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, 2018

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 every Interactive Data File required to be submitted 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 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, a 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 29, 2018 was approximately $22.5 billion, based upon the closing price of $43.96 per share as reported by the New York Stock Exchange on such date. On February 6, 2019, 438.3 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's definitive Proxy Statement relating to Registrant's 2019 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
TABLE OF CONTENTS

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.

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

"2012 Senior Credit Facility" means Devon's syndicated unsecured revolving line of credit, effective as of October 24, 2012.

"2018 Senior Credit Facility" means Devon's syndicated unsecured revolving line of credit, effective as of October 5, 2018.

"ASC" means Accounting Standards Codification.

"ASR" means an accelerated share-repurchase transaction with a financial institution to repurchase Devon's common stock.

"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.

"EnLink" means EnLink Midstream Partners, LP, 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, and, unless the context otherwise indicates, EnLink Midstream Manager, LLC, the managing member of EnLink Midstream, LLC.

"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.

“MMBbls” means million barrels.

“MMBoe” means million Boe.

“MMBtu” means million Btu.

“MMcf” means million cubic feet.

“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.

“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.

“WTI” means West Texas Intermediate.

“/Bbl” means per barrel.

“/d” means per day.

“/MMBtu” means per MMBtu.

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 and phrases “expects,” “believes,” “will,” “would,” “could,” “continue,” “may,” “aims,” “likely to be,” “intends,” “forecasts,” “projections,” “estimates,” “plans,” “expectations,” “targets,” “opportunities,” “potential,” “anticipates,” “outlook” and other similar terminology. All statements, other than statements of historical facts, included in this report that address activities, events or developments that Devon expects, believes or anticipates will or may occur in the future are forward-looking statements. 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 our operations, including as a result of employee misconduct;
- regulatory restrictions, compliance costs and other risks relating to governmental regulation, including with respect to environmental matters;
- risks related to regulatory, social and market efforts to address climate change;
- 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 assets, 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. In July 2018, we exited the midstream business by divesting our aggregate ownership interests in EnLink and the General Partner.

Our principal and administrative offices are located at 333 West Sheridan, Oklahoma City, OK 73102-5015 (telephone 405-235-3611). As of December 31, 2018, Devon and its consolidated subsidiaries had approximately 2,900 employees.

Devon files or furnishes annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to these reports, with the SEC. Through our website, 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.

Our Strategy

Our business strategy is focused on delivering a consistently competitive shareholder return among our peer group. Because the business of exploring for, developing and producing oil and natural gas is capital intensive, delivering sustainable capital efficient cash flow growth is a key tenant to our success. While our cash flow is highly dependent on volatile and uncertain commodity prices, we pursue our strategy throughout all commodity price cycles with three fundamental principles.

A premier, sustainable portfolio of assets – As discussed in the next section of this Annual Report, we own a portfolio of assets located in the United States and Alberta, Canada. We strive to own premier assets capable of generating cash flows in excess of our capital and operating requirements, as well as competitive rates of return. We also desire to own a portfolio of assets that can provide a production growth platform extending many years into the future. Because of the strength of oil prices relative to natural gas, we have been positioning our portfolio to be more heavily weighted to U.S. oil assets in recent years.

During 2018, we made significant progress in our transition to a U.S. oil company. We sold our midstream business and certain non-core upstream assets, generating nearly $5 billion in proceeds. In February 2019, we announced our intent to separate our Canadian business and our Barnett Shale assets from the Company. After these separations, we expect our oil production growth, price realizations and field-level margins will all improve, as we sharpen our focus on four core U.S. oil plays located in the Delaware Basin, STACK, Eagle Ford and Rockies.

Superior execution – As we pursue cash flow growth, we continually work to optimize the efficiency of our capital programs and production operations, with an underlying objective of reducing absolute and per unit costs and enhancing our returns. We also strive to leverage our culture of health, safety and environmental stewardship in all aspects of our business.

Throughout 2018, we continued to achieve efficiency gains in various aspects of our business. Our initial production rates from new wells continued to improve in our four core U.S. oil plays and have exceeded the average of the top 40 U.S. producers since 2015 by more than 40%. We continued to improve cycle times, incorporate production optimization strategies and other cost reduction initiatives, driving down breakeven costs across our portfolio of assets.

As we focus on a more streamlined portfolio of U.S. oil assets, we are aggressively pursuing an improved cost structure with $780 million of annual costs savings expected by 2021. We expect to realize about 70% of the annualized savings by the end of 2019. Our retained U.S. oil business is expected to realize $300 million of annual well cost savings by 2021, as we increase our focus on development drilling, reduce our facility costs and optimize well spacing in the STACK. Additionally, we will streamline and align our workforce with our go-forward business, which should result in $300 million of annual cost savings by the end of the three-year period. As we continue deleveraging, we expect to reduce annual interest costs by $130 million. Finally, we have plans to reduce our annual production expenses by $50 million over the next three years.

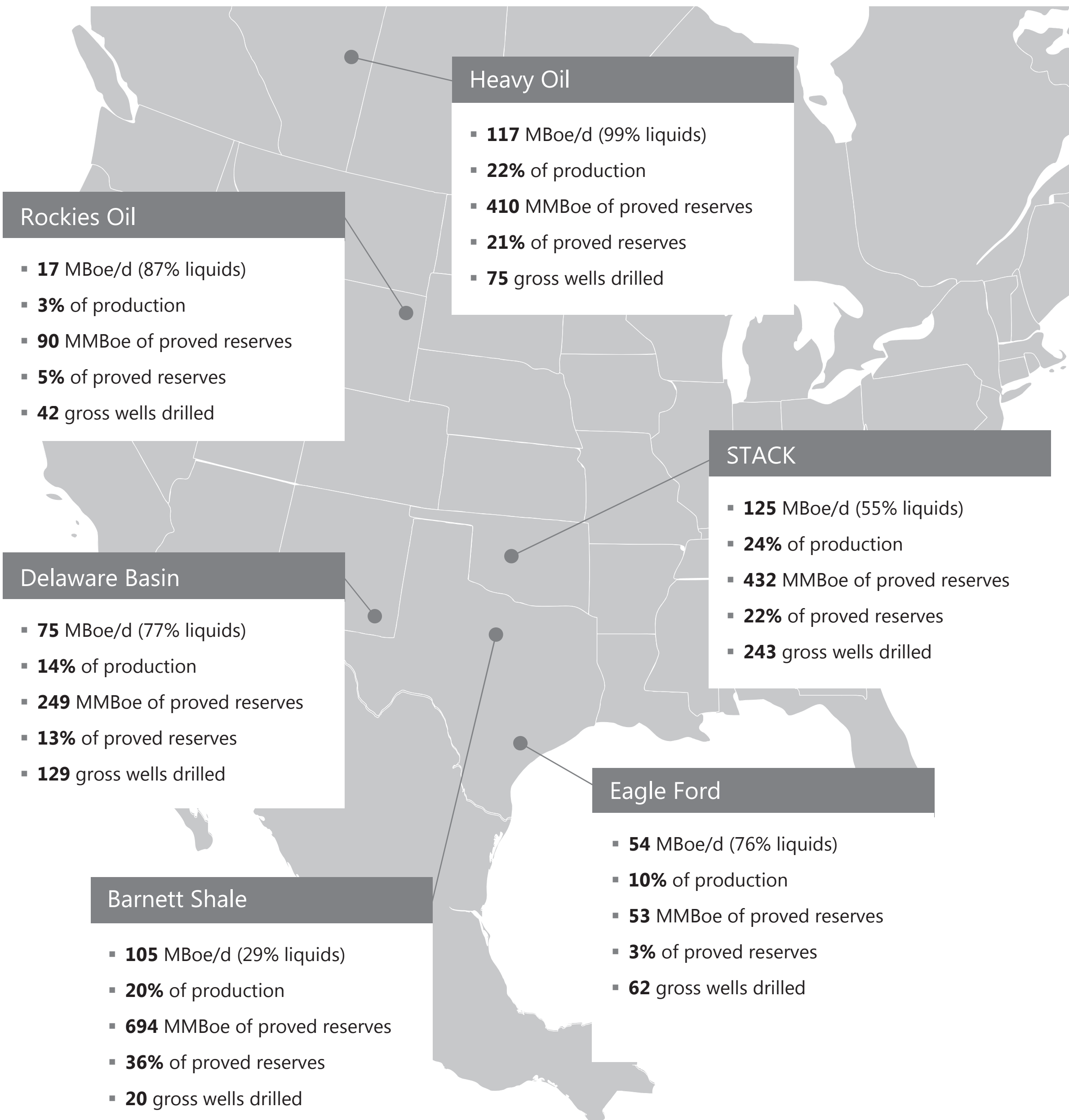
Financial strength and flexibility – Commodity prices are uncertain and volatile, so we strive to maintain a strong balance sheet, as well as adequate liquidity and financial flexibility, in order to operate competitively in all commodity price cycles. Our capital allocation decisions are made with attention to these financial stewardship principles, as well as the priorities of funding our core operations, protecting our investment-grade credit ratings, and paying and growing our shareholder dividend.

During 2018, we reduced our consolidated debt by 40%, primarily from our divestitures. We also raised our quarterly dividend 33% and began a $4 billion share repurchase program. As we dispose of our Canadian and Barnett Shale assets in 2019, we expect to use the proceeds to reduce debt further and repurchase additional common shares. As a result of our planned dispositions, our Board of Directors has increased our share repurchase program to $5 billion in February 2019 and raised our quarterly dividend 12.5% to $0.09 per share.

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, 2018 are detailed in the map below. Notes 22 and 23 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.



Delaware Basin – The Delaware Basin is one of Devon's top assets and continues to offer exploration and low-risk development opportunities from many geologic reservoirs and play types, including the oil-rich Bone Spring, 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 2018, our continued appraisal and development work enabled us to increase our proved reserves in this area by approximately 24%. At December 31, 2018, we had 10 operated rigs developing this asset. In 2019, we plan to invest approximately $900 million of capital in the Delaware Basin, making it the top-funded asset in the portfolio.

STACK – The STACK development, located primarily in Oklahoma's Canadian, Kingfisher and Blaine counties, is one of Devon's top assets. Our STACK position is one of the largest in the industry, providing visible long-term stable production. At December 31, 2018, we had five operated rigs with drilling focused in the Meramec formation. In 2019, we plan approximately $400 million of capital investment. The STACK is Devon's second highest funded asset in the portfolio for 2019.

Eagle Ford – We acquired our position in the Eagle Ford in 2014. Since acquiring these assets, we have delivered tremendous results by producing 173 million oil-equivalent barrels. Our excellent results are driven by our development in DeWitt County, located in the economic core of the play. Our Eagle Ford assets generated significant cash flow in 2018. In 2019, we plan approximately $300 million of capital investment.

Rockies Oil – Our acreage in the Rockies is focused on emerging oil opportunities in the Powder River Basin. Recent drilling success in this basin has expanded our drilling inventory, and we expect further growth as we accelerate activity and continue to de-risk this emerging light-oil opportunity. As of December 31, 2018, we had two operated rigs targeting the Turner, Parkman, Teapot and Niobrara formations in northern Converse County of the Powder River Basin. In 2019, we plan approximately $300 million of capital investment and adding two additional operated rigs.

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 15 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, 2018. Currently, we have minimal planned capital outlays for Pike in the near future. 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 oil development play that produces heavy oil by conventional means, without the need for steam injection.

In 2019, we plan to separate our operations in Canada.

Barnett Shale – This is our largest property in terms of proved reserves. Our leases are located primarily in Denton, Parker, Tarrant and Wise counties in north Texas. 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. In 2019, we plan to separate our Barnett Shale assets.

Proved Reserves

For estimates of our proved developed and proved undeveloped reserves and the discussion of the contribution by each property, see Note 23 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 over 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 18 years, including the past 11 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 2018, we engaged two such firms to audit approximately 89% of our proved reserves in accordance with generally accepted petroleum engineering and evaluation methods and procedures. LaRoche Petroleum Consultants, Ltd. audited approximately 87% of our U.S. reserves, and Deloitte LLP audited approximately 97% 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)
2018					
Barnett Shale	—	—	186	12	43
STACK	12	—	121	14	45
Jackfish	—	35	—	—	35
U.S.	47	—	397	39	153
Canada	7	35	4	—	42
Total North America	54	35	401	39	195
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

Year Ended December 31,	Average Sales Price (1)				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Production Cost (Per Boe) (1)(2)
2018 (1)					
Barnett Shale	$ 62.89	$ —	$ 2.45	$ 22.72	$ 9.42
STACK	$ 63.81	$ —	$ 2.29	$ 25.53	$ 7.16
Jackfish	$ —	$ 17.88	$ —	$ —	$ 12.85
U.S.	$ 61.97	$ —	$ 2.37	$ 24.74	$ 8.61
Canada	$ 27.36	$ 17.88	N/M	$ —	$ 13.43
Total North America	$ 57.76	$ 17.88	$ 2.37	$ 24.74	$ 9.66
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

(1) 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 changed from a net to a gross presentation. The

change resulted in an increase to our upstream revenues and production expenses by $254 million during 2018 with no impact to net earnings. These changes primarily related to our Barnett Shale and STACK properties.

(2) 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
2018							
U.S.	165.6	3.1	69.4	—	235.0	3.1	238.1
Canada	70.5	—	—	—	70.5	—	70.5
Total North America	236.1	3.1	69.4	—	305.5	3.1	308.6
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

(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, 2018. As of February 1, 2019, these wells were still in progress.

	Gross (1)	Net (2)
U.S.	184.0	105.2
Canada	1.0	1.0
Total North America	185.0	106.2

(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, 2018.

	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.	9,284	3,445	8,235	5,703	17,519	9,148
Canada	3,183	3,071	544	380	3,727	3,451
Total North America	12,467	6,516	8,779	6,083	21,246	12,599

(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 902 and 350 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 12,900 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, 2018. Of our 3.8 million net acres, approximately 1.9 million acres are held by production. The acreage in the table includes 0.2 million, 0.1 million and 0.1 million net acres subject to leases that are scheduled to expire during 2019, 2020 and 2021, respectively. As of December 31, 2018, there were no proved undeveloped reserves associated with our expiring acreage. Of the 0.3 million net acres set to expire by December 31, 2021, 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 2018, we allowed approximately 0.1 million acres to expire.

	Developed		Undeveloped		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
			(Thousands)			
U.S.	1,449	909	3,373	1,463	4,822	2,372
Canada	674	495	2,086	967	2,760	1,462
Total North America	2,123	1,404	5,459	2,430	7,582	3,834

(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 legal counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

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

As of January 2019, our production was sold under the following contract terms.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	75%	—	25%	—
Natural gas	67%	4%	29%	—
NGLs	41%	20%	39%	—

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, 2018, 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)	53	25	28	—
Natural gas (Bcf)	360	220	125	15
NGLs (MMBbls)	10	10	—	—
Total (MMBoe)	123	72	49	2

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 2018, we had one purchaser that accounted for approximately 11% of our consolidated sales revenue.

During 2017 and 2016, 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 unitization 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, from time to time, evaluated and, in some cases, promulgated 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 can sometimes be subject to 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.

In December 2018, Alberta enacted the Curtailment Rules (Rules) in an effort to reduce Alberta's oversupply of oil which resulted from pipeline and rail constraints. Pursuant to the Rules, operators that produce either or both crude oil or crude bitumen in amounts in excess of 10 MBbls/d are required to curtail their production. As of January 1, 2019, the production curtailment amount was set at 325 MBbls/d. The curtailment amounts are expected to reduce over 2019 to an average of approximately 95 MBbls/d as storage levels ease and price differential improve, and the Rules terminate on December 31, 2019. Devon's curtailments in the first quarter of 2019 as a result of the Rules are anticipated to total approximately 10 MBbls/d of bitumen, or approximately 2% of our total production.

Environmental, Pipeline Safety and Occupational Regulations

We strive to conduct our operations in a socially and environmentally responsible manner, which includes compliance with applicable law. 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. Environmental protection and health and safety compliance are 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, over the last five 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:

- the domestic and worldwide supply of and demand for oil, gas and NGLs;
- 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, including in Canada, the Delaware Basin and other areas of our operations;
- 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;
- changes in trade relations and policies, including the imposition of tariffs by the U.S. or China; and
- other governmental regulations and taxes.

The differential between WTI and Western Canadian Select, a benchmark for the Canadian oil market, recently expanded, widening to nearly $46 per barrel in November 2018. As a result, our Canadian heavy oil unhedged realized price for the fourth quarter was near zero. This negatively affected our results of operations in 2018, and a sustained weakness or further deterioration in differentials or commodity prices could materially and adversely impact our business by resulting in, or exacerbating, the following effects:

- reducing the amount of oil, bitumen, 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 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.

Our 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.

In addition, we rely on our employees, consultants and sub-contractors to conduct our operations in compliance with applicable laws and standards. Any violation of such laws or standards by these individuals, whether through negligence, harassment, discrimination or other misconduct, could result in significant liability for us and adversely affect our business. For example, negligent operations by employees could result in serious injury, death or property damage, and sexual harassment or racial and gender discrimination could result in legal claims and reputational harm.

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 and decommissioning obligations. 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 and public policy 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. In addition, changes in public policy may indirectly impact our operations by, among other things, increasing the cost of supplies and equipment and fostering general economic uncertainty. For example, changes in U.S. trade relations, particularly the imposition of tariffs by the U.S. and China, may increase the cost of materials we or our vendors use, thereby increasing our operating expense. 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 and income taxes, 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 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 or hydraulic fracturing or are considering doing so or banning the practice altogether. 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, 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. PHMSA has announced its intent to address the 2016 proposed rules for gas pipelines through three separate final rulemakings in 2019. 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 half of 2019. 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.

Concerns About Climate Change and Related Regulatory, Social and Market Actions May Adversely Affect Our Business

Continuing and increasing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives, including international agreements, 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. 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. Following the change in presidential administrations, however, the agencies have attempted to revise or rescind their previously issued methane standards. Litigation concerning these methane regulations and subsequent attempts to revise or rescind them is ongoing. Nevertheless, several states where we operate, including Wyoming, have already imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. With respect to more comprehensive regulation, federal and state initiatives to date have generally focused on the development of cap-and-trade or carbon tax programs. As generally proposed, a cap-and-trade program 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, while a carbon tax could impose taxes based on emissions from our operations and downstream uses of our products.

In Canada, greenhouse gas emissions are also being addressed at both the federal and provincial level. Devon will continue to be subject to Alberta's climate change laws and regulations until at least 2021. Those laws and regulations include a legislated oil sands emission limit, with forthcoming regulations involving methane emissions reduction targets. Beginning January 2019, the Greenhouse Gas Pollution Pricing Act subjects all of Canada to a federal price on greenhouse gas emissions unless a province or territory has implemented a compliant carbon pricing regime. Litigation concerning the act is ongoing, and it is unclear how the act will ultimately treat provincial plans. In Alberta, large industrial emitters are subject to the Carbon Competitiveness Incentive Regulation (CCIR). The CCIR 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 laws and regulations is expected to be minimal in the near term. Oil and gas facilities that are not subject to the CCIR are exempt from its economy-wide carbon levy until 2023.

