Devon Energy

2017 Letter to Shareholders and Form 10-K

Commitment Runs Deep

Letter to Shareholders

The year 2017 represented an inflection point for Devon as we built operating momentum across our U.S. resource plays and dramatically improved the profitability of our business. It also brought into clear focus our **2020 Vision** – a strategy to accelerate value creation for our shareholders by delivering capital-efficient, cash-flow growth in the years ahead.

As we focus forward, we're confident in our ability to execute our strategy. Some highlights from 2017 help to illustrate why:

- Our operating cash flow nearly doubled during the year and we generated free cash flow that allowed us to grow our cash balances by $700 million in 2017.
- This improved profitability was driven by strong growth in Devon's highest-margin product, U.S. oil production, which contributed to a 57 percent increase in per-unit operating margins during 2017.
- With capital programs focused in the Delaware Basin and STACK, we increased U.S. oil reserves by 32 percent while delivering the best well productivity in our 46-year history.

Devon's 2020 Vision is a three-year plan that is underpinned by our focus on maximizing returns on the capital we invest in our oil and natural gas operations. In 2018, we expect to invest $2.3 billion in our upstream properties, with this activity concentrated in the economic core of the Delaware and STACK plays. This focused activity will allow us to bring online at least 25 percent more wells than in 2017, with similar capital investment. Additionally, this program is self-funded at a conservative $50 WTI price point, and we're positioned to deliver meaningful free cash flow at today's market prices.

In addition to focusing on **capital efficiency** through more measured and consistent investments across our upstream business, we're also well positioned to **maximize and expand cash flow**. We'll accomplish this as we deploy leading technologies to further optimize well performance and aggressively reduce costs to get the most value out of every barrel produced.

We also intend to **simplify our portfolio**. With our Delaware and STACK assets rapidly building momentum and operating scale, we're committed to simplifying our asset portfolio by selling less competitive assets. We will sell assets only at the right price as market conditions allow to ensure we generate the appropriate value for our shareholders. Given our resource-rich asset base, we see the potential to monetize more than $5 billion of non-core assets. Over time, we expect to operate more effectively and deliver significantly improved financial results with a more focused asset portfolio.

Another key component of our strategy is to further improve our investment-grade **financial strength**. We're targeting a net debt-to-EBITDA ratio of 1 to 1.5 times, which would represent a top-tier balance sheet in the E&P space. We fundamentally believe the combination of low debt leverage and ample liquidity is vital to our success and a major competitive advantage.

As we pursue our vision to be North America's premier independent oil and natural gas exploration and production company, we're providing reliable, environmentally responsible production and a platform for future growth. As we execute our strategy, we'll **return increasing amounts of cash to shareholders** through higher dividends and opportunistic share buybacks. Already in 2018 we've announced a 33 percent dividend increase, a $1 billion share-repurchase program and a $1 billion debt-reduction plan. To be clear, this is just the beginning, and we expect more of these shareholder-friendly actions in the near future.

Change is everywhere, but our values are the same – hire the best people, do the right thing, be a team player, be a good neighbor, deliver results. We do these things for all of our stakeholders. Working safely and operating responsibly, we'll expect to get the job done, and done right.

Sincerely,

Dave Hager
President and CEO

April 9, 2018

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, 2017

or

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

Commission File Number 001-32318

devon

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

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

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

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

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

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

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

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

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

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

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

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

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐	
Smaller reporting company ☐	Emerging growth company ☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2017 was approximately $16.7 billion, based upon the closing price of $31.97 per share as reported by the New York Stock Exchange on such date. On February 7, 2018, 526.1 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's definitive Proxy Statement relating to Registrant's 2018 annual meeting of stockholders have been incorporated by reference in Part III of this Annual Report on Form 10-K.

DEVON ENERGY CORPORATION
FORM 10-K
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DEFINITIONS

Unless the context otherwise indicates, references to "us," "we," "our," "ours," "Devon," the "Company" and "Registrant" refer to Devon Energy Corporation and its consolidated subsidiaries. All monetary values, other than per unit and per share amounts, are stated in millions of U.S. dollars unless otherwise specified. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

"2009 Plan" means the Devon Energy Corporation 2009 Long-Term Incentive Plan, as amended and restated.

"2015 Plan" means the Devon Energy Corporation 2015 Long-Term Incentive Plan, as amended and restated.

"2017 Plan" means the Devon Energy Corporation 2017 Long-Term Incentive Plan.

"ASC" means Accounting Standards Codification.

"ASU" means Accounting Standards Update.

"Bbl" or "Bbls" means barrel or barrels.

"Bcf" means billion cubic feet.

"BLM" means the United States Bureau of Land Management.

"Boe" means barrel of oil equivalent. Gas proved reserves and production are converted to Boe, at the pressure and temperature base standard of each respective state in which the gas is produced, 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.

"Btu" means British thermal units, a measure of heating value.

"Canada" means the division of Devon encompassing oil and gas properties located in Canada. All dollar amounts associated with Canada are in U.S. dollars, unless stated otherwise.

"Canadian Plan" means Devon Canada Corporation Incentive Savings Plan.

"DD&A" means depreciation, depletion and amortization expenses.

"Devon Financing" means Devon Financing Company, L.L.C.

"Devon Plan" means Devon Energy Corporation Incentive Savings Plan.

"EMH" means EnLink Midstream Holdings, LP.

"EnLink" means EnLink Midstream Partners, L.P., a master limited partnership.

"EPA" means the United States Environmental Protection Agency.

"FASB" means Financial Accounting Standards Board.

"Federal Funds Rate" means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

"G&A" means general and administrative expenses.

"GAAP" means U.S. generally accepted accounting principles.

"General Partner" means EnLink Midstream, LLC, the indirect general partner entity of EnLink.

"GeoSouthern" means GeoSouthern Energy Corporation.

"Inside FERC" refers to the publication *Inside F.E.R.C.'s Gas Market Report.*

"LIBOR" means London Interbank Offered Rate.

"LOE" means lease operating expenses.

"MBbls" means thousand barrels.

"MBoe" means thousand Boe.

"Mcf" means thousand cubic feet.

"MLP" means master limited partnership.

"MMBbls" means million barrels.

"MMBoe" means million Boe.

"MMBtu" means million Btu.

"MMcf" means million cubic feet.

"M&M operations" means marketing and midstream revenues minus marketing and midstream expenses.

"N/M" means not meaningful.

"NGL" or "NGLs" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"NYSE" means New York Stock Exchange.

"OPEC" means Organization of the Petroleum Exporting Countries.

"OPIS" means Oil Price Information Service.

"PHMSA" means United States Department of Transportation Pipeline and Hazardous Materials Safety Administration.

"SEC" means United States Securities and Exchange Commission.

"Senior Credit Facility" means Devon's syndicated unsecured revolving line of credit.

"Standardized measure" means the present value of after-tax future net revenues discounted at 10% per annum.

"S&P 500 Index" means Standard and Poor's 500 index.

"Tax Reform Legislation" means Tax Cuts and Jobs Act.

"TSR" means total shareholder return.

"Upstream operations" means upstream revenues minus production expenses.

"U.S." means United States of America.

"VEX" means Victoria Express Pipeline and related truck terminal and storage assets.

"WTI" means West Texas Intermediate.

"/d" means per day.

"/gal" means per gallon.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" as defined by the SEC. Such statements include those concerning strategic plans, our expectations and objectives for future operations, as well as other future events or conditions, and are often identified by use of the words "expects," "believes," "will," "would," "could," "forecasts," "projections," "estimates," "plans," "expectations," "targets," "opportunities," "potential," "anticipates," "outlook" and other similar terminology. Such forward-looking statements are based on our examination of historical operating trends, the information used to prepare our December 31, 2017 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, including, but not limited to:

- the volatility of oil, gas and NGL prices;
- uncertainties inherent in estimating oil, gas and NGL reserves;
- the extent to which we are successful in acquiring and discovering additional reserves;
- the uncertainties, costs and risks involved in oil and gas operations;
- regulatory restrictions, compliance costs and other risks relating to governmental regulation, including with respect to environmental matters;
- risks related to our hedging activities;
- counterparty credit risks;
- risks relating to our indebtedness;
- cyberattack risks;
- our limited control over third parties who operate some of our oil and gas properties;
- midstream capacity constraints and potential interruptions in production;
- the extent to which insurance covers any losses we may experience;
- competition for leases, materials, people and capital;
- our ability to successfully complete mergers, acquisitions and divestitures; and
- any of the other risks and uncertainties discussed in this report.

All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements above. We assume no duty to update or revise our forward-looking statements based on new information, future events or otherwise.

PART I

Items 1 and 2. *Business and Properties*

General

A Delaware corporation formed in 1971, and publicly held since 1988, Devon (NYSE: DVN) is an independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Our operations are concentrated in various North American onshore areas in the U.S. and Canada. Additionally, we control EnLink, a publicly traded MLP with an integrated midstream business with significant size and scale in key operating regions in the U.S. For additional information regarding our control of, and ownership interest in, EnLink and its indirect general partner, the General Partner, see Note 20 in "Item 8. Financial Statements and Supplementary Data" of this report.

Our principal and administrative offices are located at 333 West Sheridan, Oklahoma City, OK 73102-5015 (telephone 405-235-3611). As of December 31, 2017, Devon and its consolidated subsidiaries had approximately 4,900 employees, of which approximately 1,500 employees are employed by 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, 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. The corporate governance documents available on our website include our Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, and any amendments to and waivers from any provision of that Code will also be posted on our website. 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. Reports filed with the SEC are also made available on its website at www.sec.gov.

Devon Strategy

Devon is committed to delivering consistent top-quartile shareholder return among its peer group through a highly engaged culture focused on innovation, safety, operational excellence, environmental stewardship and social responsibility. We also maintain a strong commitment to financial strength and flexibility through all commodity price cycles, as reflected in the company's investment grade credit ratings.

Devon's "2020 Vision" is our plan through the end of the decade intended to optimize returns and deliver top-tier capital-efficient, cash-flow growth. Our 2020 Vision is focused on the following strategic priorities:

- Maximize cash flow by optimizing base production and reducing per-unit cash costs;
- Improve capital efficiency with a concentration of investment on highest-returning development projects in the Delaware Basin and STACK;
- Simplify our portfolio by monetizing non-core assets;
- Improve financial strength by reducing debt; and
- Return cash to shareholders.

Our portfolio of exploration and production assets and operations provides stable, environmentally responsible production and a platform for future growth. In 2017, we continued the development of our world-class operations in the STACK and Delaware Basin. These assets provide us with a sustainable, multi-decade growth platform that continues to improve with our successful drilling programs. During 2017, we delivered the best well productivity in Devon's 46-year history and continued a five-year streak of increasing Devon's initial 90-day production rates. With investments in proprietary data tools, predictive analytics and artificial intelligence, we are delivering industry-leading, initial-rate well productivity and improving the performance of our established wells. Devon has more than doubled its onshore North American oil production since 2012 and has a deep inventory of development opportunities to deliver future oil growth.

As we enter 2018 and look toward the future, we expect to achieve additional efficiencies across our portfolio. We expect to fund activity within our cash flow, and remain committed to allocating capital in a disciplined manner to maximize value and return. We believe we capture the full value of our assets and improve returns through maximizing our base production and optimizing our capital program. The activities that support this strategy include minimizing controllable downtime, enhancing well productivity, ensuring disciplined project execution, performing premier technical work, focusing on developmental drilling and reducing our operating and capital costs.

We also continue to implement new shareholder-friendly initiatives, which include new returns-based metrics aligned to employee compensation and the conversion to successful efforts accounting which provides greater transparency into our financial performance.

EnLink Strategy

EnLink focuses on providing gathering, transmission, processing, storage, fractionation and marketing to upstream oil and natural gas producers, including Devon.

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. Furthermore, 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.

EnLink's primary business objective is to provide stable cash flow, while growing through prudent and profitable investments. EnLink accomplishes its objectives through long-term, fee-based contracts and maintaining a strong financial position through a conservative and balanced capital structure highlighted by its investment grade status. EnLink has consistently demonstrated expertise within the MLP space and continues to employ a proven business model that includes growing, expanding and executing on its strategy within top basins where Devon and other successful upstream producers operate.

Oil and Gas Properties

Property Profiles

Key summary data from each of our areas of operation as of and for the year ended December 31, 2017 are detailed in the map below. Notes 23 and 24 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.

Led by results from our franchise assets, STACK and Delaware Basin, Devon achieved the best drilling results in our 46-year history. Our initial 90-day production rates in 2017 increased more than 400% from 2012 levels. These productivity improvements were driven by activity focused in top resource plays, improved subsurface reservoir characterization, leading-edge completion designs and improvements in lateral placement. The most significant reserves growth came from our U.S. operations, where we replaced approximately 150% of our 2017 production with proved reserves additions from the drill bit.

Delaware Basin – The Delaware Basin is one of Devon's top-two franchise assets and continues to offer exploration and low-risk development opportunities from many geologic reservoirs and play types, including the oil-rich Bone Spring, Delaware, Wolfcamp and Leonard formations. We expect these oil and liquids-rich opportunities across our acreage in the Delaware Basin to deliver high-margin growth for many years to come. During 2017, our continued appraisal and development work enabled us to increase our proved reserves by approximately 60%. At

December 31, 2017, we had eight operated rigs developing this asset. In 2018, we plan to invest approximately $725 million of capital in the Delaware Basin as we shift to expanded development operations, primarily focused on the Bone Spring formation.

STACK – The STACK development, located primarily in Oklahoma's Canadian, Kingfisher and Blaine counties, is one of Devon's top-two franchise assets. Devon is currently targeting the Woodford Shale and the Meramec zones. Our STACK position is one of the largest and best in the industry, providing visible long-term growth. Completion design enhancements have resulted in greater productivity and improved economics. Drilling activity in the Meramec has produced record setting initial production across our core position in the oil and liquids window. At December 31, 2017, we had nine operated rigs with drilling focused in the Meramec formation. In 2018, we plan approximately $700 million of capital investment and expect to accelerate full-field development activity.

Heavy Oil – Our operations in Canada are focused on our heavy oil assets in Alberta, Canada. Our most significant Canadian operation is our Jackfish complex, an industry-leading thermal heavy oil operation in the non-conventional oil sands of east central Alberta. We employ a recovery method known as steam-assisted gravity drainage at Jackfish. The Jackfish operation consists of three facilities. We expect Jackfish to maintain a reasonably flat production profile for greater than 20 years requiring approximately $200 million of annual maintenance capital based on current economic conditions.

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, 2017. With our 50% partner, we continue to evaluate our development timeline for Pike. The majority of our Pike leasehold does not expire until 2025 and 2026.

In addition to Jackfish and Pike, we hold acreage and own producing assets in the Bonnyville region, located to the south and east of Jackfish in eastern Alberta. Bonnyville is a low-risk, high margin oil development play that produces heavy oil by conventional means, without the need for steam injection.

In 2018, we plan approximately $275 million of capital investment in our Canadian Heavy Oil business.

Eagle Ford – We acquired our position in the Eagle Ford in 2014, with acres located in DeWitt and Lavaca counties in south Texas. In 2017, we closed on the sale of our Lavaca assets for approximately $200 million. Since acquiring these assets, we have delivered tremendous results by producing 119 million oil-equivalent barrels. Our excellent results are driven by our development in DeWitt County, located in the economic core of the play. With the highest margins in our portfolio, our Eagle Ford assets generated significant cash flow in 2017. In 2018, we plan approximately $250 million of capital investment.

Rockies Oil – Our acreage in the Rockies is focused on emerging oil opportunities in the Powder River Basin and the Wind River Basin. 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. As of December 31, 2017, we had one operated rig targeting the Turner formation in northern Converse County of the Powder River Basin. In 2018, we plan approximately $150 million of capital investment.

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 Johnson County assets are currently being marketed as part of our non-core divestiture program. Since acquiring a substantial position in this field in 2002, we continue to introduce technology and new innovations to optimize production operations and have transformed this asset into one of the top producing gas fields in North America. Given the sustained low gas price environment, we continue to focus on enhancing existing well performance through re-fracturing, artificial lift and line pressure reduction projects. In 2018, we plan on minimal development activity, with planned capital investment of up to $50 million to optimize base production and further de-risk future development resources.

Proved Reserves

For estimates of our proved developed and proved undeveloped reserves and the discussion of the contribution by each property, see Note 24 in "Item 8. Financial Statements and Supplementary Data" of this report.

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, 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 Director and key members of the Group have appropriate technical qualifications to oversee the preparation of reserves estimates. The Group reports to and is managed through our finance department. No portion of the Group's compensation is directly dependent on the quantity of reserves booked.

The Director of the Group has approximately 30 years of industry experience with positions of increasing responsibility for the estimation and evaluation of reserves. He has been employed by Devon for the past 17 years, including the past 10 in his current position. His further professional qualifications include a degree in petroleum engineering, registered professional engineer, member of the Society of Petroleum Engineers and 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.

Throughout the year, the Group performs internal reserves reviews of each operating country's reserves. The Group also oversees audits and reserves estimates performed by qualified third-party petroleum consulting firms. During 2017, we engaged two such firms to audit approximately 88% of our proved reserves in accordance with generally accepted petroleum engineering and evaluation methods and procedures. LaRoche Petroleum Consultants, Ltd. audited approximately 85% of our 2017 U.S. reserves, and Deloitte LLP audited approximately 99% of our Canadian reserves.

In addition to conducting these internal reviews and external reserves audits, 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 members of our Reserves Committee 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 third-party petroleum consultants.

The following tables present production, price and cost information for each significant field, country and continent.

Year Ended December 31,	Production				
	Oil (MMBbls)	Bitumen (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
2017					
Barnett Shale	—	—	237	14	54
STACK	9	—	107	11	38
Jackfish	—	40	—	—	40
U.S.	42	—	433	36	150
Canada	7	40	6	—	48
Total North America	49	40	439	36	198
2016					
Barnett Shale	—	—	265	15	60
STACK	7	—	103	9	33
Jackfish	—	40	—	—	40
U.S.	47	—	510	42	174
Canada	8	40	7	—	49
Total North America	55	40	517	42	223
2015					
Barnett Shale	—	—	291	17	66
STACK	3	—	86	8	25
Jackfish	—	31	—	—	31
U.S.	60	—	579	50	206
Canada	10	31	8	—	42
Total North America	70	31	587	50	248

Year Ended December 31,	Average Sales Price				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Production Cost (Per Boe) [(1)]
2017					
Barnett Shale	$ 49.72	$ —	$ 2.47	$ 13.67	$ 6.86
STACK	$ 48.43	$ —	$ 2.40	$ 17.78	$ 4.72
Jackfish	$ —	$ 29.38	$ —	$ —	$ 11.02
U.S.	$ 49.41	$ —	$ 2.48	$ 15.66	$ 6.74
Canada	$ 33.73	$ 29.38	N/M	$ —	$ 11.70
Total North America	$ 47.31	$ 29.38	$ 2.48	$ 15.66	$ 7.94
2016					
Barnett Shale	$ 41.03	$ —	$ 1.76	$ 10.31	$ 5.75
STACK	$ 39.81	$ —	$ 1.91	$ 10.86	$ 4.34
Jackfish	$ —	$ 19.82	$ —	$ —	$ 8.70
U.S.	$ 38.92	$ —	$ 1.84	$ 9.81	$ 6.44
Canada	$ 23.96	$ 19.82	N/M	$ —	$ 9.36
Total North America	$ 36.72	$ 19.82	$ 1.84	$ 9.81	$ 7.08
2015					
Barnett Shale	$ 46.47	$ —	$ 2.00	$ 9.62	$ 5.96
STACK	$ 43.73	$ —	$ 2.22	$ 8.97	$ 5.39
Jackfish	$ —	$ 23.41	$ —	$ —	$ 12.43
U.S.	$ 44.01	$ —	$ 2.14	$ 9.32	$ 7.52
Canada	$ 30.58	$ 23.41	N/M	$ —	$ 13.18
Total North America	$ 42.12	$ 23.41	$ 2.14	$ 9.32	$ 8.48

(1) Represents production expense per BOE excluding production and property taxes. Jackfish and Canada include purchases of natural gas used to heat the heavy oil reservoirs. The gas is purchased at prevailing market prices, which vary from year to year.

Drilling Statistics

The following table summarizes our development and exploratory drilling results.

	Development Wells (1)		Exploratory Wells (1)		Total Wells (1)		
Year Ended December 31,	**Productive**	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**	**Total**
2017							
U.S.	149.8	—	44.0	—	193.8	—	193.8
Canada	100.5	—	—	—	100.5	—	100.5
Total North America	250.3	—	44.0	—	294.3	—	294.3
2016							
U.S.	88.5	—	36.4	2.0	124.9	2.0	126.9
Canada	21.5	—	—	—	21.5	—	21.5
Total North America	110.0	—	36.4	2.0	146.4	2.0	148.4
2015							
U.S.	298.6	1.8	40.7	—	339.3	1.8	341.1
Canada	79.0	—	—	—	79.0	—	79.0
Total North America	377.6	1.8	40.7	—	418.3	1.8	420.1

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

The following table presents the wells that were in progress on December 31, 2017. As of February 1, 2018, these wells were still in progress.

	Gross (1)	Net (2)
U.S.	26.0	10.1
Canada	5.0	5.0
Total North America	31.0	15.1

(1) Gross wells are the sum of all wells in which we own a working 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, 2017.

	Oil Wells (1)		Natural Gas Wells		Total Wells (1)	
	Gross (2)(4)	Net (3)	Gross (2)(4)	Net (3)	Gross (2)(4)	Net (3)
U.S.	9,165	3,379	10,103	7,245	19,268	10,624
Canada	3,195	3,085	590	413	3,785	3,498
Total North America	12,360	6,464	10,693	7,658	23,053	14,122

(1) Includes bitumen wells.
(2) Gross wells are the sum of all wells in which we own a working interest.

(3) Net wells are gross wells multiplied by our fractional working interests in each well.
(4) Includes 821 and 367 gross oil and gas wells, respectively, which had multiple completions.

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions. We are the operator of approximately 14,600 gross wells. As operator, we receive reimbursement for direct expenses incurred to perform our duties, as well as monthly per-well producing, drilling, and construction 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 G&A, 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, 2017. Of our 4.3 million net acres, approximately 2.3 million acres are held by production. The acreage in the table includes 0.1 million, 0.2 million and 0.1 million net acres subject to leases that are scheduled to expire during 2018, 2019 and 2020, respectively. As of December 31, 2017, there were no proved undeveloped reserves associated with our expiring acreage. Of the 0.4 million net acres set to expire by December 31, 2020, we anticipate performing 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 2017, we allowed approximately 0.2 million acres to expire.

	Developed		Undeveloped		Total	
	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]
			(Thousands)			
U.S.	1,808	1,203	3,587	1,598	5,395	2,801
Canada	685	504	2,091	968	2,776	1,472
Total North America	2,493	1,707	5,678	2,566	8,171	4,273

(1) Gross acres are the sum of all acres in which we own a working 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, a preliminary title investigation, typically consisting of a review of local title records, is made at the time of acquisitions of undeveloped properties. More thorough title investigations, which generally include a review of title records and the preparation of title opinions by outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

EnLink Midstream Properties

EnLink represents the primary component of our midstream operations. EnLink's assets are comprised of systems and other assets located in four primary regions:

- *Texas* – The Texas assets consist of natural gas gathering, processing and transmission operations in north Texas and the Midland and Delaware Basins in west Texas.
- *Oklahoma* – The Oklahoma assets consist of natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, STACK and Central Northern Oklahoma Woodford shale areas.
- *Louisiana* – The Louisiana assets consist of natural gas pipelines, natural gas processing plants, gas and NGL storage facilities, fractionation facilities and NGL pipelines located in Louisiana.
- *Crude and Condensate* – The Crude and Condensate assets consist of Ohio River Valley crude oil, condensate, condensate stabilization, natural gas compression and brine disposal activities in the Utica and Marcellus Shales, crude oil operations in the Permian Basin and central Oklahoma, and crude oil activities associated with VEX located in the Eagle Ford Shale.

Marketing Activities

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 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 4 in "Item 8. Financial Statements and Supplementary Data" of this report for further information.

As of January 2018, our production was sold under the following contract terms.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	80%	—	20%	—
Natural gas	52%	4%	44%	—
NGLs	33%	20%	47%	—

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, 2017, we were committed to deliver the following fixed quantities of production.

	Total	Less Than 1 Year	1-3 Years	3-5 Years
Oil and bitumen (MMBbls)	86	31	49	6
Natural gas (Bcf)	293	265	28	—
NGLs (MMBbls)	11	11	—	—
Total (MMBoe)	146	86	54	6

We expect to fulfill our delivery commitments primarily with production from our proved developed reserves. Moreover, our proved reserves have generally been sufficient to satisfy our delivery commitments during the three most recent years, and we expect such reserves will continue to be the primary means of fulfilling our future commitments. However, where our proved reserves are not sufficient to satisfy our delivery commitments, we can and may use spot market purchases to satisfy the commitments.

Customers

During 2017, 2016 and 2015, no purchaser accounted for over 10% of our consolidated sales revenue.

Competition

See "Item 1A. Risk Factors."

Public Policy and Government Regulation

Our industry is subject to a wide range of regulations. 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 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 materially 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, tribal, state, provincial and local laws and regulations. These laws and regulations relate to matters that include:

- acquisition of seismic data;
- location, drilling and casing of wells;
- well design;
- hydraulic fracturing;
- well production;
- spill prevention plans;
- emissions and discharge permitting;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- endangered species and habitat.

Our operations also are subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units; the number of wells that may be drilled in a unit; the rate of production allowable from oil and gas wells; and the unitization or pooling of oil and gas properties. In the U.S., some states allow the forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws 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 or approved by the federal government and administered by the BLM or Bureau of Indian Affairs 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, tribes or tribal members. 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, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. In addition, permitting activities on federal lands are subject to frequent delays.

Royalties and Incentives in Canada

The royalty calculation in Canada is a significant factor in the profitability of Canadian oil and gas production. Oil sands 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. For pre-payout oil sands projects, the regulations prescribe lower royalty rates for oil sands projects until allowable capital costs have been recovered. In early 2016, the Alberta government adopted the recommendation of its Royalty Review Panel. The new royalty framework preserves the existing royalty structure and rates for oil sands. For conventional oil and gas royalty calculations, wells drilled after January 1, 2017 would use the Modernized Royalty Framework (MRF) which prescribes a lower royalty rate until allowable costs have been recovered. The calculation for wells post payout is based on a percentage of production net of allowed deductions and varies with commodity price.

Marketing in Canada

Any oil or gas export requires an exporter to obtain export authorizations from Canada's National Energy Board.

Environmental, Pipeline Safety and Occupational Regulations

We are subject to many federal, state, provincial, tribal and local laws and regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment and natural resources. Environmental laws and regulations relate to:

- the discharge of pollutants into federal, provincial and state waters;
- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials, including hazardous substances;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;

- the development of emergency response and spill contingency plans;
- the monitoring, repair and design of pipelines used for the transportation of oil and natural gas;
- the protection of threatened and endangered species; and
- worker protection.

Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, administrative, civil or criminal fines or penalties or injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. 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 may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

Item 1A. *Risk Factors*

Our business and operations, and our industry in general, are subject to a variety of risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the following risks should occur, our business, financial condition, results of operations and liquidity could be materially and adversely impacted. As a result, holders of our securities could lose part or all of their investment in Devon.

Volatile Oil, Gas and NGL Prices Significantly Impact our Business

Our financial condition, results of operations and the value of our properties 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. Historically, market prices and our realized prices have been volatile. For example, in recent years, NYMEX WTI oil and NYMEX Henry Hub prices ranged from a high of over $100 per Bbl and $6 per MMBtu, respectively, to a low of under $27 per Bbl and $1.70 per MMBtu, respectively. Such volatility is likely to continue in the future due to numerous factors beyond our control, including, but not limited to:

- supply of and demand for oil, gas and NGLs, including consumer demand in emerging markets, such as China and India;
- volatility and trading patterns in the commodity-futures markets;
- conservation and environmental protection efforts;
- production levels of members of OPEC, Russia or other producing countries;
- geopolitical risks, including political and civil unrest in the Middle East, Africa and South America;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes and hurricanes;
- regional pricing differentials;
- differing quality of production, including NGL content of gas produced;
- the level of imports and exports of oil, gas and NGLs and the level of global oil, gas and NGL inventories;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption and production;

- the overall economic environment; and
- governmental regulations and taxes.

Commodity prices began to decline in the second half of 2014 and, despite a moderate recovery, have generally been pressured since then. This commodity price decline adversely affected our business and results of operations and led to substantial impairments to our oil and gas properties during 2015. A sustained weakness or further deterioration in commodity prices could materially and adversely impact our business by resulting in, or exacerbating, the following effects:

- reducing the amount of oil, gas and NGLs that we can produce economically;
- limiting our financial flexibility, liquidity and access to sources of capital, such as equity and debt;
- reducing our revenues, operating cash flows and profitability;
- causing us to decrease our capital expenditures or maintain reduced capital spending for an extended period, resulting in lower future production of oil, gas and NGLs; and
- reducing the carrying value of our properties, resulting in additional noncash write-downs.

Estimates of Oil, Gas and NGL Reserves Are Uncertain and May Be Subject to Revision

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 and appraisal activity, the viability of production under varying economic conditions, including commodity price declines, 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 financial condition and the value of our properties, as well as the estimates of our future net revenue and profitability. Our policies and internal controls related to estimating and recording reserves are included in “Items 1 and 2. Business and Properties” of this report.

Discoveries or Acquisitions of Reserves Are Needed to Avoid a Material Decline in Reserves and Production

The production rates from oil and gas properties generally decline as reserves are depleted, while related per unit production costs generally increase due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future oil, gas and NGL production will decline materially as reserves are produced unless we conduct successful exploration and development activities, such as identifying additional producing zones in existing wells, utilizing secondary or tertiary recovery techniques or acquiring 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.

Oil and Gas Operations Are Uncertain and Involve Substantial Costs and Risks

Our operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, gas and NGLs can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. 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. In addition, our oil and gas properties can become damaged, our operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control, as well as the mishandling or underground migration of fluids and chemicals;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures;
- issues with title or in receiving governmental permits or approvals;
- restricted takeaway capacity for our production, including due to inadequate midstream infrastructure or constrained downstream markets;
- environmental hazards or liabilities;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations; and
- shortages or delays in the availability of services or delivery of equipment.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities. Moreover, certain of these events could result in environmental pollution and impact to third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death or significant damage to property and natural resources.

We Are Subject to Extensive Governmental Regulation, Which Can Change and Could Adversely Impact Our Business

Our operations are subject to extensive federal, state, provincial, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGLs, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. In addition, we may be required to make large expenditures to comply with applicable governmental laws, rules, regulations, permits or orders. For example, certain regulations require the plugging and abandonment of wells and removal of production facilities by current and former operators, which may result in significant costs associated with the removal of tangible equipment and other restorative actions at the end of operations.

In addition, changes in public policy have affected, and in the future could further affect, our operations. Regulatory developments could, among other things, restrict production levels, impose price controls, change environmental protection requirements and increase taxes, royalties and other amounts payable to governments or governmental agencies. 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, pipeline safety, seismic activity, income taxes and climate change, as discussed below.

