

DEVON ENERGY CORP/DE
Form 10-K
February 20, 2015
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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

(State of other jurisdiction of incorporation or organization)

73-1567067

(I.R.S. Employer identification No.)

333 West Sheridan Avenue, Oklahoma City, Oklahoma

(Address of principal executive offices)

73102-5015

(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

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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.

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PART I

Items 1 and 2. *Business and Properties*

General

Devon Energy Corporation (Devon) is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and 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.

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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.

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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.

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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			Gross Wells Drilled
	MMBoe	% of Total	% Liquids	MBoe/d	% of Total	% Liquids	
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.

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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.

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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 CO₂ Flood (Oklahoma);

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West Loco Hills Unit Waterflood and CO₂ 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;

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oversee and evaluate our compliance with legal and regulatory requirements related to our reserves;

review the qualifications and independence of our independent engineering consultants; and

monitor the performance of our independent engineering consultants.

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The following table presents our estimated 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.

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

Year Ended December 31,	Oil (MBbls/d)	Bitumen (MBbls/d)	Production 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

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The following table summarizes our development and exploratory drilling results.

Year Ended December 31,	Development Wells ⁽¹⁾		Exploratory Wells ⁽¹⁾		Total Wells ⁽¹⁾		Total
	Productive	Dry	Productive	Dry	Productive	Dry	
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⁾

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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

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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.

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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%	

Table of Contents***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;

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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

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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;

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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.

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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

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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

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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

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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.

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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.

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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.

Table of Contents**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 Per Share
	High	Low	
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

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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.

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.

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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.

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

Introduction

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

Overview of 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.

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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.

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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.

Table of Contents*Oil, Gas and NGL Production*

	2014	Year Ended December 31, 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

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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

Table of Contents*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 (In millions)	NGLs	Total
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

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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

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	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
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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.

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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)

	2014	Change	Year Ended December 31, 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

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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)

	2014	Year Ended December 31,		2012	
		Change	2013		Change
(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

	2014	Year Ended December 31,		2012	
		Change	2013		Change
(\$ 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%

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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,		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

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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.

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	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.

Table of Contents**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

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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

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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

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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.

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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.

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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.

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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

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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.

	Total	Payments Due by Period			More Than 5 Years
		Less Than 1 Year	1-3 Years (In millions)	3-5 Years	
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.

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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

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- (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.

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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.

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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

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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.

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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.

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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

Table of Contents**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.

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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.

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Item 8. *Financial Statements and Supplementary Data*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 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

Table of Contents**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)

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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.

Table of Contents**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

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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.

Table of Contents**DEVON ENERGY CORPORATION AND SUBSIDIARIES****CONSOLIDATED BALANCE SHEETS**

	December 31, 2014 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

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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.

Table of Contents**DEVON ENERGY CORPORATION AND SUBSIDIARIES****CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY**

	Common Stock		Additional	Retained	Accumulated Other Comprehensive	Treasury	Noncontrolling	Total
	Shares	Amount	Paid-In Capital	Earnings	Earnings (In millions)	Stock	Interests	Stockholders Equity
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

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Balance as of December 31, 2014	409	\$	41	\$	4,088	\$	16,631	\$	779	\$	4,802	\$	26,341
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See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Devon Energy Corporation (Devon) is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Devon s operations are concentrated in various North American onshore areas in the U.S. and Canada. Devon also owns natural gas pipelines, plants and treatment facilities 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;

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and that are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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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	1.0x
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:	

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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.

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- (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.

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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 Partners 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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 w