In addition to regulatory risk, other market and social initiatives resulting from the changing perception of climate change present risks for our business. For example, in an effort to promote a lower-carbon economy, there are various public and private initiatives subsidizing the development of alternative energy sources, including by mandating the use of specific fuels or technologies. These initiatives may reduce the competitiveness of carbon-based fuels, such as oil and gas. Moreover, certain financial institutions, funds and other sources of capital have begun restricting or eliminating their investment in oil and natural gas activities due to their concern regarding climate change. Such restrictions in capital could make it more difficult to secure funding to operate our business. Finally, governmental entities and other plaintiffs have brought, and may continue to bring, claims against us and other oil and gas companies for purported damages caused by the alleged effects of climate change. These and the other regulatory, social and market risks relating to climate change described above could result in unexpected costs, increase our operating expense and reduce the demand for our products, which in turn 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 financial derivative instruments 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 will 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, 2018, we had total indebtedness of $5.9 billion. Our indebtedness and other financial commitments have important consequences to our business, including, but not limited to:

- requiring us to dedicate a 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 financial 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. All or a portion of our production in one or more regions 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, the midstream operators may be subject to constraints that limit 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 and production 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, we have limited or no insurance coverage for a variety of other risks, including pollution events that are considered gradual, war and political risks and fines or penalties 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 and may have established superior strategic long-term positions and relationships, including with respect to midstream take-away capacity. As a consequence, we may be at a competitive disadvantage in bidding for assets or services and accessing capital and downstream markets. 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 Business Could Be Adversely Impacted by Investors Attempting to Effect Change

Stockholder activism has been increasing in our industry, and investors may from time to time attempt to effect changes to our business or governance, whether by stockholder proposals, public campaigns, proxy solicitations or otherwise. Such actions could adversely impact our business by distracting our board of directors and employees from core business operations, requiring us to incur increased advisory fees and related costs, interfering with our ability to successfully execute on strategic transactions and plans and provoking perceived uncertainty about the future direction of our business. Such perceived uncertainty may, in turn, make it more difficult to retain employees and could result in significant fluctuation in the market price of our common stock.

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 or businesses 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 or business 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 Energy Production Company, 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

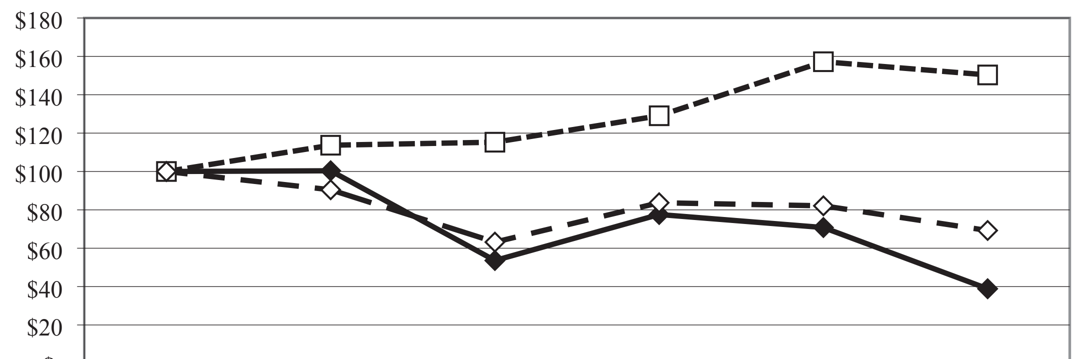
Item 5. *Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock is traded on the NYSE under the “DVN” ticker symbol. On February 6, 2019, there were 7,094 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, and will depend on Devon’s financial condition and other relevant factors. Additional information on our dividends can be found in Note 18 in “Item 8. Financial Statements and Supplementary Data” of this report.

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, 2013 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



	2013	2014	2015	2016	2017	2018
Devon	$100.00	$100.37	$53.60	$77.57	$70.79	$38.88
S&P 500	$100.00	$113.69	$115.26	$129.05	$157.22	$150.33
Peer Group	$100.00	$90.47	$63.19	$83.71	$82.10	$69.24

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 provides information regarding purchases of our common stock that were made by us during the fourth quarter of 2018 (shares in thousands).

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (2)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (2)
October 1 - October 31	10,532	$ 36.01	10,529	$ 2,388
November 1 - November 30	7,079	$ 31.55	7,068	$ 2,165
December 1 - December 31	6,020	$ 23.82	6,015	$ 2,022
Total	23,631	$ 31.57	23,612	

(1) In addition to shares purchased under the share repurchase program described below, these amounts also included approximately 19,000 shares received by us from employees for the payment of personal income tax withholding on vesting transactions.

(2) On March 7, 2018, we announced a $1.0 billion share repurchase program. On June 6, 2018, we announced the expansion of this program to $4.0 billion. On February 19, 2019, we announced a further expansion to $5.0 billion with a December 31, 2019 expiration date. During 2018, we repurchased 78.1 million shares of common stock for $3.0 billion, or $38.11 per share. Future purchases under the program will be made in the open market, private transactions or through the use of ASR programs.

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 39,000 shares of our common stock in 2018, 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. Shares sold under the Canadian Plan were acquired through open-market purchases. These shares and any interest in the Canadian Plan were offered and sold in reliance on the exemptions for offers and sales of securities made outside of the U.S., including under Regulation S for offers and sales of securities to employees pursuant to an employee benefit plan established and administered in accordance with the law of a country other than the U.S. In 2018, there were no shares purchased by Canadian employees under the plan.

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.

	2018	2017	2016	2015	2014
Statement of Earnings data:					
Upstream revenues [(1)]	$ 6,285	$ 5,307	$ 3,981	$ 5,885	$ 11,619
Total revenues [(1)]	$ 10,734	$ 8,878	$ 6,753	$ 9,372	$ 16,636
Net earnings (loss) from continuing operations [(2)]	$ 764	$ 758	$ (574)	$(12,231)	$ (1,004)
Net earnings (loss) from continuing operations per share:					
Basic [(2)]	$ 1.53	$ 1.44	$ (1.14)	$ (30.09)	$ (2.49)
Diluted [(2)]	$ 1.52	$ 1.43	$ (1.14)	$ (30.09)	$ (2.49)
Cash dividends per common share	$ 0.30	$ 0.24	$ 0.42	$ 0.96	$ 0.94
Balance Sheet data:					
Total assets [(2)(3)]	$ 19,566	$ 30,241	$ 28,675	$ 29,673	$ 49,253
Long-term debt	$ 5,785	$ 6,749	$ 6,859	$ 8,990	$ 7,738
Stockholders' equity	$ 9,186	$ 14,104	$ 12,722	$ 11,111	$ 24,789
Common shares outstanding	450	525	523	418	409

(1) In January 2018, Devon adopted ASC 606 – *Revenue from Contracts with Customers* using the modified retrospective method and has applied the standard to all existing contracts. The impact of adoption for 2018 is further discussed in Note 1 of "Item 8. Financial Statements and Supplementary Data" of this report. Prior periods have not been restated.

(2) Material asset impairments and acquisition and divestiture activity had significant impacts on operating results and the carrying value of our oil and gas assets. Specifically, there were asset impairments of $0.4 billion, $16.1 billion and $3.4 billion in 2016, 2015 and 2014, respectively. 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 2 and Note 5 of "Item 8. Financial Statements and Supplementary Data" of this report.

(3) Amounts in 2014 through 2017 include assets related to our aggregate ownership interest in EnLink and the General Partner. As discussed further in Note 19 of "Item 8. Financial Statements and Supplementary Data" of this report, the 2018 divestment of our aggregate ownership interests in EnLink and the General Partner resulted in the reclassification of EnLink and the General Partners' assets to assets held for sale, which are included within this amount.

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

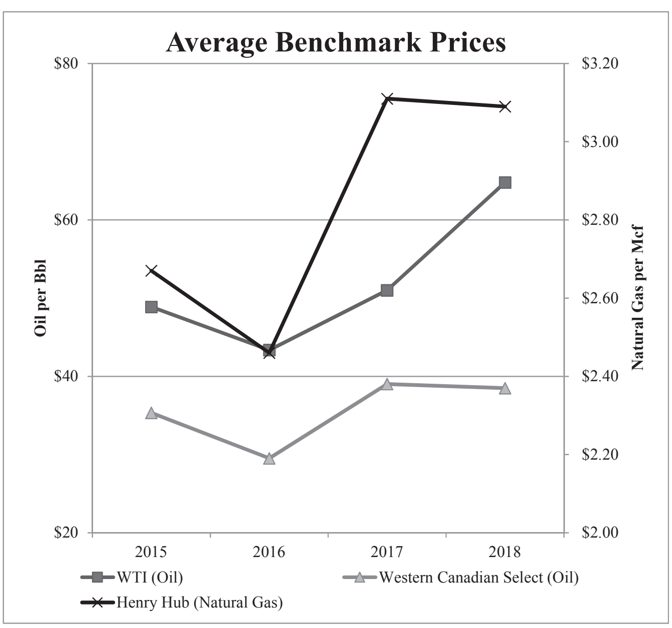
Introduction

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 2018 Results

2018 was a pivotal year for Devon as we took several significant steps toward achieving our long-term strategic goals. Operationally, we successfully transitioned our U.S. oil business into full-field development, which resulted in high-return, light-oil production advancing 14 percent in 2018. In addition to this strong operating performance, we made substantial progress high-grading our asset portfolio, building per-share value through our share-repurchase program and reducing our financial leverage by more than 40 percent.

- Increased STACK and Delaware Basin production 27% in 2018 compared to 2017.
- Maintained our 2018 capital expenditure forecast.
- Substantially achieved $5.0 billion in asset sales, including the monetization of EnLink and the General Partner.
- Repurchased $3.0 billion of common stock, representing a 14% share count reduction since December 31, 2017.
- Reduced long-term debt by $922 million, which is expected to reduce annualized financing costs by $66 million.
- Completed workforce reduction and cost reduction initiatives expected to generate $150 million of annualized savings.
- Increased our quarterly common stock dividend 33% to $0.08 per share beginning in the second quarter of 2018.
- Exited 2018 with $2.4 billion of cash and $2.9 billion of available credit under our Senior Credit Facility and have no significant debt maturities until 2021.



As presented in the graph at the left, our operating achievements are subject to the volatility of commodity prices. Over the last four years, NYMEX WTI oil and NYMEX Henry Hub prices ranged from an average high of $64.79 per Bbl and $3.11 per MMBtu, respectively, to an average low of $43.36 per Bbl and $2.46 per MMBtu, respectively. Widening Western Canadian Select differentials negatively impacted the prices we realized on our heavy oil production in the fourth quarter of 2018. In the first two months of 2019, Western Canadian Select differentials have improved significantly.

Key measures of our financial performance in 2018 are summarized in the following table. Increased oil and natural gas liquids prices as well as continued focus cost management improved our 2018 financial performance as compared to 2017, as seen in the table below. Additionally, we recognized a gain of approximately $2.6 billion ($2.2 billion after-tax) related to the sale of EnLink and the General Partner during 2018. More details for these metrics are found within the "Results of Operations – 2018 vs. 2017" below.

	2018	Change	2017	Change	2016
Total:					
Net earnings (loss) attributable to Devon	$ 3,064	+241%	$ 898	+185%	$ (1,056)
Net earnings (loss) per diluted share attributable to Devon	$ 6.10	+259%	$ 1.70	+181%	$ (2.09)
Core earnings (loss) attributable to Devon (1)	$ 655	+53%	$ 427	+216%	$ (367)
Core earnings (loss) attributable to Devon per diluted share (1)	$ 1.30	+60%	$ 0.81	+212%	$ (0.73)
Continuing Operations:					
Net earnings (loss)	$ 764	+1%	$ 758	+232%	$ (574)
Net earnings (loss) per diluted share	$ 1.52	+6%	$ 1.43	+225%	$ (1.14)
Core earnings (loss) (1)	$ 587	+48%	$ 397	+207%	$ (371)
Core earnings (loss) per diluted share (1)	$ 1.17	+57%	$ 0.75	+202%	$ (0.73)
Discontinued Operations:					
Net earnings (loss) attributable to Devon	$ 2,300	+1543%	$ 140	+129%	$ (481)
Net earnings (loss) per diluted share attributable to Devon	$ 4.58	+1596%	$ 0.27	+128%	$ (0.95)
Core earnings attributable to Devon (1)	$ 68	+127%	$ 30	+580%	$ 4
Core earnings attributable to Devon per diluted share (1)	$ 0.13	+120%	$ 0.06	+1628%	$ 0.00
Other Metrics:					
Retained production (MBoe/d)	500	+4%	481	- 3%	497
Total production (MBoe/d)	535	- 2%	543	- 11%	611
Realized price per Boe (2)	$ 29.08	+12%	$ 25.96	+39%	$ 18.72
Operating cash flow from continuing operations	$ 2,228	+1%	$ 2,209	+165%	$ 834
Capitalized expenditures, including acquisitions	$ 2,576	+19%	$ 2,169	- 23%	$ 2,826
Cash and cash equivalents	$ 2,414	- 9%	$ 2,642	+36%	$ 1,947
Total debt	$ 5,947	- 13%	$ 6,864	+0%	$ 6,859
Reserves (MMBoe)	1,927	- 10%	2,152	+5%	2,058

(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

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. In 2018, WTI oil prices averaged approximately $67/Bbl through October, supported by stronger-than-expected oil demand, market management by both OPEC and non-OPEC partners and unplanned supply outages. However, oil prices markedly declined in November and December, averaging approximately $53/Bbl and reaching as low as $42.53/Bbl in December. The deterioration of WTI was driven by OPEC and non-OPEC partners unwinding their production cut agreement, compounded by rising supply and concerns over slowing global economic growth. Western Canadian Select basis differentials were challenged in the fourth quarter of 2018 due to robust production outpacing local demand, pipeline capacity and rail capacity out of the region. Looking ahead, current market fundamentals indicate that 2019 crude pricing is expected to improve from its fourth quarter 2018 levels. Additionally, Western Canadian Select differentials are also projected to improve, driven by provincially mandated production cuts combined with takeaway capacity additions expected in late 2019. Changes in OPEC production strategies, the macro-economic environment, geopolitical risks and other factors could impact our current forecasts.

In 2018, Devon marked its 30th year as a public company and 47th anniversary in the oil and gas business, so we are experienced in dealing with the volatile nature of commodity prices. To mitigate our exposure to commodity market volatility and ensure our financial strength, we use a disciplined, risk-management hedging program. Our hedging program incorporates both systematic hedges added on a regular basis and discretionary hedges layered in on an opportunistic basis to take advantage of favorable market conditions. We have approximately 50% of our anticipated 2019 oil and gas volumes hedged, and we are currently adding hedges for 2020 as well. Further insulating our cash flow, we are proactively locking in hedges on the Western Canadian Select basis differential to WTI and currently have approximately 50% of our 2019 Canadian heavy oil production hedged.

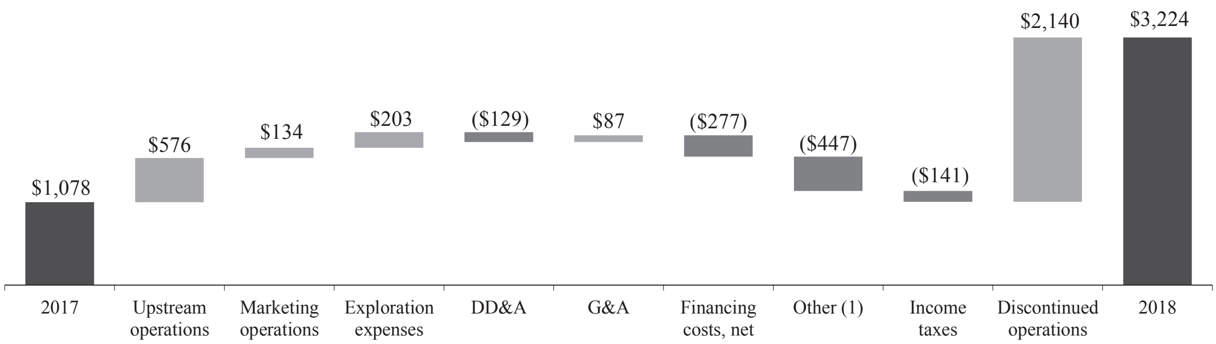
Despite the uncertainties pertaining to commodity prices, we remain focused on our strategic priorities of having a premier portfolio of assets, delivering superior execution as we drill and operate oil and natural gas wells, and maintaining our financial strength and flexibility. 2019 will be an important year for Devon as we plan to separate our Canadian and Barnett Shale assets and complete our multi-year transition to a U.S. oil company with operations focused on four core areas in the Delaware Basin, STACK, Eagle Ford and Rockies. With a focused portfolio of U.S. oil assets, we also intend to optimize our cost structure by reducing our annual capital costs, G&A costs, interest expense and production expenses by $780 million in the aggregate by 2021. We expect to deliver 70% of these annualized cost savings in 2019, as the Canadian and Barnett Shale assets are separated, and we align our workforce with the retained business and reduce outstanding debt.

Importantly, the portfolio changes and optimized cost performance are expected to enhance our competitive positioning as oil production growth, price realizations, field-level margins and corporate rates-of-return should all improve. With these improved expected outcomes, we remained focused on our 2019 capital allocation priorities of funding our core operations, protecting our investment-grade credit ratings and paying our shareholder dividend. Further, when considering the current commodity price environment and our current hedge position, we can achieve all our capital allocation priorities at $46/Bbl WTI and $3.00/Mcf Henry Hub. Should WTI drop closer to $40/Bbl for an extended period, we would shift our focus to preserving our financial strength and operational continuity. However, as WTI rises above $46/Bbl, our free cash flow will accelerate, providing additional capital allocation opportunities.

Results of Operations – 2018 vs. 2017

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 2017 to 2018. 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.

Net Earnings



(1) Other in the table above includes asset impairments, asset dispositions, restructuring and transaction costs and other expenses.

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

Upstream Operations

(2) As further discussed in Note 1 in "Item 8. Financial Statements and Supplementary Data" in this report, in 2018 the presentation of certain processing arrangements changed from a net to a gross presentation. The change resulted in an increase to our upstream revenues and production expenses by $254 million during 2018 with no impact to net earnings.

Upstream Operations

Oil, Gas and NGL Production

	2018	% of Total	2017	Change
Oil and bitumen (MBbls/d)				
Delaware Basin	42	17%	29	+42%
STACK	32	13%	25	+28%
Rockies Oil	14	6%	10	+37%
Heavy Oil	18	7%	18	+1%
Eagle Ford	28	12%	34	- 17%
Barnett Shale	1	0%	1	- 7%
Other	5	2%	5	- 3%
Retained assets	140	57%	122	+14%
U.S. divested assets	9	4%	12	- 23%
Total Oil	149	61%	134	+11%
Bitumen	97	39%	110	- 12%
Total Oil and bitumen	246	100%	244	+1%

	2018	% of Total	2017	Change
Gas (MMcf/d)				
Delaware Basin	105	10%	86	+22%
STACK	334	30%	294	+13%
Rockies Oil	16	1%	8	+85%
Heavy Oil	10	1%	17	- 39%
Eagle Ford	79	7%	95	- 17%
Barnett Shale	447	41%	475	- 6%
Other	1	0%	1	+6%
Retained assets	992	90%	976	+2%
U.S. divested assets	108	10%	227	- 52%
Total	1,100	100%	1,203	- 9%

	2018	% of Total	2017	Change
NGLs (MBbls/d)				
Delaware Basin	16	15%	10	+53%
STACK	37	35%	30	+24%
Rockies Oil	1	2%	1	+75%
Eagle Ford	13	12%	13	+2%
Barnett Shale	30	28%	31	- 4%
Other	1	1%	1	- 5%
Retained assets	98	93%	86	+14%
U.S. divested assets	8	7%	13	- 40%
Total	106	100%	99	+7%

	2018	% of Total	2017	Change
Combined (MBoe/d)				
Delaware Basin	75	14%	54	+39%
STACK	125	24%	104	+20%
Rockies Oil	17	3%	12	+43%
Heavy Oil	117	22%	131	- 11%
Eagle Ford	54	10%	62	- 13%
Barnett Shale	105	20%	111	- 5%
Other	7	1%	7	- 3%
Retained assets	500	94%	481	+4%
U.S. divested assets	35	6%	62	- 44%
Total	535	100%	543	- 2%

Focused development activities in the Delaware Basin, STACK and Rockies resulted in an approximate 28% increase in production from those areas compared to 2017. These increases also drove a 17% increase in our U.S. retained oil production. This strong performance led to the overall growth in our retained assets during 2018. Production increases from our capital focused assets were partially offset by the effects of facility repairs and other maintenance work at the Jackfish facilities, as well as by lower production resulting from our U.S. non-core divestitures.