Hydraulic Fracturing – In recent years, the EPA has made proposals that subject hydraulic fracturing to further regulation and that could potentially restrict the practice of hydraulic fracturing. For example, the EPA has issued final regulations under the federal Clean Air Act establishing performance standards for oil and gas activities, including standards for the capture of air emissions released during hydraulic fracturing and finalized in 2016 regulations that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA also released a study in 2016 finding that certain aspects of hydraulic fracturing, such as water withdrawals and wastewater management practices, could result in impacts to water resources, although the report did not identify a direct link between hydraulic fracturing and impacts to groundwater resources. The BLM previously finalized regulations to regulate hydraulic fracturing on federal lands, but subsequently issued a repeal of those regulations in 2017. Several states in which we operate have already adopted and more states are considering adopting laws and/or regulations that require disclosure of chemicals used in hydraulic fracturing and impose more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations. 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.

Pipeline Safety – The pipeline assets in which we own interests, through EnLink or otherwise, are subject to stringent and complex regulations related to pipeline safety and integrity management. The PHMSA has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect "high consequence areas." Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. For example, in 2016 PHMSA proposed new rules for gas pipelines that extend pipeline safety programs beyond high consequence areas to newly proposed "moderate consequence areas" and would also impose more rigorous testing and reporting requirements on such pipelines. To date, no further action has been taken. More recently, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline's proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. Following the change in presidential administrations, implementation of this rule was delayed, but the final rule is expected to be published in the Federal Register and become effective during the first quarter of 2018. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Seismic Activity – Earthquakes in northern and central Oklahoma and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we are currently defending against certain third-party lawsuits and could be subject to additional claims, seeking alleged property damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Changes to Tax Laws – We are subject to U.S. federal income tax as well as income or capital taxes in various state and foreign jurisdictions, and our operating cash flow is sensitive to the amount of income taxes we must pay. In the jurisdictions in which we operate, income taxes are assessed on our earnings after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types of costs that are considered allowable deductions or the rates assessed on our taxable earnings would all impact our income taxes and resulting operating cash flow. Recently enacted legislation commonly referred to as the Tax Cuts and Jobs Act (the "Tax Reform Legislation") significantly affects U.S. tax law by changing how the U.S. imposes income tax on multinational corporations. These changes include, among others, a permanent reduction to the corporate income tax offset by other items intended to broaden the tax base (for example, by imposing significant additional limitations on the deductibility of interest expense and limiting the ability to deduct net operating losses).

The U.S. Department of Treasury has broad authority to issue regulations and interpretative guidance that may significantly impact how we will apply the law and impact our results of operations in the period issued. Further, compliance with the Tax Reform Legislation and the accounting for such provisions require complex computations and accumulation of information not previously required or regularly produced. As a result, we have provided a provisional estimate in our financial statements of the effect of the Tax Reform Legislation. As additional regulatory guidance is issued by the applicable taxing authorities, as accounting treatment is clarified, as we perform additional analysis on the application of the law, and as we refine estimates in calculating the effect, our final analysis, which will be recorded in the period completed, may be different from our current provisional amounts, which could materially affect our tax obligations and effective tax rate.

Climate Change – Continuing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives to reduce greenhouse gas emissions, such as carbon dioxide and methane. Policy makers at both the U.S. federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations and/or taxes on greenhouse gas emissions. For example, both the EPA and the BLM have issued regulations for the control of methane emissions, which also include leak detection and repair requirements, for the oil and gas industry; however, following the change in presidential administrations, both agencies have published proposed rules that seek to delay implementation of their previously issued methane standards while the agencies review and reconsider both rules. Nevertheless, several states where we operate, including Wyoming, have imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally 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. Carbon taxes could likewise affect us by being based on emissions from our equipment and/or emissions resulting from the use of our products by our customers.

In Canada, greenhouse gas emissions are also being addressed at both the federal and provincial level. Recent climate policies include a legislated oil sands emission limit, and forthcoming policies include methane emissions reduction targets. Beginning January 1, 2018, large industrial emitters are subject to the Carbon Competitiveness Incentive Regulation (CCIR). This regulation prices carbon, but provides cost protection to emission-intensive / trade-exposed industries, including Devon's oil sands operations. The impact to our operations from these regulations is expected to be minimal in the near term. Oil and gas facilities that are not subject to the CCIR are exempt from the economy-wide carbon levy until 2023.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity.

Our Hedging Activities Limit Participation in Commodity Price Increases and Involve Other Risks

We 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. Moreover, as a result of the Dodd-Frank Wall Street Reform and Consumer Protection Act and other legislation, hedging transactions and many of our contract counterparties have become subject to increased governmental oversight and regulations in recent years. Although we cannot predict the ultimate impact of these laws and the related rulemaking, some of which is ongoing, existing or future regulations may adversely affect the cost and availability of our hedging arrangements, including by causing our contract counterparties, which are generally financial institutions and other market participants, to curtail or cease their derivatives activities.

The Credit Risk of Our Counterparties Could Adversely Affect Us

We enter into a variety of transactions that expose us to counterparty credit risk. For example, we have exposure to financial institutions and insurance companies through our hedging arrangements, our syndicated revolving credit facility and our insurance policies. Disruptions in the financial markets or otherwise may impact these counterparties and affect their ability to fulfill their existing obligations and their willingness to enter into future transactions with us.

In addition, we are exposed to the risk of financial loss from trade, joint interest billing and other receivables. We sell our oil, gas and NGLs to a variety of purchasers, and, as an operator, we pay expenses and bill our non-operating partners for their respective share of costs. We also frequently look to buyers of oil and gas properties from us to perform certain obligations associated with the disposed assets, including the removal of production facilities and plugging and abandonment of wells. Certain of these counterparties may experience insolvency, liquidity problems or other issues and may not be able to meet their obligations and liabilities (including contingent liabilities) owed to, and assumed from, us, particularly during a depressed or volatile commodity price environment. Any such default by these counterparties may result in us being forced to cover the costs of those obligations and liabilities, which could adversely impact our financial results and condition.

Our Debt May Limit Our Liquidity and Financial Flexibility, and Any Downgrade of Our Credit Rating Could Adversely Impact Us

As of December 31, 2017, we had total consolidated indebtedness of $10.4 billion. Our indebtedness and other financial commitments have important consequences to our business, including, but not limited to:

- requiring us to dedicate a significant portion of our cash flows from operations to debt service payments, thereby limiting our ability to fund working capital, capital expenditures, investments or acquisitions and other general corporate purposes;
- increasing our vulnerability to general adverse economic and industry conditions, including low commodity price environments; and
- limiting our ability to obtain additional financing due to higher costs and more restrictive covenants.

In addition, we receive credit ratings from rating agencies in the U.S. with respect to our debt. Factors that may impact our credit ratings include, among others, debt levels, planned asset sales and purchases, liquidity, forecasted production growth and commodity prices. We are currently required to provide letters of credit or other assurances under certain of our contractual arrangements. Any credit downgrades could adversely impact our ability to access financing and trade credit, require us to provide additional letters of credit or other assurances under contractual arrangements and increase our interest rate under any credit facility borrowing as well as the cost of any other future debt.

Environmental Matters and Related 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 remediating pollution that results from our operations. Environmental laws may impose strict, joint and several liability, and failure to comply with environmental laws and regulations can result in the imposition of administrative, civil or criminal fines and penalties, as well as injunctions limiting 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.

Cyber Attacks May Adversely Impact Our Operations

Our business has become increasingly dependent on digital technologies, and we anticipate expanding our use of technology in our operations, including through process automation and data analytics. Concurrent with this growing dependence on technology is greater sensitivity to cyberattack activities, which have been increasing against our industry. Cyber attackers often attempt to gain unauthorized access to digital systems for purposes of misappropriating sensitive information, intellectual property or other assets, corrupting data or causing operational disruptions. These attacks may be perpetrated by third parties or insiders. Techniques used in these attacks 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. In addition, our vendors, midstream providers and other business partners may separately suffer disruptions or breaches from cyber attacks, which, in turn, could adversely impact our operations and compromise our information. Although we have not suffered material losses related to cyber attacks to date, if we were successfully attacked, we could incur substantial remediation and other costs or suffer other negative consequences, including litigation risks. Moreover, 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.

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 and timing 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 delays, curtailments or cancellations of operations or future development, which could adversely affect our financial condition and results of operations.

Midstream Capacity Constraints and Interruptions Impact Commodity Sales

We rely on midstream facilities and systems to process our gas production and to transport our oil, 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. 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 losing access to plants, pipelines or gathering systems. Such access could be lost due to a number of factors, including, but not limited to, weather conditions and natural disasters, accidents, field labor issues or strikes. Additionally, we and third parties may be subject to constraints that limit our or their 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.

Insurance Does Not Cover All Risks

As discussed above, 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, gas and NGLs.

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 workers' compensation and employer's liability insurance. However, our insurance coverage does not provide 100% reimbursement of potential losses resulting from these operational hazards. Additionally, insurance coverage is generally not available to us for pollution events that are considered gradual, and we have limited or no insurance coverage for certain risks such as political risk and war. 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.

Competition for Assets, 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. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield services, which could adversely affect our ability to execute our development plans on a timely basis and within budget. Competition is also prevalent in the marketing of oil, gas and NGLs. Certain of our competitors have financial and other resources substantially greater 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 assets or services and accessing capital. 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.

Our Acquisition and Divestiture Activities Involve Substantial Risks

Our business depends, in part, on making acquisitions that complement or expand our current business and successfully integrating any acquired assets or businesses. If we are unable to make attractive acquisitions, our future growth could be limited. Furthermore, even if we do make acquisitions, they may not result in an increase in our cash flow from operations or otherwise result in the benefits anticipated due to various risks, including, but not limited to:

- mistaken estimates or assumptions about reserves, potential drilling locations, revenues and costs, including synergies and the overall costs of equity or debt;
- difficulties in integrating the operations, technologies, products and personnel of the acquired assets or business; and
- unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections prove inadequate, including environmental liabilities and title defects.

In addition, from time to time, we may sell or otherwise dispose of certain of our properties as a result of an evaluation of our asset portfolio and to help enhance our liquidity. These transactions also have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets and potential post-closing claims for indemnification. Moreover, volatility in commodity prices may result in fewer potential bidders, unsuccessful sales efforts and a higher risk that buyers may seek to terminate a transaction prior to closing.

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

Not applicable.

Item 3. ***Legal Proceedings***

We are involved in various 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.

Devon Gas Services, L.P., a wholly-owned subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of EPA regulations promulgated under the Clean Air Act at its Beaver Creek Gas Plant located near Riverton, Wyoming. Although management cannot predict the outcome of settlement negotiations, the resolution of this matter may result in a fine or penalty in excess of $100,000.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

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

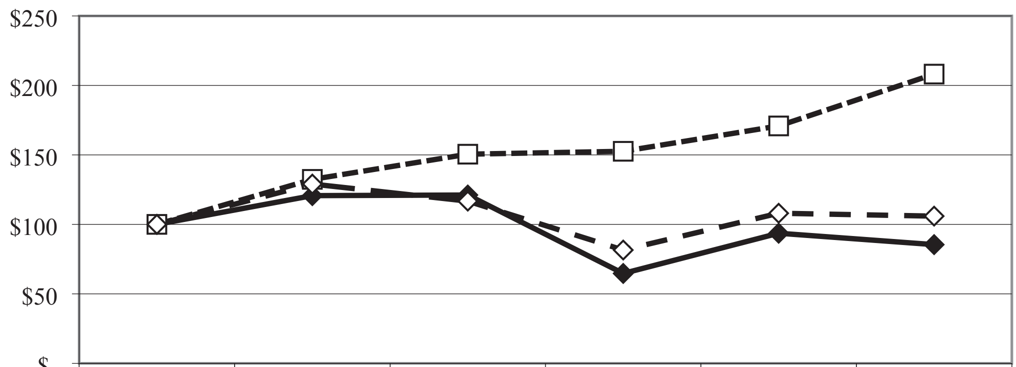
Our common stock is traded on the NYSE. On February 7, 2018, there were 7,466 holders of record of our common stock. We began paying regular quarterly cash dividends in the second quarter of 1993. The declaration of future dividends is a business decision made by our Board of Directors from time to time, and will depend on Devon's financial condition and other relevant factors. The following table sets forth the quarterly high and low prices for our common stock during 2017 and 2016, as well as the quarterly dividends per share.

	Price Range of Common Stock		Dividends
	High	Low	Per Share
Quarter Ended 2017:			
December 31, 2017	$ 42.60	$ 33.98	$ 0.06
September 30, 2017	$ 37.44	$ 28.80	$ 0.06
June 30, 2017	$ 43.50	$ 29.89	$ 0.06
March 31, 2017	$ 49.45	$ 38.02	$ 0.06
Quarter Ended 2016:			
December 31, 2016	$ 50.66	$ 36.64	$ 0.06
September 30, 2016	$ 45.62	$ 35.01	$ 0.06
June 30, 2016	$ 39.47	$ 25.55	$ 0.06
March 31, 2016	$ 32.93	$ 18.07	$ 0.24

Performance Graph

The following graph compares the cumulative TSR over a five-year period on Devon's common stock with the cumulative total returns of 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, Concho Resources, Inc., ConocoPhillips, Continental Resources, Inc., Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Occidental Petroleum Corporation and Pioneer Natural Resources Company. The graph was prepared assuming $100 was invested on December 31, 2012 in Devon's common stock, the S&P 500 Index and the peer group, and dividends have been reinvested subsequent to the initial investment.

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



	2012	2013	2014	2015	2016	2017
Devon	$100.00	$120.69	$121.13	$64.69	$93.62	$85.43
S&P 500	$100.00	$132.39	$150.51	$152.59	$170.84	$208.14
Peer Group	$100.00	$129.02	$116.72	$81.53	$108.01	$105.93

The graph and related information should not be deemed "soliciting material" or to be "filed" with the SEC, nor should 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 details purchases of our common stock that were made by us during the fourth quarter of 2017. During 2017, we did not repurchase any shares that were a part of a publicly announced program.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
October 1 - October 31	9,768	$ 35.27
November 1 - November 30	29,160	$ 38.68
December 1 - December 31	2,321	$ 39.06
Total	41,249	$ 37.89

(1) Share repurchases represent shares received by us from employees for the payment of personal income tax withholding on share-based compensation vesting.

Under the Devon Plan, eligible employees may purchase shares of our common stock through an investment in the Devon Stock Fund, which is administered by an independent trustee. Eligible employees purchased approximately 46,000 shares of our common stock in 2017, at then-prevailing stock prices, that they held through their ownership in the Devon Stock Fund. We acquired the shares of our common stock sold under this plan through open-market purchases.

Similarly, eligible Canadian employees may purchase shares of our common stock through an investment in the Canadian Plan, which is administered by an independent trustee. Eligible employees purchased approximately 6,200 shares of our common stock in 2017. 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.

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.

	2017	2016*	2015*	2014*	2013*
Statement of Earnings data:					
Upstream revenues	$ 5,307	$ 3,981	$ 5,885	$ 11,619	$ 7,296
Total revenues	$ 13,949	$ 10,304	$ 13,145	$ 19,285	$ 9,362
Earnings (loss) from continuing operations (1)	$ 1,078	$ (1,458)	$(13,645)	$ (753)	$ (938)
Earnings (loss) from continuing operations attributable to Devon (1)	$ 898	$ (1,056)	$(12,896)	$ (837)	$ (938)
Earnings (loss) from continuing operations per share attributable to Devon:					
Basic (1)	$ 1.71	$ (2.09)	$ (31.72)	$ (2.08)	$ (2.34)
Diluted (1)	$ 1.70	$ (2.09)	$ (31.72)	$ (2.08)	$ (2.34)
Cash dividends per common share	$ 0.24	$ 0.42	$ 0.96	$ 0.94	$ 0.86
Balance Sheet data:					
Total assets (1)	$ 30,241	$ 28,675	$ 29,673	$ 49,253	$ 44,390
Long-term debt (2)	$ 10,291	$ 10,154	$ 12,056	$ 9,761	$ 7,888
Stockholders' equity	$ 14,104	$ 12,722	$ 11,111	$ 24,789	$ 20,729
Common shares outstanding	525	523	418	409	406

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

(1) Material asset impairments and acquisition and divestiture activity have had significant impacts on operating results and the carrying value of our oil and gas assets. More discussion on these items can be found in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 3 and Note 6 of "Item 8. Financial Statements and Supplementary Data" of this report.

(2) Debt balances at December 31, 2017, 2016, 2015 and 2014 include $3.5 billion, $3.3 billion, $3.1 billion and $2.0 billion, respectively, of EnLink and the General Partner debt that is non-recourse to Devon.

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 2017 Results

During 2017, we generated solid operating results with our strategy of operating in North America's best resource plays, delivering superior execution, continuing disciplined capital allocation and maintaining a high degree of financial strength. Led by our development in the STACK and Delaware Basin, we continued to improve our 90-day initial production rates. With investments in proprietary data tools, predictive analytics and artificial intelligence, we are delivering industry-leading, initial-rate well productivity performance and improving the performance of our established wells.

Compared to 2016, commodity prices increased significantly and were the primary driver for improvements in Devon's earnings and cash flow during 2017. We exited 2017 with liquidity comprised of $2.7 billion of cash and $2.9 billion of available credit under our Senior Credit Facility. We have no significant debt maturities until 2021.

We further enhanced our financial strength by completing approximately $415 million of our announced $1 billion asset divestiture program in 2017. We anticipate closing the remaining divestitures in 2018.

In 2018 and beyond, we have the financial capacity to further accelerate investment across our best-in-class U.S. resource plays. We are increasing drilling activity and will continue to shift our production mix to high-margin products. We will continue our premier technical work to drive capital allocation and efficiency and industry-leading well productivity results. We will continue to maximize the value of our base production by sustaining the operational efficiencies we have achieved. Finally, we will continue to manage activity levels within our cash flows. We expect this disciplined approach will position us to deliver capital-efficient, cash-flow expansion over the next two years.

Key measures of our financial performance in 2017 are summarized in the following table. Increased commodity prices as well as continued focus on our production expenses improved our 2017 financial performance as compared to 2016, as seen in the table below. More details for these metrics are found within the "Results of Operations – 2017 vs. 2016", below.

	2017	Change	2016*	Change	2015*
Net earnings (loss) attributable to Devon	$ 898	+185%	$ (1,056)	+92%	$(12,896)
Net earnings (loss) per diluted share attributable to Devon	$ 1.70	+181%	$ (2.09)	+93%	$ (31.72)
Core earnings (loss) attributable to Devon [(1)]	$ 427	+217%	$ (367)	- 430%	$ 111
Core earnings (loss) per diluted share attributable to Devon [(1)]	$ 0.81	+210%	$ (0.73)	- 382%	$ 0.26
Retained production (MBoe/d)	541	- 4%	563	- 3%	580
Total production (MBoe/d)	543	- 11%	611	- 10%	680
Realized price per Boe [(2)]	$ 25.96	+39%	$ 18.72	- 14%	$ 21.68
Operating cash flow	$ 2,909	+94%	$ 1,500	- 69%	$ 4,898
Capitalized expenditures, including acquisitions	$ 2,937	- 25%	$ 3,908	- 32%	$ 5,712
Shareholder and noncontrolling interests distributions	$ 481	- 8%	$ 525	- 19%	$ 650
Cash and cash equivalents	$ 2,673	+36%	$ 1,959	- 15%	$ 2,310
Total debt	$10,406	+2%	$10,154	- 22%	$ 13,032
Reserves (MMBoe)	2,152	+5%	2,058	- 6%	2,182

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

(1) Core earnings and core earnings per share attributable to Devon are financial measures not prepared in accordance with 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) Excludes any impact of oil, gas and NGL derivatives.

Business and Industry Outlook

Devon marked its 46th anniversary in the oil and gas business and its 29th year as a public company during 2017. As an established company with a strong leadership team, we have experience operating in periods of challenged commodity prices. With our focused strategy and portfolio of quality assets, we are focused on navigating the current environment while ensuring our long-term financial strength.

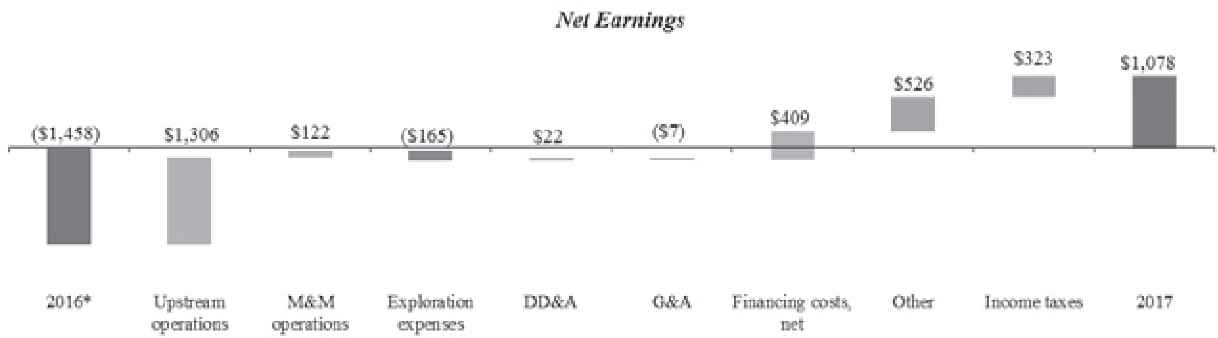
Market prices for crude oil and natural gas are inherently volatile. Therefore, we cannot predict with certainty the future prices for the commodities we produce and sell. During 2017, WTI oil prices ranged from approximately $42.00/Bbl to $60.00/Bbl, supported by increasing global demand and historically high OPEC compliance with its oil production cuts that were put in place in 2016 for the first half of 2017. Following the decision by both OPEC and non-OPEC producers to extend the agreement to reduce output by nearly 1.8 million barrels per day through the end of 2018, oil prices increased approximately 15% in the fourth quarter of 2017, averaging $55.49/Bbl. Current market fundamentals indicate improved prices for crude oil in 2018; however, changes in OPEC production strategies, the macro-economic environment, geopolitical risks or other factors could impact current forecasts. As such, we anticipate continued volatility into 2018 and we continue to execute on our hedging strategy to mitigate such volatility.

Leveraging the success of our 2017 results, we have a solid financial condition and anticipate expanding our oil and gas investment by approximately 10% in 2018, while drilling and completing approximately 25% more wells. Our 2018 outlook is focused on our high returning assets in the STACK and Delaware Basin and achieving top-line oil-equivalent production growth of 6%-9%, on a retained asset basis, through some of our best-in-class positions. Additionally, we continued to execute our hedging program in 2017 and now have approximately 40% of our oil and 50% of our gas production hedged for 2018. With our anticipated results and hedging program, we intend to fully fund our increased activity with our operating cash flow. Additionally, we are targeting reducing our debt by approximately $1 billion.

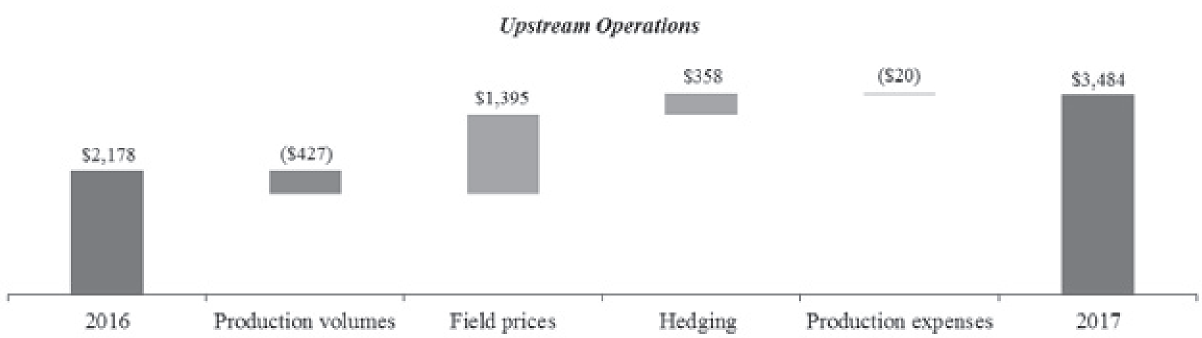
Finally, EnLink continues to be a strategic advantage for us. With annual distributions to us of approximately $270 million, EnLink provides a visible cash flow stream to be further invested in our upstream capital programs.

Results of Operations – 2017 vs. 2016

The following graphs, discussion and analysis are intended to provide an understanding of our results of operations and current financial condition. Specifically, the graph below shows the change in net earnings from 2016 to 2017. The material changes are further discussed by category on the following pages. To facilitate the review, these numbers are being presented before consideration of earnings attributable to noncontrolling interests. Additional information regarding noncontrolling interests is discussed in Note 20 in "Item 8. Financial Statements and Supplementary Data" of this report.



The graph below presents the drivers of the upstream operations change presented above, with additional details and discussion of the drivers following the graph.



* Prior year amounts, including amounts in the following tables, have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Upstream Operations

Oil, Gas and NGL Production

	2017	% of Total	2016	Change
Oil and bitumen (MBbls/d)				
STACK	26	11%	19	+38%
Delaware Basin	31	13%	33	- 7%
Rockies Oil	14	6%	14	+1%
Heavy Oil	18	7%	22	- 19%
Eagle Ford	34	14%	39	- 14%
Barnett Shale	1	1%	1	- 25%
Other	8	2%	11	- 28%
Retained assets	132	54%	139	- 4%
Divested assets	2	1%	12	- 87%
Total Oil	134	55%	151	- 11%
Bitumen	110	45%	109	+1%
Total Oil and bitumen	244		260	- 6%

	2017	% of Total	2016	Change
Gas (MMcf/d)				
STACK	304	25%	293	+4%
Delaware Basin	90	7%	90	+1%
Rockies Oil	15	1%	25	- 39%
Heavy Oil	17	2%	20	- 14%
Eagle Ford	95	8%	101	- 6%
Barnett Shale	667	55%	741	- 10%
Other	11	1%	13	- 16%
Retained assets	1,199	99%	1,283	- 7%
Divested assets	4	1%	130	- 97%
Total	1,203		1,413	- 15%

	2017	% of Total	2016	Change
NGLs (MBbls/d)				
STACK	31	31%	26	+18%
Delaware Basin	11	11%	12	- 9%
Rockies Oil	1	1%	1	+2%
Eagle Ford	13	13%	16	- 19%
Barnett Shale	41	42%	45	- 8%
Other	2	2%	2	+39%
Retained assets	99	100%	102	- 2%
Divested assets	—	—	14	- 100%
Total	99		116	- 15%

	2017	% of Total	2016	Change
Combined (MBoe/d)				
STACK	107	20%	93	+15%
Delaware Basin	56	10%	60	- 6%
Rockies Oil	17	3%	19	- 8%
Heavy Oil	131	24%	134	- 2%
Eagle Ford	62	11%	72	- 13%
Barnett Shale	153	28%	169	- 10%
Other	15	3%	16	- 5%
Retained assets	541	99%	563	- 4%
Divested assets	2	1%	48	- 96%
Total	543		611	- 11%

Production declines reduced our upstream revenues by $427 million primarily as a result of our U.S. non-core divestitures that occurred throughout 2016 and 2017. Retained production volumes decreased due to reduced completion activity in the Eagle Ford and natural production declines in the Barnett Shale. These decreases were partially offset by expanded drilling and performance in the STACK.

Oil, Gas and NGL Prices

	2017	Realization	2016	Change
Oil and bitumen (per Bbl)				
WTI index	$50.99		$43.36	+18%
Access Western Blend index	$36.90		$26.96	+37%
U.S.	$49.41	97%	$38.92	+27%
Canada	$29.99	59%	$20.53	+46%
Realized price, unhedged	$39.23	77%	$29.65	+32%
Cash settlements	$ 0.23		$ (0.43)	
Realized price, with hedges	$39.46	77%	$29.22	+35%

	2017	Realization	2016	Change
Gas (per Mcf)				
Henry Hub index	$3.11		$2.46	+26%
Realized price, unhedged	$2.48	80%	$1.84	+35%
Cash settlements	$0.08		$0.07	
Realized price, with hedges	$2.56	82%	$1.91	+34%

	2017	Realization	2016	Change
NGLs (per Bbl)				
Mont Belvieu blended index [(1)]	$24.77		$17.20	+44%
Realized price, unhedged	$15.66	63%	$ 9.81	+60%
Cash settlements	$ (0.10)		$ (0.11)	
Realized price, with hedges	$15.56	63%	$ 9.70	+60%

(1) Based upon composition of our NGL barrel.

	2017	2016	Change
Combined (per Boe)			
U.S.	$ 24.88	$ 18.34	+36%
Canada	$ 29.39	$ 20.07	+46%
Realized price, unhedged	$ 25.96	$ 18.72	+39%
Cash settlements	$ 0.27	$ (0.05)	
Realized price, with hedges	$ 26.23	$ 18.67	+40%

Upstream revenues increased $1.4 billion as a result of higher unhedged, realized prices across our entire portfolio. The increase in oil and bitumen sales primarily resulted from higher average WTI crude index prices, which were 18% higher in 2017. Additionally, our oil and bitumen sales benefited from tighter differentials to the WTI index. The increase in gas sales were driven by higher North American regional index prices upon which our gas sales are based and higher NGL prices at the Mont Belvieu, Texas hub.

As further discussed in Note 1 in "Item 8. Financial Statements and Supplementary Data" of this report, in 2018 the presentation of certain processing arrangements will change from a net to a gross presentation. We estimate the change to increase our upstream revenues and production expenses by approximately $250 million annually with no impact to net earnings.

Commodity Derivatives

	2017	2016	Change
Oil	$ 21	$ (41)	+151%
Natural gas	35	35	+0%
NGL	(3)	(5)	+40%
Total cash settlements	53	(11)	N/M
Valuation changes	104	(190)	+155%
Total	$ 157	$ (201)	+178%

Cash settlements as presented in the tables above represent realized gains or losses related to the instruments described in Note 4 in "Item 8. Financial Statements and Supplementary Data" of this report.

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 relationship between contract prices and the associated forward curves.

Production Expenses

	2017	2016	Change
LOE	$ 927	$ 1,027	- 10%
Gathering & transportation	647	555	+17%
Production taxes	194	147	+32%
Property taxes	55	74	- 26%
Total	$ 1,823	$ 1,803	+1%
Per Boe:			
LOE	$ 4.67	$ 4.59	+2%
Gathering & transportation	$ 3.26	$ 2.48	+31%
Percent of oil, gas and NGL sales:			
Production taxes	3.8%	3.5%	+7%

LOE decreased $100 million primarily due to our non-core U.S. property divestitures in 2016. Continued well optimization and cost reduction initiatives across our portfolio have offset industry inflation. These initiatives have been primarily focused on reducing costs associated with water disposal, power and fuel, compression and workovers.

Gathering and transportation expense increased $92 million primarily due to a full year of the Access Pipeline transportation tolls, which commenced in the fourth quarter of 2016 subsequent to the sale of our interest in the pipeline. Our Access transportation agreement contains a base transportation commitment, which for the initial five years averages $110 million annually.

Production taxes increased on an absolute dollar basis primarily due to the increase in our U.S. upstream revenues, on which the majority of our production taxes are assessed.

Property taxes decreased as a result of lower property value assessments from the local taxing authorities across our key operating areas and as a result of our U.S. non-core divestitures.

