" in any of our or EnLink's debt contractual obligations that would accelerate scheduled maturities should debt ratings 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 could 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 from our current debt ratings would increase the drawn borrowing costs by 12.5 basis points. Similarly, a ratings downgrade would not accelerate EnLink's scheduled maturities, however, it could adversely impact the interest rate on any borrowings under EnLink's credit facility. Under the terms of EnLink's credit facility, a one notch downgrade would increase the drawn borrowing costs by 25 basis points. A ratings downgrade could also adversely impact our and EnLink's ability to economically access debt markets in the future.

Capital Expenditures

Excluding EnLink, our 2015 capital expenditures are expected to range from $4.7 billion to $5.2 billion, including $4.5 billion to $4.9 billion for our oil and gas operations, which include capitalized G&A and interest. This estimate is approximately 20% lower than our 2014 capital expenditures. 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 2015 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2015 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2015, our existing commodity hedging contracts, available cash balances and credit availability, we anticipate having adequate capital resources to fund our 2015 capital expenditures.

Additionally, our financial and operational flexibility has been further enhanced by the joint venture transactions that we entered into in 2012. Pursuant to the joint venture agreements, our joint venture partners are subject to drilling carries with remaining commitments that totaled approximately $250 million at the end of 2014. 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 has allowed us to accelerate the de-risking and commercialization of the joint venture properties without diverting capital from our core development projects. We expect a significant portion of the carries will be utilized by the end of 2015.

EnLink Capital Resources and Expenditures

On January 31, 2015, EnLink acquired LPC Crude Oil Marketing LLC, which has crude oil gathering, transportation and marketing operations in the Permian Basin for approximately $100 million in cash, subject to certain adjustments.

On February 1, 2015, EnLink signed a definitive agreement to acquire Coronado Midstream Holdings LLC, which owns natural gas gathering and processing facilities in the Permian Basin for approximately $600 million in cash and equity, subject to certain adjustments.

Beyond these acquisitions, EnLink's 2015 capital budget includes approximately $350 million to $400 million of identified growth projects, including capitalized interest. EnLink's primary capital projects for 2015 include the construction of its ORV condensate pipeline, Bearkat plant facilities and West Texas expansion project. During 2014, EnLink invested in several capital projects which primarily included the expansion of the Cajun-Sibon NGL Pipeline and the construction of the Bearkat facilities.

EnLink expects to fund its 2015 maintenance capital expenditures from operating cash flows. EnLink expects to fund the growth capital expenditures from the proceeds of borrowings under its bank credit facility and proceeds from other debt and equity sources. In 2015, it is possible that not all of the planned projects will be commenced or completed. EnLink's ability to pay distributions to its unitholders, fund planned capital expenditures and make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond its control.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2014 is provided in the following table.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In millions)		
Debt [1]	$11,257	$1,432	$ 350	$2,212	$ 7,263
Interest expense [2]	8,185	505	1,003	945	5,732
Purchase obligations [3]	5,306	663	1,694	1,815	1,134
Operational agreements [4]	5,084	943	1,809	1,190	1,142
Asset retirement obligations [5]	1,399	60	107	94	1,138
Drilling and facility obligations [6]	446	234	193	14	5
Lease obligations [7]	405	72	100	84	149
Other [8]	362	128	103	127	4
Total	$32,444	$4,037	$5,359	$6,481	$16,567

(1) Debt amounts represent scheduled maturities of our debt obligations at December 31, 2014, excluding $5 million of net premiums included in the carrying value of debt.

(2) Interest expense represents the scheduled cash payments on long-term, fixed-rate debt and an estimate of our floating-rate notes.

(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. Operational agreements include approximately $2.1 billion of minimum volume commitments between Devon and EnLink. The initial terms of the contracts with EnLink are summarized in the following table. All contracts began in March 2014.

Contract	Contract Terms (Years)	Minimum Gathering Volume Commitment (MMcf/d)	Minimum Processing Volume Commitment (MMcf/d)	Minimum Volume Commitment Term (Years)	Annual Rate Escalators
Bridgeport gathering and processing contract	10	850	650	5	CPI
East Johnson County gathering contract	10	125	—	5	CPI
Cana gathering and processing contract	10	330	330	5	CPI

(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, 2014 balance sheet.

(6) Drilling and facility obligations represent gross 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 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 2014, 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 three 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 generally 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.

Although uncertain future prices impact the ability to predict future full cost write-downs, we do expect to recognize full cost write-downs in 2015, beginning with the first quarter of 2015. This conclusion is based on the historic prices for the last 9 months of 2014 and the short-term pricing outlook. Although we can predict with relative certainty we will recognize full cost write-downs in 2015, we are not able to reasonably estimate the amounts. However, we expect the amounts will be material to our net earnings but will have no impact to our cash flow or liquidity.

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. Additionally, EnLink periodically enters into derivative financial instruments with respect to its oil, gas and NGL marketing activity. These 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.

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 oil, gas and NGL commodity derivative contracts are held with fourteen separate counterparties, and our foreign exchange forward contracts are held with five separate counterparties. Second, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below certain credit rating levels. The mark-to-market exposure threshold for collateral posting decreases as the debt rating falls further below such credit levels.

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.

Business Combinations

Accounting for the acquisition of a business requires the assets and liabilities of the acquired business to be recorded at fair value. Deferred taxes are recorded for any differences between the fair value and the tax basis of the acquired assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill.

There are various assumptions we make in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, we prepare estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by our engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies a historical 12-month average price to the reserves to arrive at the ceiling amount. By contrast, the fair value of reserves acquired in a business combination must be based on our estimates of future oil, natural gas and NGL prices. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Forecasts of future prices from independent third parties are noted when we make our pricing estimates.

We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

We also apply these same general principles to estimate the fair value of unproved properties acquired in a business combination. These unproved properties generally represent the value of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by what we consider to be an appropriate risk-weighting factor in each particular instance.

In addition, our acquisitions have involved other entities whose operations included substantial midstream activities. In these transactions, the purchase price is allocated to the fair value of midstream facilities and equipment, generally consisting of processing facilities and pipeline systems. Estimating the fair value of these assets requires certain assumptions to be made regarding future quantities of commodities estimated to be processed and transported through these facilities and pipelines, as well as estimates of future expected prices and operating and capital costs.

Goodwill

We test goodwill for impairment annually at October 31, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. While we use data as of October 31 for our test, we typically complete the test in late December or early January as the October 31 market data used in our test becomes available. We first assess the qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If we determine that it is more likely than not that its fair value is less than its carrying amount, then the two-step goodwill impairment test is performed.

In the first step of the impairment test, the fair value of a reporting unit is compared to its carrying value. Because quoted market prices are not available for our reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid. If the carrying value of a reporting unit exceeds its fair value, the second step of the impairment test is performed for purposes of measuring the impairment. In the second step, the fair value of the reporting unit is allocated to all of the assets and liabilities of the reporting unit to determine an implied goodwill value. This allocation is similar to a purchase price allocation. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess. The determination of fair value requires judgment and involves the use of significant estimates and assumptions about expected future cash flows derived from internal forecasts and the impact of market conditions on those assumptions. Critical assumptions primarily include revenue growth rates driven by future commodity prices and volume expectations, operating margins and capital expenditures.

For our October 31, 2014 impairment test, step one of our impairment analysis showed that the fair value of our U.S. and EnLink reporting units exceeded their carrying value. However, the fair value of the EnLink Louisiana reporting unit did not substantially exceed its carrying value. As of October 31, 2014, the fair value of the EnLink Louisiana reporting unit exceeded its carrying value by approximately 14 percent. Furthermore, the fair value of our Canadian reporting unit did not exceed its carrying value.

As disclosed in previous years, the fair value of our Canadian unit did not significantly exceed its carrying value. Consequently, we performed the requisite qualitative analysis of our Canadian goodwill each quarter throughout 2014. We also performed quantitative analysis following the significant Canadian asset divestitures we completed in the second quarter of 2014. None of this analysis indicated the existence of a Canadian goodwill impairment through September 30, 2014. Therefore, with the failure of step one as a result of our October 31 test, we concluded the impairment was the result of the decline in oil prices that began in the third quarter of 2014 and intensified after OPEC's decision not to reduce its production targets that was announced in late November 2014.

Because the oil price decline continued into early 2015, we decided to perform a revised step one and then step two of the impairment test as of December 31, 2014 to measure the amount of the Canadian impairment. As a result of this evaluation, we concluded the implied fair value of our Canadian goodwill was zero as of December 31, 2014. Consequently, in the fourth quarter of 2014, we wrote off our remaining Canadian goodwill and recognized a $1.9 billion impairment.

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 "core earnings attributable to Devon" and "core earnings per share attributable to Devon" in "Overview of 2014 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. Core earnings attributable to Devon, as well as the per share amount, represent net earnings excluding certain noncash 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 2014 relate to derivatives and financial instrument fair value changes, asset impairments (including an impairment of goodwill), our divestiture programs and related gains on asset sales, repatriation of proceeds to the U.S., restructuring costs, loss on early retirement of debt and deferred income tax on the formation of EnLink. Amounts excluded for 2013 relate to our office consolidation and asset impairments. Amounts excluded in 2012 relate to our office consolidation, offshore exit and asset impairments. 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.

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

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except per share amounts)		
Net earnings (loss) attributable to Devon (GAAP)	$ 1,607	$ (20)	$ (185)
Adjustments (net of taxes):			
Derivatives and other financial instruments	(1,262)	131	(425)
Cash settlements on derivatives and financial instruments	31	139	558
Noncash effect of derivatives and financial instruments	(1,231)	270	133
Asset impairments	1,948	1,353	1,308
Gain on asset sales and related repatriation	(421)	97	—
Investment in EnLink deferred income tax	48	—	—
Restructuring costs	35	34	49
Early retirement of debt	31	—	—
Core earnings attributable to Devon (Non-GAAP)	$ 2,017	$1,734	$1,305
Earnings (loss) per share (GAAP)	$ 3.91	$ (0.06)	$ (0.47)
Adjustments (net of taxes):			
Derivatives and other financial instruments	(3.07)	0.31	(1.04)
Cash settlements on derivatives and financial instruments	0.08	0.34	1.37
Noncash effect of derivatives and financial instruments	(2.99)	0.65	0.33
Asset impairments	4.74	3.35	3.23
Gain on asset sales and related repatriation	(1.02)	0.24	—
Investment in EnLink deferred income tax	0.12	—	—
Restructuring costs	0.08	0.08	0.13
Early retirement of debt	0.07	—	—
Core earnings per share (Non-GAAP)	$ 4.91	$ 4.26	$ 3.22

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 production. Pricing for oil and gas 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 and gas derivative financial instruments as of December 31, 2014 are presented in Note 3 to the financial statements under "Item 8. Financial Statements and Supplementary Data" of this report.

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2014, a 10 percent increase or a 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	$ (74)	$ 69
Oil derivatives	$(282)	$279
Processing and fractionation derivatives	$ (2)	$ 2

Interest Rate Risk

At December 31, 2014, we had total debt of $11.3 billion. Of this amount, $9.3 billion bears fixed interest rates averaging 5.4 percent. Of the $11.3 billion of total debt, $2.0 billion is comprised of floating rate debt that bear interest rates averaging 0.74 percent. Our commercial paper borrowings typically have maturities between 1 and 90 days.

As of December 31, 2014, we had open interest rate swap positions that are presented in "Item 8. Financial Statements and Supplementary Data – Note 3" in this report. The fair values of our interest rate swaps are largely determined by estimates of the forward curves of the 3 month LIBOR rate. A 10 percent change in these forward curves would not have materially impacted our balance sheet at December 31, 2014.

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, 2014 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 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, 2014, 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, 2014, a 10 percent change in the foreign currency exchange rates would not have materially impacted our balance sheet.