Oil, Gas and NGL Prices

	2018	Realization	2017	Change
Oil and bitumen (per Bbl)				
WTI index	$64.79		$50.99	+27%
Access Western Blend index	$34.75		$36.90	- 6%
U.S.	$61.97	96%	$49.41	+25%
Canada	$19.37	30%	$29.99	- 35%
Realized price, unhedged	$42.04	65%	$39.23	+7%
Cash settlements	$ (0.49)		$ 0.23	
Realized price, with hedges	$41.55	64%	$39.46	+5%

	2018	Realization	2017	Change
Gas (per Mcf)				
Henry Hub index	$ 3.09		$ 3.11	- 1%
Realized price, unhedged	$ 2.37	77%	$ 2.48	- 5%
Cash settlements	$ 0.01		$ 0.08	
Realized price, with hedges	$ 2.38	77%	$ 2.56	- 7%

	2018	Realization	2017	Change
NGLs (per Bbl)				
Mont Belvieu blended index [1]	$28.31		$24.77	+14%
Realized price, unhedged	$24.74	87%	$15.66	+58%
Cash settlements	$ (1.17)		$ (0.10)	
Realized price, with hedges	$23.57	83%	$15.56	+51%

(1) Based upon composition of our NGL barrel.

	2018	2017	Change
Combined (per Boe)			
U.S.	$ 31.86	$ 24.88	+28%
Canada	$ 19.12	$ 29.39	- 35%
Realized price, unhedged	$ 29.08	$ 25.96	+12%
Cash settlements	$ (0.43)	$ 0.27	
Realized price, with hedges	$ 28.65	$ 26.23	+9%

Upstream revenues increased as a result of higher unhedged, realized prices for our U.S. oil and NGLs.

The increase in oil sales primarily resulted from higher average WTI crude index prices, which were 27% higher in 2018, resulting in an increase of approximately $568 million.

NGL sales increased $351 million as a result of 14% higher NGL prices at the Mont Belvieu, Texas hub, as well as improved realizations in our NGL price.

These increases were partially offset by widening differentials to the WTI index for bitumen sales, which negatively impacted our upstream revenues by $406 million. In the fourth quarter of 2018, market forces widened Canadian heavy oil differentials beyond historical norms and negatively impacted the price we realized on our Canadian production. We had basis swaps for approximately half of our fourth quarter production to mitigate the effect of the lower market price. To further mitigate the effects of the lower price, we reduced our Jackfish production in November 2018 which impacted our fourth quarter production by approximately 8 MBbls/d. Our Canadian heavy oil unhedged realized price for the fourth quarter was near zero. To date in 2019, heavy oil differentials have significantly improved driven by provincially mandated production cuts combined with takeaway capacity additions expected in 2019.

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 changed from a net to a gross presentation. The change resulted in an increase to our upstream revenues and production expenses by approximately $254 million with no impact to net earnings.

Commodity Derivatives

	2018	2017	Change
Oil	$ (44)	$ 21	- 310%
Natural gas	5	35	- 86%
NGL	(45)	(3)	- 1400%
Total cash settlements	(84)	53	- 258%
Valuation changes	692	104	+565%
Total	$ 608	$ 157	+287%

Cash settlements as presented in the tables above represent realized gains or losses related to the instruments described in Note 3 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

	2018	2017	Change
LOE	$ 995	$ 927	+7%
Gathering, processing & transportation	891	647	+38%
Production taxes	278	194	+43%
Property taxes	61	55	+11%
Total	$2,225	$1,823	+22%
Per Boe:			
LOE	$ 5.10	$ 4.67	+9%
Gathering, processing & transportation	$ 4.56	$ 3.26	+40%
Percent of oil, gas and NGL sales:			
Production taxes	4.9%	3.8%	+27%

LOE increased $68 million primarily due to continued focus on growing our liquids-rich assets within the STACK and Delaware Basin and higher maintenance costs at our Jackfish facilities, partially offset by our U.S. non-core divestitures.

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 changed from a net to a gross presentation. The change resulted in an increase to our upstream revenues and production expenses by approximately $254 million with no impact to net earnings.

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. Additionally, the increase in Oklahoma severance tax rates that became effective during the third quarter of 2018 also contributed to the increase on an absolute dollar basis and as a percentage of oil, gas and NGL sales.

Property taxes increased as a result of higher property value assessments, primarily on our Texas properties, partially offset by our U.S. non-core divestitures.

Marketing Operations

	2018	2017	Change
Marketing revenues	$ 4,449	$ 3,571	+25%
Marketing expenses	(4,363)	(3,619)	- 21%
Margin	$ 86	$ (48)	+279%

The overall increase in marketing operating margin was primarily due to improved commodity prices, which were partially offset by the impact of our downstream marketing commitments.

Exploration Expenses

	2018	2017	Change
Unproved impairments	$ 95	$ 217	- 56%
Geological and geophysical	21	110	- 81%
Exploration overhead and other	61	53	+15%
Total	$ 177	$ 380	- 53%

Unproved impairments in both periods 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 decreased primarily in the STACK and Delaware Basin.

Depreciation, Depletion and Amortization

	2018	2017	Change
Oil and gas per Boe	$ 7.98	$ 7.15	+12%
Oil and gas	$1,559	$ 1,419	+10%
Other property and equipment	99	110	- 10%
Total	$1,658	$1,529	+8%

Our oil and gas DD&A increased primarily due to continued development in the STACK, Delaware Basin and Rockies properties. The increases were slightly offset by reduced production volumes at the Jackfish facilities and from our 2018 U.S. non-core asset divestitures.

General and Administrative Expenses

	2018	2017	Change
Labor and benefits	$ 494	$ 582	- 15%
Non-labor	236	228	+4%
Reimbursed G&A	(80)	(73)	- 10%
Total Devon	$ 650	$ 737	- 12%

Labor and benefits decreased primarily as a result of the workforce reduction that occurred during 2018 as discussed in Note 6 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.

Financing Costs, net

Financing costs, net increased $277 million as a result of a $312 million loss on early retirement of debt. For further discussion of early retirement premiums and reduced interest expense resulting from our lower debt balances, see Note 15 in “Item 8. Financial Statements and Supplementary Data” of this report.

Other

	2018	2017	Change
Asset impairments	$ 156	$ —	N/M
Asset dispositions	(263)	(217)	- 21%
Restructuring	114	—	N/M
Other	140	(83)	+269%
Total	$ 147	$ (300)	+149%

Additional information regarding the impairments is discussed in Note 5 in “Item 8. Financial Statements and Supplementary Data” of this report.

We recognized gains in conjunction with certain of our U.S. asset dispositions in 2017 and 2018. For further discussion, see Note 2 in “Item 8. Financial Statements and Supplementary Data” of this report.

During 2018, we recognized restructuring and transaction costs of $114 million primarily as a result of our workforce reduction. See Note 6 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

	2018	2017
Current expense (benefit)	$ (70)	$ 112
Deferred expense (benefit)	226	(97)
Total expense	$ 156	$ 15
Effective income tax rate	17%	2%

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

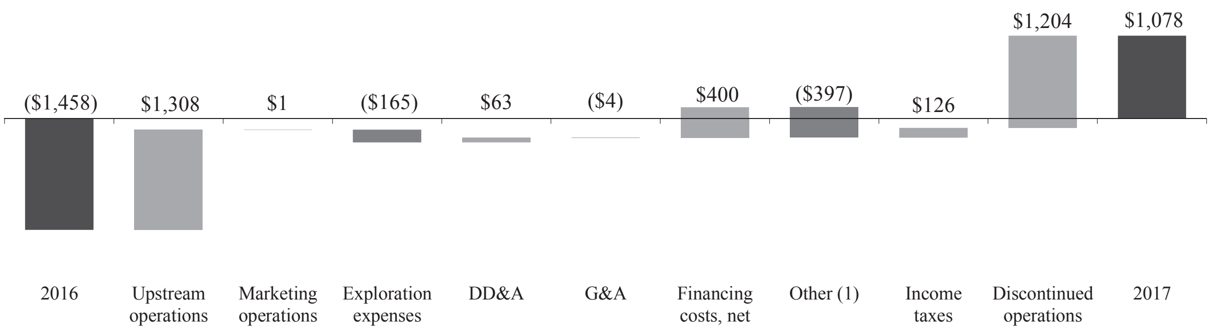
Discontinued Operations

Discontinued operations net earnings increased primarily due to the gain on the sale of our aggregate ownership interests in EnLink and the General Partner of $2.6 billion ($2.2 billion after-tax). For discussion on discontinued operations, see Note 19 in “Item 8. Financial Statements and Supplementary Data” of this report” of this report.

Results of Operations – 2017 vs. 2016

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.

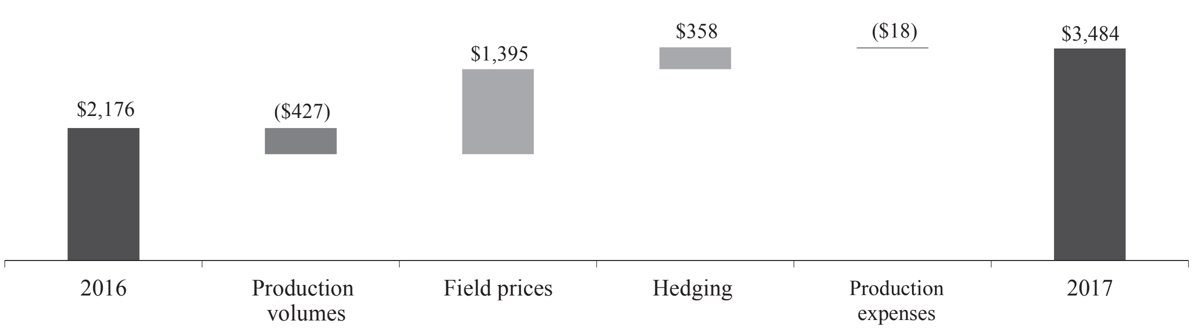
Net Earnings



(1) Other in the table above includes asset impairments, asset dispositions, restructuring and transaction costs and other expenses.

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

Upstream Operations



Upstream Operations

Oil, Gas and NGL Production

	2017	% of Total	2016	Change
Oil and bitumen (MBbls/d)				
Delaware Basin	29	12%	32	- 7%
STACK	25	11%	18	+39%
Rockies Oil	10	4%	9	+9%
Heavy Oil	18	7%	22	- 19%
Eagle Ford	34	14%	39	- 14%
Barnett Shale	1	0%	1	- 25%
Other	5	2%	6	- 13%
Retained assets	122	50%	127	- 4%
U.S. divested assets	12	5%	24	- 51%
Total Oil	134	55%	151	- 11%
Bitumen	110	45%	109	+1%
Total Oil and bitumen	244	100%	260	- 6%

	2017	% of Total	2016	Change
Gas (MMcf/d)				
Delaware Basin	86	7%	86	+1%
STACK	294	24%	282	+4%
Rockies Oil	8	1%	16	- 48%
Heavy Oil	17	2%	20	- 14%
Eagle Ford	95	8%	101	- 6%
Barnett Shale	475	39%	530	- 10%
Other	1	0%	1	- 10%
Retained assets	976	81%	1,036	- 6%
U.S. divested assets	227	19%	377	- 40%
Total	1,203	100%	1,413	- 15%

	2017	% of Total	2016	Change
NGLs (MBbls/d)				
Delaware Basin	10	10%	11	- 10%
STACK	30	30%	25	+19%
Rockies Oil	1	1%	1	+23%
Eagle Ford	13	13%	16	- 19%
Barnett Shale	31	32%	34	- 9%
Other	1	1%	1	- 4%
Retained assets	86	87%	88	- 3%
U.S. divested assets	13	13%	28	- 53%
Total	99	100%	116	- 15%

	2017	% of Total	2016	Change
Combined (MBoe/d)				
Delaware Basin	54	10%	57	- 6%
STACK	104	19%	90	+15%
Rockies Oil	12	2%	13	- 3%
Heavy Oil	131	24%	134	- 2%
Eagle Ford	62	11%	72	- 13%
Barnett Shale	111	21%	123	- 10%
Other	7	1%	8	- 6%
Retained assets	481	88%	497	- 3%
U.S. divested assets	62	12%	114	- 45%
Total	543	100%	611	- 11%

Production declines reduced our upstream revenues by $427 million primarily as a result of our U.S. divested assets. 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 average Devon 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 was 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.

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%

Production Expenses

	2017	2016	Change
LOE	$ 927	$ 1,027	- 10%
Gathering, processing & transportation	647	555	+17%
Production taxes	194	149	+30%
Property taxes	55	74	- 26%
Total	$ 1,823	$ 1,805	+1%
Per Boe:			
LOE	$ 4.67	$ 4.59	+2%
Gathering, processing & 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 U.S. property divestitures in 2016. Well optimization and cost reduction initiatives across our portfolio 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. asset divestitures.

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%
Other property and equipment	110	146	- 25%
Total	$ 1,529	$ 1,592	- 4%

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 other property and equipment decreased due to the divestiture of the Access Pipeline in the fourth quarter of 2016.

Financing Costs, net

Financing costs, net decreased $400 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 15 in “Item 8. Financial Statements and Supplementary Data” of this report.

Other

	2017	2016	Change
Asset impairments	$ —	$ 437	- 100%
Asset dispositions	(217)	(1,496)	+85%
Restructuring	—	261	- 100%
Other	(83)	101	- 183%
Total	$ (300)	$ (697)	+57%

In 2016, we recognized proved asset impairments on a portion of our U.S. assets. See Note 5 in “Item 8. Financial Statements and Supplementary Data” of this report for additional information.

We recognized gains in conjunction with certain of our 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 2 in “Item 8. Financial Statements and Supplementary Data” of this report.

During 2016, we recognized restructuring and transaction costs of $261 million primarily as a result of our workforce reduction. For discussion of our reorganization programs and the associated restructuring costs, see Note 6 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	$ 98
Deferred expense (benefit)	(97)	43
Total expense	$ 15	$ 141
Effective income tax rate	2%	(33%)

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

Discontinued Operations

For discussion on discontinued operations, see Note 19 in “Item 8. Financial Statements and Supplementary Data” of this report.

Capital Resources, Uses and Liquidity

Sources and Uses of Cash

The following table presents the major changes in cash and cash equivalents for the time periods presented below.

	Year ended December 31,		
	2018	2017	2016
Operating cash flow from continuing operations	$ 2,228	$ 2,209	$ 834
Divestitures of property and equipment	1,013	426	3,020
Capital expenditures	(2,451)	(1,968)	(1,384)
Acquisitions of property and equipment	(55)	(46)	(849)
Debt activity, net	(1,226)	—	(3,383)
Repurchases of common stock	(2,956)	—	—
Common stock dividends	(149)	(127)	(221)
Issuance of common stock	—	—	1,469
Effect of exchange rate and other	151	(53)	(96)
Net change in cash, cash equivalents and restricted cash from discontinued operations	3,207	284	259
Net change in cash, cash equivalents and restricted cash	$ (238)	$ 725	$ (351)
Cash, cash equivalents and restricted cash at end of period	$ 2,446	$ 2,684	$ 1,959

Operating Cash Flow – Continuing Operations

Net cash provided by operating activities continued to be a significant source of capital and liquidity in 2018. Our operating cash flow was relatively flat compared to 2017. In 2018, our operating cash flow funded approximately 86% of our capital expenditure program and dividends. We utilized available cash balances and divestiture proceeds to supplement our operating cash flows. Operating cash flow for 2018 included a realized foreign exchange loss of $241 million relating to foreign currency denominated intercompany loan activity as described in Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report. There was an offset in the effect of exchange rate and other line in the above table, resulting in no impact to the net change in cash, cash equivalents and restricted cash.

Our operating cash flow increased $1.4 billion, or 165%, from 2016 to 2017. In 2017, our operating cash flow fully funded our capital expenditures program as well as our dividends. In 2016, 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.

Divestitures of Property and Investments

During 2018, as part of our announced divestiture program, we sold non-core U.S. upstream assets for approximately $1.0 billion. For further discussion, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

During 2017, as part of our announced divestiture program, we sold non-core U.S. upstream assets for approximately $420 million. For further discussion, see Note 2 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 our core resource plays. For further discussion, see Note 2 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 2018, 2017 and 2016.

Capital Expenditures

The following table summarizes our capital expenditures and property acquisitions.

	Year ended December 31,		
	2018	2017	2016
Oil and gas	$ 2,395	$ 1,879	$ 1,341
Corporate and other	56	89	43
Total capital expenditures	$ 2,451	$ 1,968	$ 1,384
Acquisitions	$ 55	$ 46	$ 849

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 or near 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 funding approximately 91% of capital expenditures in 2018 and fully funding capital expenditures in 2017.

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. See Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report for more information.

Debt Activity, Net

During 2018, our debt decreased $922 million due to completed tender offers of certain long-term debt as well as the maturity of certain senior notes. In conjunction with the tender offers, we recognized a $312 million loss on the early retirement of debt, including $304 million of cash retirement costs and fees. For additional information, see Note 15 in "Item 8. Financial Statements and Supplementary Data" of this report.

During 2016, our debt decreased $3.1 billion 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. For additional information, see Note 15 in "Item 8. Financial Statements and Supplementary Data" of this report.

Repurchases of Common Stock and Shareholder Distributions

In June 2018, in conjunction with the announcement of the divestiture of our investment in EnLink and the General Partner, our Board of Directors authorized a $4.0 billion share repurchase program of our common stock. The share repurchase program expires December 31, 2019. As discussed further in Note 18 in "Item 8. Financial Statements and Supplementary Data" in this report, we repurchased 78.1 million shares of common stock for $3.0 billion, or $38.11 per share, under the ASR agreement and through open-market share repurchases through December 31, 2018.

Devon paid common stock dividends of $149 million, $127 million and $221 million during 2018, 2017 and 2016, respectively. During the second quarter of 2018, we increased our quarterly dividend 33% to $0.08 per share as part of our initiative to return cash to shareholders. Our prior quarterly dividend was $0.06 per share subsequent to a reduction from $0.24 per share in the second quarter of 2016 due to the depressed commodity price environment. For additional information, see Note 18 in "Item 8. Financial Statements and Supplementary Data" of this report.

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.

Cash Flows from Discontinued Operations

All cash flows in the following table relate to activities of EnLink and the General Partner.