Marketing & Midstream Operations

	2017	2016	Change
Operating revenues	$ 5,740	$ 4,252	+35%
Product purchases	(4,362)	(3,015)	+45%
Operations and maintenance expenses	(418)	(398)	+5%
EnLink margin	960	839	+14%
Devon margin	(48)	(49)	- 2%
Total	$ 912	$ 790	+15%

The overall increase in marketing and midstream operating margin was primarily due to an increase in EnLink's throughput volumes related to gas processing and transmission activities. Devon's margins continue to be negatively impacted by downstream marketing commitments. We are actively engaged in optimization activities to reduce the costs of downstream commitments; however, we expect such commitments will continue to negatively impact our margin in 2018. As further discussed in Note 1 in "Item 8. Financials Statements and Supplementary Data" of this report, in 2018 EnLink's marketing and midstream revenues are estimated to decrease by 6-10% with a corresponding decrease to marketing and midstream expenses as a result of complying with the new revenue recognition accounting standard.

Exploration Expenses

	2017	2016	Change
Unproved impairments	$ 217	$ 77	+182%
Geological and geophysical	110	65	+70%
Exploration overhead and other	53	73	- 27%
Total	$ 380	$ 215	+77%

Unproved impairments primarily relate to a portion of acreage in our U.S. non-core operations upon which we do not intend to pursue further exploration and development. Geological and geophysical costs increased primarily in the STACK and Delaware Basin.

Depreciation, Depletion and Amortization

	2017	2016	Change
Oil and gas per Boe	$ 7.15	$ 6.47	+11%
Oil and gas	$ 1,419	$ 1,446	- 2%
Midstream and other assets	110	146	- 25%
Devon	1,529	1,592	- 4%
EnLink	545	504	+8%
Total	$ 2,074	$ 2,096	- 1%

Our oil and gas DD&A remained relatively flat as compared to the prior year. Increases in oil and gas DD&A rates due to continued development in the STACK and Delaware Basin were offset by reduced production volumes resulting from the 2016 U.S. asset divestitures. DD&A from our midstream and other assets decreased due to the divestiture of the Access Pipeline in the fourth quarter of 2016.

General and Administrative Expenses

	2017	2016	Change
Labor and benefits	$ 589	$ 614	- 4%
Non-labor	228	215	+6%
Reimbursed G&A	(73)	(82)	- 11%
Total Devon	744	747	- 0%
EnLink	128	118	+8%
Total	$ 872	$ 865	+1%

Labor and benefits decreased primarily as a result of the workforce reduction that occurred in February 2016 as discussed in Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report. Non-labor costs were higher due to an increase in costs related to automation and process improvements. Reimbursed G&A decreased primarily due the divestitures of operated properties in 2016. EnLink G&A increased primarily due to higher compensation costs.

Financing Costs, net

Financing costs, net decreased $409 million primarily as a result of our $2.1 billion early debt retirement in 2016. For further discussion of early retirement premiums and reduced interest expense resulting from our lower debt balances, see Note 16 in "Item 8. Financial Statements and Supplementary Data" of this report.

Other

	2017	2016	Change
Asset impairments	$ 17	$ 1,310	- 99%
Asset dispositions	(217)	(1,483)	- 85%
Restructuring	—	267	N/M
Other	(124)	108	- 215%
Total	$ (324)	$ 202	- 260%

Asset impairments in 2016 primarily related to goodwill and other intangible asset impairments related to EnLink's business. Additional information regarding the impairments is discussed in Note 6 in "Item 8. Financial Statements and Supplementary Data" of this report.

We recognized gains in conjunction with our non-core U.S. upstream asset dispositions in both 2016 and 2017 and the divestiture of our 50% interest in the Access Pipeline in 2016. For further discussion, see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

During 2016, we recognized restructuring and transaction costs of $267 million primarily as a result of our workforce reduction. For discussion of our reorganization programs and the associated restructuring costs, see Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report.

The remaining change in other expense was driven primarily by changes on foreign currency exchange instruments as further discussed in Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report.

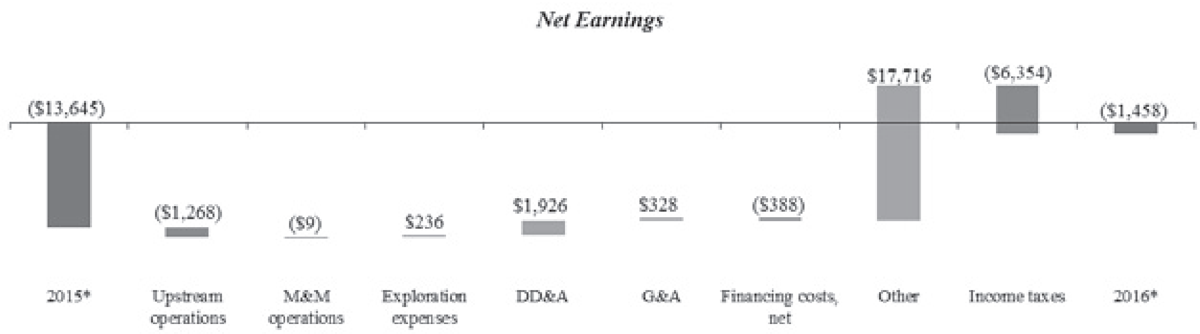
Income Taxes

	2017	2016
Current expense	$ 112	$ 100
Deferred expense (benefit)	(294)	41
Total expense (benefit)	$ (182)	$ 141
Effective income tax rate	(20%)	(11%)

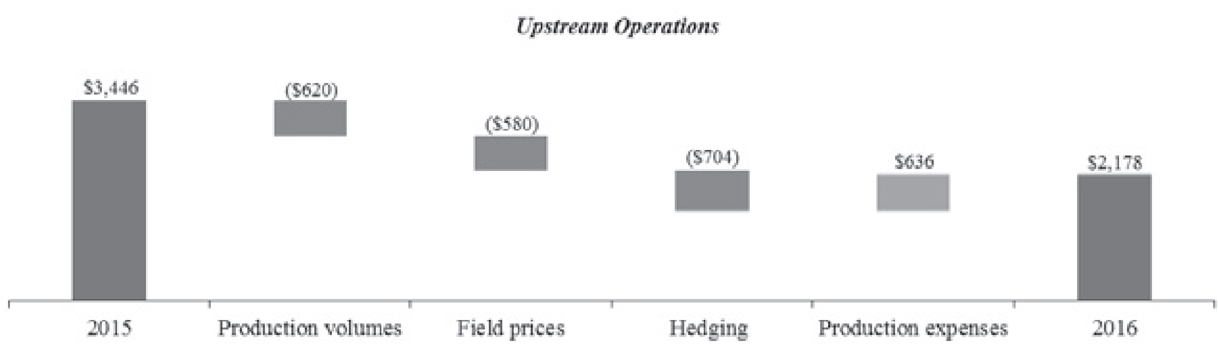
For discussion on income taxes, see Note 8 in "Item 8. Financial Statements and Supplementary Data" of this report.

Results of Operations – 2016 vs. 2015

The graph below shows the change in net earnings from 2015 to 2016. The material changes are further discussed by category on the following pages. To facilitate the review, these numbers are being presented before consideration of earnings attributable to noncontrolling interests. Additional information regarding noncontrolling interests is discussed in Note 20 in "Item 8. Financial Statements and Supplementary Data" of this report.



The graph below presents the drivers of the upstream operations changed presented above, with additional details and discussion of the drivers following the graph.



* Prior year amounts, including amounts in the following tables, have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Upstream Operations

Oil, Gas and NGL Production

	2016	% of Total	2015	Change
Oil and bitumen (MBbls/d)				
STACK	19	7%	7	+152%
Delaware Basin	33	13%	39	- 16%
Rockies Oil	14	5%	15	- 9%
Heavy Oil	22	9%	27	- 17%
Eagle Ford	39	15%	61	- 35%
Barnett Shale	1	0%	1	- 28%
Other	11	4%	13	- 11%
Retained assets	139	53%	163	- 15%
Divested assets	12	5%	28	- 56%
Total Oil	151	58%	191	- 21%
Bitumen	109	42%	84	+29%
Total Oil and bitumen	260		275	- 6%

	2016	% of Total	2015	Change
Gas (MMcf/d)				
STACK	293	21%	239	+23%
Delaware Basin	90	6%	71	+27%
Rockies Oil	25	2%	40	- 37%
Heavy Oil	20	1%	22	- 11%
Eagle Ford	101	7%	141	- 28%
Barnett Shale	741	53%	815	- 9%
Other	13	1%	17	- 22%
Retained assets	1,283	91%	1,345	- 5%
Divested assets	130	9%	265	- 51%
Total	1,413		1,610	- 12%

	2016	% of Total	2015	Change
NGLs (MBbls/d)				
STACK	26	23%	21	+22%
Delaware Basin	12	10%	9	+28%
Rockies Oil	1	1%	1	- 9%
Eagle Ford	16	14%	23	- 33%
Barnett Shale	45	39%	51	- 12%
Other	2	1%	4	- 59%
Retained assets	102	88%	109	- 7%
Divested assets	14	12%	27	- 50%
Total	116		136	- 15%

	2016	% of Total	2015	Change
Combined (MBoe/d)				
STACK	93	15%	68	+37%
Delaware Basin	60	10%	60	- 1%
Rockies Oil	19	3%	23	- 17%
Heavy Oil	134	22%	115	+17%
Eagle Ford	72	12%	107	- 33%
Barnett Shale	169	28%	188	- 10%
Other	16	2%	19	- 13%
Retained assets	563	92%	580	- 3%
Divested assets	48	8%	100	- 52%
Total	611		680	- 10%

Production declines reduced our upstream revenues by $620 million. Production volumes decreased due to our reduction in exploration and development activity related to our retained assets during 2016. While expanded drilling in the STACK and the performance of our Jackfish assets drove production increases, these production increases were more than offset by reduced completion activity in the Eagle Ford and natural production declines in the Barnett Shale and Rockies Oil. Additionally, our production decreased as a result of our U.S. non-core divestitures that occurred throughout 2016.

Oil, Gas and NGL Prices

	2016	Realization	2015	Change
Oil and bitumen (per Bbl)				
WTI index	$43.36		$48.87	- 11%
Access Western Blend index	$26.96		$32.18	- 16%
U.S.	$38.92	90%	$44.01	- 12%
Canada	$20.53	47%	$25.14	- 18%
Realized price, unhedged	$29.65	68%	$36.39	- 19%
Cash settlements	$ (0.43)		$20.72	
Realized price, with hedges	$29.22	67%	$57.11	- 49%

	2016	Realization	2015	Change
Gas (per Mcf)				
Henry Hub index	$2.46		$2.67	- 8%
Realized price, unhedged	$1.84	75%	$2.14	- 14%
Cash settlements	$0.07		$0.57	
Realized price, with hedges	$1.91	77%	$2.71	- 30%

	2016	Realization	2015	Change
NGLs (per Bbl)				
Mont Belvieu blended index (1)	$17.20		$16.93	+2%
Realized price, unhedged	$ 9.81	57%	$ 9.32	+5%
Cash settlements	$ (0.11)		$ —	
Realized price, with hedges	$ 9.70	56%	$ 9.32	+4%

(1) Based upon composition of average Devon NGL barrel.

	2016	2015	Change
Combined (per Boe)			
U.S.	$ 18.34	$ 21.12	- 13%
Canada	$ 20.07	$ 24.46	- 18%
Realized price, unhedged	$ 18.72	$ 21.68	- 14%
Cash settlements	$ (0.05)	$ 9.74	
Realized price, with hedges	$ 18.67	$ 31.42	- 41%

Upstream revenues decreased $580 million as a result of lower unhedged, realized prices for oil, bitumen and gas. The decrease in oil and bitumen sales primarily resulted from lower average WTI crude index prices, which were 11% lower in 2016 as compared to 2015. The decrease in gas sales was driven by lower North American regional index prices upon which our gas sales are based. These decreases were partially offset by slightly higher NGL prices at the Mont Belvieu, Texas hub.

Commodity Derivatives

	2016	2015	Change
Oil	$ (41)	$ 2,083	- 102%
Natural gas	35	333	- 89%
NGL	(5)	—	N/M
Total cash settlements	(11)	2,416	- 100%
Valuation changes	(190)	(1,913)	+90%
Total	$ (201)	$ 503	- 140%

Production Expenses

	2016	2015	Change
LOE	$1,027	$1,509	- 32%
Gathering & transportation	555	595	- 7%
Production taxes	147	207	- 29%
Property taxes	74	128	- 42%
Total	$1,803	$2,439	- 26%
Per Boe:			
LOE	$ 4.59	$ 6.08	- 24%
Gathering & transportation	$ 2.48	$ 2.40	+4%
Percent of oil, gas and NGL sales:			
Production taxes	3.5%	3.8%	- 8%

LOE and LOE per BOE decreased as a result of our cost reduction initiatives, well optimization and our non-core oil and gas property divestitures. On an absolute dollar basis, LOE decreased approximately $200 million as a result of our U.S. upstream divestitures.

Gathering and transportation decreased primarily as a result of U.S. upstream asset divestitures partially offset by $28 million of Access Pipeline transportation tolls which commenced in the fourth quarter of 2016 subsequent to the sale of our interest in the pipeline.

Production taxes decreased on an absolute dollar basis primarily due to the decrease in our U.S. upstream revenues, on which the majority of our production taxes are assessed. Property taxes decreased as a result of lower property value assessments from the local taxing authorities across our key operating areas and as a result of our U.S. non-core divestitures.

Marketing & Midstream Operations

	2016	2015	Change
Operating revenues	$ 4,252	$ 4,451	- 4%
Product purchases	(3,015)	(3,245)	- 7%
Operations and maintenance expenses	(398)	(419)	- 5%
EnLink margin	839	787	+7%
Devon margin	(49)	12	N/M
Total	$ 790	$ 799	- 1%

The overall decrease was primarily due to lower margins on Devon's downstream marketing commitments, offset by EnLink's margin growth largely related to its acquisition activity in late 2015 and the first quarter of 2016.

Exploration Expenses

	2016	2015	Change
Unproved impairments	$ 77	$ 260	- 70%
Geological and geophysical	65	108	- 40%
Exploration overhead and other	73	83	- 13%
Total	$ 215	$ 451	- 52%

Unproved impairments primarily relate to a portion of acreage in our non-core U.S. operations upon which we do not intend to pursue further exploration and development. Geological and geophysical costs were lower due to a reduced exploration capital program in 2016.

Depreciation, Depletion and Amortization

	2016	2015	Change
Oil and gas per Boe	$ 6.47	$ 13.99	- 54%
Oil and gas	$ 1,446	$ 3,474	- 58%
Midstream and other assets	146	161	- 10%
Devon	1,592	3,635	- 56%
EnLink	504	387	+30%
Total	$ 2,096	$ 4,022	- 48%

DD&A from our oil and gas properties decreased largely because of our significant asset impairments recognized in 2015. For discussion on asset impairments, see Note 6 in "Item 8. Financial Statements and Supplementary Data" of this report. EnLink's DD&A increased primarily due to acquisitions in 2015 and 2016.

General and Administrative Expenses

	2016	2015	Change
Labor and benefits	$ 614	$ 866	- 29%
Non-labor	215	310	- 31%
Reimbursed G&A	(82)	(120)	- 31%
Total Devon	747	1,056	- 29%
EnLink	118	137	- 14%
Total	$ 865	$1,193	- 27%

G&A decreased due to workforce reductions, as discussed in Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report, and other cost reduction initiatives in response to the decline in commodity prices. Reimbursed G&A decreased primarily due to a reduction in drilling activity, as well as the divestiture of operated properties. EnLink G&A decreased primarily due to lower employee compensation expense and other cost reduction initiatives during 2016.

Financing Costs, net

Financing costs, net increased $388 million primarily as a result of our $2.1 billion early debt retirement. For further discussion, see Note 16 in "Item 8. Financial Statements and Supplementary Data" of this report.

Other

	2016	2015	Change
Asset impairments	$ 1,310	$17,647	- 93%
Asset dispositions	(1,483)	7	N/M
Restructuring	267	78	+242%
Other	108	186	- 42%
Total	$ 202	$17,918	- 99%

Asset impairments largely related to our oil and gas assets and resulted from a significant decline in forecasted commodity prices during 2015 and 2016. Asset impairments for 2016 and 2015 also related to goodwill and other intangible asset impairments related to EnLink's business. Additional information regarding the impairments is discussed in Note 6 in "Item 8. Financial Statements and Supplementary Data" of this report.

We recognized gains in conjunction with our non-core U.S. upstream asset dispositions in 2016 and the divestiture of our 50% interest in the Access Pipeline in 2016. For further discussion, see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

During 2016, we recognized restructuring and transactions costs of $267 million primarily as a result of our workforce reduction. For discussion of our restructuring programs and the associated restructuring costs, see Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report.

Income Taxes

	2016	2015
Current expense	$ 100	$ (237)
Deferred expense (benefit)	41	(5,976)
Total expense (benefit)	$ 141	$ (6,213)
Effective income tax rate	(11%)	31%

For discussion on income taxes, see Note 8 in "Item 8. Financial Statements and Supplementary Data" of this report.

Capital Resources, Uses and Liquidity

The following table presents the major source and use categories of Devon and EnLink's cash and cash equivalents.

	Devon			EnLink			Consolidated		
	2017	2016*	2015*	2017	2016*	2015*	2017	2016*	2015*
Operating cash flow	$ 2,209	$ 834	$ 4,271	$ 700	$ 666	$ 627	$ 2,909	$ 1,500	$ 4,898
Issuance of common stock	—	1,469	—	—	—	—	—	1,469	—
Divestitures of property and investments	415	3,020	106	192	93	1	607	3,113	107
Capital expenditures	(1,968)	(1,384)	(4,214)	(791)	(663)	(573)	(2,759)	(2,047)	(4,787)
Acquisitions of property, equipment and businesses	(46)	(849)	(583)	—	(792)	(524)	(46)	(1,641)	(1,107)
Debt activity, net	—	(3,383)	770	2	228	1,061	2	(3,155)	1,831
Shareholder and noncontrolling interests distributions	(127)	(221)	(396)	(354)	(304)	(254)	(481)	(525)	(650)
EnLink and General Partner distributions	265	265	268	(265)	(265)	(268)	—	—	—
Subsidiary unit transactions	—	—	654	501	892	25	501	892	679
Effect of exchange rate and other	(53)	(96)	4	34	139	(145)	(19)	43	(141)
Net change in cash and cash equivalents	$ 695	$ (345)	$ 880	$ 19	$ (6)	$ (50)	$ 714	$ (351)	$ 830
Cash and cash equivalents at end of period	$ 2,642	$ 1,947	$ 2,292	$ 31	$ 12	$ 18	$ 2,673	$ 1,959	$ 2,310

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Devon Sources and Uses of Cash

Operating Cash Flow

Net cash provided by operating activities continued to be a significant source of capital and liquidity in 2017. Our operating cash flow increased $1.4 billion, or 165%, as compared to 2016 due to significantly higher commodity prices. In 2017, our operating cash flow fully funded our capital expenditure program as well as our dividends.

Our operating cash flow decreased $3.4 billion, or 80% from 2015 to 2016. While commodity prices decreased from 2015 to 2016, the primary driver of the decrease was due to the expiration of certain favorable hedge positions that provided us with an additional $2.4 billion of additional operating cash flow in 2015. In 2016 and 2015, our operating cash flow did not fully fund our capital requirements and dividends; as a result, we utilized available cash balances and divestiture proceeds to supplement our operating cash flows.

Issuance of Common Stock

In February 2016, we issued 79 million shares of our common stock to the public, inclusive of 10 million shares sold as part of the underwriters' option. Net proceeds from the offering were approximately $1.5 billion.

Divestitures of Property and Investments

During 2017, as part of our announced divestiture program, we sold non-core U.S. assets for $415 million. For further discussion, see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

During 2016, we divested certain non-core upstream assets in the U.S. and our 50% interest in the Access Pipeline in Canada for approximately $3.0 billion, net of purchase price adjustments. Proceeds from these divestitures were used primarily for debt repayment and to support capital investment in Devon's core resource plays. For further discussion, see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

We did not have significant current cash income taxes resulting from the divestitures in 2017 and 2016.

Capital Expenditures

The following table summarizes our capital expenditures and property acquisitions.

	Year Ended December 31,		
	2017	2016*	2015*
Oil and gas	$ 1,879	$ 1,341	$ 4,056
Corporate and other	89	43	158
Total capital expenditures	$ 1,968	$ 1,384	$ 4,214
Acquisitions	$ 46	$ 849	$ 583

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Capital expenditures consist primarily of amounts related to our oil and gas exploration and development operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling and development of oil and gas properties. Our capital program is designed to operate within operating cash flow and may fluctuate with changes to commodity prices and other factors impacting cash flow. This is evidenced by our operating cash flow fully funding capital expenditures in 2017. In response to the lower commodity prices, our total capital expenditures have been reduced by approximately 50% since 2015.

Acquisition costs in 2016 primarily consisted of Devon's bolt-on acquisition of assets in the STACK play for $1.5 billion. Approximately $849 million was paid in cash at closing with the remainder of the purchase price funded with equity consideration. In 2015 our acquisition activity primarily consisted of the Powder River Basin asset acquisition in the fourth quarter. For further discussion on acquisition activity, see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

Debt Activity, Net

During 2016, our debt decreased $3.1 billion. The decrease was primarily due to completed tender offers to purchase and redeem $2.1 billion of debt securities prior to their maturity and a $1 billion reduction in short-term borrowings. In conjunction with the tender offers, we recognized a $269 million loss on the early retirement of debt, including $265 million of cash retirement costs and fees.

During 2015, our net debt increased $770 million. In June 2015, we issued $750 million of 5.0% senior notes. We used these proceeds to repay the aggregate principal amount of our floating rate senior notes upon maturity on December 15, 2015, as well as outstanding commercial paper balances. In December 2015, we issued $850 million of 5.85% senior notes to fund acquisitions announced in the fourth quarter.

Shareholder Distributions

Devon paid common stock dividends of $127 million, $221 million and $396 million during 2017, 2016 and 2015, respectively. In response to the depressed commodity price environment, we reduced our quarterly dividend from $0.24 to $0.06 per share in the second quarter of 2016.

EnLink and General Partner Distributions

Devon received $265 million, $265 million and $268 million in distributions from EnLink and the General Partner during 2017, 2016 and 2015, respectively.

Subsidiary Unit Transactions

In 2015, we conducted an underwritten secondary public offering of 26.2 million common units representing limited partner interests in EnLink, raising proceeds of $654 million, net of underwriting discount. See Note 20 in "Item 8. Financial Statements and Supplementary Data" of this report.

EnLink Sources and Uses of Cash

EnLink's operating cash flow has increased each year since 2015 as a result of the growth experienced from its acquisition activity and continued development activities.

Capital expenditures for EnLink's midstream operations are primarily for the construction and expansion of oil and gas gathering facilities and pipelines. During 2016, EnLink acquired Anadarko Basin gathering and processing midstream assets for $1.5 billion. Approximately $792 million was paid in cash at closing with the remainder of the purchase price funded with equity consideration and debt. For additional information on this acquisition, see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report. EnLink's acquisitions in 2015 consisted of additional oil and gas pipeline assets, including gathering, transportation and processing facilities.

During 2017, EnLink divested its ownership interest in Howard Energy Partners for approximately $190 million. Proceeds were primarily used to pay a portion of the first $250 million installment payment related to EnLink's 2016 acquisition noted above.

During 2017, EnLink's debt increased $247 million. In May 2017, EnLink issued $500 million of 5.45% senior notes due in 2047 to repay outstanding borrowings under its revolving credit facility and for general partnership purposes. In June 2017, EnLink redeemed its 7.125% senior unsecured notes due in 2022 for aggregate cash consideration of $174 million. Additionally, EnLink reduced its credit facility borrowings to $74 million during 2017. As noted above, EnLink made the first installment payment in 2017 related to its 2016 acquisition.

EnLink and the General Partner distributed $354 million, $304 million and $254 million to non-Devon unitholders during 2017, 2016 and 2015, respectively.

During 2017, 2016 and 2015, EnLink issued and sold approximately 6.2 million, 10.0 million and 1.3 million common units through general public offerings and its "at the market" equity program, generating net proceeds of approximately $107 million, $167 million and $25 million, respectively.

In 2017, EnLink issued preferred units in an underwritten public offering generating net proceeds of approximately $394 million.

In 2016, to fund a portion of the cash consideration of its acquisition of Anadarko Basin gathering and processing midstream assets, EnLink issued 50 million preferred units in a private placement generating cash proceeds of approximately $725 million. General Partner common units were also issued as consideration in the transaction.

In 2017 and 2016, EnLink received contributions from noncontrolling interests. For further discussion see Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

Devon 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. Available sources of capital and liquidity also include, among other things, debt and equity securities that can be issued pursuant to our shelf registration statement filed with the SEC, as well as the sale of a portion of our common units representing interests in our investment in EnLink and the General Partner. The most significant source of liquidity in 2017 has come from our operating cash flow supplemented with approximately $415 million of proceeds related to our asset divestitures. We estimate the combination of these sources of capital will continue to be adequate to fund our planned capital expenditures, future debt repayments, dividends and other contractual commitments as discussed in this section.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which are the prices of the oil, bitumen, gas and NGLs we produce and sell. Our consolidated operating cash flow increased 165% in 2017 largely due to increases in commodity prices. We expect operating cash flow to continue to be a key source of liquidity as we adjust our capital program to invest within our operating cash flow. Furthermore, proceeds from our non-core asset divestitures will provide additional liquidity as needed.

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. To mitigate some of the risk inherent in prices, we utilize various derivative financial instruments to protect a portion of our production against downside price risk. We target hedging approximately 50% of our production in a manner that systematically places hedges for several quarters in advance, allowing us to maintain a disciplined risk management program as it relates to commodity price volatility. We supplement the systematic hedging program with discretionary hedges that take advantage of favorable market conditions. As a result, entering into 2018 we have hedged approximately 40% of our anticipated oil and 50% of our anticipated gas production. The key terms to our oil, gas and NGL derivative financial instruments as of December 31, 2017 are presented in Note 4 in “Item 8. Financial Statements and Supplementary Data” of this report.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price decreases can lead to a decrease in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also decrease, causing a positive impact on our cash flow as the prices paid for services and equipment decline. However, the inverse is also generally true during periods of rising commodity prices.

Divestitures of Property and Equipment – In 2017, we announced a program to divest approximately $1 billion of upstream assets. These non-core assets identified for monetization include select portions of the Barnett Shale focused primarily in and around Johnson County and other properties located principally within Devon’s U.S. resource base. Through December 31, 2017, Devon completed divestiture transactions totaling approximately $415 million. The most significant asset remaining in this program is select Barnett Shale properties which we expect to close in 2018.

Interest Rates – Our operating cash flow can also be impacted by interest rate fluctuations. As of December 31, 2017, we had total debt of $6.9 billion that bears fixed interest rates averaging 5.7%.

As of December 31, 2017, we had open interest rate swap positions that are presented in Note 4 in “Item 8. Financial Statements and Supplementary Data” in this report.

Credit Losses – Our operating cash flow is also exposed to credit risk in a variety of ways. This includes the credit risk related to customers who purchase our oil, gas and NGL production, the collection of receivables from our joint-interest partners for their proportionate share of expenditures made on projects we operate and 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.

At the end of 2017, we held approximately $2.6 billion of cash. Included in this total was $732 million of cash held by our foreign subsidiaries.

Credit Availability

We have a $3.0 billion Senior Credit Facility. 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 of short-term credit under our commercial paper program. As of December 31, 2017, there were no borrowings under our commercial paper program. See Note 16 in "Item 8. Financial Statements and Supplementary Data" of this report for further discussion.

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%. 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 oil and gas property impairments and goodwill impairments. As of December 31, 2017, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2017, as calculated pursuant to the terms of the agreement, was 27.2%.

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.

As market conditions warrant and subject to our contractual restrictions, liquidity position and other factors, we may from time to time seek to repurchase or retire our outstanding debt through cash purchases and/or exchanges for other debt or equity securities in open market transactions, privately negotiated transactions, by tender offer or otherwise. Any such cash repurchases by us may be funded by cash on hand or incurring new debt. The amounts involved in any such transactions, individually or in the aggregate, may be material. Furthermore, any such repurchases or exchanges may result in our acquiring and retiring a substantial amount of such indebtedness, which would impact the trading liquidity of such indebtedness. We are currently targeting up to $1.5 billion of debt reduction in 2018.

Debt Ratings

We receive debt ratings from the major ratings agencies in the U.S. In determining our debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, commodity pricing levels, our liquidity, asset quality, reserve mix, debt levels, cost structure, planned asset sales and near-term and long-term production growth opportunities. Our credit rating from Standard and Poor's Financial Services is BBB with a stable outlook. In March 2017, Fitch Ratings affirmed our BBB+ rating and revised our outlook to stable from negative. In April 2017, Moody's Investor Service upgraded our credit rating from Ba2 to Ba1 with a stable outlook. Any rating downgrades may result in additional letters of credit or cash collateral being posted under certain contractual arrangements.

There are no "rating triggers" in any of our or EnLink's contractual debt obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. However, a downgrade could adversely impact our and EnLink's interest rate on any credit facility borrowings and the ability to economically access debt markets in the future.

Capital Expenditures

Our 2018 exploration and development budget is expected to be approximately $2.2 billion to $2.4 billion and funded within operating cash flow. Although negative movements in any of the variables discussed above would impact our operating cash flow, we likely would not change our 2018 planned capital investment. Should our operating cash flow decrease from our forecasts, we could divest non-core assets to balance capital sources and uses.

EnLink Liquidity

EnLink has a $1.5 billion unsecured revolving credit facility. The General Partner has a $250 million revolving credit facility. As of December 31, 2017, there were $10 million in outstanding letters of credit and no outstanding borrowings under the $1.5 billion credit facility and $74 million outstanding borrowings under the $250 million credit facility. All of EnLink's and the General Partner's debt is non-recourse to Devon.

As of December 31, 2017, EnLink had total debt of $3.5 billion. Of this amount, $3.4 billion bears fixed interest rates averaging 4.6% and $74 million is comprised of floating rate debt with interest rates averaging 3.2%.

EnLink's 2018 capital budget includes approximately $600 million to $800 million of identified growth projects. EnLink's primary capital projects for 2018 include the construction of the Thunderbird processing plant in Central Oklahoma, the Lobo III processing plant in the Delaware Basin and the development of additional gathering and compression assets in Central Oklahoma and the Permian Basin.