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2014 and 2013, 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, 2014. We also have audited Devon Energy Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control – Integrated Framework* (2013) 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, 2014 and 2013, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2014, 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, 2014, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Oklahoma City, Oklahoma
February 20, 2015

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except per share amounts)		
Oil, gas and NGL sales	$ 9,910	$ 8,522	$7,153
Oil, gas and NGL derivatives	1,989	(191)	693
Marketing and midstream revenues	7,667	2,066	1,655
Total operating revenues	19,566	10,397	9,501
Lease operating expenses	2,332	2,268	2,074
Marketing and midstream operating expenses	6,815	1,553	1,246
General and administrative expenses	847	617	692
Production and property taxes	535	461	414
Depreciation, depletion and amortization	3,319	2,780	2,811
Asset impairments	1,953	1,976	2,024
Restructuring costs	46	54	74
Gains and losses on asset sales	(1,072)	9	(13)
Other operating items	93	112	105
Total operating expenses	14,868	9,830	9,427
Operating income	4,698	567	74
Net financing costs	526	417	370
Other nonoperating items	113	1	21
Earnings (loss) from continuing operations before income taxes	4,059	149	(317)
Income tax expense (benefit)	2,368	169	(132)
Earnings (loss) from continuing operations	1,691	(20)	(185)
Earnings (loss) from discontinued operations, net of tax	—	—	(21)
Net earnings (loss)	1,691	(20)	(206)
Net earnings attributable to noncontrolling interests	84	—	—
Net earnings (loss) attributable to Devon	$ 1,607	$ (20)	$ (206)
Net earnings (loss) per share attributable to Devon:			
Basic earnings (loss) from continuing operations per share	$ 3.93	$ (0.06)	$ (0.47)
Basic earnings (loss) from discontinued operations per share	—	—	(0.05)
Basic net earnings (loss) per share:	$ 3.93	$ (0.06)	$ (0.52)
Diluted earnings (loss) from continuing operations per share	$ 3.91	$ (0.06)	$ (0.47)
Diluted earnings (loss) from discontinued operations per share	—	—	(0.05)
Diluted net earnings (loss) per share	$ 3.91	$ (0.06)	$ (0.52)
Comprehensive earnings (loss):			
Net earnings (loss)	$ 1,691	$ (20)	$ (206)
Other comprehensive earnings (loss), net of tax:			
Foreign currency translation	(465)	(548)	194
Pension and postretirement plans	(24)	45	2
Other comprehensive earnings (loss), net of tax	(489)	(503)	196
Comprehensive earnings (loss)	1,202	(523)	(10)
Comprehensive earnings attributable to noncontrolling interests	84	—	—
Comprehensive earnings (loss) attributable to Devon	$ 1,118	$ (523)	$ (10)

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
		(In millions)	
Cash flows from operating activities:			
Net earnings (loss)	$ 1,691	$ (20)	$ (206)
Loss from discontinued operations, net of tax	—	—	21
Adjustments to reconcile earnings (loss) from continuing operations to net cash from operating activities:			
Depreciation, depletion and amortization	3,319	2,780	2,811
Asset impairments	1,953	1,976	2,024
Gains and losses on asset sales	(1,072)	9	(13)
Deferred income tax expense (benefit)	1,891	97	(184)
Derivatives and other financial instruments	(2,070)	135	(660)
Cash settlements on derivatives and financial instruments	104	277	865
Other noncash charges	457	309	253
Net change in working capital	50	(298)	(50)
Change in long-term other assets	(421)	10	(36)
Change in long-term other liabilities	79	161	105
Cash from operating activities – continuing operations	5,981	5,436	4,930
Cash from operating activities – discontinued operations	—	—	26
Net cash from operating activities	5,981	5,436	4,956
Cash flows from investing activities:			
Capital expenditures	(6,988)	(6,758)	(8,225)
Acquisitions of property, equipment and businesses	(6,462)	—	—
Proceeds from property and equipment divestitures	5,120	419	1,468
Purchases of short-term investments	—	(1,076)	(4,106)
Redemptions of short-term investments	—	3,419	3,266
Redemptions of long-term investments	57	—	—
Other	89	(3)	14
Cash from investing activities – continuing operations	(8,184)	(3,999)	(7,583)
Cash from investing activities – discontinued operations	—	—	57
Net cash from investing activities	(8,184)	(3,999)	(7,526)
Cash flows from financing activities:			
Proceeds from borrowings of long-term debt, net of issuance costs	5,340	2,233	3,208
Net short-term debt repayments	(385)	(1,872)	(537)
Long-term debt repayments	(7,189)	—	(750)
Proceeds from stock option exercises	93	3	27
Proceeds from issuance of subsidiary units	410	—	—
Dividends paid on common stock	(386)	(348)	(324)
Distributions to noncontrolling interests	(235)	—	—
Other	(2)	4	5
Net cash from financing activities	(2,354)	20	1,629
Effect of exchange rate changes on cash	(29)	(28)	23
Net change in cash and cash equivalents	(4,586)	1,429	(918)
Cash and cash equivalents at beginning of period	6,066	4,637	5,555
Cash and cash equivalents at end of period	$ 1,480	$ 6,066	$ 4,637

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,480	$ 6,066
Accounts receivable	1,959	1,520
Derivatives, at fair value	1,993	75
Income taxes receivable	522	89
Other current assets	544	255
Total current assets	6,498	8,005
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	75,738	73,995
Not subject to amortization	2,752	2,791
Total oil and gas	78,490	76,786
Midstream and other	9,695	6,195
Total property and equipment, at cost	88,185	82,981
Less accumulated depreciation, depletion and amortization	(51,889)	(54,534)
Property and equipment, net	36,296	28,447
Goodwill	6,303	5,858
Other long-term assets	1,540	567
Total assets	$ 50,637	$ 42,877
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,400	$ 1,229
Revenues and royalties payable	1,193	786
Short-term debt	1,432	4,066
Deferred income taxes	730	19
Other current liabilities	1,180	555
Total current liabilities	5,935	6,655
Long-term debt	9,830	7,956
Asset retirement obligations	1,339	2,140
Other long-term liabilities	948	834
Deferred income taxes	6,244	4,793
Stockholders' equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 409 million and 406 million shares in 2014 and 2013, respectively	41	41
Additional paid-in capital	4,088	3,780
Retained earnings	16,631	15,410
Accumulated other comprehensive earnings	779	1,268
Total stockholders' equity attributable to Devon	21,539	20,499
Noncontrolling interests	4,802	—
Total stockholders' equity	26,341	20,499
Commitments and contingencies (Note 18)		
Total liabilities and stockholders' equity	$ 50,637	$ 42,877

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Noncontrolling Interests	Total Stockholders' Equity
	Shares	Amount						
					(In millions)			
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
Net earnings	—	—	—	1,607	—	—	84	1,691
Other comprehensive loss, net of tax	—	—	—	—	(489)	—	—	(489)
Stock option exercises	1	—	93	—	—	—	—	93
Restricted stock grants, net of cancellations	2	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(27)	—	(27)
Common stock retired	—	—	(27)	—	—	27	—	—
Common stock dividends	—	—	—	(386)	—	—	—	(386)
Share-based compensation	—	—	151	—	—	—	—	151
Share-based compensation tax benefits	—	—	(3)	—	—	—	—	(3)
Acquisition of noncontrolling interests	—	—	—	—	—	—	4,670	4,670
Subsidiary equity transactions	—	—	93	—	—	—	277	370
Distributions to noncontrolling interests	—	—	—	—	—	—	(235)	(235)
Other	—	—	1	—	—	—	6	7
Balance as of December 31, 2014	409	$ 41	$4,088	$16,631	$ 779	$—	$4,802	$26,341

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Devon Energy Corporation ("Devon") is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Devon's operations are concentrated in various North American onshore areas in the U.S. and Canada. Devon also owns natural gas pipelines, plants and treatment facilities through its ownership in EnLink Midstream Partners, LP, a publicly traded MLP.

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 accompanying consolidated financial statements include the accounts of Devon and entities in which it holds a controlling interest. All intercompany transactions have been eliminated. Undivided interests in oil and natural gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in non-controlled entities, over which Devon has the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for Devon's proportionate share of earnings, losses and distributions. Investments accounted for using the equity method and cost method are reported as a component of other long-term assets.

As discussed more fully in Note 2, on March 7, 2014, Devon completed a business combination whereby Devon controls both EnLink Midstream Partners, LP ("EnLink") and its general partner entity, EnLink Midstream, LLC (the "General Partner"). Devon controls both the General Partner's and EnLink's operations; therefore, the General Partner's and EnLink's accounts are included in Devon's accompanying consolidated financial statements subsequent to the completion of the transaction. The portions of the General Partner's and EnLink's net earnings and stockholders' equity not attributable to Devon's controlling interest are shown separately as noncontrolling interests in the accompanying consolidated comprehensive statements of earnings and consolidated balance sheets.

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 and midstream assets;
- derivative financial instruments;
- the fair value of reporting units and related assessment of goodwill for impairment;
- the fair value of intangible assets other than goodwill;
- 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 consolidated comprehensive statements of earnings.

Devon follows the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which Devon is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the underproduced owner to recoup its entitled share through production. The liability is 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 2014, 2013 and 2012, 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. Additionally, Devon, through EnLink, periodically enters into derivative financial instruments with respect to a portion of EnLink's oil, gas and NGL marketing activities. 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, 2014, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment. Cash settlements with counterparties on Devon's derivative financial instruments are also recorded in earnings.

By using derivative financial instruments to hedge exposures to changes in commodity prices, interest rates and foreign currency rates, Devon is exposed to credit risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom Devon believes are acceptable credit risks. It is Devon's policy to enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Additionally, Devon's derivative contracts generally require cash collateral to be posted if either its or the counterparty's credit rating falls below certain credit rating levels. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below such credit levels. As of December 31, 2014, Devon held $524 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 consolidated 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

Independent of EnLink, Devon grants share-based awards to independent members of its Board of Directors and selected employees. EnLink and its General Partner also grant share-based awards to independent 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 consolidated comprehensive statements of earnings over the applicable requisite service periods. As a result of Devon's restructuring activity discussed in Note 6, certain share-based awards were accelerated and recognized as a component of restructuring costs in the accompanying consolidated 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 canceled 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 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 Share Attributable to Devon

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. At December 31, 2013, such debt securities totaled $62 million and are included in other long-term assets in the accompanying consolidated balance sheet. Devon redeemed all these securities in the first quarter of 2014.

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.

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, 2014 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 annually, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid.

Devon performed annual impairment tests of goodwill in the fourth quarters of 2014, 2013 and 2012. No impairment of goodwill was required in 2012 and 2013. However, based on the 2014 assessment, Devon's Canadian reporting unit goodwill was deemed impaired. See Note 12 for further discussion.

Intangible Assets

Unamortized capitalized intangible assets, consisting of EnLink customer relationships, are presented in other long-term assets in the accompanying consolidated balance sheets. These assets are amortized on a straight-line basis over the expected periods of benefits, which range from 10-20 years.

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 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 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.

Noncontrolling Interests

Noncontrolling interests represent third-party ownership in the net assets of Devon's consolidated subsidiaries and are presented as a component of equity. Changes in Devon's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity.

Recently Issued Accounting Standards Not Yet Adopted

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, Revenue from Contracts with Customers (Topic 606). The update provides guidance concerning the recognition and measurement of revenue from contracts with customers. Its objective is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. The update is effective for Devon beginning on January 1, 2017. The standard permits the use of either the retrospective or cumulative effect transition method. Devon has not yet selected a transition method and is evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

2. Acquisitions and Divestitures

Formation of EnLink Midstream, LLC and EnLink Midstream Partners, LP

On March 7, 2014, Devon, Crosstex Energy, Inc. and Crosstex Energy, LP (together with Crosstex Energy, Inc., "Crosstex") completed a transaction to combine substantially all of Devon's U.S. midstream assets with Crosstex's assets to form a new midstream business. The new business consists of the General Partner and EnLink, which are both publicly traded.

In exchange for a controlling interest in both EnLink and the General Partner, Devon contributed its equity interest in a newly formed Devon subsidiary, EnLink Midstream Holdings, LP ("EnLink Holdings") and $100 million in cash. EnLink Holdings owns midstream assets in the Barnett Shale in north Texas and the Cana- and Arkoma-Woodford Shales in Oklahoma, as well as an economic interest in Gulf Coast Fractionators in Mont Belvieu, Texas. As of December 31, 2014, the General Partner and EnLink each own 50% of EnLink Holdings.

As of December 31, 2014, the ownership of the General Partner is approximately:

- 70% – Devon
- 30% – Public unitholders

As of December 31, 2014, the ownership of EnLink is approximately:

- 49% – Devon
- 43% – Public unitholders
- 8% – General Partner

This business combination was accounted for using the acquisition method of accounting. Under the acquisition method of accounting, EnLink Holdings was the accounting acquirer because its parent company, Devon, obtained control of EnLink and the General Partner as a result of the business combination. Consequently, EnLink Holdings' assets and liabilities retained their carrying values. Additionally, the Crosstex assets acquired and liabilities assumed by the General Partner and EnLink in the business combination, as well as the General Partner's noncontrolling interest in EnLink, were recorded at their fair values which were measured as of the acquisition date, March 7, 2014. The excess of the purchase price over the estimated fair values of Crosstex's net assets acquired was recorded as goodwill.

The following table summarizes the purchase price (in millions, except unit price).

Crosstex Energy, Inc. outstanding common shares:	
Held by public shareholders	48.0
Restricted shares	0.4
Total subject to conversion	48.4
Exchange ratio	1.0 x
Converted shares	48.4
Crosstex Energy, Inc. common share price (1)	$37.60
Crosstex Energy, Inc. consideration	$1,823
Fair value of noncontrolling interest in E2 (2)	18
Total Crosstex Energy, Inc. consideration and fair value of noncontrolling interests	$1,841
Crosstex Energy, LP outstanding units:	
Common units held by public unitholders	75.1
Preferred units held by third party (3)	17.1
Restricted units	0.4
Total	92.6
Crosstex Energy, LP common unit price (4)	$30.51
Crosstex Energy, LP common units value	$2,825
Crosstex Energy, LP outstanding unit options value	$ 4
Total fair value of noncontrolling interests in the Crosstex Energy, LP (4)	2,829
Total consideration and fair value of noncontrolling interests	$4,670

(1) The final purchase price is based on the fair value of Crosstex Energy, Inc.'s common shares as of the closing date, March 7, 2014.