	Year ended December 31,		
	2018	**2017**	**2016**
Cash flows from discontinued operations:			
Operating activities	$ 476	$ 700	$ 666
Capital expenditures and other	(556)	(801)	(1,381)
Divestitures of investments	3,104	190	—
Investing activities	2,548	(611)	(1,381)
Debt activity, net	347	2	228
Issuance of subsidiary units	1	501	892
Distributions to noncontrolling interests	(217)	(354)	(304)
Other	52	46	158
Financing activities	183	195	974
Net change in cash, cash equivalents and restricted cash of discontinued operations	$ 3,207	$ 284	$ 259

Operating cash flow in 2018 decreased $224 million and $190 million from 2017 and 2016, respectively, as a result of the divestiture of our aggregate ownership interests in EnLink and the General Partner in July 2018.

Cash flows from investing activities for 2018 includes $3.125 billion received from the divestiture of our aggregate ownership interests in EnLink and the General Partner, partially offset by capital expenditures and other items. Capital expenditures for EnLink's midstream operations are primarily for the construction and expansion of oil and gas gathering facilities and pipelines. During 2017, EnLink divested its ownership interest in Howard Energy Partners for approximately $190 million. 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.

Cash flows from financing activities includes common and preferred units EnLink issued and sold during 2017 and 2016 generating net proceeds of approximately $501 million and $892 million, respectively. Distributions to noncontrolling interests in the table above exclude the distributions EnLink and the General Partner paid to Devon, which have been eliminated in consolidation. Distributions Enlink and the General Partner paid to Devon were $134 million, $265 million and $265 million during 2018, 2017 and 2016, respectively.

Liquidity

The business of exploring for, developing and producing oil and natural gas is capital intensive. Because oil, natural gas and NGL reserves are a depleting resource, we, like all upstream operators, must continually make capital investments to grow and even sustain production. Generally, our capital investments are focused on drilling and completing new wells and maintaining production from existing wells. At opportunistic times, we also acquire operations and properties from other operators or land owners to enhance our existing portfolio of assets.

Historically, our primary sources of capital funding and liquidity have been our operating cash flow, cash on hand and asset divestiture proceeds. 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. If needed, we can also issue debt and equity securities pursuant to our shelf registration statement filed with the SEC. In February 2019, we also announced plans to separate our Canadian and Barnett Shale assets and operations. We expect to complete these asset separations in 2019. We plan to use the proceeds from these transactions for debt repayments and common share repurchases. We estimate the combination of our sources of capital will continue to be adequate to fund our planned capital requirements as discussed in this section.

Operating Cash Flow

Key inputs into determining our planned capital investment is the amount of cash we hold and operating cash flow we expect to generate over the next one to three or more years. At the end of 2018, we held approximately $2.4 billion of cash. Our operating cash flow forecasts are sensitive to many variables and include a measure of uncertainty as these variables differ from our expectations.

Commodity Prices – The most uncertain and volatile variables for our operating cash flow are the prices of the oil, bitumen, gas and NGLs we produce and sell. 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. For illustration, our operating cash flow slightly increased in 2018 largely due to 16% growth from our retained U.S. liquids portfolio, as well as 32% higher realized pricing related to these assets. These increases were mostly offset by a significant decrease in our realized price for our bitumen production in 2018. Western Canadian Select basis differentials widened significantly above historical norms due to robust production outpacing local demand, pipeline capacity and rail capacity out of the region. The market fundamentals led our fourth quarter unhedged realized price for bitumen to be near $0 per Bbl. In the first two months of 2019, government-mandated production curtailments and current market fundamentals have led to a significant improvement in the Western Canadian Select basis differential.

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. We currently have approximately 50% of our anticipated 2019 oil and gas volumes hedged, and we are adding hedges for 2020 as well. Further insulating our cash flow, we are proactively locking in hedges on the Western Canada Select basis differential to WTI and currently have approximately 50% of our 2019 Canadian heavy oil production hedged. The key terms to our oil, gas and NGL derivative financial instruments as of December 31, 2018 are presented in Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

Further, when considering the current commodity price environment and our current hedge position, we expect to achieve our capital investment priorities at $46/Bbl WTI and $3.00/Mcf Henry Hub. Should WTI drop closer to $40/Bbl for an extended period, we would shift our focus to preserving our financial strength and operational continuity. However, as WTI/Bbl rises above $46, our free cash flow will accelerate, providing additional capital allocation opportunities.

Operating Expenses – 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.

For 2019, we expect to aggressively optimize our cost structure in conjunction with our planned Canadian and Barnett Shale asset divestitures, as we focus on our remaining four U.S. oil plays, align our workforce with the retained business and reduce outstanding debt. We anticipate the planned $780 million reduction of annualized costs will occur over three years, with roughly 70% of the savings delivered by the end of 2019. Approximately 40% of the reduced costs relate to our capital programs and the remainder relates to our operating expenses, including G&A, interest expense and production expenses.

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.

Divestitures of Property and Equipment

In the first quarter of 2019, we sold non-core assets for approximately $300 million. We also anticipate separating our Canadian and Barnett Shale businesses from our Company in 2019.

Credit Availability

Our 2018 Senior Credit Facility, under which we have $2.9 billion of available borrowing capacity at December 31, 2018, matures on October 5, 2023, with the option to extend the maturity date by two additional one-year periods subject to lender consent. The 2018 Senior Credit Facility supports our $3.0 billion of short-term credit under our commercial paper program. As of December 31, 2018, there were no borrowings under our commercial paper program. See Note 15 in "Item 8. Financial Statements and Supplementary Data" of this report for further discussion.

The 2018 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%. As of December 31, 2018, we were in compliance with this covenant with a 21.0% debt-to-capitalization ratio.

Our access to funds from the 2018 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.

In January 2019, we repaid the $162 million of 6.30% senior notes at maturity with cash on hand.

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 production growth opportunities. Our credit rating from Standard and Poor's Financial Services is BBB with a stable outlook. Our credit rating from Fitch is BBB+ with a stable outlook. Our credit rating from Moody's Investor Service is Ba1 with a positive 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 contractual debt obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. However, a downgrade could adversely impact our interest rate on any credit facility borrowings and the ability to economically access debt markets in the future.

Share Repurchase Program

In February 2019, our Board of Directors increased our share repurchase program by an additional $1 billion. The $5 billion share repurchase program expires December 31, 2019. Through February 15, 2019, we have executed $3.4 billion of the authorized program.

Capital Expenditures

Our 2019 exploration and development budget is expected to be approximately $2.0 billion to $2.25 billion, including capital associated with our Canadian and Barnett Shale upstream assets.

Contractual Obligations

The following table presents a summary of our contractual obligations as of December 31, 2018.

	Payments Due by Period				
	Total	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Devon obligations:					
Debt [(1)]	$ 6,011	$ 162	$ 500	$ 1,000	$ 4,349
Interest expense [(2)]	4,951	317	623	535	3,476
Purchase obligations [(3)]	1,248	541	707	—	—
Operational agreements [(4)]	5,626	587	892	773	3,374
Asset retirement obligations [(5)]	1,057	27	76	79	875
Drilling and facility obligations [(6)]	445	274	133	22	16
Lease obligations [(7)]	500	64	74	51	311
Other [(8)]	295	32	78	27	158
Total obligations	$ 20,133	$ 2,004	$ 3,083	$ 2,487	$ 12,559

(1) Debt amounts represent scheduled maturities of debt obligations at December 31, 2018, 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. Approximately $1.9 billion relates to the transportation agreement we entered in 2016 in which we

dedicated our thermal-oil acreage to the Access Pipeline for an initial term of 25 years following the divestment of our 50% interest in the Access Pipeline. For additional information, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

(5) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2018 balance sheet.

(6) Drilling and facility obligations represent gross contractual agreements with third-party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction.

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

(8) Other obligations primarily relate to various tax obligations.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 20 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, Classification, Reserves & Valuation

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 section below. 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, 2018, 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. At December 31, 2018, Devon had $1.2 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, 2018, approximately $10 million is scheduled to expire in 2019. The leasehold expiring in 2019 relates to areas in which Devon is actively drilling. If our drilling is not successful, this leasehold could become partially or entirely impaired.

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 2018, 89% 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.

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 is 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 2016, we recognized significant asset impairments. With generally higher pricing in 2017 and 2018, we did not recognize material asset impairments.

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. As of December 31, 2018, the U.S. reporting unit had goodwill totaling $841 million.

We perform a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If our qualitative assessment determines that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill, then a quantitative goodwill impairment test is performed. As part of our qualitative assessment, we considered the general macroeconomic, industry and market conditions, changes in cost factors, actual and expected financial performance, significant changes in management, strategy or customers, and stock performance. If the qualitative assessment determines that a quantitative goodwill impairment test is required, then the fair value of each reporting unit is compared to the carrying value of the reporting unit. If the fair value of the reporting unit is less than the carrying value, an impairment charge will be recognized for the amount by which the carrying amount exceeds the fair value. Because quoted market prices are not available for our reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid. 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.

Based on our qualitative assessment as of October 31, 2018, it is not more likely than not that the fair value of the U.S. reporting unit is less than its carrying amount. Since our annual test for goodwill impairment on October 31, 2018 was performed, our stock price decreased 30% from October 31 to December 31. As such, we performed an updated assessment as of December 31, 2018 to determine if it is more likely than not that the fair value of our reporting unit is less than its carrying amount. Based on our qualitative assessment as of December 31, 2018, it is not more likely than not that the fair value of the U.S. reporting unit is less than its carrying value.

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 U.S. reporting unit 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.

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, we recorded a 100% valuation allowance against our U.S. deferred tax assets. Upon closing the EnLink divestiture in the third quarter of 2018, Devon reassessed its position and determined that its U.S. segment is no longer in a full valuation allowance position, maintaining only valuation allowances against certain deferred tax assets, including certain tax credits and state net operating losses. Devon also has recorded a partial valuation allowance against certain Canadian deferred tax assets that were generated by a 2017 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. 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:

- 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 and 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.

Non-GAAP Measures

Core Earnings

We make reference to “core earnings (loss) attributable to Devon” and “core earnings (loss) per share attributable to Devon” in “Overview of 2018 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 (loss) attributable to Devon, as well as the per share amount, represent net earnings excluding certain noncash and other items that are typically excluded by securities analysts in their published estimates of our financial results. Additionally, we’ve presented our discontinued operations associated with the sale of our aggregate ownership interests in EnLink and the General Partner separately to show our results on a go-forward basis. For more information on the results of operations for EnLink and the General Partner, see Note 19 in “Item 8. Financial Statements and Supplementary Data” in this report. Our non-GAAP measures are typically used as a performance measure. Amounts excluded for 2018 relate to asset dispositions, the gain on the sale of Devon’s aggregate ownership interests in EnLink and the General Partner, noncash asset impairments including noncash unproved asset impairments, deferred tax asset valuation allowance, costs associated with early retirement of debt, fair value changes in derivative financial instruments and foreign currency, restructuring and transaction costs associated with the 2018 workforce reduction and settlements relating to minimum volume contract commitments.

Amounts excluded for 2017 relate to asset dispositions, noncash asset impairments including noncash unproved asset impairments, 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 EnLink 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.

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
2018				
Continuing Operations				
Earnings attributable to Devon (GAAP)	$ 920	$ 764	$ 764	$ 1.52
Adjustments:				
Asset dispositions	(263)	(202)	(202)	(0.41)
Asset and exploration impairments	257	198	198	0.40
Deferred tax asset valuation allowance	—	(42)	(42)	(0.08)
Early retirement of debt	312	240	240	0.48
Fair value changes in financial instruments and foreign currency	(614)	(458)	(458)	(0.92)
Restructuring and transaction costs	114	87	87	0.18
Core earnings attributable to Devon (Non-GAAP)	$ 726	$ 587	$ 587	$ 1.17
Discontinued Operations				
Earnings attributable to Devon (GAAP)	$ 2,863	$ 2,460	$ 2,300	$ 4.58
Adjustments:				
Gain on sale of EnLink and the General Partner	(2,607)	(2,222)	(2,222)	(4.43)
Fair value changes, and minimum volume commitment settlement	(34)	(28)	(10)	(0.02)
Core earnings attributable to Devon (Non-GAAP)	$ 222	$ 210	$ 68	$ 0.13
Total				
Earnings attributable to Devon (GAAP)	$ 3,783	$ 3,224	$ 3,064	$ 6.10
Adjustments:				
Continuing Operations	(194)	(177)	(177)	(0.35)
Discontinued Operations	(2,641)	(2,250)	(2,232)	(4.45)
Core earnings attributable to Devon (Non-GAAP)	$ 948	$ 797	$ 655	$ 1.30
2017				
Continuing Operations				
Earnings attributable to Devon (GAAP)	$ 773	$ 758	$ 758	$ 1.43
Adjustments:				
Asset dispositions	(217)	(138)	(138)	(0.26)
Asset and exploration impairments	217	138	138	0.25
Deferred tax asset valuation allowance	—	(76)	(76)	(0.14)
Fair value changes in financial instruments and foreign currency	(214)	(199)	(199)	(0.37)
Legal entity restructuring	—	(86)	(86)	(0.16)
Core earnings attributable to Devon (Non-GAAP)	$ 559	$ 397	$ 397	$ 0.75
Discontinued Operations				
Earnings attributable to Devon (GAAP)	$ 123	$ 320	$ 140	$ 0.27
Adjustments:				
U.S. tax reform	—	(211)	(112)	(0.21)
Asset dispositions, impairments, fair value changes and early retirement of debt	4	4	2	0.00
Core earnings attributable to Devon (Non-GAAP)	$ 127	$ 113	$ 30	$ 0.06
Total				
Earnings attributable to Devon (GAAP)	$ 896	$ 1,078	$ 898	$ 1.70
Adjustments:				
Continuing Operations	(214)	(361)	(361)	(0.68)
Discontinued Operations	4	(207)	(110)	(0.21)
Core earnings attributable to Devon (Non-GAAP)	$ 686	$ 510	$ 427	$ 0.81

	Before tax	After tax	After Noncontrolling Interests	Per Diluted Share
2016				
Continuing Operations				
Loss attributable to Devon (GAAP)	$ (433)	$ (574)	$ (575)	$ (1.14)
Adjustments:				
Asset dispositions	(1,496)	(1,001)	(1,001)	(1.97)
Asset and exploration impairments	537	340	340	0.69
Rig stacking costs	10	6	6	0.01
Deferred tax asset valuation allowance	—	385	385	0.76
Restructuring and transaction costs	261	168	168	0.33
Fair value changes in financial instruments and foreign currency	248	135	135	0.26
Early retirement of debt	269	171	171	0.33
Core loss attributable to Devon (Non-GAAP)	$ (604)	$ (370)	$ (371)	$ (0.73)
Discontinued Operations				
Loss attributable to Devon (GAAP)	$ (884)	$ (884)	$ (481)	$ (0.95)
Adjustments:				
Asset impairments	893	890	467	0.91
Asset dispositions, restructuring and transaction costs and fair value changes	41	35	18	0.04
Core earnings attributable to Devon (Non-GAAP)	$ 50	$ 41	$ 4	$ 0.00
Total				
Loss attributable to Devon (GAAP)	$ (1,317)	$ (1,458)	$ (1,056)	$ (2.09)
Adjustments:				
Continuing Operations	(171)	204	204	0.41
Discontinued Operations	934	925	485	0.95
Core loss attributable to Devon (Non-GAAP)	$ (554)	$ (329)	$ (367)	$ (0.73)

EBITDAX and Field-Level Cash Margin

To assess the performance of our assets, we use EBITDAX and Field-Level Cash Margin. We compute EBITDAX as net earnings from continuing operations before income tax expense; financing costs, net; exploration expenses; depreciation, depletion and amortization; asset impairments; asset disposition gains and losses; non-cash share-based compensation; non-cash valuation changes for derivatives and financial instruments; restructuring and transaction costs; accretion on discounted liabilities; and other items not related to our normal operations. Field-Level Cash Margin is computed as oil, gas and NGL revenues less production expenses. Production expenses consist of lease operating, gathering, processing and transportation expenses, as well as production and property taxes.

We exclude financing costs from EBITDAX to assess our operating results without regard to our financing methods or capital structure. Exploration expenses and asset disposition gains and losses are excluded from EBITDAX because they are not indicators of operating efficiency for a given reporting period. DD&A and impairments are excluded from EBITDAX because capital expenditures are evaluated at the time capital costs are incurred. We exclude share-based compensation, valuation changes, restructuring and transaction costs, accretion on discounted liabilities and other items from EBITDAX because they are not considered a measure of asset operating performance.

We believe EBITDAX and Field-Level Cash Margin provide information useful in assessing our operating and financial performance across periods. EBITDAX and Field-Level Cash Margin as defined by Devon may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net earnings from continuing operations.

Below are reconciliations of net earnings from continuing operations to EBITDAX and a further reconciliation to Field-Level Cash Margin. Because we have sold upstream assets in the periods presented and have plans to dispose our Canadian and Barnett Shale businesses, which represent approximately 40% of our 2018 production volumes, we have also excluded the EBITDAX and Field-Level Cash Margin for our divested assets, Canada and the Barnett Shale to compute Adjusted EBITDAX and Adjusted Field-Level Cash Margin. We use Adjusted EBITDAX and Adjusted Field-Level Cash Margin to assess the performance of our portfolio of upstream assets on a “same-store” basis across periods.

	Year Ended December 31,		
	2018	2017	2016
Net earnings from continuing operations (GAAP)	$ 764	$ 758	$ (574)
Financing costs, net	594	317	717
Income tax expense	156	15	141
Exploration expenses	177	380	215
Depreciation, depletion and amortization	1,658	1,529	1,592
Asset impairments	156	—	437
Asset disposition gains	(263)	(217)	(1,496)
Share-based compensation	122	141	124
Derivative and financial instrument non-cash valuation changes	(614)	(214)	248
Restructuring and transaction costs	114	—	261
Accretion on discounted liabilities and other	61	29	44
EBITDAX (non-GAAP)	2,925	2,738	1,709
Marketing revenues and expenses, net	(86)	48	49
Commodity derivative cash settlements	84	(53)	11
General and administration expenses, cash-based	529	596	609
Field-level cash margin (non-GAAP)	$ 3,452	$ 3,329	$ 2,378
EBITDAX (non-GAAP)	$ 2,925	$ 2,738	$ 1,709
EBITDAX, Divested assets	(184)	(267)	(346)
EBITDAX, Canada	(593)	(748)	(491)
EBITDAX, Barnett Shale	(248)	(262)	(148)
Adjusted EBITDAX (non-GAAP)	$ 1,900	$ 1,461	$ 724
Field-level cash margin (non-GAAP)	$ 3,452	$ 3,329	$ 2,378
Field-level cash margin, divested assets	(184)	(267)	(346)
Field-level cash margin, Canada	(210)	(812)	(490)
Field-level cash margin, Barnett Shale	(248)	(262)	(148)
Adjusted field-level cash margin (non-GAAP)	$ 2,810	$ 1,988	$ 1,394

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, bitumen, 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, bitumen, 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, 2018 are presented in Note 3 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, 2018, a 10% change in the forward curves associated with our commodity derivative instruments would have changed our net asset positions by approximately $270 million.

Interest Rate Risk

At December 31, 2018, we had total debt of $5.9 billion. All of our debt is based on fixed interest rates averaging 5.4%.

As of December 31, 2018, we had one open interest rate swap position that is presented in Note 3 in “Item 8. Financial Statements and Supplementary Data” of this report. The fair value of our interest rate swap is 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, 2018.

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, 2018 balance sheet.