EnLink expects to fund the growth capital expenditures with borrowings under its bank credit facility and proceeds from other debt and equity sources, including capital contributions by joint venture partners. EnLink expects to fund its 2018 maintenance capital expenditures from operating cash flows. EnLink employs a strategy that includes maintaining stable operating cash flows that are supported by long-term, fixed-fee contracts. Approximately 94% of EnLink's cash flows were generated from fee-based services in 2017. It is possible that not all of the planned projects for 2018 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

The following table presents a summary of our contractual obligations as of December 31, 2017.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Devon obligations:					
Debt (1)	$ 6,933	$ 115	$ 162	$ 1,500	$ 5,156
Interest expense (2)	6,188	390	756	715	4,327
Purchase obligations (3)	1,880	613	1,133	134	—
Operational agreements (4)	5,259	522	756	739	3,242
Operational agreements with EnLink (5)	909	637	272	—	—
Asset retirement obligations (6)	1,152	39	134	171	808
Drilling and facility obligations (7)	629	216	218	89	106
Lease obligations (8)	381	88	157	117	19
Other (9)	115	115	—	—	—
Total Devon obligations	23,446	2,735	3,588	3,465	13,658
EnLink obligations:					
Debt (1)	3,574	—	474	—	3,100
Interest expense (2)	2,573	160	304	298	1,811
Other (9)	496	306	55	45	90
Total EnLink obligations	6,643	466	833	343	5,001
Total obligations	$ 30,089	$ 3,201	$ 4,421	$ 3,808	$ 18,659

(1) Debt amounts represent scheduled maturities of debt obligations at December 31, 2017, excluding net discounts and debt issue costs included in the carrying value of debt.

(2) Interest expense represents the scheduled cash payments on long-term fixed-rate debt (including current portion of long term debt).

(3) Purchase obligation amounts represent contractual commitments primarily to purchase condensate at market prices for use at our heavy oil projects in Canada. We have entered into these agreements because condensate is an integral part of the heavy oil transportation process. Any disruption in our ability to obtain condensate could negatively affect our ability to transport heavy oil at these locations. Our total obligation related to condensate purchases expires in 2021. The value of the obligation in the table above is based on the contractual volumes and our internal estimate of future condensate market prices.

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

(5) Operational agreements between Devon and EnLink represent fixed-fee gathering and processing and transportation agreements. These agreements also include minimum volume commitments that will remain in effect for approximately one more year, as well as annual rate escalators.

(6) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2017 balance sheet.

(7) 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.

(8) Lease obligations consist primarily of non-cancelable leases for office space and equipment.

(9) Other Devon obligations primarily relate to uncertain tax positions as discussed in Note 8 in “Item 8. Financial Statements and Supplementary Data” of this report. Other EnLink obligations primarily consist of a $250 million installment payment on the Anadarko Basin assets acquisition as discussed in Note 3 in “Item 8. Financial Statements and Supplementary Data” of this report.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 21 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 U.S. 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.

Oil and Gas Assets Accounting, Reserves, Classification & Valuation

Change in Accounting Principle

In the fourth quarter of 2017, we changed our method of accounting for our oil and gas exploration and development activities from the full cost method to the successful efforts method. In accordance with FASB ASC 250 *"Accounting Changes and Error Corrections,"* financial information for prior periods has been recast to reflect retrospective application of the successful efforts method, as prescribed by the FASB ASC 932 *"Extractive Activities—Oil and Gas."* As required by ASC 250, we have presented the accumulated effect of the change in accounting principle from Devon's inception to December 31, 2014 as a change in the beginning balance of our 2015 consolidated statements of equity.

To recast our financial statements, we made certain critical estimates, judgments and assumptions to apply successful efforts accounting to our historical operations. These critical items are similar to those pertaining to our ongoing successful efforts accounting, which are described below. For additional information regarding the effects of the change to the successful efforts method, including our underlying successful efforts accounting policies, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

To illustrate the effect of the change to successful efforts accounting, the following table summarizes the $1.9 billion increase to our historical equity as of September 30, 2017, the date of our conversion. The increase was primarily driven by lower impairments, offset by higher DD&A and less capitalized expenses.

Category		
Total equity as of September 30, 2017 (Full Cost)		$ 11,934
Adjustments from inception through 2007, net		(2,147)
Adjustments after 2007:		
Lower asset impairments, net	18,317	
Exploration expense	(5,402)	
Higher DD&A, driven largely by lower impairments	(5,036)	
G&A expensed rather than capitalized	(3,075)	
Other (asset dispositions, foreign exchange cumulative translation adjustment, etc.)	418	
Deferred income tax on the above items	(1,152)	
Total adjustments after 2007		4,070
Equity increase (+16%)		1,923
Total equity as of September 30, 2017 (Successful Efforts)		$ 13,857

Reserves

Our estimates of proved and proved developed reserves are a major component of DD&A 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 third-party petroleum consulting firms. In 2017, 88% 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 5% 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.

Successful Efforts Method of Accounting and Classification

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities which requires management's assessment of the proper designation of wells and associated costs as developmental or exploratory. This classification assessment is dependent on the determination and existence of proved reserves, which is a critical estimate discussed in the previous section. The classification of developmental and exploratory costs has a direct impact on the amount of costs we initially recognize as exploration expense or capitalize, then subject to DD&A calculations and impairment assessments and valuations.

Once a well is drilled, the determination that proved reserves have been discovered may take considerable time and requires both judgment and application of industry experience. Development wells are always capitalized. Costs associated with drilling an exploratory well are initially capitalized, or suspended, pending a determination as to whether proved reserves have been found. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs to determine whether the costs should continue to remain capitalized or shall be expensed. When making this determination, management considers current activities, near-term plans for additional exploratory or appraisal drilling and the likelihood of reaching a development program. If management determines future development activities and the determination of proved reserves are unlikely to occur, the associated suspended exploratory well costs are recorded as dry hole expense and reported in exploration expense in the Consolidated Comprehensive Statement of Earnings. Otherwise, the costs of exploratory wells remain capitalized. At December 31, 2017, Devon had approximately $200 million of well costs suspended for more than one year, which largely pertain to its Pike Heavy Oil project. Stratigraphic testing has demonstrated reserves can be produced economically at Pike. However, this capital intensive, long-duration project remains unsanctioned by Devon and its 50% partner, which is the primary reason reserves have not been designated as proven at Pike. With no lease expiration at Pike in the near future, management continues to keep the Pike exploratory costs capitalized.

Similar to the evaluation of suspended exploratory well costs, costs for undeveloped leasehold, for which reserves have not been proven, must also be evaluated for continued capitalization or impairment. At the end of each quarter, management assesses undeveloped leasehold costs for impairment by considering future drilling plans, drilling activity results, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. Based on this assessment, Devon impaired $139 million of undeveloped leasehold in the fourth quarter of 2017. At December 31, 2017, Devon had $1.4 billion of undeveloped leasehold and capitalized interest which includes approximately $750 million related to Pike. Consistent with the evaluation above on suspended well costs, the costs for Pike continue to remain capitalized. Of the remaining undeveloped leasehold costs at December 31, 2017, $85 million is scheduled to expire in 2018. The leasehold expiring in 2018 relates to areas in which Devon is actively drilling. If our drilling is not successful, this leasehold could become partially or entirely impaired.

Valuation of Long-Lived Assets

Long-lived assets used in operations, including proved and unproved oil and gas properties, are depreciated and assessed for impairment annually or whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. For DD&A calculations and impairment assessments, management groups individual assets based on a judgmental assessment of the lowest level ("common operating field") for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. The determination of common operating fields is largely based on geological structural features or stratigraphic condition, which requires judgment. Management also considers the nature of production, common infrastructure, common sales points, common processing plants, common regulation and management oversight to make common operating field determinations. These determinations impact the amount of DD&A recognized each period and could impact the determination and measurement of a potential asset impairment.

Management evaluates assets for impairment through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments of future production volumes, commodity prices, operating costs, and capital investment plans, considering all available information at the date of review. Besides the estimates of reserves and future production volumes, future commodity prices are the largest driver in the variability of undiscounted pre-tax cash flows. For our impairment determinations, we generally utilize the forward strip prices for the first five years and apply internally generated price forecasts for subsequent years. We estimate and escalate or de-escalate future capital and operating costs by using a method that correlates cost movements to price movements similar to recent history. Changes to any of these assumptions could result in lower undiscounted pre-tax cash flows and impact both the recognition and timing of impairments. Due to suppressed commodity prices in 2015 and 2016, we recognized significant asset impairments in each of those years. With more stabilized and higher pricing in 2017, we did not recognize material asset impairments.

Goodwill and Other Intangibles

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 assess the qualitative and quantitative factors to determine whether the fair value of a reporting unit is less than its carrying amount. 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, 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 the October 31, 2017 impairment tests for Devon's U.S. reporting unit and each of EnLink's reporting units, the fair value of each reporting unit exceeded its carrying value.

Sustained weakness in the overall energy sector driven by low commodity prices, together with a decline in the EnLink unit price, caused a change in circumstances warranting an interim impairment test for EnLink's reporting units in 2015 and an update to be performed at December 31, 2015. Using the fair value approaches described above, it was determined that the estimated fair value of EnLink's Texas, Louisiana and Crude and Condensate reporting units were less than their carrying amounts and a goodwill impairment loss of $492 million, $787 million and $49 million, respectively, was recognized in 2015.

Additionally, another interim impairment test was warranted during 2016 for EnLink's reporting units. Using the fair value approaches described above, it was determined that the estimated fair value of EnLink's Texas, General Partner and Crude and Condensate reporting units were less than their carrying amounts and a goodwill impairment loss of $473 million, $307 million and $93 million, respectively, was recognized in 2016.

Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual future results are not consistent with these assumptions and estimates, or the assumptions and estimates change due to new information, we may be exposed to additional goodwill impairment charges, which would be recognized in the period in which we would determine that the carrying value exceeds fair value. We would expect that a prolonged or sustained period of lower commodity prices would adversely affect the estimate of future operating results, which could result in future goodwill impairments for our reporting units due to the potential impact on the cash flows of our operations.

The impairment of goodwill has no effect on liquidity or capital resources. However, it adversely affects our results of operations in the period recognized.

Other Intangible Assets

In 2015, the assessment of customer relationships was updated due to the factors described in the aforementioned goodwill section. This assessment resulted in a $223 million impairment of other intangible assets related to EnLink's Crude and Condensate reporting unit. Level 3 fair value measurements were utilized for the impairment analysis of definite-lived intangible assets, which included discounted cash flow estimates, consistent with those utilized in the goodwill impairment assessment.

The other intangible assets impairment has no effect on liquidity or capital resources. However, it adversely affects our results of operations in the period recognized.

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. At the end of 2017 and 2016, we had deferred tax assets that largely resulted from the asset impairments recognized throughout 2016. As a result of our recent cumulative losses and our current realization assessment, we recorded a 100% valuation allowance against our U.S. deferred tax assets as of December 31, 2017 and December 31, 2016. Further, in 2017, we recognized a $660 million partial valuation allowance against certain Canadian deferred tax assets as a result of the Canadian legal entity restructuring.

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 U.S. 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, U.S./foreign country tax treaty provisions and the related foreign taxes paid by our foreign subsidiaries, whose earnings are deemed permanently reinvested, over a lengthy history of operations.

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

Under the Tax Reform Legislation, the corporate income tax rate was reduced to 21% effective January 1, 2018. We are required to recognize the effect of the tax law changes in the period of enactment, such as determining the transition tax, remeasuring our U.S. deferred tax assets and liabilities and reassessing the net realizability of our deferred tax assets and liabilities.

In December 2017, the SEC staff issued Staff Accounting Bulletin No. 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* (SAB 118), which allows us to record provisional amounts during a measurement period not to extend beyond one year after the enactment date. As the Tax Reform Legislation was passed late in the fourth quarter of 2017 and ongoing guidance and accounting interpretation are expected over the next 12 months, we consider the accounting of the transition tax, deferred tax remeasurements, and other items to be incomplete due to the forthcoming guidance and our ongoing analysis of final year-end data and tax positions. We expect to complete our analysis within the measurement period in accordance with SAB 118.

Absent unexpected events and unexpected effects of the Tax Reform Legislation, Devon expects a positive impact on its future after-tax earnings, primarily due to the lower federal statutory tax rate.

Non-GAAP Measures

We make reference to “core earnings (loss) attributable to Devon” and “core earnings (loss) per share attributable to Devon” in “Overview of 2017 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 when comparing on an annual basis. In the table below, restructuring and transaction costs were incurred in two of the three year periods; however, these costs relate to different restructuring programs. Amounts excluded for 2017 relate to asset dispositions, noncash asset impairments including noncash unproved asset impairments (included in exploration expenses), U.S. tax reform changes, deferred tax asset valuation allowance, derivatives and financial instrument fair value changes, legal entity restructuring and costs associated with early retirement of debt.

Amounts excluded for 2016 relate to asset dispositions, noncash asset impairments (including an impairment of goodwill) including noncash unproved asset impairments and dry hole costs relating to exploration expenses, rig stacking costs, deferred tax asset valuation allowance, restructuring and transaction costs associated with the 2016 workforce reduction, derivatives and financial instrument fair value changes and costs associated with early retirement of debt.

Amounts excluded for 2015 relate to asset dispositions, noncash asset impairments (including an impairment of goodwill) including noncash unproved asset impairments and dry hole costs relating to exploration expenses, rig stacking costs, deferred tax asset valuation allowance, restructuring and transaction costs, derivatives and financial instrument fair value changes and repatriation of funds to the U.S.

We believe these non-GAAP measures facilitate comparisons of our performance to earnings estimates published by securities analysts, which typically make similar adjustments in their estimates of our financial results. 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.

	Before tax	After tax	After Noncontrolling Interests	Per Diluted Share
2017				
Earnings attributable to Devon (GAAP)	$ 896	$ 1,078	$ 898	$ 1.70
Adjustments:				
Asset dispositions	(217)	(138)	(138)	(0.26)
Asset and exploration impairments	234	152	146	0.27
U.S. tax reform	—	(211)	(112)	(0.21)
Deferred tax asset valuation allowance	—	(76)	(76)	(0.14)
Fair value changes in financial instruments and foreign currency	(218)	(202)	(201)	(0.38)
Legal entity restructuring	—	(86)	(86)	(0.16)
Early retirement of debt	(9)	(7)	(4)	(0.01)
Core earnings attributable to Devon (Non-GAAP)	$ 686	$ 510	$ 427	$ 0.81
2016*				
Loss attributable to Devon (GAAP)	$ (1,317)	$ (1,458)	$ (1,056)	$ (2.09)
Adjustments:				
Asset dispositions	(1,483)	(989)	(995)	(1.95)
Asset and exploration impairments	1,430	1,230	807	1.60
Rig stacking costs	10	6	6	0.01
Deferred tax asset valuation allowance	—	385	385	0.76
Restructuring and transaction costs	267	173	170	0.33
Fair value changes in financial instruments and foreign currency	270	153	145	0.28
Early retirement of debt	269	171	171	0.33
Core loss attributable to Devon (Non-GAAP)	$ (554)	$ (329)	$ (367)	$ (0.73)
2015*				
Loss attributable to Devon (GAAP)	$ (19,858)	$ (13,645)	$ (12,896)	$ (31.72)
Adjustments:				
Asset dispositions	7	8	8	0.02
Asset and exploration impairments	17,914	11,955	11,131	27.37
Rig stacking costs	54	34	34	0.08
Deferred tax asset valuation allowance	—	403	403	0.99
Restructuring and transaction costs	78	52	52	0.13
Fair value changes in financial instruments and foreign currency	1,967	1,349	1,346	3.31
Repatriations	—	33	33	0.08
Core earnings attributable to Devon (Non-GAAP)	$ 162	$ 189	$ 111	$ 0.26

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to our risk of loss arising from adverse changes in oil, gas and NGL prices, interest rates and foreign currency exchange rates. The following disclosures are not meant to be precise indicators of expected future losses but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is the pricing applicable to our oil, gas and NGL production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian gas and NGL production. Pricing for oil and gas production has been volatile and unpredictable as discussed in “Item 1A. Risk Factors” of this report. Consequently, we systematically hedge a portion of our production through various financial transactions. The key terms to our oil and gas derivative financial instruments as of December 31, 2017 are presented in Note 4 in “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, 2017, a 10% change in the forward curves associated with our commodity derivative instruments would have changed our net asset positions by approximately $260 million.

Interest Rate Risk

At December 31, 2017, we had total debt of $10.4 billion. Of this amount, $10.3 billion bears fixed interest rates averaging 5.3%, and approximately $74 million is comprised of floating rate debt with interest rates averaging 3.2%.

As of December 31, 2017, we had open interest rate swap positions that are presented in Note 4 in “Item 8. Financial Statements and Supplementary Data” of this report. The fair values of our interest rate swaps are largely determined by estimates of the forward curves of the three month LIBOR rate. A 10% change in these forward curves would not have materially impacted our balance sheet or liquidity at December 31, 2017.

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% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not have materially impacted our December 31, 2017 balance sheet.

Our non-Canadian foreign subsidiaries have a U.S. dollar functional currency. However, some of these subsidiaries hold Canadian-dollar cash and engage 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. Based on the amount of the cash and intercompany loans as of December 31, 2017, a 10% change in the foreign currency exchange rates would not have materially impacted our balance sheet.

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of comprehensive earnings, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company has elected to change its method of accounting for oil and gas exploration and development activities from the full cost method of accounting to the successful efforts method of accounting in 2017.

Basis for Opinion

The Company'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 the accompanying Management's Annual Report on Internal Control over Financial Reporting contained in "Item 9A. Controls and Procedures." Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control Over Financial Reporting

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.

/s/ KPMG LLP

We have served as the Company's auditor since 1980.

Oklahoma City, Oklahoma
February 21, 2018

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2017	2016*	2015*
Upstream revenues	$ 5,307	$ 3,981	$ 5,885
Marketing and midstream revenues	8,642	6,323	7,260
Total revenues	13,949	10,304	13,145
Production expenses	1,823	1,803	2,439
Exploration expenses	380	215	451
Marketing and midstream expenses	7,730	5,533	6,461
Depreciation, depletion and amortization	2,074	2,096	4,022
Asset impairments	17	1,310	17,647
Asset dispositions	(217)	(1,483)	7
General and administrative expenses	872	865	1,193
Financing costs, net	498	907	519
Other expenses	(124)	375	264
Total expenses	13,053	11,621	33,003
Earnings (loss) before income taxes	896	(1,317)	(19,858)
Income tax expense (benefit)	(182)	141	(6,213)
Net earnings (loss)	1,078	(1,458)	(13,645)
Net earnings (loss) attributable to noncontrolling interests	180	(402)	(749)
Net earnings (loss) attributable to Devon	$ 898	$ (1,056)	$ (12,896)
Net earnings (loss) per share attributable to Devon:			
Basic	$ 1.71	$ (2.09)	$ (31.72)
Diluted	$ 1.70	$ (2.09)	$ (31.72)
Comprehensive earnings (loss):			
Net earnings (loss)	$ 1,078	$ (1,458)	$ (13,645)
Other comprehensive earnings, net of tax:			
Foreign currency translation and other	83	11	(443)
Pension and postretirement plans	29	22	10
Other comprehensive earnings, net of tax	112	33	(433)
Comprehensive earnings (loss)	1,190	(1,425)	(14,078)
Comprehensive earnings (loss) attributable to noncontrolling interests	180	(402)	(749)
Comprehensive earnings (loss) attributable to Devon	$ 1,010	$ (1,023)	$ (13,329)

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in “Item 8. Financial Statements and Supplementary Data” of this report.

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016*	2015*
Cash flows from operating activities:			
Net earnings (loss)	$ 1,078	$ (1,458)	$ (13,645)
Adjustments to reconcile net earnings (loss) to net cash from operating activities:			
Depreciation, depletion and amortization	2,074	2,096	4,022
Exploratory dry hole expense and unproved leasehold impairments	219	113	248
Asset impairments	17	1,310	17,647
Gains and losses on asset sales	(217)	(1,483)	7
Deferred income tax expense (benefit)	(294)	41	(5,976)
Commodity derivatives	(157)	201	(503)
Cash settlements on commodity derivatives	53	1	2,416
Other derivatives and financial instruments	23	185	(235)
Cash settlements on other derivatives and financial instruments	(6)	(143)	272
Asset retirement obligation accretion	62	75	75
Share-based compensation	198	233	244
Other	(122)	270	312
Net change in working capital	21	24	(265)
Change in long-term other assets	(46)	36	285
Change in long-term other liabilities	6	(1)	(6)
Net cash from operating activities	2,909	1,500	4,898
Cash flows from investing activities:			
Capital expenditures	(2,759)	(2,047)	(4,787)
Acquisitions of property, equipment and businesses	(46)	(1,641)	(1,107)
Divestitures of property and equipment	417	3,113	107
Proceeds from sale of investment	190	—	—
Other	(12)	(19)	(16)
Net cash from investing activities	(2,210)	(594)	(5,803)
Cash flows from financing activities:			
Borrowings of long-term debt, net of issuance costs	2,376	2,145	4,772
Repayments of long-term debt	(2,118)	(4,409)	(2,634)
Payment of installment payable	(250)	—	—
Net short-term debt repayments	—	(626)	(307)
Early retirement of debt	(6)	(265)	—
Issuance of common stock	—	1,469	—
Sale of subsidiary units	—	—	654
Issuance of subsidiary units	501	892	25
Dividends paid on common stock	(127)	(221)	(396)
Contributions from noncontrolling interests	57	168	16
Distributions to noncontrolling interests	(354)	(304)	(254)
Shares exchanged for tax withholdings	(68)	(35)	(51)
Other	(2)	(10)	(13)
Net cash from financing activities	9	(1,196)	1,812
Effect of exchange rate changes on cash	6	(61)	(77)
Net change in cash and cash equivalents	714	(351)	830
Cash and cash equivalents at beginning of period	1,959	2,310	1,480
Cash and cash equivalents at end of period	$ 2,673	$ 1,959	$ 2,310

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,673	$ 1,959
Accounts receivable	1,670	1,356
Assets held for sale	—	193
Other current assets	448	264
Total current assets	4,791	3,772
Oil and gas property and equipment, based on successful efforts accounting, net	13,318	12,998
Midstream and other property and equipment, net	7,853	7,535
Total property and equipment, net	21,171	20,533
Goodwill	2,383	2,383
Other long-term assets	1,896	1,987
Total assets	$ 30,241	$ 28,675
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 819	$ 642
Revenues and royalties payable	1,180	908
Short-term debt	115	—
Other current liabilities	1,201	1,066
Total current liabilities	3,315	2,616
Long-term debt	10,291	10,154
Asset retirement obligations	1,113	1,226
Other long-term liabilities	583	894
Deferred income taxes	835	1,063
Equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 525 million and 523 million shares in 2017 and 2016, respectively	53	52
Additional paid-in capital	7,333	7,237
Retained earnings (accumulated deficit)	702	(69)
Accumulated other comprehensive earnings	1,166	1,054
Total stockholders' equity attributable to Devon	9,254	8,274
Noncontrolling interests	4,850	4,448
Total equity	14,104	12,722
Total liabilities and equity	$ 30,241	$ 28,675

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Additional Paid-In	Retained Earnings (Accumulated	Accumulated Other Comprehensive	Treasury	Noncontrolling	Total
	Shares	Amount	Capital	Deficit)	Earnings	Stock	Interests	Equity
Previously reported as of December 31, 2014	409	$ 41	$ 4,088	$ 16,631	$ 779	$ —	$ 4,802	$ 26,341
Effect of change in accounting principle	—	—	—	(2,227)	675	—	—	(1,552)
Balance as of December 31, 2014 as recast*	409	$ 41	$ 4,088	$ 14,404	$ 1,454	$ —	$ 4,802	$ 24,789
Net loss	—	—	—	(12,896)	—	—	(749)	(13,645)
Other comprehensive loss, net of tax	—	—	—	—	(433)	—	—	(433)
Stock option exercises	—	—	4	—	—	—	—	4
Restricted stock grants, net of cancellations	2	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(35)	—	(35)
Common stock retired	—	—	(35)	—	—	35	—	—
Common stock dividends	—	—	—	(396)	—	—	—	(396)
Common stock issued	7	1	198	—	—	—	—	199
Share-based compensation	—	—	165	—	—	—	—	165
Share-based compensation tax expense	—	—	(9)	—	—	—	—	(9)
Subsidiary equity transactions	—	—	585	—	—	—	141	726
Distributions to noncontrolling interests	—	—	—	—	—	—	(254)	(254)
Balance as of December 31, 2015*	418	$ 42	$ 4,996	$ 1,112	$ 1,021	$ —	$ 3,940	$ 11,111
Net loss	—	—	—	(1,056)	—	—	(402)	(1,458)
Other comprehensive earnings, net of tax	—	—	—	—	33	—	—	33
Restricted stock grants, net of cancellations	2	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(28)	—	(28)
Common stock retired	—	—	(28)	—	—	28	—	—
Common stock dividends	—	—	(96)	(125)	—	—	—	(221)
Common stock issued	103	10	2,117	—	—	—	—	2,127
Share-based compensation	—	—	168	—	—	—	—	168
Subsidiary equity transactions	—	—	80	—	—	—	1,214	1,294
Distributions to noncontrolling interests	—	—	—	—	—	—	(304)	(304)
Balance as of December 31, 2016*	523	$ 52	$ 7,237	$ (69)	$ 1,054	$ —	$ 4,448	$ 12,722
Net earnings	—	—	—	898	—	—	180	1,078
Other comprehensive earnings, net of tax	—	—	—	—	112	—	—	112
Restricted stock grants, net of cancellations	1	1	—	—	—	—	—	1
Common stock repurchased	—	—	—	—	—	(44)	—	(44)
Common stock retired	—	—	(44)	—	—	44	—	—
Common stock dividends	—	—	—	(127)	—	—	—	(127)
Share-based compensation	1	—	126	—	—	—	—	126
Subsidiary equity transactions	—	—	14	—	—	—	576	590
Distributions to noncontrolling interests	—	—	—	—	—	—	(354)	(354)
Balance as of December 31, 2017	525	$ 53	$ 7,333	$ 702	$ 1,166	$ —	$ 4,850	$ 14,104

* Prior year amounts have been recast due to change in accounting principle. See Note 2 in “Item 8. Financial Statements and Supplementary Data” of this report.

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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 and the General Partner.

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

Change in Accounting Principle and Presentation Changes

In the fourth quarter of 2017, Devon changed its method of accounting for its oil and gas exploration and development activities from the full cost method to the successful efforts method. In accordance with FASB ASC 250 "*Accounting Changes and Error Corrections*," financial information for prior periods has been recast to reflect retrospective application of the successful efforts method, as prescribed by the FASB ASC 932 "*Extractive Activities—Oil and Gas*." Although the full cost method of accounting for oil and gas exploration and development activities continues to be an accepted alternative, the successful efforts method of accounting is the preferred method and is more widely used in the industry and will improve comparison to Devon's peer group. Devon believes the successful efforts method provides a more transparent representation of its results of operations. The successful efforts method also provides our investments in oil and gas properties to be assessed for impairment as of the balance sheet date in accordance with FASB ASC 360 "*Property, Plant and Equipment*" rather than valuations based on 12-month historical prices and costs prescribed under the full cost method. For more detailed information regarding the effects of the change in accounting principle to the successful efforts method, see Note 2.

As Devon recast its financial statements to the successful efforts method, the financial statements and disclosures were examined through the lens of simplicity and transparency. From this assessment, certain changes were made to the financial statement presentation not specifically required by the successful efforts method of accounting. In general, Devon sought to simplify the presentation of its consolidated comprehensive statements of earnings and provide expanded and improved disclosures of key components in its operating results. These presentation judgments improve the clarity and utility of the financial operating results for investors and other stakeholders. As a result, certain prior period amounts have been reclassified to align to this new approach. To ensure financial statement users clearly understand the changes, a description of each enhancement is provided below.

- *Operating income* – Devon previously segregated expenses between operating and nonoperating on the statement of operations. The only material nonoperating expense was generally financing costs. Devon streamlined the overall comprehensive statements of earnings by eliminating the operating income distinction.
- *Upstream revenues* – On the statement of operations, Devon is combining sales of oil, gas and NGL volumes, as well as oil, gas and NGL derivative activity, into this new line item. With the streamlined presentation of upstream revenues, MD&A and other disclosures of these items were expanded.
- *Production expenses* – Similar to streamlining the presentation of upstream revenues, Devon is simplifying the presentation of cash-based expenses associated with upstream production. Previously these expenses were reported separately as lease operations and production and property taxes in the comprehensive statements of earnings. These items are now combined in this new line item. Devon has expanded the MD&A and other disclosures of expenses for lease operations, gathering and transportation, production taxes and property taxes.

- *Asset impairments* – Except for unproved oil and gas property impairments, this line item will capture all impairments of Devon's assets. After research of peers, Devon decided to report unproved impairments as part of exploration expenses. Because asset impairments are non-routine adjustments to the cost basis of assets, this item was placed adjacent to DD&A, the routine adjustment of the cost basis of assets, on the comprehensive statements of earnings.
- *Asset dispositions* – This line item will capture gains and losses from dispositions of assets. As a full cost company, Devon rarely had material gains and losses on asset dispositions. However, when it did, such amounts were reported as part of revenues. Devon has more gains and losses under the successful efforts method of accounting. Since recognizing gains and losses on asset dispositions are largely affected by previously recognized DD&A and asset impairments, this item was placed adjacent to those items on the comprehensive statements of earnings.

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, contributions and distributions. Investments accounted for using the equity method and cost method are reported as a component of other long-term assets.

Devon completed a business combination in 2014 whereby Devon controls both EnLink and 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 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;
- evaluation of suspended well costs;
- the carrying and fair values of oil and gas properties, midstream assets and product and equipment inventories;
- derivative financial instruments;
- the fair value of reporting units and related assessment of goodwill for impairment;
- the fair value of intangible assets other than goodwill;
- income taxes;
- asset retirement obligations;
- obligations related to employee pension and postretirement benefits;

- legal and environmental risks and exposures; and
- general credit risk associated with receivables and other assets.

Revenue Recognition

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 typically 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.

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 2017, 2016 and 2015, no purchaser accounted for more than 10% of Devon's consolidated sales revenue.

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 enters into derivative financial instruments with respect to a portion of its oil, gas and NGL production to hedge future prices received. Additionally, Devon and EnLink periodically enter into derivative financial instruments with respect to a portion of their oil, gas and NGL marketing activities. These instruments are used to manage the inherent uncertainty of future revenues resulting from commodity price volatility. Devon's derivative financial instruments typically include financial price swaps, basis swaps, costless price collars and call options. Under the terms of the price swaps, Devon receives a fixed price for its production and pays a variable market price to the contract counterparty. For the basis swaps, Devon receives a fixed differential between two regional index prices and pays a variable differential on the same two index prices to the contract counterparty. The price collars set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon will cash-settle the difference with the counterparty to the collars. The call options give counterparties the right to purchase production at a predetermined price.

Devon periodically enters into interest rate swaps to manage its exposure to interest rate volatility and foreign exchange forward contracts to manage its exposure to fluctuations in the U.S. and Canadian dollar exchange rates. As of December 31, 2017, Devon did not have any open foreign exchange contracts.

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, 2017, 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. Cash settlements that Devon is entitled to are accrued for in other current assets in the accompanying consolidated balance sheets.

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. As of December 31, 2017, Devon held no cash collateral of its counterparties nor posted collateral to its counterparties.

General and Administrative Expenses

G&A is reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Devon.

Share-Based Compensation

Independent of EnLink, Devon grants share-based awards to members of its Board of Directors and select employees. EnLink and the General Partner also grant share-based awards to members of its Board of Directors and select employees. All such awards are measured at fair value on the date of grant and are generally recognized as a component of G&A 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 7, certain share-based awards were accelerated and recognized as a component of restructuring costs in the accompanying 2016 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 generally available to be issued as part of Devon's share-based awards. However, Devon has historically canceled these shares upon repurchase.