(2) Represents the value of noncontrolling interests related to the General Partner's equity investment in E2 Energy Services, LLC and E2 Appalachian Compression, LLC (collectively "E2").
(3) Crosstex Energy, LP converted the preferred units to common units in February 2014.
(4) The final purchase price is based on the fair value of Crosstex Energy, LP's common units as of the closing date, March 7, 2014.

The allocation of the purchase price is as follows (in millions):

Assets acquired:	
Current assets	$ 437
Property, plant and equipment, net	2,438
Intangible assets	569
Equity investment	222
Goodwill [(1)]	3,283
Other long-term assets	1
Liabilities assumed:	
Current liabilities	(515)
Long-term debt	(1,454)
Deferred income taxes	(210)
Other long-term liabilities	(101)
Total consideration and fair value of noncontrolling interests	$ 4,670

(1) Goodwill is the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill is not amortized and is not deductible for tax purposes.

EnLink Acquisitions and Dropdowns

On October 22, 2014, EnLink acquired equity interests in E2 Appalachian Compression, LLC and E2 Energy Services, LLC (together "E2") from the General Partner. The total consideration for the transaction was approximately $194 million, including a $163 million cash payment and 1.0 million EnLink units valued at $31.2 million based on the fair value of the EnLink units as of the closing date of the transaction. Furthermore, on November 1, 2014, EnLink acquired Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana for $234 million, subject to certain adjustments.

GeoSouthern Energy Acquisition

On February 28, 2014, Devon completed its acquisition of interests in certain affiliates of GeoSouthern Energy Corporation ("GeoSouthern") for approximately $6.0 billion. Devon funded the acquisition with cash on hand and debt financing. In connection with the GeoSouthern transaction, Devon acquired approximately 82,000 net acres (unaudited) located in DeWitt and Lavaca counties in south Texas. The transaction was accounted for using the acquisition method, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date.

The allocation of the purchase price is as follows (in millions).

Cash and cash equivalents	$ 95
Other current assets	256
Proved properties	5,026
Unproved properties	1,007
Midstream assets	86
Current liabilities	(434)
Long-term liabilities	(6)
Net assets acquired	$6,030

EnLink and GeoSouthern Operating Results

The following table presents the General Partner's and EnLink's (acquired Crosstex operations) and GeoSouthern's operating revenues and net earnings included in Devon's consolidated comprehensive statements of earnings subsequent to the transactions described above.

	Year Ended December 31, 2014	
	GeoSouthern	EnLink
	(In millions)	
Total operating revenues	$1,873	$2,509
Total operating expenses	960	2,464
Operating income	$ 913	$ 45

Pro Forma Financial Information

The following unaudited pro forma financial information has been prepared assuming both the EnLink formation and the GeoSouthern acquisition occurred on January 1, 2013. The pro forma information is not intended to reflect the actual results of operations that would have occurred if the business combination and acquisition had been completed at the dates indicated. In addition, they do not project Devon's results of operations for any future period.

	Year Ended December 31,	
	2014	2013
	(In millions)	
Total operating revenues	$20,213	$12,979
Net earnings	$ 1,716	$ 35
Noncontrolling interests	$ 97	$ 45
Net earnings (loss) attributable to Devon	$ 1,619	$ (10)
Net earnings (loss) per common share attributable to Devon	$ 3.94	$ (0.02)

Asset Divestitures

In November 2013, Devon announced plans to divest certain properties located throughout Canada and the U.S.

Canada

In the first quarter of 2014, Devon completed minor divestiture transactions for $142 million ($155 million Canadian dollars). In the second quarter of 2014, Devon sold conventional assets to Canadian Natural Resources Limited for $2.8 billion ($3.125 billion Canadian dollars).

Under full cost accounting rules, sales or dispositions of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the disposition would otherwise significantly alter the relationship between a cost center's capitalized costs and proved reserves, then a gain or loss must be recognized. The Canadian divestitures significantly altered such relationship. Therefore, Devon recognized gains totaling $1.1 billion ($0.6 billion after-tax) in 2014. These gains are included as a separate item in the accompanying consolidated comprehensive statements of earnings.

Included in the gain calculation noted above were asset retirement obligations of approximately $700 million assumed by the purchaser as well as the derecognition of approximately $700 million of goodwill allocated to the sold assets.

In conjunction with the divestitures noted above, Devon repatriated approximately $2.8 billion of proceeds to the U.S. in the second quarter of 2014. The proceeds were used to repay $0.7 billion of commercial paper and the $2.0 billion term loans that were drawn in the first quarter of 2014 to fund a portion of the GeoSouthern acquisition. Between collecting the divestiture proceeds and repatriating funds to the U.S., Devon recognized an $84 million foreign currency exchange loss and a $29 million foreign exchange currency derivative loss. These losses are included in other nonoperating items in the accompanying consolidated comprehensive statements of earnings.

U.S.

On August 29, 2014, Devon sold certain U.S. assets to LINN Energy for $2.2 billion ($2.0 billion after-tax proceeds). Additionally, approximately $200 million of asset retirement obligations were assumed by LINN Energy. No gain or loss was recognized on the sale. These proceeds were used towards the early retirement of $1.9 billion in senior notes in November 2014 as discussed in Note 13.

3. Derivative Financial Instruments

Commodity Derivatives

As of December 31, 2014, Devon had the following open oil derivative positions. The first table presents Devon's oil derivatives that settle against the average of the prompt month NYMEX West Texas Intermediate futures price. The second table presents Devon's oil derivatives that settle against the Western Canadian Select, West Texas Sour and Midland Sweet indices.

	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Q1-Q4 2015	107,203	$91.07	31,500	$89.67	$97.84	28,000	$116.43
Q1-Q4 2016	—	$ —	—	$ —	$ —	18,500	$103.11

	Oil Basis Swaps		
Period	Index	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q1-Q4 2015	Western Canadian Select	22,514	$(18.35)
Q1-Q4 2015	West Texas Sour	8,000	$ (3.68)
Q1-Q4 2015	Midland Sweet	14,247	$ (2.92)

As of December 31, 2014, 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 Panhandle Eastern Pipe Line, El Paso Natural Gas and Houston Ship Channel indices.

	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Q1-Q4 2015	250,000	$4.32	328,452	$4.05	$4.36	550,000	$5.09
Q1-Q4 2016	—	$ —	—	$ —	$ —	400,000	$5.00

	Natural Gas Basis Swaps		
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q1-Q4 2015	Panhandle Eastern Pipe Line	100,000	$(0.28)
Q1-Q4 2015	El Paso Natural Gas	70,000	$(0.11)
Q1-Q4 2015	Houston Ship Channel	200,000	$ 0.01
Q1-Q4 2016	Panhandle Eastern Pipe Line	30,000	$(0.33)
Q1-Q4 2016	El Paso Natural Gas	15,000	$(0.13)
Q1-Q4 2016	Houston Ship Channel	30,000	$ 0.11

As of December 31, 2014, the following were open derivative positions associated with gas processing and fractionation at EnLink. EnLink's NGL positions settle by purity product against the average of the prompt month OPIS Mont Belvieu, Texas index. EnLink's natural gas positions settle against the Henry Hub Gas Daily index as defined by the pricing dates in the derivative contracts.

Period	Product	Volume	Weighted Average Price Paid	Weighted Average Price Received
Q1 2015-Q4 2016	Ethane	1,168 MBbls	Index	$0.29/gal
Q1 2015-Q4 2016	Propane	1,171 MBbls	Index	$1.01/gal
Q1-Q4 2015	Normal Butane	53 MBbls	Index	$1.14/gal
Q1-Q4 2015	Natural Gasoline	44 MBbls	Index	$1.81/gal
Q1-Q4 2015	Natural Gas	1,225 MMBtu/d	$4.08/MMBtu	Index

Interest Rate Derivatives

As of December 31, 2014, Devon had the following open interest rate derivative positions:

Notional (In millions)	Rate Received	Rate Paid	Expiration
$100	Three Month LIBOR	0.92%	December 2016
$100	1.76%	Three Month LIBOR	January 2019

Foreign Currency Derivatives

As of December 31, 2014, Devon had the following open foreign currency derivative position:

	Forward Contract			
Currency	Contract Type	CAD Notional	Weighted Average Fixed Rate Received	Expiration
		(In millions)	(CAD-USD)	
Canadian Dollar	Sell	$1,884	0.864	March 2015

Financial Statement Presentation

The following table presents the net gains and losses recognized in the accompanying consolidated comprehensive statements of earnings associated with derivative financial instruments.

	Comprehensive Statements of Earnings Caption	Year Ended December 31, 2014	2013	2012
		(In millions)		
Oil, gas and NGL commodity derivatives	Oil, gas and NGL derivatives	$1,989	$(191)	$693
Midstream commodity derivatives	Marketing and midstream revenues	22	—	—
Interest rate derivatives	Other nonoperating items	(1)	—	(15)
Foreign currency derivatives	Other nonoperating items	60	56	(18)
Net gains (losses) recognized in comprehensive statements of earnings		$2,070	$(135)	$660

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

	Balance Sheet Caption	December 31, 2014	2013
		(In millions)	
Asset derivatives:			
Oil, gas and NGL commodity derivatives	Derivatives, at fair value	$1,967	$ 75
Oil, gas and NGL commodity derivatives	Other long-term assets	1	28
Midstream commodity derivatives	Derivatives, at fair value	17	—
Midstream commodity derivatives	Other long-term assets	10	—
Interest rate derivatives	Derivatives, at fair value	1	—
Foreign currency derivatives	Derivatives, at fair value	8	—
Total asset derivatives		$2,004	$103
Liability derivatives:			
Oil, gas and NGL commodity derivatives	Other current liabilities	$ 25	$ 58
Oil, gas and NGL commodity derivatives	Other long-term liabilities	26	62
Midstream commodity derivatives	Other current liabilities	3	—
Midstream commodity derivatives	Other long-term liabilities	2	—
Interest rate derivatives	Other current liabilities	1	—
Foreign currency derivatives	Other current liabilities	—	1
Total liability derivatives		$ 57	$121

4. 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, 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 consolidated comprehensive statements of earnings. Devon's gross general and administrative expense for the year ended December 31, 2014 includes $17 million of unit-based compensation related to grants made under EnLink's long-term incentive plans.

The vesting for certain share-based awards was accelerated as part of Devon's restructuring as discussed in Note 6. The associated expense for these accelerated awards is included in restructuring costs in the accompanying consolidated comprehensive statements of earnings.

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Gross general and administrative expense	$199	$157	$179
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 53	$ 60	$ 56
Related income tax benefit	$ 30	$ 23	$ 34

Stock Options

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

The fair value of stock options on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires Devon to make several assumptions. The volatility of Devon's common stock is based on the historical volatility of the market price of Devon's common stock over a period of time equal to the expected term of the option and ending on the grant date. The dividend yield is based on Devon's historical and current yield in effect at the date of grant. The risk-free interest rate is based on the zero-coupon 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. All such amounts represent the weighted-average amounts for the year. No stock options were granted in 2014 and 2013.

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

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

		Weighted Average		
	Options	Exercise Price	Remaining Term	Intrinsic Value
	(In thousands)		(In years)	(In millions)
Outstanding at December 31, 2013	6,446	$69.35		
Granted	—	$ —		
Exercised	(1,417)	$65.55		
Expired	(528)	$70.64		
Forfeited	(283)	$67.86		
Outstanding at December 31, 2014	4,218	$70.56	3.11	$1
Vested and expected to vest at December 31, 2014	4,201	$70.57	3.10	$1
Exercisable at December 31, 2014	3,969	$70.80	3.00	$1

The aggregate intrinsic value of stock options that were exercised during 2014, 2013 and 2012 was $9 million, $0.3 million and $34 million, respectively. As of December 31, 2014, Devon's unrecognized compensation cost related to unvested stock options was $3 million. Such cost is expected to be recognized over a weighted-average period of 1.0 years.

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	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2013	3,292	$59.76
Granted	3,487	$62.75
Vested	(1,767)	$60.23
Forfeited	(708)	$60.47
Unvested at December 31, 2014	4,304	$60.85

The aggregate fair value of restricted stock awards and units that vested during 2014, 2013 and 2012 was $112 million, $141 million and $112 million, respectively. As of December 31, 2014, Devon's unrecognized compensation cost related to unvested restricted stock awards and units was $194 million. Such cost is expected to be recognized over a weighted-average period of 2.5 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	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2013	316	$56.25
Granted	234	$61.33
Vested	(170)	$56.18
Unvested at December 31, 2014	380	$59.41

The aggregate fair value of performance-based restricted stock awards that vested during 2014 and 2013 was $10 million and $5 million, respectively. No awards vested in 2012. As of December 31, 2014, Devon's unrecognized compensation cost related to these awards was $5 million. Such cost is expected to be recognized over a weighted-average period of 2.9 years.