Devon engages in intercompany loan activity between subsidiaries with different functional currencies. The value of these foreign currency denominated intercompany loans increases or decreases from the remeasurement into the subsidiaries’ functional currency. Based on the amount of the intercompany loans as of December 31, 2018, 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, 2018 and 2017, 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, 2018, 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, 2018, 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 the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Adoption of New Accounting Standard

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for revenue from contracts with customers in 2018 due to the adoption of Accounting Standards Update 2014-09, *Revenue from Contracts with Customers (ASC 606)*.

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 20, 2019

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2018	2017	2016
Upstream revenues	$ 6,285	$ 5,307	$ 3,981
Marketing revenues	4,449	3,571	2,772
Total revenues	10,734	8,878	6,753
Production expenses	2,225	1,823	1,805
Exploration expenses	177	380	215
Marketing expenses	4,363	3,619	2,821
Depreciation, depletion and amortization	1,658	1,529	1,592
Asset impairments	156	—	437
Asset dispositions	(263)	(217)	(1,496)
General and administrative expenses	650	737	733
Financing costs, net	594	317	717
Restructuring and transaction costs	114	—	261
Other expenses	140	(83)	101
Total expenses	9,814	8,105	7,186
Earnings (loss) from continuing operations before income taxes	920	773	(433)
Income tax expense	156	15	141
Net earnings (loss) from continuing operations	764	758	(574)
Net earnings (loss) from discontinued operations, net of income tax expense	2,460	320	(884)
Net earnings (loss)	3,224	1,078	(1,458)
Net earnings (loss) attributable to noncontrolling interests	160	180	(402)
Net earnings (loss) attributable to Devon	$ 3,064	$ 898	$ (1,056)
Basic net earnings (loss) per share:			
Basic earnings (loss) from continuing operations per share	$ 1.53	$ 1.44	$ (1.14)
Basic earnings (loss) from discontinued operations per share	4.61	0.27	(0.95)
Basic net earnings (loss) per share	$ 6.14	$ 1.71	$ (2.09)
Diluted net earnings (loss) per share:			
Diluted earnings (loss) from continuing operations per share	$ 1.52	$ 1.43	$ (1.14)
Diluted earnings (loss) from discontinued operations per share	4.58	0.27	(0.95)
Diluted net earnings (loss) per share	$ 6.10	$ 1.70	$ (2.09)
Comprehensive earnings (loss):			
Net earnings (loss)	$ 3,224	$ 1,078	$ (1,458)
Other comprehensive earnings (loss), net of tax:			
Foreign currency translation	(152)	83	11
Pension and postretirement plans	44	29	22
Other comprehensive earnings (loss), net of tax	(108)	112	33
Comprehensive earnings (loss)	3,116	1,190	(1,425)
Comprehensive earnings (loss) attributable to noncontrolling interests	160	180	(402)
Comprehensive earnings (loss) attributable to Devon	$ 2,956	$ 1,010	$ (1,023)

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net earnings (loss)	$ 3,224	$ 1,078	$ (1,458)
Adjustments to reconcile net earnings to net cash from operating activities:			
Net (earnings) loss from discontinued operations, net of income tax expense	(2,460)	(320)	884
Depreciation, depletion and amortization	1,658	1,529	1,592
Asset impairments	156	—	437
Leasehold impairments	95	219	113
Accretion on discounted liabilities	61	63	75
Total (gains) losses on commodity derivatives	(608)	(157)	201
Cash settlements on commodity derivatives	(84)	53	1
Gains on asset dispositions	(263)	(217)	(1,496)
Deferred income tax expense (benefit)	226	(97)	43
Share-based compensation	161	150	203
Early retirement of debt	312	—	269
Total (gains) losses on foreign exchange	139	(132)	(121)
Settlements of intercompany foreign denominated assets/liabilities	(241)	9	63
Other	(5)	(1)	4
Changes in assets and liabilities, net	(143)	32	24
Net cash from operating activities - continuing operations	2,228	2,209	834
Cash flows from investing activities:			
Capital expenditures	(2,451)	(1,968)	(1,384)
Acquisitions of property and equipment	(55)	(46)	(849)
Divestitures of property and equipment	1,013	426	3,020
Net cash from investing activities - continuing operations	(1,493)	(1,588)	787
Cash flows from financing activities:			
Repayments of long-term debt principal	(922)	—	(2,492)
Net short-term debt repayments	—	—	(626)
Early retirement of debt	(304)	—	(265)
Issuance of common stock	—	—	1,469
Repurchases of common stock	(2,956)	—	—
Dividends paid on common stock	(149)	(127)	(221)
Shares exchanged for tax withholdings	(48)	(59)	(35)
Other	(7)	—	—
Net cash from financing activities - continuing operations	(4,386)	(186)	(2,170)
Effect of exchange rate changes on cash:			
Settlements of intercompany foreign denominated assets/liabilities	241	(9)	(63)
Other	(35)	15	2
Total effect of exchange rate changes on cash - continuing operations	206	6	(61)
Net change in cash, cash equivalents and restricted cash of continuing operations	(3,445)	441	(610)
Cash flows from discontinued operations:			
Operating activities	476	700	666
Investing activities	2,548	(611)	(1,381)
Financing activities	183	195	974
Net change in cash, cash equivalents and restricted cash of discontinued operations	3,207	284	259
Net change in cash, cash equivalents and restricted cash	(238)	725	(351)
Cash, cash equivalents and restricted cash at beginning of period	2,684	1,959	2,310
Cash, cash equivalents and restricted cash at end of period	$ 2,446	$ 2,684	$ 1,959
Reconciliation of cash, cash equivalents and restricted cash:			
Cash and cash equivalents	$ 2,414	$ 2,642	$ 1,947
Restricted cash included in other current assets	32	11	—
Cash and cash equivalents included in current assets held for sale	—	31	12
Total cash, cash equivalents and restricted cash	$ 2,446	$ 2,684	$ 1,959

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

		December 31, 2018		December 31, 2017
ASSETS				
Current assets:				
Cash and cash equivalents	$	2,414	$	2,642
Accounts receivable		885		989
Current assets held for sale		197		760
Other current assets		941		400
Total current assets		4,437		4,791
Oil and gas property and equipment, based on successful efforts accounting, net		12,813		13,318
Other property and equipment, net		1,122		1,266
Total property and equipment, net		13,935		14,584
Goodwill		841		841
Other long-term assets		353		296
Long-term assets held for sale		—		9,729
Total assets	$	19,566	$	30,241
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable	$	662	$	633
Revenues and royalties payable		898		748
Short-term debt		162		115
Current liabilities held for sale		69		991
Other current liabilities		435		828
Total current liabilities		2,226		3,315
Long-term debt		5,785		6,749
Asset retirement obligations		1,030		1,099
Other long-term liabilities		462		549
Long-term liabilities held for sale		—		3,936
Deferred income taxes		877		489
Equity:				
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 450 million and 525 million shares in 2018 and 2017, respectively		45		53
Additional paid-in capital		4,486		7,333
Retained earnings		3,650		702
Accumulated other comprehensive earnings		1,027		1,166
Treasury stock, at cost, 1.0 million shares in 2018		(22)		—
Total stockholders' equity attributable to Devon		9,186		9,254
Noncontrolling interests		—		4,850
Total equity		9,186		14,104
Total liabilities and equity	$	19,566	$	30,241

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Earnings	Treasury Stock	Noncontrolling Interests	Total Equity
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
Net earnings	—	—	—	3,064	—	—	160	3,224
Other comprehensive loss, net of tax	—	—	—	—	(108)	—	—	(108)
Restricted stock grants, net of cancellations	3	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(3,017)	—	(3,017)
Common stock retired	(79)	(8)	(2,987)	—	—	2,995	—	—
Common stock dividends	—	—	—	(149)	—	—	—	(149)
Share-based compensation	1	—	140	—	—	—	—	140
Divestment of subsidiary equity investment	—	—	—	—	2	—	(4,863)	(4,861)
Subsidiary equity transactions	—	—	—	—	—	—	72	72
Distributions to noncontrolling interests	—	—	—	—	—	—	(219)	(219)
Other	—	—	—	33	(33)	—	—	—
Balance as of December 31, 2018	450	$ 45	$ 4,486	$ 3,650	$ 1,027	$ (22)	$ —	$ 9,186

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.

As further discussed in Note 2, Devon sold its interests in EnLink and the General Partner on July 18, 2018. Activity relating to EnLink and the General Partner are classified as discontinued operations within Devon's consolidated comprehensive statements of earnings and consolidated statements of cash flows. The associated assets and liabilities of EnLink and the General Partner are presented as assets and liabilities held for sale on the consolidated balance sheets.

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.

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.

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, other property and equipment and product and equipment inventories;
- derivative financial instruments;
- the fair value of reporting units and related assessment of goodwill for impairment;
- income taxes;
- asset retirement obligations;
- obligations related to employee pension and postretirement benefits;
- legal and environmental risks and exposures; and
- general credit risk associated with receivables and other assets.

Revenue Recognition

Impact of ASC 606 Adoption

In January 2018, Devon adopted ASC 606 – Revenue from Contracts with Customers (ASC 606) using the modified retrospective method and has applied the standard to all existing contracts. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration in exchange for those goods or services.

The impact of adoption in the current period results is as follows:

	Year Ended December 31, 2018		
	Under ASC 606	Under ASC 605	Increase/ (Decrease)
Upstream revenues	$ 6,285	$ 6,031	$ 254
Marketing revenues	4,449	4,449	—
Total impacted revenues	$ 10,734	$ 10,480	$ 254
Production expenses	$ 2,225	$ 1,971	$ 254
Marketing expenses	4,363	4,363	—
Total impacted expenses	$ 6,588	$ 6,334	$ 254
Earnings from continuing operations before income taxes	$ 920	$ 920	$ —

Changes to upstream revenues and production expenses are due to the conclusion that Devon represents the principal and controls a promised product before transferring it to the ultimate third party customer in accordance with the control model in ASC 606. This is a change from previous conclusions reached for these agreements utilizing the principal versus agent indicators under ASC 605 where the assessment was focused on Devon passing title and not control to the processing entity and Devon ultimately receiving a net price from the third-party end customer. As a result, Devon has changed the presentation of revenues and expenses for these agreements. Revenues related to these agreements are now presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Gathering, processing and transportation expenses related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are now presented as production expenses.

Upstream Revenues

Upstream revenues include the sale of oil, gas and NGL production. Oil, gas and NGL sales are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. Devon's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The transaction price used to recognize revenue is a function of the contract billing terms. Revenue is invoiced, if required, by calendar month based on volumes at contractually based rates with payment typically received within 30 days of the end of the production month. 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.

Natural gas and NGL sales

Under Devon's natural gas processing contracts, natural gas is delivered to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds for the resulting sales of NGLs and residue gas. In these scenarios, Devon evaluates whether it is the principal or the agent in the transaction. Devon has concluded it is the principal under these contracts and the ultimate third party is the customer. Revenue is recognized on a gross basis, with gathering, processing and transportation fees presented as a component of production expenses in the consolidated comprehensive statements of earnings.

In certain natural gas processing agreements, Devon may elect to take residue gas and/or NGLs in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the product is delivered to the ultimate third-party purchaser at a contractually agreed-upon delivery point, and Devon receives a specified index price from the purchaser. In this scenario, revenue is recognized when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as gathering, processing and transportation expense as a component of production expenses in the consolidated comprehensive statements of earnings.

Oil sales

Devon's oil sales contracts are generally structured in one of two ways. First, production is sold at the wellhead at an agreed-upon index price, net of pricing differentials. In this scenario, revenue is recognized when control transfers to the purchaser at the wellhead at the net price received. Alternatively, production is delivered to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product. Under this arrangement, a third party is paid to transport the product and Devon receives a specified index price from the purchaser with no transportation deduction. In this scenario, revenue is recognized when control transfers to the purchaser at the delivery point based on the price received from the purchaser. The third-party costs are recorded as gathering, processing and transportation expense as a component of production expenses in the consolidated comprehensive statements of earnings.

Marketing Revenues

Marketing revenues are generated primarily as a result of Devon selling commodities purchased from third parties. Marketing revenues are recognized when performance obligations are satisfied. This occurs at the time contract specified products are sold to third parties at a contractually fixed or determinable price, delivery occurs at a specified point or performance has occurred, control has transferred and collectability of the revenue is probable. The transaction price used to recognize revenue and invoice customers is based on a contractually stated fee or on a third party published index price plus or minus a known differential. Devon typically receives payment for invoiced amounts within 30 days. Marketing revenues and expenses attributable to oil, gas and NGL purchases are reported on a gross basis when Devon takes control of the products and has risks and rewards of ownership.

Satisfaction of Performance Obligations and Revenue Recognitions

Because Devon has a right to consideration from its customers in amounts that correspond directly to the value that the customer receives from the performance completed on each contract, Devon recognizes revenue for sales at the time the natural gas, NGLs or crude oil are delivered at a fixed or determinable price.

Transaction Price Allocated to Remaining Performance Obligations

Most of Devon's contracts are short-term in nature with a contract term of one year or less. Devon applies the practical expedient in ASC 606 exempting the disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For contracts with terms greater than one year, Devon applies the practical expedient in ASC 606 exempting the disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under Devon's contracts, each unit of product typically represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract Balances

Cash received relating to future performance obligations is deferred and recognized when all revenue recognition criteria are met. Contract liabilities generated from such deferred revenue are not considered material as of December 31, 2018. Devon's product sales and marketing contracts do not give rise to contract assets.

Disaggregation of Revenue

Revenue from oil, gas and NGL sales and marketing revenues represent revenue from contracts with customers. Disaggregation of revenue disclosures can be found in Note 22.

Customers

During 2018, Devon had one purchaser that accounted for approximately 11% of Devon's consolidated sales revenue.

During 2017 and 2016, 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. 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 and costless price collars. 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. For price collars, Devon utilizes both two-way price collars and three-way price collars. The two-way 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. The three-way price collars consist of a two-way collar with an additional short put option sold by Devon, and cash-settle similarly to the two-way collars unless the market price falls below the additional short put causing the company to receive the market price plus the long put to short put price differential.

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, 2018, 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, 2018, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment. Cash settlements with counterparties on Devon's derivative financial instruments are also recorded in earnings.

By using derivative financial instruments to hedge exposures to changes in commodity prices, interest rates and foreign currency rates, Devon is exposed to credit risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom Devon believes are acceptable credit risks. It is Devon's policy to enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Additionally, Devon's derivative contracts generally require cash collateral to be posted if either its or the counterparty's credit rating falls below certain credit rating levels. As of December 31, 2018, 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

Devon grants 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 6, certain share-based awards were accelerated and recognized as a component of restructuring costs in the accompanying consolidated comprehensive statements of earnings.

Generally, Devon uses new shares from approved incentive programs to grant share-based awards and to issue shares upon stock option exercises. Shares repurchased under approved programs are 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 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, including joint interest receivables, 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. 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") 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.

Other Property and Equipment

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 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 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 a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If the qualitative assessment determines that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill, then a quantitative goodwill impairment test is performed. The quantitative goodwill 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, an impairment charge will be recognized for the amount by which the carrying amount exceeds the fair value. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid.

Devon performed impairment tests of goodwill in the fourth quarters of 2018, 2017 and 2016. No impairment was required as a result of the annual tests in these time periods.

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 2018, Devon adopted ASU 2014-09, *Revenue from Contracts with Customers (ASC 606)*, using the modified retrospective method. See revenue recognition section above for further discussion regarding Devon's adoption of this revenue recognition standard.

In January 2018, Devon adopted ASU 2017-07, *Compensation – Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. This ASU requires 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. As a result of the adoption of this ASU, consolidated statements of earnings presentation changes were applied retrospectively, while service cost component capitalization was applied prospectively. Upon adoption, Devon reclassified $7 million and $14 million of non-service cost components of net periodic benefit costs for 2017 and 2016, respectively, from G&A to other expenses.

In January 2018, Devon adopted 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. As a result of the adoption of this ASU, Devon made changes to the statement of cash flows to include the required presentation and reconciliation of cash, cash equivalents, restricted cash, and restricted cash equivalents retrospectively. Other than presentation, adoption of this ASU did not have a material impact on Devon's consolidated statements of cash flows.

In the fourth quarter of 2018, Devon early adopted ASU 2018-02, *Income Statement – Reporting Comprehensive Income – Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (Topic 220)*. This ASU allows for a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Reform Legislation. As a result of adopting this ASU, Devon reclassified $33 million from accumulated other comprehensive income to retained earnings in the December 31, 2018 consolidated balance sheet.

In the fourth quarter of 2018, Devon early adopted ASU 2018-14, *Compensation, Retirement Benefits and Defined Benefit Plans (Subtopic 715-20): Changes to the Disclosure Requirements for Defined Benefit Plans*. This ASU eliminated and added certain disclosure requirements for employers that sponsors defined benefit plans and/or other postretirement plans. Other than changes to required disclosures, this ASU did not have a material impact on Devon's consolidated financial statements and related disclosures.

The SEC released Final Rule No. 33 -10532, *Disclosure Update and Simplification*, which amends various SEC disclosure requirements determined to be redundant, duplicative, overlapping, outdated or superseded as part of the SEC's ongoing disclosure effectiveness initiative. The rule was effective November 5, 2018. The rule amended numerous SEC rules, items and forms covering a diverse group of topics. Devon has implemented these required changes to disclosures which generally reduced or eliminated disclosures. Devon will adopt the requirement of presenting a current and comparative year-to-date change in stockholder's equity roll forward during the first quarter of 2019.

Issued Accounting Standards Not Yet Adopted

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. Short-term leases can continue being accounted for off balance sheet based on a policy election. Lessor accounting does not significantly change, except for some changes made to align with new revenue recognition requirements. Devon is adopting this ASU beginning January 1, 2019.

Devon will apply the guidance using a modified retrospective transition method at the adoption date. Devon has elected the practical expedient provided in the standard that allows the new guidance to be applied prospectively to all new or modified land easements and rights-of-way. Devon also has elected a policy not to recognize right-of-use assets and lease liabilities related to short-term leases. Devon will be allowed to continue to apply the legacy guidance in Topic 840, including its disclosure requirements, in the comparative periods presented with the 2019 adoption year. Devon has implemented processes, controls, and a technology solution needed to comply with the requirements of this ASU.

To adopt Topic 842, Devon expects to recognize right-of-use assets of approximately $400 million with a corresponding lease liability based on the present value of the remaining term minimum lease payments. Devon's right-of-use assets are for certain leases related to real estate, drilling rigs and other equipment related to the exploration, development and production of oil and gas. Additionally, Devon will recognize a $24 million before tax, $19 million net of tax cumulative-effect adjustment to reduce retained earnings.

The FASB issued ASU 2018-04, *Fair Value Measurement (Topic 820): Changes to the Disclosure Requirements for Fair Value Measurement*. This ASU will eliminate, add and modify certain disclosure requirements for fair value measurement. The ASU is effective for annual and interim periods beginning January 1, 2020, with early adoption permitted for either the entire standard or only the provisions that eliminate or modify requirements. The ASU requires the additional disclosure requirements to be adopted using a retrospective approach. Devon is currently evaluating the provisions of this ASU and assessing the impact it may have on its disclosures in the notes to the consolidated financial statements.