Income Taxes

Devon is subject to current income taxes assessed by the federal and various state jurisdictions in the U.S. and by other foreign jurisdictions. In addition, Devon accounts for deferred income taxes related to these jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets 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.

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 the deferred tax assets is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Devon periodically weighs the positive and negative evidence to determine if it is more likely than not that some or all of the deferred tax assets will be realized. Forming a conclusion that a valuation allowance is not required is difficult when there is negative evidence, such as cumulative losses in recent years. See Note 8 for further discussion.

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.

Devon estimates its annual effective income tax rate in recording its provision for income taxes in the various jurisdictions in which it operates. Statutory tax rate changes and other significant or unusual items are recognized as discrete items in the period in which they occur.

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, as well as performance-based restricted stock awards that have met the requisite performance targets. 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 unvested performance share units.

Cash and Cash Equivalents

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

Accounts Receivable

Devon's accounts receivable balance primarily consists of oil and gas sales receivables, marketing and midstream revenue receivables and joint interest receivables for which Devon does not require collateral security. Devon has established an allowance for bad debts equal to the estimable portions of accounts receivable for which failure to collect is considered probable. When a portion of the receivable is deemed uncollectible, the write-off is made against the allowance.

Property and Equipment

Oil and Gas Property and Equipment

Devon follows the successful efforts method of accounting for its oil and gas properties. Under this method exploration costs, such as exploratory geological and geophysical costs, and costs associated with nonproductive exploratory wells, delay rentals and exploration overhead are charged against earnings as incurred. Costs of drilling successful exploratory wells along with acquisition costs and the costs of drilling development wells, including those that are unsuccessful, are capitalized. Devon groups its oil and gas properties with a common geological structure or stratigraphic condition ("common operating field") in accordance with ASC 932 "*Extractive Activities – Oil and Gas*" for purposes of computing DD&A, assessing proved property impairments and accounting for asset dispositions.

Exploratory drilling costs and exploratory-type stratigraphic test wells are initially capitalized, or suspended, pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized as proved properties. Costs of unsuccessful wells are charged to exploration expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory well costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. Devon reviews the status of all suspended exploratory drilling costs quarterly.

Capitalized costs of proved oil and gas properties are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six Mcf of gas to one Bbl of oil. Proved leasehold acquisition costs, less accumulated amortization, are depleted over total proved reserves, which includes proved undeveloped reserves. Capitalized costs of wells and related equipment and facilities, including estimated asset retirement costs, net of estimated salvage values and less accumulated amortization are depreciated over proved developed reserves associated with those capitalized costs. Depletion is calculated by applying the DD&A rate (amortizable base divided by beginning of period proved reserves) to current period production.

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 annually, or more frequently if events or changes in circumstances dictate that the carrying value of those assets may not be recoverable. Significant unproved properties are assessed individually. Costs of insignificant unproved properties are amortized to exploration expense on a group basis using estimated lease surrender rates over average lease terms.

Proved properties are assessed for impairment annually, or more frequently if events or changes in circumstances dictate that the carrying value of those assets may not be recoverable. Individual assets are grouped for impairment purposes based on a common operating field. If there is an indication the carrying amount of an asset may not be recovered, the asset is assessed for potential impairment by management through an established process. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset, the carrying value is written down to estimated fair value. Because there is usually a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or by comparable transactions. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments of future production volumes, commodity prices, operating costs, and capital investment plans, considering all available information at the date of review.

Gains or losses are recorded for sales or dispositions of oil and gas properties which constitute an entire common operating field or which result in a significant alteration of the common operating field's DD&A rate. These gains and losses are classified as asset dispositions in the accompanying consolidated statements of earnings. Partial common operating field sales or dispositions deemed not to significantly alter the DD&A rates are generally accounted for as adjustments to capitalized costs with no gain or loss recognized.

Devon capitalizes interest costs incurred and attributable to material unproved oil and gas properties and major development projects of oil and gas properties.

Midstream and Other Property and Equipment

Costs for midstream assets that are in use are depreciated over the assets' estimated useful lives, using the 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.

Asset Retirement Obligations

Devon recognizes liabilities for retirement obligations associated with tangible long-lived assets, such as producing well sites and midstream pipelines and processing plants when there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. When the assumptions used to estimate a recorded asset retirement obligation change, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Devon's asset retirement obligations also 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 the fair value of each reporting unit be compared to the carrying value of the reporting unit. If the fair value of the reporting unit is less than the carrying value, then goodwill is written down to the 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 and EnLink performed annual impairment tests of goodwill in the fourth quarters of 2017, 2016 and 2015. No impairment was required as a result of the annual tests in 2017 or 2016; however, sustained weakness in the overall energy sector driven by lower commodity prices, together with a decline in the EnLink unit price, caused a change in circumstances warranting an interim impairment test and write-down for certain of EnLink's reporting units in the first quarter of 2016. Write-downs were also required in 2015 for certain EnLink reporting units. See Note 14 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 to 20 years. During 2017, 2016 and 2015, EnLink's customer relationships were also evaluated for impairment, and in 2015, a portion of these intangible assets was considered impaired. See Note 14 for further discussion.

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 allegations of improper operation of assets are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with Devon's accounting policy for property and equipment.

Fair Value Measurements

Certain of Devon's assets and liabilities are measured at fair value at each reporting date. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. This price is commonly referred to as the "exit price." Fair value measurements are classified according to a hierarchy that prioritizes the inputs underlying the valuation techniques. This hierarchy consists of three broad levels:

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

Foreign Currency Translation Adjustments

The U.S. dollar is the functional currency for Devon's consolidated operations except its Canadian subsidiaries, which use the Canadian dollar as the functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using an average exchange rate during the reporting period. Translation adjustments have no effect on net income and are included in accumulated other comprehensive earnings in stockholders' equity.

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 Adopted Accounting Standards

In January 2017, Devon adopted ASU 2016-09, *Compensation – Stock Compensation (Topic 718), Improvements to Employee Share-Based Payment Accounting*. Its objective is to simplify several aspects of the accounting for share-based payments, including income taxes when awards vest or are settled, statutory withholding and forfeitures. As the result of adoption, Devon made certain income tax presentation changes, most notably prospectively presenting excess tax benefits and deficiencies in the consolidated comprehensive statements of earnings and as operating cash flows in the consolidated statements of cash flows. Devon also retrospectively applied the new cash flow statement guidance dictating the presentation of shares exchanged for tax-withholding purposes as a financing activity. The adoption of the new guidance did not materially impact the consolidated financial statements for the year ended December 31, 2017 or previously reported financial information but could have a more material future impact.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill And Other (Topic 350)*, *Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 simplifies the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test. Under ASU 2017-04, an entity should perform its goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An impairment charge should be recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. However, the impairment loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. ASU 2017-04 is effective for annual reporting periods beginning after December 15, 2019, including any interim impairment tests within those annual periods, with early application for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. In January 2017, Devon elected to early adopt ASU 2017-04. The adoption had no impact on the consolidated financial statements.

Issued Accounting Standards Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which established ASC Topic 606, *Revenue from Contracts with Customers* (ASC 606). ASC 606 will replace existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 will also require significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers* (Topic 606): *Narrow-Scope Improvements and Practical Expedients* (ASU 2016-12), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles, including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied using the modified retrospective or full retrospective transition methods, with early application permitted for annual reporting periods beginning after December 15, 2016. Devon will adopt ASC 606 using the modified retrospective method for annual and interim reporting periods beginning January 1, 2018.

Devon has aggregated and reviewed its contracts that are within the scope of ASC 606. Based on its evaluation, Devon does not anticipate the adoption of ASC 606 will have a material impact on its balance sheet or related consolidated statements of earnings, equity or cash flows. Accordingly, Devon will continue to recognize revenue at the time commodities are delivered. However, ASC 606 will affect how certain transactions are presented in its financial statements. Under this guidance, an entity generally shall record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity shall record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Devon will change its presentation of certain processing arrangements from a net presentation to a gross presentation. This change will impact Devon's upstream revenues and production expenses by approximately $250 million for 2016 and 2017, and will impact 2018 by a similar amount. EnLink will change the presentation of certain marketing and midstream revenues to marketing and midstream operating expenses or from marketing and midstream operating expenses to marketing and midstream revenues. Devon estimates this reclassification will result in a net decrease in EnLink's marketing and midstream revenues of approximately 6-10%. These estimates are based on historical information and could change based on future volumes and commodity prices. These presentation changes will have no impact on net earnings or cash flows.

Based on the disclosure requirements of ASC 606, upon adoption, Devon expects to provide expanded disclosures relating to its revenue recognition policies and how these relate to its revenue-generating contractual performance obligations. In addition, Devon expects to present revenues disaggregated based on the type of good or service in order to more fully depict the nature of its revenues.

The FASB issued ASU 2016-02, *Leases (Topic 842)*. This ASU will supersede the lease requirements in Topic 840, *Leases*. Its objective is to increase transparency and comparability among organizations. This ASU provides guidance requiring lessees to recognize most leases on their balance sheet. Lessor accounting does not significantly change, except for some changes made to align with new revenue recognition requirements. This ASU is effective for Devon beginning January 1, 2019. Early adoption is permitted, but Devon does not plan to early adopt. Currently the guidance would be applied using a modified retrospective transition method, which requires applying the new guidance to leases that exist or are entered into after the beginning of the earliest period in the financial statements. However, the FASB recently issued Proposed ASU No. 2018-200, *Leases (Topic 842), Targeted Improvements* which would allow entities to apply the transition provisions of the new standard at its adoption date instead of at the earliest comparative period presented in the consolidated financial statements. The proposed ASU will allow entities to continue to apply the legacy guidance in Topic 840, including its disclosure requirements, in the comparative periods presented in the year the new leases standard is adopted. Entities that elect this option would still adopt the new leases standard using a modified retrospective transition method, but would recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption rather than in the earliest period presented. Devon is in the process of evaluating contracts and gathering the necessary terms and data elements for purposes of determining the impact this ASU will have on its consolidated financial statements and related disclosures. Recently, the FASB issued ASU No. 2018-01, *Leases (Topic 842), Land Easement Practical Expedient for Transition to Topic 842*. This ASU would permit an entity not to apply Topic 842 to land easements and rights-of-way that exist or expired before the effective date of Topic 842 and that were not previously assessed under Topic 840. An entity would continue to apply its current accounting policy for accounting for land easements that existed before the effective date of Topic 842. Once an entity adopts Topic 842, it would apply that Topic prospectively to all new (or modified) land easements and rights-of-way to determine whether the arrangement should be accounted for as a lease. For Devon, these contracts represent a relatively small percentage of the aggregate value of contracts being evaluated but represent a significant number of contracts.

Based on continuing research, Devon estimates a large number of contracts and data elements must be gathered and reviewed to ensure proper accounting of these contracts once this ASU is effective. Devon has preliminarily determined its portfolio of leased assets and is reviewing all related contracts to determine the impact the adoption will have on its consolidated financial statements. Devon anticipates the adoption of this standard will significantly impact its consolidated financial statements, systems, processes and controls and is evaluating technology requirements and solutions needed to comply with the requirements of this ASU. While we cannot currently estimate the quantitative effect that ASU 2016-02 will have on our consolidated financial statements, the adoption will increase our asset and liability balances on the consolidated balance sheets due to the required recognition of right-of-use assets and corresponding lease liabilities.

The FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* This ASU will require entities to present the service cost component of net periodic benefit cost in the same line item as other employee compensation costs. Only the service cost component of net periodic benefit cost is eligible for capitalization. This ASU is effective for Devon beginning January 1, 2018, and income statement presentation changes will be applied retrospectively, while service cost component capitalization will be applied prospectively. Upon adoption of this ASU, Devon will reclassify $7 million, $14 million and $16 million of non-service cost components of net periodic benefit costs for 2017, 2016 and 2015, respectively, as other expenses. Such amounts are currently classified in Devon's G&A. No other changes upon adopting this ASU are expected to be material.

The FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash.* This ASU requires an entity to show the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents on the statement of cash flows and to provide a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. This reconciliation can be presented either on the face of the consolidated statement of cash flows or in the notes to the financial statements. This ASU is effective for Devon beginning January 1, 2018, and will be applied retrospectively. Currently, Devon does not expect the adoption to have a material impact on its consolidated statement of cash flows.

The FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business.* This ASU clarifies the definition of a business to assist entities with evaluating whether a set of transferred assets and activities should be accounted for as an acquisition or disposals of assets or as a business. The guidance requires an entity to evaluate if substantially all of the fair value of the gross assets acquired, or disposed of, are concentrated in a single identifiable asset or a group of similar identifiable assets; if so, the set of transferred assets and activities would not represent a business. The guidance also requires that a set of assets must include an input and a substantive process that together significantly contribute to the ability to create an output to be considered a business. This ASU is effective for Devon beginning January 1, 2018, and will be applied prospectively. Devon does not expect the adoption to have a material impact on its consolidated financial statements; however these amendments could result in the recording of fewer business combinations in future periods.

The FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.* This ASU will expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with a company's risk management activities. The guidance also eliminates the requirement to separately measure and report hedge ineffectiveness. This ASU only applies to entities that elect hedge accounting, which Devon has not for derivative financial instruments during the three year period ended December 31, 2017. This ASU is effective for annual and interim periods beginning January 1, 2019, with early adoption permitted in 2018. The ASU is required to be adopted using a cumulative effect (modified retrospective) transition method, which utilizes a cumulative-effect adjustment to retained earnings in the period of adoption to account for prior period effects rather than restating previously reported results. Devon is currently evaluating the provisions of this ASU and assessing the impact it may have on its consolidated financial statements if hedge accounting were elected by Devon in the future.

2. Change in Accounting Principle

In the fourth quarter of 2017, Devon changed its method of accounting for oil and gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods has been recast to reflect retrospective application of the successful efforts method. In general, under successful efforts, exploration costs such as exploratory dry holes, exploratory geological and geophysical costs, delay rentals, unproved impairments, and exploration overhead are charged against earnings as incurred, versus being capitalized under the full cost method of accounting. In addition, gains or losses, if applicable, are recognized more frequently on the dispositions of oil and gas property and equipment under the successful efforts method. Devon has recast certain historical information for all periods presented, including the Consolidated Comprehensive Statements of Earnings, Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Equity and related information in Notes 1, 2, 3, 5, 6, 7, 8, 9, 10, 11, 13, 14, 16, 22, 23, 24 and 25.

The following tables present the effects of the change to the successful efforts method in the consolidated financial statements.

	Changes to the Consolidated Comprehensive Statement of Earnings		
For the Year Ended December 31, 2017	**Under Full Cost**	**Changes**	**As Reported Under Successful Efforts**
Exploration expenses	$ —	$ 380	$ 380
Depreciation, depletion and amortization	1,579	495	2,074
Asset dispositions	(5)	(212)	(217)
General and administrative expenses	682	190	872
Financing costs, net	494	4	498
Other expenses	(102)	(22)	(124)
Earnings before income taxes	1,731	(835)	896
Income tax benefit	(140)	(42)	(182)
Net earnings	1,871	(793)	1,078
Net earnings attributable to Devon	1,691	(793)	898
Net earnings per share attributable to Devon:			
Basic	3.22	(1.51)	1.71
Diluted	3.20	(1.50)	1.70
Comprehensive earnings:			
Net earnings	1,871	(793)	1,078
Foreign currency translation and other	4	79	83
Comprehensive earnings	1,904	(714)	1,190
Comprehensive earnings attributable to Devon	1,724	(714)	1,010

For the Year Ended December 31, 2016	Changes to the Consolidated Comprehensive Statement of Earnings		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Exploration expenses	$ —	$ 215	$ 215
Depreciation, depletion and amortization	1,792	304	2,096
Asset impairments	4,975	(3,665)	1,310
Asset dispositions	(1,887)	404	(1,483)
General and administrative expenses	658	207	865
Financing costs, net	904	3	907
Other expenses	403	(28)	375
Loss before income taxes	(3,877)	2,560	(1,317)
Income tax expense (benefit)	(173)	314	141
Net loss	(3,704)	2,246	(1,458)
Net loss attributable to Devon	(3,302)	2,246	(1,056)
Net loss per share attributable to Devon:			
Basic	(6.52)	4.43	(2.09)
Diluted	(6.52)	4.43	(2.09)
Comprehensive loss:			
Net loss	(3,704)	2,246	(1,458)
Foreign currency translation and other	32	(21)	11
Comprehensive loss	(3,650)	2,225	(1,425)
Comprehensive loss attributable to Devon	(3,248)	2,225	(1,023)

For the Year Ended December 31, 2015	Changes to the Consolidated Comprehensive Statement of Earnings		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Exploration expenses	$ —	$ 451	$ 451
Depreciation, depletion and amortization	3,129	893	4,022
Asset impairments	20,820	(3,173)	17,647
Asset dispositions	—	7	7
General and administrative expenses	868	325	1,193
Financing costs, net	517	2	519
Other expenses	179	85	264
Loss before income taxes	(21,268)	1,410	(19,858)
Income tax benefit	(6,065)	(148)	(6,213)
Net loss	(15,203)	1,558	(13,645)
Net loss attributable to Devon	(14,454)	1,558	(12,896)
Net loss per share attributable to Devon:			
Basic	(35.55)	3.83	(31.72)
Diluted	(35.55)	3.83	(31.72)
Comprehensive loss:			
Net loss	(15,203)	1,558	(13,645)
Foreign currency translation and other	(559)	116	(443)
Comprehensive loss	(15,752)	1,674	(14,078)
Comprehensive loss attributable to Devon	(15,003)	1,674	(13,329)

For the Year Ended December 31, 2017	Changes to the Consolidated Statement of Cash Flows		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Net earnings	$ 1,871	$ (793)	$ 1,078
Depreciation, depletion and amortization	1,579	495	2,074
Exploratory dry hole expense and unproved leasehold impairments	—	219	219
Gains and losses on asset sales	(5)	(212)	(217)
Deferred income tax benefit	(252)	(42)	(294)
Share-based compensation	158	40	198
Other	(108)	(14)	(122)
Net cash from operating activities	3,216	(307)	2,909
Capital expenditures	(3,074)	315	(2,759)
Divestitures of property and equipment	425	(8)	417
Net cash from investing activities	(2,517)	307	(2,210)

For the Year Ended December 31, 2016	Changes to the Consolidated Statement of Cash Flows		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Net loss	$ (3,704)	$ 2,246	$ (1,458)
Depreciation, depletion and amortization	1,792	304	2,096
Exploratory dry hole expense and unproved leasehold impairments	—	113	113
Asset impairments	4,975	(3,665)	1,310
Gains and losses on asset sales	(1,887)	404	(1,483)
Deferred income tax expense (benefit)	(273)	314	41
Share-based compensation	194	39	233
Other	303	(33)	270
Net cash from operating activities	1,778	(278)	1,500
Capital expenditures	(2,330)	283	(2,047)
Divestitures of property and equipment	3,118	(5)	3,113
Net cash from investing activities	(872)	278	(594)

For the Year Ended December 31, 2015	Changes to the Consolidated Statement of Cash Flows		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Net loss	$ (15,203)	$ 1,558	$ (13,645)
Depreciation, depletion and amortization	3,129	893	4,022
Exploratory dry hole expense and unproved leasehold impairments	—	248	248
Asset impairments	20,820	(3,173)	17,647
Gains and losses on asset sales	—	7	7
Deferred income tax benefit	(5,828)	(148)	(5,976)
Share-based compensation	181	63	244
Other	281	31	312
Net cash from operating activities	5,419	(521)	4,898
Capital expenditures	(5,308)	521	(4,787)
Net cash from investing activities	(6,324)	521	(5,803)

For the Year Ended December 31, 2017	Changes to the Consolidated Balance Sheet		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Oil and gas property and equipment, net	$ 9,702	3,616	$ 13,318
Total property and equipment, net	17,555	3,616	21,171
Goodwill	3,964	(1,581)	2,383
Total assets	28,206	2,035	30,241
Deferred income taxes	434	401	835
Additional paid-in capital	7,206	127	7,333
Retained earnings	44	658	702
Accumulated other comprehensive earnings	317	849	1,166
Total stockholders' equity attributable to Devon	7,620	1,634	9,254
Total equity	12,470	1,634	14,104
Total liabilities and equity	28,206	2,035	30,241

For the Year Ended December 31, 2016	Changes to the Consolidated Balance Sheet		
	Under Full Cost	Changes	As Reported Under Successful Efforts
Oil and gas property and equipment, net	$ 8,655	$ 4,343	$ 12,998
Total property and equipment, net	16,190	4,343	20,533
Goodwill	3,964	(1,581)	2,383
Total assets	25,913	2,762	28,675
Deferred income taxes	648	415	1,063
Accumulated deficit	(1,646)	1,577	(69)
Accumulated other comprehensive earnings	284	770	1,054
Total stockholders' equity attributable to Devon	5,927	2,347	8,274
Total equity	10,375	2,347	12,722
Total liabilities and equity	25,913	2,762	28,675

3. Acquisitions and Divestitures

Devon Acquisitions

In January 2016, Devon acquired approximately 80,000 net acres (unaudited) and assets in the STACK play for approximately $1.5 billion. Devon funded the acquisition with $849 million of cash, after adjustments, and $659 million of equity. The allocation of the purchase price was approximately $1.3 billion to unproved properties and approximately $200 million to proved properties.

In December 2015, Devon acquired approximately 253,000 net acres (unaudited) and assets in the Powder River Basin for approximately $499 million. Devon funded the acquisition with $300 million of cash and $199 million of equity. The allocation of the purchase price was $393 million to unproved properties and $106 million to proved properties.

Devon Asset Divestitures

Upstream Assets

In May 2017, Devon announced a program to divest approximately $1 billion of upstream assets. The non-core assets identified for monetization include select portions of the Barnett Shale focused primarily in and around Johnson County and other properties located principally within Devon's U.S. resource base. Through December 31, 2017, Devon completed divestiture transactions with proceeds totaling approximately $415 million, before purchase price adjustments, and a net gain of $212 million. Estimated proved reserves associated with these assets were less than 1% of total U.S. proved reserves. Devon's remaining divestiture of Johnson County assets is expected to close in 2018.

During 2016, in several separate transactions with different purchasers, Devon divested non-core assets located in the Mississippian, east Texas, the Anadarko Basin and the Midland Basin. The following table presents a summary of Devon's divestiture activity for 2016.

Date	Proceeds Received	Gains on Sale	Proved Reserves (MMBoe)	Percentage of U.S. Proved Reserves
Second quarter 2016	$ 200	$ 83	11	1%
Third quarter 2016	1,653	726	146	9%
Total	$ 1,853	$ 809	157	10%

These divestitures in 2017 and 2016 primarily related to sales of entire common operating fields. Therefore, Devon recognized a gain on the transactions. As part of the gain computations, approximately $290 million of asset retirement obligations were assumed by purchasers and $80 million of goodwill was allocated to these divested assets.

Access Pipeline

In October 2016, Devon divested its 50% interest in Access Pipeline for $1.1 billion ($1.4 billion Canadian dollars) and recognized a gain of approximately $540 million on the transaction. In conjunction with the divestiture, Devon entered into a transportation agreement whereby Devon's Canadian thermal-oil acreage is dedicated to Access Pipeline for an initial term of 25 years. Devon will be charged a market-based toll on its thermal-oil production over this term. Devon is committed to use less than 90% of the potential pipeline capacity. In addition, Devon is entitled to an incremental payment of approximately $150 million Canadian dollars following sanctioning and committing to the requisite volume increase in respect of a new thermal-oil project on Devon's Pike lease in Alberta, with such incremental payment being received prior to tolls being payable on such volumes.

EnLink Acquisitions

In January 2016, EnLink acquired Anadarko Basin gathering and processing midstream assets, along with dedicated acreage service rights and service contracts, for approximately $1.4 billion. The purchase price was $1.0 billion to intangible assets and approximately $400 million to property and equipment. EnLink funded the acquisition with approximately $215 million of General Partner common units and approximately $800 million of cash, primarily financed with the issuance of EnLink preferred units. The remaining $500 million of the purchase price was to be paid within one year with the option to defer $250 million of the final payment 24 months from the close date. The first installment payment of $250 million was paid in January 2017 using divestiture proceeds, proceeds from equity issuances and borrowings under EnLink's credit facility. The remaining $250 million payment is reported in other current liabilities in the accompanying consolidated balance sheets and was made in January 2018 using proceeds from equity issuances and borrowings under EnLink's credit facility.

In August 2016, EnLink formed a joint venture to operate and expand its midstream assets in the Delaware Basin. The joint venture is initially owned 50.1% by EnLink and 49.9% by the joint venture partner. As of December 31, 2016, EnLink contributed approximately $251 million of existing non-monetary assets and cash to the joint venture and had committed an additional $285 million in capital to fund potential future development projects and potential acquisitions. The joint venture partner committed an aggregate of approximately $400 million of capital, including cash contributions of approximately $144 million, and granted EnLink call rights beginning in 2021 to acquire increasing portions of the joint venture partner's interest.

In November 2016, EnLink entered into a gathering and compression joint venture with a commitment of approximately $40 million to expand its midstream assets in the STACK. The joint venture is initially owned 30% by EnLink and 70% by the joint venture partner. As of December 31, 2016, EnLink contributed approximately $29 million in cash for new infrastructure build. After the initial capital commitment, EnLink and the joint venture partner will be responsible for their proportionate share of capital costs.

The following table presents a summary of EnLink's acquisition activity for 2015.

		Purchase Price		Allocation			
Date	Midstream assets	Cash	EnLink Units	PP&E	Goodwill	Intangibles	Other
January 2015	Permian Basin	$ 108	—	$ 30	$ 30	$ 43	$ 5
March 2015	Permian Basin	$ 240	$ 360	$ 302	$ 18	$ 281	$ (1)
October 2015	Delaware Basin	$ 141	—	$ 36	$ 11	$ 99	$ (5)

EnLink Asset Divestitures and Dropdowns

In December 2016, EnLink entered into definitive agreements to divest approximately $278 million of certain non-core midstream assets. As of December 31, 2016, these assets were classified as held for sale. During the first quarter of 2017, EnLink divested its ownership interest in Howard Energy Partners for approximately $190 million.

In February 2015, EnLink acquired a 25% equity interest in EMH from the General Partner in exchange for units valued at approximately $925 million. In May 2015, EnLink acquired the remaining 25% equity interest in EMH from the General Partner in exchange for units valued at approximately $900 million.

In April 2015, EnLink acquired VEX from Devon for approximately $176 million in cash and equity. EnLink also assumed approximately $35 million in certain future construction costs to expand the system to full capacity. Because Devon controls EnLink and the General Partner, the acquisition of VEX by EnLink from Devon was accounted for as a transfer of net assets between entities under common control.

4. Derivative Financial Instruments

Commodity Derivatives

As of December 31, 2017, Devon had the following open oil derivative positions. The first table presents Devon's oil derivatives that settle against the average of the prompt month NYMEX WTI futures price. The second table presents Devon's oil derivatives that settle against the respective indices noted within the table.

	Price Swaps		Price Collars		
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q1-Q4 2018	49,625	$ 52.13	51,860	$ 46.06	$ 56.06
Q1-Q4 2019	7,307	$ 52.22	6,559	$ 45.82	$ 55.82

	Oil Basis Swaps			Oil Basis Collars		
Period	Index	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Differential to WTI ($/Bbl)	Weighted Average Ceiling Differential to WTI ($/Bbl)
Q1-Q4 2018	Midland Sweet	23,000	$ (1.02)	—	$ —	$ —
Q1-Q4 2018	Argus LLS	12,000	$ 3.95	—	$ —	$ —
Q1-Q4 2018	Western Canadian Select	75,490	$ (14.84)	1,830	$ (15.50)	$ (13.93)
Q1-Q4 2019	Midland Sweet	27,000	$ (0.47)	—	$ —	$ —

As of December 31, 2017, Devon had the following open natural gas derivative positions. The first table presents Devon's natural gas derivatives that settle against the Inside FERC first of the month Henry Hub index. The second table presents Devon's natural gas derivatives that settle against the respective indices noted within the table.

	Price Swaps		Price Collars		
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
Q1-Q4 2018	371,956	$ 3.06	197,516	$ 2.94	$ 3.26
Q1-Q4 2019	28,466	$ 2.98	28,466	$ 2.84	$ 3.14

	Natural Gas Basis Swaps		
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q1-Q4 2018	Panhandle Eastern Pipe Line	50,000	$ (0.29)

As of December 31, 2017, Devon had the following open NGL derivative positions. Devon's NGL positions settle against the average of the prompt month OPIS Mont Belvieu, Texas index.

		Price Swaps	
Period	Product	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Q1-Q4 2018	Ethane	6,747	$ 11.89
Q1-Q4 2018	Natural Gasoline	5,500	$ 54.24
Q1-Q4 2018	Normal Butane	6,750	$ 38.46
Q1-Q4 2018	Propane	9,500	$ 33.19

As of December 31, 2017, EnLink had the following open derivative positions associated with gas processing and fractionation. EnLink's NGL positions settle by purity product against the average of the prompt month OPIS Mont Belvieu, Texas index. EnLink's natural gas positions settle against the Henry Hub Gas Daily index.

Period	Product	Volume (Total)		Weighted Average Price Paid	Weighted Average Price Received
Q1-Q4 2018	Propane	681	MBbls	Index	$0.88/gal
Q1 2018-Q1 2019	Natural Gas	122,629	MMBtu/d	Index	$2.57/MMBtu

Interest Rate Derivatives

As of December 31, 2017, Devon had the following open interest rate derivative positions:

Notional	Rate Received	Rate Paid	Expiration
$ 750	Three Month LIBOR	2.98%	December 2048 (1)
$ 100	1.76%	Three Month LIBOR	January 2019

(1) Mandatory settlement in December 2018.

Financial Statement Presentation

The following table presents the net gains and losses by derivative financial instrument type followed by the corresponding individual consolidated comprehensive statements of earnings caption.

	Year Ended December 31,		
	2017	2016	2015
Commodity derivatives:			
Upstream revenues	$ 157	$ (201)	$ 503
Marketing and midstream revenues	(1)	(13)	9
Interest rate derivatives:			
Other expenses	(22)	(19)	(20)
Foreign currency derivatives:			
Other expenses	—	(153)	246
Net gains (losses) recognized	$ 134	$ (386)	$ 738

The following table presents the derivative fair values by derivative financial instrument type followed by the corresponding individual consolidated balance sheet caption.

	December 31, 2017	December 31, 2016
Commodity derivative assets:		
Other current assets	$ 209	$ 9
Other long-term assets	2	1
Interest rate derivative assets:		
Other current assets	1	1
Total derivative assets	$ 212	$ 11
Commodity derivative liabilities:		
Other current liabilities	$ 267	$ 187
Other long-term liabilities	27	16
Interest rate derivative liabilities:		
Other current liabilities	64	—
Other long-term liabilities	—	41
Total derivative liabilities	$ 358	$ 244

5. Share-Based Compensation

In the second quarter of 2017, Devon's stockholders approved the 2017 Plan. The 2017 Plan replaces the 2015 Plan. From the effective date of the 2017 Plan, no further awards may be made under the 2015 Plan, and awards previously granted will continue to be governed by the terms of the respective award documents. Subject to the terms of the 2017 Plan, awards may be made for a total of 33.5 million shares of Devon common stock, plus the number of shares available for issuance under the 2015 Plan (including shares subject to outstanding awards that were transferred to the 2017 Plan in accordance with its terms). The 2017 Plan authorizes the Compensation Committee, which consists of independent, non-management members of Devon's Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards or units, Canadian restricted stock units, performance units and stock appreciation rights to eligible employees. The 2017 Plan also authorizes the grant of nonqualified stock options, restricted stock awards or units and stock appreciation rights to non-employee directors. To calculate the number of shares that may be granted in awards under the 2017 Plan, options and stock appreciation rights represent one share and other awards represent 2.3 shares.