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.

	2014	2013	2012
Grant-date fair value	$70.18 – $81.05	$61.27 – $63.48	$61.27 – $63.48
Risk-free interest rate	0.54%	0.26% – 0.36%	0.26% – 0.36%
Volatility factor	28.8%	30.3%	30.3%
Contractual term (in years)	2.89	3.0	3.0

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

	Performance Share Units	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2013	925	$66.64
Granted	708	$77.77
Forfeited	(156)	$76.59
Unvested at December 31, 2014 (1)	1,477	$70.90

(1) A maximum of 3.0 million common shares could be awarded based upon Devon's final TSR ranking.

As of December 31, 2014, Devon's unrecognized compensation cost related to unvested units was $34 million. Such cost is expected to be recognized over a weighted-average period of 1.8 years.

EnLink Share-Based Awards

As of December 31, 2014, EnLink's unrecognized compensation cost related to unvested restricted incentive units was $20 million. Such cost is expected to be recognized over a weighted-average period of 1.9 years.

As of December 31, 2014, the General Partner's unrecognized compensation cost related to unvested restricted incentive units was $21 million. Such cost is expected to be recognized over a weighted-average period of 1.9 years.

5. Asset Impairments

In 2014, 2013 and 2012, Devon recognized asset impairments as presented below.

	Year Ended December 31, 2014		Year Ended December 31, 2013		Year Ended December 31, 2012	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)					
Goodwill	$1,941	$1,941	$ —	$ —	$ —	$ —
U.S. oil and gas assets	—	—	1,110	707	1,793	1,142
Canada oil and gas assets	—	—	843	632	163	122
Midstream assets	12	7	23	14	68	44
Asset impairments	$1,953	$1,948	$1,976	$1,353	$2,024	$1,308

Goodwill Impairment

In 2014, Devon recognized $1.9 billion in goodwill impairment related to its Canadian reporting unit. Additional information regarding the impairment is discussed in Note 12.

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 the significant decline in oil prices during the fourth quarter of 2014, Devon wrote down its pipeline line fill inventory, as the carrying amount exceeded its fair value, which was determined based on the West Texas Intermediate spot price at December 31, 2014.

Due to declining natural gas production resulting from low natural gas and NGL prices in 2013 and 2012, 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.

6. Restructuring Costs

Canadian Divestitures

During 2014, Devon recognized $46 million of employee related and other costs associated with its divestiture of certain Canadian assets. Approximately $15 million of the employee related costs resulted from accelerated vesting of share-based grants, which are noncash charges.

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. The employee severance and retention costs included amounts related to cash severance costs and accelerated vesting of share-based grants. The lease obligations and other costs related to certain office space that is subject to non-cancellable operating lease agreements and that Devon ceased using as part of the office consolidation.

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 consolidated comprehensive statements of earnings.

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Canada divestitures:			
Employee severance and retention	$ 42	$—	$—
Lease obligations and other	4	—	—
Office consolidation:			
Employee severance and retention	—	13	77
Lease obligations and other	—	41	3
Offshore divestiture:			
Employee severance and retention	—	—	(3)
Lease obligations and other	—	—	(3)
Restructuring costs	$ 46	$ 54	$ 74

The schedule below summarizes Devon's restructuring liabilities.

	Other Current Liabilities	Other Long-term Liabilities	Total
	(In millions)		
Balance as of December 31, 2012	$ 52	$ 9	$ 61
Changes due to office consolidation	(22)	11	(11)
Changes due to offshore divestiture	(3)	(2)	(5)
Balance as of December 31, 2013	27	18	45
Changes due to Canadian divestitures	4	—	4
Changes due to office consolidation	(15)	(10)	(25)
Changes due to offshore divestiture	(3)	(1)	(4)
Balance as of December 31, 2014	$ 13	$ 7	$ 20

7. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31, 2014	2013	2012
	(In millions)		
Current income tax expense (benefit):			
U.S. federal	$ 152	$ 73	$ 60
Various states	18	(5)	(3)
Canada and various provinces	307	4	(5)
Total current tax expense (benefit)	477	72	52
Deferred income tax expense (benefit):			
U.S. federal	1,610	198	(188)
Various states	93	59	34
Canada and various provinces	188	(160)	(30)
Total deferred tax expense (benefit)	1,891	97	(184)
Total income tax expense (benefit)	$2,368	$ 169	$(132)

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, 2014	2013	2012
Total income tax expense (benefit) (in millions)	$2,368	$169	$(132)
U.S. statutory income tax rate	35%	35%	(35)%
Non-deductible goodwill transactions	23%	0%	0%
Taxation on Canadian operations	(4)%	9%	(6)%
State income taxes	2%	23%	6%
Repatriations	2%	65%	0%
Taxes on EnLink formation	1%	0%	0%
Other	(1)%	(19)%	(7)%
Effective income tax rate	58%	113%	(42)%

During 2014, Devon had non-deductible goodwill transactions. Goodwill was removed in conjunction with the Canadian conventional asset divestiture to Canadian Natural Resources Limited, and there was a goodwill impairment in the Canadian reporting unit. See Note 12 for further discussion.

Additionally, during 2014, Devon repatriated to the U.S. $2.8 billion of cash relating to the Canadian asset divestiture. In conjunction with the repatriation, Devon recognized approximately $105 million of additional income tax expense for the full year. Prior to the repatriation, Devon had recognized a $143 million deferred income tax liability associated with the planned repatriation. When the repatriation was made, Devon retained a larger property basis in Canada than was previously estimated, resulting in the incremental tax. After the use of foreign tax credits, the current income tax on the repatriation was $67 million.

Furthermore, Devon completed its divestiture program of certain assets in the U.S. In conjunction with the divestiture closing and due to the availability of additional tax deductions, Devon recognized $294 million of current income tax expense. The current tax expense was entirely offset by the recognition of deferred tax benefits.

Devon also recorded a $46 million deferred tax liability in conjunction with the formation of EnLink in 2014.

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.

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,	
	2014	2013
	(In millions)	
Deferred tax assets:		
Asset retirement obligations	$ 458	$ 673
Foreign tax credits	—	248
Net operating loss carryforwards	200	183
Alternative minimum tax credits	57	105
Pension benefit obligations	113	104
Other	273	163
Total deferred tax assets	1,101	1,476
Deferred tax liabilities:		
Property and equipment	(6,940)	(5,895)
Long-term debt	(115)	(161)
Taxes on unremitted foreign earnings	(6)	(157)
Fair value of financial instruments	(699)	(7)
Other	(154)	(52)
Total deferred tax liabilities	(7,914)	(6,272)
Net deferred tax liability	$(6,813)	$(4,796)

Devon has recognized $200 million of deferred tax assets related to various net operating loss carryforwards available to offset future income taxes. The carryforwards consist of $621 million of Canadian net operating loss carryforwards, which expire between 2029 and 2034, $180 million of state net operating loss carryforwards, which expire primarily between 2018 and 2032 and $135 million of net operating loss carryforwards related to EnLink's operations, which expire between 2028 and 2034. Devon expects the tax benefits from the Canadian net operating loss carryforwards to be utilized between 2015 and 2017 and the state net operating loss carryforwards to be utilized between 2017 and 2029. The EnLink net operating losses are expected to be utilized during 2015. Devon has also recognized a $57 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, 2014, Devon's unremitted foreign earnings totaled approximately $1.8 billion. All but $22 million of the $1.8 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 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.

For the remaining $22 million of unremitted earnings deemed not to be indefinitely reinvested, Devon has recognized a $6 million deferred tax liability associated with such unremitted earnings as of December 31, 2014.

Unrecognized Tax Benefits

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

	December 31,	
	2014	2013
	(In millions)	
Balance at beginning of year	$243	$216
Tax positions taken in prior periods	—	(17)
Tax positions taken in current year	—	42
Accrual of interest related to tax positions taken	2	5
Foreign currency translation	(4)	(3)
Balance at end of year	$241	$243

Devon's unrecognized tax benefit balance at December 31, 2014 and 2013 included $34 million and $32 million, respectively, of interest and penalties. If recognized, $223 million of Devon's unrecognized tax benefits as of December 31, 2014 would affect Devon's effective income tax rate. Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

Jurisdiction	Tax Years Open
U.S. Federal	2008-2014
Various U.S. states	2008-2014
Canada Federal	2004-2014
Various Canadian provinces	2004-2014

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.

8. Net Earnings (Loss) Per Share Attributable to Devon

The following table reconciles net earnings (loss) attributable to Devon and common shares outstanding used in the calculations of basic and diluted net earnings per share.

	Earnings (loss)	Common Shares	Earnings (loss) per Share
	(In millions, except per share amounts)		
Year Ended December 31, 2014:			
Net earnings attributable to Devon	$1,607	409	
Attributable to participating securities	(17)	(4)	
Basic net earnings per share	1,590	405	$ 3.93
Dilutive effect of potential common shares issuable	—	2	
Diluted net earnings per share	$1,590	407	$ 3.91
Year Ended December 31, 2013:			
Net loss attributable to Devon	$ (20)	406	
Attributable to participating securities	(2)	(4)	
Basic net loss per share	(22)	402	$(0.06)
Dilutive effect of potential common shares issuable	—	—	
Diluted net loss per share	$ (22)	402	$(0.06)
Year Ended December 31, 2012:			
Net loss attributable to Devon	$ (206)	404	
Attributable to participating securities	(3)	(4)	
Basic net loss per share	(209)	400	$(0.52)
Dilutive effect of potential common shares issuable	—	—	
Diluted net loss per share	$ (209)	400	$(0.52)

Certain options to purchase shares of Devon's common stock were excluded from the dilution calculations because the options were antidilutive. These excluded options totaled 3 million, 7 million and 9 million in 2014, 2013 and 2012, respectively.

9. Other Comprehensive Earnings

Components of other comprehensive earnings consist of the following:

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Foreign currency translation:			
Beginning accumulated foreign currency translation	$1,448	$1,996	$1,802
Change in cumulative translation adjustment	(499)	(574)	203
Income tax benefit (expense)	34	26	(9)
Ending accumulated foreign currency translation	983	1,448	1,996
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(180)	(225)	(227)
Net actuarial gain (loss) and prior service cost arising in current year	(57)	48	(47)
Recognition of net actuarial loss and prior service cost in earnings (1)	20	24	51
Income tax benefit (expense)	13	(27)	(2)
Ending accumulated pension and postretirement benefits	(204)	(180)	(225)
Accumulated other comprehensive earnings, net of tax	$ 779	$1,268	$1,771

(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 consolidated comprehensive statements of earnings (see Note 15 note for additional details).

10. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Net change in working capital accounts:			
Accounts receivable	$ 128	$(288)	$140
Income taxes receivable	(467)	29	(55)
Other current assets	(222)	20	(73)
Accounts payable	(68)	26	(8)
Revenues and royalties payable	133	35	19
Other current liabilities	546	(120)	(73)
Net change in working capital	$ 50	$(298)	$ (50)
Interest paid (net of capitalized interest)	$ 514	$ 406	$334
Income taxes paid	$ 899	$ 13	$100

On March 7, 2014, Devon completed a business combination to form EnLink. With the exception of a $100 million cash payment to noncontrolling interests, the business combination was a non-monetary transaction. See Note 2 for additional details.

11. Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2014	December 31, 2013
	(In millions)	
Oil, gas and NGL sales	$ 723	$ 851
Joint interest billings	475	447
Marketing and midstream revenues	706	172
Other	71	61
Gross accounts receivable	1,975	1,531
Allowance for doubtful accounts	(16)	(11)
Net accounts receivable	$1,959	$1,520

12. Goodwill and Other Intangible Assets

Goodwill

The table below provides a summary of Devon's goodwill by assigned reporting unit.

	U.S.	Canada	EnLink	Total
		(In millions)		
Balance as of December 31, 2012	$2,644	$ 3,033	$ 402	$ 6,079
Asset divestitures	(26)	—	—	(26)
Foreign currency translation adjustments	—	(195)	—	(195)
Balance as of December 31, 2013	$2,618	$ 2,838	$ 402	$ 5,858
Acquired during period	—	—	3,283	3,283
Asset divestitures	—	(706)	—	(706)
Impairment	—	(1,941)	—	(1,941)
Foreign currency translation adjustments	—	(191)	—	(191)
Balance as of December 31, 2014	$2,618	$ —	$3,685	$ 6,303

Acquired During Period

Included in the assets Devon contributed to EnLink Holdings was $402 million of goodwill. The additional EnLink goodwill of $3.3 billion represents the goodwill recognized upon the formation of EnLink and General Partner as described in Note 2.

The General Partner's and EnLink's goodwill was recognized and assigned to the five reporting units as follows.