The FASB issued ASU 2018-05-15, *Intangibles, Goodwill and Other Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract*. This ASU will require a customer in a cloud computing arrangement (i.e., hosting arrangement) that is a service contract to follow the internal-use software guidance in ASC 350-40 to determine which implementation costs to capitalize as assets or expense as incurred. Capitalized implementation costs related to a hosting arrangement that is a service contract will be amortized over the term of the hosting arrangement, beginning when the module or component of the hosting arrangement is ready for its intended use. This ASU is effective for annual and interim periods beginning January 1, 2020, with early adoption permitted. Entities have the option to adopt the ASU using either a retrospective approach or a prospective approach applied to all implementation costs incurred after the date of the adoption. Devon is currently evaluating the provisions of this ASU and assessing the impact it may have on its consolidated financial statements.

2. Acquisitions and Divestitures

Acquisitions

In January 2016, Devon acquired approximately 80,000 net acres 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.

Divestitures

EnLink and General Partner

During the third quarter of 2018, Devon completed the sale of its aggregate ownership interests in EnLink and the General Partner for $3.125 billion and recognized a gain of approximately $2.6 billion ($2.2 billion after-tax). The proceeds from the sale were utilized to increase Devon's share repurchase program to $4.0 billion, which is discussed further in Note 18. Additional information on these discontinued operations can be found in Note 19.

Upstream Assets

During 2018, Devon received proceeds of approximately $1.0 billion and recognized a net gain on asset dispositions of approximately $260 million, primarily from sales of non-core assets in the Barnett Shale and Delaware Basin. As part of the transactions, approximately $84 million of asset retirement obligations were assumed by the purchasers. In conjunction with the divestitures, Devon settled certain gas processing contracts and recognized $40 million in settlement expense, which is included in asset dispositions within the 2018 consolidated statements of earnings. In aggregate, the total estimated proved reserves associated with these divested assets were approximately 267 MMBoe, or 18%, of total U.S. proved reserves.

Additionally, in the first quarter of 2019, Devon completed two separate divestitures of non-core assets in the Permian Basin totaling $300 million. One of the divestitures related to the sale of an entire common operating field, and Devon expects to recognize a gain of approximately $35 million during the first quarter of 2019. As of December 31, 2018, these associated assets and liabilities were classified as held for sale in the accompanying consolidated balance sheet. See Note 19 for additional information. In aggregate, the total estimated proved reserves associated with these divested assets were approximately 25 MMBoe, or less than 2%, of total U.S. proved reserves.

During 2017, Devon received proceeds totaling approximately $420 million, and recognized a net gain on asset dispositions of $212 million. Estimated proved reserves associated with these assets were less than 1% of total U.S. proved reserves.

During 2016, Devon received proceeds totaling approximately $1.9 billion and recognized a net gain on asset dispositions of $809 million, primarily from sales of non-core assets in the Mississippian, east Texas, the Anadarko Basin and the Midland Basin. Estimated proved reserves associated with these assets were approximately 157 MMBoe, or 10%, of total U.S. proved reserves. As part of the transactions, approximately $290 million of asset retirement obligations were assumed by purchasers and approximately $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.

Canada and Barnett Shale (Subsequent Event)

In February 2019, Devon announced its intent to separate its Canadian business and Barnett Shale assets from the Company, based on authorizations provided by its Board of Directors subsequent to December 31, 2018. Devon will evaluate multiple methods of separation for these assets, including potential sales or spin-offs. Devon is in the early stages of marketing these assets and does not currently have any indications that it would recognize an impairment upon separating its Canadian business or its Barnett Shale assets.

Devon anticipates reporting all financial information for its Canadian business and Barnett Shale assets as discontinued operations in 2019 when all the requisite criteria are met for such financial statement presentation.

3. Derivative Financial Instruments

Commodity Derivatives

As of December 31, 2018, Devon had the following open oil derivative positions. The first two tables present Devon's oil derivatives that settle against the average of the prompt month NYMEX WTI futures price. The third 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 2019	51,719	$ 59.48	87,921	$ 54.48	$ 64.49
Q1-Q4 2020	1,740	$ 62.88	8,951	$ 52.85	$ 63.13

	Three-Way Price Collars			
Period	Volume (Bbls/d)	Weighted Average Floor Sold Price ($/Bbl)	Weighted Average Floor Purchased Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q1-Q4 2019	5,000	$ 50.00	$ 63.00	$ 74.80

	Oil Basis Swaps		
Period	Index	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q1-Q4 2019	Midland Sweet	28,000	$ (0.46)
Q1-Q4 2019	Argus LLS	17,500	$ 5.00
Q1-Q4 2019	Argus MEH	16,000	$ 2.84
Q1-Q4 2019	NYMEX Roll	38,000	$ 0.45
Q1-Q4 2019	Western Canadian Select	31,505	$ (21.73)
Q1-Q4 2020	NYMEX Roll	38,000	$ 0.31
Q1-Q4 2020	Western Canadian Select	915	$ (20.75)

As of December 31, 2018, 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 2019	266,293	$ 2.86	231,474	$ 2.69	$ 3.06
Q1-Q4 2020	26,480	$ 2.92	24,490	$ 2.74	$ 3.04

	Natural Gas Basis Swaps		
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q1-Q4 2019	Panhandle Eastern Pipe Line	84,466	$ (0.73)
Q1-Q4 2019	El Paso Natural Gas	130,000	$ (1.46)
Q1-Q4 2019	Houston Ship Channel	142,637	$ 0.01
Q1-Q4 2019	Transco Zone 4	7,397	$ (0.03)

As of December 31, 2018, 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 2019	Ethane	1,000	$ 11.55
Q1-Q4 2019	Natural Gasoline	4,500	$ 55.93
Q1-Q4 2019	Normal Butane	4,000	$ 33.69
Q1-Q4 2019	Propane	8,500	$ 30.01

Interest Rate Derivatives

As of December 31, 2018, Devon had the following open interest rate derivative positions:

Notional	Rate Received	Rate Paid	Expiration
$ 100	1.76%	Three Month LIBOR	January 2019

In January 2019, this interest rate derivative position settled.

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,		
	2018	2017	2016
Commodity derivatives:			
Upstream revenues	$ 608	$ 157	$ (201)
Marketing revenues	(1)	3	(2)
Interest rate derivatives:			
Other expenses	65	(22)	(19)
Foreign currency derivatives:			
Other expenses	—	—	(153)
Net gains (losses) recognized	$ 672	$ 138	$ (375)

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

	December 31, 2018	December 31, 2017
Commodity derivative assets:		
Other current assets	$ 637	$ 203
Other long-term assets	40	2
Interest rate derivative assets:		
Other current assets	—	1
Total derivative assets	$ 677	$ 206
Commodity derivative liabilities:		
Other current liabilities	$ 67	$ 259
Other long-term liabilities	1	27
Interest rate derivative liabilities:		
Other current liabilities	—	64
Total derivative liabilities	$ 68	$ 350

4. Share-Based Compensation

In 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 2018 and 2016 in conjunction with the reduction of workforce activities described in Note 6 and is included in restructuring and transaction costs 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,		
	2018	2017	2016
G&A	$ 122	$ 141	$ 124
Exploration expenses	4	7	6
Restructuring and transaction costs	31	—	60
Total	$ 157	$ 148	$ 190
Related income tax benefit	$ 22	$ 6	$ 6

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 12/31/17	6,328	$ 36.81	575	$ 38.92	2,758	$ 41.21
Granted	3,592	$ 35.98	—	$ —	845	$ 37.40
Vested	(3,114)	$ 38.75	(273)	$ 42.22	(571)	$ 84.22
Forfeited	(843)	$ 35.58	—	$ —	(164)	$ 33.92
Unvested at 12/31/18	5,963	$ 35.47	302	$ 35.93	2,868 (1)	$ 30.14

(1) A maximum of 5.7 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.

	2018	2017	2016
Restricted Stock Awards and Units	$ 111	$ 105	$ 73
Performance-Based Restricted Stock Awards	$ 10	$ 10	$ 5
Performance Share Units	$ 20	$ 38	$ 13

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, 2018.

	Restricted Stock Awards and Units	Performance-Based Restricted Stock Awards	Performance Share Units
Unrecognized compensation cost	$ 117	$ 1	$ 23
Weighted average period for recognition (years)	2.4	1.0	1.7

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 were 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.

	2018	2017	2016
Grant-date fair value	\$36.23 — \$37.88	\$51.05 — \$53.12	\$9.24 — \$10.61
Risk-free interest rate	2.28%	1.50%	0.94%
Volatility factor	45.8%	45.8%	37.7%
Contractual term (years)	2.89	2.89	2.83

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 2018, 2017 and 2016. 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, 2017	1,746	\$ 70.04		
Expired	(1,029)	\$ 72.51		
Outstanding at December 31, 2018	717	\$ 66.49	0.87	\$ —
Exercisable at December 31, 2018	717	\$ 66.49	0.87	\$ —

As of December 31, 2018, Devon had no unrecognized compensation cost related to unvested stock options.

5. 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,		
	2018	2017	2016
Proved oil and gas assets	$ 109	$ —	$ 435
Other assets	47	—	2
Total asset impairments	$ 156	$ —	$ 437
Unproved impairments	$ 95	$ 217	$ 77

Proved Oil and Gas and Other Asset Impairments

In 2018, Devon recognized $109 million of proved asset impairments relating to U.S. non-core assets no longer in its development plans and approximately $47 million of non-oil and gas asset impairments.

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

Unproved Impairments

In 2018, 2017 and 2016, Devon allowed certain non-core acreage to expire without plans for development resulting in unproved impairments.

6. 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, 2016	$ 48	$ 62	$ 110
Changes related to prior years' restructurings	(29)	(31)	(60)
Balance as of December 31, 2017	$ 19	$ 31	$ 50
Changes due to 2018 workforce reductions	30	—	30
Changes related to prior years' restructurings	(2)	(15)	(17)
Balance as of December 31, 2018	$ 47	$ 16	$ 63

2018 Workforce Reductions

In 2018, Devon announced workforce reductions and other initiatives designed to enhance its operational focus and cost structure. As a result, Devon recognized $114 million of restructuring expenses during 2018, primarily consisting of employee-related costs. Of these expenses, $31 million resulted from accelerated vesting of share-based grants, which are noncash charges. Additionally, $14 million resulted from estimated settlements of defined retirement benefits.

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.

Transaction Costs

In 2016, Devon recognized $11 million in transaction costs primarily associated with the closing of the STACK acquisition discussed in Note 2.

7. Other Expenses

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

	Year Ended December 31,		
	2018	2017	2016
Foreign exchange (gain) loss, net	$ 139	$ (132)	$ 39
Asset retirement obligation accretion	59	62	75
Other, net	(58)	(13)	(13)
Total	$ 140	$ (83)	$ 101

Foreign exchange (gain) loss, net

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. The amounts in the table above include both unrealized and realized foreign exchange impacts of foreign currency denominated monetary assets and liabilities, including intercompany loans between subsidiaries with different functional currencies. Unrealized gains and losses arise from the remeasurement of these foreign currency denominated monetary assets and liabilities and intercompany loans. Realized gains and losses arise when there are settlements of these foreign currency denominated monetary assets and liabilities and intercompany loans.

Foreign currency denominated intercompany loan activity during 2018 resulted in a realized loss of $241 million, as a result of the strengthening of the U.S. dollar in relation to the Canadian dollar. These losses during 2018, were partially offset by reversing $195 million of previously recognized unrealized losses on intercompany loan activity.

Foreign currency denominated intercompany loan activity during 2016 resulted in a realized gain of $63 million, as a result of the weakening of the U.S. dollar in relation to the Canadian dollar. These gains during

2016, were partially offset by reversing $10 million of previously recognized unrealized gains on intercompany loan activity.

8. Income Taxes

Income Tax Expense (Benefit)

The following table presents Devon's income tax components.

	Year Ended December 31,		
	2018	2017	2016
Current income tax expense (benefit):			
U.S. federal	$ (14)	$ 9	$ 3
Various states	(3)	—	(11)
Canada and various provinces	(53)	103	106
Total current tax expense (benefit)	(70)	112	98
Deferred income tax expense (benefit):			
U.S. federal	248	—	—
Various states	63	—	—
Canada and various provinces	(85)	(97)	43
Total deferred tax expense (benefit)	226	(97)	43
Total income tax expense	$ 156	$ 15	$ 141

Total income tax expense 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,		
	2018	2017	2016
Current income tax expense (benefit)	$ (70)	$ 112	$ 98
Deferred income tax expense (benefit)	226	(97)	43
Total income tax expense	$ 156	$ 15	$ 141
U.S. statutory income tax rate	21%	35%	35%
U.S. Tax Reform	0%	36%	0%
Legal entity restructuring	2%	(94%)	19%
State income taxes	5%	0%	10%
Change in unrecognized tax benefits	(5%)	2%	(16%)
Other	(0%)	(13%)	8%
Deferred tax asset valuation allowance	(6%)	36%	(89%)
Effective income tax rate	17%	2%	(33%)

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 judgments 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.

2018

In the second quarter of 2018, Devon’s Canadian segment utilized a portion of its capital losses as a part of an internal legal entity restructuring. A valuation allowance remains recorded against the remaining balance of the capital losses.

During 2018, Devon recorded a tax benefit of $42 million related to unrecognized tax benefits, primarily as a result of a favorable Canadian court decision and the closure of prior year IRS audits.

Throughout 2017 and through the first two quarters of 2018, Devon’s U.S. segment maintained a 100% valuation allowance against its U.S. deferred tax assets. However, upon closing the EnLink divestiture in the third quarter of 2018, Devon realized a pre-tax gain of $2.6 billion. Based on its net deferred tax liability position, current period projected net operating loss utilization, and projections of future taxable income, Devon reassessed its position and determined that its U.S. segment is no longer in a full valuation allowance position, maintaining only valuation allowances against certain deferred tax assets, including certain tax credits and state net operating losses. As part of its reassessment, Devon determined that apart from the sale of EnLink and the General Partner, Devon’s U.S. segment would have remained in a full valuation allowance position. Accordingly, the deferred tax benefit resulting from the release of the valuation allowance that was generated in the first two quarters was allocated to continuing operations, while the $259 million of the deferred tax benefit resulting from the release of the remainder of the full valuation allowance position was allocated entirely to discontinued operations. A partial valuation allowance continues to be held against certain Canadian segment deferred tax assets. During 2018, the Canadian segment reduced its valuation allowance by approximately $59 million.

2017

The Tax Reform Legislation, enacted on December 22, 2017, contained several key tax provisions that affected 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. Devon was 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. Devon’s U.S. segment recognized $167 million of deferred tax expense for the one-time mandatory transition tax on accumulated foreign earnings, and $108 million in deferred tax expense 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.

Devon maintained 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.

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.

2016

Devon recorded a tax expense of $63 million related to unrecognized tax benefits during 2016, primarily as a result of Canadian audits and legal proceedings.

During 2016, Devon's U.S. segment recognized an additional $313 million valuation allowance against its deferred tax assets. The allowance resulted 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.

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 were not deductible for purposes of calculating income tax and, therefore, impacted the effective tax rate.

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, 2018	December 31, 2017
Deferred tax assets:		
Asset retirement obligations	$ 300	$ 313
Accrued liabilities	50	62
Net operating loss carryforwards	287	796
Pension benefit obligations	44	54
Canadian capital loss carryforwards	609	760
Other	87	135
Total deferred tax assets before valuation allowance	1,377	2,120
Less: valuation allowance	(640)	(968)
Net deferred tax assets	737	1,152
Deferred tax liabilities:		
Property and equipment	(1,473)	(1,288)
Long-term debt	—	(92)
Other	(141)	(261)
Total deferred tax liabilities	(1,614)	(1,641)
Net deferred tax liability	$ (877)	$ (489)

At December 31, 2018, Devon has recognized $287 million of deferred tax assets related to various net operating loss carryforwards available to offset future income taxes. The Canadian segment has $595 million of noncapital loss carryforwards expiring between 2029 and 2038. Devon's U.S. segment has $389 million of U.S. federal net operating loss carryforwards expiring in 2037 and $784 million of U.S. state net operating loss carryforwards expiring between 2019 and 2038. In the current environment, Devon expects tax benefits from the U.S. federal, majority of U.S. state and Canadian noncapital loss carryforwards to be utilized in 2019 and beyond.

As a result of Devon's sale of its aggregate ownership interests in EnLink and the General Partner during the third quarter of 2018, Devon's U.S. segment reassessed its position and released its full valuation allowance position, maintaining only $31 million of valuation allowance against certain deferred tax assets, including certain tax credits and state net operating losses. Also during 2018, Devon's Canadian segment maintained a valuation allowance of $609 million 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.

After enactment of the Tax Reform Legislation, Devon's Canadian segment is the sole foreign operation to be considered for the indefinitely reinvested assertion of APB 23. Devon's Canadian operations are robust and active and requires continuing capital investment. Accordingly, as of December 31, 2018, no income taxes should be accrued by Devon relative to its investment in its Canadian operations. In view of Devon's decision in February 2019 to dispose of the Canadian business, the indefinitely reinvested assertion of APB 23 and any required accrual of income tax will be reevaluated in 2019.

Unrecognized Tax Benefits

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

	December 31, 2018	December 31, 2017
Balance at beginning of year	$ 115	$ 202
Tax positions taken in prior periods	(43)	(7)
Tax positions taken in current year	(2)	(3)
Accrual of interest related to tax positions taken	3	16
Settlements	—	(101)
Foreign currency translation	(3)	8
Balance at end of year	$ 70	$ 115

Devon's unrecognized tax benefit balance at December 31, 2018 and 2017 included $12 million and $28 million, respectively, of interest and penalties. If recognized, $70 million of Devon's unrecognized tax benefits as of December 31, 2018 would affect Devon's effective income tax rate. During 2018, Devon removed $43 million of unrecognized tax benefits, including $20 million of interest, as a result of the closure 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	2015-2018
Various U.S. states	2014-2018
Canada Federal	2004-2018
Various Canadian provinces	2004-2018

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 from Continuing Operations

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

	Year Ended December 31,		
	2018	2017	2016
Net earnings (loss) from continuing operations:			
Net earnings (loss) from continuing operations	$ 764	$ 758	$ (574)
Attributable to participating securities	(9)	(8)	(2)
Basic and diluted earnings (loss) from continuing operations	$ 755	$ 750	$ (576)
Common shares:			
Common shares outstanding - total	499	525	513
Attributable to participating securities	(5)	(5)	(6)
Common shares outstanding - basic	494	520	507
Dilutive effect of potential common shares issuable	3	3	—
Common shares outstanding - diluted	497	523	507
Net earnings (loss) per share from continuing operations:			
Basic	$ 1.53	$ 1.44	$ (1.14)
Diluted	$ 1.52	$ 1.43	$ (1.14)
Antidilutive options (1)	1	2	3

(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,		
	2018	2017	2016
Foreign currency translation:			
Beginning accumulated foreign currency translation	$ 1,309	$ 1,226	$ 1,215
Change in cumulative translation adjustment	(166)	113	22
Income tax benefit (expense)	14	(30)	(11)
Ending accumulated foreign currency translation	1,157	1,309	1,226
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(143)	(172)	(194)
Net actuarial loss and prior service cost arising in current year	(3)	10	(28)
Recognition of net actuarial loss and prior service cost in earnings (1)	12	19	26
Curtailment and settlement of pension benefits	47	—	24
Income tax expense	(12)	—	—
Other (2)	(33)	—	—
Ending accumulated pension and postretirement benefits	(132)	(143)	(172)
Other	2	—	—
Accumulated other comprehensive earnings, net of tax	$ 1,027	$ 1,166	$ 1,054

(1) These accumulated other comprehensive earnings components are included in the computation of net periodic benefit cost, which is a component of other expenses in the accompanying consolidated comprehensive statements of earnings. See Note 17 for additional details.