The vesting for certain share-based awards was accelerated in 2016 in conjunction with the reduction of workforce described in Note 7. Approximately $60 million of associated expense for these accelerated awards is included in other expenses in the accompanying consolidated comprehensive statements of earnings.

The table below presents the share-based compensation expense included in Devon's accompanying consolidated comprehensive statements of earnings.

	Year Ended December 31,		
	2017	2016	2015
G&A	$ 141	$ 124	$ 185
Exploration expenses	7	6	9
Total Devon	148	130	194
G&A	37	24	31
Marketing and midstream expenses	11	7	5
Total EnLink	48	31	36
Total	$ 196	$ 161	$ 230
Related income tax benefit	$ 6	$ 6	$ 67

The following table presents a summary of Devon's unvested restricted stock awards and units, performance-based restricted stock awards and performance share units granted under the plans.

	Restricted Stock Awards and Units		Performance-Based Restricted Stock Awards		Performance Share Units	
	Awards and Units	Weighted Average Grant-Date Fair Value	Awards	Weighted Average Grant-Date Fair Value	Units	Weighted Average Grant-Date Fair Value
	(Thousands, except fair value data)					
Unvested at 12/31/16	6,407	$ 34.40	585	$ 37.60	2,604	$ 46.66
Granted	2,691	$ 44.87	223	$ 44.85	1,010	$ 52.58
Vested	(2,431)	$ 39.51	(233)	$ 41.27	(832)	$ 78.19
Forfeited	(339)	$ 35.92	—	$ —	(24)	$ 40.70
Unvested at 12/31/17	6,328	$ 36.81	575	$ 38.92	2,758 (1)	$ 41.21

(1) A maximum of 5.5 million common shares could be awarded based upon Devon's final TSR ranking.

The following table presents the aggregate fair value of awards and units that vested during the indicated period.

	2017	2016	2015
Restricted Stock Awards and Units	$ 105	$ 73	$ 101
Performance-Based Restricted Stock Awards	$ 10	$ 5	$ 8
Performance Share Units	$ 38	$ 13	$ 22

The following table presents the unrecognized compensation cost and the related weighted average recognition period associated with unvested awards and units as of December 31, 2017.

	Restricted Stock Awards and Units	Performance-Based Restricted Stock Awards	Performance Share Units
Unrecognized compensation cost	$ 135	$ 5	$ 28
Weighted average period for recognition (years)	2.4	1.6	1.9

Restricted Stock Awards and Units

Restricted stock awards and units are subject to the terms, conditions, restrictions and limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, the service requirement for vesting ranges from one to four years. During the vesting period, recipients of restricted stock awards made under the 2015 Plan or 2009 Plan receive dividends that are not subject to restrictions or other limitations. However, dividends declared during the vesting period with respect to restricted stock awards made under the 2017 Plan and all restricted stock units will not be paid until the underlying award vests. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon's common stock on the grant date of the award or unit, which is expensed over the applicable vesting period.

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards are granted to certain members of Devon's senior management. Vesting of the awards is dependent on Devon meeting certain internal performance targets and the recipient meeting certain service requirements. Generally, the service requirement for vesting ranges from one to four years. In order for awards to vest, the performance target must be met in the first year. If the performance target is met, the recipient is entitled to dividends under the same terms described above for nonperformance-based restricted stock. If the performance target and service period requirements are not met, the award does not vest. Devon estimates the fair values of the awards as the closing price of Devon's common stock on the grant date of the award, which is expensed over the applicable vesting period.

Performance Share Units

Performance share units are granted to certain members of Devon's management and senior employees. Each unit that vests entitles the recipient to one share of Devon common stock. The vesting of these units is based on comparing Devon's TSR to the TSR of a predetermined group of fourteen peer companies over the specified three-year performance period. The vesting of units may be between zero and 200% of the units granted depending on Devon's TSR as compared to the peer group on the vesting date.

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

	2017	2016	2015
Grant-date fair value	$ 51.05 — $ 53.12	$ 9.24 — $ 10.61	$ 81.99 — $ 85.05
Risk-free interest rate	1.50%	0.94%	1.06%
Volatility factor	45.8%	37.7%	26.2%
Contractual term (years)	2.89	2.83	2.89

Stock Options

In accordance with Devon's incentive plans, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which may not exceed eight years from the date of grant. The recipient must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Generally, the service requirement for vesting ranges from one to four years. The fair value of stock options on the date of grant is expensed over the applicable vesting period. No stock options were granted in 2017, 2016 and 2015. The following table presents a summary of Devon's outstanding stock options.

		Weighted Average		
	Options	Exercise Price	Remaining Term	Intrinsic Value
	(Thousands)		(Years)	
Outstanding at December 31, 2016	2,532	$ 68.06		
Expired	(786)	$ 63.67		
Outstanding at December 31, 2017	1,746	$ 70.04	1.33	$ —
Exercisable at December 31, 2017	1,746	$ 70.04	1.33	$ —

The aggregate intrinsic value of stock options that were exercised during 2015 was $0.2 million. As of December 31, 2017, Devon had no unrecognized compensation cost related to unvested stock options.

EnLink Share-Based Awards

In March 2017, the General Partner and EnLink issued restricted incentive units as bonus payments to officers and certain employees. The combined grant date fair value was $10 million, and the total cost was recognized in the first quarter of 2017 due to the awards vesting immediately.

The following table presents a summary of the unrecognized compensation cost and the related weighted average recognition period associated with the General Partner's and EnLink's unvested restricted incentive units and performance units as of December 31, 2017.

	General Partner		EnLink	
	Restricted Incentive Units	Performance Units	Restricted Incentive Units	Performance Units
Unrecognized compensation cost	$ 11	$ 5	$ 12	$ 5
Weighted average period for recognition (years)	1.7	1.8	1.7	1.8

6. Asset Impairments

The following table presents a summary of Devon's asset impairments. Unproved impairments shown below are included in exploration expenses in the consolidated comprehensive statements of earnings.

	Year Ended December 31,		
	2017	2016	2015
Proved oil and gas assets	$ —	$ 435	$ 16,076
EnLink goodwill	—	873	1,328
EnLink other intangible assets	—	—	223
Other assets	17	2	20
Total asset impairments	$ 17	$ 1,310	$ 17,647
Unproved impairments	$ 217	$ 77	$ 260

Proved Oil and Gas Impairments

In 2015 and 2016, Devon impaired a significant portion of its U.S. oil and gas portfolio due to lower forecasted oil, gas and NGL prices.

EnLink Goodwill and Other Intangible Assets Impairments

In 2016 and 2015, Devon recognized goodwill and other intangible asset impairments related to EnLink's business. Additional information regarding the impairments is discussed in Note 14.

Unproved Impairments

In 2017, 2016 and 2015, Devon allowed certain non-core acreage to expire without plans for development resulting in unproved impairments

7. Other Expenses

The following table summarizes Devon's other expenses presented in the accompanying consolidated comprehensive statement of earnings.

	Year Ended December 31,		
	2017	2016	2015
Foreign exchange (gain) loss, net	$ (132)	$ 39	$ 25
Asset retirement obligation accretion	62	75	75
Restructuring and transaction costs	—	267	78
Other, net	(54)	(6)	86
Total	$ (124)	$ 375	$ 264

Certain of Devon's non-Canadian foreign subsidiaries have a U.S. dollar functional currency, hold Canadian-dollar cash and engage 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. During 2017, Devon recognized foreign exchange gains related to these activities resulting from the weakening of the U.S. dollar in relation to the Canadian dollar.

Restructuring and Transaction Costs

The following table summarizes Devon's restructuring liabilities presented in the accompanying consolidated balance sheets.

	Other Current Liabilities	Other Long-term Liabilities	Total
Balance as of December 31, 2015	$ 13	$ 63	$ 76
Changes related to prior years' restructurings	35	(1)	34
Balance as of December 31, 2016	$ 48	$ 62	$ 110
Changes related to prior years' restructurings	(29)	(31)	(60)
Balance as of December 31, 2017	$ 19	$ 31	$ 50

Prior Years' Restructurings

In 2016, Devon recognized $227 million in employee-related and other costs associated with a reduction in workforce that was made in response to the depressed commodity price environment. Of these employee-related costs, approximately $60 million resulted from accelerated vesting of share-based grants, which are noncash charges. Additionally, approximately $24 million resulted from estimated defined benefit settlements.

As a result of the reduction of workforce, Devon ceased using certain office space that was subject to non-cancellable operating lease arrangements. Devon recognized $23 million in restructuring costs that represent the present value of its future obligations under the leases and impairment charges for leasehold improvements and furniture associated with the office space it ceased using.

In 2015, Devon recognized $24 million of employee-related and other costs associated with the reduction in workforce made subsequent to the completion of the Jackfish development projects and a decrease in planned Canadian capital investment resulting from the drop in commodity prices.

As part of the U.S. corporate headquarters office consolidation, Devon recognized an additional $54 million expense in 2015, due to the inability to fully sublease remaining office space.

Transaction Costs

In 2016, Devon and EnLink recognized $17 million in transaction costs primarily associated with the closing of the acquisitions discussed in Note 3.

8. Income Taxes

Income Tax Expense (Benefit)

The following table presents Devon's income tax components.

	Year Ended December 31,		
	2017	2016	2015
Current income tax expense (benefit):			
U.S. federal	$ 10	$ 5	$ (243)
Various states	—	(11)	(8)
Canada and various provinces	102	106	14
Total current tax expense (benefit)	112	100	(237)
Deferred income tax expense (benefit):			
U.S. federal	(192)	(3)	(5,487)
Various states	(5)	—	(332)
Canada and various provinces	(97)	44	(157)
Total deferred tax expense (benefit)	(294)	41	(5,976)
Total income tax expense (benefit)	$ (182)	$ 141	$ (6,213)

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

	Year Ended December 31,		
	2017	2016	2015
Total income tax expense (benefit)	$ (182)	$ 141	$ (6,213)
U.S. statutory income tax rate	35%	35%	35%
Non-deductible goodwill and intangible impairment	0%	(23%)	(3%)
U.S. Tax Reform	8%	0%	0%
Legal entity restructuring	(81%)	6%	0%
Other	(13%)	0%	1%
Deferred tax asset valuation allowance	31%	(29%)	(2%)
Effective income tax rate	(20%)	(11%)	31%

Devon and its subsidiaries are subject to U.S. federal income tax as well as income or capital taxes in various state and foreign jurisdictions. Devon's tax reserves are related to tax years that may be subject to examinations by the relevant taxing authority. Devon is under audit in the U.S. and various foreign jurisdictions as part of its normal course of business.

Devon assesses the realizability of its deferred tax assets. If Devon concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the asset is reduced by a valuation allowance. Numerous judgements and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

2017

On December 22, 2017, the Tax Reform Legislation was enacted into law and contains several key tax provisions that affect Devon, including a one-time mandatory transition tax on accumulated foreign earnings and a reduction of the corporate income tax rate to 21% effective January 1, 2018, among others. Devon is required to recognize the effect of the tax law changes in the period of enactment, such as determining the transition tax, remeasuring U.S. deferred tax assets and liabilities and reassessing the net realizability of deferred tax assets and liabilities.

In December 2017, the SEC staff issued Staff Accounting Bulletin No. 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* (SAB 118), which allows Devon to record provisional amounts during a measurement period not to extend beyond one year after the enactment date. As the Tax Reform Legislation was passed late in the fourth quarter of 2017 and ongoing guidance and accounting interpretation are expected over the next 12 months, Devon considers the accounting of the transition tax, deferred tax remeasurements, and other items to be incomplete due to the forthcoming guidance and our ongoing analysis of final year-end data and tax positions. Devon expects to complete its analysis within the measurement period in accordance with SAB 118. Provisional amounts recorded this quarter are as follows:

(a) Devon’s U.S. segment recognized $167 million of deferred tax expense for the one-time mandatory transition tax on accumulated foreign earnings.

(b) Devon’s U.S. segment recognized $108 million in deferred tax expense and EnLink recognized $211 million in deferred tax benefit related to the reduction of the U.S. corporate income tax rate to 21%.

In the fourth quarter of 2017, Devon’s Canadian segment generated nonrecurring capital losses from internal legal entity restructuring. A deferred tax asset of $727 million was recognized related to the capital losses, offset by a $641 million increase in the valuation allowance.

Throughout 2017, Devon continued to maintain a 100% valuation allowance against its U.S. deferred tax assets resulting from prior year cumulative financial losses largely due to asset impairments and significant net operating losses for U.S. federal and state income tax. Devon reduced its U.S. segment valuation allowance by $323 million in 2017 based primarily on the financial income recorded during the period. Furthermore, a partial allowance continues to be held against certain Canadian segment deferred tax assets. The valuation allowances impacted the effective tax rate and are discussed in the next section.

Also in the table above, the “other” effect is primarily composed of permanent differences for which dollar amounts do not increase or decrease in relation to the change in pre-tax earnings. Generally, such items have an insignificant impact on our effective income tax rate. However, these items have a more noticeable impact to our rate in 2017 due to lower relative earnings during the period. During 2017, “other” is primarily related to the taxation of other financing items.

2016

During 2016, Devon’s U.S. segment recognized an additional $313 million valuation allowance against its deferred tax assets. The allowance results from continued financial losses in 2016. As of December 31, 2016, the allowance continued to represent a 100% valuation against the U.S. net deferred tax assets. Additionally, the Canadian segment recognized a $71 million partial valuation allowance resulting from continued financial losses.

In the first quarter of 2016, EnLink recognized a goodwill impairment of approximately $873 million. Additionally, during the third quarter of 2016, Devon derecognized $83 million of goodwill related to its U.S. operations in conjunction with the divestiture of certain non-core U.S. upstream oil and gas assets. These items are not deductible for purposes of calculating income tax and, therefore, impact the effective tax rate.

2015

In the third and fourth quarters of 2015, EnLink recognized goodwill and intangibles impairments of approximately $1.6 billion, which impacted the effective tax rate.

During 2015, Devon recognized approximately $16 billion of oil and gas impairments related to its U.S. operations. These impairments resulted in deferred tax assets against which Devon recognized a $403 million valuation allowance.

Deferred Tax Assets and Liabilities

The following table presents the tax effects of temporary differences that gave rise to Devon's deferred tax assets and liabilities.

	December 31, 2017	December 31, 2016
Deferred tax assets:		
Asset retirement obligations	$ 313	$ 488
Accrued liabilities	62	130
Net operating loss carryforwards	865	777
Pension benefit obligations	54	98
Canadian capital loss carryforwards	760	17
Other	135	186
Total deferred tax assets before valuation allowance	2,189	1,696
Less: valuation allowance	(968)	(645)
Net deferred tax assets	1,221	1,051
Deferred tax liabilities:		
Property and equipment	(1,703)	(1,635)
Long-term debt	(92)	(53)
Other	(261)	(426)
Total deferred tax liabilities	(2,056)	(2,114)
Net deferred tax liability	$ (835)	$ (1,063)

At December 31, 2017, Devon has recognized $865 million of deferred tax assets related to various net operating loss carryforwards available to offset future income taxes. The Canadian segment has $710 million of noncapital loss carryforwards expiring between 2029 and 2037. Devon's U.S. segment has $2.4 billion of U.S. federal carryforwards expiring between 2036 and 2037 and $1.7 billion of U.S. state carryforwards expiring between 2018 and 2037. EnLink has $259 million of U.S. federal carryforwards expiring between 2034 and 2037 and $263 million of state carryforwards expiring between 2028 and 2037. In the current environment, Devon expects tax benefits from the Canadian carryforwards to be utilized in 2018 and beyond and EnLink carryforwards to be utilized in 2020 and beyond. Devon currently does not anticipate utilizing the U.S. federal or state net operating loss carryforwards, as indicated by the full valuation allowance position in the U.S. segment.

As a result of the reduction in U.S. statutory income tax rate and favorable temporary differences, Devon reduced its valuation allowance by $337 million against the U.S. deferred tax assets in 2017 and remains in a full valuation allowance position. Also during 2017, Devon's Canadian segment recognized a $660 million partial valuation allowance against the deferred tax asset related to the Canadian capital loss carryforward due to projected lack of future capital gain income. In the event Devon were to determine that it would be able to realize the deferred income tax assets in the future, Devon would adjust the valuation allowance, reducing the provision for income taxes in the period of such adjustment.

As of December 31, 2017, Devon's unremitted foreign earnings from its international operations totaled approximately $908 million. All of this amount was deemed to be indefinitely reinvested into the development and growth of Devon's Canadian business. Therefore, Devon has not recognized a deferred tax liability for U.S. income taxes associated with such earnings. If such earnings were to be repatriated to the U.S., Devon may be subject to U.S. income taxes and foreign withholding taxes. However, it is not practical to estimate the amount of such additional taxes that may be payable due to the inter-relationship of the various factors involved in making such an estimate.

Unrecognized Tax Benefits

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

	December 31,	
	2017	2016
Balance at beginning of year	$ 202	$ 131
Tax positions taken in prior periods	(7)	36
Tax positions taken in current year	(3)	—
Accrual of interest related to tax positions taken	16	39
Settlements	(101)	—
Lapse of statute of limitations	—	(5)
Foreign currency translation	8	1
Balance at end of year	$ 115	$ 202

Devon's unrecognized tax benefit balance at December 31, 2017 and 2016 included $28 million and $68 million, respectively, of interest and penalties. If recognized, $115 million of Devon's unrecognized tax benefits as of December 31, 2017 would affect Devon's effective income tax rate. During 2017, Devon removed $101 million of unrecognized tax benefits, including $50 million of interest, as a result of the settlement of certain tax examinations. Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

Jurisdiction	Tax Years Open
U.S. Federal	2012-2017
Various U.S. states	2012-2017
Canada Federal	2004-2017
Various Canadian provinces	2004-2017

Certain statute of limitation expirations are scheduled to occur in the next twelve months. However, Devon is currently in various stages of the administrative review process for certain open tax years. In addition, Devon is currently subject to various income tax audits that have not reached the administrative review process.

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

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

	Year Ended December 31,		
	2017	2016	2015
Net earnings (loss):			
Net earnings (loss) attributable to Devon	$ 898	$ (1,056)	$ (12,896)
Attributable to participating securities	(10)	(2)	(5)
Basic and diluted earnings (loss)	$ 888	$ (1,058)	$ (12,901)
Common shares:			
Common shares outstanding - total	525	513	412
Attributable to participating securities	(5)	(6)	(5)
Common shares outstanding - basic	520	507	407
Dilutive effect of potential common shares issuable	3	—	—
Common shares outstanding - diluted	523	507	407
Net earnings (loss) per share attributable to Devon:			
Basic	$ 1.71	$ (2.09)	$ (31.72)
Diluted	$ 1.70	$ (2.09)	$ (31.72)
Antidilutive options [1]	2	3	4

(1) Amounts represent options to purchase shares of Devon's common stock that are excluded from the diluted net earnings per share calculations because the options are antidilutive.

10. Other Comprehensive Earnings

Components of other comprehensive earnings consist of the following:

	Year Ended December 31,		
	2017	2016	2015
Foreign currency translation and other:			
Beginning accumulated foreign currency translation and other	$ 1,226	$ 1,215	$ 1,658
Change in cumulative translation adjustment and other	113	22	(490)
Income tax benefit (expense)	(30)	(11)	47
Ending accumulated foreign currency translation and other	1,309	1,226	1,215
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(172)	(194)	(204)
Net actuarial loss and prior service cost arising in current year	10	(28)	(5)
Recognition of net actuarial loss and prior service cost in earnings [1]	19	26	21
Curtailment and settlement of pension benefits	—	24	—
Income tax expense	—	—	(6)
Ending accumulated pension and postretirement benefits	(143)	(172)	(194)
Accumulated other comprehensive earnings, net of tax	$ 1,166	$ 1,054	$ 1,021

(1) These accumulated other comprehensive earnings components are included in the computation of net periodic benefit cost, which is a component of G&A on the accompanying consolidated comprehensive statements of earnings. See Note 18 for additional details.

11. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2017	2016	2015
Net change in working capital accounts, net of assets and liabilities assumed:			
Accounts receivable	$ (284)	$ (176)	$ 942
Income taxes receivable	8	130	384
Other current assets	(12)	215	(57)
Accounts payable	105	(167)	(190)
Revenues and royalties payable	257	96	(526)
Other current liabilities	(53)	(74)	(818)
Net change in working capital	$ 21	$ 24	$ (265)
Interest paid (net of capitalized interest)	$ 481	$ 569	$ 497
Income taxes paid (received)	$ 78	$ (159)	$ (279)

In 2016, Devon's acquisition of certain STACK assets included the noncash issuance of Devon common stock. Further, in 2016, EnLink's acquisition of Anadarko Basin gathering and processing midstream assets included noncash issuance of General Partner common units. Additionally, EnLink's formation of a joint venture during the third quarter of 2016 included non-monetary asset contributions. See Note 3 for additional details.

In 2015, Devon's acquisition of certain Powder River Basin assets included a noncash common stock issuance totaling $199 million. EnLink's acquisitions in 2015 also included $360 million of noncash equity.

12. Accounts Receivable

Components of accounts receivable include the following:

	December 31, 2017	December 31, 2016
Oil, gas and NGL sales	$ 559	$ 487
Joint interest billings	134	110
Marketing and midstream revenues	959	708
Other	29	69
Gross accounts receivable	1,681	1,374
Allowance for doubtful accounts	(11)	(18)
Net accounts receivable	$ 1,670	$ 1,356

13. Property, Plant and Equipment

Capitalized Costs

The following tables reflect the aggregate capitalized costs related to Devon's oil and gas and non-oil and gas activities.

	December 31, 2017		
	U.S.	Canada	Total
Proved	$ 40,491	$ 6,804	$ 47,295
Unproved and properties under development	984	1,473	2,457
Total oil and gas	41,475	8,277	49,752
Accumulated DD&A	(32,379)	(4,055)	(36,434)
Oil and gas property and equipment, net	$ 9,096	$ 4,222	$ 13,318

	December 31, 2016		
	U.S.	Canada	Total
Proved	$ 38,842	$ 6,163	$ 45,005
Unproved and properties under development	2,115	1,277	3,392
Total oil and gas	40,957	7,440	48,397
Accumulated DD&A	(31,979)	(3,420)	(35,399)
Oil and gas property and equipment, net	$ 8,978	$ 4,020	$ 12,998

	December 31,	
	2017	2016
EnLink	$ 9,120	$ 8,381
Devon	1,955	1,919
Total midstream and other	11,075	10,300
EnLink	(2,533)	(2,124)
Devon	(689)	(641)
Total accumulated DD&A	(3,222)	(2,765)
Midstream and other property and equipment, net	$ 7,853	$ 7,535

Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs for the three years ended December 31, 2017.

	Year Ended December 31,		
	2017	2016	2015
Beginning balance	$ 261	$ 225	$ 199
Additions pending determination of proved reserves	504	247	348
Charges to exploration expense	—	(29)	(5)
Reclassifications to proved properties	(466)	(189)	(285)
Foreign currency translation adjustment	14	7	(32)
Ending balance	$ 313	$ 261	$ 225

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

	Year Ended December 31,		
	2017	2016	2015
Exploratory well costs capitalized for a period of one year or less	$ 113	$ 88	$ 60
Exploratory well costs capitalized for a period greater than one year	200	173	165
Ending balance	$ 313	$ 261	$ 225
Number of projects with exploratory well costs capitalized for a period greater than one year	2	2	2

Projects with suspended exploratory well costs capitalized for a period greater than one year since the completion of drilling relate to Devon's heavy oil operations. Management believes these projects with suspended exploratory well costs exhibit sufficient quantities of hydrocarbons to justify potential development. Devon continues to assess the development timeline of these long cycle projects.

14. Goodwill and Other Intangible Assets

Goodwill

The following table presents a summary of Devon's goodwill. For the year ended December 31, 2017, there were no changes to the carrying amount of goodwill.

	U.S.	EnLink	Total
Balance as of December 31, 2015	$ 923	$ 2,414	$ 3,337
Acquired during period	—	2	2
Asset divestitures	(83)	—	(83)
Impairment	—	(873)	(873)
Balance as of December 31, 2016	$ 840	$ 1,543	$ 2,383

The following table presents the General Partner's and EnLink's goodwill activity by reporting unit. For the year ended December 31, 2017, there were no changes to the carrying amount of goodwill.

	Texas	Oklahoma	Crude and Condensate	General Partner	Total
Balance as of December 31, 2015	$ 704	$ 190	$ 93	$ 1,427	$ 2,414
Acquired during period	2	—	—	—	2
Impairment	(473)	—	(93)	(307)	(873)
Balance as of December 31, 2016	$ 233	$ 190	$ —	$ 1,120	$ 1,543

Asset Divestitures

In conjunction with the U.S. non-core upstream asset divestitures in 2016 discussed in Note 3, Devon removed goodwill allocated to these assets.

Impairment

As further discussed in Note 1, Devon performs an annual impairment test of goodwill at October 31, or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit may not be recoverable. Sustained weakness in the overall energy sector driven by low commodity prices, together with a decline in EnLink's unit price, caused a change in circumstances warranting an interim impairment test of EnLink's reporting units in the first quarter of 2016. Based on that test, EnLink recorded noncash goodwill impairments related to its Texas, Crude and Condensate and General Partner reporting units.

Additionally, during 2015, EnLink recorded noncash goodwill impairments related to its Texas, Louisiana and Crude and Condensate reporting units.

Other Intangible Assets

The following table presents other intangible assets reported in other long-term assets in the accompanying consolidated balance sheets.

	December 31, 2017	December 31, 2016
Customer relationships	$ 1,796	$ 1,796
Accumulated amortization	(299)	(172)
Net intangibles	$ 1,497	$ 1,624

The weighted-average amortization period for the customer relationships is 15 years. Amortization expense for intangibles was approximately $127 million, $117 million and $56 million for the years ended 2017, 2016 and 2015, respectively. The remaining aggregate amortization expense is estimated to be approximately $123 million in each of the next five years.

15. Other Current Liabilities

Components of other current liabilities include the following:

	December 31, 2017	December 31, 2016
Derivative liabilities	$ 331	$ 187
Installment payment - see Note 3	250	249
Income taxes payable	145	32
Accrued interest payable	131	130
Restructuring liabilities	19	48
Other	325	420
Other current liabilities	$ 1,201	$ 1,066

16. Debt and Related Expenses

See below for a summary of debt instruments and balances. The notes and debentures are senior, unsecured obligations of Devon.

	December 31, 2017	December 31, 2016
Devon debt:		
8.25% due July 1, 2018 (1)(2)	$ 20	$ 20
2.25% due December 15, 2018 (1)	95	95
6.30% due January 15, 2019 (1)	162	162
4.00% due July 15, 2021	500	500
3.25% due May 15, 2022	1,000	1,000
5.85% due December 15, 2025 (1)	485	485
7.50% due September 15, 2027 (1)(2)	73	73
7.875% due September 30, 2031 (1)(3)	1,059	1,059
7.95% due April 15, 2032 (1)	789	789
5.60% due July 15, 2041	1,250	1,250
4.75% due May 15, 2042	750	750
5.00% due June 15, 2045	750	750
Net discount on debentures and notes	(30)	(30)
Debt issuance costs	(39)	(44)
Total Devon debt	6,864	6,859
EnLink and General Partner debt:		
Credit facilities	74	148
2.70% due April 1, 2019	400	400
7.125% due June 1, 2022	—	163
4.40% due April 1, 2024	550	550
4.15% due June 1, 2025	750	750
4.85% due July 15, 2026	500	500
5.60% due April 1, 2044	350	350
5.05% due April 1, 2045	450	450
5.45% due June 1, 2047	500	—
Net premium (discount) on debentures and notes	(6)	9
Debt issuance costs	(26)	(25)
Total EnLink and General Partner debt	3,542	3,295
Total debt	10,406	10,154
Less amount classified as short-term debt (4)	115	—
Total long-term debt	$ 10,291	$ 10,154

(1) These senior notes were included in 2016 tender offer redemptions discussed below.

(2) These instruments were assumed by Devon in April 2003 in conjunction with the merger with Ocean Energy. The fair value and effective rates of these 8.25% notes and 7.50% notes at the time assumed was $147 million and 5.5%, respectively, and $169 million and 6.5%, respectively. These instruments are the unsecured and unsubordinated obligations of Devon OEI Operating, L.L.C. and are guaranteed by Devon Energy Production Company, L.P. Each of these entities is a wholly-owned subsidiary of Devon.

(3) Issued in October 2001, these are unsecured and unsubordinated obligations of Devon Financing, a wholly owned finance subsidiary of Devon. These instruments are fully and unconditionally guaranteed by Devon.

(4) 2017 short-term debt consists of $20 million of 8.25% senior notes due July 1, 2018 and $95 million of 2.25% senior notes due December 15, 2018.

Debt maturities as of December 31, 2017, excluding debt issuance costs, premiums and discounts, are as follows:

	Devon	EnLink	Total
2018	$ 115	$ —	$ 115
2019	162	474	636
2020	—	—	—
2021	500	—	500
2022	1,000	—	1,000
Thereafter	5,156	3,100	8,256
Total	$ 6,933	$ 3,574	$ 10,507

Credit Lines

Devon has a $3.0 billion Senior Credit Facility. The facility matures as follows: $164 million on October 24, 2018 and the remaining $2.8 billion on October 24, 2019. Amounts borrowed under the Senior Credit Facility may, at the election of Devon, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, Devon may elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $7.4 million. As of December 31, 2017, Devon had $59 million in outstanding letters of credit under the Senior Credit Facility. There were no borrowings under the Senior Credit Facility as of December 31, 2017.

The Senior Credit Facility contains only one material financial covenant. This covenant requires Devon's ratio of total funded debt to total capitalization, as defined in the credit agreement, to be no greater than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in the accompanying consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial write-downs such as asset impairments. As of December 31, 2017, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 27.2%. Devon's change to successful efforts did not materially change this ratio.

Commercial Paper

Devon's Senior Credit Facility supports its $3.0 billion of short-term credit under its commercial paper program. Commercial paper debt generally has a maturity of between 1 and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is generally based on a standard index such as the Federal Funds Rate, LIBOR or the money market rate as found in the commercial paper market. As of December 31, 2017, Devon had no outstanding commercial paper borrowings.

Retirement of Senior Notes

During 2016, Devon completed tender offers to repurchase $2.1 billion of debt securities, using proceeds from the asset divestitures discussed in Note 3. Devon recognized a loss on early retirement of debt, primarily consisting of $265 million in cash retirement costs and other fees. These costs, along with other minimal noncash charges associated with retiring the debt, are included in net financing costs in the consolidated comprehensive statements of earnings.