	Texas	Louisiana	Oklahoma	Ohio River Valley	General Partner	Total
			(In millions)			
Balance as of December 31, 2013	$ 326	$—	$ 76	$—	$ —	$ 402
Acquired during period	842	787	114	113	1,427	3,283
Balance as of December 31, 2014	$1,168	$787	$190	$113	$1,427	$3,685

Asset Divestitures

In conjunction with the asset divestitures in 2013 and 2014, Devon removed $26 million and $706 million of goodwill, respectively, which were allocated to these assets.

Impairment

Devon's Canadian goodwill was originally recognized in 2001 as a result of a business combination consisting almost entirely of conventional gas assets that Devon no longer owns.

As a result of performing the goodwill impairment test described in Note 1, Devon concluded the implied fair value of its Canadian goodwill was zero as of December 31, 2014. This conclusion was largely based on the significant decline in benchmark oil prices, particularly after OPEC's decision not to reduce its production targets that was announced in late November 2014. Consequently, in the fourth quarter of 2014, Devon wrote off its remaining Canadian goodwill and recognized a $1.9 billion impairment.

Other Intangible Assets

As of December 31, 2014, intangible assets associated with customer relationships had a gross carrying amount of $569 million and $36 million of accumulated amortization. The weighted-average amortization period for the customer relationships is 13.7 years. Amortization expense for intangibles was approximately $36 million for the year ended December 31, 2014. Other intangible assets are reported in other long-term assets in the accompanying consolidated balance sheets.

The following table summarizes the estimated aggregate amortization expense for the next five years.

Year	Amortization Amount (In millions)
2015	$45
2016	$45
2017	$45
2018	$45
2019	$44

13. Debt and Related Expenses

A summary of Devon's debt is as follows:

	December 31, 2014	December 31, 2013
	(In millions)	
Devon debt		
Commercial paper	$ 932	$ 1,317
5.625% due January 15, 2014	—	500
Floating rate due December 15, 2015	500	500
2.40% due July 15, 2016	—	500
Floating rate due December 15, 2016	350	350
1.20% due December 15, 2016	—	650
1.875% due May 15, 2017	—	750
8.25% due July 1, 2018	125	125
2.25% due December 15, 2018	750	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	(18)	(20)
Total Devon debt	9,239	12,022
EnLink debt		
Credit facilities	237	—
2.70% due April 1, 2019	400	—
7.125% due June 1, 2022	163	—
4.40% due April 1, 2024	550	—
5.60% due April 1, 2044	350	—
5.05% due April 1, 2045	300	—
Net premium on debentures and notes	23	—
Total EnLink debt	2,023	—
Total debt	11,262	12,022
Less amount classified as short-term debt (1)	1,432	4,066
Total long-term debt	$ 9,830	$ 7,956

(1) 2014 short-term debt consists of $932 million of commercial paper and $500 million floating rate due on December 15, 2015. 2013 short-term debt consists of $2.25 billion of senior notes issued in conjunction with the GeoSouthern acquisition, $1.3 billion of commercial paper and $500 million of senior notes due January 15, 2014.

Debt maturities as of December 31, 2014, excluding premiums and discounts, are as follows (in millions):

2015	$ 1,432
2016	350
2017	—
2018	875
2019	1,337
2020 and thereafter	7,263
Total	$11,257

Credit Lines

Devon has a $3.0 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility). The maturity date for $30 million of the Senior Credit Facility is October 24, 2017. The maturity date for $164 million of the Senior Credit Facility is October 24, 2018. The maturity date for the remaining $2.8 billion is October 24, 2019. 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, 2014, 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 consolidated 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, 2014, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 20.9 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, 2014, Devon's commercial paper borrowings of $932 million have a weighted-average borrowing rate of 0.44 percent.

Retirement of Senior Notes

On November 13, 2014, Devon redeemed $1.9 billion of senior notes prior to their scheduled maturity, primarily with proceeds received from its asset divestitures. The redemption includes the 2.4% $500 million senior notes due 2016, the 1.2% $650 million senior notes due 2016 and the 1.875% $750 million senior notes due 2017. The notes were redeemed for $1.9 billion, which included 100 percent of the principal amount and a make-whole premium of $40 million. On the date of redemption, these notes also had an unamortized discount of $2 million and unamortized debt issuance costs of $6 million. The make-whole premium, unamortized discounts and debt issuance costs are included in net financing costs on the accompanying 2014 consolidated comprehensive statement of earnings.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2014 and 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 $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 (1)	650
2.25% due December 15, 2018	750
Discount and issuance costs	(2)
Net proceeds	$2,248

(1) The 1.20% $650 million note due December 15, 2016 was redeemed on November 13, 2014.

The senior notes were classified as short-term debt on Devon's consolidated balance sheet as of December 31, 2013 due to certain redemption features in the event that the GeoSouthern acquisition was not completed on or prior to June 30, 2014. On February 28, 2014, the GeoSouthern acquisition closed and thus the senior notes were subsequently classified as long-term debt.

Additionally, during December 2013, Devon entered into a term loan agreement with a group of major financial institutions pursuant to which Devon could draw up to $2.0 billion to finance, in part, the GeoSouthern acquisition and to pay transaction costs. In February 2014, Devon drew the $2.0 billion of term loans for the GeoSouthern transaction, and the amount was subsequently repaid on June 30, 2014 with the Canadian divestiture proceeds that were repatriated to the U.S. in June 2014, at which point the term loan was terminated.

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 (1)	$ 750	$ —	$ —	$ —
3.25% due May 15, 2022	1,000	—	—	—
4.75% due May 15, 2042	750	—	—	—
2.40% due July 15, 2016 (1)	—	500	—	—
4.00% due July 15, 2021	—	500	—	—
5.60% due July 15, 2041	—	1,250	—	—
5.625% due January 15, 2014 (2)	—	—	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

(1) The 1.875% $750 million note due May 15, 2017 and 2.4% $500 million note due July 15, 2016 were redeemed on November 13, 2014.
(2) The 5.625% $500 million note due January 15, 2014 was redeemed upon maturity.

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, 2014, 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.

EnLink Debt

All of EnLink’s and the General Partner’s debt is non-recourse to Devon.

The table below summarizes the fair value of EnLink's debt as of March 7, 2014, the formation date of EnLink. The premiums are being amortized using the effective interest method.

	March 7, 2014 Fair Value of Debt	Effective Rate of Debt
	(In millions)	
8.875% due February 15, 2018 (principal of $725 million) (1)	$ 760	7.7%
7.125% due June 1, 2022 (principal of $197 million)	226	5.3%
Credit facilities	468	
Total long-term debt	$1,454	

(1) The 2018 senior notes were redeemed on April 18, 2014.

EnLink has a $1.0 billion unsecured revolving credit facility. As of December 31, 2014, there were $14 million in outstanding letters of credit and $237 million outstanding borrowings under the $1.0 billion credit facility, leaving $749 million available for future borrowing.

The $1.0 billion credit facility matures on the fifth anniversary of the initial funding date, which was March 7, 2014, unless EnLink requests, and the requisite lenders agree, to extend it pursuant to its terms. On February 5, 2015, the commitments under EnLink's credit facility were increased to $1.5 billion, and the maturity date was extended by a year to March 7, 2020.

The credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of EnLink's consolidated indebtedness to consolidated EBITDA (as defined in the credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If EnLink consummates one or more acquisitions in which the aggregate purchase price is $50 million or more, the maximum allowed ratio of EnLink's consolidated indebtedness to consolidated EBITDA may increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Additionally, as of December 31, 2014, E2 Energy Services, LLC had certain promissory notes outstanding related to its vehicle fleet in the amount of $0.4 million due in increments through July 2017.

The General Partner also has a $250 million revolving credit facility. As of December 31, 2014, the General Partner had no outstanding borrowings under the $250 million credit facility.

The $250 million credit facility will mature on March 7, 2019. The credit facility contains certain financial, operational and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter, and include (i) maintaining a maximum consolidated leverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated funded indebtedness to consolidated earnings before interest, taxes, depreciation, amortization and certain other noncash charges) of 4.00 to 1.00, provided that the maximum consolidated leverage ratio is 4.50 to 1.00 during an acquisition period (as defined in the credit facility) and (ii) maintaining a minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other noncash charges to consolidated interest charges) of 2.50 to 1.00 at all times unless an investment grade event (as defined in the credit facility) occurs. EnLink and the General Partner are in compliance with all such covenants as of December 31, 2014.

On March 19, 2014, EnLink issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400 million aggregate principal amount of its 2.70% senior notes due 2019, $450 million aggregate principal amount of its 4.40% senior notes due 2024 and $350 million aggregate principal amount of its 5.60% senior notes due 2044, at discounts of their face value. The 2019 notes mature on April 1, 2019, the 2024 notes mature on April 1, 2024 and the 2044 notes mature on April 1, 2044. The interest payments on the notes are due semi-annually in arrears in April and October.

On November 12, 2014, EnLink issued $100 million aggregate principal amount of its 4.40% senior notes due 2024 and $300 million aggregate principal amount of its 5.05% senior notes due 2045, at a premium and discount, respectively, of their face value. The 2024 notes were offered as an additional issue of EnLink's outstanding 4.40% senior notes due 2024, issued in an aggregate principal amount of $450 million on March 19, 2014. The 2024 notes and the notes issued March 19, 2014 are treated as a single class of debt securities and have identical terms, other than the issue date. The 2045 notes mature on April 1, 2045, and interest payments on the 2045 notes are due semi-annually in arrears in April and October.

Net Financing Costs

The following schedule includes the components of net financing costs.

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Interest based on debt outstanding	$546	$466	$440
Early retirement of debt	48	—	—
Capitalized interest	(70)	(56)	(48)
Other fees and expenses	12	27	14
Interest expense	536	437	406
Interest income	(10)	(20)	(36)
Net financing costs	$526	$417	$370

14. Asset Retirement Obligations

The schedule below summarizes changes in asset retirement obligations.

	Year Ended December 31,	
	2014	2013
	(In millions)	
Asset retirement obligations as of beginning of period	$2,228	$2,095
Liabilities incurred	97	112
Liabilities settled	(56)	(83)
Revision of estimated obligation	70	104
Liabilities assumed by others	(953)	(28)
Accretion expense on discounted obligation	89	115
Foreign currency translation adjustment	(76)	(87)
Asset retirement obligations as of end of period	1,399	2,228
Less current portion	60	88
Asset retirement obligations, long-term	$1,339	$2,140

During 2014, Devon reduced its asset retirement obligation by $953 million for those obligations that were assumed by purchasers of Devon's Canadian and U.S. divested oil and gas properties.

15. 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 $25 million and $27 million at December 31, 2014 and 2013, respectively and is included in other long-term assets in the accompanying consolidated balance sheets. For the remaining nonqualified plans for which trusts have not been established, benefits are funded from Devon's available cash and cash equivalents.

Devon also has defined benefit postretirement plans that provide benefits for substantially all U.S. employees. The plans provide medical and, in some cases, life insurance benefits and are either contributory or non-contributory, depending on the type of plan. Benefit obligations for such plans are estimated based on Devon's future cost-sharing intentions. Devon's funding policy for the plans is to fund the benefits as they become payable with available cash and cash equivalents.

Benefit Obligations and Funded Status

The following table presents the funded status of Devon's qualified and nonqualified pension and postretirement benefit plans. The benefit obligation for pension plans represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for pension plans was $1.2 billion and $1.1 billion at December 31, 2014 and 2013, respectively. Devon's benefit obligations and plan assets are measured each year as of December 31. The projected benefit obligation for Devon's qualified plans was fully funded as of December 31, 2014 and 2013.

	Pension Benefits		Postretirement Benefits	
	2014	2013	2014	2013
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,177	$1,360	$ 24	$ 34
Service cost	30	36	1	1
Interest cost	55	51	1	1
Actuarial loss (gain)	203	(158)	—	(3)
Plan amendments	—	2	—	(8)
Plan settlements	(4)	—	—	—
Foreign exchange rate changes	(3)	(2)	—	—
Participant contributions	—	—	2	3
Benefits paid	(81)	(112)	(4)	(4)
Benefit obligation at end of year	1,377	1,177	24	24
Change in plan assets:				
Fair value of plan assets at beginning of year	1,006	1,165	—	—
Actual return on plan assets	200	(57)	—	—
Employer contributions	29	11	2	1
Participant contributions	—	—	2	3
Plan settlements	(4)	—	—	—
Benefits paid	(81)	(112)	(4)	(4)
Foreign exchange rate changes	(1)	(1)	—	—
Fair value of plan assets at end of year	1,149	1,006	—	—
Funded status at end of year	$ (228)	$ (171)	$ (24)	$ (24)
Amounts recognized in balance sheet:				
Other long-term assets	$ 22	$ 47	$—	$—
Other current liabilities	(10)	(12)	(3)	(3)
Other long-term liabilities	(240)	(206)	(21)	(21)
Net amount	$ (228)	$ (171)	$ (24)	$ (24)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 317	$ 279	$ (11)	$ (13)
Prior service cost (credit)	19	23	(9)	(11)
Total	$ 336	$ 302	$ (20)	$ (24)

The plan assets for pension benefits in the table above exclude the assets held in trusts for the nonqualified plans. However, employer contributions for pension benefits in the table above include $10 million and $11 million for 2014 and 2013, 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, 2014 and 2013, as presented in the table below.