(2) As a result of Devon's early adoption of ASU 2018-02 in the fourth quarter of 2018, Devon reclassified $33 million from accumulated other comprehensive income to retained earnings in the December 31, 2018 consolidated balance sheet. See Note 1 for additional details.

11. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2018	2017	2016
Changes in assets and liabilities, net			
Accounts receivable	$ 88	$ (94)	$ (58)
Other current assets	(128)	20	326
Other long-term assets	(28)	(47)	36
Accounts payable	—	113	(196)
Revenues and royalties payable	153	106	(26)
Other current liabilities	(150)	(53)	(74)
Other long-term liabilities	(78)	(13)	16
Total	$ (143)	$ 32	$ 24
Supplementary cash flow data - total operations:			
Interest paid (net of capitalized interest)	$ 385	$ 481	$ 569
Income taxes paid (received)	$ 40	$ 78	$ (159)

In 2016, Devon's acquisition of certain STACK assets included the noncash issuance of Devon common stock. See Note 2 for additional details. 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.

12. Accounts Receivable

Components of accounts receivable include the following:

	December 31, 2018	December 31, 2017
Oil, gas and NGL sales	$ 430	$ 559
Joint interest billings	155	134
Marketing revenues	285	278
Other	23	29
Gross accounts receivable	893	1,000
Allowance for doubtful accounts	(8)	(11)
Net accounts receivable	$ 885	$ 989

13. Property, Plant and Equipment

Capitalized Costs

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

	December 31, 2018		
	U.S.	Canada	Total
Property and equipment:			
Proved	$ 40,378	$ 6,427	$ 46,805
Unproved and properties under development	833	1,434	2,267
Total oil and gas	41,211	7,861	49,072
Less accumulated DD&A	(32,229)	(4,030)	(36,259)
Oil and gas property and equipment, net	$ 8,982	$ 3,831	$ 12,813
Other property and equipment			1,832
Less accumulated DD&A			(710)
Other property and equipment, net			1,122
Property and equipment, net			$ 13,935

	December 31, 2017		
	U.S.	Canada	Total
Property and equipment:			
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
Less accumulated DD&A	(32,379)	(4,055)	(36,434)
Oil and gas property and equipment, net	$ 9,096	$ 4,222	$ 13,318
Other property and equipment			1,955
Less accumulated DD&A			(689)
Other property and equipment, net			1,266
Property and equipment, net			$ 14,584

Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs for the three years ended December 31, 2018.

	Year Ended December 31,		
	2018	2017	2016
Beginning balance	$ 313	$ 261	$ 225
Additions pending determination of proved reserves	672	504	247
Charges to exploration expense	—	—	(29)
Reclassifications to proved properties	(662)	(466)	(189)
Foreign currency translation adjustment	(19)	14	7
Ending balance	$ 304	$ 313	$ 261

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,		
	2018	2017	2016
Exploratory well costs capitalized for a period of one year or less	$ 110	$ 113	$ 88
Exploratory well costs capitalized for a period greater than one year	194	200	173
Ending balance	$ 304	$ 313	$ 261
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. Currently, Devon has not planned additional exploratory work in the near future on these assets and will continue to assess its future development timeline of these long cycle projects as it competes for capital allocation within Devon's portfolio. Devon's interest in this acreage does not begin to expire until 2025.

14. Other Current Liabilities

Components of other current liabilities include the following:

	December 31, 2018	December 31, 2017
Derivative liabilities	$ 67	$ 323
Accrued interest payable	80	96
Income taxes payable	14	144
Restructuring liabilities	47	19
Other	227	246
Other current liabilities	$ 435	$ 828

15. 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, 2018	December 31, 2017
8.25% due July 1, 2018 (1)	$ —	$ 20
2.25% due December 15, 2018	—	95
6.30% due January 15, 2019	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	485	485
7.50% due September 15, 2027 (1)	73	73
7.875% due September 30, 2031 (2) (3)	675	1,059
7.95% due April 15, 2032 (2)	366	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	(24)	(30)
Debt issuance costs	(40)	(39)
Total debt	5,947	6,864
Less amount classified as short-term debt (4)	162	115
Total long-term debt	$ 5,785	$ 6,749

(1) 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.

(2) These senior notes were included in 2018 tender offer repurchases discussed below.

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

(4) 2018 short-term debt consists of $162 million of 6.30% senior notes due January 15, 2019.

Debt maturities as of December 31, 2018, excluding debt issuance costs, premiums and discounts, are as follows:

	Total
2019	$ 162
2020	—
2021	500
2022	1,000
2023	—
Thereafter	4,349
Total	$ 6,011

Credit Lines

Under its 2012 Senior Credit Facility, Devon had $3.0 billion of available credit. On October 5, 2018, Devon terminated its 2012 Senior Credit Facility and subsequently entered into its new $3.0 billion revolving 2018 Senior Credit Facility. The 2018 Senior Credit Facility matures on October 5, 2023, with the option to extend the maturity date by two additional one-year periods subject to lender consent. Amounts borrowed under the 2018 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 2018 Senior Credit Facility currently provides for an annual facility fee of $6.1 million. As of December 31, 2018, Devon had $48 million in outstanding letters of credit under the 2018 Senior Credit Facility. There were no borrowings under the Senior Credit Facility as of December 31, 2018.

The 2018 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. For example, total capitalization is adjusted to add back noncash financial write-downs such as asset impairments. As of December 31, 2018, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 21.0%.

Commercial Paper

Devon's 2018 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, 2018, Devon had no outstanding commercial paper borrowings.

Retirement of Senior Notes

During 2018, Devon completed tender offers to repurchase $807 million in aggregate principal amount of debt using cash on hand. This included $384 million of the 7.875% senior notes due September 30, 2031 and $423 million of the 7.95% senior notes due April 15, 2032. Devon recognized a $312 million loss on early retirement of debt, consisting of $304 million in cash retirement costs and $8 million of noncash charges. These costs, along with other charges associated with retiring the debt, are included in net financing costs in the consolidated comprehensive statements of earnings. In December 2018, Devon repaid the $95 million of 2.25% senior notes at maturity. Additionally, in January 2019, Devon repaid the $162 million of 6.30% senior notes at maturity.

During 2016, Devon completed tender offers to repurchase $2.1 billion of debt securities, using proceeds from the asset divestitures discussed in Note 2. 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.

Financing Costs, Net

The following schedule includes the components of net financing costs.

	Year Ended December 31,		
	2018	2017	2016
Interest based on debt outstanding	$ 339	$ 390	$ 488
Early retirement of debt	312	—	269
Capitalized interest	(41)	(69)	(61)
Other	(16)	(4)	21
Total net financing costs	$ 594	$ 317	$ 717

16. Asset Retirement Obligations

The following table presents the changes in asset retirement obligations.

	Year Ended December 31,	
	2018	2017
Asset retirement obligations as of beginning of period	$ 1,138	$ 1,258
Liabilities incurred	39	40
Liabilities settled and divested	(116)	(68)
Revision of estimated obligation	(25)	(184)
Accretion expense on discounted obligation	59	62
Foreign currency translation adjustment	(38)	30
Asset retirement obligations as of end of period	1,057	1,138
Less current portion	27	39
Asset retirement obligations, long-term	$ 1,030	$ 1,099

During 2018, Devon reduced its asset retirement obligation by $84 million, primarily as a result of Devon's 2018 divestitures. For additional information, see Note 2.

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.

17. 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 $50 million, $53 million and $57 million to these plans in 2018, 2017 and 2016, 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; 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 $193 million and $342 million at December 31, 2018 and 2017, 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 $301 million and $401 million at December 31, 2018 and 2017, respectively.

Equity – Devon's equity securities include commingled global equity funds that invest in large, mid and small capitalization stocks across the world's developed and emerging markets and international large cap equity securities. These equity securities can be sold 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 $84 million and $157 million at December 31, 2018 and 2017, respectively.

Other – Devon's other securities include short-term investment funds and a hedge fund that invest 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 $132 million and $135 million at December 31, 2018 and 2017, respectively.

Defined Postretirement Plans

Devon also has defined benefit postretirement plans that provide benefits for substantially all qualifying U.S. retirees. 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, 2018 and 2017.

	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 1,279	$ 1,249	$ 19	$ 21
Service cost	10	15	—	—
Interest cost	39	42	—	—
Actuarial loss (gain)	(83)	59	(3)	—
Plan amendments	—	—	—	—
Plan curtailments	2	—	2	—
Plan settlements	(241)	—	—	—
Foreign exchange rate changes	(3)	2	—	—
Participant contributions	—	—	2	1
Benefits paid	(60)	(88)	(3)	(3)
Benefit obligation at end of year	943	1,279	17	19
Change in plan assets:				
Fair value of plan assets at beginning of year	1,035	985	—	—
Actual return on plan assets	(36)	122	—	—
Employer contributions	14	14	1	2
Participant contributions	—	—	2	1
Plan settlements	(241)	—	—	—
Benefits paid	(60)	(88)	(3)	(3)
Foreign exchange rate changes	(3)	2	—	—
Fair value of plan assets at end of year	709	1,035	—	—
Funded status at end of year	$ (234)	$ (244)	$ (17)	$ (19)
Amounts recognized in balance sheet:				
Other long-term assets	$ 3	$ 4	$ —	$ —
Other current liabilities	(14)	(13)	(3)	(3)
Other long-term liabilities	(223)	(235)	(14)	(16)
Net amount	$ (234)	$ (244)	$ (17)	$ (19)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 202	$ 257	$ (11)	$ (11)
Prior service cost (credit)	4	6	(2)	(3)
Total	$ 206	$ 263	$ (13)	$ (14)

During the third quarter of 2018, Devon entered into a group annuity contract, under which a third party has permanently assumed certain of Devon's defined benefit pension obligations. The purchase of this group annuity contract reduced Devon's pension assets and liabilities and is the primary component of the $241 million of plan settlements within the preceding table. In connection with the group annuity contract transaction, Devon recorded a settlement expense of approximately $33 million, which was reclassified from other comprehensive earnings to other expense on the consolidated comprehensive statements of earnings in 2018.

Certain of Devon's pension plans have a combined projected benefit obligation or accumulated benefit obligation in excess of plan assets at December 31, 2018 and December 31, 2017, as presented in the table below.

	December 31,	
	2018	2017
Projected benefit obligation	$ 922	$ 1,255
Accumulated benefit obligation	$ 906	$ 1,226
Fair value of plan assets	$ 685	$ 1,007

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

	Pension Benefits			Postretirement Benefits		
	2018	2017	2016	2018	2017	2016
Net periodic benefit cost:						
Service cost	$ 10	$ 15	$ 15	$ —	$ —	$ —
Interest cost	39	42	42	—	—	1
Expected return on plan assets	(49)	(54)	(55)	—	—	—
Recognition of net actuarial loss (gain) (1)	13	19	25	(1)	(1)	(1)
Recognition of prior service cost (1)	1	2	3	(1)	(1)	(1)
Total net periodic benefit cost (2)	14	24	30	(2)	(2)	(1)
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	4	(9)	26	(1)	(1)	—
Prior service cost arising in current year	—	—	2	—	—	—
Recognition of net actuarial gain (loss), including settlement expense, in net periodic benefit cost (3)	(60)	(19)	(43)	1	1	1
Recognition of prior service cost, including curtailment, in net periodic benefit cost (3)	(2)	(2)	(9)	1	1	1
Total other comprehensive loss (earnings)	(58)	(30)	(24)	1	1	2
Total recognized	$ (44)	$ (6)	$ 6	$ (1)	$ (1)	$ 1

(1) These net periodic benefit costs were reclassified out of other comprehensive earnings in the current period.
(2) The service cost component of net periodic benefit cost is included in G&A expense and the remaining components of net periodic benefit costs are included in other expenses in the accompanying consolidated comprehensive statements of earnings.
(3) These amounts include restructuring costs that were reclassified out of other comprehensive earnings in 2018 and 2016. See Note 6 for further discussion.

Assumptions

	Pension Benefits			Postretirement Benefits		
	2018	2017	2016	2018	2017	2016
Assumptions to determine benefit obligations:						
Discount rate	4.21%	3.59%	4.07%	4.01%	3.25%	3.46%
Rate of compensation increase	2.50%	2.50%	4.49%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate - service cost	3.98%	4.29%	4.39%	4.13%	4.22%	3.63%
Discount rate - interest cost	3.22%	2.99%	4.39%	2.67%	2.39%	3.63%
Rate of compensation increase	2.50%	4.48%	4.49%	N/A	N/A	N/A
Expected return on plan assets	5.67%	5.69%	5.20%	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 for 2017 and 2018 and the actuary's best estimate of mortality for 2016 for the population of participants in Devon's plans.

Other assumptions – For measurement of the 2018 benefit obligation for the other postretirement medical plans, a 7.1% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2019. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2029 and remain at that level thereafter.

Expected Cash Flows

Devon expects benefit plan payments to average approximately $59 million a year for the next five years and $153 million total for the five years thereafter. Of these payments to be paid in 2019, $17 million is expected to be funded from Devon's available cash, cash equivalents and other assets.

18. 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 2. 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.

Share Repurchase Program

In March 2018, Devon announced a share repurchase program to buy up to $1.0 billion of shares of common stock. In June 2018, in conjunction with the announced divestiture of its investment in EnLink and the General Partner, Devon increased its program by an additional $3.0 billion. In February 2019, Devon's Board of Directors authorized an expansion of the share repurchase program by an additional $1.0 billion, bringing the total to $5.0 billion. The share repurchase program expires December 31, 2019.

During the third quarter of 2018, Devon entered into and completed an ASR transaction to repurchase $1.0 billion of the $4.0 billion program. The table below provides information regarding purchases of Devon's common stock that were made during 2018 (shares in thousands).

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
First quarter 2018:			
Open-Market	2,561	$ 82	$ 32.19
Second quarter 2018:			
Open-Market	11,154	439	39.35
Third quarter 2018:			
Open-Market	16,492	712	43.13
ASR	24,330	1,000	41.10
Total	40,822	1,712	41.92
Fourth quarter 2018:			
Open-Market	23,612	745	31.57
Total year-to-date	78,149	$ 2,978	$ 38.11

Dividends

The table below summarizes the dividends Devon paid on its common stock.

	Amounts	Rate Per Share
Year Ended 2018:		
First quarter	$ 32	$ 0.06
Second quarter	42	$ 0.08
Third quarter	38	$ 0.08
Fourth quarter	37	$ 0.08
Total year-to-date	$ 149	
Year Ended 2017:		
First quarter	$ 32	$ 0.06
Second quarter	33	$ 0.06
Third quarter	30	$ 0.06
Fourth quarter	32	$ 0.06
Total year-to-date	$ 127	
Year Ended 2016:		
First quarter	$ 125	$ 0.24
Second quarter	33	$ 0.06
Third quarter	32	$ 0.06
Fourth quarter	31	$ 0.06
Total year-to-date	$ 221	

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. Devon increased the quarterly dividend by 33% to $0.08 per share in the second quarter of 2018. In February 2019, Devon announced a 12.5% increase to its quarterly dividend, to $0.09 per share, beginning in the second quarter of 2019.

19. Discontinued Operations and Assets Held For Sale

On June 6, 2018, Devon announced that it had entered into an agreement to sell its aggregate ownership interests in EnLink and the General Partner for $3.125 billion. Upon entering into the agreement to sell its ownership interest in June 2018, Devon concluded that the transaction was a strategic shift and met the requirements of assets held for sale and discontinued operations. As part of its assessment, Devon considered the following: 1) Devon is exiting its entire midstream business ownership; 2) EnLink and the General Partner are a separate reportable segment and are a component of Devon's business; and 3) the transaction resulted in a material reduction in total assets, debt, revenues, net earnings and operating cash flows. As a result, Devon classified the results of operations and cash flows related to EnLink and the General Partner as discontinued operations on its consolidated financial statements. Additionally, Devon ceased depreciation and amortization for all plant, property and equipment and intangible assets classified as assets held for sale on the date the sales agreement was signed.

On July 18, 2018, Devon completed the sale of its aggregate ownership interests in EnLink and the General Partner for $3.125 billion and recognized a gain of approximately $2.6 billion ($2.2 billion after-tax). Current (cash) income tax associated with the transaction was approximately $12 million. The vast majority of the tax effect relates to deferred tax expense offset by the valuation allowance adjustment explained in Note 8.

As part of the sale agreement, Devon extended its fixed-fee gathering and processing contracts with respect to the Bridgeport and Cana plants with EnLink through 2029. Although the agreements were extended to 2029, the minimum volume commitments for the Bridgeport and Cana plants expired at the end of 2018. Devon has minimum volume commitments for gathering and processing of 77-128 MMcf/d with EnLink at the Chisholm plant through early 2021.

From the period of July 19, 2018 through December 31, 2018, Devon had net outflows of approximately $380 million with EnLink, which primarily related to gathering and processing expenses. These net outflows represent gross cash amounts and not net working interest amounts.

Prior to the divestment of Devon's aggregate ownership of EnLink and the General Partner, certain activity between Devon and EnLink were eliminated in consolidation. Subsequent to the divestment, all activity related to EnLink represent third-party transactions and are no longer eliminated in consolidation.

The following table presents the amounts reported in the consolidated comprehensive statements of earnings as discontinued operations.

	Year Ended December 31,		
	2018	**2017**	**2016**
Marketing and midstream revenues	$ 3,567	$ 5,071	$ 3,551
Marketing and midstream expenses	2,912	4,111	2,712
Depreciation, depletion and amortization	244	545	504
General and administrative expenses	65	128	118
Financing costs, net	98	181	190
Asset impairments	—	17	873
Asset dispositions	(2,607)	—	13
Other expenses	(8)	(34)	25
Total expenses	704	4,948	4,435
Earnings (loss) from discontinued operations before income taxes	2,863	123	(884)
Income tax expense (benefit)	403	(197)	—
Net earnings (loss) from discontinued operations, net of income tax expense	2,460	320	(884)
Net earnings (loss) attributable to noncontrolling interests	160	180	(403)
Net earnings (loss) from discontinued operations attributable to Devon	$ 2,300	$ 140	$ (481)

The following table presents the carrying amounts of the assets and liabilities classified as held for sale on the consolidated balance sheets. The assets and liabilities classified as held for sale at December 31, 2018 are related to the divestiture of non-core upstream Permian Basin assets which closed in January 2019 as further discussed in Note 2. The assets and liabilities classified as held for sale at December 31, 2017 are related to the divestiture of EnLink and the General Partner.

	December 31, 2018	December 31, 2017
Cash and cash equivalents	$ —	$ 31
Accounts receivable	7	681
Other current assets	—	48
Oil and gas property and equipment, based on successful efforts accounting, net	190	—
Midstream and other property and equipment, net	—	6,587
Goodwill	—	1,542
Other long-term assets	—	1,600
Total assets held for sale	$ 197	$ 10,489
Accounts payable	$ 3	$ 186
Revenues and royalties payable	—	432
Other current liabilities	19	373
Long-term debt	—	3,542
Deferred income taxes	—	346
Asset retirement obligations	47	14
Other long-term liabilities	—	34
Total liabilities held for sale	$ 69	$ 4,927

20. 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 likely 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 natural gas producers and related parties, including Devon, have been named in various lawsuits alleging royalty underpayments. Devon is currently named as a defendant in a number of such lawsuits, including some lawsuits in which the plaintiffs seek to certify classes of similarly situated plaintiffs. Among the allegations typically asserted in these suits are claims that Devon used below-market prices, made improper deductions, used improper measurement techniques and entered into gas purchase and processing arrangements with affiliates that resulted in underpayment of royalties in connection with oil, natural gas and NGLs produced and sold. Devon is also involved in governmental agency proceedings and royalty 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.