EnLink Debt

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

EnLink has a $1.5 billion unsecured revolving credit facility that will mature on March 6, 2020. As of December 31, 2017, there were $10 million in outstanding letters of credit and no outstanding borrowings under the $1.5 billion credit facility. The General Partner has a $250 million revolving credit facility that will mature on March 7, 2019. As of December 31, 2017, the General Partner had $74 million in outstanding borrowings under the $250 million credit facility at a weighted average borrowing rate of 3.2%. EnLink and the General Partner were in compliance with all financial covenants in their respective credit facilities as of December 31, 2017.

In the second quarter of 2017, EnLink issued $500 million of 5.45% unsecured senior notes due in 2047. The proceeds were used to repay outstanding borrowings under its revolving credit facility and for general partnership purposes. Additionally, in the second quarter of 2017, EnLink redeemed its $163 million 7.125% senior unsecured notes due in 2022. EnLink redeemed the notes at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174 million, which resulted in a gain on extinguishment of debt of $9 million during the second quarter of 2017. The gain is included in net financing costs in the consolidated comprehensive statement of earnings.

In July 2016, EnLink issued $500 million of 4.85% unsecured senior notes due 2026. EnLink used the net proceeds to repay outstanding borrowings under its revolving credit facility and for general partnership purposes.

Financing Costs, Net

The following schedule includes the components of net financing costs.

	Year Ended December 31,		
	2017	2016	2015
Devon net financing costs:			
Interest based on debt outstanding	$ 390	$ 488	$ 450
Early retirement of debt	—	269	—
Capitalized interest	(69)	(61)	(52)
Other	(4)	21	14
Total Devon net financing costs	317	717	412
EnLink net financing costs:			
Interest based on debt outstanding	167	144	115
Interest accretion on deferred installment payment	26	52	—
Early retirement of debt	(9)	—	—
Other	(3)	(6)	(8)
Total EnLink net financing costs	181	190	107
Total net financing costs	$ 498	$ 907	$ 519

17. Asset Retirement Obligations

The following table presents the changes in asset retirement obligations.

	Year Ended December 31, 2017	2016
Asset retirement obligations as of beginning of period	$ 1,272	$ 1,414
Liabilities incurred and assumed through acquisitions	40	27
Liabilities settled and divested	(68)	(324)
Revision of estimated obligation	(184)	66
Accretion expense on discounted obligation	62	75
Foreign currency translation adjustment	30	14
Asset retirement obligations as of end of period	1,152	1,272
Less current portion	39	46
Asset retirement obligations, long-term	$ 1,113	$ 1,226

During 2017, Devon reduced its asset retirement obligations by $184 million primarily due to changes in the assumed inflation rate and retirement dates for its oil and gas assets.

During 2016, Devon reduced its asset retirement obligation by $287 million for those obligations that were assumed by purchasers of certain upstream U.S. assets.

18. Retirement Plans

Defined Contribution Plans

Devon sponsors defined contribution plans covering its employees in the U.S. and Canada. Such plans include its 401(k) plan, enhanced contribution plan and Canadian pension and savings plan. Contributions are primarily based upon percentages of annual compensation and years of service. In addition, each plan is subject to regulatory limitations by each respective government. Devon contributed $60 million, $64 million and $79 million to these plans in 2017, 2016 and 2015, respectively.

Defined Benefit Plans

Devon has various non-contributory defined benefit pension plans, including qualified plans and nonqualified plans covering eligible U.S. and Canadian employees and former employees meeting certain age and service requirements. Benefits under the defined benefit plans have been closed to new employees since 2007; however, eligible employees continue to accrue benefits based upon years of service and compensation. Benefits are primarily funded from assets held in the plans' trusts.

Devon's investment objective for its plans' assets is to achieve stability of the funded status while providing long-term growth of invested capital and income to ensure benefit payments can be funded when required. Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. Devon's target allocations for its plan assets are 70% fixed income, 20% equity and 10% other. See the following discussion for Devon's pension assets by asset class.

Fixed-income – Devon's fixed-income securities consist of U.S. Treasury obligations, bonds issued by investment-grade companies from diverse industries and asset-backed securities. These fixed-income securities are actively traded securities that can be redeemed upon demand. The fair values of these Level 1 securities are based upon quoted market prices and were $342 million and $311 million at December 31, 2017 and 2016, respectively. Also, included are commingled funds that primarily invest in long-term bonds and U.S. Treasury securities. These fixed income securities can be redeemed on demand but are not actively traded. The fair values of these securities are based upon the net asset values provided by the investment managers and were $401 million and $367 million at December 31, 2017 and 2016, respectively.

Equity – Devon's equity securities include a commingled global equity fund that invests in large, mid- and small capitalization stocks across the world's developed and emerging markets. These equity securities can be redeemed on demand but are not actively traded. The fair values of these securities are based upon the net asset values provided by the investment managers and were $157 million and $171 million at December 31, 2017 and 2016, respectively.

Other – Devon's other securities include short-term investments funds, an actively traded global mutual fund focusing on alternative investment strategies and a hedge fund that invests both long and short using a variety of investment strategies. The fair value of these securities is based upon the net asset values provided by investment managers and were $135 million and $136 million at December 31, 2017 and 2016, respectively.

Defined Postretirement Plans

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

Benefit Obligations and Funded Status

The following table summarizes the benefit obligations, assets, funded status and balance sheet impacts associated with its defined pension and postretirement plans. Devon's benefit obligations and plan assets are measured each year as of December 31. The accumulated benefit obligation for pension plans approximated the projected benefit obligation at December 31, 2017 and 2016.

	Pension Benefits		Postretirement Benefits	
	2017	2016	2017	2016
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 1,249	$ 1,308	$ 21	$ 23
Service cost	15	15	—	—
Interest cost	42	42	—	1
Actuarial loss (gain)	59	63	—	(1)
Plan amendments	—	2	—	—
Plan curtailments	—	(31)	—	—
Plan settlements	—	(94)	—	—
Foreign exchange rate changes	2	1	—	—
Participant contributions	—	—	1	—
Benefits paid	(88)	(57)	(3)	(2)
Benefit obligation at end of year	1,279	1,249	19	21
Change in plan assets:				
Fair value of plan assets at beginning of year	985	1,059	—	—
Actual return on plan assets	122	61	—	—
Employer contributions	14	16	2	2
Participant contributions	—	—	1	—
Plan settlements	—	(94)	—	—
Benefits paid	(88)	(57)	(3)	(2)
Foreign exchange rate changes	2	—	—	—
Fair value of plan assets at end of year	1,035	985	—	—
Funded status at end of year	$ (244)	$ (264)	$ (19)	$ (21)
Amounts recognized in balance sheet:				
Other long-term assets	$ 4	$ 3	$ —	$ —
Other current liabilities	(13)	(13)	(3)	(3)
Other long-term liabilities	(235)	(254)	(16)	(18)
Net amount	$ (244)	$ (264)	$ (19)	$ (21)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 257	$ 285	$ (11)	$ (11)
Prior service cost (credit)	6	8	(3)	(5)
Total	$ 263	$ 293	$ (14)	$ (16)

Certain of Devon's pension plans are unfunded and have a combined projected benefit obligation and accumulated benefit obligation of $239 million and $225 million, respectively, at December 31, 2017 and $234 million and $211 million, respectively, at December 31, 2016.

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

	Pension Benefits			Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Net periodic benefit cost:						
Service cost	$ 15	$ 15	$ 33	$ —	$ —	$ 1
Interest cost	42	42	52	—	1	1
Expected return on plan assets	(54)	(55)	(58)	—	—	—
Recognition of net actuarial loss (gain) (1)	19	25	20	(1)	(1)	(1)
Recognition of prior service cost (1)	2	3	4	(1)	(1)	(2)
Total net periodic benefit cost (2)	24	30	51	(2)	(1)	(1)
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	(9)	26	5	(1)	—	(1)
Prior service cost (credit) arising in current year	—	2	—	—	—	1
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost (3)	(19)	(43)	(20)	1	1	1
Recognition of prior service cost, including curtailment, in net periodic benefit cost (3)	(2)	(9)	(4)	1	1	1
Total other comprehensive loss (earnings)	(30)	(24)	(19)	1	2	2
Total recognized	$ (6)	$ 6	$ 32	$ (1)	$ 1	$ 1

(1) These net periodic benefit costs were reclassified out of other comprehensive earnings in the current period.
(2) Net periodic benefit cost is a component of G&A on the accompanying consolidated comprehensive statements of earnings.
(3) These amounts include restructuring costs that were reclassified out of other comprehensive earnings in 2016. See Note 7 for further discussion.

The estimated net actuarial loss and prior service cost for our pension and postretirement benefits that will be amortized from accumulated other comprehensive earnings into net periodic benefit cost during 2018 are $14 million and $1 million, respectively.

Assumptions

	Pension Benefits			Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Assumptions to determine benefit obligations:						
Discount rate	3.59%	4.07%	4.25%	3.25%	3.46%	3.63%
Rate of compensation increase	2.50%	4.49%	4.49%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	4.08%	4.39%	3.90%	3.46%	3.63%	3.25%
Rate of compensation increase	4.48%	4.49%	4.49%	N/A	N/A	N/A
Expected return on plan assets	5.69%	5.20%	5.22%	N/A	N/A	N/A

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

Expected return on plan assets – This was determined by evaluating input from external consultants and economists, as well as long-term inflation assumptions and consideration of target allocation of investment types.

Mortality rate – Devon utilized the Society of Actuaries produced mortality tables and an improvement scale derived from the updated tables and the actuary's best estimate of mortality for the population of participants in Devon's plans.

Other assumptions – For measurement of the 2017 benefit obligation for the other postretirement medical plans, a 7.3% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2018. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2029 and remain at that level thereafter. A one percentage point change in assumed health care cost trend rates would not have a material impact on periodic benefit cost or benefit obligations.

Expected Cash Flows

Devon expects benefit plan payments to average approximately $76 million a year for the next five years and $406 million total for the five years thereafter. Of these payments to be paid in 2018, $3 million is expected to be funded from Devon's available cash and cash equivalents.

19. Stockholders' Equity

The authorized capital stock of Devon consists of 1.0 billion shares of common stock, par value $0.10 per share, and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

Common Stock Issued

In January 2016, Devon issued approximately 23 million shares of common stock in conjunction with the STACK asset acquisition discussed in Note 3. Additionally, in February 2016, Devon issued 79 million shares of common stock to the public, inclusive of 10 million shares sold as part of the underwriters' option. Net proceeds from the offering were $1.5 billion.

In December 2015, Devon issued approximately 7 million shares of common stock as part of the Powder River Basin asset acquisition discussed in Note 3.

Dividends

Devon paid common stock dividends of $127 million, $221 million and $396 million during 2017, 2016 and 2015, respectively. In response to the depressed commodity price environment, Devon reduced the quarterly dividend rate from $0.24 to $0.06 per share in the second quarter of 2016.

20. Noncontrolling Interests

Subsidiary Equity Transactions

EnLink has the ability to sell common units through its "at the market" equity offering programs. In the third quarter of 2017, EnLink entered into additional equity distribution agreements to sell up to $600 million in common units through its programs. Future common units that EnLink issues will be issued under the new equity distribution agreement. During 2017, 2016 and 2015, EnLink issued and sold approximately 6.2 million, 10.0 million and 1.3 million common units through its "at the market" program and general public offerings, generating net proceeds of $107 million, $167 million and $25 million, respectively. During the first quarter of 2016, the General Partner issued common units in conjunction with the Anadarko Basin assets acquisition discussed in Note 3.

In October 2015, EnLink issued approximately 2.8 million common units in a private placement transaction with the General Partner, generating approximately $50 million in proceeds. In 2015, Devon conducted an underwritten secondary public offering of 26.2 million common units representing limited partner interests in EnLink, raising net proceeds of $654 million.

In September 2017, EnLink issued 400,000 preferred units through an underwritten public offering for net proceeds of approximately $394 million. As a result of these transactions and EnLink's acquisition and dropdown activity discussed further in Note 3, the table below shows the ownership interest activity in the General Partner and EnLink for the last three years.

	EnLink			General Partner	
Ownership interest as of	**Devon**	**Non-Devon Unitholders**	**General Partner**	**Devon**	**Non-Devon Unitholders**
December 31, 2015	28%	45%	27%	70%	30%
December 31, 2016	24%	53%	23%	64%	36%
December 31, 2017	23%	55%	22%	64%	36%

Distributions to Noncontrolling Interests

EnLink and the General Partner distributed $354 million, $304 million and $254 million to non-Devon unitholders during 2017, 2016 and 2015, respectively.

21. Commitments and Contingencies

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

Royalty Matters

Numerous oil and gas producers and related parties, including Devon, have been named in various lawsuits alleging royalty underpayments. These suits typically assert various allegations, including that the producers and related parties used below-market prices, made improper deductions, used improper measurement techniques and entered into gas purchase and processing arrangements with affiliates that resulted in the underpayment of royalties in connection with oil, natural gas and NGLs produced and sold. Devon is also involved in governmental agency proceedings and audits and is subject to related contracts and regulatory controls in the ordinary course of business, some that may lead to additional royalty claims. Devon does not currently believe that it is subject to material exposure with respect to such royalty matters.

Environmental Matters

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

Other Matters

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

Commitments

The following table presents Devon's commitments that have initial or remaining noncancelable terms in excess of one year as of December 31, 2017.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases	EnLink Obligations
2018	$ 613	$ 216	$ 1,159	$ 88	$ 53
2019	577	109	562	84	36
2020	556	109	466	73	19
2021	134	51	366	61	18
2022	—	38	373	56	17
Thereafter	—	106	3,242	19	90
Total	$ 1,880	$ 629	$ 6,168	$ 381	$ 233

Purchase obligation amounts represent contractual commitments primarily to purchase condensate at market prices for use at Devon's heavy oil projects in Canada. Devon has entered into these agreements because condensate is an integral part of the heavy oil transportation process. Any disruption in Devon's ability to obtain condensate could negatively affect its ability to transport heavy oil at these locations. Devon's total obligation related to condensate purchases expires in 2021. The value of the obligation in the table above is based on the contractual volumes and Devon's internal estimate of future condensate market prices.

Devon has certain drilling and facility obligations under contractual agreements with third-party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. The value of the drilling obligations reported is based on gross contractual value.

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

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense recognized for operating leases, net of sublease income, was $67 million, $78 million and $88 million in 2017, 2016 and 2015, respectively.

22. Fair Value Measurements

The following table provides carrying value and fair value measurement information for certain of Devon's financial assets and liabilities. None of the items below are measured using Level 3 inputs. The carrying values of cash, accounts receivable, other current receivables, accounts payable, other current payables and accrued expenses included in the accompanying consolidated balance sheets approximated fair value at December 31, 2017 and December 31, 2016, as applicable. Therefore, such financial assets and liabilities are not presented in the following table. Additionally, the fair values of oil and gas assets, goodwill and other intangible assets and related impairments are measured as of the impairment date using Level 3 inputs. More information on these items and the pension plan assets is provided in Note 6, Note 14 and Note 18, respectively.

			Fair Value Measurements Using:	
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs
December 31, 2017 assets (liabilities):				
Cash equivalents	$ 1,533	$ 1,533	$ 1,454	$ 79
Commodity derivatives	$ 211	$ 211	$ —	$ 211
Commodity derivatives	$ (294)	$ (294)	$ —	$ (294)
Interest rate derivatives	$ 1	$ 1	$ —	$ 1
Interest rate derivatives	$ (64)	$ (64)	$ —	$ (64)
Debt	$ (10,406)	$ (11,782)	$ —	$ (11,782)
Installment payment	$ (250)	$ (250)	$ —	$ (250)
Capital lease obligations	$ (4)	$ (3)	$ —	$ (3)
December 31, 2016 assets (liabilities):				
Cash equivalents	$ 1,542	$ 1,542	$ 1,298	$ 244
Commodity derivatives	$ 10	$ 10	$ —	$ 10
Commodity derivatives	$ (203)	$ (203)	$ —	$ (203)
Interest rate derivatives	$ 1	$ 1	$ —	$ 1
Interest rate derivatives	$ (41)	$ (41)	$ —	$ (41)
Debt	$ (10,154)	$ (10,760)	$ —	$ (10,760)
Installment payment	$ (473)	$ (477)	$ —	$ (477)
Capital lease obligations	$ (7)	$ (6)	$ —	$ (6)

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

Level 1 Fair Value Measurements

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

Level 2 Fair Value Measurements

Cash equivalents – Amounts consist primarily of commercial paper and Canadian agency and provincial securities investments. The fair value approximates the carrying value.

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

Debt – Devon's debt instruments do not actively trade in an established market. The fair values of its debt are estimated based on rates available for debt with similar terms and maturity. The fair values of commercial paper and credit facility balances are the carrying values.

Installment payment – The fair value of the EnLink installment payment was based on Level 2 inputs from third-party market quotations.

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

23. Segment Information

Devon manages its operations through distinct operating segments, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its U.S. operating segments into one reporting segment due to the similar nature of the businesses. However, Devon's Canadian exploration and production operating segment is reported as a separate reporting segment primarily due to the significant differences between the U.S. and Canadian regulatory environments. Devon's U.S. and Canadian segments are both primarily engaged in oil and gas exploration and production activities, and certain information regarding such activities for each segment is included in Note 24.

Devon considers EnLink, combined with the General Partner, to be an operating segment that is distinct from the U.S. and Canadian operating segments. EnLink's operations consist of midstream assets and operations located across the U.S. Additionally, EnLink has a management team that is primarily responsible for capital and resource allocation decisions. Therefore, EnLink is presented as a separate reporting segment.

	U.S. (1)	Canada	EnLink (1)	Eliminations	Total
Year Ended December 31, 2017:					
Revenues from external customers	$ 7,326	$ 1,552	$ 5,071	$ —	$ 13,949
Intersegment revenues	$ —	$ —	$ 669	$ (669)	$ —
Depreciation, depletion and amortization	$ 1,149	$ 380	$ 545	$ —	$ 2,074
Asset impairments	$ —	$ —	$ 17	$ —	$ 17
Asset dispositions	$ (218)	$ 1	$ —	$ —	$ (217)
Interest expense	$ 324	$ 69	$ 181	$ (57)	$ 517
Earnings before income taxes	$ 500	$ 273	$ 123	$ —	$ 896
Income tax expense (benefit)	$ 9	$ 6	$ (197)	$ —	$ (182)
Net earnings	$ 491	$ 267	$ 320	$ —	$ 1,078
Net earnings attributable to noncontrolling interests	$ —	$ —	$ 180	$ —	$ 180
Net earnings attributable to Devon	$ 491	$ 267	$ 140	$ —	$ 898
Property and equipment, net	$ 10,274	$ 4,310	$ 6,587	$ —	$ 21,171
Total assets	$ 14,254	$ 5,498	$ 10,538	$ (49)	$ 30,241
Capital expenditures, including acquisitions	$ 1,821	$ 348	$ 768	$ —	$ 2,937
Year Ended December 31, 2016:					
Revenues from external customers	$ 5,722	$ 1,031	$ 3,551	$ —	$ 10,304
Intersegment revenues	$ —	$ —	$ 701	$ (701)	$ —
Depreciation, depletion and amortization	$ 1,178	$ 414	$ 504	$ —	$ 2,096
Asset impairments	$ 435	$ 2	$ 873	$ —	$ 1,310
Asset dispositions	$ (955)	$ (541)	$ 13	$ —	$ (1,483)
Restructuring and transaction costs	$ 242	$ 19	$ 6	$ —	$ 267
Interest expense	$ 624	$ 184	$ 190	$ (84)	$ 914
Earnings (loss) before income taxes	$ (673)	$ 240	$ (884)	$ —	$ (1,317)
Income tax expense (benefit)	$ (8)	$ 149	$ —	$ —	$ 141
Net earnings (loss)	$ (665)	$ 91	$ (884)	$ —	$ (1,458)
Net earnings (loss) attributable to noncontrolling interests	$ 1	$ —	$ (403)	$ —	$ (402)
Net earnings (loss) attributable to Devon	$ (666)	$ 91	$ (481)	$ —	$ (1,056)
Property and equipment, net	$ 10,166	$ 4,110	$ 6,257	$ —	$ 20,533
Total assets	$ 13,390	$ 5,071	$ 10,276	$ (62)	$ 28,675
Capital expenditures, including acquisitions	$ 2,640	$ 186	$ 1,082	$ —	$ 3,908
Year Ended December 31, 2015:					
Revenues from external customers	$ 8,360	$ 1,012	$ 3,773	$ —	$ 13,145
Intersegment revenues	$ —	$ —	$ 679	$ (679)	$ —
Depreciation, depletion and amortization	$ 3,164	$ 471	$ 387	$ —	$ 4,022
Asset impairments	$ 16,069	$ 15	$ 1,563	$ —	$ 17,647
Asset dispositions	$ (33)	$ 39	$ 1	$ —	$ 7
Restructuring and transaction costs	$ 54	$ 24	$ —	$ —	$ 78
Interest expense	$ 368	$ 97	$ 107	$ (46)	$ 526
Loss before income taxes	$ (17,898)	$ (576)	$ (1,384)	$ —	$ (19,858)
Income tax expense (benefit)	$ (6,100)	$ (143)	$ 30	$ —	$ (6,213)
Net loss	$ (11,798)	$ (433)	$ (1,414)	$ —	$ (13,645)
Net earnings (loss) attributable to noncontrolling interests	$ 1	$ —	$ (750)	$ —	$ (749)
Net loss attributable to Devon	$ (11,799)	$ (433)	$ (664)	$ —	$ (12,896)
Property and equipment, net	$ 10,357	$ 4,962	$ 5,667	$ —	$ 20,986
Total assets	$ 14,399	$ 5,830	$ 9,541	$ (97)	$ 29,673
Capital expenditures, including acquisitions	$ 4,143	$ 591	$ 978	$ —	$ 5,712

(1) Due to Devon's control of EnLink through its control of the General Partner, the acquisition of VEX by EnLink from Devon in the second quarter of 2015 was considered a transfer of net assets between entities under common control, and EnLink was required to recast its financial statements as of December 31, 2015 to include the activities of such assets from the date of common control. Therefore, the results of VEX have been moved from the U.S. segment to the EnLink segment for the recast period.

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

Supplemental unaudited information regarding Devon's oil and gas activities is presented in this note. The information is provided separately by country.

Included in this note are disclosures of Devon's results of operations for oil and gas producing activities and standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities. In conjunction with Devon's oil and gas accounting policy change discussed in Note 1, Devon also modified its treatment of certain "production support" costs in these two disclosures. Production support costs consisted of labor, supervision, materials and supplies for oil and gas production monitoring and support activities, including information technology, accounting and certain other administrative support functions. These costs are included in G&A expenses in the accompanying consolidated comprehensive statements of earnings. Devon used a method to allocate these costs to its country-based results of operations and standardized measure disclosures. In 2016 and 2015, Devon's results of operations disclosures included production support costs of $168 million and $224 million, respectively, and its standardized measure disclosures included estimated future production support costs of $2.8 billion and $2.7 billion, respectively.

Devon's 2016 and 2015 disclosures have been revised to exclude these amounts.

Based on research conducted by Devon, diversity of practice has existed across peer companies regarding the treatment of production support costs in results of operations and standardized measure disclosures. Devon's research of public filings indicates most companies exclude such costs from results of operations and standardized measure disclosures, but some companies appear to include such costs in their disclosures. Considering the apparent diversity of practice, Devon is making this disclosure change for two primary reasons. First, by converting to the successful efforts method of accounting and making this disclosure change, Devon's results of operations and standardized measure disclosures will be most comparable to the vast majority of its peers. Second, allocating these costs to more granular common operating fields as opposed to country-based full cost pools is cost prohibitive and not materially important to investors and stakeholders, considering such allocated costs represented approximately 4% of Devon's 2016 and 2015 oil, gas and NGL sales.

Costs Incurred

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

	Year Ended December 31, 2017		
	U.S.	Canada	Total
Property acquisition costs:			
Proved properties	$ 2	$ —	$ 2
Unproved properties	50	4	54
Exploration costs	590	87	677
Development costs	1,036	225	1,261
Costs incurred	$ 1,678	$ 316	$ 1,994

	Year Ended December 31, 2016		
	U.S.	Canada	Total
Property acquisition costs:			
Proved properties	$ 237	$ —	$ 237
Unproved properties	1,356	2	1,358
Exploration costs	282	78	360
Development costs	875	54	929
Costs incurred	$ 2,750	$ 134	$ 2,884

	Year Ended December 31, 2015		
	U.S.	Canada	Total
Property acquisition costs:			
Proved properties	$ 193	$ 2	$ 195
Unproved properties	635	81	716
Exploration costs	432	120	552
Development costs	2,982	351	3,333
Costs incurred	$ 4,242	$ 554	$ 4,796

Development costs in the tables above include additions and revisions to Devon's asset retirement obligations. Additionally, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $69 million, $61 million and $52 million in 2017, 2016 and 2015, respectively.

Results of Operations

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

	December 31, 2017		
	U.S.	Canada	Total
Oil, gas and NGL sales	$ 3,746	$ 1,404	$ 5,150
Production expenses	(1,232)	(591)	(1,823)
Exploration expenses	(346)	(34)	(380)
Depreciation, depletion and amortization	(1,050)	(369)	(1,419)
Asset dispositions	211	1	212
Accretion of asset retirement obligations	(38)	(24)	(62)
Income tax expense	—	(104)	(104)
Results of operations	$ 1,291	$ 283	$ 1,574
Depreciation, depletion and amortization per Boe	$ 6.97	$ 7.73	$ 7.15

	December 31, 2016		
	U.S.	Canada	Total
Oil, gas and NGL sales	$ 3,198	$ 984	$ 4,182
Production expenses	(1,311)	(492)	(1,803)
Exploration expenses	(176)	(39)	(215)
Depreciation, depletion and amortization	(1,066)	(380)	(1,446)
Asset dispositions	946	1	947
Asset impairments	(435)	—	(435)
Accretion of asset retirement obligations	(49)	(26)	(75)
Income tax expense	—	(13)	(13)
Results of operations	$ 1,107	$ 35	$ 1,142
Depreciation, depletion and amortization per Boe	$ 6.11	$ 7.75	$ 6.47

	December 31, 2015		
	U.S.	Canada	Total
Oil, gas and NGL sales	$ 4,356	$ 1,026	$ 5,382
Production expenses	(1,853)	(586)	(2,439)
Exploration expenses	(323)	(128)	(451)
Depreciation, depletion and amortization	(3,051)	(423)	(3,474)
Asset dispositions	32	(39)	(7)
Asset impairments	(16,061)	(15)	(16,076)
Accretion of asset retirement obligations	(47)	(28)	(75)
Income tax benefit	5,783	50	5,833
Results of operations	$ (11,164)	$ (143)	$ (11,307)
Depreciation, depletion and amortization per Boe	$ 14.79	$ 10.08	$ 13.99

Proved Reserves

The following table presents Devon's estimated proved reserves by product and by country.

	Oil (MMBbls)			Bitumen (MMBbls)	Gas (Bcf)			NGL (MMBbls)	Combined (MMBoe) (1)		
	U.S.	Canada	Total	Canada	U.S.	Canada	Total	U.S.	U.S.	Canada	Total
Proved developed and undeveloped reserves:											
December 31, 2014	351	23	374	521	7,651	36	7,687	578	2,205	549	2,754
Revisions due to prices	(53)	4	(49)	103	(1,412)	(9)	(1,421)	(119)	(408)	106	(302)
Revisions other than price	(52)	2	(50)	(84)	(3)	(6)	(9)	(6)	(59)	(83)	(142)
Extensions and discoveries	51	3	54	11	171	—	171	24	104	14	118
Purchase of reserves	5	—	5	—	17	—	17	1	9	—	9
Production	(60)	(10)	(70)	(31)	(579)	(8)	(587)	(50)	(206)	(42)	(248)
Sale of reserves	—	—	—	—	(37)	—	(37)	—	(7)	—	(7)
December 31, 2015	242	22	264	520	5,808	13	5,821	428	1,638	544	2,182
Revisions due to prices	(18)	(2)	(20)	23	(103)	—	(103)	(13)	(48)	21	(27)
Revisions other than price	(2)	3	1	(19)	628	10	638	48	151	(14)	137
Extensions and discoveries	36	2	38	—	280	—	280	42	124	2	126
Purchase of reserves	8	—	8	—	33	—	33	7	20	—	20
Production	(47)	(8)	(55)	(40)	(510)	(7)	(517)	(42)	(174)	(49)	(223)
Sale of reserves	(25)	—	(25)	—	(521)	—	(521)	(45)	(157)	—	(157)
December 31, 2016	194	17	211	484	5,615	16	5,631	425	1,554	504	2,058
Revisions due to prices	12	(1)	11	(37)	398	1	399	32	111	(38)	73
Revisions other than price	6	2	8	(10)	—	2	2	(10)	(5)	(7)	(12)
Extensions and discoveries	90	4	94	12	403	—	403	63	221	16	237
Production	(42)	(7)	(49)	(40)	(433)	(6)	(439)	(36)	(150)	(48)	(198)
Sale of reserves	(3)	—	(3)	—	(9)	—	(9)	(1)	(6)	—	(6)
December 31, 2017	257	15	272	409	5,974	13	5,987	473	1,725	427	2,152
Proved developed reserves:											
December 31, 2014	255	23	278	137	6,948	36	6,984	486	1,900	165	2,065
December 31, 2015	203	22	225	219	5,694	13	5,707	411	1,563	243	1,806
December 31, 2016	160	17	177	190	5,361	16	5,377	387	1,439	210	1,649
December 31, 2017	178	15	193	200	5,619	13	5,632	410	1,524	218	1,742
Proved developed-producing reserves:											
December 31, 2014	224	19	243	137	6,746	34	6,780	467	1,815	162	1,977
December 31, 2015	192	19	211	219	5,546	13	5,559	393	1,509	240	1,749
December 31, 2016	143	13	156	190	5,243	16	5,259	370	1,386	207	1,593
December 31, 2017	165	12	177	197	5,512	13	5,525	397	1,481	212	1,693
Proved undeveloped reserves:											
December 31, 2014	96	—	96	384	703	—	703	92	305	384	689
December 31, 2015	39	—	39	301	114	—	114	17	75	301	376
December 31, 2016	34	—	34	294	254	—	254	38	115	294	409
December 31, 2017	79	—	79	209	355	—	355	63	201	209	410

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

Proved Undeveloped Reserves

The following table presents the changes in Devon's total proved undeveloped reserves during 2017 (MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2016	115	294	409
Extensions and discoveries	116	12	128
Revisions due to prices	—	(27)	(27)
Revisions other than price	(21)	(6)	(27)
Conversion to proved developed reserves	(9)	(64)	(73)
Proved undeveloped reserves as of December 31, 2017	201	209	410

Total proved undeveloped reserves remained consistent from 2016 to 2017 with the year-end 2017 balance representing 19% of total proved reserves. Devon's focus on drilling and development activities in the STACK and Delaware Basin was the primary driver of the 128 MMBoe increase in extensions and discoveries. Continued development primarily at Jackfish led to the conversion of 73 MMBoe, or 18%, of the 2016 proved undeveloped reserves to proved developed reserves. Costs incurred to develop and convert Devon's proved undeveloped reserves were approximately $237 million for 2017.