	December 31, 2014	December 31, 2013
	(In millions)	
Projected benefit obligation	$250	$218
Accumulated benefit obligation	$191	$179
Fair value of plan assets	$—	$—

Net Periodic Benefit Cost and Other Comprehensive Earnings

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

	Pension Benefits			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 30	$ 36	$ 43	$ 1	$ 1	$ 1
Interest cost	55	51	60	1	1	1
Expected return on plan assets	(54)	(62)	(64)	—	—	—
Curtailment and settlement expense	1	—	26	—	—	1
Recognition of net actuarial loss (gain) (1)	18	22	24	(1)	(1)	(1)
Recognition of prior service cost (1)	4	4	3	(2)	(1)	(1)
Total net periodic benefit cost (2)	54	51	92	(1)	—	1
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	57	(39)	37	—	(3)	(4)
Prior service cost (credit) arising in current year	—	2	14	—	(8)	—
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost	(19)	(22)	(45)	1	1	1
Recognition of prior service cost, including curtailment, in net periodic benefit cost	(4)	(4)	(8)	2	1	1
Total other comprehensive loss (earnings)	34	(63)	(2)	3	(9)	(2)
Total recognized	$ 88	$ (12)	$ 90	$ 2	$ (9)	$ (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 consolidated comprehensive statements of earnings.

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 2015.

	Pension Benefits	Postretirement Benefits
	(In millions)	
Net actuarial loss (gain)	$21	$(1)
Prior service cost (credit)	4	(2)
Total	$25	$(3)

Assumptions

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

	Pension Benefits			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Assumptions to determine benefit obligations:						
Discount rate	3.90%	4.80%	3.85%	3.25%	3.65%	3.30%
Rate of compensation increase	4.49%	4.48%	4.48%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	4.80%	3.85%	4.65%	3.65%	3.30%	4.25%
Rate of compensation increase	4.49%	4.48%	4.97%	N/A	N/A	N/A
Expected return on plan assets	5.42%	5.48%	5.48%	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. As a result of the discount rate decrease, Devon's benefit obligations increased approximately $135 million for the year ended December 31, 2014.

Rate of compensation increase – For measurement of the 2014 benefit obligation for the pension plans, a 4.49 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.

Mortality rate assumptions – In 2014, the Society of Actuaries issued updated versions of its mortality tables and mortality improvement scale, reflecting the increasing life expectancies in the United States. While not required to strictly adhere to this data, Devon utilized actuary-produced mortality tables and an improvement scale derived from the updated tables and the actuary's best estimate of mortality for the population of participants in Devon's plans. As a result of the mortality rate assumption update, Devon's benefit obligation increased approximately $61 million for the year ended December 31, 2014.

Other assumptions – For measurement of the 2014 benefit obligation for the other postretirement medical plans, a 7.7 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for

2015. 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, 2014 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.

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,	
	2014	2013
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, 2014				
			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	35.2%	$ 405	$ 50	$355	$—
Corporate bonds	31.7%	364	269	95	—
Other bonds	2.6%	30	30	—	—
Total fixed-income securities	69.5%	799	349	450	—
Equity securities:					
Global (large, mid, small cap)	17.2%	197	—	197	—
Other securities:					
Hedge fund and alternative investments	9.7%	112	—	—	112
Short-term investments	3.6%	41	15	26	—
Total other securities	13.3%	153	15	26	112
Total investments	100.0%	$1,149	$364	$673	$112

	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 and alternative investments	12.5%	127	15	—	112
Short-term investments	1.9%	19	—	19	—
Total other securities	14.4%	146	15	19	112
Total investments	100.0%	$1,006	$401	$493	$112

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 cash and commingled, short-term investment funds. The short-term investment funds' securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by investment managers.

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

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

December 31, 2012	$103
Investment returns	9
December 31, 2013	112
Disbursements	(6)
Investment returns	6
December 31, 2014	$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 2015 contributions	$ 10	$3
Benefit payments:		
2015	$ 73	$3
2016	$ 75	$3
2017	$ 79	$3
2018	$ 82	$3
2019	$ 86	$2
2020 to 2024	$466	$8

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 2015, the $10 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

Independent of EnLink, 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. EnLink also maintains a 401(k) plan covering eligible employees. The following table presents expense related to these defined contribution plans.

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
401(k) and enhanced contribution plans	$49	$41	$36
Canadian pension and savings plans	20	26	23
Total	$69	$67	$59

16. Stockholders' Equity

The authorized capital stock of Devon consists of 1.0 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.

Dividends

Devon paid common stock dividends of $386 million, $348 million and $324 million in 2014, 2013 and 2012, respectively. The quarterly cash dividend was $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 and to $0.24 per share in the second quarter of 2014.

Stock Option Proceeds

Devon received $93 million, $3 million and $27 million from stock option proceeds in 2014, 2013 and 2012, respectively.

17. Noncontrolling Interests

Acquisition of Noncontrolling Interests

In March 2014, EnLink was formed as a publicly traded consolidated subsidiary of Devon to provide midstream services to Devon and third parties. Devon obtained approximately 120.5 million units, or a 52% ownership interest, as a result of this transaction. Approximately 92.7 million units were issued to the public for a 41% ownership interest, with the remaining 7% ownership interest held by the General Partner.

Distributions to Noncontrolling Interests

In conjunction with the formation of the General Partner in the first quarter of 2014, Devon made a payment of $100 million to noncontrolling interests. Further, EnLink and the General Partner distributed $135 million to non-Devon unitholders during 2014.

Subsidiary Equity Transactions

Periodically, EnLink enters into Equity Distribution Agreements ("EDAs") facilitating the selling of common units representing limited partner interests. In 2014, EnLink sold approximately 14.8 million common units under these EDAs, generating net proceeds of approximately $410 million. EnLink used the net proceeds for general partnership purposes, to fund working capital, capital expenditures and debt repayments. Subsequent to these sales, Devon's ownership interest in EnLink was 49%.

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 does not currently believe that it is subject to material exposure with respect to such royalty matters.

Environmental Matters

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

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, 2014.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases
		(In millions)		
2015	$ 663	$234	$ 943	$ 72
2016	809	116	919	50
2017	885	77	890	50
2018	920	13	856	45
2019	895	1	334	39
Thereafter	1,134	5	1,142	149
Total	$5,306	$446	$5,084	$405

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. The value of the drilling obligations reported is based on gross contractual value.

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 $64 million, $26 million and $42 million in 2014, 2013 and 2012, respectively.

19. Fair Value Measurements

The following tables provide carrying value and fair value measurement information for certain of Devon's financial assets and liabilities. The carrying values of cash, accounts receivable, other current receivables, accounts payable, other current payables and accrued expenses included in the accompanying consolidated balance sheets approximated fair value at December 31, 2014 and December 31, 2013. Therefore, such financial assets and liabilities are not presented in the following tables. Additionally, information regarding the fair values of midstream, goodwill and pension plan assets is provided in Note 5, Note 12 and Note 15, respectively.

			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2014 assets (liabilities):					
Cash equivalents	$ 950	$ 950	$ 340	$ 610	$—
Oil, gas and NGL commodity derivatives	$ 1,968	$ 1,968	$ —	$ 1,968	$—
Oil, gas and NGL commodity derivatives	$ (51)	$ (51)	$ —	$ (51)	$—
Midstream commodity derivatives	$ 27	$ 27	$ —	$ 27	$—
Midstream commodity derivatives	$ (5)	$ (5)	$ —	$ (5)	$—
Interest rate derivatives	$ 1	$ 1	$ —	$ 1	$—
Interest rate derivatives	$ (1)	$ (1)	$ —	$ (1)	$—
Foreign currency derivatives	$ 8	$ 8	$ —	$ 8	$—
Debt	$(11,262)	$(12,472)	$ —	$(12,472)	$—
Capital lease obligations	$ (20)	$ (20)	$ —	$ (20)	$—
December 31, 2013 assets (liabilities):					
Cash equivalents	$ 5,305	$ 5,305	$4,191	$ 1,114	$—
Long-term investments	$ 62	$ 62	$ —	$ —	$ 62
Oil, gas and NGL commodity derivatives	$ 103	$ 103	$ —	$ 103	$—
Oil, gas and NGL commodity derivatives	$ (120)	$ (120)	$ —	$ (120)	$—
Foreign currency derivatives	$ (1)	$ (1)	$ —	$ (1)	$—
Debt	$(12,022)	$(12,908)	$ —	$(12,908)	$—

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

Level 1 Fair Value Measurements

Cash equivalents – Amounts consist primarily of U.S. and Canadian treasury securities and money market investments. The fair value approximates the carrying value.

Level 2 Fair Value Measurements

Cash equivalents – 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 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 are the carrying values.

Capital lease obligations – The fair value was calculated using inputs from third-party banks.

Level 3 Fair Value Measurements

Long-term investments – Devon's long-term investments as of December 31, 2013 consisted entirely of auction rate securities. In the first quarter of 2014, Devon redeemed all these securities for approximately $57 million, or $5 million below their carrying value.

20. Discontinued Operations

In 2012, Devon incurred a loss related to discontinued operations of $16 million ($21 million net of taxes) for the sale of assets in Angola. Devon did not have operating revenues related to discontinued operations during 2012.

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 U.S. and Canadian segments are both primarily engaged in oil and gas exploration and production activities, and certain information regarding such activities for each segment is included in Note 22.

With the formation of EnLink in the first quarter of 2014, Devon considers EnLink, combined with the General Partner, to be an operating segment that is distinct from its existing operating segments. EnLink's operations consist of midstream assets and operations located across the U.S. Additionally, EnLink has a management team that is primarily responsible for capital and resource allocation decisions. Therefore, EnLink is presented as a separate reporting segment. For the reporting periods prior to the formation of EnLink, Devon has reclassified, from its U.S. segment to the EnLink segment, all asset-level amounts related to the midstream assets that it contributed to EnLink.

	U.S.	Canada	EnLink	Eliminations	Total
			(In millions)		
Year Ended December 31, 2014:					
Revenues from external customers	$14,862	$ 2,063	$ 2,641	$ —	$19,566
Intersegment revenues	$ —	$ —	$ 859	$ (859)	$ —
Depreciation, depletion and amortization	$ 2,479	$ 560	$ 280	$ —	$ 3,319
Asset impairments	$ 12	$ 1,941	$ —	$ —	$ 1,953
Gains and losses on asset sales	$ 5	$ (1,077)	$ —	$ —	$ (1,072)
Interest expense	$ 441	$ 85	$ 54	$ (44)	$ 536
Earnings (loss) before income taxes	$ 4,388	$ (657)	$ 328	$ —	$ 4,059
Income tax expense	$ 1,797	$ 495	$ 76	$ —	$ 2,368
Net earnings (loss)	$ 2,591	$ (1,152)	$ 252	$ —	$ 1,691
Net earnings attributable to noncontrolling interests	$ 1	$ —	$ 83	$ —	$ 84
Net earnings (loss) attributable to Devon	$ 2,590	$ (1,152)	$ 169	$ —	$ 1,607
Property and equipment, net	$24,572	$ 6,790	$ 4,934	$ —	$36,296
Total assets	$32,147	$ 8,517	$10,097	$ (124)	$50,637
Capital expenditures	$11,245	$ 1,344	$ 970	$ —	$13,559
Year Ended December 31, 2013:					
Revenues from external customers	$ 6,807	$ 2,656	$ 934	$ —	$10,397
Intersegment revenues	$ —	$ —	$ 1,362	$(1,362)	$ —
Depreciation, depletion and amortization	$ 1,744	$ 849	$ 187	$ —	$ 2,780
Asset impairments	$ 1,133	$ 843	$ —	$ —	$ 1,976
Interest expense	$ 392	$ 80	$ —	$ (35)	$ 437
Earnings (loss) before income taxes	$ 495	$ (532)	$ 186	$ —	$ 149
Income tax expense (benefit)	$ 258	$ (156)	$ 67	$ —	$ 169
Net earnings (loss)	$ 237	$ (376)	$ 119	$ —	$ (20)
Property and equipment, net	$18,201	$ 8,478	$ 1,768	$ —	$28,447
Total assets	$27,080	$13,560	$ 2,237	$ —	$42,877
Capital expenditures	$ 4,589	$ 1,841	$ 213	$ —	$ 6,643
Year Ended December 31, 2012:					
Revenues from external customers	$ 6,098	$ 2,600	$ 803	$ —	$ 9,501
Intersegment revenues	$ —	$ —	$ 1,105	$(1,105)	$ —
Depreciation, depletion and amortization	$ 1,679	$ 987	$ 145	$ —	$ 2,811
Asset impairments	$ 1,845	$ 163	$ 16	$ —	$ 2,024
Interest expense	$ 343	$ 82	$ —	$ (19)	$ 406
Earnings (loss) before income taxes	$ (372)	$ (73)	$ 128	$ —	$ (317)
Income tax expense (benefit)	$ (143)	$ (35)	$ 46	$ —	$ (132)
Net earnings (loss)	$ (229)	$ (38)	$ 82	$ —	$ (185)
Property and equipment, net	$16,622	$ 8,955	$ 1,739	$ —	$27,316
Total assets	$22,050	$19,070	$ 2,206	$ —	$43,326
Capital expenditures	$ 6,159	$ 1,963	$ 352	$ —	$ 8,474

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, 2014		
	U.S.	Canada	Total
		(In millions)	
Property acquisition costs:			
Proved properties	$ 5,210	$ —	$ 5,210
Unproved properties	1,176	1	1,177
Exploration costs	270	52	322
Development costs	4,400	1,063	5,463
Costs incurred	$11,056	$1,116	$12,172

	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

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, 2014, our partners' remaining commitments to fund our future costs associated with these joint venture transactions totaled approximately $250 million.