Beginning in 2013, various parishes in Louisiana filed suit against more than 100 oil and gas companies, including Devon, alleging that the companies' operations and activities in certain fields violated the State and Local Coastal Resource Management Act of 1978, as amended, and caused substantial environmental contamination, subsidence and other environmental damages to land and water bodies located in the coastal zone of Louisiana. The plaintiffs seek, among other things, the payment of the costs necessary to clear, re-vegetate and otherwise restore the allegedly impacted areas. Although we cannot predict the ultimate outcome of these matters, Devon is vigorously defending against these claims.

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, 2018.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases
2019	$ 541	$ 274	$ 587	$ 64
2020	567	85	519	43
2021	140	48	373	31
2022	—	14	419	26
2023	—	8	354	25
Thereafter	—	16	3,374	311
Total	$ 1,248	$ 445	$ 5,626	$ 500

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 $11 million, $7 million and $11 million in 2018, 2017 and 2016, respectively.

21. 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, 2018 and December 31, 2017, as applicable. Therefore, such financial assets and liabilities are not presented in the following table. Additionally, the fair values of oil and gas assets and related impairments are measured as of the impairment date using Level 3 inputs. Additional information on asset impairments and the pension plan assets is provided in Note 5, and Note 17, respectively.

			Fair Value Measurements Using:	
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs
December 31, 2018 assets (liabilities):				
Cash equivalents	$ 1,505	$ 1,505	$ 1,405	$ 100
Commodity derivatives	$ 677	$ 677	$ —	$ 677
Commodity derivatives	$ (68)	$ (68)	$ —	$ (68)
Debt	$ (5,947)	$ (5,965)	$ —	$ (5,965)
December 31, 2017 assets (liabilities):				
Cash equivalents	$ 1,533	$ 1,533	$ 1,454	$ 79
Commodity derivatives	$ 205	$ 205	$ —	$ 205
Commodity derivatives	$ (286)	$ (286)	$ —	$ (286)
Interest rate derivatives	$ 1	$ 1	$ —	$ 1
Interest rate derivatives	$ (64)	$ (64)	$ —	$ (64)
Debt	$ (6,864)	$ (8,131)	$ —	$ (8,131)

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 money market investments and 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.

22. 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 23.

Devon considers EnLink, combined with the General Partner, to be a segment that is distinct from the U.S. and Canadian operating segments. EnLink's operations consist of midstream assets and operations located in the U.S. Additionally, EnLink has a management team that is primarily responsible for capital and resource allocation decisions. However, with Devon's closing of the divestment of EnLink and the General Partner in July 2018, activity related to EnLink and the General Partner have now been classified as discontinued operations within Devon's consolidated comprehensive statements of earnings and consolidated statements of cash flows, and the associated assets and liabilities of EnLink and the General Partner are presented as assets and liabilities held for sale on the consolidated balance sheets. Additional information can be found in Note 19.

	U.S.	Canada	Total
Year Ended December 31, 2018:			
Revenues from external customers [(1)]	$ 9,674	$ 1,060	$ 10,734
Depreciation, depletion and amortization	$ 1,328	$ 330	$ 1,658
Interest expense	$ 469	$ 166	$ 635
Asset impairments	$ 156	$ —	$ 156
Asset dispositions	$ (263)	$ —	$ (263)
Restructuring and transaction costs	$ 97	$ 17	$ 114
Earnings (loss) from continuing operations before income taxes	$ 1,294	$ (374)	$ 920
Income tax expense (benefit)	$ 294	$ (138)	$ 156
Net earnings (loss) from continuing operations	$ 1,000	$ (236)	$ 764
Property and equipment, net	$ 10,026	$ 3,909	$ 13,935
Total assets [(2)]	$ 14,853	$ 4,516	$ 19,369
Capital expenditures, including acquisitions	$ 2,294	$ 282	$ 2,576
Year Ended December 31, 2017:			
Revenues from external customers	$ 7,326	$ 1,552	$ 8,878
Depreciation, depletion and amortization	$ 1,149	$ 380	$ 1,529
Interest expense	$ 324	$ 12	$ 336
Asset dispositions	$ (218)	$ 1	$ (217)
Earnings from continuing operations before income taxes	$ 443	$ 330	$ 773
Income tax expense	$ 9	$ 6	$ 15
Net earnings from continuing operations	$ 434	$ 324	$ 758
Property and equipment, net	$ 10,274	$ 4,310	$ 14,584
Total assets [(3)]	$ 14,254	$ 5,498	$ 19,752
Capital expenditures, including acquisitions	$ 1,821	$ 348	$ 2,169
Year Ended December 31, 2016:			
Revenues from external customers	$ 5,722	$ 1,031	$ 6,753
Depreciation, depletion and amortization	$ 1,178	$ 414	$ 1,592
Interest expense	$ 624	$ 100	$ 724
Asset impairments	$ 435	$ 2	$ 437
Asset dispositions	$ (955)	$ (541)	$ (1,496)
Restructuring and transaction costs	$ 242	$ 19	$ 261
Earnings (loss) from continuing operations before income taxes	$ (757)	$ 324	$ (433)
Income tax expense (benefit)	$ (8)	$ 149	$ 141
Net earnings (loss) from continuing operations	$ (749)	$ 175	$ (574)
Property and equipment, net	$ 10,166	$ 4,110	$ 14,276
Total assets [(3)]	$ 13,390	$ 5,071	$ 18,461
Capital expenditures, including acquisitions	$ 2,640	$ 186	$ 2,826

(1) Revenues from oil, gas and NGL sales and marketing revenues represent revenue from contracts with customers.
(2) Total assets in the table above do not include assets held for sale related to Devon's non-core assets in the Permian Basin closed in January 2019, which totaled $197 million.
(3) Total assets in the table above do not include assets held for sale related to Devon's discontinued operations, which totaled $10.5 billion and $10.2 billion in 2017 and 2016, respectively.

The following table presents revenue from contracts with customers that are disaggregated based on the type of good.

	Year Ended December 31, 2018		
	U.S.	Canada	Total
Oil	$ 2,957	$ 814	$ 3,771
Gas	950	—	950
NGL	956	—	956
Oil, gas and NGL revenues from contracts with customers	4,863	814	5,677
Oil, gas and NGL derivatives	457	151	608
Upstream revenues	5,320	965	6,285
Oil	2,745	95	2,840
Gas	738	—	738
NGL	871	—	871
Total marketing revenues from contracts with customers	4,354	95	4,449
Total revenues	$ 9,674	$ 1,060	$ 10,734

23. 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.

Costs Incurred

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

	Year Ended December 31, 2018		
	U.S.	Canada	Total
Property acquisition costs:			
Proved properties	$ 2	$ —	$ 2
Unproved properties	71	—	71
Exploration costs	679	85	764
Development costs	1,537	249	1,786
Costs incurred	$ 2,289	$ 334	$ 2,623

	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

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 $41 million, $69 million and $61 million in 2018, 2017 and 2016, 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.

	Year Ended December 31, 2018		
	U.S.	Canada	Total
Oil, gas and NGL sales	$ 4,863	$ 814	$ 5,677
Production expenses	(1,620)	(605)	(2,225)
Exploration expenses	(129)	(48)	(177)
Depreciation, depletion and amortization	(1,234)	(325)	(1,559)
Asset dispositions	262	—	262
Asset impairments	(109)	—	(109)
Accretion of asset retirement obligations	(35)	(24)	(59)
Income tax (expense) benefit	(460)	51	(409)
Results of operations	$ 1,538	$ (137)	$ 1,401
Depreciation, depletion and amortization per Boe	$ 8.08	$ 7.63	$ 7.98

	Year Ended 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

	Year Ended December 31, 2016		
	U.S.	Canada	Total
Oil, gas and NGL sales	$ 3,198	$ 984	$ 4,182
Production expenses	(1,313)	(492)	(1,805)
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	$ 1,105	$ 35	$ 1,140
Depreciation, depletion and amortization per Boe	$ 6.11	$ 7.75	$ 6.47

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, 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
Revisions due to prices	12	1	13	10	94	(3)	91	12	40	11	51
Revisions other than price	(10)	2	(8)	2	(163)	(4)	(167)	(23)	(60)	3	(57)
Extensions and discoveries	93	5	98	7	446	—	446	64	232	11	243
Production	(47)	(7)	(54)	(35)	(397)	(4)	(401)	(39)	(153)	(42)	(195)
Sale of reserves	(7)	—	(7)	—	(1,195)	—	(1,195)	(61)	(267)	—	(267)
December 31, 2018	298	16	314	393	4,759	2	4,761	426	1,517	410	1,927
Proved developed reserves:											
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
December 31, 2018	198	16	214	187	4,331	2	4,333	359	1,278	204	1,482
Proved developed-producing reserves:											
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
December 31, 2018	189	12	201	187	4,261	2	4,263	349	1,249	199	1,448
Proved undeveloped reserves:											
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
December 31, 2018	100	—	100	206	428	—	428	67	239	206	445

(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 2018 (MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2017	201	209	410
Extensions and discoveries	107	6	113
Revisions due to prices	1	6	7
Revisions other than price	(8)	(15)	(23)
Sale of reserves	(10)	—	(10)
Conversion to proved developed reserves	(52)	—	(52)
Proved undeveloped reserves as of December 31, 2018	239	206	445

Total proved undeveloped reserves increased 9% from 2017 to 2018 with the year-end 2018 balance representing 23% of total proved reserves. Devon's focus on drilling and development activities in the STACK and Delaware Basin was the primary driver of the 113 MMBoe in extensions and discoveries. Continued development primarily in the STACK and Delaware Basin led to the conversion of 52 MMBoe, or 26%, of the 2017 U.S. proved undeveloped reserves to proved developed reserves. Costs incurred to develop and convert Devon's proved undeveloped reserves were approximately $691 million for 2018.

A significant amount of Devon's proved undeveloped reserves at the end of 2018 related to its Jackfish operations. At December 31, 2018 and 2017, Devon's Jackfish proved undeveloped reserves were 206 MMBoe and 209 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 2032. At the end of 2018, approximately 125 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 81 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 40 MMBoe in the U.S. primarily due to price increases in the trailing 12 month average for oil, gas and NGLs in 2018. Reserves increased 11 MMBoe in Canada due to a decrease in the trailing 12 month average price for bitumen in 2018. The decreased price has the effect of decreasing the applicable royalties, which increases the after-royalty volumes.

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 the royalties, which decreases the after-royalty volumes.

Reserves decreased 27 MMBoe during 2016 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 2018 primarily related to Devon's evaluation of certain oil and dry gas regions, with the largest revisions being made in the STACK.

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).

Extensions and Discoveries

2018 – Approximately 72% of the additions were through our focused efforts in the STACK (87 MMBoe) and the Delaware Basin (88 MMBoe). The remaining extensions were added throughout the remainder of Devon's portfolio.

The 2018 extensions and discoveries included 21 MMBoe related to additions from Devon's infill drilling activities, primarily relating to the STACK.

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 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 related to the STACK.

Purchase of Reserves

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

Sale of Reserves

Related to Devon's 2018, 2017 and 2016 U.S. non-core asset divestitures as discussed further in Note 2.

Standardized Measure

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

	Year Ended December 31, 2018		
	U.S.	Canada	Total
Future cash inflows	$ 40,183	$ 9,146	$ 49,329
Future costs:			
Development	(3,444)	(1,558)	(5,002)
Production	(18,107)	(5,445)	(23,552)
Future income tax expense	(2,969)	—	(2,969)
Future net cash flow	15,663	2,143	17,806
10% discount to reflect timing of cash flows	(6,897)	(717)	(7,614)
Standardized measure of discounted future net cash flows	$ 8,766	$ 1,426	$ 10,192

	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

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 2018 estimates, Devon's future realized prices were assumed to be $58.64 per Bbl of oil, $22.12 per Bbl of bitumen, $2.45 per Mcf of gas and $24.72 per Bbl of NGLs. Of the $5.0 billion of future development costs as of the end of 2018, $1.2 billion, $0.6 billion and $0.3 billion are estimated to be spent in 2019, 2020 and 2021, respectively.

Future development costs include not only development costs but also future asset retirement costs. Included as part of the $5.0 billion of future development costs are $1.4 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,		
	2018	2017	2016
Beginning balance	$ 11,337	$ 5,440	$ 7,883
Net changes in prices and production costs	(243)	5,218	(2,027)
Oil, bitumen, gas and NGL sales, net of production costs	(3,452)	(3,327)	(2,377)
Changes in estimated future development costs	(216)	789	112
Extensions and discoveries, net of future development costs	3,139	2,497	674
Purchase of reserves	—	2	224
Sales of reserves in place	(588)	(3)	(577)
Revisions of quantity estimates	(414)	(318)	(21)
Previously estimated development costs incurred during the period	962	559	663
Accretion of discount	960	1,034	537
Foreign exchange and other	(329)	(7)	72
Net change in income taxes	(964)	(547)	277
Ending balance	$ 10,192	$ 11,337	$ 5,440

24. Supplemental Quarterly Financial Information (Unaudited)

The following tables present a summary of Devon's unaudited interim results of operations.

	2018				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Total revenues	$ 2,198	$ 2,249	$ 2,579	$ 3,708	$ 10,734
Asset dispositions [(1)]	$ (12)	$ 23	$ (6)	$ (268)	$ (263)
Earnings (loss) from continuing operations before income taxes [(2)]	$ (245)	$ (481)	$ 162	$ 1,484	$ 920
Net earnings (loss) from continuing operations	$ (211)	$ (474)	$ 300	$ 1,149	$ 764
Net earnings from discontinued operations, net of income tax expense [(3)]	$ 58	$ 139	$ 2,263	$ —	$ 2,460
Net earnings (loss) attributable to Devon	$ (197)	$ (425)	$ 2,537	$ 1,149	$ 3,064
Basic net earnings (loss) per share attributable to Devon	$ (0.38)	$ (0.83)	$ 5.17	$ 2.50	$ 6.14
Diluted net earnings (loss) per share attributable to Devon	$ (0.38)	$ (0.83)	$ 5.14	$ 2.48	$ 6.10

	2017				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Total revenues	$ 2,400	$ 2,165	$ 1,933	$ 2,380	$ 8,878
Asset dispositions [(1)]	$ (8)	$ (22)	$ (170)	$ (17)	$ (217)
Earnings from continuing operations before income taxes	$ 313	$ 207	$ 207	$ 46	$ 773
Net earnings from continuing operations	$ 308	$ 212	$ 194	$ 44	$ 758
Net earnings from discontinued operations, net of income tax expense	$ 9	$ 33	$ 18	$ 260	$ 320
Net earnings attributable to Devon	$ 303	$ 219	$ 193	$ 183	$ 898
Basic net earnings per share attributable to Devon	$ 0.58	$ 0.41	$ 0.37	$ 0.35	$ 1.71
Diluted net earnings per share attributable to Devon	$ 0.58	$ 0.41	$ 0.37	$ 0.35	$ 1.70

(1) Additional discussion regarding asset dispositions can be found in Note 2.

(2) Includes asset impairments of approximately $150 million in the second quarter of 2018. Additional discussion regarding asset impairments can be found in Note 5.

(3) Includes a gain on sale associated with the divestment of Devon's aggregate ownership interests in EnLink and the General Partner of approximately $2.2 billion (after-tax) in the third quarter of 2018, as discussed in Note 19.

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

Not applicable.

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

Disclosure Controls and Procedures

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

Based on their evaluation, our principal executive and principal financial officers have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2018 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 20, 2019, management concluded that its internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 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, 2018, 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

There was no change in our internal control over financial reporting during the fourth quarter of 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

Not applicable.

PART III

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2018.

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, 2018.

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, 2018.

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, 2018.

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, 2018.

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	Purchase Agreement, dated June 7, 2018, by and among Devon Gas Services, L.P. and Southwestern Gas Pipeline, L.L.C., as sellers, and Enlink Midstream Manager, LLC, Registrant, and GIP III Stetson I, L.P. and GIP III Stetson II, L.P., as acquirors (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed June 7, 2018; 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).
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. 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).
4.5	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).
4.6	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).

Exhibit No.	Description
4.7	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).
4.8	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).
4.9	Supplemental Indenture No. 4, dated as of March 22, 2018, 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 Notes due 2032 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed March 22, 2018; 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	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).
4.12	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).
4.13	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).
4.14	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).
10.1	Credit Agreement, dated as of October 5, 2018, among Registrant, as U.S. Borrower, Devon Canada Corporation, as Canadian Borrower, Bank of America, N.A., as Administrative Agent, Swing Line Lender and an L/C Issuer, and each Lender and L/C Issuer from time to time party thereto (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K filed October 9, 2018; File No. 001-32318).
10.2	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).*
10.3	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).*
10.4	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).*

Exhibit No.	Description
10.5	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).*
10.6	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).*
10.7	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).*
10.8	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).*
10.9	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).*
10.10	Amendment 2018-1, executed August 21, 2018, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective April 15, 2014).*
10.11	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).*
10.12	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).*
10.13	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).*
10.14	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).*
10.15	Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.16	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).*
10.17	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).*
10.18	Amendment 2018-1, executed August 21, 2018, to the Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012).*
10.19	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).*

Exhibit No.	Description
10.20	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).*
10.21	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).*
10.22	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).*
10.23	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).*
10.24	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).*
10.25	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).*
10.26	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).*
10.27	Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2018) (incorporated by reference to Exhibit 10.28 to Registrant's Form 10-K filed February 21, 2018; File No. 001-32318).*
10.28	Amendment 2018-1, executed December 14, 2018, to the Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2018).*
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 10.29 to Registrant's Form 10-K filed February 20, 2015; File No. 001-32318).*
10.34	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).*

Exhibit No.	Description
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 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).*
10.36	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).*
10.37	2018 Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2017 Long-Term Incentive Plan between Registrant and executive officers for restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed on May 2, 2018; File No. 001-32318).*
10.38	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).*
10.39	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).*
10.40	2018 Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2017 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 2, 2018; File No. 001-32318).*
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	2018 Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2017 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 May 2, 2018; File No. 001-32318).*
10.44	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).*
10.45	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).*
10.46	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).*

Exhibit No.	Description
21	List of Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants, Ltd.
23.3	Consent of Deloitte LLP.
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 – the XBRL Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL 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.

* 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 20, 2019

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 20, 2019
/s/ JEFFREY L. RITENOUR Jeffrey L. Ritenour	Executive Vice President and Chief Financial Officer (Principal financial officer)	February 20, 2019
/s/ JEREMY D. HUMPHERS Jeremy D. Humphers	Senior Vice President and Chief Accounting Officer (Principal accounting officer)	February 20, 2019
/s/ JOHN RICHELS John Richels	Chairman of the Board	February 20, 2019
/s/ DUANE C. RADTKE Duane C. Radtke	Vice Chairman of the Board	February 20, 2019
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 20, 2019
/s/ JOHN E. BETHANCOURT John E. Bethancourt	Director	February 20, 2019
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 20, 2019
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 20, 2019
/s/ JOHN KRENICKI JR. John Krenicki Jr.	Director	February 20, 2019
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 20, 2019
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 20, 2019

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]