A significant amount of Devon's proved undeveloped reserves at the end of 2017 related to its Jackfish operations. At December 31, 2017 and 2016, Devon's Jackfish proved undeveloped reserves were 209 MMBoe and 294 MMBoe, respectively. Development schedules for the Jackfish reserves are primarily controlled by the need to keep the processing plants at their 35 MBbl daily facility capacity. Processing plant capacity is controlled by factors such as total steam processing capacity and steam-oil ratios. Furthermore, development of these projects involves the up-front construction of steam injection/distribution and bitumen processing facilities. Due to the large up-front capital investments and large reserves required to provide economic returns, the project conditions meet the specific circumstances requiring a period greater than five years for conversion to developed reserves. As a result, these reserves are classified as proved undeveloped for more than five years. Currently, the development schedule for these reserves extends through 2028. At the end of 2017, approximately 196 MMBoe of proved undeveloped reserves at Jackfish have remained undeveloped for five years or more since the initial booking. No other projects have proved undeveloped reserves that have remained undeveloped more than five years from the initial booking of the reserves. Furthermore, approximately 88 MMBoe of proved undeveloped reserves at Jackfish will require in excess of five years, from the date of this filing, to develop.

Price Revisions

Reserves increased 111 MMBoe in the U.S. primarily due to significant price increases in the trailing 12 month average for oil, gas and NGLs in 2017. Reserves decreased 38 MMBoe in Canada due to a significant increase in the trailing 12 month average price for bitumen in 2017. The increased price has the effect of increasing its royalties, which decreases its after-royalty volumes.

Reserves decreased 27 MMBoe and 302 MMBoe during 2016 and 2015, respectively, primarily due to lower commodity prices for oil and gas. The lower bitumen price increased Canadian reserves due to the decline in royalties, which increases Devon's after-royalty volumes.

Revisions Other Than Price

Total revisions other than price in 2016 primarily related to Devon's evaluation of certain dry gas regions and NGLs, with the largest revisions being made in the Barnett Shale and STACK (Cana-Woodford Shale).

Revisions other than price for 2015 primarily related to evaluations of Eagle Ford and Jackfish. Negative revisions other than price at Jackfish were primarily due to a refined reserves methodology that resulted in a reduced recovery factor.

Extensions and Discoveries

2017 – Over 80% of the additions were through our focused efforts in the STACK (120 MMBoe) and the Delaware Basin (79 MMBoe). The remaining extensions were added throughout the remainder of Devon's portfolio.

The 2017 extensions and discoveries included 66 MMBoe related to additions from Devon's infill drilling activities, which was primarily related to the STACK.

2016 – Of the 126 MMBoe of extensions and discoveries, 97 MMBoe related to STACK, 18 MMBoe related to the Delaware Basin and 7 MMBoe related to the Eagle Ford.

The 2016 extensions and discoveries included 74 MMBoe related to additions from Devon's infill drilling activities, primarily consisting of 73 MMBoe related to STACK.

2015 – Of the 118 MMBoe of extensions and discoveries, 38 MMBoe related to the Delaware Basin, 30 MMBoe related to the Anadarko Basin, 21 MMBoe related to the Eagle Ford and 11 MMBoe related to Jackfish.

The 2015 extensions and discoveries included 13 MMBoe related to additions from Devon's infill drilling activities, primarily consisting of 11 MMBoe at Jackfish.

Purchase of Reserves

2016 – Primarily related to Devon's acquisition in the STACK play.

2015 – Primarily related to Devon's acquisition in the Powder River Basin.

Sale of Reserves

2017 – Related to Devon's non-core asset divestitures in the U.S. as discussed further in Note 3.

2016 – Related to Devon's non-core upstream asset divestitures discussed further in Note 3.

Standardized Measure

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

	Year Ended December 31, 2017		
	U.S.	Canada	Total
Future cash inflows	$ 34,701	$ 13,602	$ 48,303
Future costs:			
Development	(3,316)	(1,853)	(5,169)
Production	(15,526)	(5,986)	(21,512)
Future income tax expense	—	(988)	(988)
Future net cash flow	15,859	4,775	20,634
10% discount to reflect timing of cash flows	(7,541)	(1,756)	(9,297)
Standardized measure of discounted future net cash flows	$ 8,318	$ 3,019	$ 11,337

	Year Ended December 31, 2016		
	U.S.	Canada	Total
Future cash inflows	$ 22,847	$ 9,672	$ 32,519
Future costs:			
Development	(2,784)	(2,201)	(4,985)
Production	(11,934)	(6,049)	(17,983)
Future income tax expense	—	(121)	(121)
Future net cash flow	8,129	1,301	9,430
10% discount to reflect timing of cash flows	(3,524)	(466)	(3,990)
Standardized measure of discounted future net cash flows	$ 4,605	$ 835	$ 5,440

	Year Ended December 31, 2015		
	U.S.	Canada	Total
Future cash inflows	$ 27,398	$ 13,047	$ 40,445
Future costs:			
Development	(3,306)	(2,759)	(6,065)
Production	(14,938)	(6,501)	(21,439)
Future income tax expense	—	(580)	(580)
Future net cash flow	9,154	3,207	12,361
10% discount to reflect timing of cash flows	(3,230)	(1,248)	(4,478)
Standardized measure of discounted future net cash flows	$ 5,924	$ 1,959	$ 7,883

Future cash inflows, development costs and production costs were computed using the same assumptions for prices and costs that were used to estimate Devon's proved oil and gas reserves at the end of each year. For 2017 estimates, Devon's future realized prices were assumed to be $47.86 per Bbl of oil, $31.86 per Bbl of bitumen, $2.43 per Mcf of gas and $16.25 per Bbl of NGLs. Of the $5.2 billion of future development costs as of the end of 2017, $0.9 billion, $0.8 billion and $0.5 billion are estimated to be spent in 2018, 2019 and 2020, respectively.

Future development costs include not only development costs but also future asset retirement costs. Included as part of the $5.2 billion of future development costs are $1.3 billion of future asset retirement costs. The future income tax expenses have been computed using statutory tax rates, giving effect to allowable tax deductions and tax credits under current laws.

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

	Year Ended December 31,		
	2017	2016	2015
Beginning balance	$ 5,440	$ 7,883	$ 21,583
Net changes in prices and production costs	5,218	(2,027)	(21,330)
Oil, bitumen, gas and NGL sales, net of production costs	(3,327)	(2,379)	(2,943)
Changes in estimated future development costs	789	112	1,313
Extensions and discoveries, net of future development costs	2,497	674	1,102
Purchase of reserves	2	224	93
Sales of reserves in place	(3)	(577)	(77)
Revisions of quantity estimates	(318)	(21)	(1,312)
Previously estimated development costs incurred during the period	559	663	2,158
Accretion of discount	1,034	537	702
Foreign exchange and other	(7)	74	(1,148)
Net change in income taxes	(547)	277	7,742
Ending balance	$ 11,337	$ 5,440	$ 7,883

25. Supplemental Quarterly Financial Information (Unaudited)

Net Earnings (Loss) Attributable to Devon

The following tables present a summary of Devon's unaudited interim results of operations as recast under the successful efforts method of accounting. See Note 2 for additional details. As a result of the conversion to the successful efforts method of accounting in the fourth quarter of 2017, Devon has provided the full consolidated comprehensive statements of earnings for each interim quarter in 2017 to aid investors and facilitate comparative periods to be shown during 2018. Devon has provided the required summary information for each interim quarter in 2016.

	2017, under Successful Efforts				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Upstream revenues	$ 1,541	$ 1,332	$ 1,101	$ 1,333	$ 5,307
Marketing and midstream revenues	2,010	1,927	2,055	2,650	8,642
Total revenues	3,551	3,259	3,156	3,983	13,949
Production expenses	457	455	448	463	1,823
Exploration expenses	95	57	57	171	380
Marketing and midstream expenses	1,814	1,714	1,824	2,378	7,730
Depreciation, depletion and amortization	528	506	512	528	2,074
Asset impairments	7	—	2	8	17
Asset dispositions	(3)	(27)	(169)	(18)	(217)
General and administrative expenses	233	214	203	222	872
Financing costs, net	128	116	128	126	498
Other expenses	(33)	(20)	(76)	5	(124)
Total expenses	3,226	3,015	2,929	3,883	13,053
Earnings before income taxes	325	244	227	100	896
Income tax expense (benefit)	8	(1)	15	(204)	(182)
Net earnings	317	245	212	304	1,078
Net earnings attributable to noncontrolling interests	14	26	19	121	180
Net earnings attributable to Devon	$ 303	$ 219	$ 193	$ 183	$ 898
Net earnings per share attributable to Devon:					
Basic	$ 0.58	$ 0.41	$ 0.37	$ 0.35	$ 1.71
Diluted	$ 0.58	$ 0.41	$ 0.37	$ 0.35	$ 1.70
Comprehensive earnings:					
Net earnings	$ 317	$ 245	$ 212	$ 304	$ 1,078
Other comprehensive earnings, net of tax:					
Foreign currency translation and other	8	28	42	5	83
Pension and postretirement plans	5	4	5	15	29
Other comprehensive earnings, net of tax	13	32	47	20	112
Comprehensive earnings	330	277	259	324	1,190
Comprehensive earnings attributable to noncontrolling interests	14	26	19	121	180
Comprehensive earnings attributable to Devon	$ 316	$ 251	$ 240	$ 203	$ 1,010

	2016, under Successful Efforts				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Total revenues	$ 2,126	$ 2,488	$ 2,882	$ 2,808	$ 10,304
Earnings (loss) before income taxes	$ (2,036)	$ (339)	$ 787	$ 271	$ (1,317)
Net earnings (loss) attributable to Devon	$ (1,550)	$ (326)	$ 613	$ 207	$ (1,056)
Basic net earnings (loss) per share attributable to Devon	$ (3.27)	$ (0.63)	$ 1.17	$ 0.41	$ (2.09)
Diluted net earnings (loss) per share attributable to Devon	$ (3.27)	$ (0.63)	$ 1.16	$ 0.41	$ (2.09)

The 2017 results include gains from asset dispositions of approximately $217 million (or $0.42 per diluted share), as discussed in Note 3.

The 2016 results include asset impairments of $1.2 billion (or $2.59 per diluted share) and $81 million (or $0.15 per diluted share), during the first quarter and the fourth quarter of 2016, respectively, as discussed in Note 6. Additionally, the 2016 quarterly results include gains from asset dispositions of approximately $3 million (or $0.01 per diluted share), $75 million (or $0.14 per diluted share), $830 million (or $1.59 per diluted share) and $575 million (or $1.10 per diluted share) during the first quarter through the fourth quarter of 2016, respectively, as discussed in Note 3.

The following tables present a summary of Devon's quarterly consolidated comprehensive statements of earnings information for 2017 and 2016 reported under the full cost method.

	2017, under Full Cost				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Total revenues	$ 3,551	$ 3,259	$ 3,156	$ 3,983	$ 13,949
Earnings before income taxes	$ 598	$ 458	$ 272	$ 403	$ 1,731
Net earnings attributable to Devon	$ 565	$ 425	$ 228	$ 473	$ 1,691
Basic net earnings per share attributable to Devon	$ 1.08	$ 0.81	$ 0.43	$ 0.90	$ 3.22
Diluted net earnings per share attributable to Devon	$ 1.07	$ 0.80	$ 0.43	$ 0.89	$ 3.20

	2016, under Full Cost				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Total revenues	$ 2,126	$ 2,488	$ 2,882	$ 2,808	$ 10,304
Earnings (loss) before income taxes	$ (3,685)	$ (1,745)	$ 1,178	$ 375	$ (3,877)
Net earnings (loss) attributable to Devon	$ (3,056)	$ (1,570)	$ 993	$ 331	$ (3,302)
Basic net earnings (loss) per share attributable to Devon	$ (6.44)	$ (3.04)	$ 1.90	$ 0.63	$ (6.52)
Diluted net earnings (loss) per share attributable to Devon	$ (6.44)	$ (3.04)	$ 1.89	$ 0.63	$ (6.52)

Quarterly Cash Flow

The following table presents a summary of Devon's quarterly cash flow information as recast under the successful efforts method of accounting. See Note 2 for additional details. Devon has provided this information for each interim quarter in 2017 to aid investors and facilitate comparative periods to be shown during 2018.

	2017				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Net earnings	$ 317	$ 245	$ 212	$ 304	$ 1,078
Net cash from operating activities	746	738	700	725	2,909
Net cash from investing activities	(454)	(587)	(457)	(712)	(2,210)
Net cash from financing activities	(124)	91	157	(115)	9
Effect of exchange rate changes on cash	(8)	8	12	(6)	6
Net change in cash and cash equivalents	160	250	412	(108)	714
Cash and cash equivalents at beginning of period	1,959	2,119	2,369	2,781	1,959
Cash and cash equivalents at end of period	$ 2,119	$ 2,369	$ 2,781	$ 2,673	$ 2,673

Effects of Accounting Change on Fourth Quarter

As Devon recast the financial statements due to a change in accounting principle during the fourth quarter of 2017, the effects of the accounting change on the fourth quarter consolidated comprehensive statement of earnings and consolidated statement of cash flow are included below. See Note 2 for additional details.

	Changes to the Consolidated Comprehensive Statement of Earnings		
For the Quarter Ended December 31, 2017	**Under Full Cost**	**Changes**	**As Reported Under Successful Efforts**
Exploration expenses	$ —	$ 171	$ 171
Depreciation, depletion and amortization	417	111	528
Asset dispositions	1	(19)	(18)
General and administrative expenses	174	48	222
Financing costs, net	124	2	126
Other expenses	15	(10)	5
Earnings before income taxes	403	(303)	100
Income tax benefit	(191)	(13)	(204)
Net earnings	594	(290)	304
Net earnings attributable to Devon	473	(290)	183
Net earnings per share attributable to Devon:			
Basic	0.90	(0.55)	0.35
Diluted	0.89	(0.54)	0.35
Comprehensive earnings:			
Net earnings	594	(290)	304
Foreign currency translation and other	6	(1)	5
Comprehensive earnings	615	(291)	324
Comprehensive earnings attributable to Devon	494	(291)	203

	Changes to the Consolidated Statement of Cash Flows		
For the Quarter Ended December 31, 2017	**Under Full Cost**	**Changes**	**As Reported Under Successful Efforts**
Net earnings	$ 594	$ (290)	$ 304
Depreciation, depletion and amortization	417	111	528
Exploratory dry hole expense and unproved leasehold impairments	—	139	139
Gains and losses on asset sales	1	(19)	(18)
Deferred income tax benefit	(232)	(13)	(245)
Share-based compensation	36	11	47
Other	26	(10)	16
Net cash from operating activities	796	(71)	725
Capital expenditures	(871)	72	(799)
Divestitures of property and equipment	102	(1)	101
Net cash from investing activities	(783)	71	(712)

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

Not applicable.

Item 9A. ***Controls and Procedure*s**

Disclosure Controls and Procedures

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

Based on their evaluation, our principal executive and principal financial officers have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2017 to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for Devon, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Devon's management, including our principal executive and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (the "2013 COSO Framework"). Based on this evaluation under the 2013 COSO Framework, which was completed on February 21, 2018, management concluded that its internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, an independent registered public accounting firm who audited our consolidated financial statements as of and for the year ended December 31, 2017, as stated in their report, which is included under "Item 8. Financial Statements and Supplementary Data" of this report.

Changes in Internal Control Over Financial Reporting

In the fourth quarter of 2017, we added and modified certain internal control processes as a result of changing our method of accounting for oil and gas exploration and development activities from the full cost method to the successful efforts method. There were no other changes in our internal control over financial reporting during the fourth quarter of 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Not applicable.

PART III

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2017.

Item 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2017.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2017.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2017.

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

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2017.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

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

1. Consolidated Financial Statements

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

2. Consolidated Financial Statement Schedules

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

3. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger dated October 21, 2013, by and among Registrant, Devon Gas Services, L.P., Acacia Natural Gas Corp I, Inc., Crosstex Energy, Inc., New Public Rangers L.L.C., Boomer Merger Sub, Inc. and Rangers Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed October 22, 2013; File No. 001-32318).
2.2	Contribution Agreement dated October 21, 2013, by and among Registrant, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., Crosstex Energy, L.P. and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed October 22, 2013; File No. 001-32318).
3.1	Registrant's Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant's Form 10-K filed February 21, 2013; File No. 001-32318).
3.2	Registrant's Bylaws (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K filed January 27, 2016; File No. 001-32318).
4.1	Indenture, dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed July 12, 2011; File No. 001-32318).
4.2	Supplemental Indenture No. 1, dated as of July 12, 2011, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 4.00% Senior Notes due 2021 and the 5.60% Senior Notes due 2041 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2011; File No. 001-32318).

Exhibit No.	Description
4.3	Supplemental Indenture No. 2, dated as of May 14, 2012, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 3.250% Senior Notes due 2022 and the 4.750% Senior Notes due 2042 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed May 14, 2012; File No. 001-32318).
4.4	Supplemental Indenture No. 3, dated as of December 19, 2013, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 2.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed December 19, 2013; File No. 001-32318).
4.5	Supplemental Indenture No. 4, dated as of June 16, 2015, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 5.000% Senior Notes due 2045 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed June 16, 2015; File No. 001-32318).
4.6	Supplemental Indenture No. 5, dated as of December 15, 2015, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 5.850% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed December 15, 2015; File No. 001-32318).
4.7	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York), as Trustee (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002; File No. 000-30176).
4.8	Supplemental Indenture No. 1, dated as of March 25, 2002, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed April 9, 2002; File No. 000-30176).
4.9	Supplemental Indenture No. 3, dated as of January 9, 2009, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 6.30% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed January 9, 2009; File No. 000-32318).
4.10	Indenture, dated as of October 3, 2001, among Devon Financing Company, L.L.C. (f/k/a Devon Financing Corporation, U.L.C.), as Issuer, Registrant, as Guarantor, and The Bank of New York Mellon Trust Company, N.A., originally The Chase Manhattan Bank, as Trustee, relating to the 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4 filed October 31, 2001; File No. 333-68694).
4.11	Indenture, dated as of July 8, 1998, among Devon OEI Operating, L.L.C. (as successor to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank, N.A. (as successor to Norwest Bank Minnesota, National Association), as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to Ocean Energy, Inc.'s Form 10-Q filed August 14, 1998; File No. 001-14252).
4.12	First Supplemental Indenture, dated March 30, 1999, to Indenture dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and Wells Fargo Bank, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc.'s Form 10-Q filed May 17, 1999; File No. 001-08094).
4.13	Second Supplemental Indenture, dated as of May 9, 2001, to Indenture dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and Wells Fargo Bank, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc.'s Form 8-K filed May 14, 2001; File No. 033-06444).

Exhibit No.	Description
4.14	Third Supplemental Indenture, dated January 23, 2006, to Indenture dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C., as Issuer, Devon Energy Production Company, L.P., as Successor Guarantor, and Wells Fargo Bank, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.23 of Registrant's Form 10-K filed March 3, 2006; File No. 001-32318).
4.15	Senior Indenture, dated as of September 1, 1997, between Devon OEI Operating, L.L.C. (as successor to Seagull Energy Corporation) and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York), as Trustee, and related Specimen of 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 4.4 to Ocean Energy Inc.'s Form 10-K filed March 23, 1998; File No. 001-08094).
4.16	First Supplemental Indenture, dated as of March 30, 1999, to Senior Indenture dated as of September 1, 1997, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 4.10 to Ocean Energy, Inc.'s Form 10-Q filed May 17, 1999; File No. 001-08094).
4.17	Second Supplemental Indenture, dated as of May 9, 2001, to Senior Indenture dated as of September 1, 1997, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc.'s Form 8-K filed May 14, 2001; File No. 033-06444).
4.18	Third Supplemental Indenture, dated as of December 31, 2005, to Senior Indenture dated as of September 1, 1997, by and among Devon OEI Operating, L.L.C., as Issuer, Devon Energy Production Company, L.P., as Successor Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 4.27 of Registrant's Form 10-K filed March 3, 2006; File No. 001-32318).
4.19	Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (the "EnLink Indenture") (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's Form 8-K filed March 21, 2014; File No. 001-36340).†
4.20	First Supplemental Indenture, dated as of March 19, 2014, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to EnLink Midstream Partners, LP's Form 8-K filed March 21, 2014; File No. 001-36340).†
4.21	Second Supplemental Indenture, dated as of November 12, 2014, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to EnLink Midstream Partners, LP's Form 8-K filed November 12, 2014; File No. 001-36340).†
4.22	Third Supplemental Indenture, dated as of May 12, 2015, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to EnLink Midstream Partners, LP's Form 8-K filed May 12, 2015; File No. 001-36340).†
4.23	Fourth Supplemental Indenture, dated as of July 14, 2016, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's Form 8-K filed July 14, 2016; File No. 001-36340).†
4.24	Fifth Supplemental Indenture, dated as May 11, 2017, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's Form 8-K filed May 11, 2017; File No. 001-36340).†

Exhibit No.	Description
10.1	Credit Agreement, dated as of October 24, 2012, among Registrant, as U.S. Borrower, Devon Canada Corporation, as Canadian Borrower, each lender from time to time party thereto, each L/C Issuer from time to time party thereto, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K filed October 29, 2012; File No. 001-32318).
10.2	Extension Agreement, dated as of September 3, 2013, to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon Canada Corporation, as Canadian Borrower, Devon Financing Company, L.L.C., the consenting lenders, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender, with respect to the extension of the maturity date from October 24, 2017 to October 24, 2018 (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed November 6, 2013; File No. 001-32318).
10.3	First Amendment to Credit Agreement, dated as of February 3, 2014, to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon Canada Corporation, as Canadian Borrower, each lender from time to time party thereto, each L/C Issuer from time to time party thereto, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K filed February 7, 2014; File No. 001-32318).
10.4	Extension Agreement, dated as of October 17, 2014, to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon Canada Corporation, as Canadian Borrower, Devon Financing Company, L.L.C., the consenting lenders, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender with respect to the extension of the maturity date from October 24, 2018 to October 24, 2019 (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed November 5, 2014; File No. 001-32318).
10.5	Devon Energy Corporation 2017 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registrant's Form S-8 filed June 7, 2017; File No. 333-218561).*
10.6	Devon Energy Corporation 2015 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registrant's Form S-8 filed June 3, 2015; File No. 333-204666).*
10.7	Devon Energy Corporation 2009 Long-Term Incentive Plan (as amended and restated effective June 6, 2012) (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed June 8, 2012; File No. 001-32318).*
10.8	2013 Amendment (effective as of March 6, 2013) to the Devon Energy Corporation 2009 Long-Term Incentive Plan (as amended and restated effective June 6, 2012) (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed May 1, 2013; File No. 001-32318).*
10.9	Devon Energy Corporation Annual Incentive Compensation Plan (amended and restated effective as of January 1, 2017) (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed June 12, 2017; File No. 001-32318).*
10.10	Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective as of April 15, 2014) (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed August 6, 2014; File No. 001-32318).*
10.11	Amendment 2014-2, executed May 9, 2014, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective April 15, 2014) (incorporated by reference to Exhibit 10.11 to Registrant's Form 10-K filed February 20, 2015; File No. 001-32318).*
10.12	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective April 15, 2014) (incorporated by reference to Exhibit 10.13 to Registrant's Form 10-K filed February 15, 2017; File No. 001-32318).*

Exhibit No.	Description
10.13	Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.15 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.14	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.6 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.15	Amendment 2015-1, executed April 15, 2015, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed May 6, 2015; File No. 001-32318).*
10.16	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.17 to Registrant's Form 10-K filed February 15, 2017; File No. 001-32318).*
10.17	Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.18	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.7 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.19	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.20 to Registrant's Form 10-K filed February 15, 2017; File No. 001-32318).*
10.20	Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.17 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.21	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.8 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.22	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.23 to Registrant's Form 10-K filed February 15, 2017; File No. 001-32318).*
10.23	Devon Energy Corporation Supplemental Executive Retirement Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.24	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Supplemental Executive Retirement Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.25 to Registrant's Form 10-K filed February 15, 2017; File No. 001-32318).*
10.25	Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.19 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.26	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.9 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.27	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.28 to Registrant's Form 10-K filed February 15, 2017; File No. 001-32318).*

Exhibit No.	Description
10.28	Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2018), executed December 18, 2017.*
10.29	Amended and Restated Form of Employment Agreement between Registrant and certain executive officers (incorporated by reference to Exhibit 10.19 to Registrant's Form 10-K filed February 27, 2009; File No. 001-32318).*
10.30	Form of Amendment No. 1 to the Amended and Restated Employment Agreement between Registrant and certain executive officers (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed April 25, 2011; File No. 001-32318).*
10.31	Form of Employment Agreement between Registrant and certain executive officers (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*
10.32	Employment Agreement, dated April 19, 2017, by and between Registrant and Mr. Jeffrey L. Ritenour (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K, filed on April 20, 2017; File No. 001-32318).*
10.33	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.25 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*
10.34	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.29 to Registrant's Form 10-K filed February 20, 2015; File No. 001-32318).*
10.35	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and David A. Hager for performance based restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed November 4, 2015; File No. 001-32318).*
10.36	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-Q filed May 4, 2016; File No. 001-32318).*
10.37	2017 Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed May 3, 2017; File No. 001-32318).*
10.38	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and executive officers for performance based restricted share units awarded (incorporated by reference to Exhibit 10.32 to Registrant's Form 10-K filed February 20, 2015; File No. 001-32318).*
10.39	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and executive officers for performance based restricted share units awarded (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed May 4, 2016; File No. 001-32318).*
10.40	2017 Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and executive officers for performance based restricted share units awarded (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-Q filed May 3, 2017; File No. 001-32318).*

Exhibit No.	Description
10.41	Form of Notice of Grant of Incentive Stock Options and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and certain employees and executive officers for incentive stock options granted (incorporated by reference to Exhibit 10.15 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.42	Form of Notice of Grant of Nonqualified Stock Options and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and certain employees and executive officers for nonqualified stock options granted (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.43	Form of Non-Management Director Nonqualified Stock Option Award Agreement under the Devon Energy Corporation 2009 Long-Term Incentive Plan between Registrant and all non-management directors for nonqualified stock options granted (incorporated by reference to Exhibit 10.20 to Registrant's Form 10-K filed on February 25, 2010; File No. 001-32318).*
10.44	Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and Thomas L. Mitchell for restricted stock awarded (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.45	Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and all non-management directors for restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed August 5, 2015; File No. 001-32318).*
10.46	2017 Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2017 Long-Term Incentive Plan between Devon and all non-management directors for restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed August 2, 2017; File No. 001-32318).*
10.47	Form of Letter Agreement amending the restricted stock award agreements and nonqualified stock option agreements under the 2009 Long-Term Incentive Plan and the 2005 Long-Term Incentive Plan between Registrant and John Richels (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.48	Form of Amendment to Incentive Stock Option Award Agreements between Registrant and post-retirement eligible executives relating to incentive stock options under the 2009 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.24 to Registrant's Form 10-K filed February 21, 2013; File No. 001-32318).*
10.49	Amendment to Performance Share Unit Award Agreement dated effective September 16, 2015, between Registrant and John Richels to Performance Share Unit Award Agreement dated February 10, 2015 (incorporated by reference to Exhibit 10.43 to Registrant's Form 10-K filed February 17, 2016; File No. 001-32318).*
10.50	Amendment to Performance Restricted Stock Award Agreement dated effective September 16, 2015, between Registrant and John Richels to Performance Restricted Stock Award Agreement dated February 10, 2015 (incorporated by reference to Exhibit 10.44 to Registrant's Form 10-K filed February 17, 2016; File No. 001-32318).*
12	Statement of computations of ratios of earnings to fixed charges.
21	List of Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants, Ltd.
23.3	Consent of Deloitte LLP.

Exhibit No.	Description
31.1	Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of LaRoche Petroleum Consultants, Ltd.
99.2	Report of Deloitte LLP.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

† As of December 31, 2017, the aggregate amount of debt issued under the EnLink Indenture, as supplemented, exceeded ten percent of Devon's consolidated total assets. Devon has not filed any other instruments defining the rights of holders of long-term indebtedness of EnLink, as such instruments do not represent debt exceeding ten percent of the total assets of Devon and its subsidiaries on a consolidated basis. Devon hereby agrees to furnish a copy of any such agreements to the SEC upon request.

* Indicates management contract or compensatory plan or arrangement.

Item 16. *Form 10-K Summary*

Not applicable.

SIGNATURES

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

DEVON ENERGY CORPORATION

By: /s/ JEFFREY L. RITENOUR
Jeffrey L. Ritenour
Executive Vice President and
Chief Financial Officer

February 21, 2018

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

/s/ DAVID A. HAGER David A. Hager	President, Chief Executive Officer and Director (Principal executive officer)	February 21, 2018
/s/ JEFFREY L. RITENOUR Jeffrey L. Ritenour	Executive Vice President and Chief Financial Officer (Principal financial officer)	February 21, 2018
/s/ JEREMY D. HUMPHERS Jeremy D. Humphers	Senior Vice President and Chief Accounting Officer (Principal accounting officer)	February 21, 2018
/s/ JOHN RICHELS John Richels	Chairman of the Board	February 21, 2018
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 21, 2018
/s/ JOHN E. BETHANCOURT John E. Bethancourt	Director	February 21, 2018
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 21, 2018
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 21, 2018
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 21, 2018
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 21, 2018
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 21, 2018

Directors

John Richels
Chairman

Barbara M. Baumann (1) (3)

John E. Bethancourt (2) (3) (4)

David A. Hager

Robert H. Henry (1) (3)

Michael M. Kanovsky (1) (4)
Chairman of Reserves Committee

Robert A. Mosbacher Jr. (2) (3)
Lead Director
Chairman of Governance Committee

Duane C. Radtke (2) (4)
Chairman of Compensation Committee

Mary P. Ricciardello (1) (3)
Chairman of Audit Committee

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

Senior Executives

David A. Hager
President and Chief Executive Officer

Tony D. Vaughn
Chief Operating Officer

Jeff L. Ritenour
Executive Vice President and Chief Financial Officer

R. Alan Marcum
Executive Vice President, Administration

Lyndon C. Taylor
Executive Vice President and General Counsel

Other Executives

Tana K. Cashion
Senior Vice President, Human Resources

Rob Dutton
Senior Vice President, Canadian Operations and President of Devon Canada

Rick A. Gideon
Senior Vice President, Exploration and Production

David G. Harris
Senior Vice President, Exploration and Production

Jeremy D. Humphers
Senior Vice President and Chief Accounting Officer

Wade Hutchings
Senior Vice President, Exploration and Production

Kevin D. Lafferty
Senior Vice President, Exploration and Production

Other Information

Investor Relations Contacts
E-mail: investor.relations@dvn.com

Scott Coody, Vice President, Investor Relations
Telephone: (405) 552-4735

Chris Carr, Supervisor, Investor Relations
Telephone: (405) 228-2496

Media Contact
John Porretto, Director, Corporate Communications
Telephone: (405) 228-7506

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

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

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

Annual Meeting
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 6, 2018, at the Devon Energy Center Auditorium, 333 W. Sheridan Avenue, Oklahoma City, OK.

Independent Auditors
KPMG LLP
Oklahoma City, OK

Stock Trading Data
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 7,400 shareholders of record.

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

Forward-Looking Statements
See information regarding forward-looking statements on page five of this report.

Devon Energy Corporation
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Oklahoma City, OK 73102
devonenergy.com
@DevonEnergy

devon