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 $376 million, $368 million and $359 million in the years 2014, 2013 and 2012, respectively. Also, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $45 million, $42 million and $36 million in the years 2014, 2013 and 2012, respectively.

Capitalized Costs

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

	December 31, 2014		
	U.S.	Canada	Total
		(In millions)	
Proved properties	$ 59,849	$ 15,889	$ 75,738
Unproved properties	1,460	1,292	2,752
Total oil & gas properties	61,309	17,181	78,490
Accumulated DD&A	(38,213)	(11,347)	(49,560)
Net capitalized costs	$ 23,096	$ 5,834	$ 28,930

	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

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2014.

	Costs Incurred In				
	2014	2013	2012	Prior to 2012	Total
			(In millions)		
Acquisition costs	$ 973	$127	$140	$650	$1,890
Exploration costs	111	76	68	107	362
Development costs	103	48	121	69	341
Capitalized interest	43	38	30	48	159
Total oil and gas properties not subject to amortization	$1,230	$289	$359	$874	$2,752

Included in the $2.8 billion of oil and gas properties not subject to amortization are approximately $2.2 billion of costs that Devon deems significant for individual assessment. These costs primarily relate to investments in the Pike thermal oil project in Canada and the Eagle Ford in Texas. Based on Devon's development plans, Pike costs will begin to be included in the amortization computation when the first phase of this project is fully approved and Devon subsequently begins recognizing the associated proved reserves. Devon is evaluating and developing the newly acquired Eagle Ford properties over the next four to five years.

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.

	December 31, 2014		
	U.S.	Canada	Total
		(In millions)	
Oil, gas and NGL sales	$ 7,867	$2,043	$ 9,910
Lease operating expenses	(1,559)	(773)	(2,332)
General and administrative expenses	(153)	(57)	(210)
Production and property taxes	(466)	(37)	(503)
Depreciation, depletion and amortization	(2,365)	(531)	(2,896)
Gain on sale of assets	—	1,077	1,077
Accretion of asset retirement obligations	(49)	(39)	(88)
Income tax expense	(1,199)	(568)	(1,767)
Results of operations [(1)]	$ 2,076	$1,115	$ 3,191
Depreciation, depletion and amortization per Boe	$ 11.41	$13.80	$ 11.79

(1) In the fourth quarter of 2014, Devon recognized a $1.9 billion Canadian goodwill impairment that is not reflected in this table.

	December 31, 2013		
	U.S.	Canada	Total
		(In millions)	
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

	December 31, 2012		
	U.S.	Canada	Total
		(In millions)	
Oil, gas and NGL sales	$ 4,679	$ 2,474	$ 7,153
Lease operating expenses	(1,059)	(1,015)	(2,074)
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

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, 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
Revisions due to prices	(1)	—	(1)
Revisions other than price	(38)	1	(37)
Extensions and discoveries	94	5	99
Purchase of reserves	132	—	132
Production	(48)	(10)	(58)
Sale of reserves	(17)	(29)	(46)
December 31, 2014	351	23	374
Proved developed reserves as of:			
December 31, 2011	146	73	219
December 31, 2012	166	62	228
December 31, 2013	194	56	250
December 31, 2014	255	23	278
Proved developed-producing reserves as of:			
December 31, 2011	139	65	204
December 31, 2012	155	56	211
December 31, 2013	178	51	229
December 31, 2014	224	19	243
Proved undeveloped reserves as of:			
December 31, 2011	22	7	29
December 31, 2012	39	3	42
December 31, 2013	35	—	35
December 31, 2014	96	—	96

	Bitumen (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
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
Revisions due to prices	—	(37)	(37)
Revisions other than price	—	18	18
Extensions and discoveries	—	8	8
Production	—	(20)	(20)
December 31, 2014	—	521	521
Proved developed reserves as of:			
December 31, 2011	—	90	90
December 31, 2012	—	99	99
December 31, 2013	—	111	111
December 31, 2014	—	137	137
Proved developed-producing reserves as of:			
December 31, 2011	—	90	90
December 31, 2012	—	99	99
December 31, 2013	—	111	111
December 31, 2014	—	137	137
Proved undeveloped reserves as of:			
December 31, 2011	—	367	367
December 31, 2012	—	429	429
December 31, 2013	—	441	441
December 31, 2014	—	384	384

	Gas (Bcf)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
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
Revisions due to prices	191	45	236
Revisions other than price	(299)	4	(295)
Extensions and discoveries	335	8	343
Purchase of reserves	457	—	457
Production	(660)	(41)	(701)
Sale of reserves	(923)	(738)	(1,661)
December 31, 2014	7,651	36	7,687
Proved developed reserves as of:			
December 31, 2011	7,957	951	8,908
December 31, 2012	7,391	679	8,070
December 31, 2013	7,707	752	8,459
December 31, 2014	6,948	36	6,984
Proved developed-producing reserves as of:			
December 31, 2011	7,409	862	8,271
December 31, 2012	7,091	624	7,715
December 31, 2013	7,425	680	8,105
December 31, 2014	6,746	34	6,780
Proved undeveloped reserves as of:			
December 31, 2011	1,550	28	1,578
December 31, 2012	1,371	5	1,376
December 31, 2013	843	6	849
December 31, 2014	703	—	703

	Natural Gas Liquids (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
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
Revisions due to prices	7	1	8
Revisions other than price	2	—	2
Extensions and discoveries	47	—	47
Purchase of reserves	57	—	57
Production	(50)	(1)	(51)
Sale of reserves	(37)	(23)	(60)
December 31, 2014	578	—	578
Proved developed reserves as of:			
December 31, 2011	402	26	428
December 31, 2012	431	20	451
December 31, 2013	468	23	491
December 31, 2014	486	—	486
Proved developed-producing reserves as of:			
December 31, 2011	372	24	396
December 31, 2012	406	19	425
December 31, 2013	442	21	463
December 31, 2014	467	—	467
Proved undeveloped reserves as of:			
December 31, 2011	123	1	124
December 31, 2012	140	—	140
December 31, 2013	84	—	84
December 31, 2014	92	—	92

	Total (MMBoe) (1)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
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
Revisions due to prices	38	(29)	9
Revisions other than price	(86)	21	(65)
Extensions and discoveries	197	14	211
Purchase of reserves	265	—	265
Production	(207)	(39)	(246)
Sale of reserves	(207)	(176)	(383)
December 31, 2014	2,205	549	2,754
Proved developed reserves as of:			
December 31, 2011	1,875	348	2,223
December 31, 2012	1,829	294	2,123
December 31, 2013	1,947	315	2,262
December 31, 2014	1,900	165	2,065
Proved developed-producing reserves as of:			
December 31, 2011	1,746	323	2,069
December 31, 2012	1,743	278	2,021
December 31, 2013	1,857	297	2,154
December 31, 2014	1,815	162	1,977
Proved undeveloped reserves as of:			
December 31, 2011	403	379	782
December 31, 2012	407	433	840
December 31, 2013	258	443	701
December 31, 2014	305	384	689

(1) Gas reserves are converted to Boe at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Bitumen and natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

Proved Undeveloped Reserves

The following table presents the changes in Devon's total proved undeveloped reserves during 2014 (in MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2013	258	443	701
Extensions and discoveries	153	8	161
Revisions due to prices	(1)	(34)	(35)
Revisions other than price	(61)	18	(43)
Sale of reserves	(4)	(2)	(6)
Conversion to proved developed reserves	(40)	(49)	(89)
Proved undeveloped reserves as of December 31, 2014	305	384	689

At December 31, 2014, Devon had 689 MMBoe of proved undeveloped reserves. This represents a 2 percent decrease as compared to 2013 and represents 25 percent of total proved reserves. Drilling and development activities increased Devon's proved undeveloped reserves 161 MMBoe and resulted in the conversion of 89 MMBoe, or 13 percent, of the 2013 proved undeveloped reserves to proved developed reserves. Costs incurred related to the development and conversion of Devon's proved undeveloped reserves were approximately $1.0 billion for 2014. Additionally, revisions other than price decreased Devon's proved undeveloped reserves 43 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, which were approximately 69 MMBoe, relate to the dry-gas areas in the Barnett Shale in north Texas.

A significant amount of Devon's proved undeveloped reserves at the end of 2014 related to its Jackfish operations. At December 31, 2014 and 2013, Devon's Jackfish proved undeveloped reserves were 384 MMBoe and 441 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 and steam-oil ratios. Furthermore, development of these projects involves the up-front construction of steam injection/distribution and bitumen processing facilities. Due to the large up-front capital investments and large reserves required to provide economic returns, the project conditions meet the specific circumstances requiring a period greater than 5 years for conversion to developed reserves. 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

2014 – Reserves increased 9 MMBoe primarily due to higher gas prices in the Barnett Shale and the Anadarko Basin, partially offset by higher bitumen prices, which result in lower after-royalty volumes, in Canada.

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.

Revisions Other Than Price

Total revisions other than price for 2014, 2013 and 2012 primarily related to Devon's evaluation of certain dry gas regions, with the largest revisions being made in the Cana-Woodford Shale and Barnett Shale.

Extensions and Discoveries

2014 – Of the 211 MMBoe of extensions and discoveries, 70 MMBoe related to the Permian Basin in west Texas and southeast New Mexico, 54 MMBoe related to the Eagle Ford in south Texas, 36 MMBoe related to the Barnett Shale, 14 MMBoe related to the Anadarko Basin, 8 MMBoe related to Jackfish and 14 MMBoe related to the Mississippian-Woodford Trend in north Oklahoma.

The 2014 extensions and discoveries included 5 MMBoe related to additions from Devon's infill drilling activities, primarily consisting of 4 MMBoe at the Permian Basin.

2013 – Of the 261 MMBoe of extensions and discoveries, 76 MMBoe related to the Permian Basin, 54 MMBoe related to the Barnett Shale, 42 MMBoe related to the Anadarko Basin, 38 MMBoe related to Jackfish and 32 MMBoe related to the Mississippian-Woodford Trend.

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.

Purchase of Reserves

2014 – Of the 265 MMBoe of reserves purchases, 246 MMBoe related to Devon's GeoSouthern acquisition in the Eagle Ford.

Sale of Reserves

2014 – The total 383 MMBoe of reserves sales related to Devon's asset divestitures in the U.S. and Canada.

Standardized Measure

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

	Year Ended December 31, 2014		
	U.S.	Canada	Total
		(In millions)	
Future cash inflows	$ 75,847	$ 31,371	$107,218
Future costs:			
Development	(7,168)	(3,619)	(10,787)
Production	(29,740)	(14,232)	(43,972)
Future income tax expense	(11,021)	(3,026)	(14,047)
Future net cash flow	27,918	10,494	38,412
10% discount to reflect timing of cash flows	(12,819)	(5,119)	(17,938)
Standardized measure of discounted future net cash flows	$ 15,099	$ 5,375	$ 20,474

	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

	Year Ended December 31, 2012		
	U.S.	Canada	Total
		(In millions)	
Future cash inflows	$ 55,297	$ 33,570	$ 88,867
Future costs:			
Development	(6,556)	(6,211)	(12,767)
Production	(24,265)	(16,611)	(40,876)
Future income tax expense	(6,542)	(1,992)	(8,534)
Future net cash 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

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 2014 estimates, Devon's future realized prices were assumed to be $87.14 per barrel of oil, $57.25 per barrel of bitumen, $3.94 per Mcf of gas and $25.05 per barrel of natural gas liquids. Of the $10.8 billion of future development costs as of the end of 2014, $2.2 billion, $1.9 billion and $1.0 billion are estimated to be spent in 2015, 2016 and 2017, 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 $1.5 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.

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

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Beginning balance	$15,741	$13,221	$17,844
Net changes in prices and production costs	2,561	3,018	(9,889)
Oil, bitumen, gas and NGL sales, net of production costs	(6,865)	(5,613)	(4,388)
Changes in estimated future development costs	(768)	399	(1,094)
Extensions and discoveries, net of future development costs	4,836	4,047	4,669
Purchase of reserves	6,422	14	18
Sales of reserves in place	(2,384)	(44)	(25)
Revisions of quantity estimates	(746)	(1,040)	162
Previously estimated development costs incurred during the period	1,933	1,986	1,321
Accretion of discount	1,746	1,940	1,420
Other, primarily changes in timing and foreign exchange rates	(107)	(583)	113
Net change in income taxes	(1,895)	(1,604)	3,070
Ending balance	$20,474	$15,741	$13,221

23. Supplemental Quarterly Financial Information (Unaudited)

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

	2014				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Operating revenues	$ 3,725	$4,510	$5,336	$5,995	$19,566
Earnings (loss) before income taxes	$ 560	$1,554	$1,654	$ 291	$ 4,059
Net earnings (loss) attributable to Devon	$ 324	$ 675	$1,016	$ (408)	$ 1,607
Basic net earnings (loss) per share attributable to Devon	$ 0.80	$ 1.65	$ 2.48	$ (1.01)	$ 3.93
Diluted net earnings (loss) per share attributable to Devon	$ 0.79	$ 1.64	$ 2.47	$ (1.01)	$ 3.91

	2013				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
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) attributable to Devon	$(1,339)	$ 683	$ 429	$ 207	$ (20)
Basic net earnings (loss) per share attributable to Devon	$ (3.34)	$ 1.69	$ 1.06	$ 0.51	$ (0.06)
Diluted net earnings (loss) per share attributable to Devon	$ (3.34)	$ 1.68	$ 1.05	$ 0.51	$ (0.06)

Net Earnings (Loss) Attributable to Devon

The fourth quarter of 2014 includes asset impairments of $1.9 billion (or $4.79 per diluted share) as discussed in Note 5.

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

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

Not Applicable.

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

Disclosure Controls and Procedures

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

Based on their evaluation, our principal executive and principal financial officers have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2014 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 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (the "2013 COSO Framework"). Based on this evaluation under the 2013 COSO Framework, which was completed on February 18, 2015, management concluded that its internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 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, 2014, 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 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

Not Applicable.

PART III

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2015.

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, 2015.

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, 2015.

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, 2015.

Item 14. ***Principal Accountant 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, 2015.

PART IV

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

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

1. Consolidated Financial Statements

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

2. Consolidated Financial Statement Schedules

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

3. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger dated 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; File No. 001-32318).
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; File No. 001-32318).
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 May 19, 2014; File No. 001-32318).
2.4	Letter Agreement dated February 28, 2014 amending certain provisions of the Purchase and Sale Agreement dated November 20, 2013 among GeoSouthern Intermediate Holdings, LLC, GeoSouthern Energy Corporation and Devon Energy Production Company, L.P.
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; File No. 001-32318).
3.2	Registrant's Bylaws (incorporated by reference to Exhibit 3.2 of Registrant's Form 8-K filed June 8, 2012; File No. 001-32318).
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; File No. 001-32318).
4.1	Indenture, dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed July 12, 2011; File No. 001-32318).
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 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; File No. 001-32318).

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 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; File No. 001-32318).
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 and the 2.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed December 19, 2013; File No. 001-32318).
4.5	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee (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).
4.17	Registrant has not filed instruments defining the rights of holders of long-term indebtedness of Registrant's majority owned subsidiary, EnLink Midstream Partners, LP, none of which exceeds ten percent of the total assets of Registrant and its subsidiaries on a consolidated basis. Registrant hereby agrees to furnish a copy of any such agreements to the Commission upon request.
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; File No. 001-32318).
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; File No. 001-32318).
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; File No. 001-32318).

Exhibit No.	Description
10.4	Extension Agreement dated as of October 17, 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, 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 the extension of the maturity date from October 24, 2018 to October 24, 2019 (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed November 5, 2014; File No. 001-32318).
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; File No. 001-32318).*
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; File No. 001-32318).*
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; File No. 001-32318).*
10.10	Devon Energy Corporation Non-Qualified Deferred Compensation Plan Amended and Restated Effective as of April 15, 2014 (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed August 6, 2014; File No. 001-32318).*
10.11	Devon Energy Corporation Amendment 2014-2, executed May 9, 2014, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan as amended effective April 15, 2014.*
10.12	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; File No. 001-32318).*
10.13	Devon Energy Corporation Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.6 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.14	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; File No. 001-32318).*
10.15	Devon Energy Corporation Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.7 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
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; File No. 001-32318).*
10.17	Devon Energy Corporation Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.8 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*

Exhibit No.	Description
10.18	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; File No. 001-32318).*
10.19	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; File No. 001-32318).*
10.20	Devon Energy Corporation Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.9 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.21	Devon Energy Corporation Incentive Savings Plan, as amended and restated effective January 1, 2014, executed September 22, 2014.*
10.22	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; File No. 001-32318).*
10.23	Form of Amendment No. 1 to the Amended and Restated 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 April 19, 2011. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed April 25, 2011; File No. 001-32318).*
10.24	Form of Employment Agreement between Registrant and Tony D. Vaughn and Thomas L. Mitchell dated June 10, 2013 (Amended and Restated Form of Employment Agreement dated December 15, 2008 (Exhibit 10.22 above), as amended by Amendment No. 1 thereto dated April 19, 2011 (Exhibit 10.23 above)) (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*
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 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; File No. 001-32318).*
10.26	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; File No. 001-32318).*
10.27	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, Thomas L. Mitchell, 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 10.25 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*

Exhibit No.	Description
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 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); File No. 001-32318*
10.29	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, Thomas L. Mitchell, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and Tony D. Vaughn for performance based restricted stock awarded.*
10.30	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; File No. 001-32318).*
10.31	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 (incorporated by reference to Exhibit 10.28 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*
10.32	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, Thomas L. Mitchell, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and Tony D. Vaughn for performance based restricted share units awarded.*
10.33	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; File No. 001-32318).*
10.34	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; File No. 001-32318).*
10.35	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; File No. 001-32318).*
10.36	Form of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and Thomas L. Mitchell for restricted stock awarded (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*

Exhibit No.	Description
10.37	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 (incorporated by reference to Exhibit 10.33 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*
10.38	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; File No. 001-32318).*
10.41	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; File No. 001-32318). *
12	Statement of computations of ratios 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.
32.2	Certification of principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of LaRoche Petroleum Consultants, Ltd.
99.2	Report of Deloitte.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Compensatory plans or arrangements

SIGNATURES

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

DEVON ENERGY CORPORATION

By: /s/ JOHN RICHELS
John Richels
President and Chief Executive Officer

February 20, 2015

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 20, 2015
/s/ THOMAS L. MITCHELL Thomas L. Mitchell	Executive Vice President and Chief Financial Officer (Principal financial officer)	February 20, 2015
/s/ JEREMY D. HUMPHERS Jeremy D. Humphers	Senior Vice President and Chief Accounting Officer (Principal accounting officer)	February 20, 2015
/s/ J. LARRY NICHOLS J. Larry Nichols	Executive Chairman of the Board	February 20, 2015
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 20, 2015
/s/ JOHN E. BETHANCOURT John E. Bethancourt	Director	February 20, 2015
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 20, 2015
/s/ JOHN A. HILL John A. Hill	Director	February 20, 2015
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 20, 2015
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 20, 2015
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 20, 2015
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 20, 2015

Directors

J. Larry Nichols
Executive Chairman, Devon Energy Corporation

John Richels
Vice Chairman
President and Chief Executive Officer, Devon Energy Corporation

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

Barbara M. Baumann (1) (3)
Owner and President, Cross Creek Energy Corporation

John E. Bethancourt (2) (3) (4)
Retired Executive Vice President, Technology and Services, Chevron Corporation

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

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

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

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

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

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

Senior Executives

John Richels
President and Chief Executive Officer

David A. Hager
Chief Operating Officer

Thomas L. Mitchell
Executive Vice President and Chief Financial Officer

R. Alan Marcum
Executive Vice President, Administration

Frank W. Rudolph
Executive Vice President, Human Resources

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

Lyndon C. Taylor
Executive Vice President and General Counsel

Tony D. Vaughn
Executive Vice President, Exploration and Production

Other Executives

Sue Alberti
Senior Vice President, Marketing

Rob Dutton
Senior Vice President, Canadian Division and President, Devon Canada

David G. Harris
Senior Vice President, Business Development

Jeremy D. Humphers
Senior Vice President and Chief Accounting Officer

Bill Penhall
Senior Vice President, Exploration and Strategic Services

Jeffrey L. Ritenour
Senior Vice President, Corporate Finance and Treasurer

Howard J. Thill
Senior Vice President, Communications and Investor Relations

Other Information

Investor Relations Contacts
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Scott Coody, Director, Investor Relations
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Shea Snyder, Director, Investor Communications
Telephone: (405) 552-4782

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John Porretto, Manager, Media Relations
Telephone: (405) 228-7506

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

Computershare Trust Company, N.A.
PO Box 43078
Providence, RI 02940-3078
Toll free: (877) 860-5820
Website: www.computershare.com/investor

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

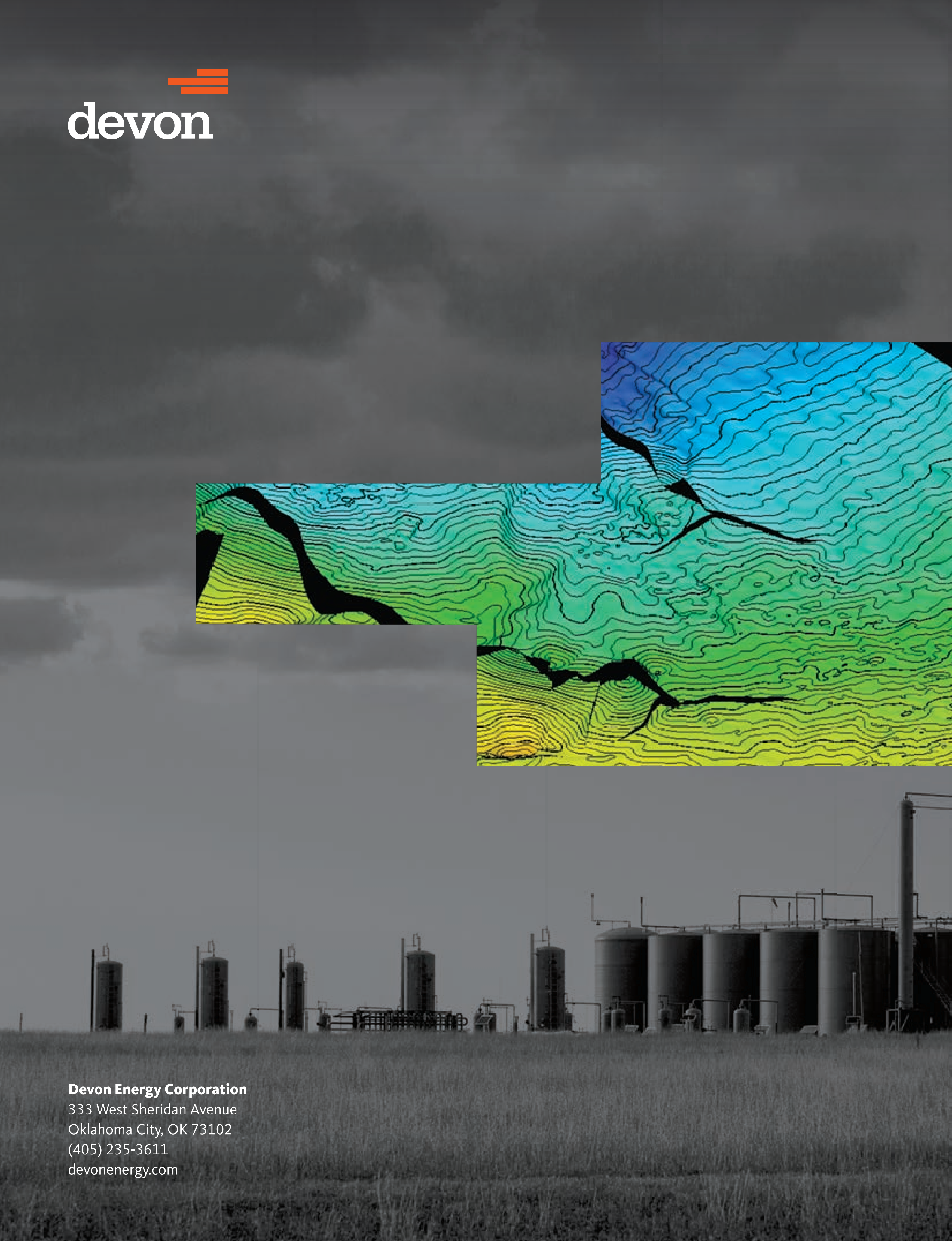
Annual Meeting
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 3, 2015, at the Devon Energy Center Auditorium, 333 West Sheridan Avenue, Oklahoma City, OK.

Independent Auditors
KPMG LLP
Oklahoma City, OK

Stock Trading Data
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 8,500 shareholders of record.

Additional Information
This report, Devon's Corporate Social Responsibility Report and other information about the company are available at www.devonenergy.com.

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



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